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April 6, 2022

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Mr. Patrick Wruck, Commission Secretary

Dear Mr. Wruck:

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 BCUC Information Request (IR) No. 1 on FortisBC Evidence

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

If further information is required, please contact the undersigned.

Sincerely,

on behalf of FORTISBC

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

Table of Contents **Page No.**

A. GENERAL

1.0 Reference: FAIR RETURN STANDARD
Exhibit B1-8, FBCU Evidence, pp. 1–2 and 10
Fair Return Standard - Energy Transition Risk
2013 Generic Cost of Capital (GCOC) Decision, p. 7
Application of the Fair Return Standard

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

> The Fair Return Standard is a fundamental element of the regulatory compact and is captured in section 59(5) of the UCA [*Utilities Commission Act*]. The BCUC has confirmed that the Fair Return Standard requires that a fair and reasonable overall return (including a return on and of capital) is one that meets all three of the following requirements:
>
> - is comparable to the return available from the application of the invested capital to other enterprises of like risk (comparable investment requirement);
> - enables the financial integrity of the regulated enterprise to be maintained (financial integrity requirement); and
> - permits incremental capital to be attracted to the enterprise on reasonable terms and conditions (capital attraction requirement). [Emphasis added]

In footnote 5 on page 1, FBCU cites the 2009 Cost of Capital Decision, the National Energy Board Decision RH-1-2008 in respect of Trans Quebec & Maritimes Pipeline, the 2013 GCOC Decision, and the 2016 Cost of Capital Decision.

The 2013 GCOC Decision, citing the Supreme Court of Canada decision in *Northwestern Utilities Ltd. v. Edmonton (City), [1929] S.C.R. 186, (Northwestern Utilities)* at pages 192–193 describes the Fair Return Standard (FRS) as follows:

> … By a fair return is meant that the company will be allowed as large a return on the capital invested in its enterprise, (which will be net to the company,) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise. [Emphasis added]

On page 12 of the 2013 GCOC Decision, the BCUC also stated:

> The Commission Panel confirms that the approval of rates to meet the FRS is not optional for the Commission. In other words, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital, which is consistent with the previous ROE decisions and the Regulatory Compact… [Emphasis added]

1.1 Please clarify how the three requirements under the FRS would apply to the return of capital. If there are other requirements or considerations for the return of capital, please specify.

Response:

As stated in the preamble, return of capital along with return on capital are components of the overall return that is considered in an investor's decision-making process. Considering that the expected return is not a guaranteed return, the return on capital should reflect the risk of investors not being able to fully recover their invested capital. In the Terasen Gas (TGI) 2006 Cost of Capital Decision, the BCUC found that the ability to earn a return on and of capital defines a utility's business risk:

> The Applicant and Intervenors broadly agree on the definition of risk to a benchmark low-risk utility. Investment risk comprises the sum of business risk, financial risk and regulatory risk.
>
> Business risk is the risk that the utility will not be able to earn a return on its capital or of its capital.[1]
>
> [Underlining added.]

The BCUC specifically considered TGI's ability to earn a return of its capital:

> The Commission Panel views the AAM, PBR and the RSAM as mechanisms that act to reduce the risk that TGI will not earn a return on its capital. As to earning a return of its capital, that is to say will TGI be able to recover its investment in

[1] 2006 Cost of Capital Decision (BCUC Order G-14-06), p. 17.

> property and plant in service through rates for service collected from its customers, the evidence is not as clear. …
>
> …
>
> The Commission Panel can say with certainty that TGI's business risk has not declined in the period 1994-2005. It cannot say by how much its business risk increased, but it can say that although the probability of TGI not earning a return of its capital has increased, it continues to be very low.[2]
>
> [Underlining added.]

TGI's ability to earn a return of its capital was also considered in the 2009 Cost of Capital Decision:

> As for the existing risks, the Commission Panel does not see how TGI's ability to earn a return on or of its capital has been adversely affected since 2005. …[3]
>
> …
>
> … The Commission Panel does not consider that the risks presently cast doubt over TGI's ability to earn a return on or of its capital.[4]
>
> …
>
> … 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. The scenario that now exists is described in a publication of a reputable consulting group which appears to have the attention of policymakers. [5]
>
> [Underlining added.]

The BCUC also considered these same risks in the 2013 Cost of Capital Stage 1 Decision[6] at pages 26 to 28.

The ability of the utility to earn a return of its capital was considered again in the 2016 Cost of Capital Decision:

> The Panel agrees the recent steps taken by some municipal governments, most notably the COV have the potential to affect the level of future demand and, at

[2] 2006 Cost of Capital Decision (BCUC Order G-14-06), pp. 25-26.
[3] 2009 Cost of Capital Decision (BCUC Order G-158-09), p. 36.
[4] 2009 Cost of Capital Decision (BCUC Order G-158-09), p. 37.
[5] 2009 Cost of Capital Decision (BCUC Order G-158-09), p. 37.
[6] 2013 Cost of Capital Stage 1 Decision (BCUC Order G-75-13).

> least to some extent, pose a threat to FEI's ability to earn a future return on and of its capital. ….[7]
>
> …
>
> The Panel agrees with AMPC/BCOAPO and CEC and finds the evidence is not persuasive that any change in the threat to FEI's operation caused by recent jurisprudence will have a material effect on the utility's ability to earn a return on and of its capital. … [8]
>
> …
>
> … Under the same political risk category, the Panel was not persuaded the evidence on recent jurisprudence concerning First Nations would have a material effect on FEI's ability to earn a return of on and of its capital. …[9]

As such, to the extent that the BCUC considers the business risk to ensure that the allowed return is comparable to the return available from the application of the invested capital to other enterprises of like risk (the comparable investment requirement), the ability to earn a return on and of capital is considered under the Fair Return Standard.

Further, the return of capital is a critical component of the financial integrity requirement under the Fair Return Standard since, similar to the return on capital, the return of capital enables the financial integrity of the regulated enterprise to be maintained.

As explained above, investors' expected return on capital is commensurate to the risk of investors not being able to fully recover their invested capital as well as being able to earn a return on that capital. As such, risks related to return of capital should be reflected in the BCUC's cost of capital determinations. This will permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction requirement).

Further, as explained in Concentric's evidence, the return on and of capital are further elaborated on in Supreme Court of the United States landmark decisions: *Bluefield Water Works & Improvement Company v. Public Service Commission of West Virginia* (Bluefield decision) and *Federal Power Commission v. Hope Natural Gas Company* (Hope decision). In the Bluefield decision, the court established that regulated utilities are also entitled to earn a fair and reasonable rate of return on their capital investments. The *Hope* decision further established that regulated utilities are entitled to a reasonable opportunity to earn a return of their prudently-incurred costs, including capital costs. Bonbright explains as follows:[10]

> The key words of the Bluefield decision are that the rates should be adequate to assure confidence in the financial soundness of the utility and to maintain and

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7 2016 Cost of Capital Decision (BCUC Order G-129-16), p. 22.
8 2016 Cost of Capital Decision (BCUC Order G-129-16), p. 23.
9 2016 Cost of Capital Decision (BCUC Order G-129-16), p. 44.
10 Bonbright, Principles of Public Utility Rates (1988), p. 316.

support its credit and to enable the utility to raise necessary capital. The Hope decision expanded on the principles set forth in Bluefield, stating:

> From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock . . . By that standard the return to the equity owner should be commensurate with return on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.

The Hope decision recognized the need for revenues not only to cover operating expenses but also to cover capital costs.

1.1.1 Please provide specific references in which past BCUC decisions and/or past court decisions had applied the FRS for the return of capital.

Response:

Please refer to the response to BCUC IR1 1.1.

1.1.2 Please discuss what are the differences for the review of return of capital in revenue requirements versus cost of capital proceedings.

Response:

As discussed in the response to BCUC IR1 1.1, the return of capital in the context of cost of capital proceedings is focused on the risk of investors not being able to fully recover their invested capital. In other words, the return of capital in the context of cost of capital proceedings focuses on the risk that a utility's best estimate of depreciation rates may end up different than actual recoverable depreciation (for example due to cost disallowances).

On the other hand, the review of the return of capital in revenue requirement proceedings is focused on the determination of the appropriate depreciation rate based on the expected useful life of the assets. A utility may seek changes to depreciation rates if it becomes apparent that depreciation rates do not adequately reflect current estimates of economic life.

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

[…]

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

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

Response:

The Fair Return Standard (FRS) does not require the support of energy and environmental policy objectives. Rather, as noted in the preamble, the application of the FRS ensures that utilities are financially healthy and can attract capital at reasonable rates, which in the case of FortisBC will in turn enable investment in initiatives that align its business with governments' energy and environmental policy objectives.

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

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

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

Response:

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 in a way that ensures that: (i) the overall return is comparable to the return available to similar risk utilities (comparable investment requirement), (ii) the financial integrity of the regulated utility is maintained (financial integrity

requirement), and (iii) the utility can attract incremental capital on reasonable terms and conditions (capital attraction requirement).

As explained in various sections of the FortisBC evidence, FEI believes that the Energy Transition risk is a material long-term risk to its business and a risk that is increasingly being recognized by utility analysts and investors. In addition, FEI is at the forefront of this Energy Transition meaning that it faces higher Energy Transition risk than most other gas utilities in its proxy group. As such, the Energy Transition risk affects each of the FRS requirements:

- **Comparable investment**: Since the Energy Transition favours electric utilities relative to gas utilities, FEI's risk (all else equal) is increasing relative to electric utilities in North America. Since FEI is at the forefront of the Energy Transition, its risk is higher (all else equal) relative to other natural gas utilities in North America. A risk adjusted return and equity ratio will (all else equal) be higher relative to other utilities.
- **Financial integrity**: Financial integrity refers to the maintenance and support of utility credit over the long term, and to the sufficiency of revenue for operating expenses and capital costs of the business. As discussed in the responses to BCUC IR1 6.2.1 and 8.1, Energy Transition is putting pressure on FEI's credit rating. For companies such as FEI with high debt ratios, this represents a significant risk going forward and puts an additional strain on the credit rating that should be compensated by the stronger financial metrics bolstered by higher allowed ROE and equity thickness.
- **Capital attraction:** As indicated above, the Energy Transition risk can make it harder to attract investment to the fossil-fuel related industries including the natural gas sector. In order to attract the same level of investment (all else equal), FEI needs to offer a higher return to compensate for this higher risk.

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.

In the case of FBC, an electric utility, the Energy Transition (other things equal) would directionally have a reverse impact on each of the elements of the FRS, but the benefits from an investor standpoint are muted. As explained in Appendix C, while FBC can expect to see some increase in load growth and customer growth from the electrification of the economy, it will be relatively small in comparison to the growth constraints that FEI faces due to these policies as the majority of FEI's customers are served by BC Hydro, not by FBC. In addition, the majority of anti-gas policies and initiatives by local governments are put forward by municipalities in the Lower Mainland and some municipalities in Vancouver Island where FBC does not operate. As explained in Appendix B to this FortisBC evidence, BC Hydro has access to a provincial funding backstop that it sometimes uses to recover costs, keep its rates low and minimize its borrowing costs. The same does not apply for FBC as it does not have the ability to use taxpayer funds to cover costs. As such, the positive impact of the Energy Transition risk on FBC's customer and load growth would be much more limited than the negative impact on FEI's business and is somewhat offset by the increased cost associated with the Energy Transition and loss of price competitiveness

1 due to BC Hydro's ability to socialize the cost of the Energy Transition. The FRS requires the
2 BCUC to consider these factors when determining the impact of Energy Transition on FBC's
3 overall business risk and consequently FBC's capital structure and allowed return on common
4 equity.

5

2.0 Reference: BENCHMARK UTILITY

Exhibit B1-8, FBCU Evidence, p. 51

ROE and Capital Structure Effective Date

On page 51 of Exhibit B1-8, FBCU states:

> In line with the BCUC statements above and as further explained in FortisBC's March 29, 2021 letter (Exhibit B1-2), the effective date should depend on the timing and progress of the GCOC proceeding. If the regulatory timetable set by the BCUC will result in a decision in the first quarter of the year, then having an effective date of January 1 of that year could be appropriate. This would avoid having interim rates in place for an extended period of time, improve administrative and regulatory efficiency, and may reduce customer bill impacts…
>
> Considering the BCUC established regulatory timetable in this Proceeding (Order G-288-21, dated October 6, 2021), FortisBC expects a decision on FEI's and FBC's cost of capital in this proceeding in the fourth quarter of 2022 or the first quarter of 2023. Therefore, FortisBC submits that given the above-mentioned conditions, an appropriate effective date for approved ROE and capital structure established in this Proceeding, is January 1, 2023.

2.1 Please discuss whether FBCU has any specific timeframe that would constitute an extended period of time of having interim rates due to a GCOC Proceeding (e.g. up to 3 months, 6 months, etc).

Response:

FortisBC believes that, from a customer perspective, having interim rates set for periods of three months or less is preferable. An extended period of interim rates can create volatility in customer bills because the difference between interim and permanent rates will have accumulated over a longer period of time and there will be a shorter timeframe (i.e., fewer months remaining in the year) over which to refund/recover the difference in customer bills. This can be confusing for customers to understand and can reduce customer acceptance of bill changes, which may result in increased calls to FortisBC's customer service centre and could potentially negatively impact FortisBC's customer satisfaction service quality indicator. Further, as explained in the FortisBC evidence, avoiding an extended period of interim rates can mitigate some of the regulatory risk that investors face by virtue of not knowing the return on the invested capital until the decision is issued.

2.2 Please clarify how would a January 1 effective date would reduce customer bill impacts. For instance, considering seasonality, would the customer bill impact be minimized if the effective date is in the summer (e.g., July 1st)?

Response:

FortisBC's reference to customer bill impacts in the above preamble was specifically referring to the length of time that interim rates might be in place. As FortisBC explained in the above preamble, under the assumption that a BCUC decision on FortisBC's cost of capital was issued in late 2022 or early 2023, establishing an effective date of January 1, 2023 would result in either no need for interim rates for 2023 or a short period of interim rates. Thus, the reference to a January 1, 2023 effective date reducing customer bill impacts was specific to FortisBC's assumption regarding the timing of a BCUC decision, not the month of an effective date. As explained in the response to BCUC IR1 2.1, an extended period of interim rates would result in any differences between interim and permanent rates accumulating over a longer timeframe, which would then be recovered from/refunded to customers in future bills and could result in a larger bill impact.

Further, the potential reduction of customer bill impacts cited in the preamble above is referring to the proposed approach of having the effective date depend on the timing and/or progress of the GCOC Proceeding, and January 1, 2023 would be appropriate if the decision is expected within the first quarter of the same year, as opposed to an approach of setting a fixed effective date that was used in the previous GCOC Proceeding. In the 2013 and 2014 Stage 1 and Stage 2 GCOC decisions, the effective date for both Stage 1 and Stage 2 was fixed as January 1, 2013 and did not depend on the timing and/or progress of the GCOC proceeding. Since the 2014 Stage 2 GCOC decision (Order G-47-14) was issued on March 25, 2014 and the effective date for both Stages 1 and 2 was January 1, 2013, customer bills in 2014 included the increases due to each utility's respective 2014 revenue requirement plus the difference between interim and approved earned return as a result of the GCOC Proceedings for the entire year of 2013 as well as the early months of 2014. FortisBC's proposed approach to set the effective date based on the expected timing of this GCOC decision (i.e., January 1, 2023) will avoid the need for a lengthy retroactive effective date and will, therefore, help to reduce the potential bill impact as a result of extensive variances due to a lengthy interim period.

With regard to the BCUC's reference to an effective date of July 1, FortisBC clarifies that it is strongly opposed to having an effective date that is not January 1. FortisBC sets its rates annually through the annual review process where it forecasts its revenue requirements for the upcoming year. The cost of capital proceeding will impact the earned return component of the revenue requirement, therefore, the rates (e.g., rates for 2023) will have to remain interim until the GCOC decision is issued. Having an effective date mid-year for the impact of the GCOC decision would mean that FortisBC would have to calculate the revenue requirement impact of a change in the earned return mid-year, and would have to determine how such a mid-year change would be applied to rate base. Such a calculation would be complicated and would be inconsistent with the effective date of when FortisBC's annual rates would be made permanent. FortisBC also

notes that seasonality would have no effect on the earned return calculation nor the variance between interim and permanent rates, thus seasonality is not a factor when considering the effective date. Having an effective date of January 1 is the only reasonable approach to implementing any changes flowing from the GCOC decision, as the changes can be incorporated with FortisBC's annual rate calculations.

2.3 As an alternative to interim rates, please discuss whether FBCU is amenable to having an effective date of the approved ROE and capital structure to be take effect at least 60 days of the next quarter after the BCUC renders its final decision.

Response:

As explained in the response to BCUC IR1 2.2, FortisBC's reference to an effective date of January 1, 2023 was based on an expectation that a BCUC decision would be issued in late 2022 or early 2023. Given the progress to date in this proceeding, FortisBC believes that January 1, 2023 is the appropriate effective date. FortisBC has also explained why an effective date that is not January 1 is problematic, and therefore does not recommend an approach where a different effective date is triggered by a BCUC decision date.

3.0 Reference: BENCHMARK UTILITY

Exhibit B1-8, FBCU Evidence, pp. 53 and 55; BCUC Order G-281-21, Reasons for Decision, p. 6; Exhibits B1-4 and B2-4, p. 2

Benchmark Utility Considerations

On page 6 of the BCUC's Reasons for Decision in Order G-281-21, it states:

> … as part of the Panel examination of these two utilities' cost of capital, the Panel will determine whether FEI, FBC, or both, will be designated as the Benchmark Utility or Benchmark Utilities for electric and natural gas utilities in BC, as well as whether either of them should serve the Benchmark Utility for determining the cost of capital for providers of TES and other energy sources in this Province.

On page 2 of Exhibits B1-4 and B2-4, in FEI and FBC's submissions that were considered in Order G-281-21, the FBCU states:

> The BCUC's model of using a Benchmark Utility, and then determining the regulated return of other utilities in relation to it, has worked well for the last 27 years. There were also sound reasons for the BCUC's selection of FEI as the Benchmark Utility in the first place, sound reasons for reaffirming it on multiple occasions, and sound reasons to maintain it now. Alternatively, the BCUC should limit a case-by-case review to larger utilities, while maintaining a generic approach for small utilities; FEI and FBC cannot be efficiently grouped with any other utility for cost of capital determination purposes without additional adjustments.

On page 53 of Exhibit B1-8, FBCU states that "… the choice of the Benchmark Utility is a topic that is better addressed by other utilities to whom the Benchmark Utility approach applies." And further on page 55, FBCU states:

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

3.1 Please clarify whether FBCU maintains the view that FEI should be the Benchmark Utility going forward as suggested in Exhibit B1-4 and B2-4 or FBCU is now indifferent as to whether FEI and/or FBC will be the Benchmark Utility (or Benchmark Utilities) going forward.

Response:

FortisBC's submissions in Exhibits B1-4 and B2-4 were premised on the assumption that the BCUC would choose a single Benchmark Utility. However, by Order G-281-21 dated September 24, 2021, the BCUC decided that the Benchmark Utility methodology for determination of the cost of capital for utilities in BC is appropriate and that a review of FEI's and FBC's cost of capital evidence is necessary before determining whether FEI or FBC, or both, shall serve as a Benchmark Utility.

Considering the BCUC's direction for each of FEI and FBC to file separate evidence, the BCUC can individually determine each of FEI's and FBC's appropriate allowed ROE and capital structure without reference to a Benchmark Utility. The BCUC direction also means that FBC should go through a complete regulatory review of its cost of capital evidence and as such the regulatory efficiencies and associated cost savings available to non-benchmark utilities in the Stage 2 proceeding would not be available to FBC. As it would appear to make little sense to treat FBC or FEI as a benchmark for the other when both are being fully evaluated independently, FortisBC had inferred that it is now unaffected by the choice of the Benchmark Utility.

3.2 Please discuss the pros and cons of having both FEI and FBC to be the Benchmark Utilities.

3.2.1 Please discuss the appropriateness of setting FEI as the Benchmark Utility for natural gas utilities and FBC as the Benchmark Utility for electric utilities.

Response:

FortisBC has interpreted this question as being directed at FBC and FEI being a Benchmark Utility for other utilities in the province. As discussed in FortisBC's response to BCUC IR1 3.1, since the BCUC has already directed that both FBC and FEI prepare complete evidence, it would be redundant to benchmark one against the other.

The major drawback of having two Benchmark Utilities for other utilities in the province is the increased costs and regulatory burden for both the BCUC and the affected utilities. Having two Benchmark Utilities requires additional regulatory process to determine the appropriate grouping of the utilities. For instance should thermal and district energy systems be benchmarked against FEI or FBC? Should they all be grouped in one category or is a sub-categorization according to size, ownership or fuel source is appropriate? These kinds of questions can prolong the regulatory process and increase the lag between the Stage 1 GCOC decision and the Stage 2 decision. Further, as mentioned in FortisBC's submissions (Exhibit B2-4), familiarity with and acceptance of the Benchmark Utility by other affected utilities is one of the considerations for determining a Benchmark Utility. FEI's long-history as the Benchmark Utility means that other affected utilities

are fairly familiar with its risk profile and are capable of comparing their risk with that of FEI. The same level of evidentiary history does not exist for FBC. Therefore, the affected utilities will need to familiarize themselves with FBC's operation and risk profile which may be difficult for smaller utilities.

A benefit of having both FEI and FBC as the Benchmark Utilities for other utilities in the province relates to the consideration of sector specific risks. Some of the political and policy risks associated with FEI are specific to natural gas utilities. For instance, Energy Transition risk is a significant long-term risk that is increasingly negatively affecting natural gas utilities' risk profile. Electric and thermal and district energy system utilities on the other hand are generally beneficiaries of these policies to various degrees. In previous years the BCUC used its informed judgement to account for sectoral, size and other risk variances when determining the appropriate discount or premium for non-benchmark utilities. Using FEI as the benchmark for gas utilities and FBC as the benchmark for electric utilities would reduce the judgement needed to adjust for these sectoral differences although informed judgement is still required since the same risk event may affect utilities in the same sector in different ways. Similarly, the service territory is another important differentiator. These kinds of differences will need to be considered even if the utilities are grouped based on their respective sectors.

On page 53 of Exhibit B1-8, FBCU cites its July 21, 2021 letter (Exhibit B2-4) which contained relevant factors to consider in determining a Benchmark Utility, including availability of comparable proxy group, credit ratings, size and stability of operation, resources and expertise, familiarity with and acceptance of the benchmark utility by other affected utilities, and ownership.

3.3 Please discuss if energy transition should be an additional factor to consider in determining whether FEI and/or FBC will be the Benchmark Utility. If so, how? If not, why not?

Response:

Please refer to the response to BCUC IR1 3.2.

3.4 Please discuss what evidence or information is needed by other utilities to consider the issue of "whether FEI and/or FBC shall act as the Benchmark Utility in Stage 2 GCOC Proceeding…"

Response:

As the BCUC summarized in its reasons for Order G-281-21, the majority of the participants in this proceeding support FEI remaining the Benchmark Utility in BC. However, if the BCUC intends to consider both FEI and FBC as the Benchmark, then the affected utilities will need to familiarize themselves with both utilities' operations and risk profiles.

Generally speaking, all the evidence and information needed by affected utilities to consider whether FEI or FBC shall act as their Benchmark Utility in the Stage 2 GCOC proceeding is already available in FEI's and FBC's cost of capital filing. Specifically, the affected utilities will need to review FEI's and FBC's business risk appendices (Appendix A and B). FEI's and FBC's credit rating reports can further assist affected utilities to understand utilities' financial and business risk from debt investors' perspective.

B. QUESTIONS PRIMARILY RELATED TO FEI

4.0 Reference: PROPOSED RETURN ON EQUITY (ROE)

Exhibit B1-8, FBCU Evidence, pp. 1, 3 and 13; FEI Application for Common Equity Component and Return on Equity for 2016 (FEI 2016 ROE) Application, Exhibit B-1; 2013 Generic Cost of Capital Proceeding, Exhibit B1-9; FEI Certificate of Public Convenience and Necessity for the Tilbury Liquefied Natural Gas Storage Expansion Project (FEI Tilbury CPCN) Application, Exhibit B-15, FEI Response to BCUC 63.1

Return on Equity

On page 1 of Exhibit B1-8, FBCU states that it seeks "For FEI, approval of a capital structure consisting of 45 percent common equity and 55 percent debt, and a return on common equity of 10.1 percent."

On page 3 of Exhibit B1-8, FBCU states:

> Most notably, the increasing pace of the Energy Transition from fossil fuels to cleaner sources of energy through electrification of the economy, and increased recognition of the effect of this transition on natural gas utilities by utility analysts and investors, represent what Concentric refers to as a "transformation of long-term risk environment" for natural gas utilities across North America since the time of the 2016 Proceeding. FEI, in particular, is at the forefront of this transition, with all levels of government introducing new policies in rapid succession. This is apparent in the provincial government's recently updated CleanBC Roadmap to 2030 (Roadmap) which won an award at the United Nations COP26[11] climate conference at Glasgow, Scotland and is anticipated to have a significant impact on FEI's competitive and operational landscape with implications for FEI's customer rates and throughput.

On page 13 of Exhibit B1-8, FBCU states that its overall business risk is significantly higher in comparison to the 2016 Proceeding.

In the FEI 2016 ROE Application, FEI proposed an allowed ROE of 9.5 percent. In the 2013 GCOC Proceeding Application, FEI proposed an allowed ROE of 10.5 percent.

In response to BCUC IR 63.1 in the FEI Tilbury CPCN Application, FEI states, "The TLSE Project is a key addition to the resiliency and integrity of BC's gas distribution system and strengthens the overall Provincial energy system as it decarbonizes in line with Provincial targets."

[11] The 26th UN Climate Change Conference of the Parties (COP26), retrieved from: https://ukcop26.org/.

4.1 Please discuss whether FEI agrees that energy transition risk was not an apparent factor in each of FEI's proposals for an allowed ROE of (i) 10.5 percent in the 2013 GCOC Proceeding and (ii) 9.5 percent in the 2016 GCOC Proceeding.

4.1.1 If FEI disagrees, and has presented energy transition as a risk factor in prior proposals for the cost of capital, please provide supporting evidence.

Response:

The term "Energy Transition" risk is a new umbrella term used in this proceeding to cover a broad spectrum of risk that are transforming gas utilities' risk profiles in North America. While FEI did discuss in prior proceedings some elements of what would fall under the umbrella of Energy Transition in the context of various risk categories (e.g., political, demand/market, operational), the nature and extent of the developments have fundamentally changed since 2016. The umbrella term Energy Transition appropriately reflects that these developments are now collectively of a truly transformative nature.

There has also been increased recognition of this risk by investors, equity analysts and credit rating agencies. The growing Environmental, Social and Governance (ESG) style of investing explained in the Evidence is a relatively new phenomenon that is impacting companies associated with fossil-fuels in ways that were not apparent in previous cost of capital proceedings. Indeed, the full impact of ESG investing on gas utilities' business is probably not going to be fully apparent for some time as the ESG investing criteria continue to evolve in the coming years.

Another point of difference in Energy Transition risk between the current environment and the previous proceedings relates to the magnitude and the pace of the transition. The Energy Transition is not a mere possibility anymore but rather is a reality happening in real time. The risks associated with the Energy Transition on FEI's business are increasing at a faster pace now than ever before. The pace and volume of new and more stringent anti-gas policies proposed or implemented by various levels of government since the 2016 proceeding is unprecedented. Since 2016, FEI has been faced with a barrage of continuous anti-gas regulation and policies. These range from climate emergency declarations from various municipalities followed by initiatives to curb natural gas attachments and consumption in those municipalities whether directly through bylaws, regulation and other policy tools such as carbon intensity targets for new construction or indirectly (for instance streamlining the permit process for buildings without natural gas connections) to the provincial government's CleanBC Roadmap to 2030 (CleanBC Roadmap) that will negatively impact FEI's customers' rates and throughput. Even since the filing of FortisBC's evidence on January 31, 2022, the provincial government's budget now includes new tax measures to incent customers to move away from installing new high-efficiency gas furnaces and instead adopt electric heat pumps for their space heating needs[12]. These developments indicate that the pace and magnitude of the Energy Transition risk is significantly greater than what was previously assessed in the 2013 or 2016 cost of capital proceedings. Consequently,

[12] Effective April 1, 2022, heat pumps are exempt from PST, and PST on fossil fuel combustion systems that heat or cool buildings or water is increased to 12 percent.

investors in natural gas utilities require returns to compensate for this heightened level of Energy Transition risk.

4.2 Please compare FEI's energy transition risk in the current environment to (i) 2013 and (ii) 2016.

Response:

Please refer to the response to BCUC IR1 4.1.

4.2.1 Please discuss FEI's near-term and long-term risks associated with energy transition. To what extent would energy transition risk necessitate another review of FEI's cost of capital. Please include any indicators or triggers for this review.

Response:

FEI's risks associated with the Energy Transition have been described in FEI's business risk appendix (Appendix A) and Concentric's evidence (Appendix C). Please also refer to the response to BCUC IR1 4.1. The following is a brief synopsis of the potential impacts of the Energy Transition risk over the near- and long-term.

Near-term risk:

As explained in Concentric's evidence, although Energy Transition is a risk event that will play out over a long period of time, its impact is already being felt in the short-term:

> The energy transition substantially affects nearly every aspect of FEI's business from its growth prospects, to the capital projects it pursues, to its fundamental ability to offer investors the opportunity to earn a fair return on, and of, invested capital. Even though the energy transition will play out over many decades, it is materially increasing FEI's risk profile today because of the long expected lives of most natural gas utility investments. Brattle recently noted:
>
> > The transition will affect gas companies' growth opportunities, cost recovery, and capital attraction. In the past decade, gas utility capital expenditures have grown by around double the rate of water and electric utilities' spending, largely driven by safety and reliability. Utilities will need to recover their costs from a changing – and possibly shrinking – customer

> base. With energy and environmental policy targets rapidly approaching, gas utilities need to decide today how best to invest capital in long-lived assets and avoid stranded asset risks. Heightened perceptions of business risk are increasing financing costs for gas utilities. In early 2021, gas utilities traded at a ~20% discount relative to electric utilities.

In the near-term, the plethora of policies and regulations put forward and implemented by various levels of government to discourage the consumption of natural gas and promote electricity consumption as well as FEI's initiatives to increase the share of more costly Renewable Gas in its supply portfolio in response to governments' mandates and policies will decrease FEI's price competitiveness and reduce consumers' energy affordability. The government policy to promote electric heat pumps at the expense of high-efficiency gas furnaces will also challenge FEI to attract new customers or retain existing ones leading to lower net customer additions than otherwise possible. FEI will continue to see a gradual change in its business profile from residential load to more volatile and economically sensitive low carbon transportation (LCT) and industrial load. Further, as explained in both FEI's business risk Appendix and Concentric's evidence, Energy Transition risk is also impacting FEI's operations.

Long-term risk:

The long-term risks of the Energy Transition will depend on the role of natural gas, and Renewable Gas, within the province's future energy landscape. While FEI believes that gas infrastructure is an optimal tool to reach decarbonization goals, there is a lack of awareness and acceptance of that role. The potential adoption of an all-electric scenario by policymakers will inevitably lead to the loss of throughput and customers particularly in FEI's more densely populated service areas such as the Lower Mainland. The snowball effect of this scenario would lead to potential underutilized assets. Concentric explains:

> The energy transition creates stranded asset risk for FEI by introducing the possibility that significant portions of FEI's assets will cease being used and useful before being fully depreciated. The potential for stranded assets was not a material concern for FEI in the 2016 cost of capital proceeding. As S&P [Standard & Poor's Global Ratings] notes, "[s]tranded costs have not up until now been an issue for gas local distribution companies." S&P observes, however, that concerns about stranded assets have spiked recently:
>
> > While new pipelines have faced fierce opposition from environmental activists and local communities since the initial shale gas development boom and the pace of new projects has declined in recent years, the specter of stranded assets did not really emerge for existing gas pipelines and the gas LDCs until recently when the zero-carbon movement picked up steam.

> S&P concludes that "[c]hallenges with respect to addressing stranded costs arising from the latest energy transition are likely to continue and intensify in 2021 and beyond."

ESG investing will continue to impact gas utilities' valuations and access to capital at reasonable terms and conditions may become more difficult. Concentric explains:

> Investor ESG concerns are already affecting capital markets, as illustrated by S&P's analysis of the financing costs of North American oil and gas companies relative to their environmental impact ... S&P concluded that it saw "evidence that issuers with lower carbon intensity were able to issue longer-dated debt at lower financing costs than their more carbon-intense peers".

As explained in FortisBC's evidence, in recent years, most of Canada's leading banks established Sustainable Finance groups within their organizations and announced ESG-related mandates and they are increasingly restricting financing to fossil-fuel related projects. The more restrictive financing by major banks and other financial institutions will discourage investments in oil and gas exploration and production which can cause higher commodity prices in the long-run for FEI's customers. For instance, since the filing of FortisBC's evidence, BMO, one of the biggest lenders to the oil and gas sector in Canada, announced its plans to cut emissions from energy loans in a net-zero push:

> Canada's fourth-largest bank said its new target is a 33 per cent cut in scope 1 and 2 emissions from oil and gas borrowers, which refers to the emissions produced by the companies themselves and their suppliers. The reduction is compared to 2019 levels. The Toronto-based bank is also aiming for 24 per cent cut by 2030 in scope 3 emissions -- those produced from the burning of the fuels that oil and gas companies produce[13].

As stated in FortisBC's evidence, all of this is a testament to the urgency and significant mobilization of capital in the financial sector and the investor community away from traditional fossil fuel based investments. It also suggests that FEI, as a contributor to BC's GHG emissions, may face increasing difficulties in attracting capital from institutional investors. Finally, it underscores how, in recent years, climate-related risk has become a significant financial risk for FEI.

With regard to triggers for the future review of FEI's cost of capital and, as explained in its evidence, FEI does not propose any triggers for future applications. This includes any particular trigger for the evolving Energy Transition risk. Rather, as Concentric stated in its evidence, 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 FEI.

[13] https://www.bnnbloomberg.ca/bmo-aims-to-cut-emissions-from-energy-loans-in-net-zero-push-1.1733861.

4.3 Please explain whether it would be appropriate to compare FEI's current proposed allowed ROE of 10.1 percent to FEI's past proposed allowed ROE in the 2013 GCOC Proceeding and the 2016 FEI Application given that FBCU's evidence has compared its business risks to past proceedings.

Response:

As discussed below, the comparison of business risk and market conditions over time is consistent with past practice, whereas comparing proposed ROEs in isolation is not. FEI believes that using a simple comparison of past proposed ROEs to draw conclusions about the appropriate ROE now would be misleading and should be avoided.

As indicated in the excerpt below from the BCUC's decision in the 2013 GCOC Stage 1 Decision, the issue of an appropriate reference point against which evidence in the current proceeding can be assessed has been discussed in the previous proceeding:

> An important issue arising within the 2012 GCOC proceeding is whether a previous cost of capital decision is an appropriate reference point against which evidence in the current proceeding can be compared. Specifically, the questions facing the Commission Panel are: (1) whether a reference point is required, and (2) in the event it is, what reference point would be most appropriate and to what extent should it be relied upon in the Commission Panel's decision - making process. Within this proceeding, the primary comparative reference point has been the 2009 Decision, which has been relied on to illustrate changes in capital markets as well as changes in short and long-term risk since that time.

The BCUC's past practice has been to compare the current evidence on capital market conditions and risk analysis with what was assessed in the previous decision and not with what was proposed in the utility's applications:

> The Commission Panel does accept that the period leading up to the 2009 Decision is a reasonable point of comparison with respect to changes in long-term risk as this is the most recent proceeding and notes that this has been used extensively by the parties. However, the Panel remains open to looking back further to the 2006 Decision where appropriate. In the view of the Panel, a determination on the degree of change in long-term risk is a much more discrete process. It is dependent upon an assessment of the level of risk, which exists in the current circumstances as compared to those which existed at a previous point in time. Therefore, we consider the periods prior to both the 2009 Decision and the 2006 Decision as appropriate reference points in assessing the level of long-term risk faced by FEI.

FEI believes that the BCUC's past practice in previous proceedings to compare the evidence in this proceeding regarding the changes in risks and capital market conditions with the BCUC's assessment in the previous decision continues to be appropriate.

FEI does not believe that comparing proposed allowed ROEs in various cost of capital proceedings would be appropriate for the following reasons:

- ROE is not simply a function of business risk, and thus ROE proposals cannot be used in isolation to draw inferences about relative business risk over time. The practice in BC has been to reflect changes in business risk primarily in the capital structure.
- Proposed ROEs are dependent on general market conditions including but not limited to companies in the proxy group and their relative risk to the utility, risk-free rate, systematic risk (adjusted beta values), equity risk premiums, analysts' earnings growth forecasts, and GDP growth forecasts. As these inputs change, the models produce higher and/or lower results. As such, even if the proposed ROEs in all years are calculated by the same expert, the changes in proposed ROEs in various years cannot be exactly associated to one or two factors nor do they necessarily represent directional changes in a utility's relative or absolute risk profile. Concentric's evidence (Appendix C) already includes some discussions around how the individual inputs to its CAPM and DCF model have changed compared to its evidence in the previous proceeding.
- Cost of capital experts use various financial models, with alternative inputs and model specifications, to determine an appropriate ROE. The assumptions and models used by each expert may be different leading to different results. Mr. Coyne of Concentric has been retained by FEI for both 2016 and current proceedings; however, Mr. Coyne was not involved in calculating FEI's return on equity in 2013 and as such cannot comment on the differences between proposed ROEs in 2016 and the current proceeding and those in the 2013 proceeding without performing a detailed analysis of experts' evidence in those proceedings; a practice that would be both time-consuming and costly.

Ultimately, the BCUC has already made its determinations about the past ROEs and capital structure based on its own assessment of the past proposals and evidence. FortisBC's approach in this proceeding has been to recognize that those findings and orders cannot be revisited now. As such, a more informative starting point for comparison is the BCUC's determinations regarding market conditions and risk that underpinned its decisions.

4.4 Please confirm, or explain otherwise, that FEI's projects, such as the TLSE Project are in line with provincial decarbonization targets.

Response:

Confirmed. The system as a whole, supported by major projects like TLSE, can play a major role in achieving decarbonization targets. Please also refer to the responses to BCUC IR1 9.4 and BCUC IR1 18.4.

4.4.1 If FEI can meet Provincial decarbonization targets, please discuss how this will impact FEI's competitive and operational landscape and the implications for FEI's customer rates and throughput. Please include a short-term vs. long-term assessment.

Response:

FEI has conducted preliminary analysis of compliance pathways to achieve the GHG emissions cap of a 47 percent reduction by 2030 in the CleanBC Roadmap and in 2018 conducted high-level modeling in the Pathways to 2050 report (Pathways report) to understand pathways for the province to achieve its 2030 and 2050 GHG emissions targets. The response to this IR will draw from the understanding developed through these two initiatives.

Analysis of future scenarios is subject to considerable uncertainty due to the unknown details of the Greenhouse Gas Reduction Standard (GHGRS) that still need to be developed by the Province. Furthermore, a pathway that sees concerted progress toward decarbonization will be a highly dynamic environment that will be subject to constant change and optimization. Discussion on the impacts of decarbonization to FEI is therefore subject to important parameters such as the political and policy environment, market conditions, technological innovation, and long-term drivers like economic and population growth.

FEI's analysis indicates that a diversified approach that leverages both gas and electric systems provides the best path to meet these objectives. Costs are minimized in a diversified approach which optimizes both the gas and electric system by avoiding the need for a more extensive build out of the electric system, while fully using the 50,000 kilometers of BC's gas delivery infrastructure. Compared to electrification, a diversified approach could require $22 billion less investment by 2030, and nearly $100 billion less by 2050. These cost reductions translate to greater energy affordability for British Columbians in the form of lower energy rates. A diversified approach can lead to a more favourable competitive and operational system for FEI.

However, the diversified approach needs greater awareness and acceptability before it can be implemented. A key risk, in the short term, is whether FEI's potential to reduce emissions will be recognized and enabled with policies and other supporting measures to achieve the provincial decarbonization targets. As discussed in the response to BCOAPO IR1 5.1, there is considerable uncertainty over what role the gas system will play in the province's decarbonization pathway and whether the above actions will be incorporated within the provincial policy framework that will be

developed to enable these strategies. As discussed, FEI believes that decarbonization solutions that continue to use the gas system represent a cost-effective strategy for BC. However, there has not been a statement or clear direction given by the provincial government on the role of the gas system. The province may not fully recognize the decarbonization potential of the gas system which would have clear negative consequences on whether FEI could meet the provincial decarbonization targets.

Should FEI be recognized and enabled to undertake actions that align with the province's decarbonization targets then it could employ essentially four main actions:

1. Significantly increasing the share of renewable and low-carbon fuel being delivered by FEI.
2. Significantly increasing the rate of energy efficiency improvement for all of FEI's customers which will require stepped-up DSM program spending and other tools such as increased deployment of alternate energy services.
3. Pursuing negative emissions strategies such as carbon capture utilization and storage for large end-users and in the upstream gas sector, and carbon offsets or nature based carbon sequestration solutions such as reforestation of disturbed lands.
4. Increasing energy delivered to sectors not primarily serviced by FEI notably for medium and heavy-duty vehicles and marine vessels.

The first three actions to align with the province's decarbonization targets will increase costs of delivering energy that will need to be recovered. This will increase the risk to FEI that its competitive position in the market will be threatened notably in the shorter-term as gas rates rise relative to electricity. Over the long-term, FEI believes, based on analysis from the Pathways to 2050 report, that upward rate pressure will be applied to both gas and electricity in BC. Gas rates will respond to increasing shares of higher-cost renewable and low-carbon gas, and electricity rates will increase due to new infrastructure requirements as the overall share of electricity consumption increases. Depending on assumptions of electricity demand growth and new infrastructure requirements, electricity and gas rate growth may increase at similar rates in the later years.

Operationally, FEI will also be subject to considerably higher risks as it delivers a significant share of renewable and low-carbon gases which will have substantive impacts to how FEI manages its system. FEI will also need to expedite the deployment and potentially rely on new technologies and practices like gas pyrolysis, hydrogen production, new thermal energy systems, building retrofits which all bring new operational practices and considerations that will increase risk as FEI adjusts.

4.4.1.1 Please discuss the same if FEI cannot meet Provincial decarbonization targets. Please include a short-term vs. long-term assessment.

Response:

FEI has solutions to help meet provincial decarbonization targets; however, they will need to be enabled through supportive policies, legislation and a regulatory framework as well as technological advances that will allow it to deploy these solutions.

If FEI were unable to meet the provincial decarbonization targets that would suggest that policy, legislation and regulatory frameworks did not allow FEI to employ its strategies and make the necessary investments in decarbonization. In this case, FEI's ability to align with the Energy Transition would be threatened. The full impacts of this are unknown, but the inability to invest in decarbonization would lead to a declining customer base, lower system throughput and lower utilization of assets, all of which would have a negative impact on customer rates and competitiveness.

5.0 Reference: PROPOSED CAPITAL STRUCTURE

Exhibit B1-8, FBCU Evidence, pp. 26 and 49; Exhibit B1-8-1, Appendix D-1, FEI – 2020 FS, p. 5; Exhibit A2-12, Government of Canada Federal Budget 2021, Annex 6, Tax Measures – Supplementary Information, International Tax Measures, Interest Deductibility Limits [14]

Capital Structure – Interest Deductibility

On page 26 of Exhibit B1-8, FBCU states:

> Another factor that is contributing to financial risk for the FortisBC utilities is proposed restrictions on interest deductibility, a risk that did not exist at the time of the 2013 and 2016 Proceedings.

On page 49 of Exhibit B1-8, FBCU states:

> In order to facilitate the transition to the new rule, the government proposes a phased approach whereby interest deductibility would be limited to a fixed ratio of 40 percent for taxation years beginning on or after January 1, 2023 and 30 percent for taxation years beginning on or after January 1, 2024.
>
> […]
>
> It is unknown at this time the exact form these rules will take when drafted and passed and to what extent the FortisBC utilities may be impacted.

The Government of Canada Federal Budget 2021 states:

> Interest expense and interest income related to debts owing between Canadian members of a corporate group would generally be excluded. This is intended to ensure, among other things, that the new rule does not impact on corporate transactions that are undertaken within Canadian corporate groups to allow the losses of one group member to be offset against the income of another group member.

On page 5 of FEI's 2020 financial statements in Appendix D-1, FEI shows its consolidated statements of earnings, which has been reproduced in part below:

[14] Retrieved on February 28, 20209 from: https://www.budget.gc.ca/2021/report-rapport/anx6-en.html#interest-deductibility-limits.

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

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

5.1 Please confirm, or explain otherwise, that the Government of Canada Federal Budget announcement regarding restrictions on interest deductibility apply to corporations in all industries in Canada, and not specific to utilities only.

Response:

Confirmed. The restriction on interest deductibility applies to corporations in all industries in Canada.

This is of particular concern for utilities because, as discussed in FortisBC's evidence, if the proposed rules are passed, utilities may be significantly impacted due to their capital intensive nature and the amount of debt financing in their capital structures. Under the rules as proposed, in any given year, utilities with a relatively high regulated debt component may be limited in the amount of interest expense that they can deduct for tax purposes, which would result in an increase in income tax expense and therefore higher costs for ratepayers. In that case, a portion of interest expense incurred would not be allowed the benefit of deductibility for tax purposes, making the regulated capital structure less efficient. The level of debt in FEI and FBC's capital structures makes this risk higher than for companies with higher equity thicknesses. If the proposed tax changes are passed into law, the proposed changes in the allowed ROE for FEI and FBC and the allowed equity thickness in FEI's capital structure would help to reduce the amount of additional income tax expense that customers may otherwise incur as a result of this tax change.

5.2 Please state the percentage of debt FEI holds with Canadian entities and with non-Canadian entities.

Response:

All of the debt issued by FEI is initially issued to Canadian investors and, to the best of its knowledge, all debt issued by FEI continues to be held by Canadian investors.

5.3 Please discuss how the proposed interest deductibility limit outlined in the Government of Canada Federal Budget 2021 as it relates to debts owing to non-Canadian entities of a fixed ratio of 40 percent and a fixed ratio of 30 percent would impact FEI's interest, income tax, and ROE. Please use FEI's 2020 audited financials as the basis for comparison and present in a similar format as suggested below:

	2020	Illustrative 2020 with Interest Deductibility Limit of 40% Fixed Ratio	Illustrative 2020 Interest Deductibility Limit of 30% Fixed Ratio
Interest			
Tax			
ROE			

Response:

The requested information for FEI is provided in the table below:

(in millions)	Illustrative 2020 with Interest Deductibility Limit of 40% Fixed Ratios	Illustrative 2020 Interest Deductibility Limit of 30% Fixed Ratio
Restricted Interest Expense	29	57
Incremental Tax Cost	8	15
Impact on ROE	0	0

Using 2020 as the illustrative year, a significant portion of interest expense would be considered restricted interest and financing expense and would not be deductible. There would be no impact to ROE, as the incremental tax cost would be considered an uncontrolled tax variance captured by the flow-through deferral account. These complex rules would also increase the administrative burden that FEI would experience and may indirectly add an additional layer of costs on current and future capital projects. All of this would lead to higher rates for ratepayers and a less efficient capital structure.

FEI notes the assessment illustrated above assumes FEI on a standalone basis, consistent with the BCUC's established approach in cost of capital proceedings. However, even if the group ratio rules are considered, it is unlikely the group ratio rules would provide relief. FortisBC is part of a multinational group that has the majority of its assets in the United States. The United States utilities are typically financed with a higher common equity ratio and earn a higher ROE. Therefore, the group ratio will likely be less than the specified thresholds in the limitation of interest deductibility rules.

6.0 Reference: PROPOSED CAPITAL STRUCTURE

Exhibit B1-8, FBCU Evidence, pp. 34 and 37

Capital Structure – Credit Ratings Outlook

On page 34 of Exhibit B1-8, FBCU states:

> While FEI's credit rating outlook returned to stable in June 2014, this signals that FEI's credit ratings are not secure.

6.1 Please provide the definitions of the different credit rating outlooks from Moody's and DBRS (i.e., stable outlook, positive outlook, and negative outlook).

Response:

According to Moody's Rating Symbols and Definitions document dated November 2, 2021[15], Moody's rating outlook is an opinion regarding the likely rating direction over the medium term. Rating outlooks fall into four categories: Positive (POS), Negative (NEG), Stable (STA), and Developing (DEV).

- A stable outlook indicates a low likelihood of a rating change over the medium term.
- A negative, positive or developing outlook indicates a higher likelihood of a rating change over the medium term.
- A developing outlook is assigned when the direction of a credit rating cannot be assessed after a given event or change in a company's circumstances, and additional information may be necessary to fully evaluate their impact on credit rating.

A rating committee that assigns an outlook of stable, negative, positive, or developing to an issuer's rating is also indicating its belief as to whether the issuer's credit profile is consistent with the relevant rating level at that point in time.

According to DBRS Morningstar Rating Actions, Commentaries and Press Releases Global Policy document dated April 1, 2021[16], DBRS Morningstar uses three categories of rating trends: "Positive", "Stable" or "Negative". The Rating Trend indicates the direction in which DBRS Morningstar considers the rating may move if present circumstances continue. It is often the Rating Trend that reflects the initial pressures or benefits of a changing environment rather than an immediate change in the rating. A Positive or Negative Trend is not an indication that a rating change is imminent. Rather, a Positive or Negative Trend represents an indication that there is a greater likelihood that the rating could change in the future than is the case if a Stable Trend was assigned to the security. Generally, the conditions that lead to the assignment of a Negative or Positive Trend are resolved within a twelve month period. However, in some instances, new factors emerge which may cause the Positive or Negative Trend to be maintained, even as the

[15] https://www.moodys.com/researchdocumentcontentpage.aspx?docid=PBC_79004.

[16] https://www.dbrsmorningstar.com/research/282423/rating-actions-commentaries-and-press-releases-global-policy.

original factors become clarified or resolved. DBRS Morningstar generally notes any changes to the basis for the Positive or Negative Trend.

6.1.1 Please provide FBCU's definition of "secure" and discuss the thresholds or measures (e.g., a particular credit rating, credit rating outlook, etc.) that would constitute FEI's credit ratings as "secure."

Response:

For clarity, the phrase "not secure" was FEI's characterization of the information in the credit rating reports and is not used in the reports themselves. FEI was using "secure" in the sense of the Oxford dictionary definition "that cannot be affected or harmed by something". For the reasons explained in the response to BCUC IR1 6.2.1, FEI believes the characterization of the rating reports is accurate FortisBC would generally consider the credit rating as "secure" if there was a significantly greater layer of financial metric protection than FEI currently has in a way that its credit rating is unlikely to be negatively affected by, for instance, a relatively modest deterioration in credit metrics. As a minimum, this would require an indication that the financial metrics listed in Table 6-4 meet the levels required for an A level rating. As noted above, with the exception of the Debt to Capitalization ratio, all financial metrics were consistent with a Baa/BBB rating. This does not provide FEI room to absorb unusual or unexpected negative events without dropping below downgrade thresholds for key financial metrics.

6.2 Please confirm if there have been any credit rating outlook changes for FEI from Moody's or DBRS since June 2014.

Response:

There have been no credit rating outlook changes for FEI from Moody's or DBRS since June 2014.

6.2.1 If there have been no changes, please discuss why FBCU finds that "FEI's credit ratings are not secure."

Response:

As discussed in the Evidence, according to Moody's published guide on utility credit rating methodology, financial metrics contribute to almost half (40 percent) of the overall credit rating. Table 6-4 included in the Evidence and reproduced below shows Moody's four key financial metrics and the relative position of these metrics compared to Moody's guidelines for an A-rated entity. As shown in the table, with the exception of Debt to Capitalization ratio, all financial metrics are consistent with Baa/BBB rating. This shows that FEI's ability to maintain an A level rating is marginal.

Table 6-4: FEI's Key Financial Indicator Scores Compared to Minimum A3 Rating per Moody's Utility Rating Methodology

	FEI's Score	A - Rating Threshold[54]	2018	2019	2020	LTM Sept 2021
CFO pre-WC + Interest / Interest	Baa	4.5x-6.0x	2.5x	3.0x	2.9x	3.6x
CFO pre-WC / Debt	Baa	19.0% - 27.0%	13.6%	13.6%	11.3%	12.7%
CFO pre-WC - Dividends / Debt	Baa	15.0% - 23.0%	8.8%	8.7%	6.6%	7.9%
Debt / Capitalization[55,56]	A	40.0% - 50.0%	47.8%	47.5%	48.8%	47.9%

Source: Moody's Credit Rating Report for FEI, dated November 25, 2021.

In addition, in its latest Credit Rating Report published in November 2021, Moody's stated that there are two factors that could lead to a credit rating downgrade:

- an adverse regulatory decision; or
- a forecast of a sustained deterioration in credit metrics including CFO pre-W/C to debt of less than 11 percent.

In the same report, FEI's CFO pre-W/C to debt metric for the year ended December 31, 2020 was 11.3 percent which means that this financial metric is critically close to a rating downgrade threshold. Considering the capital intensive nature of FEI's business where the utility needs regular access to capital, it is prudent to maintain a greater layer of financial metric protection than FEI currently has. Being so close to a rating downgrade threshold due to weak financial metrics does not provide FEI room to absorb unusual or unexpected negative events without dropping below downgrade thresholds for key financial metrics.

Another important factor that is putting pressure on FEI's credit rating is the Energy Transition risk. Since 2019, Moody's credit rating reports include a discussion on ESG related risks. For example, according to the latest Moody's Credit Rating Report for FEI published in November 2021, Moody's views FEI as having a "very negative carbon transition risk" because of risks associated with carbon emissions targets and the fact that the Province of BC's legislated targets of 40 percent GHG reduction by 2020 and 80 percent GHG reduction by 2050 exceed FEI's own 30 percent GHG reduction target by 2030. Consistent with the general market trends and growing awareness around ESG related risks, FEI is expecting that ESG will play an increasingly important role in credit rating determination. For a natural gas distribution company such as FEI, that represents a significant risk going forward and puts an additional strain on the credit rating.

The weak financial metrics, the majority of which are below an A rating threshold, and increasing importance of ESG related risks and their impact on the credit rating, indicate that FEI's credit rating may not be secure.

On page 37 of Exhibit B1-8, FBCU states:

> Issuers with BBB category ratings can be shut out of the Canadian debt capital markets at times, particularly during periods of market distress and for longer tenure issuances, such as 30 years.

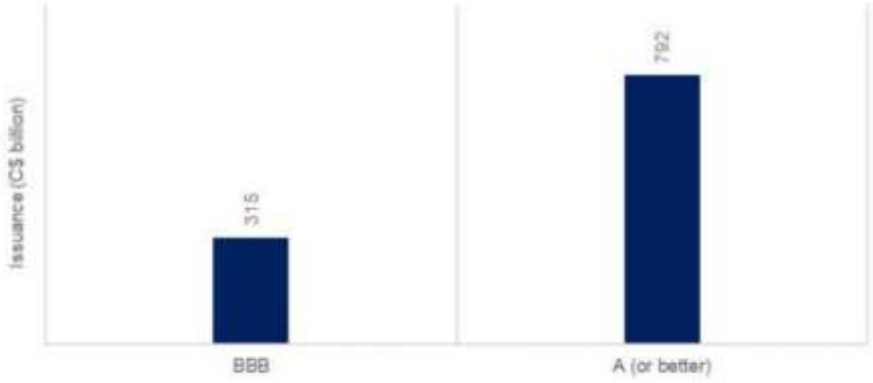
6.3 Please indicate whether FEI has had any historical instances of being denied funding from a Canadian institution in the debt capital markets. If so, please describe the circumstances for each denied funding.

Response:

In advance of debt issuances, FEI engages a dealer (bank) who acts as an underwriter and financial advisor whose role, among other things, is to make recommendations to FEI on the best time to proceed with the debt issuance based on market conditions and potential investor interest. Based on the bank's recommendations, FEI would not go ahead with a transaction if there was risk that funding would be denied. There have been certain instances where the debt issuance timing had shifted because of volatile and unpredictable market conditions, most recently during the COVID-19 pandemic. Please refer to the response to BCUC IR1 7.5 which discusses the COVID-19 pandemic's impact on FEI's liquidity. In addition, as discussed in the response to BCUC IR1. 6.4, at times during the 2008 financial crisis access to debt capital for even A rated companies like FEI was unavailable.

In addition, FEI's A level rating ensures that the utility is able to access capital markets on reasonable terms and pricing in most market conditions. FEI's access to debt capital markets would be more restricted if FEI were downgraded from its current A level rating to the BBB category rating. As discussed in FortisBC's evidence, there is a much larger market for A-rated debt compared to BBB-rated debt, with a large majority of debt issued in the A-rating category (see Figure 6-3 below). Many institutional investors face limits on the proportion of BBB rated debt they are allowed to hold in their portfolios and in case of a downgrade they may have to rebalance their portfolios by selling their lower rated bonds to meet their investment guidelines. As indicated in Figure 6-3, approximately 72 percent of long-term domestic corporate debt issuances from January 2011 to October 2021 were A-rated or higher. Please refer to the response to BCUC IR1 6.4 which further discusses this issue.

Figure 6-3: Corporate Bond Issuance Volumes by Rating from January 2011 to October 2021



Source: RBC Capital Markets

If FEI is downgraded to a BBB category rating, coupled with the fact that FEI is facing increasing scrutiny from investors, credit rating agencies and financial institutions around ESG related risks, it may become more difficult for FEI to access debt capital markets in the future especially in times of significant volatility.

6.4 Please provide examples and further details on the instances to support FBCU's statement that "Issuers with BBB category ratings can be shut out of the Canadian debt capital markets at times…" As part of the response, please clarify whether issuers with BBB category ratings can be shut out from all instruments in debt capital markets and whether the issuers are specific to the utility sector.

Response:

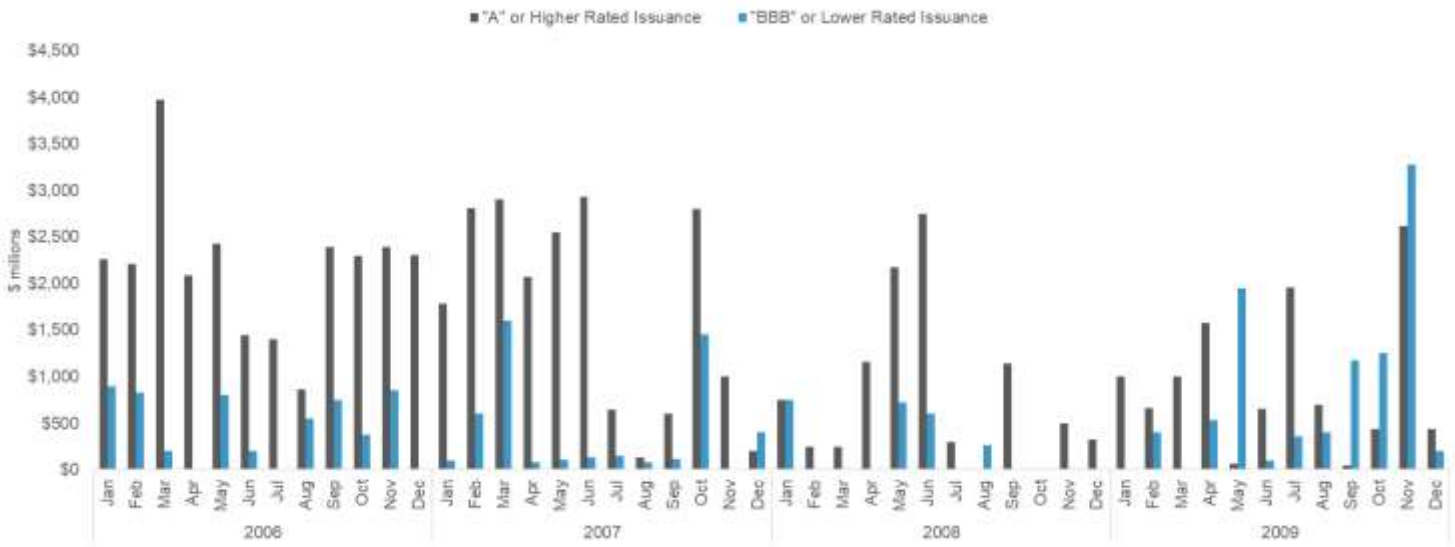
In simple terms, a credit rating is a formal, independent opinion of a borrower's ability to service its debt obligations. The majority of ratings are used by debt investors in their investment appraisal processes. FortisBC's traditional investors include insurance companies and pension funds who tend to hold these investments to maturity. These types of investors are conservative by mandate, are subject to prudent and well-defined investment policies and tend to invest in higher quality bonds with a significant majority of investments focused on A or higher rated companies. Therefore, even in normal market conditions, BBB rated companies tend to receive less interest from these types of investors compared to A rated companies. To demonstrate this, the proportion of debt securities held by FortisBC's traditional investors rated A or higher versus BBB or lower is summarized below:

- 83 percent of Industrial Alliance's bond portfolio of $32 billion is invested in A or higher rated bonds[17];

[17] https://www.annualreports.com/HostedData/AnnualReports/PDF/TSX_IAG_2020.pdf.

- 80 percent of Canada Life's bond portfolio of $101.3 billion is invested in A or higher rated debt[18];
- 75 percent of Great-West Life's bond portfolio of $138 billion is invested in A or higher rated bonds[19];
- 73 percent of Manulife's bond portfolio of $259.5 billion is invested in A or higher rated bonds[20]; and
- 72 percent of Sunlife's bond portfolio of $89 billion is invested in A or higher rated bonds[21].

The inclination to invest in higher rated companies becomes especially apparent during financial crises when markets are extremely volatile. For example, when the bond markets shut for several weeks post Lehman Brothers collapse in September 2008, even the strongest investment grade companies could not issue bonds, let alone BBBs and below. This can be seen looking at October 2008 in the graph below when there were no debt issuances in the Canadian market by either A or BBB rated companies. When the markets did reopen, they did so gradually, opening first to issuers at the top end of the rating spectrum and then eventually moving down towards the bottom. This can also be seen in the graph below, as for the rest of 2008 only A or higher rated companies were able to access the debt capital market. Overall, for the majority of 2008 (8 out of 12 months) and the first several months of 2009, BBB or lower rated issuers were not able to issue bonds in the Canadian marketplace.



Source: Scotiabank

Therefore, maintaining an A level credit rating ensures FEI is able to access capital markets on reasonable terms and pricing in most market conditions.

[18] https://www.canadalife.com/about-us/financial-information.html.
[19] https://www.greatwestlifeco.com/content/dam/gwlco/documents/reports/2021/lifeco-2020-annual-report-en.pdf.
[20] https://www.manulife.com/content/dam/corporate/en/documents/investors/MFC_SR_2020_Y1_EN.pdf.
[21] https://www.sunlife.com/content/dam/sunlife/regional/global-marketing/documents/com/annual-report-2020-e.pdf.

6.5 Please provide evidence or examples of regulated utilities with BBB category ratings being shut out of the Canadian debt capital markets.

Response:

Please refer to the response to BCUC IR1 6.4.

7.0 Reference: PROPOSED CAPITAL STRUCTURE

Exhibit B1-8, FBCU Evidence, p. 33; Exhibit B1-8-1, Appendix D-2, p. 2, "FEI - Moody's - 2021 Credit Rating Report dated November 25, 2021", pp. 2 and 7

Capital Structure – Credit Ratings Historical

On page 2 of Appendix D-2, FBCU states that "FortisBC Energy Inc. has not had any credit rating changes since 2015" and shows the following table which has been reproduced:

Rating Agency	Rating
DBRS*	A (stable outlook)
Moody's**	A3 (stable outlook)

*DBRS rating for FortisBC Energy Inc. is for issuer rating and unsecured debentures.
**Moody's rating is for FortisBC Energy Inc. unsecured debentures only.

On page 33 of Exhibit B1-8, FBCU provides the following table:

Table 6-4: FEI's Key Financial Indicator Scores Compared to Minimum A3 Rating per Moody's Utility Rating Methodology

	FEI's Score	A - Rating Threshold[54]	2018	2019	2020	LTM Sept 2021
CFO pre-WC + Interest / Interest	Baa	4.5x-6.0x	2.5x	3.0x	2.9x	3.6x
CFO pre-WC / Debt	Baa	19.0% - 27.0%	13.6%	13.6%	11.3%	12.7%
CFO pre-WC - Dividends / Debt	Baa	15.0% - 23.0%	8.8%	8.7%	6.6%	7.9%
Debt / Capitalization[55,58]	A	40.0% - 50.0%	47.8%	47.5%	48.8%	47.9%

Source: Moody's Credit Rating Report for FEI, dated November 25, 2021.

Footnote 54: Threshold for A-rated entities with low business risk per Moody's Rating Methodology for Regulated Electric and Gas Utilities June 2017.

On page 2 of "FEI - Moody's - 2021 Credit Rating Report" in Appendix D-2, Moody's discusses factors that could lead to a downgrade for FEI and states "[w]hile we do not expect it, an adverse regulatory decision or a forecast of a sustained deterioration in credit metrics including CFO pre-W/C to debt of less than 11%."

On page 7 of "FEI - Moody's - 2021 Credit Rating Report" in Appendix D-2, Moody's shows FEI's scorecard which has been reproduced below:

Exhibit 7
Methodology Scorecard Factors
FortisBC Energy Inc.

Regulated Electric and Gas Utilities Industry Scorecard [1][2]	Current LTM 9/30/2021		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	Aa	Aa	Aa	Aa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	3.0x	Baa	2.5x - 3x	Ba
b) CFO pre-WC / Debt (3 Year Avg)	12.6%	Baa	11% - 13%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	7.8%	Baa	6% - 9%	Baa
d) Debt / Capitalization (3 Year Avg)	47.6%	A	46% - 49%	A
Rating:				
Scorecard-Indicated Outcome Before Notching Adjustment		A3		A3
HoldCo Structural Subordination Notching		0		0
a) Scorecard-Indicated Outcome		A3		A3
b) Actual Rating Assigned		A3		A3

[1] All ratios are based on 'Adjusted' financial data and incorporate Moody's Global Standard Adjustments for Non-Financial Corporations.
[2] As of 9/30/2021(L)
[3] This represents Moody's forward view; not the view of the issuer; and unless noted in the text, does not incorporate significant acquisitions and divestitures.
Source: Moody's Financial Metrics

7.1 Please expand Table 6-4: FEI's Key Financial Indicator Scores Compared to Minimum A3 Rating per Moody's Utility Rating Methodology from the start of 2009 to last twelve months (LTM) September 2021.

Response:

Please refer to the table below, which expands Table 6-4 to include the 2009 – 2017 fiscal years.

	A-Rating Threshold	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	LTM Sept 2021
CFO pre-WC + Interest / Interest	4.5x-6.0x	2.6x	2.7x	2.2x	2.4x	2.5x	2.5x	2.2x	2.5x	2.6x	2.5x	3.0x	2.9x	3.6x
CFO pre-WC / Debt	19.0%-27.0%	10.2%	10.6%	11.2%	12.6%	12.9%	11.5%	8.4%	13.5%	15.5%	13.6%	13.6%	11.3%	12.7%
CFO pre-WC – Dividends / Debt	15.0%-23.0%	6.5%	5.9%	6.5%	8.1%	6.2%	7.6%	3.1%	8.8%	10.8%	8.8%	8.7%	6.6%	7.9%
Debt / Capitalization	40.0%-50.0%	61.8%	59.1%	47.4%	45.7%	44.9%	46.5%	46.7%	46.3%	46.8%	47.8%	47.5%	48.8%	47.9%

Note: The 2009 – 2014 fiscal years shown represent FEI, and as such, do not incorporate FortisBC Energy (Vancouver Island) Inc. (FEVI). FEI and FEVI were separately rated by Moody's and were amalgamated on December 31, 2014.

7.2 Please confirm that the "A" Rating Thresholds shown in Table 6-4 (third column), which are from June 2017 remains current (i.e., effective as of November 25, 2021, the date of Moody's most recent credit opinion on FEI).

7.2.1 If not, please provide an updated table with the most recent "Threshold for A-rated entities with low business risk per Moody's Rating Methodology for Regulated Electric and Gas Utilities"

Response:

Confirmed.

7.3 Please explain why FEI's cash flow from operations (CFO) Pre-W/C / debt ratio decreased from 13.6 percent in 2019 to 11.3 percent in 2020.

Response:

The decrease in FEI's CFO Pre-WC / Debt ratio from 13.6 percent in 2019 to 11.3 percent in 2020 was primarily due to:

- A decrease in cash flow from operations pre-working capital driven by changes in regulatory assets and liabilities reflecting the increase of midstream and commodity costs that were recognized in the MCRA and CCRA deferral accounts, respectively, and had not yet been recovered through customer rates; and
- An increase in borrowings to finance the debt component of FEI's capital expenditure program.

7.3.1 Please discuss whether FEI anticipates its CFO Pre-W/C / debt ratio to decrease below 11 percent for a sustained duration. As part of the response, please provide supporting evidence.

Response:

The CFO Pre-WC / debt ratio financial metric is impacted by a number of factors that are difficult to forecast with accuracy over a number of years, including operating performance, changes in deferral accounts and how they are financed, the level of debt required based on the capital program, and depreciation of assets. In addition, FortisBC does not have access to the proprietary elements of Moody's methodology and therefore is not able to necessarily incorporate all elements of the methodology that are required to calculate forward-looking metrics.

In general, FortisBC does not expect its financial metrics to move materially outside the range they have been at for the last number of years; however, unexpected events, drivers such as material changes in regulatory assets and liabilities, and operational performance could materially impact financial metrics and cause them to go below the rating downgrade thresholds. As discussed, the current level provides limited cushion for FortisBC to absorb unexpected risks.

For example, per the S&P report published in January 2022, S&P noted that for the second consecutive year, rating downgrades outpaced upgrades for the investor-owned North American regulated utility industry, causing the median investor-owned utility ratings to fall to the BBB category for the first time ever. The two main reasons for downgrades in rating were ESG related risks and weak financial metrics. With respect to weak financial metrics, S&P specifically noted the following:

> Strategically, an increasing percentage of the industry has been managing their financial measures with only minimal financial cushion from their downgrade threshold. While this strategy of limiting excess credit capacity works well under ordinary conditions, when unexpected risks occur or base case assumptions deviate from expectations, the utility can become susceptible to a weakening of credit quality. <u>This has been one of the primary drivers of the industry's weakening of credit quality over the past two years</u>.

This report is filed as Attachment 13.3.1 in the response to BCUC IR1 13.3.1.

7.4 Please provide the historical scores for FEI's other factors (regulatory framework, ability to recover costs and earn returns and diversification factors, as outlined in blue above) and FEI's financial strengths (as outlined in green above) for years 2016 to current.

Response:

Please see below for the scores for FEI's other factors (regulatory framework, ability to recover costs and earn returns and diversification factors, as outlined in blue above) and FEI's financial strengths (as outlined in green above) for years 2016 to current.

	LTM March 2016	LTM March 2017	LTM March 2018	LTM June 2019	LTM Sept 2020	LTM Sept 2021
Factor 1: Regulatory Framework (25%)						
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A	A	A
b) Consistency and Predictability of Regulation	Aa	Aa	Aa	Aa	Aa	Aa
Factor 2: Ability to Recover Costs and Earn Returns (25%)						
a) Timeliness of Recovery of Operating Costs	Aa	Aa	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa	Baa	Baa
Factor 3: Diversification (10%)						
a) Market Position	A	A	A	Baa	Baa	Baa
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A	N/A	N/A
Factor 4: Financial Strength (40%)						
a) CFO pre-WC + Interest / Interest (3 Year Avg)	Ba	Ba	Ba	Ba	Ba	Baa
b) CFO pre-WC / Debt (3 Year Avg)	Baa	Baa	Baa	Baa	Baa	Baa
c) CFO pre-WC - Dividends / Debt (3 Year Avg)	Ba	Baa	Baa	Baa	Baa	Baa
d) Debt / Capitalization (3 Year Avg)	A	A	A	A	A	A

7.5 Please explain whether COVID-19 has had any impacts on FEI's credit metrics and liquidity.

Response:

This response also addresses BCUC IR1 59.2.

At the beginning of the COVID-19 pandemic, there was significant volatility in the debt capital markets and access to debt was limited. As a result of this volatility and the COVID-19 pandemic's expected negative effect on FortisBC's cash flows at the time, on April 17, 2020, FortisBC brought forward an application to BCUC for COVID-19 Financing for the purposes of advance approval of a number of financing options that FortisBC deemed as potentially necessary depending on the extent of the impact to FortisBC's cash flows.

FEI was requesting to increase its borrowing capacity by establishing a new credit facility of up to $300 million and issue common shares to its holding company, FortisBC Holdings Inc., of up to $50 million. FEI also obtained a separate approval to issue up to $800 million in long-term Unsecured Debentures under its short form shelf prospectus. Similarly, FBC requested to increase its borrowing capacity by establishing a new credit facility of up to $100 million and issue common shares to its holding company, FortisBC Pacific Holdings Inc., of up to $50 million. In addition, FBC sought approval to issue up to $200 million in long-term Unsecured Debentures.

The full extent of the impact of the COVID-19 pandemic at the time of the filing the application for COVID-19 Financing was uncertain and outside of the control of FortisBC. Further, the economic effects from the COVID-19 pandemic were deemed as likely to continue for a prolonged period of time even after the State of Emergency was lifted. In addition, the financial markets were experiencing significant volatility and a reduction in access to liquidity. Under typical circumstances, to seek the establishment of a credit facility or an extension, FortisBC would have submitted the proposed pricing grid to the BCUC in advance of the approval with the expectation that pricing would remain stable for several weeks. However, under the economic conditions at

the time of filing the application for COVID-19 Financing, it posed a challenge to do so as the pricing grid was changing constantly and remained extremely unpredictable.

The above demonstrates the significant volatility that FortisBC was experiencing at the beginning of the COVID-19 pandemic and had FEI or FBC been in the position at the time where they had to access debt capital markets, it would have proven challenging to do so.

The debt capital markets improved over several months after the application for COVID-19 Financing was filed and FEI issued $200 million of long-term debt in July 2020 which improved its liquidity position. Similarly, FBC issued $75 million of long-term debt in May 2020. 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.

8.0 Reference: PROPOSED CAPITAL STRUCTURE

Exhibit B1-8, FBCU Evidence, pp. 38 and 47; Exhibit B1-8-1, Appendix D-2, "FEI - Moody's - 2021 Credit Rating Report dated November 25, 2021", pp. 1–2, "FEI - DBRS - 2021 Credit Rating Report dated January 5, 2022", pp. 1 and 9

Capital Structure – Expected Credit Ratings

On page 38 of Exhibit B1-8, FBCU states:

> A downgrade to below an A-category credit rating would result in a higher cost of debt, which would result in FEI incurring significant additional cost to finance its large capital program. An increase in FEI's equity component would support the company's current credit ratings and provide confidence that FEI will have access to low cost debt to finance its capital projects, even under challenging economic and capital market conditions.

On page 47 of Exhibit B1-8, FBCU states:

> The downward pressure that ESG related risks will place on FEI's credit rating will have to be offset by stronger financial metrics in order to maintain FEI's current credit rating. Increasing FEI's equity thickness and ROE will strengthen FEI's financial metrics and help alleviate some of the challenges related to ESG from credit rating agencies perspectives.

On page 1 of "FEI - Moody's - 2021 Credit Rating Report" in Appendix D-2, Moody's states that FEI's credit profile is driven by its low business risk gas transmission and distribution assets that operate in the credit supportive regulatory environment of British Columbia and its monopoly position in its service territory.

Further, on page 2, Moody's states that it does not expect a downgrade.

On pages 1 and 9 of "FEI - DBRS - 2021 Credit Rating Report" in Appendix D-2, DBRS submits that FEI has a "strong financial and business risk profile" and that its "credit metrics continue to be supported by relatively stable cash flow from operations and a reasonable adjusted capital structure near the 60% range."

8.1 Please explain and provide evidence to support that environmental, social and governance (ESG)-related activities contribute as a risk factor and will place downward pressure on FEI's credit ratings.

Response:

As discussed in FortisBC's evidence, the shift towards increasing awareness of ESG related risks by credit rating agencies and institutional investors only started in the last several years, particularly 2020-2021, as evidenced by the timing of the specific examples that have been provided:

- World Economic Forum citing climate risk as the biggest long-term risk for the world in its Global Risks Report published in 2020;
- Blackrock, the world's largest asset manager, publishing a letter to CEOs in 2020 noting that companies that do not respond to stakeholders and address sustainability risks will encounter growing scepticism from the markets and higher cost of capital;
- Major Canadian banks establishing Sustainable Finance groups within their organizations and announcing ESG mandates, all announcements made in 2020;
- British Columbia Investment Management Corporation targeting $5 billion investment in sustainability bonds and reducing carbon exposure in its public equity portfolio by 30 percent by 2025, announcement made in 2021;
- University endowment funds divesting of fossil fuel investments, most announcements were made by universities in 2020-2021;
- Dominion Energy announcing in 2020 that it is divesting its $10 billion gas transportation and storage business and focusing on regulated clean energy;
- Duke Energy and Dominion Energy announcing in 2020 that they are cancelling the Atlantic Coast Pipeline and taking a $2 billion and $2.8 billion write-off, respectively;
- Public Service Enterprise Group announcing in 2020 its intention to sell about 6.8 GW of merchant fossil generation assets and focus on regulated clean energy.

In addition, since the filing of FortisBC's evidence, the following events of note occurred:

- On March 30, 2022, the government of Canada released a comprehensive plan titled 2030 Emissions Reduction Plan: Canada's Next Steps for Clean Air and a Strong Economy[22]. The government laid out ambitious sectoral targets and added significant new funding in several areas to drive towards its goal of cutting emissions by 40 percent by 2030. It aims to achieve half those cuts by 2026, just four years from now. The Government of Canada last upped its ambition in December 2020, releasing a plan to cut emissions to 503 Mt. This latest release adds another 64 million tonnes in projected cuts, nearly half from Canada's carbon-intensive oil and gas sector. In addition, the carbon price is set to rise steeply from its current level of $50 per tonne of emissions to $170 by 2030 in order to push consumers to cleaner energy sources;
- On March 21, 2022, the Securities and Exchange Commission (SEC) proposed rule changes that would require registrants to include certain climate-related disclosures in their registration statements and periodic reports, including information about climate-related risks that are reasonably likely to have a material impact on their business, results of operations, or financial condition, and certain climate-related financial statement metrics in a note to their audited financial statements. The required information about climate-related risks would also include disclosure of a registrant's greenhouse gas emissions

[22] https://www.canada.ca/content/dam/eccc/documents/pdf/climate-change/erp/Canada-2030-Emissions-Reduction-Plan-eng.pdf.

(GHG), which have become a commonly used metric to assess a registrant's exposure to such risks[23]. This means that FortisBC's climate related risks and GHG emissions will need to be disclosed in Fortis Inc.'s audited financial statements as Fortis Inc. is an SEC registrant;

- On March 7, 2022, BMO, one of Canada's leading banks, laid out a plan to sharply reduce emissions connected to loans to the energy and power generation sectors by 2030 as it aims for a longer-term goal of being net zero. BMO said its new target is a 33 percent cut in scope 1 and 2 emissions from oil and gas borrowers, which refers to the emissions produced by the companies themselves and their suppliers. The bank is also aiming for a 24 percent cut by 2030 in scope 3 emissions, those produced from the burning of the fuels that oil and gas companies produce[24];
- On February 10, 2022, Canada Pension Plan Investment Board announced a commitment to for its portfolio and operations to achieve net-zero GHG emissions across all scopes by 2050. As part of this commitment, Canada Pension Plan will increase its current investments in green and transition assets from $67 billion to at least $130 billion by 2030[25]; and
- On January 20, 2022, S&P issued a report stating that for the first time ever, the median investor-owned utility ratings fell to the BBB credit rating category. The credit rating agency noted that during 2021, credit quality was primarily pressured by weak financial measures and ESG credit risks. S&P expects that physical and environmental risks will continue to constrain the industry's credit quality in 2022. This report was filed as Attachment 13.3.1 in response to BCUC IR1 13.3.1.

Moody's

As materiality and importance of key environmental and social issues continues to rise, the credit rating agencies will increasingly start pricing in these risks in their credit ratings. As noted by Moody's in its Sector In-Depth publication called "ESG Factors Frequently Cited as Material Credit Considerations in 2019 Rating Actions" dated April 14, 2020, Moody's expects deeper market integration of climate risks to start constraining the availability of capital for the most-exposed sectors which will impact issuer credit quality:

> We expect ESG considerations to be of growing importance in our assessment of issuer credit quality. While our ratings have always reflected our views of ESG risks, the materiality of key environmental and social issues continues to increase. Climate risk, which includes the transition to a low-carbon economy as well as the adverse effects of physical climate change, is taking on greater prominence in discussions of credit quality, as the financial effects of climate risks are becoming

[23] https://www.sec.gov/news/press-release/2022-46.
[24] https://www.bnnbloomberg.ca/bmo-aims-to-cut-emissions-from-energy-loans-in-net-zero-push-1.1733861.
[25] https://www.cppinvestments.com/public-media/headlines/2022/cpp-investments-announces-commitment-to-net-zero-by-2050#:~:text=CPP%20Investments%20portfolio%20and%20operations,across%20all%20scopes%20by%202050.

> clearer and environmental regulations become stricter. Deeper market integration of climate risks will constrain the availability of capital for the most-exposed sectors. Natural capital concerns, such as water scarcity, deforestation and food insecurity, will put the spotlight on efficient resource management. On the social side, demographic and social trends, including aging populations, shifting consumer preferences and socially driven regulation, will create risks and opportunities. Heightened public awareness of such disparate issues as climate change, sustainability challenges, diversity, data security and income inequality will also create risks and opportunities. As these considerations grow in importance and materiality over time, we also expect them to be increasingly material to credit analysis. (emphasis added)[26]

Additionally, Moody's started including discussion on ESG related risks in its credit rating reports in 2019. For example, according to Moody's Credit Rating Report for FEI published in November 2021, Moody's views FEI as having a "very negative carbon transition risk" because of risks associated with carbon emissions targets and the fact that the Province of BC's legislated targets of 40 percent GHG reduction by 2030 and 80 percent GHG reduction by 2050 exceed FEI's own 30 percent GHG reduction target by 2030.

In September 2020, Moody's published Sector-in-Depth – Regulated Electric & Gas Utilities – North America, which discusses how "shifting environmental agendas [have raised] long-term credit risk for natural gas investments."[27] The key risk factors from the publication have been grouped into the categories of environmental, social and governance and included in the table below, to demonstrate the potential implications of ESG considerations on FEI's credit quality:

[26] Moody's Sector-in-Depth – ESG Factors Frequently Cited as Material Credit Considerations in 2019 Rating Actions, April 2020.

[27] Moody's Sector-in-Depth – Shifting environmental agendas raise long-term credit risk for natural gas investments, September 2020.

Factor	Context
Environmental	"Natural gas is increasingly being called into question over environmental and GHG emissions. Permitting difficulties related to new pipelines, local government mandates favoring electrification and state carbon reduction commitments raise operating risks and cost of capital. As carbon transition efforts gain ground, natural gas consumption may see a measured reduction in order to meet 2040 and 2050 GHG goals." "The political and legislative push for lower carbon emissions will impact more than just the fuel source of electric generation units. For the gas sector, decarbonization goals are more disruptive than renewable portfolio standards because the latter typically affects only power generation, whereas mandates to reduce emissions affect all fossil-fuel infrastructure." "Corporate sustainability strategies continue to evolve as well, with nearly dozens of holding companies expanding their environmental goals to include net-zero carbon emissions, including industry bellwethers like Duke Energy Corporation (Baa1 stable), The Southern Company (Baa2 stable) and Dominion Energy Inc. (Baa2 stable). We view this trend as noteworthy because each of these three companies have material operations in gas distribution and such corporate-wide targets will affect all of their asset classes. In a similar vein, Consolidated Edison, Inc. (Baa2 stable) has expressed their bearish view of gas transmission assets made over the past five years, capped their investment in the Mountain Valley Pipeline at $530 million in November 2019 and provided commentary around their willingness to sell their midstream assets for an adequate price." "Why does this matter now? The utility sector is accustomed to issuing long-dated debt to match the useful life of its assets, including 30-year bonds. The LDC sector has roughly $18 billion in 30-year bonds outstanding and a weighted average long-term debt tenor of 14 years on roughly $64 billion of total debt outstanding as of 30 June 2020. This means that most existing debt will retire prior to the 2045-50 target dates that some states, cities and companies have identified for the elimination of GHG emissions. Around $13 billion of long-term debt will mature beyond 2045 when some assets may not be producing the cash to service or repay debt."
Social	"Occasional gas explosions in residential neighborhoods only heighten the political and social scrutiny on the sector and on the fuel's role in providing energy. These concerns increase risks for gas investments made today, given the long-lived nature of the assets and related ESG considerations, such as emissions levels, public health and safety, corporate reputational risk, financial policies and the cost of capital over a multi-decade time horizon." "Development of oil and gas transmission infrastructure, in particular, continues to face legal challenges from environmental groups, which are succeeding in delaying pipeline development by opposing efforts by project developers to secure needed permits, highlighting the potential effect of pipeline construction or leaks on protected land and water resources and urging the completion of more comprehensive biological impact studies. Environmentalists and indigenous communities have opposed both oil and gas pipelines as well as broader development projects, such as the Frontier oil sands project in Alberta, Canada. Because of growing uncertainties about whether new projects will be completed, we generally do not incorporate any revenue from such pipelines in our base case financial projections for a company. Instead, cash contribution will occur when construction has been completed and the pipeline is in operation. The debt used to finance a given project is, however, on-credit and will depress financial metrics during the construction period, all else being equal."

Factor	Context
Governance	"Although natural gas transportation and distribution companies continue to provide generally safe, reliable service while reducing emissions, there are ESG reputational risks associated with any hydrocarbon-based business, including financial governance policy risks around a higher cost of capital and lower asset returns over a multi-decade time horizon. Events like the August 2020 Baltimore explosion exact heavy social costs related to customer relations and public health and safety. Financial risks also stem from the likelihood of construction delays and greenfield project budget overruns, potential cancellations, regulatory fines and penalties for accidents, increasing debt obligations associated with gas infrastructure expansion and potential write-offs of stranded assets as the carbon transition progresses.

On December 14, 2020, Moody's published new environmental classification that sharpens its focus on physical climate risks. In this publication, Moody's stated that:

> Our revised environmental classification reflects evolving ESG standards, disclosure frameworks and market conventions among issuers and investors. These changes to our environmental classification, which we introduced in our new ESG methodology update, represent a reclassification and/or renaming of our existing environmental categories, rather than a change in the specific environmental issues considered. A key modification is a category focused on physical climate risks, which considers the effects of climate change. Extreme weather events have increased in severity and frequency and are expected to intensify in the future, causing significant economic losses, hazards for the local population and environmental damage.[28]

Moody's states further that:

> Environmental risks vary in terms of timing, severity and certainty. They can comprise regulatory and policy issues, environmental hazards or a combination of both. Environmental considerations increasingly also influence consumer preferences and hence market demand for a company's products and services. Environmental considerations can increase capital expenditures and operating costs, reduce cash flow and lead to asset write-downs, which can erode credit quality (…).[29]

In this revised methodology, Moody's introduced five environmental categories that are considered most material to credit quality (1) carbon transition, (2) physical climate risks, (3) water management, (4) waste and pollution and (5) natural capital. All five environmental categories will be considered in determining Moody's newly launched environmental issuer profile scores and credit impact scores.

[28] Moody's Sector Profile – Revised classification of environmental considerations reflects evolving standards, December 2020.

[29] Moody's Sector Profile – Revised classification of environmental considerations reflects evolving standards, December 2020.

Relevant excerpts from the publication describing the five environmental risk factors that pose a risk to FEI have been included in the table below:

Environmental Factor	Context
Carbon Transition	"Carbon transition risk encompasses policy, legal, technological and market changes likely to be associated with a transition to a lower carbon economy. We expect these transition risks to manifest themselves at varying speeds and scales across different geographies and sectors. The tightening of global greenhouse gas regulatory regimes is having a tangible – and, in some cases, disruptive – impact on corporate strategies, business models and long-term planning." "Sectors that face heightened carbon transition risks include oil and gas, utilities, automotive manufacturers and parts suppliers, chemicals, steel, shipping, surface transport and airlines. Carbon regulations were cited as the top environmental category for material credit considerations in Moody's private-sector ratings actions in 2019."
Physical Climate Risks	"The physical climate risks category encompasses the present and future effects of climate change, which contributes to extreme weather events, as well as long-term trends. Such weather events have increased in severity and frequency, causing significant economic losses, hazards for the local population and environmental damage." "Sectors that have a high concentration of valuable physical assets in such regions could have elevated exposure to physical risks. Sectors such as oil and gas, chemicals, protein and agriculture, metals and mining, ports, shipping and power generation projects face elevated physical climate risks (…). Wildfire liabilities were a key driver of PG&E Corporation's (Ba2 stable) January 2019 filing for Chapter 11 bankruptcy protection."
Waste and Pollution	"This category covers air and land-based waste and pollution, including air pollutants, hazardous and non hazardous waste, as well as man-made accidents (spills, leaks and related incidents) and circular economy issues."
Natural Capital	"Natural capital refers to assets provided by nature that are essential for human habitation and economic activity. The Natural Capital Coalition defines the term as "the stock of renewable and non-renewable resources (e.g. plants, animals, air, water, soils, minerals) that combine to yield a flow of benefits to people." This category also includes the need to restore sites that have been exploited for industrial activity, such as land reclamation in mining." "Determining risk levels for natural capital across sectors will be driven by the extent to which a sector is directly exposed to or reliant on the natural environment and the extent to which it benefits from goods and services from nature (such as food, fiber, crops, metals, etc.). Some sectors such as energy, metals and mining, forest and paper resources, protein and agriculture, food products and some consumer goods sectors such as textiles and apparel have relatively more direct interaction with land, air and water resources, compared to other sectors."

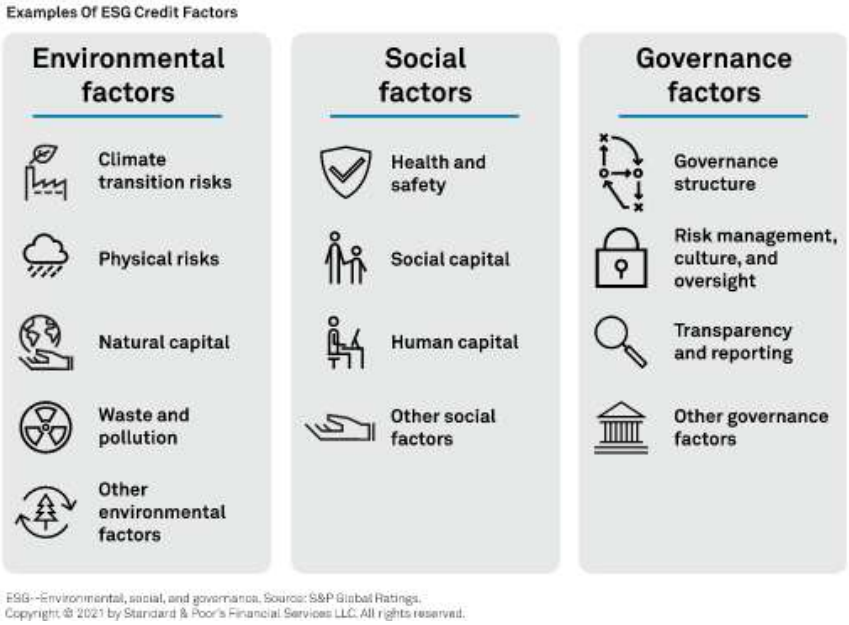
Lastly, to conclude Moody's discussion around ESG, it is important to note that Moody's current rating methodology that was presented in Table 6-2 in FortisBC's evidence has not been updated since 2017 and, therefore, ESG and climate related risks do not officially form part of Moody's

rating methodology. Based on what was presented above, FEI expects that Moody's will be updating their rating methodology in the near future to include ESG and climate related risks. Before an updated methodology is published, it is unclear how much ESG and climate related risks will contribute in percentage terms to FEI's credit rating.

S&P

On October 10, 2021, S&P published "General Criteria: Environmental, Social, and Governance Principles in Credit Ratings", which outlines the principles S&P has implemented to incorporate ESG factors into credit ratings. S&P define ESG credit factors as "those ESG factors that can materially influence the creditworthiness of a rated entity or issue and for which we have sufficient visibility and certainty to include in our credit rating analysis."[30]

The key ESG credit factors that may influence credit ratings in S&P's opinion are included in the figure below:



Source: S&P Global Ratings

Of the ESG credit factors listed above, S&P believes that "[c]limate transition risk and physical risk-related factors may be among the most significant ESG credit factors that affect the creditworthiness of rated entities. This is primarily because of policymakers' efforts to reduce emissions or to ensure that greenhouse emissions reflect their full social costs ("climate transition risk") and climate change, which is leading to more frequent and severe extreme weather events ("physical risk") (…). A small subset of corporate industries may have greater exposure to climate transition risk than other corporate industries (...). For example, the exposure to climate transition risks due to public policy actions aimed at increasing the cost of carbon dioxide and GHG

[30] S&P Global Ratings *General Criteria: Environmental, Social, and Governance Principles in Credit Ratings* https://disclosure.spglobal.com/ratings/en/regulatory/article/-/view/sourceId/12085396.

emissions may be relatively concentrated in industries like transportation or fossil fuel and basic material production…"[31]

In another S&P publication dated October 10, 2021 "General Criteria: Environmental, Social, And Governance Principles In Credit Ratings", S&P states that there is still significant uncertainty on the impact of ESG-related risks and that its views on the credit risk of ESG consideration can evolve based on future developments:

> "We monitor the impact of credit factors, including ESG credit factors, and our view can evolve as new information becomes available, perhaps as a result of new standardized disclosure regulations or as an issuer's fundamentals change. Also, our view can evolve, for example, if changes in public policy influence the economics of a business and its creditworthiness.
>
> In some cases, a risk or strength that we currently consider immaterial to creditworthiness can later become material. This could happen, for example, if new information becomes available, or if a policy or legal change imposes new or higher costs, such as carbon dioxide and other greenhouse gas emission costs, on the obligor.
>
> Finally, feedback loops between certain ESG credit factors heighten future uncertainty. For example, public policy decisions about carbon pricing and emissions reduction targets may influence levels of greenhouse gas emissions, which may affect the frequency and severity of future physical risk beyond those stemming from historical emissions. Similarly, changes in public awareness of social risks may lead to changes in citizen or customer behavior, which may affect a government's or company's creditworthiness." (emphasis added)

DBRS

According to DBRS rating methodology dated September 2021[32], DBRS generally considers four key components in determining company's credit rating: (1) business risk, (2) financial risk, (3) overlay considerations, and (4) specific instrument considerations. Business risk captures the major business risk aspects of the issuer and is determined by assessing each of the business risk factors. The financial risk pertains to financial soundness and is determined by assessing each of the financial risk factors. The business risk and financial risk are then combined to derive the issuer's core assessment. As noted by DBRS, for investment-grade credits, which includes FEI and FBC, the business risk will have greater weight than the financial risk in determining the core assessment.

The overlay factors are the last consideration in the determination of the issuer rating. When deemed relevant and material to the analysis of an issuer, an overlay factor positively or

[31] S&P Global Ratings *General Criteria: Environmental, Social, and Governance Principles in Credit Ratings* https://disclosure.spglobal.com/ratings/en/regulatory/article/-/view/sourceId/12085396.

[32] DBRS Morningstar: Rating Companies in the Regulated Electric, Natural Gas, and Water Utilities Industry dated September 2021.

negatively modifies the core assessment derived from the combination of the business and financial risk, with the impact of a single factor potentially ranging from less than one notch to as much as several notches in the case of more significant factors. DBRS considers both sector-specific and general overlay factors. Sector specific factors include capital spending, energy supply considerations, ownership, retail exposure, competitive environment and environmental issues while general overlay factors include strategic advantage, parent-subsidiary relationship, sovereign risk, ESG considerations and other financial considerations.

DBRS notes that where an ESG factor is material to a corporate rating, but is not otherwise addressed in a business or financial risk factor or other overlay, DBRS will reflect the impact of the ESG factor on the rating through this general ESG overlay. On May 28, 2021, DBRS published ESG Risk Factors for Regulated Utilities, which outlines credit rating agency's approach to evaluating ESG risk factors and their potential effect on credit ratings for regulated utilities. Of the seventeen ESG factors that DBRS considers relevant in its ratings process, DBRS identified seven factors that are applicable to regulated utilities. These factors are listed in the table below:

Factor	Context
Environmental Factors	
Carbon and GHG Costs	"Governments and regulators around the globe are setting GHG emission reduction targets and placing a price on carbon to mitigate the impact these particles have on the environment. If the regulator does not approve for a utility to completely passthrough these costs to customers, earnings would be increasingly pressured year over year as the targets become more and more stringent. As well, even if costs are fully passed through, customer rates would climb annually which could hinder customer affordability. Similarly, natural gas distribution utilities face risk related to carbon pricing and emission reduction targets as these costs would have to be passed through to customers as well."
Emissions, Effluents and Waste	"For natural gas distributors, there is emissions risk associated with the infrastructure in place. Pipelines that are not managed in accordance with safety guidelines could lead to leaks or, in extreme cases, even explosions…These instances of noncompliance would all harm the environment and the surrounding communities, and lead to financial penalties by environmental agencies and lawsuits from the affected communities, resulting in a negative impact to a utility's credit profile."[33]
Climate and Weather Risks	"…extreme weather events have become more and more frequent, and are testing the resiliency of the grids as well as the adequacy of the regulatory framework in place for utilities to recover costs. Utilities that fail to maintain operations during extreme weather events have seen reputational loss, faced extra scrutiny from regulations, and increased expenditures to harden the grid." "Greater natural gas and electricity demand during the winter heating or summer cooling months could also drive commodity prices higher, which would require utilities to maintain stronger liquidity to ensure there is adequate working capital in place to purchase supplies for their customers." [34]

[33] DBRS Morningstar ESG Risk Factors for Regulated Utilities, May 28, 2021.
[34] DBRS Morningstar ESG Risk Factors for Regulated Utilities, May 28, 2021.

Factor	Context
Social Factors	
Access to Basic Services	"More and more jurisdictions have also transitioned to some form of incentive rate-making regime where utilities must find productivity gains in order to earn the allowed return on equity. These regimes are meant to incentivize utilities to become more efficient and keep rate increases at around inflation so customers' bills would remain affordable. However, if the mechanisms are not properly designed or the productivity and stretch factors are too onerous, a utility's earnings could then become pressured and negatively affect its credit profile."
Governance Factors	
Bribery, Corruption, and Political Risks	"Energy policies, as determined by governments, could influence regulators and their ability to independently and impartially arrive at a decision; some regulators in fact function as an arm of the government. Governments could also pass legislation to override a decision made by a regulator. Many utilities may also be directly owned by governments and are thus directly overseen by the government. If legislation passed by government or decisions approved by regulators have an adverse impact on a utility's business or financial profile, especially if it affects a utility's ability to pass through costs to customers, this could negatively affect credit ratings."

Lastly, as discussed in FortisBC's evidence, as climate related financial disclosures become mandatory in the near future, investors and credit rating agencies will have increased visibility and new sources of information which will significantly improve their ability to access climate related information.

8.1.1 Please discuss any benefits of ESG investing for FEI (e.g., customers in FEI's Renewable Gas Program who will be able to meet their ESG goals).

Response:

As a natural gas utility, even while FEI is taking steps to actively position itself in response to the Energy Transition, there is no reasonable scenario where investors face less risk than before the advent of the ESG investing.

FEI's programs to increase the share of Renewable Gas in its supply portfolio and its proposals in the recently filed comprehensive review of Renewable Gas program to expand its Renewable Gas offerings may enable some customers to meet their ESG goals and/or mandates. However, these initiatives involve significant risk as renewable natural gas is more costly than conventional natural gas and will require further development of production and processing infrastructure by FEI and its suppliers.

While FEI is planning to significantly increase its Renewable Gas offerings, it will continue to rely on conventional natural gas for its base supply for some time and it is unlikely that ESG investors view FEI as a renewable company.

8.1.2 Please discuss whether higher demand of ESG products will increase a company's market value and thereby strengthen a company's financial metrics.

Response:

Please refer to the response to BCUC IR1 8.1.1.

8.2 Please discuss if FEI expects a downgrade to below an A-category credit rating and explain why. Include the supporting evidence.

Response:

While FEI does not expect a downgrade to below an A-category credit rating in the near term, it does not consider its A level credit rating to be secure. Please refer to the response to BCUC IR1 6.2.1.

8.3 Please discuss how FEI can offset the downward pressure on FEI's credit rating from ESG-related risks apart from strengthening its financial metrics.

Response:

As discussed in FortisBC's evidence, Moody's rating methodology for electric and natural gas utilities is primarily based on a rating grid comprised of four key factors. Table 6-2 reproduced below provides a description of Moody's rating factors and sub-factors as defined for regulated utilities.

Table 6-2: Moody's Rating Grid for Regulated Utilities

Broad Rating Factor	Factor Weighting	Rating Sub-factor	Sub-factor weighting
Regulatory Framework	25 %	Legislative and judicial underpinnings of regulatory framework Consistency and predictability of regulation	12.5 % 12.5%
Ability to recover costs and earn returns	25 %	Timeliness of recovery of operating and capital costs Sufficiency of rates and returns	12.5 % 12.5 %
Diversification	10 %	Market Position[1] Generation and Fuel Diversity[2]	5 % 5 %
Financial Strength	40 %	CFO Pre-WC[52] + Interest / Interest CFO Pre-WC / Debt CFO Pre-WC – Dividends / Debt Debt / Capitalization	7.5 % 15 % 10 % 7.5 %

Source: Moody's Rating Methodology for Regulated Electric and Gas Utilities, June 2017.

The factors in the rating grid do not constitute an exhaustive treatment of all of the considerations for ratings of companies in the regulated electric and gas utility sector. Other considerations that may play a part in a rating process include items such as ownership, management, corporate legal structure or governance. Moody's considers these and other qualitative considerations that do not lend themselves to a transparent presentation in a scorecard format. Therefore, the grid indicated ratings do not always match the actual Moody's rating of each company. FEI is not aware of any other factors that may play a role in determining FEI's credit rating and therefore will focus on the four key factors outlined in Table 6-2.

The table reproduced below and included in 2021 FEI's credit rating report published by Moody's on November 25, 2021, outlines how FEI has scored in the four key categories of (1) regulatory framework; (2) ability to recover costs and earn returns; (3) diversification; and (4) financial strength for last twelve months September 31, 2021 and provides Moody's 12-18 month forward view as of date published.

Exhibit 7
Methodology Scorecard Factors
FortisBC Energy Inc.

Regulated Electric and Gas Utilities Industry Scorecard [1][2]	Current LTM 9/30/2021		Moody's 12-18 Month Forward View As of Date Published [3]	
Factor 1 : Regulatory Framework (25%)	**Measure**	**Score**	**Measure**	**Score**
a) Legislative and Judicial Underpinnings of the Regulatory Framework	A	A	A	A
b) Consistency and Predictability of Regulation	Aa	Aa	Aa	Aa
Factor 2 : Ability to Recover Costs and Earn Returns (25%)				
a) Timeliness of Recovery of Operating and Capital Costs	Aa	Aa	Aa	Aa
b) Sufficiency of Rates and Returns	Baa	Baa	Baa	Baa
Factor 3 : Diversification (10%)				
a) Market Position	Baa	Baa	Baa	Baa
b) Generation and Fuel Diversity	N/A	N/A	N/A	N/A
Factor 4 : Financial Strength (40%)				
a) CFO pre-WC + Interest / Interest (3 Year Avg)	3.0x	Baa	2.5x - 3x	Ba
b) CFO pre-WC / Debt (3 Year Avg)	12.6%	Baa	11% - 13%	Baa
c) CFO pre-WC – Dividends / Debt (3 Year Avg)	7.8%	Baa	6% - 9%	Baa
d) Debt / Capitalization (3 Year Avg)	47.6%	A	46% - 49%	A

As discussed in the evidence and as can be seen above, most financial metrics score below an A level rating threshold.

Other factors that have scored below an A level rating threshold are:

- Sufficiency of rates and returns that has scored Baa; and
- Market position that has also scored Baa.

The factors that drive sufficiency of rates and financial strength are primarily based on allowed ROE and equity thickness. Based on Table 6-2 above, the remaining factor that is below A level rating threshold and could be improved, market position, contributes 5 percent to FEI's overall credit rating vs. financial metrics and sufficiency of rates and returns that contribute over half (52.5 percent) on a combined basis. As such, strengthening market position would not improve FEI's credit score in a meaningful way compared to strengthening the returns and financial metrics to offset the downward pressure on FEI's credit rating from ESG-related risks.

8.4 Please discuss how FEI can strengthen its financial metrics apart from increasing FEI's equity component.

Response:

As discussed in FortisBC's evidence, key determinants of FEI's weak financial metrics are the low allowed equity component of its capital structure and relatively low return on equity. FEI's 2021 credit rating report from Moody's published on November 25, 2021 stated:

> FEI's credit profile is driven by its low business risk gas transmission and distribution assets that operate in the credit supportive regulatory environment of British Columbia and its monopoly position in its service territory. The company has a long term track record of earning its allowed return on equity and its cash flow continues to be highly predictable. These strengths are offset by the company's weak financial metrics that we forecast will be in the range of 11-13% CFO pre-W/C to debt. These financial metrics are primarily a product of a low allowed equity component of its capital structure, a relatively low return on equity, and depreciation rates.

Based on the above statement from Moody's, the weak financial metrics are primarily a product of:

- the low allowed equity component of its capital structure;
- the relatively low return on equity; and
- the depreciation rates.

Increasing FEI's equity component of capital structure would directly improve three out of four financial metrics and indirectly improve the remaining financial metric as it would increase the equity levels that FEI is carrying and decrease the debt amount that goes into calculating the following financial metrics:

- CFO Pre-WC/Debt;
- CFO Pre-W/C – Dividends/Debt; and
- Debt/Book Capitalization.

It would also indirectly improve the CFO Pre-WC + Interest/Interest Expense financial metric as it would limit the interest expense that FEI otherwise would have taken on had the equity component stayed the same.

Increasing return on equity would directly improve the following financial metrics as it would increase FEI's net income that goes into the numerator of the following metrics:

- CFO Pre-WC/Debt;
- CFO Pre-W/C – Dividends/Debt; and
- CFO Pre-WC + Interest/Interest Expense.

Increasing depreciation rates would also increase cost of service (revenue requirements) which would increase the CFO Pre-WC and improve the three financial metrics that include CFO Pre-WC/Debt in the numerator. Depreciation rates are based on objective estimates of remaining useful life, are reviewed by the BCUC, and are not at the discretion of FEI.

Lowering capital cost allowance (CCA) would be another way to increase FEI's cost of service and therefore improve the CFO Pre-WC; however, changing CCA is outside of FEI's control as the rates are determined by the Canada Revenue Agency.

Based on the above, increasing FEI's allowed equity component of capital structure, return on equity and/or depreciation rates would have the greatest impact on improving FEI's weak financial metrics.

9.0 Reference: PROPOSED CAPITAL STRUCTURE

Exhibit B1-8, FBCU Evidence, p. 38; FEI Annual Review for 2022 Delivery Rates (FEI 2022 Rates) Application, Exhibit B-2 and Exhibit B-3

Capital Structure – Capital Expenditures

On page 38 of Exhibit B1-8, FBCU states that FEI's rate base assets have grown by approximately 36 percent over the past three years and "FEI's financing requirements for its large capital projects are expected to increase substantially in the upcoming years."

Also, on page 38 of Exhibit B1-8, FBCU provides the following table:

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

FEI's Major Capital Projects[1]	Actuals[2]		Pro-Forma[3]						Total Project	
(C$ millions)	2019	2020	2021	2022	2023	2024	2025	2026	Costs[4]	Approval
Tilbury 1B	7.8	12.1	-	32.1	40.6	52.2	80.9	-	400.0	OIC
Inland Gas Upgrades Project	8.2	50.1	99.3	93.5	67.4	31.2	-	-	360.2	BCUC
Okanagan Capacity Upgrade	-	7.9	11.3	113.5	139.2	-	-	-	271.3	Under Review
Pattullo Bridge Crossing Replacement	-	6.4	51.9	118.7	11.3	2.9	-	-	191.7	BCUC
TIMC CTS[5]	-	9.4	21.3	7.4	4.5	92.5	2.9	-	137.8	Under Review
Advanced Metering Infrastructure	-	-	28.0	17.1	116.1	193.3	182.9	97.5	638.4	Under Review
Tilbury LNG Storage Expansion	-	8.6	4.6	18.0	165.8	251.7	210.2	110.9	769.0	Under Review
Sustainment and other capital[6]	151.5	163.2	166.1	159.7	162.2	165.8	169.2	172.5	995.5	
Total	**167.5**	**257.7**	**382.5**	**560.0**	**707.1**	**789.6**	**646.1**	**380.9**	**3,763.9**	

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

In the FEI 2022 Rates Application, FEI states that the Regional Gas Supply Diversity (RGSD) Project "will provide significant benefits with respect to system resiliency, gas supply, decarbonization, and Indigenous reconciliation" and "is anticipated to be in the range of $4 billion."

9.1 Please provide the total capital cost for FEI's major capital projects from 2009 to 2018.

Response:

Please see the table below for FEI's major capital projects from 2009 to 2018. Please note the following regarding the information provided in the table below:

- FEI has included the annual sustainment and other capital costs to be consistent with what was provided in Table 6-5 of Exhibit B1-8;
- All actuals are from FEI's Annual Reports filed with the BCUC; and

- The sustainment and other capital and major capital projects for 2009 through 2014 include FortisBC Energy (Vancouver Island) Inc. (FEVI) and FortisBC Energy (Whistler) Inc. (FEW) prior to amalgamation with FEI in 2014.

	Actuals										
FEI's Major Capital Projects (C$millions)	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	Approval
Sustainment and other capital (2009-2014 Incl. FEVI and FEW)	81.6	76.3	94.1	95.0	123.1	125.4	117.4	122.4	148.3	159.2	
Tilbury 1A				14.7	2.7	141.8	181.2	80.8	50.5	5.7	OIC
Tilbury 1B										1.4	OIC
LMIPSU							1.3	9.1	29.5	165.5	BCUC
Lower Mainland System Upgrade (LMSU-CTS)						1.7	8.4	19.5	115.7	18.6	OIC
Huntingdon Control Station							5.8	0.6	-		BCUC
Kootenay River Crossing Project		1.1	0.8	3.9	0.8	(0.7)					BCUC
SBSA Fraser River Crossing	9.0	10.3	11.1	1.4	0.0						BCUC
Customer Care Enhancement Project		26.7	29.8	9.8							BCUC
Victoria Regional Office and Customer Service (FEVI)				20.8	0.0						BCUC
Mt Hayes LNG Storage (FEVI)			209.7	0.5							BCUC
Whistler Pipeline Project (FEVI)	45.4										BCUC
Whistler Conversion Project (FEW)	3.0										BCUC
Total	139.0	114.4	345.6	146.1	126.6	268.2	314.1	232.4	343.9	350.4	

9.2 Please explain why the RGSD Project is not included in FBCU's Table 6-5: Capital Cost for FEI's Major Capital Projects for 2019–2026.

Response:

The RGSD Project was not included in FortisBC's Table 6-5 for FEI's Major Capital Projects for 2019 to 2026 because FEI is not expecting the RGSD Project construction to commence until late in 2026 (at the earliest). Furthermore, FEI is only at the preliminary stage of the RGSD Project and does not have detailed information regarding the forecast capital expenditures or construction schedule (beyond the high level estimate of $4 billion provided in the 2022 Annual Review and the high level estimate that construction may commence in late 2026). FEI is currently preparing the RGSD Development Costs Deferral Account Application following the decision in FEI's 2022 Annual Review[35]. As discussed during the 2022 Annual Review, FEI expects to incur approximately $49.3 million[36] in project development costs for the RGSD Project prior to filing a CPCN application. These project development costs would fall within the period of 2019 to 2026.

9.3 Please re-state Table 6-5 to add the RGSD Project and include any other projects that FEI intends to apply for BCUC approval up to 2026. As part of the response, please categorize the projects as either (i) mandatory maintenance or replacement of existing infrastructure; (ii) upgrades for system resiliency and supply

[35] Order G-366-21.
[36] Exhibit B-11 of FEI's 2022 Annual Review.

diversification; or (iii) upgrades in response to load growth. Include the expected revenue generated for the projects identified.

Response:

Please refer to Table 1 below for an updated Table 6-5 that includes the TIMC ITS Project. FEI is currently expecting to file the TIMC ITS Project CPCN application later this year with construction expected to begin prior to 2026. FEI has added the requested Project Category for each project as requested, but many projects will have attributes that cross categories (for example, AMI replaces existing meters but also provides resiliency benefits).

Please also refer to Table 2 below for the expected incremental revenue requirement (i.e., incremental cost of service) for each project. Please refer to the response to BCUC IR1 9.2 for an explanation of why the RGSD Project is not included in the tables.

Table 1: Updated Table 6-5 Capital Costs of FEI's Major Capital Projects for 2019 to 2026

FEI's Major Capital Projects	Actuals		Pro-Forma						Total Project		
Capital Expenditures (C$millions)	2019	2020	2021	2022	2023	2024	2025	2026	Costs	Approval	Project Category
Tilbury 1B	7.8	12.1	-	32.1	40.6	52.2	80.9	-	400.0	OIC	iii) Load Growth (LNG)
Inland Gas Upgrades Project	8.2	50.1	99.3	93.5	67.4	31.2	-	-	360.2	BCUC	i) Maintenance/Replacement
Okanagan Capacity Upgrade	-	7.9	11.3	113.5	139.2	-	-	-	271.3	Under Review	iii) Load Growth (Local)
Pattullo Bridge Crossing Replacement	-	6.4	51.9	118.7	11.3	2.9	-	-	191.7	BCUC	i) Maintenance/Replacement
TIMC (CTS)	-	9.4	21.3	7.4	4.5	92.5	2.9	-	137.8	Under Review	i) Maintenance/Replacement
TIMC (ITS)	-	-	2.6	5.7	11.1	30.2	30.3	0.04	79.9	Developing	i) Maintenance/Replacement
Advanced Metering Infrastructure	-	-	28.0	17.1	116.1	193.3	182.9	97.5	638.4	Under Review	ii) Resiliency and/or Supply Diversification
Tilbury LNG Storage Expansion	-	8.6	4.6	18.0	165.8	251.7	210.2	110.9	769.0	Under Review	ii) Resiliency and/or Supply Diversification
Sustainment and other capital	151.5	163.2	166.1	159.7	162.2	165.8	169.2	172.5	995.5		i) Maintenance/Replacement
Total	**167.5**	**257.6**	**385.0**	**565.7**	**718.2**	**819.8**	**676.4**	**381.0**	**3,843.9**		

Table 2: Incremental Cost of Service for each of FEI's Major Projects for 2019 to 2026

FEI's Major Capital Projects	Actuals		Pro-Forma						Cumulative		
Incremental Cost of Service (C$millions)	2019	2020	2021	2022	2023	2024	2025	2026	2019-2026	Approval	Project Category
Tilbury 1B	-	-	-	-	-	-	-	-	-	OIC	iii) Load Growth (LNG)
Inland Gas Upgrades Project	-	-	2.8	9.8	19.2	28.3	34.2	36.0	130.3	BCUC	i) Maintenance/Replacement
Okanagan Capacity Upgrade	-	-	-	(0.4)	(0.3)	19.4	20.8	21.0	60.6	Under Review	iii) Load Growth (Local)
Pattullo Bridge Crossing Replacement	-	-	-	(3.0)	9.1	15.0	15.3	15.3	51.6	BCUC	i) Maintenance/Replacement
TIMC (CTS)	-	-	-	-	10.7	11.0	10.7	11.5	43.9	Under Review	i) Maintenance/Replacement
TIMC (ITS)	-	-	-	-	-	(1.1)	1.6	6.7	7.2	Developing	i) Maintenance/Replacement
Advanced Metering Infrastructure	-	-	-	-	(3.4)	13.1	31.1	41.7	82.6	Under Review	ii) Resiliency and/or Supply Diversification
Tilbury LNG Storage Expansion	-	-	-	-	-	0.2	1.3	22.9	24.4	Under Review	ii) Resiliency and/or Supply Diversification
Sustainment and other capital	16.2	28.7	42.0	55.3	68.2	81.3	94.7	108.2	494.6		i) Maintenance/Replacement
Total	**16.2**	**28.7**	**44.8**	**61.7**	**103.5**	**167.3**	**209.6**	**263.3**	**895.2**		

9.4 Please discuss how FEI's $3.8 billion expected major capital projects spending is expected to increase or decrease FEI's business risk over the short-term and long-term.

Response:

The majority of FEI's major capital projects spending is undertaken to improve safety, system integrity, reliability, reduce operating costs, or accommodate government orders or third-party

drivers. Examples include the Pattullo Bridge Crossing Replacement, Inland Gas Upgrades (IGU), Advanced Metering Infrastructure (AMI), and the Coastal Transmission System (CTS) Upgrades projects. Due to the wide range of purposes of these projects, it is not possible to reach a general conclusion regarding their impact on risk. For example, a project like the IGU project can reduce operating risk but increase rates without attracting any incremental revenue.

Other major projects, such as Tilbury 1B (note that this is a different project from the TLSE project currently before the BCUC, which is not a growth project), are expected to provide benefits to existing ratepayers by increasing throughput while also helping to reduce customers' GHG emissions. However, this growth project will provide only partial mitigation of the potential unfavourable risks in FEI's residential market since the increased throughput will be mainly in the more volatile and economically sensitive Industrial and LCT sectors, which have lower delivery rates than the residential rate class in which the throughput decreases are occurring, and there are incremental costs associated with securing the new load. In other words, it will take a larger number of gigajoules of this more volatile throughput from the new initiatives to offset each gigajoule of lost load in the residential class.

9.5 Please discuss whether or not FEI considers the anticipated $4 billion RGSD Project, which FEI expects to "provide significant benefits with respect to system resiliency, gas supply, decarbonization, and Indigenous reconciliation", helps to mitigate concerns related to energy transition and therefore, the proposed ROE increase.

Response:

New pipeline infrastructure such as the RGSD project will support the decarbonization initiatives in the region, and will thus mitigate growing Energy Transition risk once approved, constructed, and in service. In the short term, natural gas usage for power generation has increased in the Pacific Northwest (PNW) due to the retirement of coal plants. As the region continues to try and replace the power generated by coal with renewable projects, it is uncertain what the future usage for natural gas will be, as renewables are not sufficiently available at this time, and will be intermittent depending on weather conditions. Therefore, natural gas and the power market in the PNW will continue to become more interconnected. Over the longer term, when hydrogen emerges in the market, it will be able to blend into natural gas transmission and distribution systems. If this occurs, the heat content of hydrogen is less than natural gas. As a result, to deliver the equivalent amount of energy as natural gas, additional pipeline capacity would be required, depending on the blend.

In conclusion, projects like the RGSD project mitigate the Energy Transition risk's impact on regional energy security and reliability. From this perspective, the RGSD project, once approved, constructed and in service, will mitigate the Energy Transition risk for all regional stakeholders

including electric utilities in the PNW that are increasingly relying on renewable sources of power for their power supply needs. The demand, political and financial side of FEI's Energy Transition risk, which are significant elements of the risk, will remain even with the RGSD project.

9.6 Please explain whether FEI's financing requirements for its major capital projects have negatively affected FEI's financial metrics or hindered FEI's ability to raise capital in the last 10 years.

Response:

FEI has been able to raise capital in the last 10 years to finance its major capital projects. While capital projects in service do not have a direct negative impact on the financial metrics, they do impact the metrics indirectly through the debt that needs to be raised to finance them. An FEI downgrade to below an A-category credit rating would result in a higher cost of debt, which would result in FEI incurring significant additional interest costs to finance its large capital program. An increase in FEI's equity component would support the company's current credit ratings and provide confidence that FEI will have access to low cost debt to finance its capital projects, even under challenging economic and capital market conditions.

10.0 Reference: PROPOSED CAPITAL STRUCTURE

Exhibit B1-8-1, Appendix D- 2, "FEI - Moody's 2021 Credit Rating Report dated November 25, 2021", p. 5

Capital Structure – Depreciation

On page 5 of "FEI - Moody's 2021 Credit Rating Report" in Appendix D-2, Moody's states that it expects FEI "to continue to generate stable cash flow, a key credit strength" and that underpinning this stability is a function of FEI's rate base, low allowed equity component of its capital structure, a relatively low return on equity, and depreciation rates.

10.1 To the best of FEI's knowledge, please clarify which companies or industries Moody's compares FEI to, such that FEI has a relative "low allowed equity component of its capital structure, a relatively low return on equity, and depreciation rates."

Response:

To the best of FEI's knowledge, Moody's compares FEI's allowed equity component of its capital structure, return on equity and depreciation rates to other North American regulated utilities that are also rated by Moody's; however, FEI does not have visibility into what companies exactly make up the comparable company group that Moody's is referencing.

10.1.1 Please confirm, or explain otherwise, that the allowed fair return is unique to regulated utilities in British Columbia (BC) because other companies or industries that are not subject to utility regulation would not have a guaranteed return.

Response:

It is true that utilities are underpinned by regulated returns and the Fair Return Standard only applies to regulated returns; however, regulated utilities do not enjoy a "guaranteed return". Rather, under the Fair Return Standard and the regulatory compact, the utilities should be given a reasonable opportunity to earn a fair return on their invested capital and recover their prudently-incurred costs.

10.2 Please explain whether FEI considers return of capital when determining depreciation rates. As part of the response, please discuss whether higher

depreciation rates increase the return of capital and whether it would be appropriate to increase depreciation rates for a quicker return of capital.

Response:

Yes, FEI considers return of capital when determining depreciation rates as depreciation rates are set to achieve just that - a return of capital invested over the useful life of the assets. With higher depreciation rates, return of capital is accelerated (i.e., timing of recovery of capital) but higher depreciation rates do not result in a greater return of capital.

One approach that FEI could take in light of the Energy Transition risk would be to develop pathways to pay for the early retirement of assets (such as accelerating depreciation). A better approach for FEI currently and one that is has been pursuing to date is to develop alternative energy products and services that leverage existing assets while also reducing emissions.

FEI believes its assets can play a critical role in the transition towards a lower carbon economy and, because of this, developing alternative energy products and services that leverage existing assets while also reducing emissions is the reasonable and appropriate pathway. Pursuing the early retirement of assets is conceptually at odds with the development of alternative products and services using those assets. Moreover, preparing for the retirement of assets today would only serve to increase costs for customers while also decreasing the competitiveness of the gas energy delivery system.

10.3 Please provide FEI's actual and forecast average depreciation rate for periods 2019 to 2026.

Response:

For the periods 2019 to 2022, the table below outlines FEI's overall forecast and actual average depreciation rate.

FEI Average Depreciation Rates 2019-2022 (in percent)

	2019	2020	2021	2022
Forecast	2.96%	2.60%	2.64%	2.65%
Actual	2.89%	2.60%	N/A	N/A

A new depreciation study, that was approved and effective for 2020, resulted in a lower average composite depreciation rate for FEI than the prior year. Variations in the average depreciation rate since that time (both forecast and actual) are not due to changes in the underlying depreciation rates, which have remained unchanged, but due to changes in the composition of FEI's assets through capital additions and retirements.

Given the current approved depreciation rates, based on the depreciation study approved by BCUC Order G-165-20, the 2023 and 2024 forecast average depreciation rates are not expected to change significantly from the 2022 forecast average depreciation rate of 2.65 percent. The 2025 and 2026 forecast average depreciation rates are expected to be based on the next depreciation study that is anticipated to be completed prior to 2025. The actual average depreciation rates for 2021 to 2026 are not available at this time.

10.4 Please discuss FEI's process in reviewing depreciation rates including how often FEI reviews depreciation rates and the involvement from third-party reviewers.

Response:

FEI follows common industry practice for utilities for reviewing and updating the depreciation rates for its assets, including working with an external depreciation specialist to determine the depreciation rates. This approach is preferred as it leverages the expertise of an external specialist who has industry-wide expertise and provides validation of the rates.

In arriving at the recommended depreciation rates, the depreciation specialist performs a number of activities including a review of FEI's assets and retirement transactions, conducting operational interviews with FEI staff, and comparing the results to FEI's industry peers. In addition to providing the financial data requested by its depreciation specialist, FEI reviews the recommended depreciation rates for accuracy, reasonableness and applicability to the assets. The rates are then adjusted to factor in the recovery of any existing retirement losses (or gains) that may be included in the accumulated depreciation account balance, consistent with the BCUC-approved approach; the adjustment is designed to recover losses (or gains) resulting from under- or over-depreciating existing assets over the remaining lives of the existing assets. Over the years, FEI has consistently followed the practice of engaging an external depreciation specialist in updating its depreciation rates.

FEI completes a depreciation study every three to five years. Three to five years is sufficient in length to detect long-term trends in changes to assets' service lives. Any shorter review interval may be unduly influenced by short-term events and lead to unnecessary rate volatility. FEI recently completed a depreciation study which was included in FEI's 2020 -2024 MRP Application. FEI's next depreciation study will be completed prior to 2025.

11.0 Reference: BUSINESS PROFILE

Exhibit B1-8-1, Appendix A - FEI Business Risk Assessment, pp. 9 and 83

Business Profile – Rate Base

On page 9 of Appendix A, FEI states that the risk related to the type and size of its gas utility is similar to the 2016 Proceeding.

On page 9 of Appendix A, FEI states that although rate base has increased by almost 50 percent since 2015, growth in demand and customers has not kept pace. FEI provides the following table:

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

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

On page 83 of Appendix A, FEI provides the following table:

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

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

11.1 Please provide a table with FEI's annual rate base, sales/transportation volumes, average number of customers and capital program for 2013–2022, inclusive.

Response:

Please refer to the table below for FEI's annual rate base, sales/transportation volumes, average number of customers and capital program (i.e., major projects/CPCNs and non-CPCN capital expenditures) with actuals for 2013 through 2021[37] and approved amounts for 2022. For 2013

[37] 2021 Actuals are based on preliminary result as FEI's 2021 Annual Report to the BCUC is not yet available.

and 2014, the numbers provided in the table below include FEVI and FEW which were separate entities prior to amalgamation in 2015. FEI notes that the 2015 numbers shown in Table A2-1 as referenced in the preamble are 2015 Approved numbers from FEI's 2015 Annual Review (Footnote 7 of Appendix A to FEI's Evidence) which differ from the 2015 Actuals shown in the table below.

Year	2013 Actual	2014 Actual	2015 Actual	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Approved
Rate Base ($000s)	3,573,354	3,587,771	3,646,848	3,676,416	3,726,808	4,391,711	4,518,093	5,012,592	5,199,050	5,409,207
Sale/Transportation Volumes (TJ)	199,810	195,174	185,836	196,419	220,095	210,816	226,121	218,770	227,460	234,057
Average Number of Customers	945,876	959,194	968,766	983,807	997,380	1,016,353	1,031,862	1,044,623	1,057,086	1,068,490
Capital Expenditures ($000s)										
Major Projects and CPCNs	7,775	140,994	211,798	122,678	152,262	191,241	216,990	121,392	80,947	201,925
Non-CPCNs	177,482	188,629	174,489	182,976	214,793	247,078	252,252	259,807	254,715	301,782
Total	185,257	329,623	386,287	305,654	367,055	438,318	469,242	381,199	335,662	503,707

11.2 Please explain the increase in residential customer additions between 2017 and 2018. As part of the response, please discuss if the driver is likely to occur again over the next five years.

Response:

The increase in net customer additions for 2018 was driven by strong Gross Customer attachments in both new construction and conversion, as well as fewer existing customers leaving the system which in turn is driven by timing differences between move in, move out, and disconnections. Together all these factors resulted in a year that had higher than normal net customer additions. FEI does not expect to see this high number of net additions in the near future.

11.3 Please discuss whether FEI considers net customer additions when applying for projects to add to its rate base.

Response:

The majority of FEI's capital spending relates to sustainment projects that are necessary to ensure the ongoing integrity, reliability, and safety of FEI's system. These non-growth projects ensure that a robust system is available to support customer growth. FEI's growth and capacity upgrade projects are driven by increasing demand in a particular region and are designed to ensure safe and reliable service even during extreme peak loading conditions. Designing the system for peak load conditions involves various considerations including but not limited to regional design day,

the forecast number of customers in each region, and reasonable and current estimates of customer peak demand (UPC_{peak}). As such, FEI's forecast net customer additions are an important component of peak load calculations for infrastructure sizing and hence net customer additions are considered in both FEI's sustainment and growth projects.

11.4 Please discuss how FEI is addressing the growth of rate base outpacing the growth of demand and customers. For example, can FEI slow the growth in rate base and what are the implications? On the other hand, if this gap continues to grow, how will this impact FEI's operations and its ability to attract and retain customers.

Response:

As noted, not all of FEI's growth in rate base is related to growth in demand and customers. FEI's growth in rate base can be attributed to three areas: 1) sustainment or resiliency of FEI's system, 2) response to the BC Government's climate policy and Energy Transition risk, and 3) growth capital investment.

First, as a public utility, FEI has a duty to provide safe and reliable service to all customers, without any undue discrimination, as long as they are connected to FEI's system. A large share of the growth in FEI's rate base during the period cited in the preamble relates to projects that are sustainment related and focus on FEI's system integrity, reliability, resiliency, and safety that are required irrespective of the growth projections for demand and number of customers. While necessary, these projects are not expected to generate offsetting revenue thus, all else equal, will increase FEI's costs and decrease FEI's price competitiveness. This is evident as shown in the responses to BCUC IR1 9.1 and 9.3 where the majority of FEI's capital expenditures in the past, as well as currently forecasted up to 2026, are related to sustainment of existing assets or resiliency of FEI's system, and not related to growth in demand and/or customers.

Second, a smaller portion of the growth in rate base during this period relates to FEI's projects and initiatives designed to align FEI's business with the BC Government's climate policy and mitigate some of the Energy Transition risk FEI is facing. These include FEI's investments to grow its nascent LCT business, LNG for marine fueling and global markets, and Renewable Gas program. These projects, while inherently more risky than traditional utility investments, are expected to provide net benefits to FEI's rate payers in terms of increased demand and revenue and are expected to partially mitigate some of the load loss from FEI's core business of space heating and water heating applications in the residential sector.

Finally, the remaining growth in FEI's rate base is associated with ongoing growth capital investments required to connect new customers in order to meet FEI's duty to serve and cannot be delayed or eliminated.

Differences between growth in rate base and growth in demand/customer are not unusual for utilities. This is because the timing of various growth and sustainment investments is not necessarily directly aligned with the rate of new customer connections. In some cases these investments may lead customer growth (i.e., capacity related projects), or potentially lag customer growth (i.e., sustainment, reliability and resiliency projects). If FEI were to intentionally underinvest in capital in an attempt to slow the growth in rate base, this underinvestment would result in impacts by FEI either:

- Not undertaking necessary integrity, reliability, and/or safety projects that could result in FEI not complying with its regulatory obligations to provide safe and reliable service;
- Not complying with Government climate policies and directions, and/or not addressing the Energy Transition risk, and hence forgoing potential growth opportunities to mitigate customer rates; or
- Not providing non-discriminatory service to new customers who request service.

FEI's focus continues to be on maintaining its customer base and growing customers and volumes to help mitigate the rate impacts of necessary rate base growth.

12.0 Reference: BUSINESS PROFILE

Exhibit B1-8-1, Appendix A - FEI Business Risk Assessment, pp. 10–11 and 15

Business Profile – Customer Profile

On page 10 of Appendix A, FEI submits that its customer profile risk is higher compared to the 2016 Proceeding. On pages 10 and 11 of Appendix A, FEI states:

> The fact that the majority of FEI's delivery margin and revenue are generated from residential customers is significant because FEI faces its greatest challenges in maintaining its share of the residential market. FEI assesses that its customer profile risk is higher compared to the 2016 Proceeding, both due to the increased risk to maintaining load in the core residential and commercial sectors, and that the load being added to mitigate those losses is subject to greater volatility and market conditions.

On page 15 of Appendix A, FEI states:

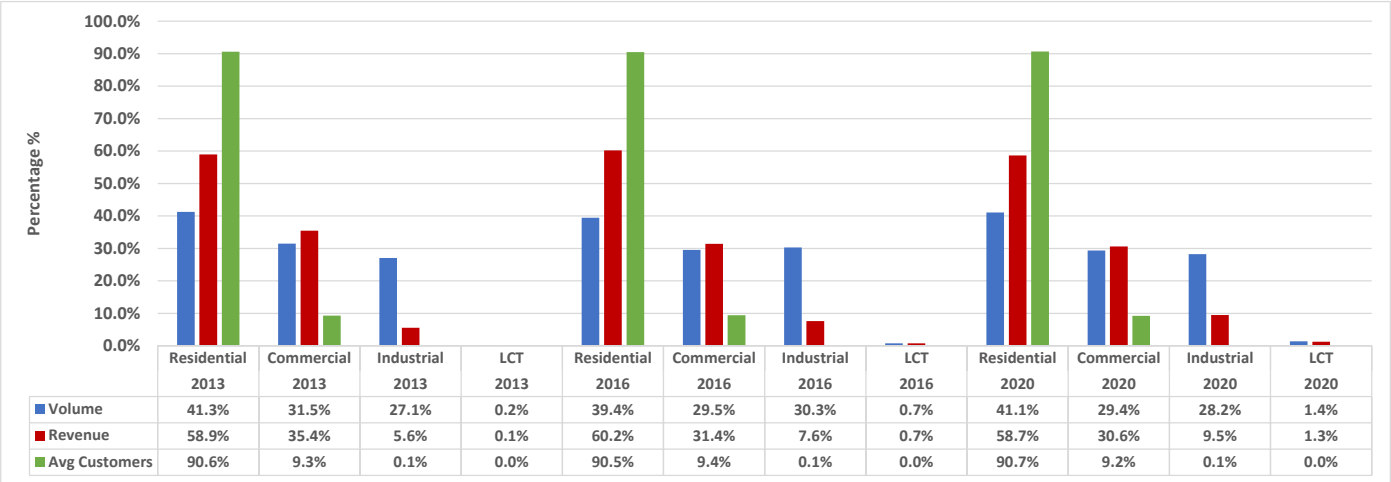
> In summary, FEI's primary market continues to be residential and commercial space and water heating end-uses. Despite some shift in load to the industrial and LCT sectors, which are both more volatile and more sensitive to economic conditions, FEI assesses its overall business profile risk to be similar to the 2016 Proceeding.

12.1 Please provide a graph in a similar format to Figure A2-1 showing FEI's Business Profile by markets served, including residential, commercial, industrial and low carbon transportation (LCT) sectors for data in years 2013, 2016 and most recent actual year (e.g., 2020). As part of the response, please include the sales/transportation volumes.

Response:

Please refer to the figure below showing FEI's business profile breakdown between residential, commercial, industrial and LCT[38] sectors in Actuals for years 2013, 2016, and 2020 in a similar format to Figure A2-1 of FEI's Evidence. Consistent with Figure A2-1 (as well as Table A2-1 of FEI's Evidence), the business profiles include non-bypass customers and LNG customers served under RS 46 only (Footnote 8 of FEI's Evidence).

[38] LCT includes CNG customers served under RS 3/23, 5/25 and 6 as well LNG customer under RS 46.



	Residential 2013	Commercial 2013	Industrial 2013	LCT 2013	Residential 2016	Commercial 2016	Industrial 2016	LCT 2016	Residential 2020	Commercial 2020	Industrial 2020	LCT 2020
Volume	41.3%	31.5%	27.1%	0.2%	39.4%	29.5%	30.3%	0.7%	41.1%	29.4%	28.2%	1.4%
Revenue	58.9%	35.4%	5.6%	0.1%	60.2%	31.4%	7.6%	0.7%	58.7%	30.6%	9.5%	1.3%
Avg Customers	90.6%	9.3%	0.1%	0.0%	90.5%	9.4%	0.1%	0.0%	90.7%	9.2%	0.1%	0.0%

12.2 Please elaborate on why FEI views that there are "increased risk to maintaining load in the core residential and commercial sectors" and "challenges in maintaining its share of the residential market". For instance, are there less new constructions since the 2016 Proceeding in FEI's service area, more fuel-efficient equipment, or are end-users fuel switching away from natural gas? Please provide support evidence where possible.

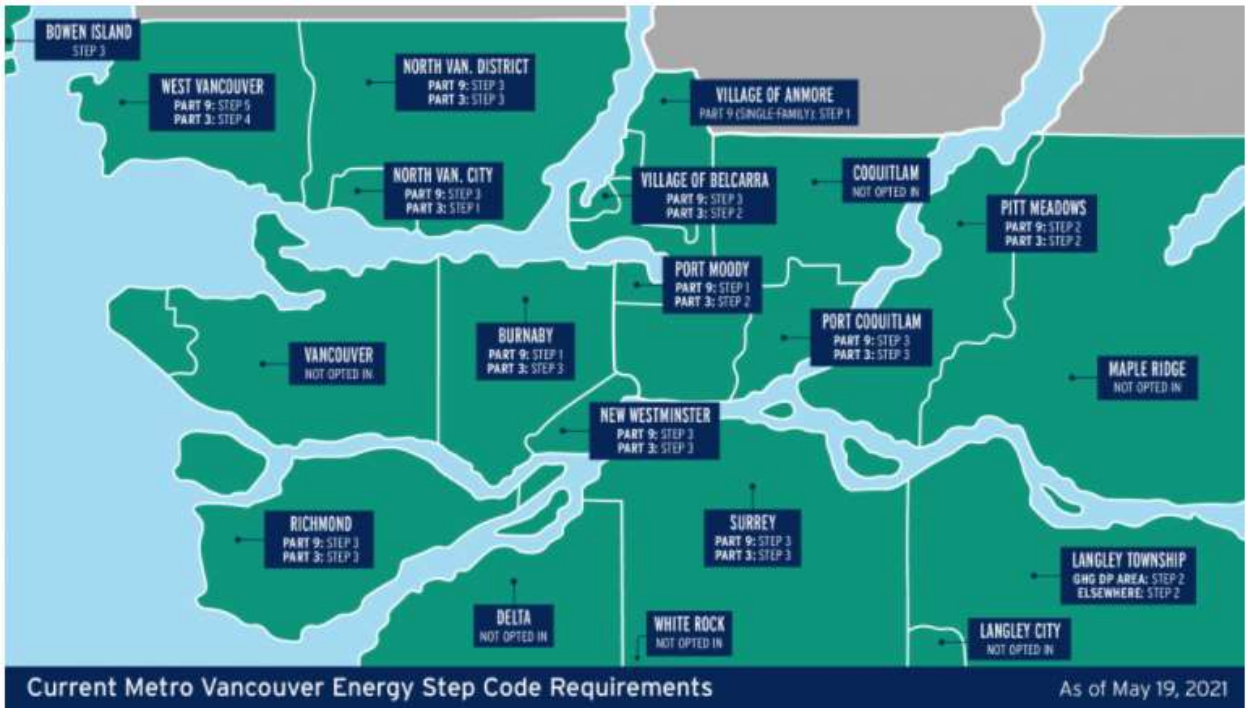
Response:

The political and demand risk sections of FEI's business risk (Appendix A) provide a comprehensive review of corroborating evidence that demonstrates FEI's challenges in maintaining load and market share in the core residential and, to a lesser extent, commercial sectors. A brief summary of this evidence in provided below.

As explained in the Section 7.2, improvements in energy efficiency are being largely driven by the BC Energy Step Code (Step Code) which is a tiered performance-based energy code that requires improvements in energy efficiency in new construction beyond the BC building code. There are two components of the Step Code in particular which directly impact core load in residential and commercial building sectors. The Energy Use Intensity (EUI) metric identifies tiered targets to reduce energy requirements from space and water heating appliances. The Thermal Energy Demand Intensity (TEDI) measures the thermal energy used by a building for space heating. The TEDI improves the building envelope so a building requires less energy, and the EUI improves the efficiency of the equipment used to heat the building. Both metrics combined contribute to reduced core load. The Step Code provides an approximate description of the

improved efficiency from 10 percent to 40 percent with the ultimate goal of achieving Net Zero Ready[39].

As explained in Section 4.2.3.1 of FEI's business risk evidence, the provincial government is giving more regulatory authority to local governments, making them, in some instances, the de facto regulators of BC's Step Code. Currently, there are 85 local governments that have submitted their notification to the Province.[40] These 85 local governments are in either the stage of consultation or adoption of the Step Code. The map below, from the Home Builders Association of Vancouver Government Relations 2021 Q2 Report, outlines the various municipalities in Metro Vancouver that have adopted the Step Code and the various levels.[41] .



FEI's ability to attach new customers or retain existing ones has also been restricted. Table A4-1, Page 33 of FEI's business risk evidence, lists municipalities that have adopted GHGI targets that restrict access to natural gas. As an indication of risk, the 5 year average of historical gross customer additions (2017 to 2021) of those municipalities are shown in the table below. Forward looking, the GHGI regulation creates challenges for FEI to attach ~5,000 gross customers in these municipalities. FEI notes that it faces similar challenges in other municipalities not on this list, such as the City of Victoria.

39 https://energystepcode.ca/how-it-works/.
40 https://energystepcode.ca/implementation_updates/.
41 https://havan.ca/news/news-release-government-relations-2021-q2-report-bc-energy-step-code-municipal-overview/.

Gross Customer Additions	Average (2017 to 2021)
City of Vancouver	1,359
District of North Vancouver	390
City of Burnaby	703
City of Richmond	768
City of Surrey	1,839
District of West Vancouver	139
Total	**5,198**

While there may be a high number of homes constructed in the province, FEI's ability to connect gas service to these homes to the grid has declined. The table below shows how FEI's overall market capture rate reached a high of 85 percent in 2017 and has since been declining, indicative of the market challenges. (This is an update of Figure A7-5, page 88 to include 2020 data now that it has become available.)

FEI's Overall Capture Rate Trend

	2015	2016	2017	2018	2019	2020
Market Capture	81%	83%	85%	82%	81%	78%

Further, and as explained in Section 7.4 of FEI's business risk evidence, the upward trend in the share of multi-family dwelling (MFDs) in new home constructions is continuing. FEI has lower capture rates in the MFD sector and the use per customer for MFDs is lower that single family dwellings. The condo/apartment segment is primarily driven by the unfavourable economics of installing a natural gas appliance as compared to an electric equivalent. This is especially true for developments where the unit cost plays a primary role in the purchasing decision. Furthermore, natural gas space heating equipment also occupies valuable living space within a multi-family unit which could otherwise reduce a developer's return. As the trend in new housing units is moving towards an increase in multi-family dwellings (refer to the response to BCOAPO IR1 8.5.1), FEI's capture rate will be negatively affected. In addition, as explained in various sections of this evidence, other implications such as the provincial and local governments' preferential treatment of electric-only solutions in the building sector, coupled with technological advantages of electric heat pump technologies, is negatively impacting FEI's ability to add new customers.

Yet another reason for the increased difficulties in maintaining load and market share is the increased adoption of heat pump technology. As explained in Sections 4.2.3.3 and 7.2, heat pump technology and the governments' financial and non-financial support for their adoption is impacting FEI's ability to maintain its market share in core space heating applications. For instance, FEI has identified an increase in end-users switching away from natural gas via customer adoption of electric heat pumps. This trend, again, is supported by the 2020 CleanBC Climate Accountability Report. The report describes the percentage of households using heat

pumps increased to 10 percent in 2019 (3 percent in 2007) with increases in sales of electric heat pumps 19, 47, and 52 percent YOY from 2017 through 2019.

Within FEI's existing customer base, the market dynamics are changing. For many years, when customers were faced with the inevitability of replacing aging equipment, they would most likely replace their old furnace or boiler with a newer, more efficient gas unit, and enjoy the savings that more efficient gas equipment would give them. Today, when customers are faced with the need to replace aging gas equipment, more and more home owners are considering switching their heating load to a heat pump. This is a result of very high incentives from various levels of municipal, provincial and federal governments (please refer to the response to BCOAPO IR1 7.8.1) designed to lower the barrier of the capital cost of installing a heat pump compared to installing a 96 percent efficient furnace. This is a significant risk to FEI when one takes into consideration incentives along with the ongoing campaign by many municipalities to restrict customer choice related to gas equipment.

FEI is experiencing challenges in growing its customer base and also with FEI's existing customer base considering replacing their aging gas equipment and switching their heating load to a heat pump. This is evident in the decline in net customer additions in the 2019-2021 period (Table A7-1, page 83) and FEI expects this trend to continue.

13.0 Reference: ECONOMIC CONDITIONS

Exhibit B1-8-1, Appendix A - FEI Business Risk Assessment, p. 16

Economic Conditions – COVID-19

On page 16 of Appendix A, FEI submits that economic conditions have increased from the 2016 Proceeding. On page 16 of Appendix A, FEI states:

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

13.1 Please provide a table in a similar format to Table A2-1 showing the average number of customers, sales/transportation volumes and rate base on a quarterly basis from January 2020 to the most recent month available (e.g., December 2021).

Response:

Please refer to the table below for the average number of customers and sales/transportation volumes for 2020 and 2021 Actuals on a quarterly basis in the same format as Table A2-1 of FEI's Evidence. Consistent with Table A2-1, the customer profile for demand and revenue excludes the bypass and special rates customers (Footnote 8 of Appendix A of FEI's Evidence). FEI notes its rate base shown in the Annual Reviews and Annual Reports is calculated on an annual basis thus a quarterly rate base is not available. As such, FEI provided the 2020 and 2021 mid-year rate base in the table calculated based on the average of the opening balance and closing balance of the rate base (i.e. (opening + closing)/2). FEI also notes that the 2021 Actuals are preliminary as FEI's 2021 Annual Report to the BCUC is not yet finalized at the time of filing this information request.

	2020 Actual				2021 Actual			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Type of Utility	Local Distribution Company (LDC)							
Energy Product Offering	Natural Gas, biomethane, propane							
Service Area	Mainland, Vancouver Island, and Whistler							
Rate Base ($000s)	5,012,592				5,199,050			
Sales/Transportation Volumes (TJ)	78,851	40,857	30,331	68,730	80,059	43,437	32,166	71,798
Average Number of Customers	1,040,721	1,042,848	1,045,198	1,049,727	1,054,963	1,056,451	1,056,270	1,060,662
Customer Profile by Demand (Excl. Bypass)								
Residential	44%	36%	30%	45%	45%	35%	29%	44%
Commerical	32%	26%	23%	31%	32%	27%	24%	30%
Industrial	25%	38%	47%	24%	23%	37%	47%	26%
Customer Profile by Sales Revenue (Excl. Bypass)								
Residential	59%	58%	55%	60%	60%	56%	53%	59%
Commerical	32%	29%	28%	31%	32%	31%	30%	32%
Industrial	9%	13%	17%	9%	8%	13%	17%	9%

13.1.1 Please discuss how economic condition risk has increased and the impact on the changes in revenues and number of customers.

Response:

The following provides a discussion of the impact of economic conditions on FortisBC's business from a macro perspective, as FortisBC cannot quantifiably separate the impact of economic conditions risk on its revenues and number of customers from other factors that impact these items.

The pandemic-induced shutdown of world economies has resulted in wide-spread and persistent supply chain issues and major labour shortages. These issues coupled with government fiscal and monetary policy to boost economic growth and improve employment have led to record high inflation numbers that are increasing production costs and putting pressure on fixed-income families. More recently, the conflict in Ukraine is an additional pressure on global energy and commodity prices that is affecting inflation numbers.

The overall impact of supply chain issues, labour shortages and the resulting record high inflation rates on FortisBC's business involves both the cost and revenue sides of its business as well as its operations.

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. In addition, the increase in costs is generally expected to impact price competitiveness.

The COVID-19 pandemic and the supply chain issues have also impacted or are expected to impact the revenue-side of the business. For instance, and as explained in Section 2.3 of FEI's business risk evidence (Appendix A), the supply chain issues caused by COVID-19 pandemic resulted in port congestion and shipping rates to increase to historic highs which affected FEI's ability to achieve the forecast revenue from its LNG export business. In addition, inflation can potentially affect the utilities' bad debts as those on fixed-income are increasingly finding it difficult to manage their finances and pay their bills on time.

Finally, supply chain issues can also impact FortisBC's operations. For instance, supply chain issues can make it difficult to procure the necessary goods and materials required to complete projects on time and on budget. As explained in Section 9.2 of FBC's business risk evidence (Appendix B), since the onset of the COVID-19 pandemic, supply chain issues have increased

the delivery times for major equipment and caused delays in capital activities for transmission, distribution and substation assets. Disruptions and delays in sourcing adequate supplies of critical parts, components, equipment and materials, whether caused by a pandemic like COVID-19 or some other unexpected event, can impact FBC's ability to properly maintain its system in a safe and reliable manner. As such, in an inflationary environment, it may be more efficient to carry higher levels of inventory as a lower cost alternative to minimizing disruptions and manage risk. Further, labour shortages can have a more pronounced impact on FEI's operation than other sectors, since as explained in Section 9.3 of FEI's business risk assessment, as a natural gas utility, FEI was already facing increased difficulty in recruiting skilled workers.

Another aspect of FEI's higher economic conditions risk relates to BC's challenges for long-term economic growth. As explained in Section 3 of FEI's business risk evidence, the Conference Board of Canada (CBOC) long-term forecast for both GDP and housing starts are lower than what was forecast in the CBOC's 2015 long-term forecast indicating that in the CBOC's view, BC's long-term outlook is slightly worse than what was assumed in 2015.

13.2 Please explain how the economic turmoil and uncertainty due to the COVID-19 pandemic and record high inflation caused a higher level of risk perceived by investors for the utility sector, including FEI as compared to other sectors.

Response:

To clarify, FEI did not state that the COVID-19 pandemic and the record high inflation have caused a higher risk to FEI, or the utility sector in general, compared to other sectors of the economy. The supply chain issues, labour shortages and the record inflation rates caused by the COVID-19 pandemic, and now by the conflict in the Ukraine, are affecting all sectors of the economy. FEI was referring to an increase in FEI's risk compared to what it had been previously. For a more detailed explanation of the impact of the COVID-19 pandemic and record high inflation on FEI's risk please refer to the response to BCUC IR1 13.1.1.

FEI has not conducted a detailed study to analyze the extent of the impact of the inflation and COVID-19 pandemic on other sectors of the economy and as such cannot compare its economic condition risk with other sectors.

13.3 Please compare and contrast the economic conditions and monetary policy of the following two events: (i) 2020 and 2021 COVID-19 pandemic and (ii) 2008 and 2009 financial crisis.

Response:

Concentric provides the following response:

One important difference is that central banks in the U.S. and Canada were much quicker to respond with monetary policy easing during the COVID pandemic in 2020-2022 than during the financial crisis of 2008-2009. In particular, Quantitative Easing was not implemented in the U.S. until many months after the financial crisis, as the economy was slow to recover then and central banks were looking to bring down long-term bond yields in order to stimulate economic growth, whereas during COVID central banks announced purchases of government and corporate bonds and mortgage backed securities starting in March 2020.[42] As a result of this quick response, financial markets stabilized and liquidity was maintained in the spring of 2020.

Another important difference is that the Bank of Canada did not engage in Quantitative Easing after the financial crisis of 2008-2009, but did for the first time during COVID. This more aggressive response by the Bank of Canada helped stabilize financial markets in spring 2020 and led to a quicker economic recovery.

In addition, as discussed in Mr. Coyne's report, governments in both Canada and the U.S. approved aggressive packages of fiscal stimulus measures in 2020-21 to support employees who were out of work and businesses that were forced to close. There was no similar support during the financial crisis of 2008-2009. As explained in Mr. Coyne's report, this combination of aggressive monetary policy accommodation by central banks and fiscal stimulus by governments has led to a sharp increase in the money supply and inflation well above central bank targets.

FortisBC adds the following response:

Another important difference between the 2008-2009 financial crisis and current economic conditions during the COVID-19 pandemic relates to the magnitude and longevity of the high inflation numbers. According to the Bank of Canada, the maximum monthly CPI number in the 2008-2009 period was 3.5 percent. Further, in the same period, the monthly CPI numbers were above the target range of 1 to 3 percent for four months. The maximum CPI in the 2020-2021 period was 4.8 percent (5.7 percent if the months up to February 2022 are included) and CPI has remained above the target since April 2021. The Bank of Canada describes the effects of high inflation as follows:

> When prices go up, money can't buy as much as it used to. This loss of purchasing power hurts everyone's standard of living.
>
> When inflation is high, consumers, businesses and investors are uncertain about what their costs will be from one day to the next. High inflation is often unstable and unpredictable, and that keeps the economy from performing at its best.
>
> High inflation makes life especially hard for people whose incomes don't keep pace with rising prices, such as pensioners and those with low pay. This is because high inflation decreases the value of their incomes and savings.[43]

[42] The U.S. Federal Reserve also purchased corporate bonds for the first time ever under the QE program in 2020.
[43] https://www.bankofcanada.ca/2020/08/understanding-inflation/

For additional details regarding the impact of high inflation on FortisBC's business, please refer to the response to BCUC IR1 13.1.1.

13.3.1 Please discuss companies' ability to raise capital and maintain financial integrity, particularly in the utility sector.

Response:

Concentric provides the following response:

Public utilities have had continued access to debt capital on favorable terms during this period of low interest rates, and those lower debt costs have been passed through to customers. Likewise, in recent years public utilities have had access to equity capital at relatively low cost compared to historical levels. However, as noted in Mr. Coyne's report, Betas for both gas and electric utilities have increased substantially since January 2020, suggesting that investors are requiring a higher risk premium for regulated utilities than before. The Energy Transition is creating a significant amount of uncertainly for utilities and investors, especially as it relates to future growth prospects and the recovery of long-lived utility investments. Mr. Coyne's report discusses how conditions in capital markets and the utility industry are affecting the forward-looking cost of capital for gas and electric utilities in North America.

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. Please refer to Attachment 13.3.1 for a copy of that S&P report. According to S&P, the key takeaways from the January 2022 report are as follows:

Key Takeaways

- 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.

- During 2021, credit quality was primarily pressured by weak financial measures and Environmental, Social, and Governance (ESG) credit risks. We expect that these risks will continue to pressure the credit quality of the industry in 2022.

- Our outlook on the investor-owned North American regulated utility industry remains negative. We believe that 2022 could be the third consecutive year that downgrades outpace upgrades.

- Recently, several new credit risks have emerged, including inflation, higher interest rates, and rising commodity prices. Persistent pressure from any of these risks would likely lead to a further weakening of the industry's credit quality in 2022

FortisBC adds the following response:

Further and as discussed in the responses to BCUC IR1 6.2.1 and BCUC IR1 8.1, since 2019, Moody's credit rating reports include a discussion on ESG related risks. For example, according to the latest Moody's Credit Rating Report for FEI published in November 2021, Moody's views FEI as having a "very negative carbon transition risk" because of risks associated with carbon emissions targets and the fact that the Province of BC's legislated targets of 40 percent GHG reduction by 2030 and 80 percent GHG reduction by 2050 exceed FEI's own 30 percent GHG reduction target by 2030. Consistent with the general market trends and growing awareness around ESG related risks, FEI is expecting that ESG will play an increasingly important role in credit rating determinations.

14.0 Reference: POLITICAL RISK

Exhibit B1-8, FBCU Evidence, p. 13; Exhibit B1-8-1, Appendix A - FEI Business Risk Assessment, pp. 11, 19 and 21, Appendix D- 2, "FEI - DBRS 2021 Credit Rating Report dated January 5, 2022", p. 5; *Clean Energy Act*, SBC 2010, c. 22[44]

Political Risk – Different Levels of Government

On page 19 of Appendix A, FEI states, "its political risk is significantly higher than what was assessed in the 2016 Proceeding."

On page 13 of Exhibit B1-8, FBCU states, "The long-term viability and acceptability of alternative pathways for natural gas, such as investments in renewable natural gas or hydrogen, is uncertain and pursuing those pathways carries risk from an investors' perspective."

On page 19 of Appendix A, FEI states:

> Climate action goals and legislation are moving forward at a rapid pace at all levels of government. While FEI's infrastructure and energy conservation programs play a critical role in climate action, there are inherent risks to FEI's approach and how it fits into the future energy landscape within BC. Factors outside of the company's control such as public perception, political decisions, increased competition from the electricity sector supported by electrification-friendly federal, provincial and municipal policies, could hamper FEI's ability to execute on its climate goals.

On page 19 of Appendix A, FEI states:

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

On page 11 of Appendix A, FEI states:

> The growth of LCT [Low Carbon Transportation] is primarily driven by the Greenhouse Gas Reduction Regulation (GGRR). The GGRR allows FEI to incentivize eligible vehicles and upgrades to maintenance facilities, invest in refueling infrastructure, and provide safety and training programs.

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

[44] https://www.bclaws.gov.bc.ca/civix/document/id/complete/statreg/10022_01#section18.

In July 2020, the provincial government announced the following amendments to GGRR:

- Increasing the amount of renewable gas FEI can acquire from 5% to 15% of system load.
- Enabling FEI to acquire hydrogen, lignin, and synthesis gas.
- Increasing the price cap for the acquisition of renewable gas to $31 per gigajoule, indexed to inflation.

DBRS Morningstar notes that these amendments are not material from a credit perspective but will support the Company's transition to a lower carbon economy.

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

14.1 Please discuss how Greenhouse Gas Reduction Regulation (GGRR) supports FEI's transition to a lower carbon economy. As part of the response, please discuss the increase in customers or sales designated as prescribed undertakings under the GGRR that FEI has benefited from.

Response:

The GGRR empowers utilities like FortisBC to make specific investments or purchases, within spending and volumetric caps, to stimulate the domestic market for renewable gas supply and LCT, thereby lowering GHG emissions and aiding in FEI and its customers in transitioning to a lower carbon economy. While helpful, the GGRR is a limited tool to assist in FEI's transition. FEI provides more details below.

For the Renewable Gas program, the GGRR supports the ability to acquire Renewable Gas, increasing the volume of renewable energy available for consumption in British Columbia. Currently there are more than 9,600 customers enrolled in the Renewable Gas Program across various rate schedules, consuming nearly 600 thousand GJs in 2021. While helpful in expanding Renewable Gas supply available for consumption in BC, the GGRR is limited to the expansion of Renewable Gas supply and does not address other risks to FEI's transition, such as municipal restrictions on the use of the gas system or competition with other low carbon energy offerings like electricity; in short, it supports the supply side but not the demand side.

For transportation, the GGRR allows utilities to incentivize the adoption of LCT solutions and invest in the infrastructure needed to support low carbon vehicles. For the year 2021, FEI has provided approximately 2.8 PJ of natural gas to its transportation customers, which has reduced GHG emissions by approximately 71,000 tonnes of CO2e. FEI has also incentivized over 1,027 vehicles and marine vessels under the GGRR. Further, as the availability of Renewable Gas supply increases, FEI expects both existing and prospective LCT customers will adopt Renewable

Gas and therefore further increase sales volumes and reduce carbon emissions. However, the GGRR supporting FEI's investments and incentives for the transportation sector expired on March 31, 2022. The timing and details of a renewal are uncertain at this time.

14.2 Please confirm that FEI is not the only gas utility in BC being affected by these federal, provincial and municipal policies being implemented throughout Canada and BC.

Response:

Confirmed.

14.3 Please provide evidence that investors are moving away from investments in gas utilities for their investment portfolio when seeking low-risk securities.

Response:

Concentric provides the following response:

As discussed on page 80 of Mr. Coyne's report, several large institutional investors (such as BlackRock, J.P. Morgan, Santander, and Goldman Sachs) and pension funds have restricted or prohibited investments in companies seen as contributing to climate change. As shown on pages 80-81 of Mr. Coyne's report, financing costs for oil and gas companies are being affected by ESG concerns, with differences in debt yields between the highest and lowest carbon intensity issuers exceeding 150 basis points for 10+ year issuances. Moreover, as discussed on pages 97-99 of Mr. Coyne's report, Moody's has indicated that gas LDCs are considered to have higher carbon transition risk than electric utilities or combination electric and gas companies. 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.

Please also refer to FortisBC's response to BCUC IR1 8.1 regarding ESG impact on credit ratings.

14.3.1 Please provide evidence that gas utilities are having difficultly attracting new investors.

Response:

Please refer to the response to BCUC IR1 14.3.

Concentric provides the following response:

While natural gas utilities are not necessarily currently having trouble attracting new investors, there is evidence that the cost of both debt and equity is higher for companies with higher carbon emissions, as shown in Figure 41 of Mr. Coyne's report. Further, that trend is expected to continue as more jurisdictions in Canada and the U.S. take an increasingly aggressive stance against carbon emissions and look for ways to slow climate change, consistent with the Paris Accord and federal government policies in both countries. This is particularly an issue in jurisdictions such as British Columbia, which has demonstrated a leadership role in this regard.

14.4 Please confirm, or explain otherwise, that the GGRR de-risks FEI as it allows the utility to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to the prescribed undertaking, such that shareholders do not bear the risk of new undertakings nor the risk of non-recovery.

Response:

FEI agrees that, relative to other utility investments, prescribed undertakings under the GGRR have lower risk of cost recovery. As explained in Concentric's evidence, while the prescribed undertakings under the GGRR may offer a pathway for FEI through the Energy Transition, investors perceive risk to that pathway because of its operational, technical and other challenges. For example, higher utility costs associated with investments in Renewable Gas can challenge rate competitiveness relative to electricity.

14.4.1 Please discuss whether amendments to GGRR would strengthen, or at least maintain, FEI's financial metrics that would have been unfavourable otherwise.

Response:

FEI does not expect GGRR to have any impact on its credit metrics.

15.0 Reference: DEMAND MARKET RISK

Exhibit B1-8-1, Appendix A - FEI Business Risk Assessment, pp. 74, 78 and 81–82

Demand Market Risk – Natural Gas

On page 78 of Appendix A, FEI states its "analysis indicates that the risk associated with demand and market shift away from natural gas is greater than what was assessed in the 2016 Proceeding."

On page 74 of Appendix A, FEI provides the following table:

Table A6-2: Upfront Costs and Efficiency Estimates for Space and Water Heating[134]

	Space Heating Options			Water Heating Options	
Equipment	Gas Furnace	Electric Baseboard	Electric Heat Pump	Gas Water Heater Tank	Electric Water Heater Tank
Capital Cost[135]	$18,000	$9,200	$21,000	$2,800	$1,550
Efficiency Rate	96%	100%	200%	67%	100%

15.1 Please discuss the benefits of natural gas space heating and water heating as compared to electric options.

Response:

The benefits of natural gas space and water heating as compared to electric are as follows:

Leaving aside the rebates, heat pumps are more expensive than gas furnaces (although electric baseboards are the least expensive option).

The average service life[45] of a natural gas furnace is 18 years, while an electric baseboard is 10 years[46]. Heat pumps are more like air conditioners with an average life span of 15 years.

Installation of electric baseboards as a space heating option is easier than a gas furnace, as they do not need an exterior vent and can be installed anywhere. A gas furnace needs an external vent and ducting. In addition to ducting, an electric heat pump needs some exterior space to install the external unit. A natural gas furnace burns fuel to generate heat and can heat a house faster than an electric baseboard. An electric heat pump transfers heat from one side of the wall to the other and tends to blow cooler air. Because of how electric heat pumps work, they produce less heat than furnaces. Electric heat pumps are technically more efficient than a gas furnace in that they can transfer more energy than they use, especially in warmer climates (Zones 1-3 on the U.S. Department of Energy climate zone map) where they use less source energy compared to gas furnaces. In colder climates, a 95 percent efficient gas furnace fares better than Energy Star heat pumps[47]

[45] The term service life is often assumed by ASHRAE to mean equipment life rather than economic life.
[46] ASHRAE Applications Handbook (A37-2015, Table 4).
[47] https://www.carrier.com/residential/en/ca/products/furnaces/heat-pump-vs-

Since natural gas water heaters work twice as fast as their electric counterparts, they can recover much more quickly than electric models, meaning that the hot water supply is easily replenished.

15.2 To the best of FEI's knowledge, would a builder/developer consider other costs and benefits associated with a building's construction and marketability when it decides on which fuel to use for the building's space and water heating? If so, beyond upfront costs and efficiency estimates, please discuss the advantages of space and water heating using natural gas, and vice versa with electricity.

Response:

Builder or end users are best suited to describe the decision matrix and the related benefits versus cost considerations.

Based on FEI's knowledge, a builder will consider many cost and design variables before making a final design decision. As outlined in the response to BCOAPO IR1 8.4, there are several design aspects related to the advantages or disadvantages of space and water heating with either gas or electricity. The complexity and number of variables increases for high rise condominiums as more design and cost considerations are factored in.

FEI does not have access to how a builder sets its priorities and determines the energy source. For example, many large developers are also building owners and consequently their priorities may shift project to project depending on if there is a continued ownership model for a building versus a building completely intended for market housing. The ability to proceed with the development or the ability to proceed in a more timely or rapid fashion would also be a consideration along with capital cost considerations. More specifically, when a builder must discuss with a municipality the benefits of connecting to FEI's infrastructure to receive a building permit but does not have to do so when choosing electricity, this would add another aspect of time and risk unique to natural gas use. This consideration can extend the permitting timeline and increase mortgage or borrowing costs for the builder.

On pages 81 and 82 of Appendix A, FEI states:

> Renewable Gas provides an alternative to hydro-generated electricity from an emissions reduction perspective and would meet new code and regulation requirements. However, there is a general lack of awareness and acceptance from

furnace/#:~:text=To%20generate%20heat%2C%20furnaces%20burn,of%20Energy%20climate%20zone%20map.

customers and stakeholders as to the role Renewable Gas plays in reducing emissions when compared to electricity. The lack of acceptance of Renewable Gas, from customers and stakeholders is largely driven by the perception that is a bridge fuel and potentially not a long term emissions reduction.

15.3 Please clarify what is meant by "bridge fuel". Is FEI referring to natural gas or Renewable Gas?

Response:

FEI is referring to Renewable Gas and the view from customers and stakeholders that RNG is only a bridge to other low emitting energy sources as opposed to a permanent solution to emission reduction.

15.4 Please provide supporting evidence to substantiate FEI's statement – "The lack of acceptance of Renewable Gas, from customers and stakeholders is largely driven by the perception that is a bridge fuel and potentially not a long term emissions reduction."

Response:

Examples are provided below.

In the September 21, 2018 Mayor's Council on Regional Transportation, agenda item 2 is a Report of Translink Management with Agenda item 2.1 a report on GHG Emissions Targets and Renewable Energy Goals. Present at the meetings were mayors from:

- Burnaby
- North Vancouver District
- White Rock
- Pitt Meadows
- Richmond
- Lions Bay
- Port Moody
- New Westminster
- Belcarra
- Langley Township
- Surrey
- North Vancouver City

- Anmore
- Port Coquitlam
- Maple Ridge
- Vancouver
- Langley City
- Bowen Island
- West Vancouver
- Coquitlam

In the report to the Mayor's Council from Kevin Desmond and Sarah Buckle there is description of how Translink would achieve the goal of 100 per cent renewable energy. The information provided highlights interim use of renewable fuels (which is described as Renewable Natural Gas or Renewable Diesel):

> By transitioning the bus fleet to battery-electric buses and with the interim use of renewable fuels, TransLink would move closer to achieving the goal of 100 per cent renewable energy by 2050. However, further study will be required to assess the feasibility of renewable energy and technologies for the remaining revenue and nonrevenue diesel and gasoline vehicles in the fleet.[48] (emphasis added).

This view in transportation is consistent with the North American Council for Freight Efficiency (NACFE) guide. On page 8 of the Trucks Guidance report, it outlines RNG as an interim fuel with Commercial Battery Electric Vehicle (CBEV) being the ultimate fuel choice.[49]

In buildings there is a similar view; however, in many cases RNG is not seen as a bridge fuel for buildings, but rather as a secondary option to electrification. In the provincial government's 2020 Climate Change Accountability Report, it outlines:

> Highlights on Supports for Better Buildings: To help British Columbians save energy and switch to clean electricity, the Province created the CleanBC Better Homes and CleanBC Better Buildings programs. These two programs offer a suite of incentives including rebates for heat pumps, envelope upgrades and new windows.[50] (emphasis added).

In working with customers and their consultants FEI has encountered several instances where retrofit designs and technology are being planned in such a way that the buildings can use RNG as an interim until full electrification is possible.

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48 https://www.translink.ca/-/media/translink/documents/about-translink/governance-and-board/council-minutes-and-reports/2018/september/2018_09_21_public_agenda.pdf#view=fitH, p. 11/33.

49 NACFEClass7-8Trucks-GuidanceReport-Final-ES-12.10.pdf.

50 https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/cleanbc/2020_climate_change_accountability_report.pdf p. 26.

Furthermore, in response to a customer survey conducted with large volume gas customers, where the objective of the research was to gauge the potential interest in RNG, and perceptions of RNG overall, responses to the survey indicated RNG being considered as a bridge fuel:

> "…You know, looking at renewable natural gas is really one of those immediately available tools, and a bridge strategy for medium to long term duration." Institutional customer (page 20)

> "We hope technology catches up in the next three years to convert to electric, but CNG is really seen as the platform to get us there." Transportation Customer (page 40)

> "We have government mandates to reduce our tailpipe emissions, and we have very specific goals that we need to meet. That's why RNG is more a bridge for us, because we really need to eventually get to zero." Transportation customer (page 54).

As explained in the response to BCOPAO IR1 5.1, another aspect to lack of acceptance of Renewable Gas as an ultimate solution to GHG emissions reduction relates to those perspectives that question the need for the gas system if significant progress can be made to fuel switching heating to electric technologies. Within this perspective is the belief that supporting the gas system to be a part of the Energy Transition works against decarbonization goals as it slows the move towards full electrification. For more details regarding this perspective please refer to the response to BCOAPO IR1 5.1.

16.0 Reference: ENERGY SUPPLY RISK

Exhibit B1-8-1, Appendix A - FEI Business Risk Assessment, pp. 3, 103 and 105; FEI Comprehensive Review and Application for Approval of a Revised Renewable Gas Program December 17, 2021 (FEI Stage 2 Comprehensive Review and Application for Approval of a Revised Renewable Gas Program), p. 81

Energy Supply Risk - Reliance on Renewable Gas Supply

On page 3 of Appendix A, FEI submits that overall, its energy supply risk remains similar since 2016. In particular, FEI submits that its risk regarding availability of supply and access to supply remains similar since 2016 but risk relating to renewable gas supply is new and higher since 2016.

On page 103 of Appendix A, FEI states:

> FEI is currently receiving RNG from ten operating Renewable Gas plants located both within and outside of BC. By the end of 2022, FEI expects to see a total of seventeen facilities supplying RNG.

On page 105 of Appendix A, FEI states:

> Operating projects may experience lower than expected performance due to operational risks similar to a gas pipeline, as described in Section 9, as well as the following, which are unique to RNG facilities:
>
> - Equipment Failures: RNG facilities are a relatively new energy form and, as such, the equipment used to create RNG can fail more often than conventional technologies.
> - Feedstock Supply Issues: Some RNG production facilities (e.g., farm facilities) can have difficulty securing manure or green waste supplies, reducing RNG output.
> - Supplier Experience: The RNG industry is also at a nascent stage in development, often with small developers/suppliers and new technologies, which creates additional risk relating to the inability for counterparties to execute on project developments and fulfil contractual obligations. [Emphasis removed]

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

> The primary means of mitigating the risk of lower than expected production is to diversify the supply portfolio. Today, FEI has a diverse mixture of supply projects that use different feedstock and technologies and are located in geographically separate areas. This diversity helps to reduce supply volume risks to the portfolio as all projects in the portfolio will not be subject to the same types of risks. As FEI

acquires Renewable Gas from new projects, this will diversify the portfolio further and reduce risk. In addition, there are now suppliers that are themselves aggregators of RNG supply, meaning they have a diverse supply of projects within their own portfolio – thereby reducing supply risk. By contracting with these aggregators, FEI may be able to secure a firmer supply, effectively transferring supply risk to the supplier.

16.1 Please confirm, or explain otherwise, that FEI's renewal natural gas (RNG) supply risk mitigation strategies as described in the FEI Stage 2 Comprehensive Review and Application for Approval of a Revised Renewable Gas Program are sufficient to address the risks identified as equipment failures, feedstock supply issues, and supplier experience in FEI's Business Risk Assessment.

Response:

FEI believes the approach described on Page 81 of the FEI Stage 2 Comprehensive Review is a tactic that will help mitigate supply risk as a result of equipment failures, feedstock supply issues and supplier inexperience risk.

16.2 Please discuss whether FEI has experienced any operational risks, and to what extent, with regards to its RNG facilities as it pertains to equipment failures, feedstock supply issues and supplier experience.

Response:

Yes, FEI has experienced equipment failures, feedstock supply issues and supplier inexperience at RNG facilities contracted to FEI's portfolio. The results of these events have been lower than expected volumes, increased operating costs, and increased purchase prices.

16.3 Please provide FEI's forecast for the number of facilities it expects will supply RNG by the end of 2030.

Response:

FEI's RNG Supply forecast is developed using a reasonable estimate of known RNG volumes available.

The forecast is not based on the number of facilities as the number of facilities required to meet the forecast depends on the volume each of the facilities is able to supply. Given that the current

number of supply projects represents more than thirty separate contracts and approximately one half of the 2030 volumes, it is reasonable to assume that FEI would expect approximately double the number of current facilities.

For FEI's forecast volume please refer to Figures 8-2 and 8-3 of FEI's Business Risk Assessment (Appendix A).

17.0 Reference: ENERGY SUPPLY RISK

Exhibit B1-8-1, Appendix A - FEI Business Risk Assessment, p. 106; FEI Stage 2 Comprehensive Review and Application for Approval of a Revised Renewable Gas Program, p. 81

Competition Risk

On page 106 of Appendix A, FEI states:

> A second supply risk is competition from other purchasers of Renewable Gas. While FEI has been a "first mover" in the Renewable Gas market, and has an established regulatory path with known guidelines for supply agreements particularly with respect to RNG, an increasing number of entities in other jurisdictions, including Énergir in Quebec, are now seeking Renewable Gas supply.

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

> FEI has mitigated this risk to an extent by being a "first-mover" in the market and has an established regulatory path with known guidelines for supply agreements, particularly with respect to RNG. This established history in the Renewable Gas market is attractive to suppliers who are interested in long-term offtake agreements with a high degree of certainty of regulatory approval.
>
> ... Therefore, to ensure FEI has access to supply at reasonable costs, FEI is working to secure biogas-derived Renewable Gas supply early in this decade rather than waiting for the market to mature further.

17.1 Please indicate which entities outside of BC are now seeking Renewable Gas supply and may be competing for Renewable Gas supply with FEI.

Response:

There are many entities outside of BC that are currently seeking Renewable Gas supply. FEI expects this to continue growing. For example, the California Public Utilities Commission (CPUC) only this past month set 2030 RNG targets for the utilities it regulates which would amount to approximately 80 PJ per year in total[51]. Some of the main entities or programs that are outside of BC that FEI is aware of include, but are not limited to:

- US RIN (Renewable Identification Number) Market for transportation fuel;
- Natural gas utilities – Energir, Enbridge, Vermont Gas, Pacific Northern Gas, Northwest Natural Gas; and

[51] https://www.spglobal.com/marketintelligence/en/news-insights/latest-news-headlines/calif-regulators-adopt-mandatory-renewable-gas-targets-for-gas-utilities-69058262.

- Direct to consumer supplier agreements.

17.1.1 Please discuss whether the competing entities identified in the preceding IR have similar legislation to the GGRR, which allow these entities to make investments related to the reduction of greenhouse gas emissions.

Response:

Some of the entities identified in the response to the BCUC IR1 17.1 are located in jurisdictions that have either legislation or utility commission-approved tariffs that enable the natural gas utilities to procure Renewable Gas and make investments related to the reduction of greenhouse gas emissions. The Coalition for Renewable Gas maintains a list of relevant regulations and laws across the U.S. According to the website, there are four overarching federal mandates that encourage emissions reductions: The Renewable Fuel Standard, The Clean Air Act, the Energy Policy act and the Energy Independence and Security Act[52]. In addition, there are state laws and regulations in California, Oregon, Washington and the Northeast/Mid-Atlantic states[53]. The list does not include the various utilities' programs that do not necessarily have regulations or laws associated with their particular jurisdictions. In addition to this legislation, numerous utilities are undertaking RNG programs. The American Gas association tracks RNG programs across North America and according to its tracker there are over twenty-seven utilities with activity related to the procurement of RNG[54].

17.1.2 Please explain whether carbon offsets purchases would be a feasible alternative if there is a lack of Renewable Gas supply.

Response:

Carbon offset purchases could be feasible if there is a lack of Renewable Gas Supply. FEI has used carbon offsets when it has had deficits in RNG supply, but these were fairly limited in volume and meant to balance between projected and actual supply and demand. FEI is unclear whether offset purchases could be relied on in any significant quantity if there is a lack of RNG supply unless there was clear policy direction from government.

[52] https://www.rngcoalition.com/data-resources-3.
[53] https://www.rngcoalition.com/data-resources-4.
[54] https://www.aga.org/contentassets/12f84f5492c0400595b9ae54884dd2d7/rng-activity-tracker.pdf.

FEI has submitted evidence to the RNG inquiry[55] indicating its openness to the use of offsets in a broader manner. In that proceeding FEI specifically stated:

> …while FEI sees the potential benefits of a regulatory scheme that would facilitate the purchase of the environmental attributes of RNG, such a scheme is not contemplated by the Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR).

Based on its submission, FEI believes that offsets could play a broader role in meeting long-term GHG reduction objectives, but at this time there are limitations on the market and no option to directly purchase offsets related to RNG production.

17.2 If available, please provide an estimate of the annual volume of Renewable Gas that will be required in aggregate by the identified competing entities by 2030, and a comparison figure of FEI's expected Renewable Gas supply in 2030.

Response:

The estimate is not available for competing entities. Please refer to Appendix A Figure A8-3 of FEI's Business Risk Assessment for FEI's 10-Year Renewable Gas Supply Forecast.

17.3 Please describe how long FEI's supply contracts typically last, and what FEI expects would be the risk of renewal of such contracts once they expire.

Response:

FEI's typical supply contracts range between 10 and 20 years. The risks at time of renewal may include higher purchase price, reduced volume, or no opportunity for renewal. It is possible that the project reaches end of life. For example, landfills can see diminishing production as they age.

[55] https://www.bcuc.com/OurWork/ViewProceeding?ApplicationId=963.

18.0 Reference: ENERGY SUPPLY RISK

Exhibit B1-8-1, Appendix A - FEI Business Risk Assessment, p. 106, Appendix C - Evidence of Mr. Coyne, p. 86; FEI Stage 2 Comprehensive Review and Application for Approval of a Revised Renewable Gas Program, pp. 80–83 and 122; FEI Tilbury CPCN Application, Exhibit B-1, p. 110; Hydro-Québec and Énergir: An unprecedented partnership to reduce greenhouse gas emissions[56]

Gas System Readiness

On page 106 of Appendix A, FEI states:

> There are technical and regulatory barriers to integrating alternate forms of Renewable Gas, such as hydrogen, into the gas system which presents FEI with a new form of energy supply risk. These barriers could delay the use of hydrogen, synthesis gas and lignin to provide FEI's customers with low carbon energy.

On page 86 of Appendix C - Evidence of Mr. James Coyne, Section VI, Mr. Coyne states:

> Credit rating agencies are pessimistic regarding the near-term prospects for hydrogen. For example, S&P recently noted that hydrogen "faces many hurdles" and that a "truly hydrogen based economy, in which hydrogen, not gas, is used to heat buildings and balance the power grid, for example, therefore appears out of reach, at least before 2030".

On page 80 of the FEI Stage 2 Comprehensive Review and Application for Approval of a Revised Renewable Gas Program, FEI states it is "currently working with the provincial government to complete an updated Renewable Gas Potential study that will further increase the future supply available to FEI's Renewable Gas Program."

On pages 81 and 82 of FEI's Stage 2 Comprehensive Review and Application for Approval of a Revised Renewable Gas Program, FEI states:

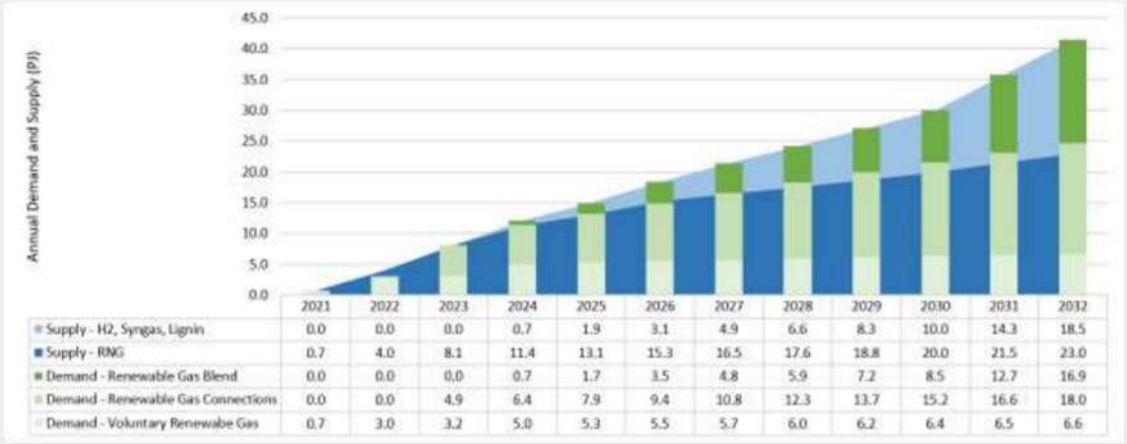
> FEI is undertaking steps to ensure that the existing gas pipeline system can accommodate other forms of Renewable Gas and, as applicable, that there are alternative methods to deliver these gases to customers. FEI is working internally, with the federal and provincial governments, and other industry participants including other utilities to remove barriers and advance the adoption of hydrogen for the whole of the province. The steps taken by FEI to date are discussed in the sections below. [headers of the three subsections that follow are included below]
>
> - Gas System Readiness, System Planning and Deployment Strategy
> - Industry Collaboration, Research and Development, Feasibility Work and Sector-Specific Approaches

[56] https://www.energir.com/en/about/media/news/partenariat-inedit-hydro-quebec-et-energir/.

- Codes, Standards and Regulations

Page 122 of FEI's Stage 2 Comprehensive Review and Application for Approval of a Revised Renewable Gas Program includes the following graph showing that the supply of hydrogen, syngas and lignin combined are forecast to be 18.5 petajoules (PJ) by 2032:

Figure 8-3: Forecast Volumes of Renewable Gas Supply, Customer Demand and Allocation to Sales Customers (PJ)



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Supply - H2, Syngas, Lignin	0.0	0.0	0.0	0.7	1.9	3.1	4.9	6.6	8.3	10.0	14.3	18.5
Supply - RNG	0.7	4.0	8.1	11.4	13.1	15.3	16.5	17.6	18.8	20.0	21.5	23.0
Demand - Renewable Gas Blend	0.0	0.0	0.0	0.7	1.7	3.5	4.8	5.9	7.2	8.5	12.7	16.9
Demand - Renewable Gas Connections	0.0	0.0	4.9	6.4	7.9	9.4	10.8	12.3	13.7	15.2	16.6	18.0
Demand - Voluntary Renewabe Gas	0.7	3.0	3.2	5.0	5.3	5.5	5.7	6.0	6.2	6.4	6.5	6.6

18.1 Given FEI's forecast volumes of hydrogen, syngas, and lignin (18.5 PJ by 2032), and the strategies FEI describes it is taking (in its 2021 Biomethane application) to ensure that the existing gas pipeline system can accommodate other forms of Renewable Gas, please describe the overall unmitigated risk that FEI views it is exposed to for gas system readiness.

Response:

FEI expects that synthesis gas (syngas) and lignin will comprise a smaller share of the total forecast volume of hydrogen, syngas, and lignin by 2032. FEI expects to acquire syngas and lignin from projects that would be located in proximity to industrial natural gas customers that could use these renewable fuels in their plant operations to replace natural gas use. FEI expects that this supply would be delivered by displacement onto the FEI system and would not be injected into the gas system for physical delivery; therefore, FEI does not consider it is exposed to unmitigated risk for gas system readiness for the forecast volume of syngas and lignin.

FEI expects that the volume of hydrogen forecast by 2032 will be distributed in dedicated gas pipeline infrastructure to customers of the gas system that can use the hydrogen directly, and to customers as a mixture of hydrogen blended in natural gas. Both of these infrastructure options to distribute hydrogen will be required to successfully develop the forecast hydrogen supply and commensurate demand by 2032. For hydrogen that will be distributed in new or repurposed gas infrastructure that is dedicated to hydrogen service, FEI does not consider it is exposed to unmitigated risk for gas system readiness. For hydrogen that will be distributed in the existing gas system, FEI considers that there are a number of key challenges to hydrogen market development and barriers to adoption outlined below.

Establishing public awareness and the safety case for hydrogen as a Renewable Gas

The issue of safety and the perception of the risks associated with hydrogen energy supplied by pipelines either in the existing natural gas network or in dedicated infrastructure, especially in urban areas, will challenge the adoption of hydrogen. There is a lack of awareness about the opportunities and safety around hydrogen within the general public, as well as within industry and government. Increased awareness about hydrogen as a viable decarbonization pathway that is safe and provides economic benefits is critical to establishing a vibrant hydrogen sector.

Codes and standards to regulate hydrogen in the existing natural gas supply chain

Various published literature reviews and studies provide general guidance regarding allowable hydrogen blend concentration in natural gas networks based on various assumptions. However, each gas network operator is currently defining this on a case-by-case basis. The lack of a standardized industry approach including codes, standards and regulations to define the allowable hydrogen blend concentration is a barrier to promoting widespread hydrogen deployment. If this barrier cannot be addressed in a meaningful way hydrogen uptake will be slow.

Lack of industry expertise and subject matter experts

FEI will need to have staff and engage experts to assist with developing hydrogen projects including production, injection/blending, dedicated hydrogen distribution systems and end use applications. The availability of qualified and experienced talent in Canada to assist FEI and other natural gas infrastructure operators to introduce hydrogen into the natural gas supply chain is currently unknown and therefore could be a challenge to hydrogen development.

How to stimulate and grow both demand and supply for hydrogen technologies

Most methods of hydrogen production are energy intensive. Producing hydrogen at a range of scales with little or no carbon emissions at acceptable cost will be a challenging economic barrier. To achieve this, existing hydrogen production technologies need to be decarbonized, flexible tariffs need to be developed to provide access to green power and new distribution and end use technologies need to be innovated and developed.

Federal and Provincial government support will be required to progress research and development including supporting initial demonstration projects, technology innovation and commercialization across the hydrogen supply chain.

Availability of hydrogen infrastructure and large-scale capital investments

Domestic supply of low-carbon hydrogen is limited in many parts of Canada today, and this is preventing both pilot and commercial rollout. As domestic production and demand grow, there will be a need for dedicated infrastructure such as hydrogen pipelines and liquefaction plants. Ensuring that these crucial assets can be built in a coordinated and timely manner will be essential to ensuring low cost, low-carbon hydrogen can be delivered to both domestic and international markets.

Existing hydrogen technologies will need to evolve to make hydrogen a sustainable energy carrier, especially for hydrogen to emerge in larger scale utility applications to displace traditional natural gas use.

Long-term planning will be required to understand how much hydrogen could be injected and blended into the regional natural gas grid. Injecting renewable/low-carbon hydrogen to replace natural gas and decarbonize the gaseous energy stream will compete for pipeline capacity with increasing volumes of natural gas required for LNG production.

18.1.1 Please discuss if there is any independent evidence regarding the gas system readiness risks for syngas and lignin integration (as opposed to hydrogen risks only).

Response:

Syngas and lignin are both intended to displace the use of natural gas at industrial customers' operations where these low-carbon fuels can be used directly at the point of use to displace natural gas. Syngas and lignin are not intended to be physically distributed in the natural gas system therefore there is no gas system readiness risk associated with these activities.

18.2 Please discuss whether FEI views the on-going Renewable Gas Potential study it is working on with the provincial government will encourage integration of alternate forms of Renewable Gas.

Response:

Yes, the Renewable and Low-Carbon Gas Potential Study[57] (the Study), conducted in partnership with FEI, the provincial government and the BC Bioenergy Network, will encourage integration of alternate forms of Renewable Gas. The purpose of the Study is to:

- Establish the supply potential of renewable and low-carbon gases in BC;
- Develop cost-curves for provincially produced gases and cost analysis for imported renewable natural gas;
- Update information from previous reports reflecting changing resource availability;

[57] https://www.cdn.fortisbc.com/libraries/docs/default-source/news-events/bc-renewable-and-low-carbon-gas-supply-potential-study-2022-03-11.pdf.

- Identify use-cases and end-uses of these gases; and
- Inform strategies to increase production capacity and deployment.

The Study finds that there exists significant potential to produce renewable and low-carbon gases in BC, and a robust deployment strategy is needed to realize this potential. FEI views the study as an important initial step to outline the potential, the barriers, the roles of key implementing agencies including government, project developers and utilities, and initiatives that should be undertaken. FEI is encouraged that the study will add further momentum to encourage the integration of alternate forms of Renewable Gas; however, as discussed on page 120 of the study, a robust strategy will be needed to realize the potential.

18.3 Please discuss whether FEI's expectations that there will be opportunities to acquire lower cost supply will encourage integration of alternate forms of Renewable Gas.

Response:

FEI expects that the acquisition of syngas and lignin, that are intended to be used by industrial gas customers to displace natural gas combustion directly at the point of use and delivered to FEI customers by displacement, could represent a significant volume of Renewable Gas supply at a lower cost in BC. FEI believes that the ability to acquire these forms of biofuels under the GGRR to decarbonize the gas system will encourage more opportunities to acquire lower cost supply that will encourage further innovation around integration of these alternate forms of Renewable Gas. At this point in the development cycle it makes sense to develop diverse sources of supply to mitigate the risk as other entities also take up renewable gasses. It remains to be seen as to whether these will be lower cost than RNG.

On page 110 of the FEI Tilbury CPCN Application, FEI states "A 3 Bcf tank maximizes the opportunity to meet Provincial energy needs in a cost-effective way by accommodating future growth and expanding FEI's ability to store and deliver renewable natural gas."

18.4 Please discuss whether FEI considers its major capital project plans, including the proposed Tilbury Liquefied Natural Gas (LNG) tank, support or hinder FEI's ability to provide customers with low carbon energy.

Response:

FEI's major capital projects are being designed to support the gas system's ability to provide customers with low carbon energy. For example, the responses to BCUC Panel IRs 1.1 and 1.2 in the Tilbury Liquefied Natural Gas Storage Expansion (TLSE) CPCN proceeding (included in Attachment 18.4) explain how the TLSE project will be important for supporting the transition to renewable and low carbon gas supplies while also improving system resiliency between now and 2050. For more discussion regarding the impact of FEI's major projects, please refer to the responses to BCUC IR1 9.4 and 11.4.

18.5 Please discuss FEI's expectation of future growth in the use of hydrogen, synthesis gas and lignin and how technical and regulatory barriers align with forecasts volumes of Renewable Gas supply and demand. As part of the response, please discuss the expected impact on FEI's business risk.

Response:

Please refer to the preamble and the response to BCUC IR1 18.1. FEI is forecasting that in this time period all renewable and low carbon gas acquired by FEI will be delivered to customers (i.e. supply equals use).

On page 38 of the FEI Stage 2 Comprehensive Review and Application for Approval of a Revised Renewable Gas Program, FEI states:

> More recently, in 2021, the provincial government amended the GGRR to broaden its scope and further increase the production and use of Renewable Gas, including renewable energy from green and waste hydrogen in BC, to reduce GHG emissions. The changes to the GGRR supporting growth in Renewable Gas supply include:
>
> - Enabling utilities to acquire and supply green and waste hydrogen, synthesis gas and lignin, in addition to RNG.
> - Increasing the amount of RNG, green and waste hydrogen, lignin and synthesis gas that utilities (such as FEI and Pacific Northern Gas) can acquire and make available to their customers from five percent to fifteen percent of the total annual supply of natural gas;
> - Broadening the methods by which utilities can obtain Renewable Gas to include producing it or upgrading it themselves for injection into the pipeline,

paying a third party to produce it or upgrade it for pipeline injection, or purchasing hydrogen, synthesis gas or lignin to displace the use of natural gas at customer facilities; and

- Increasing the price cap utilities can pay to acquire Renewable Gas from $30 to $31 per GJ for contracts for purchase signed after March 31, 2021 and increasing the price cap annually by inflation.

18.6 Please discuss whether FEI views the amendments in the GGRR to broaden scope and further increase the production and use of Renewable Gas as mitigating the regulatory barrier to integrate alternate forms of Renewable Gas for FEI.

Response:

FEI agrees that amendments to the GGRR enable FEI to bring on more renewables at a faster pace and assist with respect to cost recovery.

Applications for acquisition of renewables, contemplated in the GGRR, will continue to be brought to the BCUC for approval and/or acceptance. In FEI's experience there will continue to be regulatory processes until such time that the acquisitions become routine. Consequently, regulatory barriers continue to exist especially when novel issues arise and are brought forward to the BCUC, such as the new forms of renewables or innovative approaches to acquisition that are enabled by recent GGRR amendments.

Hydro-Québec and Énergir have announced a partnership to help reduce natural gas consumption among participating customers in efforts to reduce greenhouse gas (GHG) emissions associated with heating the residential, commercial, and institutional buildings involved through a dual-energy system.

18.7 Please discuss whether FEI has considered or plans to implement dual-energy systems with both natural gas and electricity with FBC, similar to the Hydro-Québec and Énergir partnership. As part of the response, please discuss whether a dual-energy system would increase or decrease FEI's business risk and whether it would improve FEI's market competitiveness.

Response:

Dual-energy systems, in addition to gas-fired heat pumps and renewable gases, are solutions for both utilizing the gas system and reducing emissions. FEI and FBC are evaluating the potential of dual energy systems in the BC context to better understand their acceptance, performance and potential to reduce emissions. These systems effectively integrate both the gas and electric systems to provide heating services at the appliance level. Coordination would be needed across both systems to understand the operational, business, and policy risks.

FEI is evaluating the potential of dual-energy heating systems for the buildings sector as one potential solution to improve energy efficiency and reduce emissions. The implementation would include electric heating equipment (such as an electric heat pump) in combination with gas equipment (such as a furnace, boiler, gas heat pump, or gas fireplace) to provide the necessary heat for a home. There are many potential configurations of these systems with the final solution dependent upon building considerations and design, cost, efficiency, GHG requirements and regulations.

FBC and FEI are both evaluating potential pilot programs that would provide incentives for dual energy systems to test market acceptance and better understand the technical performance and potential of these systems in the portions of FBC's and FEI's service territories that overlap. Any future pilots would be brought forward in an upcoming DSM expenditures application.

FortisBC's initial perspective in this area is that, while these systems show promise to moderate peak electricity loads, usage of these systems will need to be balanced to sufficiently use the gas system to ensure rates remain affordable and support overall resilience of the energy system. At this point, it is still early to offer specific discussion on whether these systems increase or decrease risk. A case can be made that dual systems may reduce risk as they enshrine a critical role for the gas system to address peak heating demand. Conversely, they may increase risk as the systems may significantly reduce load on the gas system and constrain the ability of the gas system to invest in other low-carbon solutions and limit its potential in other areas.

Further, the overall approach of the decarbonization policy framework and the partnerships and agreements across different utilities required to deploy these systems will also significantly influence risk to the utility. Because BC Hydro is a publicly owned entity, policy direction will have a key role in shaping risk to FEI if and when the gas and electric systems are further integrated through the use of dual energy systems.

19.0 Reference: OPERATING RISK

Exhibit B1-8-1, Appendix A - FEI Business Risk Assessment, p. 108;

FEI Certificate of Public Convenience and Necessity for the Coastal Transmission System Transmission Integrity Management Capabilities Project (FEI CTS TIMC CPCN) Application, Exhibit B-5, IR 24.2, p. 74

Operating Risk – Aging Infrastructure and Useful Life

As per Section 38 of the UCA:

> A public utility must
>
> (a) provide, and
>
> (b) maintain its property and equipment in a condition to enable it to provide, a service to the public that the commission considers is in all respects adequate, safe, efficient, just and reasonable.

On page 108 of Appendix A, FEI assesses that, compared to the 2016 Proceeding, operating risk facing has increased. On page 108 of Appendix A, FEI states:

> Aging assets and time dependent threats increase the risk of asset failure resulting from corrosion and cracking, known to exist on some FEI assets. FEI's risk of aging infrastructure and time dependent asset failure remains similar to that of the 2016 Proceeding…
>
> FEI anticipates, given the current understanding of the expected service life of assets over the next forty years, 79 percent of steel mains and 54 percent of transmission system pipelines will be past their expected service life of approximately 65 years.

In Exhibit B-5 of the FEI CTS TIMC CPCN Application, FEI states "FEI also notes that well designed and constructed pipeline assets, if maintained properly and continuously, can be used indefinitely."

19.1 Please discuss the impact FEI's infrastructure upgrade CPCNs that the BCUC has approved since 2016 has had on FEI's operating risk, including whether operating risk has increased or decreased and why.

Response:

FEI's infrastructure upgrade CPCNs have numerous drivers that enable FEI to manage a variety of risks. In the following table, FEI describes impacts on operating risk due to infrastructure upgrade CPCNs approved by the BCUC since 2016:

Infrastructure upgrade CPCN's	Description	Primary Driver	Status	Discussion of impact on FEI's Operating Risk	Operating Risk Increased or Decreased?
Inland Gas Upgrade (IGU)	Modifies applicable transmission lateral pipelines for running in-line inspection tools.	Integrity	CPCN was approved January 21, 2020. Project is in-progress.	This project primarily enables FEI to: • Continue to operate its pipelines without rupture failures, consistent with its prior safe operating history; and • Manage risk of time-dependent failure mechanisms consistent with its Canadian peer companies, leveraging proven and commercialized technology. FEI recognizes that the capability to detect imperfections and perform pipeline repairs at a site-specific level does reduce risk of failure at that site, to the extent that such imperfections are detected and repaired on a particular transmission pipeline.	Operating risk remains stable. Project capabilities enable FEI to manage time-dependent integrity threats on transmission pipelines, that could otherwise grow, undetected, to failure.
Pattullo Gas Line Replacement (PGR)	Replaces the distribution system capacity currently provided by FEI's distribution pressure gas line affixed on the Pattullo Bridge. A third-party driven infrastructure project is resulting in the decommissioning and demolition of the Pattullo Bridge.	Third-party driven infrastructure upgrade	CPCN was approved August 31, 2020. Project is in-progress.	This project primarily enables FEI to continue to serve customers, consistent with its prior reliable operating history. The project mitigates the loss of an existing pipeline that is affixed on the Pattullo Bridge and is an appropriate response to a third-party driven infrastructure project.	Operating risk remains stable. Project will enable FEI to continue to serve its customers reliably.

1

19.2 Out of the 79 percent of steel mains and 54 percent of transmission system pipelines that FEI submits will be past their expected service life over the next 40 years, please confirm that these assets can still be used and useful so long as they are maintained properly and continuously. If not confirmed, please clarify.

Response:

The citation in the preamble from the CTS TIMC application pertained specifically to transmission pipelines with in-line inspection capabilities and was assuming that there are no other intervening non-maintenance reasons causing the service life to be limited. In that context, the statement is accurate. However, as discussed below, those pipelines are a limited subset of FEI's pipelines and there are a variety of other reasons that can limit the life of FEI assets.

FEI's in-line inspection activities are enabling the safe operation of transmission pipelines beyond their expected service life (i.e., their financial life) and can potentially defer the need to replace transmission pipelines indefinitely. Periodic in-line inspection, where feasible, is part of a proper and continuous maintenance program for transmission pipelines. However, ninety-four percent of FEI's assets are not affected by CPCN projects such as the CTS TIMC, and are classified as distribution assets; in-line inspection is not feasible on these assets.

FEI's increasing operating risk is influenced by a number of factors unrelated to pipeline maintenance, and hence outside of FEI's control. Examples of the wide-ranging issues that are impacting FEI's operations and increasing its operating risk included in FEI's evidence are:

- Infrastructure and time-dependent threats;
- Third-party damage;
- Negative sentiment towards the fossil-fuel industry;
- Municipal permitting challenges;
- System resiliency risks, as illustrated by the Westcoast T-South pipeline rupture;
- Extreme weather events that are impacting FEI's operations; and
- Evolving cybersecurity risks that are impacting FEI's cybersecurity mitigation practices.

Factors other than integrity condition also impact the need for transmission and distribution asset replacements. These include system demand growth, system alterations for operating benefits, and replacements driven by increased population density. Many replacement reasons are beyond FEI's control, including infrastructure modifications (e.g., municipal, road, or bridge construction activities), third-party relocation requests, and natural events such as the recent flooding event in the Fraser Valley, Merritt, and Princeton.

An example of a pipeline that could not be used indefinitely is the 508 mm Coquitlam to Vancouver pipeline, which was replaced by the Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) Project. The primary project driver was pipeline integrity, but the deficiency was not

attributable to improper maintenance. Rather, the pipeline was experiencing external corrosion leaks despite being constructed in accordance with industry standards and practices of the time and being maintained properly and continuously as a distribution pipeline.

20.0 Reference: REGULATORY RISK

Exhibit B1-8-1, Appendix A - FEI Business Risk Assessment, pp. 115–116 and 119–120

Regulatory Risk – General

On page 115 of Appendix A, FEI states, "there is an increased level of regulatory uncertainty, driven both by the BCUC's decision to review the financing of deferral accounts, increased uncertainty of approval for FEI's initiatives supporting the future of the gas system, as well as uncertainty around pre-project approval funding."

On page 116 of Appendix A, FEI states, "There has been no fundamental change in FEI's regulatory framework under the UCA since the 2016 Proceeding, although there has been some increase in the level of costs that are subject to earnings sharing rather than flow-through treatment."

On page 119 of Appendix A, FEI states:

> Further, due to the uncertainty around the future role of natural gas in BC's energy infrastructure, FEI's capital intensive CPCN projects are also facing a higher level of regulatory uncertainty such that the BCUC may be hesitant to approve projects that add to the system capacity and lead to higher rates.

On page 120 of Appendix A, FEI states:

> One aspect of regulatory lag is the time between BCUC application filings and final approvals. Given the complexity of the regulatory process, there is going to be an inherent delay between the time an application is filed and when the final order related to that application is issued.
>
> […]
>
> FEI believes that, compared to the 2016 Proceeding, the risk associated with regulatory lag has experienced a notable increase. FEI has observed increased interest and active participation by Indigenous and environmental groups in regulatory proceedings.

20.1 Given there has been no fundamental change in the regulatory framework under the UCA, please confirm, or explain otherwise, that the increased level of uncertainty is driven by the nature and scope of the utility's application and the necessary regulatory review to accommodate participants in the process.

Response:

With respect to regulation under the UCA, FortisBC agrees that there has been no fundamental change in the legislation. As such, the lead cause of increased regulatory uncertainty under the UCA is the increased complexity in the nature and scope of applications and the regulatory review

to accommodate additional and non-traditional participants in the process. FortisBC notes that static legislation could also pose challenges to the extent that the existing UCA is not up to the task of accommodating or supporting certain expectations placed on utilities by government policy. As explained in FEI's and FBC's business risk appendices, another source of regulatory uncertainty, despite unchanged legislation, is the BCUC's decision to revisit deferral account financing costs.

Regulatory risk is not limited to the BCUC and the UCA; FEI is subject to a number of other regulatory regimes, and there have been changes in other areas that increase regulatory uncertainty. These include regulations associated with requirements to seek the FPIC of Indigenous Peoples prior to proceeding with project development as well as heightened requirements for environmental work in advance of project development, including in some cases Environmental Assessments.

20.2 Please elaborate on the risk of uncertainty of approval for FEI's initiatives supporting the future of the gas system as being categorically a regulatory risk compared to a political risk. How did FEI segregate the two risk categories to avoid overlap?

Response:

As explained in FEI's business risk evidence, when performing risk analysis, other risk factors and categorizations are possible, and some risk factors could be captured under a different risk category. Nevertheless, in this case there is a clear distinction between political risk and regulatory risk due to uncertainty around regulatory approvals for FEI's initiatives to support the future of the gas system in BC's economy.

FEI defines political risk as the potential for governments or other stakeholders to intervene directly in the utility regulatory process or negatively impact utility operations through policy, legislation and/or regulations. A root cause of political risk is the change in public opinion and governments' response to these changes. FEI's initiatives to expand its Renewable Gas program and LCT and LNG export strive to partially mitigate these risks and align FEI's business with governments' climate policies.

The main source of regulatory risk on the other hand is regulatory discretion in approving and/or denying the utility's applications. Consider the BCUC, for instance, which is an important regulator of the FortisBC. While public policy is a factor that may be considered in BCUC regulatory decisions, other factors such as cost of service and rate design considerations are prominent. As explained in Section 10.1.2 of FEI's business risk evidence, low-carbon gas alternatives such as Renewable Gas may require approval of different cost recovery approaches. For instance, different rate structures will need to be approved for customers who may not be able to access natural gas due to governments' carbon intensity targets and would therefore require a

Renewable Gas blend or 100 percent Renewable Gas. If the BCUC exercises its discretion in a way that impedes development, or emphasizes short-term affordability over resilience and decarbonization goals, this can hinder FEI's ability to implement important initiatives that align its operations with government policy and promote FEI's role in the low-carbon economy. Further, the rapid pace of change in governments' policies means that FEI may need to bring new applications for BCUC approval in shorter periods which would then require more expedited review processes. In all these instances, FEI's applications are in line with governments' policies but the regulatory risk caused by regulatory discretion still remains, which shows the two risks are separate.

20.3 Please elaborate on the risk of regulatory lag associated with increased interest and active participation by Indigenous and environmental groups in regulatory proceedings as being categorically a regulatory risk compared to Indigenous Rights and Engagement. How did FEI segregate the two risk categories to avoid overlap?

Response:

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

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

Section 5 of FEI's business risk discusses the legal and legislative underpinning of Indigenous Rights and Engagement risk and provides general comments on their impact on FEI's business. The impact of Indigenous Rights and Engagement risk on FEI's business is widespread and covers many aspects of FEI's business, ranging from financial risk and credit rating (as discussed by Moody's) and price risk (for instance due to potential loss of load to an Indigenous Utility) to regulatory risk (for instance as relates to increased regulatory lag and pre-project approval funding). Section 10 of FEI's business risk considers in more detail, among other things, the impact of increased requirements and uncertainty around Indigenous Rights and Engagement on regulatory lag and regulatory uncertainty.

21.0 Reference: REGULATORY RISK

Exhibit B1-8-1, Appendix A - FEI Business Risk Assessment, pp. 115–116, Appendix C - Evidence of Mr. James Coyne, p. 105

Exhibit A2-13, The Brattle Group, "A Review of International Approaches to Regulated Rates of Return, prepared for the Australian Energy Regulator" dated June 2020 (2020 Brattle Group Report), pp. 8 and 56

Regulatory Risk – COS vs. Performance Based Ratemaking (PBR)

On page 115 of Appendix A, FEI states that its overall regulatory risk is higher than what was assessed in the 2016 Proceeding. In particular, FEI states there is an increased potential for regulatory lag and processes while its risk exposure associated with administrative penalties under the UCA and other regulatory frameworks applicable is similar to the 2016 Proceeding

On page 116 of Appendix A, FEI states that it believes that the risks associated with the Multi-Year Rate Plan are similar to the risks identified for the PBR plan in the 2016 Proceeding.

On page 105 of Appendix C, Mr. Coyne states:

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

21.1 Please confirm, or explain otherwise, that incentive regulation such as FEI's and FBC's PBR plan provides a higher earnings potential than cost of service.

21.1.1 If confirmed, please discuss whether equity investors may find utilities under incentive regulation a more attractive investment than utilities under cost-of-service ratemaking.

Response:

The earnings potential of PBR plans depends on the individual plan's components. PBR plans with no earnings sharing mechanism, high off-ramp thresholds and/or more cost and revenue items subject to incentive mechanisms can potentially result in higher earnings and/or losses.

However, most PBR plans include various mechanisms to limit windfall earnings and/or losses and protect both ratepayers and utilities.

As shown in the responses to CEC IR1 12.1 and CEC IR1 18.3, FEI's and FBC's own experiences with both cost of service and PBR/MRP plans indicate that the difference between allowed and actual ROE during the cost of service and PBR/MRP periods is not significant and indeed for a number of the years the variance between allowed ROE and actual ROE under PBR plan (after earnings sharing) is lower than under the cost of service years with no earnings sharing mechanism.

FortisBC does not believe that utilities under PBR/MRP regulatory framework are more attractive to equity investors. Utility stocks are generally characterized as defensive and most investors holding utility stocks expect that utility earnings remain stable and grow slowly in most economic conditions. As such, FortisBC does not believe that earnings volatility caused by windfall earnings and/or losses is attractive to the majority of utility investors.

21.2 Please discuss how the structure of FBCU's PBR mechanism impacts each of its business risks. For example, earning sharing mechanism, off-ramps, allowance of deferral accounts of various expenditures, annual review process, etc.

Response:

The structure of the MRPs is discussed under the regulatory risk section and has little to no impact on other risk categories (other than the price risk which is impacted by the rates). The potential risks and rewards depends on the strength of the incentives and the type of safeguard mechanisms in place. The impact of major components of the approved MRPs on FEI's and FBC's risk are discussed below. Please also refer to the response to BCUC IR1 21.1.

Item	Risk Impact
Term	The longer the plan's term, the higher the risk/reward potential.
Costs subject to the incentive framework	The more costs and revenues subject to the incentives, the higher the risk/reward. The 2020-2024 MRPs include a larger set of cost items under an incentive framework as cost items such as depreciation expense are now subject to the sharing mechanism. Further, although the capital formulas for the most part are replaced with capital cost forecasts, the capital expenditures are still subject to an incentive framework.
Non-controllable costs	Both MRPs use mechanisms such as Y-Factor (flow-through) and Z-Factor (exogenous factors) to exclude non-controllable costs items from the incentive framework by way of deferral accounts. These mechanisms have the effect (all else equal) of reducing the risks to ratepayers and utilities otherwise associated with an MRP.
Capital exclusion mechanisms	Both utilities can exclude major lumpy capital projects that are over certain dollar thresholds from the incentive framework. This is an important mechanism to reduce risk otherwise associated with a MRP particularly for plans with longer terms.

Item	Risk Impact
Earnings Sharing Mechanism	Both plans have a symmetric earning sharing mechanism (ESM) which is designed to reduce the risk of windfall surpluses or losses for both utilities and ratepayers; however, it also reduces the strength of the plans' incentives.
Other safeguards	Both plans have a set of safeguard mechanisms that reduce the potential risks to both utilities and/or ratepayers. These include items such as off-ramp provisions and service quality indicators. Compared to the 2014-2019 PBR plans, the 2020 MRP has fewer safeguard mechanisms since the capital dead-band mechanism was eliminated although the mid-term review of capital forecasts can be regarded as a safeguard mechanism that did not exist in 2014-2019 PBR plans.
Annual Reviews	Annual reviews provide the opportunity for all stakeholders to monitor the utilities' performance during the MRP period. A streamlined annual process for rate setting is favourable to drawn out rate COS or rebasing proceedings from the perspective of regulatory lag. In the 2020 MRP decision, the BCUC directed FortisBC to update their 2023 and 2024 forecast capital expenditures. FEI's and FBC's risk in this regard will depend on the result of the review of these updated forecasts.
Clean Growth Innovation Fund	The approval of an innovation fund aimed at accelerating investments in new technologies is the only regulatory mechanism in the MRP that, if successful, can mitigate FEI's increasing long-term risk and provide long-term benefits to ratepayers by achieving performance breakthroughs and supporting the transition to a lower carbon economy.

In the 2020 Brattle Group Report dated June 2020, on page 8, the Brattle Group states:

> In addition to encouraging utilities to operate efficiently, sometimes regulators have other objectives that they wish utilities to achieve. For example, regulators in many jurisdictions require electricity distribution utilities to measure various aspects of service quality, such as the average number of power outages per customer per year. The regulator will set a performance target, and often will provide a financial incentive for the utility to perform at the target level: performance better than the target attracts a financial reward (i.e., an increase in authorised revenues), and performance worse than the target attracts a financial penalty in the form of a reduction in authorised revenues. [Emphasis added]

On page 56, the Brattle Group states:

> Ofgem [the energy regulator in Great Britain] subtracts 0.5% from its cost of equity estimate to reflect "expected outperformance". We think that this means Ofgem anticipates that utilities will be able to reduce their expenses, and/or earn net incentive payments, equivalent to an additional return to equity of 0.5%. However, rather than adjusting the opex building block or making its incentive schemes symmetrical (with an expected payout of zero), Ofgem is proposing to reduce its authorised rate of return by an equivalent of 0.5% on the cost of equity. Since this

reduction has nothing to do with the cost of equity, we remove the adjustment from Ofgem's figures. [Emphasis added]

21.3 Please confirm, or explain otherwise, that the Brattle Group's statement on page 8 of its report is similar to FEI's and FBC's Multi-Year Rate Plan, or as Mr. Coyne refers to, the PBR.

Response:

Not confirmed. The underlined statement refers to the approach used by Ofgem in the UK in its incentive regulation which is different from the approach used in North America and BC.

Under Ofgem's RIIO[58] framework, the actual rate of return on equity is made up of several components:

- **Allowed equity return**: The allowed equity return is the return on equity that a company would earn if their expenditure and allowance matched and there were no other incentives. As explained in Brattle's report, Ofgem distinguishes between authorized return and investors' expected return. These concepts also exist in North American regulation but in practice North American regulators set the authorized return equal to the investors' expected return. PBR plans such as those referred to by Concentric often contain incentives for the utility to exceed its allowed return if it can achieve efficiencies during the rate period. However, in North America, regulators have a legal duty to determine a cost of capital that meets the Fair Return Standard (FRS), and then set rates that provide the utility with a reasonable opportunity of achieving it. The FRS requires that a fair and reasonable overall return on capital reflect the comparable return that investors expect from investing in enterprises of like risk. In other words, under the FRS, the authorized return should be set to meet investors' expected return. Outside of North America, the same judicial and legal underpinnings in determining the cost of capital do not exist and European regulators, including Ofgem, are not obligated to meet the FRS. Dr. Makholm of NERA, a well-known expert in utility regulation and cost of capital, explains the institutional foundation for cost of capital in North America versus Europe as follows:

> The regulation of utilities in North America faces a special kind of constraint that most other nations do not exhibit. Particularly in the United States, major regulatory statutes do not become settled methods of government control over private businesses until they are tested in the courts … The major test for the US Supreme Court revolves around property—that is, whether any regulation somehow deprives investors of the value of their property without due process of law (and due compensation). No other country bases its regulations on questions of constitutionally protected private property in this fashion, though Canada has a practical judicial equivalent.

[58] Revenue = Incentives + Innovation + Outputs.

> As is the case with many legal and institutional issues in regulation, the definitions in the major US Supreme Court decisions that underlie regulation in North America, particularly involving the valuation of capital, do not generalize easily around the world—even to UK or the rest of Europe … Regulation in the US (and to a lesser but important extent Canada) rests heavily on the ability to gauge investor expectations via those companies and that investment-analysis industry. Other parts of the world do not have a history of investor ownership of utilities. [Underlined added][59]

- **Operational performance (totex):** This compares the totex allowance to actual totex expenditure and any underspend or overspend is then shared between the company and consumer through the totex incentive mechanism. Totex combines a portion of utility capital expenditures and operating expenditures into one regulatory asset that allows a rate of return on both, based on a pre-set percentage split. To the best of FortisBC's knowledge, the Totex approach as applied by Ofgem is not common in North America. However, the overall approach to share any underspend or overspend is comparable to the approach used in FortisBC's MRPs.

- **Performance Incentives:** In addition to the cost efficiency incentive included in the multi-year rate plan and revenue cap, Ofgem sets up specific targets that utilities must meet, with some tied to financial incentives worth up to +/- 250 basis points. The targets are tied to six performance categories: reliability and availability, environment, connections, customer service, social obligations and safety. This is the section of the RIIO that the underlined section of the preamble is referring to. FortisBC's MRPs do not have similar performance incentives that are tied to financial incentives worth up to 250 basis points. The targeted incentives proposed in the MRP application can be considered as a watered down version of RIIO's performance incentives but those were ultimately not approved. Under the MRPs, failure to meet SQI benchmark thresholds, if determined by the BCUC after further process to be considered a serious degradation of service quality, may result in a reduction to the share of earnings sharing retained by the Companies, up to a maximum of 10 percent of the earning sharing earned. However, this is different from the approach by Ofgem which provides for both rewards and penalties, which are more extensive. It should also be recognized that Ofgem implements its RIIO plans with extensive stakeholder sessions, involving consultants retained by Ofgem, and inputs from a wide variety of stakeholders, which can last several years and apply to all distributors or transmitters under the plan.

21.4 Based on Ofgem's expectation that utilities under incentive regulation will "outperform" their targets, please explain whether the BCUC should consider a reduction adjustment in the allowed rate of return.

[59] https://www.nera.com/content/dam/nera/publications/2015/PUB_Cost_of_Capital_1115.pdf.

21.4.1 If so, why, and how would the BCUC determine the reduction? And would a 50 basis points (bps) reduction to the allowed ROE be appropriate?

21.4.2 If not, why, and how do utilities in BC under PBR differ from the utilities Ofgem regulates?

Response:

In FortisBC's view, reducing the allowed return for the FortisBC by any amount on the basis of Ofgem approach would represent a departure from the FRS.

In Canada, unlike the UK, a cost of capital determination is about setting the investors' opportunity cost according to the three tests under the FRS. The regulator must first fix this "allowed return" in accordance with the FRS, and then set rates that provide a reasonable opportunity to achieve it. The incentive mechanisms under performance-based/multi-year rate plans are intended to influence behaviour by holding out the prospect of (a) the utility being able to earn more than the allowed return that the regulator has determined meets the FRS, and (b) the utility not being able to achieve its allowed return unless it takes reasonable steps. The only way that a performance-based/multi-year rate plan impacts the FRS itself is if it is designed in such a way as to systematically make it easier or harder to achieve the allowed return to an extent that investors would see a different risk profile.

As explained in response to the BCUC IR1 21.1, performance-based/multi-year rate plans' earnings potential, and the risk associated with that potential, depends on the structure of the plan. Regardless of Ofgem's views under its own regulatory framework, FEI's and FBC's experience is that the earnings potential under the approved PBR plans/MRPs are not that different from cost of service regulation.

Moreover, as described in the response to BCUC IR1 21.3, Ofgem's decision to reduce the expected investors' return represented a deliberate decision to set the authorized return below the expected return, which would be at odds with the FRS applicable in Canada. It is also based on Ofgem's extensive stakeholdering and evaluation of performance under prior plans and requires consideration of whether or not the allowed return is sufficient to attract capital and meet tests of financial integrity. The reduction contemplated in the question would be particularly punitive for FortisBC since (i) the question does not appear to contemplate the MRP introducing performance targets with the potential to earn an additional 250 basis points, which are part of the Ofgem plan, and (ii) FEI's and FBC's indexing formulas already include a 50 basis points reduction to the composite inflation factor to reflect "expected outperformance" of the utilities in finding efficiencies and reducing costs. The differences between regulation of utilities in the UK and North America (including BC) are significant and can be viewed from historical, legal, accounting and regulatory perspectives. Dr. Makholm's article titled "A Half-Century of Computing the Cost of Capital for Utilities at NERA"[60] explains some of these differences, which include the fact that the FRS does not apply in the UK. A deeper dive into why and how regulation of utilities

[60] https://www.nera.com/content/dam/nera/publications/2015/PUB_Cost_of_Capital_1115.pdf.

in BC and the UK differ would require substantial research, which is beyond the scope of this proceeding. For additional details, please refer to the response to BCUC IR1 21.3.

22.0 Reference: REGULATORY RISK

Exhibit B1-8-1, Appendix A - FEI Business Risk Assessment, p. 118, Appendix D, "D-7.2 - FEI List of Significant Deferral Accounts"

Regulatory Risk – Deferral Accounts

On page 118 of Appendix A, FEI states:

> A more generic approach to deferral account financing can lead to approval of unfair and inappropriate financing treatment if a utility's specific circumstances are not fully recognized. The decision to revisit deferral account financing costs itself creates uncertainty for FEI.

In "D-7.2 - FEI List of Significant Deferral Accounts" in Appendix D, FEI provides a list of its deferral accounts which has been reproduced in part below:

	A	B	C	D	E
1					
2	**FEI Deferrals with Significant Activity**	**2009**	**2012**	**2015**	**2021**
3					
4	**Margin Related**				
5	Revenue Stabilization Adjustment Mechanism (RSAM)	X	X	X	X
6	Commodity Cost Reconciliation Account (CCRA)	X	X	X	X
7	Midstream Cost Reconciliation account (MCRA)	X	X	X	X
8	Revelstoke Propane Cost Deferral account	X	X	X	
9	Interest on CCRA/MCRA/RSAM	X	X	X	X

22.1 Please explain what the years in row 2 of "D-7.2 - FEI List of Significant Deferral Accounts" in Appendix D represent.

Response:

The years in Row 2 of "D-7.2 – FEI List of Significant Deferral Accounts" in Appendix D represent the years in which FEI provided evidence on its deferral accounts in Cost of Capital filings; for comparison of current deferral accounts to those years.

22.2 Please provide any commentary from independent agencies, since the issuance of Order G-205-21 dated July 7, 2021, that they are concerned that the BCUC's review of deferral account financing costs would create uncertainty for FEI.

Response:

In the latest credit rating report for FEI and FBC published by Moody's on November 25, 2021, Moody's noted the following:

> In January 2021, the BCUC announced that it was initiating a generic cost of capital proceeding that will revisit the capital structure and allowed ROE. We have

assumed that there will be no changes stemming from this decision that would put downward pressure on financial metrics (...).

As discussed, FEI's and FBC's financial metrics are already weak and a switch in approach to deferral financing could lead to further deterioration in FEI's and FBC's financial metrics and impact their credit rating, especially if the new approach is debt only financed.

23.0 Reference: INDIGENOUS RELATIONS

Exhibit B1-8, FBCU Evidence, pp. 14–15; Exhibit B1-8-1, Appendix A - FEI Business Risk Assessment, pp. 43 and 49

Indigenous Rights and Engagement Risk

On page 43 of Appendix A, FEI states that it "has made Indigenous Rights and Engagement risk its own risk category (instead of being one of the risk factors under Political Risk in the 2016 Proceeding) to reflect the increasing significance of these considerations for FEI's overall business."

On pages 14 and 15 of Exhibit B1-8, FBCU states:

> Indigenous groups in BC are diverse and the added uncertainty from outstanding claims to Aboriginal title and rights further complicates the landscape within which FEI operates. Combined with regulatory updates that have increased consultation requirements and included a focus on seeking consensus and consent of Indigenous groups, as well as the risk of litigation in the absence of consent, FEI faces an elevated risk of cost escalation, project delays and/or projects being denied approval.

On page 49 of Appendix A, FEI states:

> While it is still somewhat unclear how or when the provincial government may implement the BCUC's recommendations, implementation of these recommendations could potentially lead to reductions in rate base and earnings, higher rates caused by loss of demand from existing customers located in Indigenous utilities' service areas and further complicate the CPCN regulatory process. Even though the recommendations have not been implemented, this risk has materialized with the Osoyoos Indian Band's notification to FBC of its discussions with a third party regarding the development of an Indigenous Utility for its business park, which is currently served by FBC.
>
> […]
>
> Project proponents such as FEI may also be affected by judicial reviews of permits and authorizations for projects based on claims of inadequate consultation or other Indigenous rights litigation.

23.1 Please discuss whether FBC and FEI, respectively, currently have a defined service area.

Response:

Attachment 23.1 outlines the service area of FEI. The following figure outlines the service area of FBC. The parameters of how those service areas are defined is discussed below.

Legislation Grants FBC the Right to Operate Within 150 Miles of Rossland and It Competes with BC Hydro

FBC was previously known as West Kootenay Power and Light Company, Limited. It was created by an 1897 statute called "An Act to Incorporate the West Kootenay Power and Light Company, Limited" (WKPA). FBC is still subject to the obligations, and has all the rights granted, pursuant to the incorporating statute, as amended.

The statute authorized FBC to conduct its utility business within the territory defined as the "said area":

> 9. The Company is hereby authorized and empowered to erect, construct, operate, and maintain compressed air and electric works, power houses, generating plant and such other appliances and conveniences as are necessary and proper for the generating of compressed air and electricity, and for transmitting the same to any

> part of the said area to be used as a motive power for the tramways by this Act authorized, or other works of the Company, or to be supplied by the Company as a motive power for hauling, propelling, pumping, lighting, heating, smelting, crushing, milling or drilling, or any other operations of any nature or kind whatever for which compressed air or electricity may be used, supplied, applied or required. And for any of the above purpose the Company is hereby authorized and empowered by its servants, agents, contractors and workmen from time to time to make and erect such compressed air and electric works, and to sink, lay, place, fit, maintain and repair such wires, accumulators, storage batteries, transformers, cables, mains, pipes, switches, connections, branches, motors, dynamics, engines, machines, cuts, drains, water-courses, buildings and other devices, and to erect and place any electric line, cable, main, wire, pipe or other compressed air and electric apparatus above or below ground, along, over or across any street, bridge or highway, or any line or lines of railway, tramway or street railway in said area, and to erect poles or pipes for the purpose of placing the same in such manner as the Company shall think fit, necessary or proper for the purpose of carrying out the operations of the Company in respect of and incidental to the making, generating or supplying of compressed air and electricity.

The "said area" was expanded in 1929 to encompass all areas within 150 miles of Rossland:

> 8A. In the following sections of this Act the expression 'said area' shall mean the area which comprises the City of Rossland and all lands within the Province situate within a distance of one hundred and fifty miles from the City of Rossland.

The purpose and effect of the WKPA was to confer upon FBC the right to provide electricity service in the "said area". Today, the entire operating area of FBC falls within the 150 mile radius established by the WKPA.

As described in section 6.2.1 of FBC's business risk evidence, the borders of FBC's service area tend to be underdeveloped regions, where customers building homes or businesses may have the option between different electricity service providers. As shown in the figure above, the boundaries of FBC's service area adjacent to BC Hydro's service area where growth is most prominent includes the area between the City of Kelowna and City of Vernon, in particular the Lake Country area.

FBC competes with BC Hydro in these underdeveloped areas where the borders of FBC's service area and BC Hydro's service area meet. BC Hydro's lower electricity rates are a factor in FBC's ability to expand beyond its currently serviced areas, but within the service area authorized by the WKPA. Customers building homes and businesses in the boundaries of FBC and BC Hydro service territory are not predetermined customers of either utility. Therefore, competition exists for FBC in these types of areas. The area outside the dark shaded area "FortisBC Service Area" and within the circle is currently served primarily by BC Hydro, although FBC has the statutory authority to expand into that area.

FEI Has Rights Conferred by CPCN

With respect to FEI, the right to operate is conferred by CPCN. Under the UCA, FEI has a deemed CPCN for the infrastructure that was in place before September 11, 1980, along with any extensions thereto (subject to any BCUC direction to apply for separate CPCNs for new extensions). FEI also had CPCNs issued in earlier decades that covered specific geographic areas (e.g., the Lower Mainland and Fraser Valley).

23.2 Please discuss the regulatory process steps that would need to be in place for an Indigenous Utility or another service provider to serve FBC or FEI's current customers.

Response:

As there have not been any changes to the UCA or any other governing statute to the present time, any entity seeking to serve customers currently served by FBC or FEI would meet the definition of a public utility under the UCA. Such entities would be subject to full regulation, unless granted an exemption under the UCA. Accordingly, the entity would need to make an application to the BCUC for a CPCN for new infrastructure and approval of the rates under which it would provide service.

Under normal conditions, the purchase of the assets of an incumbent utility would require the utility's consent and agreement on the appropriate terms and conditions of the purchase followed by a regulatory review process to ensure that the transaction does not harm the existing customers (no harm test). The BCUC has no jurisdiction to require a sale, nor is there existing legislative authority for the province to require it. However, in the Indigenous Utilities Regulation Inquiry (Inquiry Report), the BCUC suggested that where the Indigenous utility will likely materially impair the franchise of the incumbent utility, "a limited carve-out of the incumbent utility's service area is required".[61] There is some uncertainty as to if, how and when the provincial government may implement the recommendations in the Inquiry Report and the details of the regulatory process under which the BCUC may implement these recommendations is unclear. For instance, it is unclear how the province or the BCUC would "require" an incumbent utility to carve-out parts of its assets, how due process requirements would be met, and how appropriate compensation would be addressed.

23.3 Please discuss the status of the discussions with the Osoyoos Indian Band and the potential development of an Indigenous Utility for its business park.

[61] Inquiry Report, section 4.9.3, p. 65.

Response:

FBC understands that there is a signed partnership agreement between the Osoyoos Indian Band (OIB) and potential on-reserve customers. FBC has received an interconnection request; however, it was returned to OIB for additional details and required revisions. FBC expects to receive a revised interconnection request following these changes.

23.4 Please discuss the likelihood that FBC or FEI would sell a portion of its rate base to an Indigenous Utility.

Response:

To date, neither FEI nor FBC has sold or planned to sell any portion of its rate base to an Indigenous Utility. While FBC has been notified of the Okanagan Indian Band's discussions with a third party to develop an Indigenous utility at a business park currently served by FBC, FEI and FBC are unable to comment on the likelihood of a sale at this time, or what conditions would be required to move forward with such a sale. As discussed in the preamble above, while the BCUC's Indigenous Utilities Regulation Inquiry contemplated the potential for this to take place, it is still somewhat unclear if, how or when the provincial government might implement the BCUC's recommendations.

23.5 Please explain whether FEI and/or FBC is currently involved or expects to be involved in any judicial reviews based on claims of inadequate consultation or other Indigenous rights litigation.

Response:

Neither FEI nor FBC is currently involved in any judicial reviews based on claims of inadequate consultation or other Indigenous rights litigation. 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.

Since the provincial and federal legislation related to the *United Nations Declaration of the Rights of Indigenous Peoples* has been enacted, there exists a number of different perspectives as to the effect of such legislation, particularly with respect to the impact such legislation may have on what is considered adequate consultation and whether consent from Indigenous groups may be required for projects to proceed. This lack of consensus increases the risk that regulatory decisions may be judicially reviewed by Indigenous groups.

The large number of Indigenous groups in BC with shared or contested/overlapping territory and the lack of treaties across the majority of FEI and FBC's service territory adds further uncertainty to the consultation process and whether Indigenous nations may consider consultation to have been adequate.

FEI and/or FBC seeks to engage early, often, and thoroughly, but there is always the potential for an Indigenous group to claim insufficient consultation or bring claims of Aboriginal title or rights, including for factors outside the responsibility or control of FEI and/or FBC, such as the Crown's relationship with such Indigenous groups. For example, the nation-wide protests in early 2020 surrounding the Coastal Gaslink Project (CGL) in relation to the rights and title of the Wet'suwet'en peoples, cannot not be viewed as an isolated conflict between CGL and a select number of leaders, but instead, a question of the Crown's recognition of Indigenous rights and title. Over twenty years ago, through *Delgamuukw v. British Columbia* the courts reaffirmed that Aboriginal rights and title do exist, but there was no decision as to whether the Gitxsan and Wet'suwet'en had Aboriginal title to the lands they claimed (in the same area, where the CGL protests were taking place).[62] Since the decision in 1997, the relationship between the Crown, and the specific question of Wet'suwet'en's rights and title was never settled. With this lack of clarity, in part, came claims that consent from those leaders was required for CGL to proceed. It also came with questions and concerns that the Wet'suwet'en's rights and title were being unjustly infringed upon by the project.

23.6 Please discuss whether earlier engagement to consult helps to mitigate any judicial reviews of permits and authorizations or project resistance.

Response:

The potential judicial review of permits and authorizations or project resistance can be mitigated by early engagement, although the risk cannot be eliminated. In addition, there may be a difference of opinion on the depth of engagement FEI completes (and consultation the Crown undertakes) required in order to meet the duty to consult.

As discussed in Moody's June 2020 in-depth report regarding Indigenous rights (Section 6.3.1.4 of the Evidence), corporations can apply actions and programs to mitigate some of these concerns; however, their best efforts may still be insufficient without the full support of Indigenous groups:

> The implementation of UNDRIP/FPIC takes place in an environment of wider historical and social issues with respect to ICs. Indigenous concerns and goals generally span four broad categories where the implementation of UNDRIP/FPIC could potentially have a positive effect with respect to addressing each category of concern (see Exhibit 3). But progress may not be consistent across all

[62] https://www.bctreaty.ca/sites/default/files/delgamuukw.pdf.

categories. Governments and the corporations that work with ICs may also work at different pace or inconsistently. For example, in a given area, a corporation may make material progress strengthening its partnership with the ICs it works with but there could still be delays in settling outstanding land claims or other claims that the government is solely responsible for. Or the governance of IC's may not have been entirely settled, resulting in internal disagreements on projects as evidenced on Coastal GasLink with the hereditary chiefs and the elected band members having different views on the merits of the project. As a result, it is possible that some projects or activities may still encounter material execution issues when, in the opinion of the affected IC, insufficient progress has been made on all four fronts or when some IC's are in fundamental opposition to certain types of project, irrespective of the project's potential economic benefits.

C. QUESTIONS PRIMARILY RELATED TO FORTISBC INC.

24.0 Reference: FBC CREDIT RATING AND PROPOSED CAPITAL STRUCTURE

Exhibit B1-8, FBCU Evidence, pp. 1–-2 and 17; BCUC GCOC Stage 2, Decision and Order G-47-14 dated March 25, 2014, p. 60

Return on Equity

On page 1 of Exhibit B1-8, FBCU states, "FortisBC seeks …For FBC, approval of a capital structure consisting of 40 percent common equity and 60 percent debt, and a return on common equity of 10.0 percent."

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

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

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

24.1 FBCU views that FBC's overall business risk is similar to what was assessed in the 2013 Proceeding and FBC requested a risk premium over the benchmark of 50–75 bps in 2013. Please explain (i) how circumstances have changed since the 2013 Proceeding and (ii) how circumstances are expected to change in the future for FBC, to request an 85 bps increase (Proposed 10 percent less approved 9.15 percent) now. In other words, is the proposed 10 percent allowed ROE based on non-business risk factors of FBC and is solely a reflection of capital market conditions?

Response:

The question erroneously compares FBC's proposed risk premium over the Benchmark Utility in the 2014 Stage 2 GCOC proceeding with the variance between FBC's proposed allowed ROE in this proceeding and the existing approved ROE of 9.15 percent. As such, FBC is unable to respond to this question as framed. FBC elaborates below.

(i) How circumstances have change since the 2013 proceeding

In the 2013 GCOC proceeding, the BCUC determined that FEI is the sole Benchmark Utility in BC and its allowed ROE and equity thickness were used as the Benchmark for setting other regulated utilities' cost of capital (including for FBC). In the 2013 Stage 1 GCOC proceeding, Ms. McShane, FEI's main expert in that proceeding, proposed an ROE of 10.5 percent on a 40 percent common equity ratio. The BCUC's 2013 Stage 1 decision however determined that the appropriate allowed ROE for FEI should be set at 8.75 percent on a 38.5 percent equity thickness.

In the 2014 Stage 2 GCOC proceeding, the BCUC compared other utilities' individual risk profiles, on a standalone basis, with that of the Benchmark Utility and to determine whether a premium or discount to the Benchmark Utility's allowed ROE and equity thickness was warranted. FBC's evidence in the 2014 Stage 2 proceeding indicated that its risk profile would warrant a 50 to 85 basis points premium over the Benchmark. In its 2014 Stage 2 GCOC decision, BCUC compared FBC's risk profile to that of the Benchmark and concluded that "FBC faces additional price competitiveness risk as compared to the Benchmark and there is some additional risk related to small size" and stated that "this higher level of risk is the basis for our support of the recommendation of maintaining the equity ratio at its present level of 40 percent". Further, the BCUC considered the evidence concerning FBC's debt ratings, the size differential between FBC and the Benchmark and the differences in the beta of the Benchmark as compared to other utilities of similar overall risk and found that "maintaining a 40 bps equity risk premium is both reasonable and appropriate".

In the 2022 proceeding, by Order G-281-21 dated September 24, 2021, the BCUC decided that the Benchmark Utility methodology for determination of the cost of capital for utilities in BC is appropriate. Additionally, the BCUC stated that a review of FEI's and FBC's cost of capital evidence is necessary before determining whether FEI or FBC, or both, shall serve as a Benchmark Utility. In other words, FBC's allowed ROE and capital structure should be set independent of FEI's cost of capital. This renders it unnecessary to determine a discount or premium over the Benchmark Utility's ROE and equity thickness.

(ii) How circumstances are expected to change in the future for FBC, to request an 85 bps increase (Proposed 10 percent less approved 9.15 percent) now.

Unlike what is suggested in the question, FBC's proposed ROE and equity thickness are below FEI's proposed allowed ROE and equity thickness. In other words, although FBC's standalone risk is similar to what was assessed in 2013, the increase in FEI's risk profile since that time is such that, on a relative basis, FEI is now a riskier utility.

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.

25.0 Reference: FBC CREDIT RATING AND PROPOSED CAPITAL STRUCTURE

Exhibit B1-8, FBCU Evidence, p. 39–40; Exhibit B1-8-1, Appendix D-2, "FBC - Moody's - 2021 Credit Rating Report dated Nov. 25, 2021", p. 5

Credit Rating

On page 39 of Exhibit B1-8, FBCU provides the following table and states:

> Maintaining FBC's credit rating is critical since FBC already has more limited access to debt capital markets compared to FEI due to its smaller size and restrictive Trust Indentures that are highly sensitive to changes in the cost of borrowing. If downgraded, FBC would further diminish its access to capital markets and would potentially not be able to finance the debt component of its capital expenditures and operations on reasonable terms…
>
> FBC is at risk of a downgrade if metrics deteriorate further, which would have significant ramifications for FBC's ability to issue debt on reasonable terms and pricing.

Table 6-7: FBC's Key Financial Indicator Scores Compared to Minimum Baa Rating per Moody's Utility Rating Methodology

	FBC's Score	Baa - Rating Threshold[64]	2018	2019	2020	LTM Sept 2021
CFO pre-WC + Interest / Interest	Ba	3.0x-4.5x	3.6x	2.5x	2.5x	2.7x
CFO pre-WC / Debt	Ba	11.0% - 19.0%	9.8%	8.8%	8.6%	9.6%
CFO pre-WC - Dividends / Debt	Ba	7.0% - 15.0%	6.1%	5.1%	5.0%	5.9%
Debt / Capitalization[65,66]	Baa	50.0% - 59.0%	55.1%	56.0%	54.3%	54.3%

Source: Moody's Credit Rating Report for FBC, dated November 25th 2021.

On page 40 of Exhibit B1-8, FBCU states:

> […] key determinants of FBC's weak financial metrics are the low allowed equity component of its capital structure and low return on equity…
>
> FBC's CFO pre-W/C to debt metric for the last two years ended 2020 and 2019 were 8.6 and 8.8 percent, respectively, which means that this financial metric is critically close to a rating downgrade threshold of 8 percent. To put this in perspective, 2019 was the first time in the last 10 years that this metric has been below 9 percent. […]
>
> FBC's proposal to maintain its allowed equity should be viewed as a floor to avoid negative credit rating agency actions.

On page 5 of Moody's 2021 Credit Rating Report, Moody states:

We forecast CFO pre-W/C to debt in the 8-10% range for the next several years, a level that provides limited cushion at its current rating level. The utility has a long track record of earning its allowed return on equity and we have assumed that the company will continue to do so.

25.1 Given Moody's assessment and the LTM for September 2021 credit metrics in Table 6-7, please discuss whether this would indicate that FBC's metrics are improving. Why or why not?

Response:

The financial metrics are impacted by a number of factors, including operating performance, changes in deferral accounts and how they are financed, level of debt required based on the capital program, allowed ROE and capital structure, and depreciation of assets. As a result, the financial metrics vary year over year and the slight improvement for the last twelve months ended September 2021, as indicated in Table 6-7, does not point to a consistent trend that will hold up after 2021. In fact, even though Table 6-7 shows a slight improvement for LTM September 2021, these financial metrics are still consistent with a non-investment grade credit rating of Ba.

25.2 Please explain the probability of FBC's CFO pre-WC / Debt falling below eight percent in the next five years.

Response:

Please refer to the response to BCUC IR1 7.3.1.

25.2.1 Please explain, and provide the supporting calculations, the capital structure (debt and equity components) and return on equity that are required to maintain a CFO pre-WC / Debt at each of the following amounts: eight percent, nine percent, 10 percent and 11 percent.

Response:

The first table below shows the equity component that would be required to maintain a 3-year average CFO Pre-WC / Debt ratio at 8, 9, 10 and 11 percent while keeping ROE at the current level of 9.15 percent. The second table below shows the ROE that would be required to maintain a 3-year average CFO Pre-WC / Debt ratio at 8, 9, 10 and 11 percent while keeping the equity component at the current level of 40.0 percent.

The following assumptions were used to calculate the ratios:

1. Moody's has not conducted a 2021 credit rating review and therefore 2021 financial metrics were calculated by FBC using assumptions. Actual financial metrics calculated by Moody's may differ.
2. Certain information presented in this table is based on assumptions of how financial metrics will change based on changes in capital structure and ROE. Actual financial metrics may differ.
3. Increase/decrease in equity earnings and interest expense associated with changes in capital structure and return on equity were treated as cash earnings in the corresponding year, resulting in an equivalent change in CFO Pre-WC.

Equity Component Required at ROE 9.15%	
CFO Pre-WC/Debt[1]	Equity Component
8%	34.8%
9%	39.5%
10%	43.8%
11%	47.8%

Note: [1] 3 year average from 2019-2021.

ROE Required at Equity Component of 40%	
CFO Pre-WC/Debt[1]	ROE
8%	5.9%
9%	8.9%
10%	11.9%
11%	14.9%

Note: [1] 3 year average from 2019-2021.

25.3 Please provide FBC's (CFO Pre-WC + Interest)/ Interest and CFO pre-WC / Debt ratio for Fiscal Year end 2021, if available.

Response:

Moody's annual credit rating reviews typically occur in the third or fourth quarter of the year and so FBC has not yet received the 2022 Moody's Credit Rating Report with 2021 fiscal year end financial metrics. The table below is based on FBC's attempt to replicate Moody's methodology for calculating its proprietary credit metrics. FBC cannot represent that it has accurately incorporated all elements and this calculation should be used solely for illustrative purposes:

	2021
CFO pre-WC + Interest/Interest	2.7x
CFO pre-WC / Debt	10.0%

While both financial metrics marginally improved from 2020, they are still consistent with a non-investment grade credit rating as referenced in Table 6-7 above.

Please note that these metrics were not calculated by Moody's and actual financial metrics for fiscal 2021 may differ.

25.4 To the extent possible, please fill out the following table using the assumptions provided in each scenario, restated on a retroactive basis:

		(CFO Pre-WC + Interest)/ Interest					CFO Pre-WC/ Debt				
		2018	2019	2020	2021	Average	2018	2019	2020	2021	Average
Scenario 1	35% equity + 9.15% ROE										
Scenario 2	38.5% equity + 9.15% ROE										
Scenario 3	40% equity + 9.15% ROE										
Scenario 4	45% equity + 9.15% ROE										
Scenario 5	35% equity + 10% ROE										
Scenario 6	38.5% equity + 10% ROE										
Scenario 7	40% equity + 10% ROE										
Scenario 8	45% equity + 10% ROE										

Response:

The table below is based on FBC's attempt to replicate Moody's methodology for calculating its proprietary credit metrics. FBC cannot represent that it has accurately incorporated all elements and this calculation should be used solely for illustrative purposes.

Please also note that Moody's annual credit rating reviews typically occur in the third or fourth quarter of the year and so FBC has not yet received the 2022 Moody's Credit Rating Report with 2021 fiscal year end financial metrics.

Please refer to the table below for the requested scenario analysis. The following assumptions were used to retroactively restate the financial metrics:

- Equity earnings associated with changes in capital structure and return on equity were treated as cash earnings in the corresponding year, resulting in an equivalent change in CFO Pre-WC;
- Any changes in capital structure would be complied with by issuing long-term debt, therefore, interest expense associated with the change in the debt component of the capital structure was calculated using FBC's cost of long-term debt; and
- FBC included Moody's standard adjustments from the 2018-2021 credit rating reviews, where applicable.

		(CFO Pre-WC + Interest)/ Interest					CFO Pre-WC/ Debt				
		2018	2019	2020	2021	Average	2018	2019	2020	2021	Average
Scenario 1	35% equity + 9.15% ROE	3.3x	2.4x	2.3x	2.6x	2.6x	8.9%	8.0%	7.7%	9.1%	8.4%
Scenario 2	38.5% equity + 9.15% ROE	3.5x	2.4x	2.4x	2.7x	2.8x	9.6%	8.5%	8.3%	9.7%	9.0%
Scenario 3	40% equity + 9.15% ROE	3.6x	2.5x	2.5x	2.7x	2.8x	9.8%	8.8%	8.6%	10.0%	9.3%
Scenario 4	45% equity + 9.15% ROE	3.9x	2.6x	2.6x	2.9x	3.0x	10.8%	9.7%	9.5%	11.1%	10.3%
Scenario 5	35% equity + 10% ROE	3.4x	2.4x	2.4x	2.6x	2.7x	9.2%	8.2%	8.0%	9.3%	8.7%
Scenario 6	38.5% equity + 10% ROE	3.6x	2.5x	2.5x	2.7x	2.8x	9.8%	8.8%	8.6%	10.0%	9.3%
Scenario 7	40% equity + 10% ROE	3.7x	2.5x	2.5x	2.8x	2.9x	10.1%	9.0%	8.8%	10.3%	9.6%
Scenario 8	45% equity + 10% ROE	4.0x	2.7x	2.7x	3.0x	3.1x	11.2%	10.0%	9.8%	11.4%	10.6%

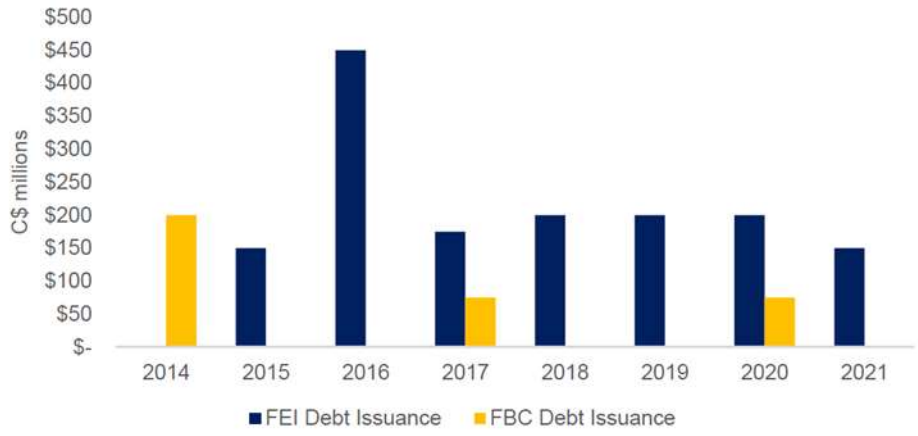
26.0 Reference: FBC CREDIT RATING AND PROPOSED CAPITAL STRUCTURE

Exhibit B1-8, FBCU Evidence, pp. 41–-42

Debt Issuance

On page 41 of Exhibit B1-8, FBCU provides the following graph and states:

Figure 6-5: Frequency and Size of Long-term Debt Issuances for FBC vs. FEI from 2014 to 2021



FBC issues debt less often and its issuance size is generally below $100 million. The smaller issuance size does not allow FBC debentures to be part of the bond index in Canada that requires the issue size to be a minimum of $100 million. Not being part of the bond index, combined with less frequent debt issuances and a lower credit rating, contribute to weaker demand and lower liquidity of FBC bonds.

26.1 Please explain whether FBC would issue debt more often and above $100 million if its credit rating improved.

Response:

FBC's issuance size and frequency is not driven by its credit rating. It is mostly a result of the smaller size of the utility, capital program and smaller credit facility capacity.

The reason FBC's issuance size and frequency was noted in the Evidence was to demonstrate that FBC already has more limited access to the market compared to a larger A-level rated utility such as FEI which is primarily a result of FBC's smaller size, its BBB level credit rating and restrictive Trust Indentures that are sensitive to changes in the cost of borrowing. Therefore, maintaining FBC's credit rating is critical. If downgraded, FBC's access to capital markets would be further diminished and pricing and terms for the financing of the debt component of its capital expenditures and operations would be less favourable.

26.2 Please explain the circumstances that led to FBC's $200 million debt issuance in 2014. Please include whether this was short-term or long-term debt, and what was FBC's allowed equity return and equity thickness at the time of this issuance.

Response:

On October 7, 2014, FBC entered into an agreement with the dealers listed in the Dealer Agreement to sell $200 million of senior unsecured MTN Debentures Series 3 (long-term debt). The closing of the issuance occurred on October 28, 2014, with net proceeds primarily used to repay Series 04-1 debenture of $140 million that matured on November 28, 2014. Remaining proceeds were used for general corporate purposes, including repayment of borrowings under credit facility and financing FBC's capital expenditure program and working capital requirements. At the time of the issuance, FBC's allowed equity return and equity thickness were 9.15 percent and 40 percent, respectively.

To clarify, while there are certain restrictions related to FBC's Trust Indentures, as discussed in its evidence, FBC is not restricted to issuing up to $100 million debentures only. FBC has traditionally issued debt up to $100 million because of its smaller capital program and therefore lower financing needs. The smaller size of the issuances means that FBC's debentures do not enter the bond index which comprises bonds above $100 million that are more frequently traded by investors and used to measure the value of the bond market. Not being part of the bond index, combined with less frequent debt issuances and a lower credit rating, contribute to weaker demand and lower liquidity of FBC bonds. This means that FBC needs to offer investors a higher interest rate to compensate them for these factors.

On page 41 and 42 of Exhibit B1-8, FBCU provides the following tables and states:

Table 6-8: Sensitivity Analysis for FBC's Earnings Coverage Test pursuant to 1983 Trust Indenture

		Sensitivity Analysis for 1983 Trust Indenture					
		Interest rate:					
		3.0%	4.0%	5.0%	6.0%	7.0%	8.0%
New Debt: (C$ millions)	$ 100	2.27	2.22	2.17	2.12	2.08	2.04
	$ 150	2.19	2.12	2.06	1.99	1.93	1.88
	$ 200	2.12	2.04	1.95	1.88	1.81	1.75
	$ 250	2.06	1.95	1.86	1.78	1.70	1.63
	$ 300	1.99	1.88	1.78	1.69	1.60	1.53
	$ 350	1.93	1.81	1.70	1.60	1.52	1.44

Note to table:
Red cells denote new debt/interest rate levels where the Earnings Coverage financial covenant test pursuant to 1983 Trust Indenture would not be met (<1.75).

Table 6-9: Sensitivity Analysis for FBC's Earnings Coverage Test pursuant to 1996 Trust Indenture

		Sensitivity Analysis for 1996 Trust Indenture					
		Interest rate:					
		3.0%	4.0%	5.0%	6.0%	7.0%	8.0%
New Debt: (C$ millions)	$ 100	2.27	2.22	2.17	2.12	2.08	2.04
	$ 150	2.19	2.12	2.06	1.99	1.93	1.88
	$ 200	2.12	2.04	1.95	1.88	1.81	1.75
	$ 250	2.06	1.95	1.86	1.78	1.70	1.63
	$ 300	1.99	1.88	1.78	1.69	1.60	1.53
	$ 350	1.93	1.81	1.70	1.60	1.52	1.44

Note to table:
Red cells denote new debt/interest rate levels where the Earnings Coverage financial covenant test pursuant to 1996 Trust Indenture would not be met (<1.90).

The tables above demonstrate that if new debt interest rates rise as a result of economic conditions or a downgrade in FBC's credit ratings, the aggregate level of new debt that FBC would be able to issue would be constrained by the Earnings Coverage Test financial covenants. For example, if the coupon rate for FBC's new bonds rises to 5 percent per annum, FBC would only be able to add an aggregate amount of $200 million in new debt in order to pass the Earnings Coverage financial covenants. This further highlights the importance of maintaining FBC's credit ratings to allow the Company to access debt capital markets to fund its operations.

26.3 Please provide FBC's current cost of borrowing for short-term and long-term debt issuances.

Response:

FBC's most recent short- and long-term debt issuances were as follows:

- **Long-term debt:** On March 10, 2022 FBC priced Series 6 long-term senior unsecured medium term note debenture of $100 million. The debenture matures in 30 years and carries a coupon rate of 4.16 percent. Before the March 2022 long-term debt issuance, FBC issued debt in May 2020 and the bond was issued at 3.12 percent for 30 years.
- **Short-term debt:** On March 1, 2022 FBC issued short-term commercial paper of $7 million for a maturity of less than 30 days at 0.56 percent. Similar commercial paper

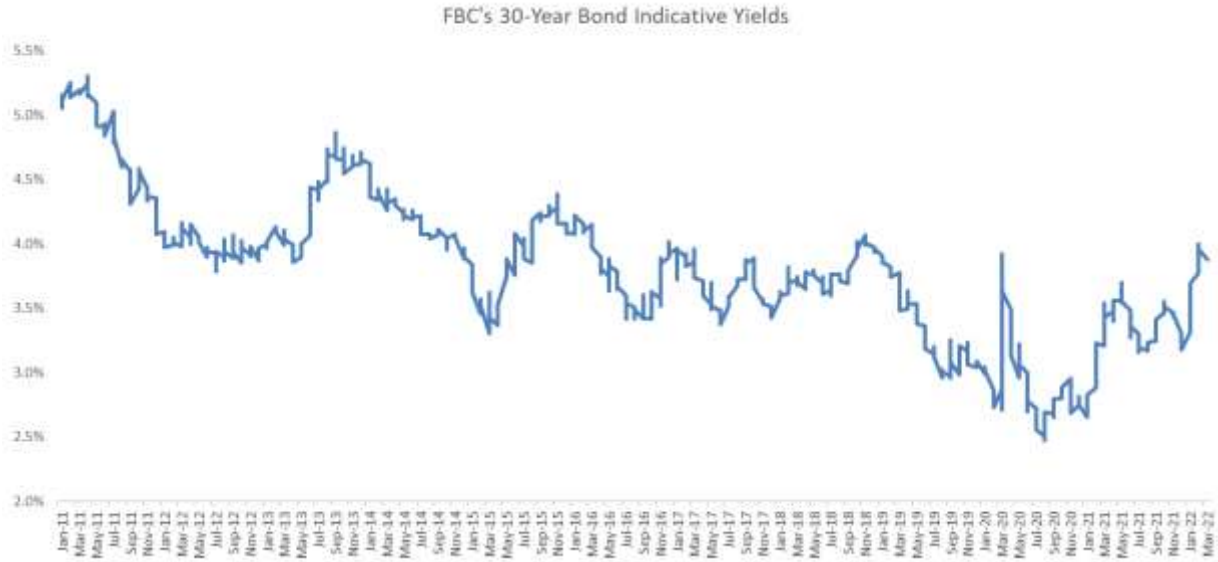
issuance in January 2022 was priced at 0.24 percent. FBC also pays an annual standby fee of 0.2 percent on its $150 million credit facility that acts as a backup to commercial paper issuances and should be incorporated in its short-term cost of borrowing.

FBC is operating in a rising interest rate environment as debt capital markets are experiencing significant volatility resulting from the war in Ukraine, concerns around inflation and rising oil and commodity prices. This trend is likely to continue as the conflict continues and commodity prices continue to rise. In addition, on March 2, 2022 the Bank of Canada raised its overnight rate by 0.25 percent, the first time the Bank of Canada raised its rate since 2018. Major Canadian banks are expecting five more interest rate hikes by the Bank of Canada by the end of 2022.

26.4 Given that FBC has not issued more that $200 million since 2014, please discuss how the Earnings Coverage Test has constrained FBC debt issuances in the last five years, if at all.

Response:

The sensitivity analysis is meant to convey that issuance restrictions arising from the Earnings Coverage Test will result in steadily increasing pressure over time based on changes in the cost of borrowing and as interest rates rise, which is the current trend with interest rates, even if the amount of issuance in a given year is of a lower amount. FEI and FBC currently find themselves in a rising interest rate environment as debt capital markets are experiencing significant volatility resulting from the war in Ukraine, concerns around inflation and rising oil and commodity prices, a trend that is expected to continue in the medium term. For example, on March 10, 2022 FBC issued a 30-year bond of $100 million at 4.16 percent which is approximately 1 percent higher than FBC's last debt issuance in May 2020 at 3.12 percent. FBC's 30 year bond indicative yields from January 2011 to March 2022 are included below.



Source: RBC

27.0 Reference: FBC BUSINESS RISK

Exhibit B1-8-1, Appendix B - FBC Business Risk Assessment, pp. 3 and 9; Appendix D-2, "FBC - DBRS - 2021 Credit Rating Report dated March 15, 2021", p. 3

Exhibit A2-14, S&P Global Market Intelligence, "Electric ROE Authorizations Drift Lower In H1'20 As Virus Worries Continue" dated August 4, 2020

Business Profile – Vertically-integrated vs. Distribution-only Utility

On page 3 of Appendix B, FBC states:

> FBC is a fully integrated electric utility that owns and operates hydroelectric generating plants, high voltage transmission lines, and a network of distribution assets in the southern interior of BC. FBC's structure as a fully-integrated electric utility contributes to a higher risk profile than for a distribution-only utility of a similar size, a situation exacerbated by a less diverse and relatively small customer base, concentrated in a small, but geographically diverse service area. [emphasis added]

On page 9 of Appendix B, FBC states:

> In conclusion, FBC submits that its vertically integrated nature adds to its business risk which should be reflected in its authorized return on common equity and/or capital structure. FBC's generation portfolio has not changed since 2013, and FBC assesses that its vertically-integrated nature poses the same level of risk as it did in the 2013 Proceeding. [emphasis added]

On page 3 of FBC-DBRS 2021 Credit Rating Report, DBRS listed its Rating Considerations for FBC's Strengths as:

> *Vertically integrated utility/supply security*
>
> FBC is a vertically integrated regulated utility that owns generation, transmission, and distribution assets. The Company's four hydroelectric generation plants with 225 MW of capacity on the Kootenay River, which are insulated from annual hydrology risk as a result of the Canal Plant Agreement (CPA), represented approximately 45% of FBC's annual energy needs.

27.1 Please discuss whether a vertically integrated electric utility is more or less risky than a distribution-only utility. Include any supporting evidence by independent agencies.

Response:

Investors generally consider vertically integrated utilities as riskier and demand higher compensation for investing in these companies than distribution-only utilities. This is corroborated

by an S&P Global examination of major rate case decisions in the U.S. released in July of 2019 which found that,"… *the annual average authorized ROEs in vertically integrated cases typically are about 30 to 65 basis points higher than in delivery-only cases, arguably reflecting the increased risk associated with ownership and operation of generation assets*."[63]

Further, as explained in Concentric's evidence, Moody's considers generation as the riskiest component of the electric utility business:

> We view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation.

FEI also notes that in Ontario, the Ontario Energy Board (OEB) approved equity thickness for Ontario Power Generation Inc (OPG) is higher than electric distributors indicating the higher risks to the generation business.

Please also refer to Concentric's response to BCUC IR1 56.1 and 56.2.1.

27.1.1 Please provide and assess advantages of a vertically integrated electric utility that are not present or apparent to a distribution-only utility. Include any supporting evidence by independent agencies.

Response:

Please refer to Concentric's response to BCUC IR1 56.2.

27.2 Given that DBRS consider FBC's vertical integration and generation ownership a strength, please explain how this should be reflected in FBC's allowed ROE and deemed capital structure.

Response:

FBC does not believe that DBRS' comments regarding FBC's strength relate to FBC having generation assets but rather DBRS comments that FBC's generation assets are insulated from annual hydrology risk as a result of the CPA and this, according to DBRS, is a source of strength.

[63] See S&P Global Intelligence, RRA Regulatory Focus, Major Rate Case Decisions January – June 2019 (July 22, 2019).

Despite DBRS' comments and, as discussed in FBC's 2021 Management Discussion and Analysis (MD&A), the sole reliance of FBC's generation assets on the Kootenay River is a source of risk to FBC:

> The Corporation's ability to generate electricity from its facilities on the Kootenay River and to receive its entitlement of capacity and energy under the second amended and restated Canal Plant Agreement (the "Canal Plant Agreement") depends upon the maintenance of its water licences issued under the Water Act (British Columbia). In addition, water flows in the Kootenay River are governed under the terms of the Columbia River Treaty between Canada and the United States as well as the International Joint Commission's order for Kootenay Lake. Government authorities in Canada and the United States have the power under the treaty and the International Joint Commission order to regulate water flows to protect environmental values in a manner that could adversely affect the amount of water available for the generation of power …
>
> Prolonged adverse weather conditions could lead to a significant and sustained loss of precipitation over the headwaters of the Kootenay River system, which could reduce the Corporation's entitlement to capacity and energy under the Canal Plant Agreement.

Please also refer to Concentric's responses to BCUC IR1 27.1 and 56.1.

27.2.1 Given that FBC's generation portfolio has not changed since 2013, and FBC assesses that its vertically integrated nature poses the same level of risk as it did in the 2013, please discuss how this factor provides justification for FBC's proposed increase in allowed ROE.

Response:

FBC's proposed allowed ROE is based on investors' expected returns in similar risk companies as calculated by Concentric. Concentric's computations indicate that FBC's allowed return should be higher than what was approved in the 2013 Proceeding.

FBC's business risk indicates that its overall risk profile is similar to what was assessed in 2013 and, as such, FBC is proposing to maintain its existing capital structure.

> In the S&P Global Market Intelligence article dated August 4, 2020, it provides information regarding the overall average authorized ROE for electric utilities in the first half of 2020.

S&P Global provides the following chart to compare vertically-integrated cases versus delivery-only cases:

H1'20 electric return on equity authorizations

Companies	State	Date of decision	ROE (%)	Decision type
Vertically integrated cases				
Interstate Power and Light Co.	IA	01/08/20	10.02	Settled
PacifiCorp	CA	02/06/20	10.00	Fully Litigated
DTE Electric Co.	MI	05/08/20	9.90	Fully Litigated
Indiana Michigan Power Co.	MI	01/23/20	9.86	Settled
Virginia Electric and Power Co.	NC	02/24/20	9.75	Settled
Indiana Michigan Power Co.	IN	03/11/20	9.70	Fully Litigated
Duke Energy Indiana, LLC	IN	06/29/20	9.70	Fully Litigated
Southwestern Public Service Co.	NM	05/20/20	9.45	Settled
Avista Corp.	WA	03/25/20	9.40	Settled
Public Service Co. of Colorado	CO	02/11/20	9.30	Fully Litigated
Duke Energy Kentucky, Inc.	KY	04/27/20	9.25	Fully Litigated
Average			**9.67**	
Median			**9.70**	
Delivery only cases				
Fitchburg Gas and Electric Light Co.	MA	04/17/20	9.70	Settled
Rockland Electric Co.	NJ	01/22/20	9.50	Settled
CenterPoint Energy Houston Electric, LLC	TX	02/14/20	9.40	Settled
AEP Texas Inc.	TX	02/27/20	9.40	Settled
Liberty Utilities (Granite State Electric) Corp.	NH	06/30/20	9.10	Settled
Consolidated Edison Co. of New York, Inc.	NY	01/16/20	8.80	Settled
Central Maine Power Co.	ME	02/19/20	8.25	Fully Litigated
Average			**9.16**	
Median			**9.40**	

27.3 Holding all else equal, based on S&P Global's findings above in the US, please explain whether the BCUC should consider an ROE adjustment where vertically integrated utilities are adjusted with a premium over distribution-only utilities, or in other words, distribution-only utilities are adjusted with a discount to vertically integrated utilities.

Response:

Generally speaking, utility investors perceive that vertically integrated utilities are riskier and expect higher compensation for this higher risk. Therefore, all else equal, an ROE premium for vertically integrated utilities is reasonable.

Please also refer to Concentric's response to BCUC IR1 56.2.1.

27.3.1 Please discuss whether a difference of approximately 30 to 50 bps would be reasonable to account for the difference between vertically integrated and distribution-only utilities in BC.

Response:

As provided in Concentric's response to BCUC IR1 56.2.1, 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. 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.

27.4 Please confirm, or explain otherwise, that all natural gas utilities in BC, including FEI, are distribution-only companies as they purchase natural gas supply in an open market and major transmission pipelines to connect upstream products are owned and operated by a third party.

Response:

Confirmed. FEI has some transmission pipelines in its network, however from investors' perspective, FEI and other North American natural gas utilities are ordinarily considered as distribution-only utilities.

28.0 Reference: FBC BUSINESS RISK

Exhibit B1-8-1, Appendix A - FEI Business Risk Assessment, p.19, Appendix B - FBC Business Risk Assessment, pp. 14–15

Order G-341-21 dated November 24, 2021, FBC Application for Approval of Rate Design and Rates for Electric Vehicle (EV) Direct Current Fast Charging Service, p. i

Political Risk

On page 19 of Appendix A, FEI states:

> Climate action goals and legislation are moving forward at a rapid pace at all levels of government... Factors outside of the company's control such as public perception, political decisions, increased competition from the electricity sector supported by electrification-friendly federal, provincial and municipal policies, could hamper FEI's ability to execute on its climate goals. [Emphasis added]

On page 14 of Appendix B, FBC states:

> FBC submits that the government's recent push for electrification is providing FBC with both opportunities and challenges; on balance, FBC assesses that its policy-related risks are lower than what was assessed in 2013 Proceeding….
>
> …electric utilities in the province face a lower risk, although a policy-driven consumer shift from gas consumption to electricity is not without its complications for FBC. In the shorter-term, increased load would be expected to have a favourable impact on rates, so long as there is capacity on the FBC system... Much like negative growth is a large risk factor to a utility, rapid policy-driven customer migration from natural gas to electricity increases risk and presents operational challenges for FBC which has limited resources in a small geographical service territory.

On pages 14 and 15 of Appendix B, FBC states:

> The Pathways report highlights that pursuing widespread electrification could bring significant long-term costs as the majority of buildings and commercial and light-duty vehicles switch to electricity. An electrification-focused pathway would lead to a less-resilient system that is approximately $100 billion more expensive in annual costs than a diversified energy pathway by 2050... [Emphasis added]
>
> FBC notes over-reliance of government policy on electrification as the only solution to the climate change crisis can lead to increased costs to the utility and its customers. [Emphasis added]

28.1 As FEI notes that increased competition from the electricity sector is supported by electrification-friendly federal, provincial and municipal policies, please clarify

whether FBC considers government policies are favourable or not to the utility's business risks.

Response:

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. 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. Nevertheless, as explained in the evidence, FBC assesses that electrification of the economy reduces its overall risk. Please refer to the response to CEC IR1 48.1.

28.2 FBC noted that rapid policy-driven customer migration from natural gas to electricity increases risk and presents operational challenges for FBC. Please explain how FBC plans to mitigate the operational challenges it faces with widespread electrification.

Response:

Generally, FBC utilizes historical data (including electrification load) to identify and confirm the impact on peak load. This is the typical planning process for FBC and each year the forecast is updated as the impacts are better understood. Then FBC plans the mitigating measures for the near and longer term.

FBC is aware that its historical practices may not be sufficient with the upcoming pace of electrification and is considering ways to improve its forecasting to become informed in a more timely manner regarding where and when gas-to-electricity load conversion will happen. This could include, for example, working with municipalities to review relevant gas-electric permits to identify where and when this work is being completed. This would then provide FBC with more insight into future electrification load areas on its system and enable FBC to better plan its infrastructure and programs to help manage such loads.

Sections 18 (2) and (3) of *Clean Energy Act* state:

Greenhouse gas reduction

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

(3) The commission must not exercise a power under the Utilities Commission Act in a way that would directly or indirectly prevent a public utility referred to in subsection (2) from carrying out a prescribed undertaking.

Section 5 of the GGRR establishes the eligibility criteria for EV charging stations as a prescribed undertaking.

On page i of the FBC EV Rates Decision issued concurrently with Order G-341-21, the BCUC found that the evidence indicated that FBC's proposed rates are sufficient to fully cover costs over a 10-year levelized period.

28.3 Please confirm, or explain otherwise, that the GGRR de-risks FBC investments by allowing the utility to collect sufficient revenue in each fiscal year to enable it to recover its costs incurred with respect to the prescribed undertaking, including eligible EV charging stations, such that shareholders do not bear the risk of new undertakings nor the risk of non-recovery.

Response:

Please refer to the response to BCUC IR1 14.4.

28.4 As FBC's EV fast-charging stations are approved based on a full cost recovery basis from its EV charging customers, please clarify how government policy on electrification has led to increased costs to the utility and its customers. If there are other contributors, please specify.

Response:

Given that the majority of customer EV charging will occur in a residential setting (i.e., at home) and not at public fast chargers (such as FBC's fast-charging stations), FBC expects any cost impacts related to government policy on electrification, specifically related to transportation, would likely relate to the upgrade and/or replacement of local distribution assets serving residential customers to the extent that mitigation measures (e.g., managed EV charging programs) are unable to offset peak demand requirements.

Other potential increased costs related to provincial electrification initiatives may include electrifying residential space and water heating, which are relatively inflexible loads compared to

EV-related loads. FBC expects to incur increased costs in order to ensure sufficient electrical capacity to serve any additional load.

28.5 To the extent possible, please quantify the annual increased costs to the utility and its customers over the next three to five years based on current government policy on electrification.

Response:

As discussed in FBC's business risk evidence (Appendix B), in the short term, increased load would be expected to have a favourable impact on rates, so long as there is capacity on the FBC system. However, over the longer-term, a drastic increase in low load factor customer consumption of electricity (i.e., heating load) drives additional investment in more capital infrastructure, which increases utility costs and rates for existing customers.

Based on FBC's long-term resource planning forecasts over the next 3 to 5 years, FBC does not expect any significant increased costs specific to provincial electrification policies. Beyond that, there is potential for increased costs related to transportation electrification as well as the electrification of space and hot water heating.

29.0 Reference: FBC BUSINESS RISK

Exhibit B1-8-1, Appendix B - FBC Business Risk Assessment, p. 16 and 54

Indigenous Rights and Engagement

On page 16 of Appendix B, FBC states:

> FBC faces an elevated level of business risk related to relationships with Indigenous groups in BC relative to the time of FBC's 2013 Proceeding. This elevated risk is based on the evolving nature of the Crown's relationship with Indigenous groups, developments in reconciliation in Canada, significantly increased expectations among Indigenous groups, and legal claims related to Aboriginal rights and title.

On page 54 of Appendix B, FBC states:

> In response to the requirement to seek the free, prior and informed consent of Indigenous Peoples prior to proceeding with project development, FBC must engage with Indigenous groups earlier and more often in support of building relationships, engaging in meaningful dialogue and seeking consent for its projects. Depending on the nature of the project, this means that engagement can begin at the outset before FBC has developed project alternatives so that it can incorporate Indigenous knowledge and input into its alternatives evaluation.

29.1 Please provide a list of capital projects in the next five years that will require Indigenous consultation.

Response:

At this time, FBC has identified the following capital projects with a forecast cost over $1 million anticipated for the next five years that may require Indigenous consultation:

- Reconductor 51 Line and 60 Line (DG Bell to OK Mission);
- Reconductor 52 Line and 53 Line (RG Anderson to Huth);
- DG Bell Terminal – distribution transformer addition;
- AS Mawdsley Terminal – transformer replacement;
- Saucier Substation – distribution transformer addition;
- Duck Lake Substation – distribution transformer addition;
- Kaleden Substation – transformer replacement; and
- Christina Lake Substation – substation rebuild.

Of the projects listed above, only the first two are considered “linear” projects (i.e., related to FBC’s transmission lines). However, the scope of these two projects will be confined to the existing transmission line corridors.

FBC expects that the majority of capital projects which require a regulatory authorization through a regulator (e.g., Fisheries and Oceans Canada) will trigger the duty to consult.

30.0 Reference: FBC BUSINESS RISK

Exhibit B1-8-1, Appendix B - FBC Business Risk Assessment, pp. 17–-20 and 23

Energy Price Risk

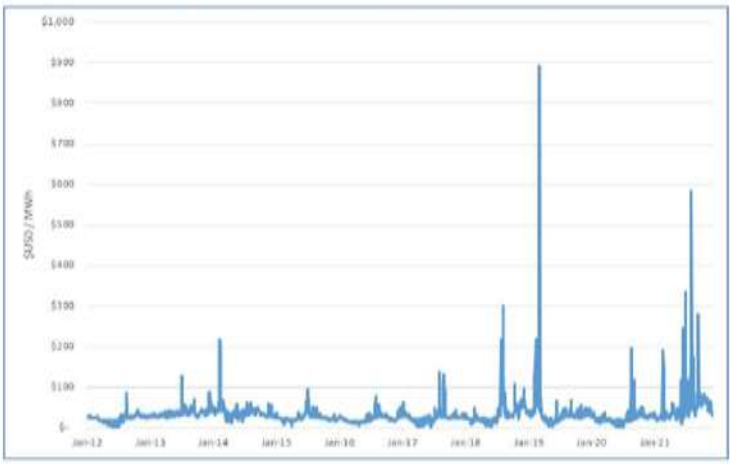
On page 17 of Appendix B, FBC states:

> The majority of FBC's power supply cost (approximately 36 percent of the total revenue requirement) relates to power purchase expenses, including contract and market purchases, with the rest composed of wheeling expense and water fees.
>
> FBC faces higher power supply cost and market price risk than in 2013. While the risks related to the BC Hydro PPA rate increases remain similar, market price volatility and Brilliant Power Purchase Agreement contract rate risk have increased.

On page 17 and 18 of Appendix B, FBC states:

> FBC relies on the market to meet short-term energy gaps when any unanticipated needs arise as well as to offset purchases under the BC Hydro PPA if and when market supplies are more cost effective. In 2020, FBC obtained 10 percent of its energy requirements through purchases made from the Wholesale market. Increases in the cost of market purchases have a direct impact on the power supply costs to FBC, and therefore to the rates charged to customers….
>
> The figure below illustrates the volatility associated with the daily Mid-C On-Peak prices. Mid-C prices can be highly volatile over short periods, mainly due to weather changes, regional precipitation and hydro flows. The figure shows that market price volatility has increased since 2013.

Figure B6-1: Day-Ahead Mid-C On-Peak Prices



30.1 Please provide an illustrative example to show what proportionate increase in wholesale market would impact FBC's rate and by how much.

Response:

FBC operates in a fully covered position in terms of its marginal energy requirements. In other words, FBC has access to all of the energy it requires to meet forecast load through the BC Hydro PPA. However, if it is economical (i.e. if the wholesale market energy price is more favourable than the BC Hydro PPA), FBC can enter into wholesale market energy purchases in order to mitigate power purchase expense and offset PPA energy purchases. FBC's capacity purchases, however, are typically not price-sensitive.[64]

To illustrate the impact of the wholesale market price to FBC's rate, below is an example using 2020 data for reference:

- FBC offset approximately 347 GWh of energy from the PPA at an average market rate of $34.04 per MWh. If the market rate had been approximately 50 percent higher[65] it would have been equal to the PPA rate of $50.69 per MWh and there would have been no advantage to purchase from the market. The avoided power purchase expense due to sourcing the incremental energy from the wholesale market is approximately $5.8 million, which is equivalent to 1.50 percent of avoided rate impact if compared to the approved 2022 rates[66]. If the wholesale market energy purchases average rate is 10 percent higher (i.e., $37.44 per MWh), the avoided power purchase expense from BC Hydro PPA would have been reduced to $4.6 million, or equivalent to 1.16 percent of avoided rate impact if compared to the approved 2022 rates. Therefore, a 10 percent increase in market rates results in close to a 20.7 percent decrease in the savings.

30.1.1 Please explain whether the Mid-C price volatility in 2021 affected FBC's 2022 annual review of rates.

Response:

Yes, Mid-C price volatility in 2021 did impact FBC's 2022 Annual Review of rates. FBC reduced its forecast market savings from $6.0 million, as was included in 2021 approved power purchase expense, down to $4.0 million in 2022 based on the increased market prices and volatility seen

[64] Market purchases made to displace PPA capacity purchases are generally cost effective at almost any market price depending on how many hours FBC expects to have to purchase. If it is only a few hours, even $1,000 per MWh is cost effective due to the high cost of capacity. Therefore, in this response, FBC has only considered how changes to the market price impact energy costs.

[65] $50.69 / $34.04 = 1.489 or market rates would have to increase by approximately 50 percent to equal the PPA rate.

[66] Based on an approved 2022 revenue requirement of 397.294 million per BCUC Order G-374-21.

in 2021. FBC included this estimate of savings in order to account for potential real-time savings on a forward-looking basis, and believed that there will likely be reduced opportunities in 2022.

On page 19 of Appendix B, FBC states:

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

30.2 Please discuss and provide calculations to illustrate FBC and BC Hydro's current rate differential.

Response:

FBC provides below a comparison of current rates for customers served under FBC's Residential, Small Commercial, Commercial and Large Commercial – Transmission rates. The rates of FBC and BC Hydro are structured differently, and do not have the same eligibility criteria. FBC has therefore made the assumptions noted in each example.

Residential:

At the current time, residential rates for BC Hydro customers are generally lower[67] than for FBC customers as shown in the table below containing the default residential rates of both companies.

[67] Due to the larger rate differential between the Tier 1 and Tier 2 rate for BC Hydro relative to FBC, a customer consuming more than approximately 9,400 kWh/month would have lower bills on FBC rates. However, this represents an extremely small number of residential customers.

	Current Rates		Differential
	FBC RS01	BCH 1101	FBC / BCH
Customer Charge ($ per month)	19.82	6.231	318%
Tier 1 Energy Rate ($/kWh)	0.12365	0.0939	132%
Tier 2 Energy Rate ($/kWh)	0.13713	0.1408	97%
Tier 1 Threshold (kWh)	800	675	

At these rates, customer consuming 1,000 kWh per month would have a bill of $146.17 for FBC and $115.37 for BC Hydro, a difference of 27 percent.

Small Commercial:

In order to respond to the question, FBC has assumed a small commercial customer consuming 2,000 kWh per month. This would place the customer on FBC RS 20 and BC Hydro RS 1301.

	Customer Charge	Energy Rate
FBC RS 20	$25.09 per Month	10.906 ¢ per kWh
BC Hydro RS 1301	36.22 ¢ per day	12.45 ¢ per kWh

Therefore, for a billing period in which the billing parameter was 2,000 kWh, billing would be as follows:

<u>FBC</u>

$25.09 + ($0.10906 x 2,000 kWh) = $243.21

<u>BC Hydro</u>

($0.36.22 x 30) + ($0.1245 x 2,000 kWh) = $259.87

Commercial:

In order to respond to the question, FBC has assumed a commercial customer with a demand of 150 kW and a 75 percent load factor served at distribution. This would place the customer on FBC RS 21 and BC Hydro RS 1501.

	Customer Charge	Energy Rate	Demand Charge
FBC RS 21	$58.90 per month	7.527¢ per kWh	$12.39 per kW of "Billing Demand" above 40 kW
BC Hydro RS 1501	26.56 ¢ per day	9.62 ¢ per kWh	$5.38 per kW of Billing Demand

Therefore, for a billing period in which the billing parameters were a peak load of 150 kW and consumption of 54,000 kWh, billing would be as follows:

FBC

$58.90 + ($0.07527 x 54,000 kWh) + ($12.39 x 110 kW) = $5,486.38

BC Hydro

($0.2656 x 30) + ($0.0962 x 54, 000 kWh) + ($8.642 x 150 kW) = $6,009.77

Large Commercial – Transmission:

In order to respond to the question, FBC has assumed an Industrial customer, with a demand of 10,000 kVA and a 75 percent load factor served at transmission voltage. This would place the customer on FBC RS 31 and on BC Hydro RS 1823 (as would apply to a new customer without a Customer Baseline (CBL)).

	Customer Charge	Energy Rate	Demand Charge
FBC RS 31	$3,366.02 per Month	5.655¢ per kWh	$8.82 per kVA
BC Hydro 1823	nil	5.065¢ per kWh	$8.642 per kVA

Therefore, for a billing period in which the billing parameters were a peak load of 10,000 kVA and consumption of 5,400,000 kWh, billing would be as follows:

FBC

$3,366.02 + ($0.05655 x 5,400,000 kWh) + ($8.82 x 10,000 kVA) = $396,936.02

BC Hydro

($0.05065 x 5,400,000 kWh) + ($8.642 x 10,000 kVA) = $359,930.00

30.2.1 Please explain how this rate differential will be impacted if BC Hydro's rate increases are approved.

Response:

Since the filing of the FBC evidence in this proceeding, BC Hydro has filed a *Fiscal 2023 Rate Schedule 1101, 1121 Residential Service Pricing Principles Application*[68]. This Pricing Principles Application, along with the impact of the Deferral Account Rate Rider noted in the preamble to this question, will provide April 1, 2022 rates as shown below. If both of the BC Hydro requests are approved, the gap between FBC and BC Hydro residential rates will widen.

[68] https://docs.bcuc.com/Documents/Proceedings/2022/DOC_65606_B-1-BCH-F23-RS1101-1121-Residential-Service-Pricing-Principles.pdf.

	Proposed April 1, 2022 Rates			Differential
	FBC RS01	Pricing Principles Application	Deferral Account Rate Rider (-2%)	FBC / BCH
Customer Charge ($ per month)	19.82	6.27	6.1446	323%
Tier 1 Energy Rate ($/kWh)	0.12365	0.0950	0.09310	133%
Tier 2 Energy Rate ($/kWh)	0.13713	0.1408	0.13798	99%
Tier 1 Threshold (kWh)	800	675	675	

With regard to the proposed BC Hydro rate increases of 2.0 percent, effective April 1, 2023, and 2.7 percent, effective April 1, 2024, the extent to which these will reduce the differential between the FBC and BC Hydro rates will depend on FBC rate changes in these years, which are uncertain at this time. However, FBC believes that its general level of rates is likely to remain above those of BC Hydro for the near future.

On page 19 and 20 of Appendix B, FBC states:

> FBC purchases approximately 26 percent of the energy and 19 percent of the capacity required to serve its customers from Columbia Power Corporation and the Columbia Basin Trust Power Corporation (jointly referred to as CPC) under the Brilliant Power Purchase Agreement at rates as set out in the agreement. The Brilliant Power Purchase Amendment Agreement dated May 2, 1996 makes provision for a market price adjustment after 30 years, or 2026. At this time, there is no agreed methodology between FBC and CPC as to how to determine the appropriate market rate.

30.3 Please provide the project timeline for FBC and CPC to determine the appropriate market rate leading up to 2026.

Response:

FBC and CPC are in preliminary discussions in regard to determining the appropriate market rate. However, no timeline to resolve this has been set as there are still several years before the market price adjustment comes into effect.

30.3.1 If there is no agreed methodology between FBC and CPC to determine the appropriate market rate, please provide the alternatives and estimate how this will affect FBC's energy price and supply.

Response:

The alternatives for a methodology to determine the appropriate market rate are speculative at this time. FBC believes that three options are possible, with the third being the most likely alternative:

- FBC and CPC continue to use the existing approach, in which case there would be no impact to FBC's energy price;
- The market price is set based on historical data; or
- The market price is set based on forward looking price estimates determined from forward price curves or a market price study.

FBC has not performed a detailed analysis of how FBC's energy price could be affected. However, based on the contract, an effective cap on the price exists at about 150 percent of the current price calculation methodology. It is extremely unlikely that prices will significantly exceed this amount.

If the market price forecast contained in FBC's 2021 LTERP,[69] currently before the BCUC, is indicative of the market price, FBC believes there will be little to no impact from the market price adjustment. However, there is currently significant uncertainty in energy markets and it is not possible to say at this time what, if any, premium is reasonable to expect.

The market price adjustment does not impact the supply of power under the contract.

On page 23 of Appendix B, FBC states:

> FBC's higher residential electricity rates compared with BC Hydro's residential rates, coupled with FBC's higher heating needs due to relatively colder temperatures in its service area, lead to higher savings for customers that use natural gas as their heating fuel in FBC's service territory compared with the customers in the majority of BC Hydro's service territory. This means that FBC is at a price disadvantage when competing for heating load against natural gas, and that disadvantage is greater for it than for BC Hydro. Even when considering BC's current level of carbon tax and the elimination of the Provincial Sales Tax (PST) for electricity consumption, FBC is currently at a price-related disadvantage to natural gas.

30.4 Please discuss, and provide calculations, to illustrate price differential for heating between FBC, BC Hydro, and FEI.

[69] FBC 2021 LTERP and LT DSM Plan, p72, F2-18.

Response:

FortisBC provides below, using the same assumptions that produced Figure B6-4 of Appendix B to its evidence, a comparison of the annual heating costs for 2022, using January 1, 2022 rates. These assumptions provide that all-electric heat would require 12,984 kWh, and that the same residence heating with natural gas would require 46.9 GJ of gas and 352 kWh of electricity. Consistent with Figure B6-4, for both FBC and BC Hydro, the exempt residential flat rate is used to calculate electricity charges. Considering FEI's plan to increase the share of more costly Renewable Gas in its supply portfolio as well as expected increases to carbon tax in the coming years, FortisBC expects that the price differential between FEI and other electric utilities to decrease.

		Gas Heat		Electric Heat	
		FEI & FBC	FEI & BC Hydro	FBC	BC Hydro
a	Customer Charge[1]	$0.4085/day	$0.4085/day	$19.82/mo.	$0.2215/day
b	All-in per GJ Rate[2]	$13.69	$13.69	n/a	n/a
c	Electric Rate (/kWh)	$0.12813	$0.11250	$0.12813	$0.11250
d	Days	365	365	365	365
e	GJ	46.9	46.9	n/a	n/a
f	kWh	352	352	12,984	12,984
a * d	Customer Charges	$149.10	$149.10	n/a	n/a
b * e	Gas Charges	$641.84	$641.84	n/a	n/a
c * f	Electric Charges	$45.10	$39.60	$1,663.64	$1,460.70
	Annual Bill	$836.04	$830.54	$1,663.64	$1,460.70

Notes:

1 Electric Customer Charges are not included in the calculation since they are required in all cases.

2 All-in GJ rate includes Commodity charges, transport related charges, delivery related charges and the carbon tax.

31.0 Reference: FBC BUSINESS RISK

Exhibit B1-8-1, Appendix B - FBC Business Risk Assessment, p. 25

Demand and Market Risk

On page 25 of Appendix B, FBC states:

> Overall, FBC assesses its demand/market risk to be similar to the 2013 Proceeding.
>
> Emerging technologies relating to alternative sources of energy, such as home solar generation, can reduce the demand on FBC as an electricity provider. While additional EV charging load increases FBC's load, adding EV charging can also create potential risks for higher costs and to grid integrity if charging demand during peak times is not managed.

31.1 Given the shift to electrification and decarbonization policies, please explain how demand and market risk is considered similar to 2013.

Response:

There are a number of components of demand/market risk which determine FBC's overall assessment of its demand/market risk to be similar to the 2013 Proceeding. Some of these components are related to electrification and decarbonization policies and some are not and so FBC's overall assessment of its demand/market risk is not solely determined by these factors.

One component that is related to electrification and decarbonization policies is emerging technologies, such as rooftop solar generation and EVs. While rooftop solar generation can reduce the demand for FBC as an electricity provider, new load requirements from EV charging can conversely increase the load requirements of FBC. Both situations create potential risks for higher costs and to grid integrity and managing the timing of load on the system to avoid peak demand impacts. As these technologies present both opportunities and risk for FBC, it has assessed this portion of its demand/market risk as being similar to 2013.

Another demand/market risk component is UPC, which is not directly related to electrification and decarbonization policies. When compared to 2013, FBC's residential and commercial UPC values have been on a downward trajectory, and Industrial UPC has increased. Given that there are some offsetting risk impacts for these customer segments, FBC has assessed this UPC risk as similar to 2013.

Another demand/market risk component is end-use market share. Over the longer term, FBC expects an increase in its electricity market share as the penetration of heat pumps increases, driven in part by electrification and decarbonization policies, perhaps somewhat offset by other energy sources such as rooftop solar generation, thereby improving FBC's market share risk from 2013 and current levels.

The last component of FBC's demand/market risk relates to its Wholesale and Industrial customer segments and is not directly related to electrification and decarbonization policies. FBC continues to face demand risk in its Wholesale and Industrial customer segments as FBC's Wholesale and some Industrial customers are able to take service from competing resources within the province, build generation to serve some or all of their load or purchase electricity from the open market. FBC also faces continuing risk associated with being highly dependent on load concentration in only a limited number of industries – forestry and cryptocurrency mining. FBC has assessed this risk as being similar to 2013.

FBC's assessment of the risk of these individual components determines the overall assessment for FBC's demand/market risk. Given that most of the components have been assessed as similar risk to 2013, FBC's overall assessment for this risk category is also similar to 2013.

31.2 Please explain whether FBC has or is planning to put into place any demand side measures to mitigate the potential risk to grid integrity and higher costs with grid integrity due to EV charging.

Response:

As discussed in its 2021 LTERP application, FBC is piloting a demand response program for residential EV charging to shift associated loads from peak demand periods to help mitigate system impacts. The results of this pilot will help inform the development of a full demand response program to help manage these loads.

31.3 Given FBC's understanding of EV drivers' charging patterns and EV technology (i.e., programmable charging times, etc.), please discuss how FBC is managing or plans to manage charging demand during peak times. For example, how can rate design influence customer usage patterns?

Response:

FBC believes EV charging can best be managed with programs that help customers charge their EV's during non-peak periods by default. The preferred approach is to control and monitor charging using software only, which is easy and inexpensive for the customer and allows the utility to offer an incentive based upon when the customer is charging.

Incenting EV charging during non-peak periods through electricity rates requires dedicated revenue metering for EV charging, adding considerable customer expense and includes the possibility of being less effective than simply helping customers manage when they charge.

On page 25 of Appendix B, FBC states:

> Non-wire alternative projects ordinarily refer to the type of projects that would replace, reduce and/or defer traditional capital infrastructure investments that otherwise would be needed to accommodate the growth in expected locational peak demand. Other regulators, such as the New York Public Commission Service, have recognized this risk and have awarded the utilities that adopt non-wire solutions additional financial incentives in the form of return premiums, reduced amortization period or expense capitalization.

31.4 Please explain the type of non-wire solutions that FBC has adopted or is considering adopting?

Response:

FBC is looking into battery energy storage systems, demand response, grid software and controls, energy efficiency projects, and considering them to defer or replace the need for transformer upgrades.

32.0 Reference: FBC BUSINESS RISK

Exhibit B1-8-1, Appendix B - FBC Business Risk Assessment, pp. 28–29

Customer Profile - Wholesale

On page 28 of Appendix B, FBC assesses that compared to 2013, its risks associated with loss of demand in Wholesale and Industrial load is unchanged.

On page 29 of Appendix B, FBC states:

> FBC currently has four municipal Wholesale customers, accounting for less than one percent of FBC's total customer base, but these four customers make up 17 percent of FBC's load.
>
> FBC's Wholesale customers have a number of options that would allow them to discontinue taking service from FBC. These include building their own generation to serve some or all of their load, purchasing electricity on the open market or taking service from BC Hydro through its OATT. FBC's Wholesale customers qualify as Eligible Customers as defined under both FBC's OATT and BC Hydro's OATT, and therefore can purchase electricity from the open market or from BC Hydro and wheel over FBC and BC Hydro transmission infrastructure. There is generally available transmission capacity on the transmission system, so access to transmission capacity is not a barrier to FBC's Wholesale customers discontinuing service [….]
>
> all the service agreements between FBC and its Wholesale customers have early termination clauses, allowing FBC's Wholesale customers to exit FBC's service by providing notice.

32.1 Please explain whether and/or which Wholesale customers have indicated they might leave FBC and for what reasons. Please include whether any Wholesale customers have indicated reliability issues as a reason to potentially leave FBC.

32.1.1 Please explain whether any municipal Wholesale customers have left FBC's service area in the last 20 years. If so, please provide their reasons for leaving.

Response:

No Wholesale or Industrial customers have left FBC, nor has FBC any record of a Wholesale customer expressing an intent to leave FBC's embedded cost service. Regardless, FBC does not believe that reliability concerns would drive such a request since most such concerns are infrastructure related and taking third party supply would rely on the same infrastructure as service pursuant to a Wholesale rate.

32.2 Please explain whether FBC's Wholesale customers' service agreements contain any take-or-pay clauses.

Response:

FBC's Wholesale customers' service agreements do not contain any specific take-or-pay clauses. The only aspect of a Wholesale customer's service that could be considered take-or-pay is contained in the underlying Wholesale tariff schedules related to the calculation of Billing Demand. Billing Demand 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 registered during the previous eleven Month period.

Items (i) and (iii) set a minimum bill for the Demand-related portion of billing that may exceed an amount based on the actual and lower amount of peak load recorded in the billing period.

32.3 Please discuss why FBC's Wholesale customers do not currently build their own generation, purchase electricity from the open market, or take service from BC Hydro under its Open Access Transmission Tariff (OATT). Please include what the barriers or conditions would be to prevent existing Wholesale customers from these supply options.

Response:

The decision to pursue any of the alternate supply options mentioned in the question rests with the individual Wholesale customers, as does the reasoning as to why such options have not been pursued. FBC assumes that given the relatively low and stable FBC Wholesale rates and high reliability of service, the Wholesale customers have determined that remaining with FBC is the preferred option. In addition, both building generation and arranging for third-party supply can be complicated and outside of the expertise of municipal government. It is also unlikely that generation resources can be put in place and operated at a price lower than FBC offers. Municipal utilities most often discuss the installation of small but utility-scale (of around 1 MW) solar resources, but none have been commissioned to date. Municipal utilities have the ability to pass power supply costs to residents which may further militate a perceived need to seek alternate sources of supply.

32.4 Please explain if Wholesale customers purchased electricity from the open market (or from BC Hydro) and wheel the commodity over FBC's transmission infrastructure, would FBC be able to obtain wheeling revenue from these customers. Please include how wheeling revenue compares to sales revenues from the Wholesale customer class and provide illustrative examples where appropriate.

Response:

Yes, if wholesale customers purchased electricity from a third party supplier, FBC would obtain wheeling revenue from these customers. The customer charges that would likely be applicable under FBC's electric tariff are outlined in the table below.

Rate Type: Monthly Transmission	Rate Schedule	2022 Rate
Customer Charge ($ Per POD/month)	RS101	$ -
Reserved Capacity Charge (Monthly Rate - $/MW)	RS101	$ 4,570.00
Scheduling, System Control and Dispatch Service (Monthly Rate $/MW)	RS103	$ 182.02
Reactive Supply & Voltage Control from Generation Sources Services ($/MWh)	RS104	$ 0.899
Imbalance ($/MWh)	RS106	formulaic
Operating Reserve (OR) - Spinning Reserve Service ($/MWh)	RS107	$ 10.15
Operating Reserve (OR) - Supplemental Reserve Service ($/MWh)	RS108	$ 10.15
Loss Compensation Service (%)	RS109	2.86%

If FBC was to supply only wheeling to a 25 MW, flat load, wholesale transmission customer for an entire year, assuming that there were no penalty charges or imbalance charges incurred by the customer, then based on 2022 rates, FBC would then receive annual revenue equal to approximately $1.8 million. FBC would also receive 6,263 MWh of physical energy under RS 109. There would be no incremental power supply cost incurred in order to service an existing wholesale transmission customer.

Under FBC's existing wholesale RS 40, the same wholesale customer would generate approximately $17.4 million in revenue for FBC. However, FBC would also have to supply the power to the customer. Relative to 2022 Approved Power Purchase Expense, the cost to FBC to supply that existing load is equal to approximately $12.2 million. Therefore, FBC's net margin would be $5.2 million in this scenario.

32.5 Please explain whether the early termination clauses contain a financial penalty. If so, please explain whether FBC believes this would reduce the risk of termination.

Response:

The early termination clauses do not contain a financial penalty. However, there are material financial considerations associated with electing third-party supply. The early termination clauses require that notice be provided pursuant to the Access Principles Settlement Agreement (APSA). Electing to leave embedded cost service under the terms of the APSA, in whole or in part, may require the Wholesale customer to make payments to ensure that those customers who remain with utility supply are made no worse off. As noted above, departing customers may be subject to paying for stranded costs associated with their exit. In addition, should a customer that left utility supply be unable to secure supply, and FBC was required to provide short-term back-up service, the cost of such service would be the higher of the market buy price or the cost of the marginal unit in FBC's supply portfolio.

33.0 Reference: FBC BUSINESS RISK

Exhibit B1-8-1, Appendix B - FBC Business Risk Assessment, pp. 10–11 and 29–32

Customer Profile – Industrial

On page 10 of Appendix B, FBC states:

> Geographic areas with more rural populations tend to have less diverse economies with fewer types of industries. This holds true for FBC; this small area of the province is dependent on relatively few industries and this lack of geographic and Industrial diversity adds to FBC's business risk.

On page 11 of Appendix B, FBC states:

> The share of FBC's overall load profile in the Industrial sector is on an upward trajectory, increasing from 9 percent in 2013 to 14 percent in 2022. This trend leads to an increase in FBC's risk profile since Industrial load is more volatile and more prone to economic downturns.

On page 29 and 30 of Appendix B, FBC states:

> […] eligible Industrial customers can also discontinue taking service from FBC by building generation to serve some or all of their load, purchasing electricity on the open market or taking service from BC Hydro through its OATT. Additionally, subject to any previously existing contract requirements, Industrial customers can simply shutdown and move to another location as the Terms and Conditions of FBC's Electric Tariff only requires a customer to provide timely notice to FBC of termination of service.
>
> FBC believes that the risk associated with the composition of its largest Industrial and commercial customers has increased slightly in recent years. This is because the mix of load continues to be dominated by a small number of customers in a few industries, namely, those related to the forest sector, as has historically been the case, and now with technology-related load associated with cryptocurrency, the shift from one to the other increases the risk profile.

On page 30 and 31 of Appendix B, FBC provides the following graphs to display the Industrial customers by load in 2013 and 2020:

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

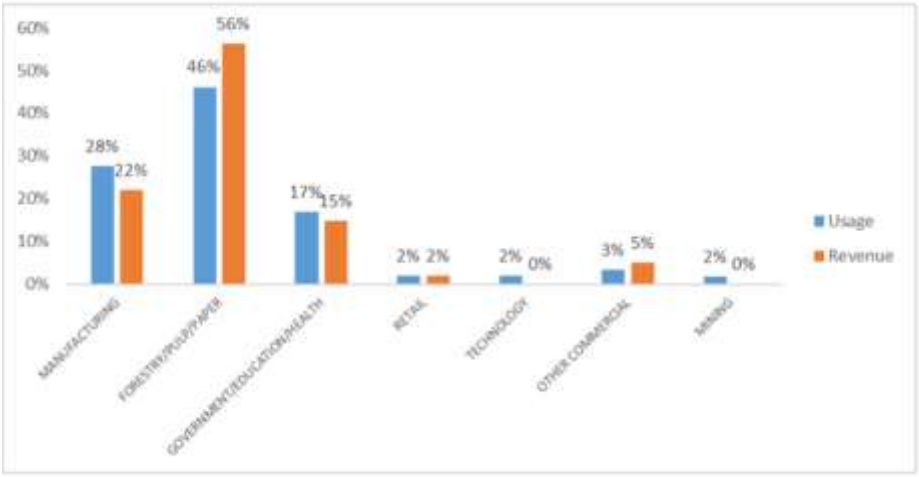
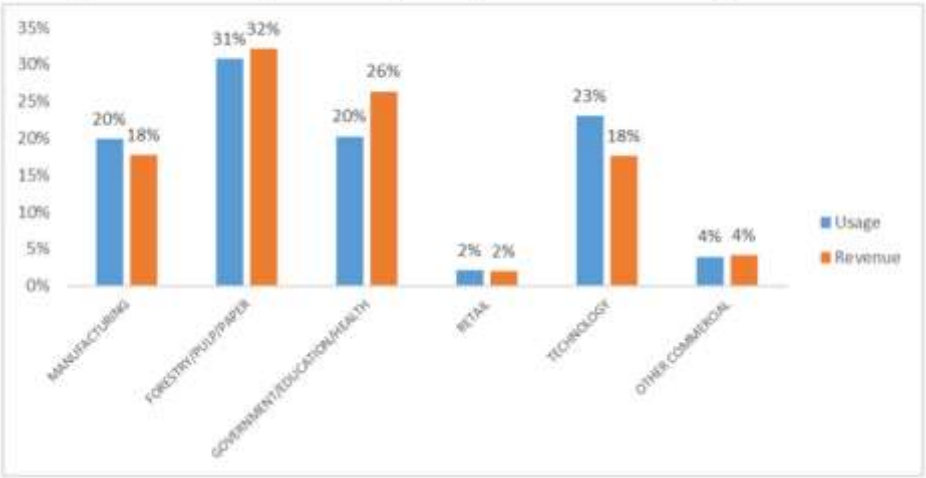


Figure B7-2: Industry of FBC's Top Twenty Industrial Customers by Load in 2020



On page 31 of Appendix B, FBC states:

> The inherent volatility of the virtual mining industry and its uncertain future creates challenges for electric utilities engaged in long-term resource planning. For FBC, the cryptocurrency industry today is comprised of a single customer. While FBC has no indication that this customer has any intention of being other than a long-term stable load, it is generally understood that cryptocurrency customers are especially price-sensitive and more mobile than is generally the case.
>
> The forestry industry is sensitive to world commodity prices, to the strength of the U.S. and Pacific Rim economies, and to the strength of the Canadian dollar.

33.1 Please discuss whether industry diversity has been increasing in FBC's geographic service area from 2013 to 2020 and how this impacts risks.

Response:

FBC has stated in its evidence that a general lack of geographic and Industrial diversity adds to FBC's overall business risk. In addition, the share of FBC's overall load represented by the Industrial sector is on an upward trajectory, increasing from 9 percent in 2013 to 14 percent in 2022 which leads (other things equal) to an increase in FBC's risk profile. FBC has noted at lines 29-31 on page 28 of Appendix B that the diversity and number of Industrial customers has increased between 2013 and 2020. 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. For this reason, FBC's summary assessment of risk for the Wholesale and Industrial load risk factor is seen as similar to 2013.

33.2 Please discuss the likelihood of an Industrial customer potentially building generation. Please include the barriers to entry for self-generators in the discussion.

33.2.1 Please discuss whether access to FBC's generation acts as a deterrent to customers leaving for self generation and whether this would be a business risk reduction for FBC.

Response:

FBC considers the likelihood of any additional industrial customers (beyond the one industrial customer that currently has on-site co-generation) to be low. The majority of the FBC industrial customer base operates with loads below 5,000 kVA and lack the scale and fuel resources required to economically add generation that would offset a significant portion of load. FBC has had discussions with some such customers in the past and understands that these factors, along with high initial capital costs and the relatively low cost of purchasing power at FBC's embedded cost rates, makes the business case for self-generation unattractive. This situation is unchanged since 2013 and represents no change in risk.

33.3 Please explain whether the existing contracts with Industrial customers contain a take-or-pay clause and/or any early termination penalties.

Response:

The existing contracts with Industrial customers do not contain take-or-pay clauses and/or any early termination penalties. However, the FBC *Electric Tariff General Terms and Conditions*, section 3.3.2 states:

3.3.2 Contract Termination by Customer

Notice of Termination requirements for contract Customers will be in accordance with the terms of the contract. If a contract Customer terminates the contract but fails to give the required notice of Termination, the minimum charges for the notice period, as well as any amounts due for Service supplied, will immediately become due and payable.

33.4 Please discuss why FBC's Industrial customers do not currently purchase electricity from the open market or take service from BC Hydro under its OATT. Please include what the barriers or conditions would be to prevent existing Industrial customers from these supply options.

Response:

FBC's Industrial customers do not currently purchase electricity from the open market or from any third party because despite both FBC and BC Hydro having a BCUC-approved Open Access Transmission Tariff (OATT) retail access is unavailable as described below.

FBC has had in place since 1999 (pursuant to BCUC Orders G-27-99 and G-28-99) an OATT and related rate schedules that, subject to the external constraints discussed below, enable Large Commercial and Wholesale customers to use the FBC transmission system to wheel power purchased from third parties to the location of their load within the FBC service area. An arrangement that allows for use of the transmission system by end-use customers is generally referred to as Retail Access.

Pursuant to BCUC Order G-12-99, the rates for this service and the equivalent service offered by BC Hydro were harmonized such that the customer would only pay the rates of the utility in whose service area the load was located (with the exception of loss compensation) in cases where power needed to be wheeled through both service areas.

However, Section 7 of Direction No. 8 to the BCUC, BC Reg 24/2019, contains the following language with respect to Retail Access:

Retail access

Except on application by the authority, the commission must not set rates for the authority that would result in the direct or indirect provision of unbundled transmission services to retail customers in British Columbia, or to those who supply such customers.

Until recently, the position of BC Hydro with regards to the impact of Special Direction 8 (and the similar wording of the preceding Special Direction 7) on the customers of FBC was as stated in

the Evidence of BC Hydro in the *FortisBC Inc. 2017 Cost of Service Analysis and Rate Design Application:*[70]

> The result of the foregoing is that there is no retail access in BC Hydro's service territory and BC Hydro retail load customers cannot use the BC Hydro OATT for retail access. The removal of retail access in BC Hydro's service territory did not impact potential FortisBC retail access customers. (Emphasis added)

However, in the BCUC Indigenous Utilities Regulation Inquiry Final Report dated April 30, 2020, the Panel stated on p. 77,

> In the Panel's view, the wording of Direction 8 does not differentiate between BC Hydro's retail customers or retail customers of any other public utility. Direction 8 does not limit customers to be a retail customer of any particular public utility, simply that they be a retail customer. Neither the term "Retail Customer" nor the term "retail" is defined in the Direction 8, the Hydro and Power Authority Act, the UCA or the Interpretation Act. However, the Oxford dictionary defines "Retail" as:
>
> > *The sale of goods to the public in relatively small quantities for use or consumption rather than for resale".*
>
> We therefore interpret Direction 8 to preclude the use of BC Hydro's transmission system to wheel electricity to any customer who will directly consume that electricity in British Columbia whether it is a customer of BC Hydro or another public utility.

Given this, BC Hydro has communicated to FBC that while BC Hydro maintained its previous position during the Indigenous Utilities Regulation Inquiry process, the Panel's view expressed in the Final Report effectively precludes BC Hydro from allowing the use of its transmission system in the provision of Retail Access to the customers of FBC.

Since delivery of power originating from outside of the FBC service area cannot practicably be delivered to a load within the FBC service area without the use of the BC Hydro system, Retail Access is effectively unavailable to FBC customers.

33.5 Please discuss the likelihood of Forestry, Manufacturing, and Government/Education/Health Industrial customers shutting down their businesses to move to another location outside FBC's service area. Please include whether their capital assets would discourage or encourage this type of move.

[70] Exhibit C1-3, page 4, lines 12-15. (These comments were based on Special Direction No. 7 which contained similar language regarding Retail Access).

Response:

It is less likely that businesses in the industries mentioned will relocate than for the more mobile and less capital intensive industries such as those in technology sector (e.g., data centres and cryptocurrency mining). This is, at least in part, due to capital assets already in place, as well as the cost of relocation. For these customer segments, price is more likely to be a consideration in the initial decision of where to locate a new plant or whether plant expansion is economic.

33.6 In a working spreadsheet format, please provide the supporting data for graphs: Industry of FBC's Top Twenty Industrial Customers by Load in 2013 and in 2020 (Figures B7-1 and B7-2).

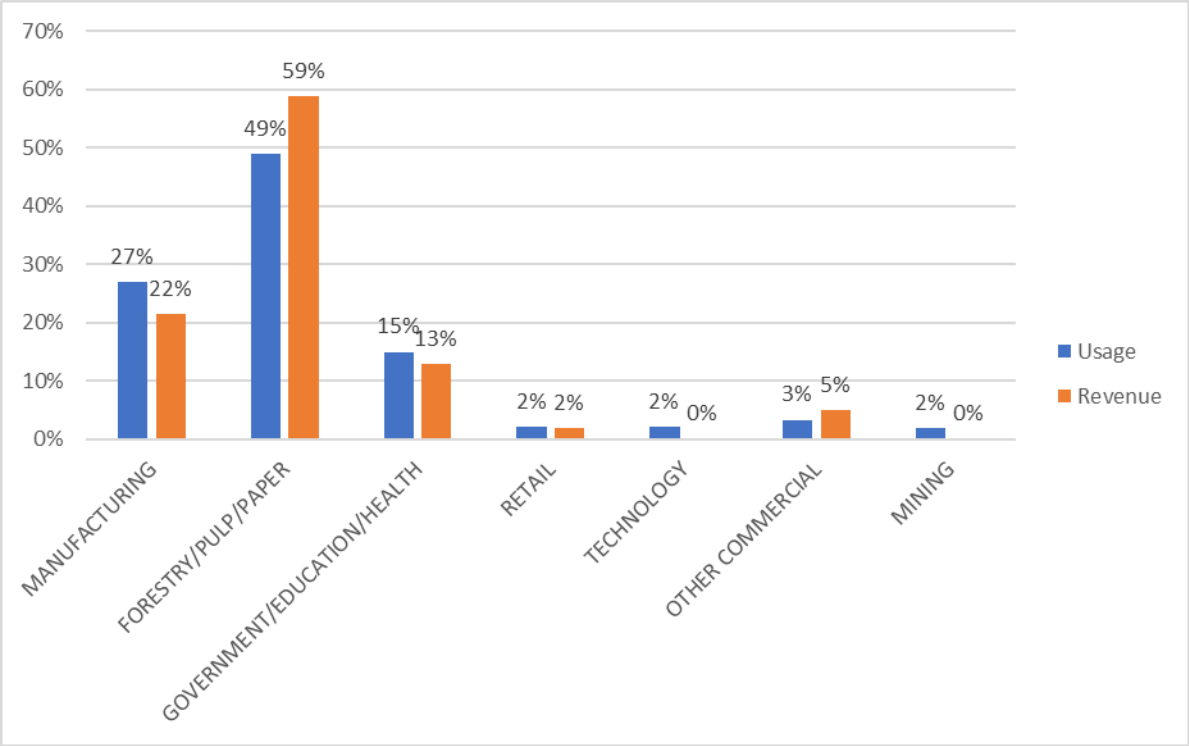
Response:

Please refer to Attachment 33.6 for the working Excel spreadsheet.

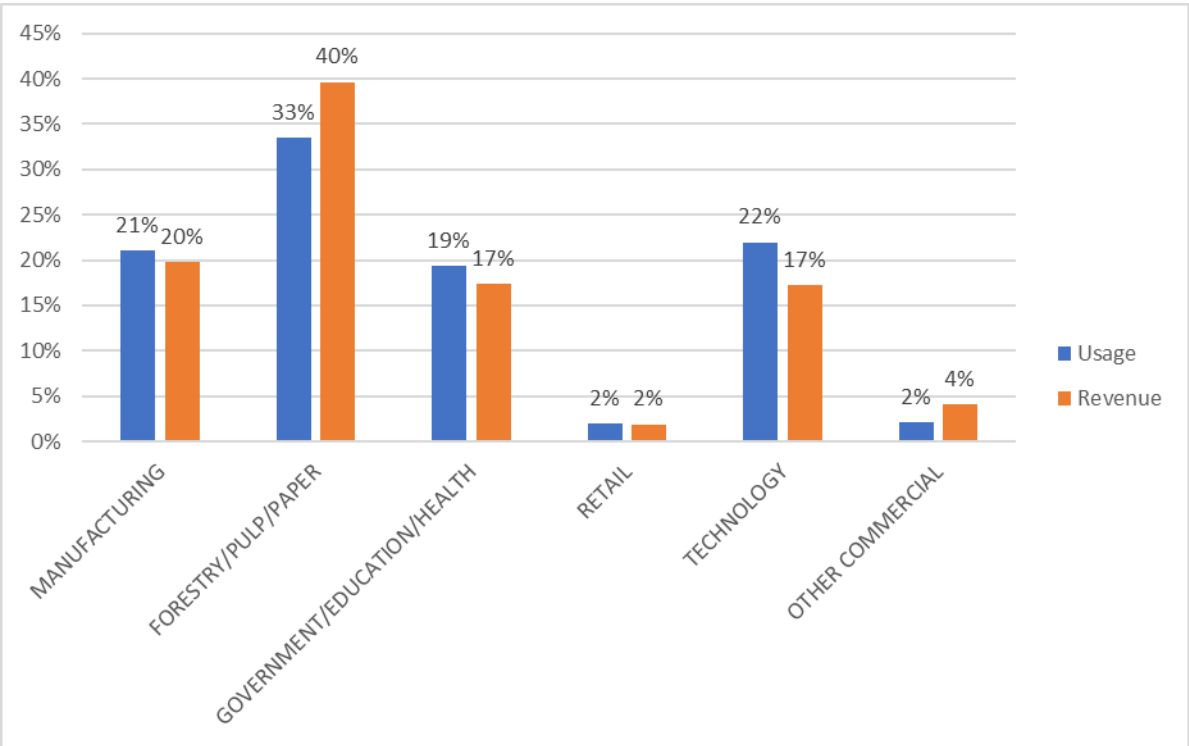
Please note that the figure titles should indicate FBC's Top Twenty Customers by Load **and Revenue,** since the top 20 customers by load and top 20 customers by revenue are slightly different in composition. In other words, a customer may be in the top 20 considering load, but not in the top 20 considering revenue.

FBC also notes that, due to one Large Commercial customer being mis-categorized and therefore filtered out of the report used to generate Figures B7-1 and B7-2, and Standby Service revenues originally being excluded from the 2020 data, a correction is required to those figures. This results in revised versions as shown below.

Revised Figure B7-1: Industry of FBC's Top Twenty Customers in 2013



Revised Figure B7-2: Industry of FBC's Top Twenty Customers in 2020



Note that this correction produces only minor changes in the distribution of customer load and revenues between the customers' industries and does not change any of the related conclusions drawn in Appendix B to the evidence.

33.6.1 Please discuss whether COVID-19 has had any impact in skewing the 2020 data as presented in Figure B7-2.

Response:

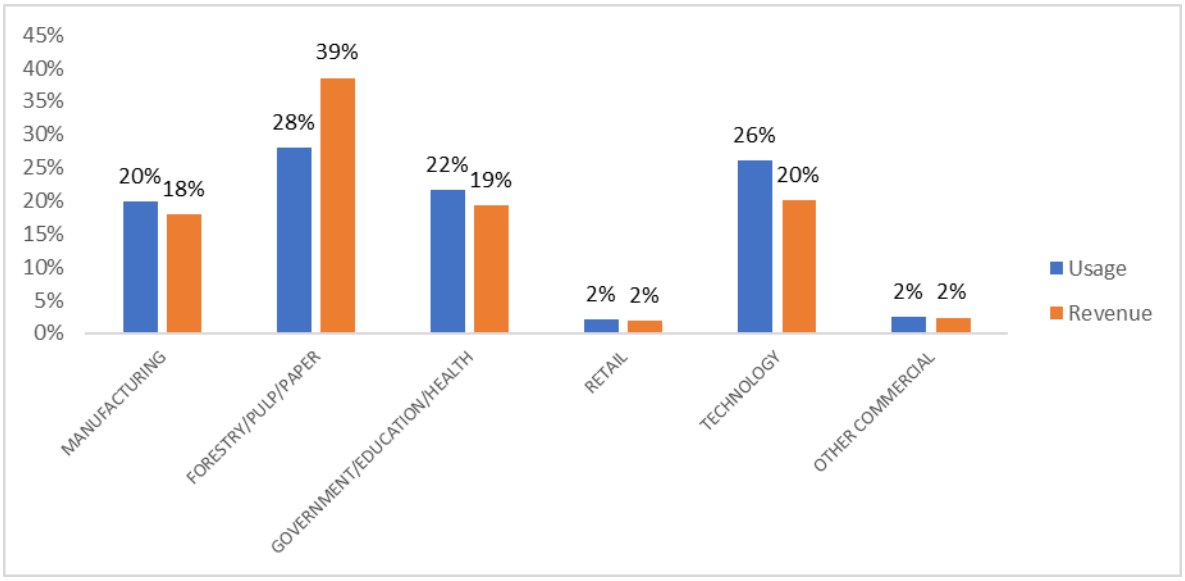
As commented upon in a general sense at page 11 of Appendix B, in 2019 FBC's Industrial load grew by 23 percent but the economic crises brought on by the COVID-19 pandemic caused Industrial load to drop by 11 percent in 2020. For the specific customers that make up the largest 20 used in the analysis, both load and revenues fell from 2019 to 2020. However, FBC would not characterize this as skewing the distribution of load and revenue between the industries since those characteristics remained fairly consistent between the years.

33.6.2 Please provide the same information as presented in Figures B7-1 and B7-2 for 2019.

Response:

The following table provides the same information as presented in Figures B7-1 and B7-2 for 2019.

Industry of FBC's Top Twenty Customers in 2019



33.7 Please explain whether the decrease in Forestry Industrial customers from 2013 to 2020 is the result of economic factors or the increase in load from Government/Education/Health and Technology Industrial customers.

Response:

FBC does not view this as an "either / or" question since it is likely that both factors played a role in the shift in distribution amongst the industries. The forestry sector decreased in load and revenue as well as number of customers, which may have resulted from economic conditions. However, the growth in the other sectors would reduce the representation of forestry in percentage terms.

33.8 Please explain why Government/Education/Health load has increased from 2013 to 2020.

Response:

There are large loads in this industry category on the FBC system in 2020 that were not on the FBC system in 2013 and were formerly loads on the City of Kelowna electric system, such as the Kelowna Regional Hospital. In examining the top 20 Large Commercial loads, the addition of load in any one category can have a marked impact on the category load proportions.

33.9 Given that Government/Education/Health and manufacturing clients have similar usage and revenue to technology in 2020, please discuss whether this mitigates any risk increase from the shift in Industrial customers from Forestry to cryptocurrency.

Response:

FBC's view is that the emergence of the Technology sector represents a standalone risk that is not mitigated by the load growth in other sectors. The Government/Education/Health sector has grown from 15 percent of the load in the top 20 customers in 2013 to 20 percent in 2020. The Manufacturing sector has decreased from 27 percent to 19 percent. During this time, the Technology sector has grown from just 2 percent in 2013 to 23 percent in 2020 and includes FBC's single largest Industrial customer. It is not simply the proportion of load that each industry represents that is relevant, but also the nature of the load, including stability and portability of the load.

33.10 Given that Government/Education/Health and manufacturing clients have similar usage and revenue to technology in 2020, please discuss whether this mitigates some of the flight risk in the virtual mining industrial customers.

Response:

Please refer to the response to BCUC IR1 33.9.

On page 32 of Appendix B, FBC states:

> Overall, the trend in UPC for FBC's customers has been mixed since 2013. While the UPC for residential and commercial customers is down, it has remained unchanged for Wholesale customers while increases have been observed in the Industrial class. This is consistent with FBC's evidence in Section 2.3, indicating that the share of Industrial load in FBC's overall load profile is growing. Therefore, FBC's assesses its overall risk related to UPC as similar to 2013.

33.11 Given that Industrial load is considered volatile and uncertain, please explain why FBC considers the overall risk related to use per customer (UPC) similar to 2013 when Industrial load is growing.

Response:

FBC has acknowledged that the increasing proportion of overall load represented by the Industrial sector does, in isolation, contribute to an increase in risk. However, this is distinct from UPC as is being discussed in the referenced passage. While the UPC for the residential and commercial customers is down, and has remained unchanged for Wholesale customers, there is an increase in UPC for the Industrial class. On balance, FBC assesses that a declining UPC in some sectors, with an unchanging or increasing UPC in others, does not present a material change in risk when compared to 2013.

34.0 Reference: FBC BUSINESS RISK

Exhibit B1-8-1, Appendix B - FBC Business Risk Assessment, p. 41

Energy Supply Risk

On page 41 of Appendix B, FBC submits that its overall risk in terms of energy supply is unchanged since 2013, and states:

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

34.1 Please discuss what are the uncertainties that affect FBC's ability to renew these agreements. Please include the likelihood that FBC will or will not be able to renew these agreements.

34.1.1 If FBC is able to renew these agreements, please discuss the likelihood that the cost will increase, stay the same, or decrease.

34.1.2 If FBC is not able to renew these agreements, what are FBC's options for filling its supply needs.

Response:

The Brilliant Expansion Agreement that expires in 2027 is a relatively small agreement and FBC expects that, on a longer-term basis, replacement power will be considered in a future LTERP process and in the short term by increases in market and BC Hydro PPA purchases. The current Agreement was entered into during a period of relatively low market prices and FBC expects that any replacement power or renewed agreement would be at higher prices.

The BC Hydro PPA Agreement is a core resource for FBC and an inability to renew has severe consequences to FBC's supply arrangements. FBC's LTERP considers not renewing the BC Hydro PPA and the potential cost impacts where FBC's Long Run Marginal Cost (LRMC) increases from $78 per MWh in the Base Case portfolio A1, in which the PPA is renewed, to $87 per MWh if a SCGT RNG unit is allowed (portfolio F4) and $157 per MWh if it is not (portfolio F5), assuming the PPA is not renewed.[71]

[71] FBC 2021 LTERP, Section 11.3.6, page 187, Figure 11-6.

35.0 Reference: FBC BUSINESS RISK

Exhibit B1-8-1, Appendix B - FBC Business Risk Assessment, pp. 43 and 49–50

Operating Risk

On page 43 of Appendix B, FBC assesses that, compared to the 2013 Proceeding, the operating risk facing the facilities in the FBC service area is increasing.

On page 49 of Appendix B, FBC states:

> Environmental concerns and general public resistance also represent a risk to FBC's ongoing annual vegetation management programs, which are very important in maintaining safe and reliable service.
>
> The trend in environmental regulation has been to impose more restrictions and limitations on activities that may impact the environment, including the generation and disposal of wastes, the use and handling of chemical substances, environmental management for sensitive species and their habitat, and conducting environmental impact assessments and remediation. FBC is experiencing increasingly strict environmental and safety laws, regulations and enforcement policies since 2013.

35.1 Please clarify how environmental concerns and public resistance represent a risk to FBC's annual vegetation management programs.

Response:

FBC's annual vegetation management program needs to consider environmental sensitivities and comply with environmental regulatory requirements. Migratory birds and species at risk are present throughout the FBC service territory. FBC recognizes the importance of protecting migratory birds and their nests and eggs and complying with the Migratory Birds Convention Act, 1994 and the Species at Risk Act while undertaking vegetation management work.

The federal *Migratory Birds Convention Act, 1994* (MBCA) includes prohibitions on harming or killing migratory birds or disturbing, destroying or taking nests or eggs. In BC, the general nesting period may start as early as mid-March and extend until late August. Vegetation management is considered an activity that does not primarily target migratory birds, but which may cause harm, particularly during the nesting period. Vegetation management activities may affect birds directly (e.g., destruction of a nest) or indirectly (e.g., noise from equipment causing birds to avoid or abandon nests). Environment and Climate Change Canada (ECCC) cannot provide authorizations or permits for activities that do not primarily target migratory birds but which may cause harm under the *Migratory Birds Regulations*. Furthermore, ECCC does not have the authority to prescribe or recognize specific avoidance or mitigation measures for specific circumstances or activities. It is FBC's responsibility to evaluate and reduce risks to migratory birds. ECCC's Guidelines to Reduce Risk to Migratory Birds states "If there are migratory birds

nests where you plan to work, activities that could disturb or destroy nests should be avoided, adapted, rescheduled or relocated". It is not practical or safe for FBC to limit vegetation activities over large parts of the system to a specific time of year (i.e. outside of the nesting period) because vegetation is dynamic and threats from vegetation grow-ins and trees falling on power lines do not always present themselves at predictable times. By restricting where and when the work can be completed, FBC is limited in its ability to effectively manage vegetation in a timely way. The risk this presents is an increase in outages related to vegetation management and associated public safety concerns and service disruptions.

Schedule 1 of the federal *Species at Risk Act* has been amended through order in council to add new species and reclassify other species. With the listing of new species, additional species specific recovery strategies and action plans need to be considered when planning and undertaking vegetation management activities, adding complexity, time and cost to FBC's vegetation management program.

In addition, public resistance is a constant pressure on the vegetation management program. FBC does not have a mechanism to prevent individuals from planting trees near power lines but does have an obligation to maintain those trees and trim them away from the power lines when they grow too close. The public is often surprised to learn that FBC has an obligation to clear vegetation away, even vegetation that was planted by others. Some of these situations can be extremely time consuming and challenging to navigate and puts pressure on FBC employees to find a solution to public concerns in order to carry out necessary power line maintenance activities involving vegetation clearing. FBC cannot transfer this liability to the public but often must work with them to come to a resolution. This impairs or hinders FBC's ability to operate and maintain its system in a timely way and can result in increased costs and possibly an increase in outages and service disruptions as described above.

35.2 Please provide the environmental and safety laws, regulations, and enforcement policies that have been instituted since 2013 and how these affect FBC.

Response:

There have been numerous changes to environmental and safety legislation and policy since 2013 that apply to FBC. Key themes in these regulatory changes are with respect to:

- **Emissions and climate change:** the federal and provincial governments are enacting regulations to support energy policies and requiring the consideration of climate factors in environmental regulation.
- **Indigenous reconciliation:** environmental regulation is increasingly becoming a forum within which to advance reconciliation. Formal roles for Indigenous peoples are being provided for in environmental legislation.

- **Enhanced enforcement:** enforcement provisions are being enhanced for both environmental and safety acts and regulations. The potential ranges of fines are being increased, and provincial regulators are being given more inspection and enforcement powers.

A list of the more pertinent regulatory changes that have occurred since 2013 that apply to FBC's operations are provided below.

Environmental Assessments

In 2019, the federal government passed omnibus legislation substantially changing federal environmental legislation. The *Canadian Environmental Assessment Act, 2012* was replaced by the *Impact Assessment Act* (IAA). The new act substantially altered federal assessment of reviewable projects. Important changes included an enhanced role for Indigenous peoples, implementation of an early project "planning phase", and elimination of the "significant adverse effects" threshold.

In 2019, the provincial government replaced the BC *Environmental Assessment Act* (EAA). Under the new statute there are new rules regarding project notifications, early engagement, increased public participation, and more structured timelines. The EAA provides consensus opportunities for engagement with Indigenous communities – working towards the commitment from the provincial government to fully adopt UNDRIP. The associated regulations include a change to the *Reviewable Project Regulations* which now features an "effect thresholds"' for GHG emissions, linear disturbance, area of disturbance, and projects in protected areas.

The IAA and EAA processes will apply for any FBC reviewable projects. The new assessment regimes broaden the application of the legislation to more projects and expand who may participate, which increases uncertainty in project planning. FBC anticipates that the new measures will add complexity, time and cost to the project planning phase for FBC's reviewable projects.

Climate Change and GHG Emissions

The *Canadian Net-Zero Emissions Accountability Act* was passed by the federal government in 2021 and sets a national net-zero GHG emissions target for 2050. It legislates emissions reductions accountability to address climate change by setting legal requirements on the current government and future governments to plan, report, and course correct on the path to net-zero emissions by or before 2050.

In 2018, the provincial government introduced the *Climate Change Accountability Act*. Under 2019 amendments, the provincial government must set interim emissions and sectoral targets to support the legislated 2030 target.

The *Greenhouse Gas Industrial Reporting and Control Act* came into force in January 2016, replacing the *Greenhouse Gas Reduction (Cap and Trade) Act.* This statute is the enabling legislation for the *Greenhouse Gas Emission Administrative Penalties and Appeals Regulation,*

Greenhouse Gas Emission Control Regulation and *Greenhouse Gas Emission Reporting Regulation.*

Increased electrification to achieve a net zero GHG emissions target by 2050 is anticipated to increase customer demand, putting pressure on FBC's electricity system infrastructure. FBC will continue to report its GHG emissions for electricity imports pursuant to provincial GHG reporting regulation.

Contaminated Sites

Amendments to the provincial *Environmental Management Act* (EMA) and *Contaminated Sites Regulation* came into force in February 2021, altering the process for identifying contaminated sites. The amendments require site disclosure statements (previously site profiles) to be submitted to the government based on certain triggers, including decommissioning, foreclosure and local government applications. The contaminated sites regime is subject to ongoing technical development.

The recent amendments have expanded the regulatory requirements for contaminated sites and soil relocation, resulting in increased environmental assessment, characterization, permitting and regulatory reporting. FBC anticipates that these expanded requirements will add complexity, time and cost to FBC's operation and maintenance activities and construction projects.

Spills

In October 2017, the EMA was amended to establish new requirements for spill preparedness, response and recovery, create new offences and penalties, enable the certification of a Preparedness and Response Organization and increase transparency, participation and accountability.

The *Spill Reporting Regulation* under the EMA was updated in 2017. Responsible persons must prepare and submit an immediate initial report, and, if required, a post-incident "lessons-learned" report. The range of spills that trigger the duty to report was expanded.

These requirements will apply to FBC for any spills over the reporting threshold or to water. Reportable spills may occur in the normal course of FBC's operations and these requirements will result in additional reporting requirements.

Water Protection

In February 2016, the *Water Sustainability Act* (WSA) came into force, replacing the *Water Act* as the primary piece of water management legislation in BC. The WSA includes broader protections for water resources than were previously found in the *Water Act*. Some of the key new features of *WSA* affecting FBC include licensing non-domestic ground water use, new water fees and rentals, stronger protection for aquatic ecosystems, expanded groundwater protection measures and enhanced dam safety.

FBC work potentially affecting surface and groundwater resources is regulated by the WSA. FBC anticipates that the broader water resource protections will add complexity, time and cost to FBC's operation and maintenance activities and construction projects.

Fish and Fish Habitat Protection

The federal *Fisheries Act* was substantially amended in 2019. Changes consisted primarily of the elimination of the "serious harm" test and reintroduction of the harmful alteration, disruption and destruction of fish habitat (HADD) prohibition and permitting requirements. A prohibition against killing fish, except in the context of fishing, was reintroduced. In addition, the changes have enhanced the role of Indigenous peoples in project reviews, increased monitoring, and enhanced the enforcement provisions, with minimum fines established and maximum fines increased substantially.

FBC work in and around water is regulated by the *Fisheries Act*. FBC anticipates expanded project review and authorization requirements for its existing hydroelectric generation facilities and projects that have the potential to impact on fish and fish habitat. FBC expects that these expanded requirements will add complexity, time and cost to FBC's operation and maintenance activities and construction projects.

Species at Risk

Schedule 1 of the federal *Species at Risk Act* has been amended through order in council to add new species and reclassify other species. Several action plans and recovery strategies have been developed for species at risk.

Federal species at risk are present through the FBC service territory. With the listing of new species, additional species specific recovery strategies and action plans will need to be considered when planning FBC works, adding complexity, time and cost to FBC's operation and maintenance activities and construction projects.

Heritage Resource Management

In May 2019, the provincial *Heritage Conservation Act* (HCA) was amended to include increased reporting, enhanced powers to suspend or cancel permits and expanded enforcement and compliance powers.

Increased reporting requirements under the HCA will apply to FBC's projects and operations that occur within or adjacent to heritage and archaeological resources, adding complexity, time and cost to FBC's operation and maintenance activities and construction projects.

Safety

WorkSafeBC has made a number of amendments to the Occupational Health and Safety Regulation (OHSR) since 2013 and has recently identified the following four areas of high risk that pertain to FBC:

- Falls from elevation;
- Struck by moving equipment;
- High voltage limits of approach; and
- Musculoskeletal and repetitive strain injuries (MSI and RSI).

FortisBC has seen a number of WorkSafeBC inspections relating to the Occupational Health and Safety Regulation (OHSR) and the four high risk areas identified above. Safety enforcement provisions and increased fines may apply to FBC if regulatory contraventions occur.

Environmental Enforcement

The federal *Environmental Violations Administrative Monetary Penalties Act* was created to supplement existing administrative monetary penalty regimes for the enforcement of certain federal environmental acts and regulations. It came into force in December 2010, and the *Environmental Violations Administrative Monetary Penalties Regulation*, which established key details of the regime, came into force in June 2017.

In March 2012, the provincial *Natural Resource Compliance Act* came into force. This statute gives authority to designate persons as natural resource offices with powers and duties to enforce legislative requirements for various statutes including the *Forest and Range Practices Act*, *Heritage Conservation Act*, *Water Sustainability Act*, and *Wildlife Act.*

Environmental enforcement provisions and increased fines may apply to FBC if regulatory contraventions occur.

35.2.1 Please discuss how investors and credit agencies view the stricter environmental and safety laws, regulations, and enforcement policies and the affect they have on credit ratings, if any.

Response:

Stricter environmental and safety laws, regulations, and enforcement policies pose a business risk to FBC. From a financial risk and investor perspective, the increasing pace of the Energy Transition from fossil fuels to cleaner sources of energy through electrification of the economy is an opportunity for FBC being a hydro-electric utility.

Further, Concentric provides the following response:

Investors and credit rating agencies view environmental and safety laws and regulations as increasing political risk for regulated utilities, which leads to more uncertainty related to project execution and timing, project delays due to permitting issues, the accuracy of project cost

estimates, and therefore leads to higher risk for investors in this sector. Please refer to Attachment 35.2.2 in response to BCUC IR1 35.2.2 for an S&P report discussing the most material environmental and social risks for regulated utilities.

35.2.2 Please provide evidence or reference to these environmental and safety laws, regulations, and enforcement policies in the Equity and Credit Rating reports.

Response:

Concentric provides the following response:

Credit rating agencies have established ESG evaluation criteria as part of the rating methodology for regulated utilities. An October 2020 S&P report discussing those criteria is provided as Attachment 35.2.2. This report discusses the most material environmental and social risks for electric, gas, and water utilities assessed in S&P's ESG Evaluation. The social risks include network reliability and safety management.

FortisBC adds the following:

The references included below from Credit Rating Reports and Equity Research Reports for the most part do not specifically reference environmental challenges for FBC as FBC is an electric utility and therefore does not face the same energy transition risks as FEI and some other Fortis Inc. subsidiaries. It is also one of the smallest utilities within the Fortis Inc. group of companies and so is not widely covered in Fortis Inc. equity research reports. However, the references provided do highlight the impact of environmental regulation on the utility sector and the Fortis Inc. group of companies as a whole and evidences how the Fortis Inc. group of companies, including FortisBC, is facing increasing scrutiny from creditors, investors, and regulators with regards to the clean energy transition.

The below references also evidence the evolution of ESG regulations and the credit rating agency views on climate related risks. For example, in 2019, Moody's stated that FEI being a T&D utility has low carbon transition risk:

> As a natural gas distribution company, FEI has a low carbon transition risk within the regulated utility sector. We generally consider T&D and LDC utilities to have low carbon transition risk because, unlike integrated utilities, they have no direct carbon emissions. The company intends to increase its use of renewable natural gas as part of its effort to support the Province of BC in achieving its legislated targets of reducing GHG emissions by 40% by 2030 and 80% by 2050 from 2007

levels. The company also expects to lead the transition to lower carbon fuels in marine transportation through LNG bunkering.[72]

Merely two years later, in 2021, as federal and BC's climate regulations became stricter, Moody's started describing FEI's carbon transition risk as "very negative":

> FEI has a very negative carbon transition risk because of the risks associated with carbon emissions targets. The Province of BC has legislated targets of reducing GHG emissions by 40% by 2030 and 80% by 2050, levels that exceed the company's own 30% reduction target by 2030 (all based on 2007 figures). The company intends to continue to increase its use of renewable natural gas as part of its effort to reach these goals, in addition to continuing its work on the use of hydrogen gas and other measures to achieve these aggressive targets. The company also expects to lead the transition to lower carbon fuels in marine transportation through LNG bunkering.[73]

Credit Rating Agency Reports

Please refer to the response to BCUC IR1 8.1 for more discussion of ESG risk factors from credit rating agency perspective.

In addition, FBC provides the following references to environmental and safety laws, regulations and enforcement policies in the credit rating reports provided as Appendix D to the:

#	Reference	Excerpts
	2022	
1	DBRS report for FEI (January 5, 2022 pg. 832/5621)	"4. Long-term competition from electricity FEI faces more intense competition from electricity in BC than most gas distributors in other provinces in Canada (except Québec) because of the relatively low power costs in the province. However, there has been upward pressure on electricity rates in BC because of new investments in electricity generation and transmission, whereas natural gas prices have remained relatively low. Recent developments such as an increase in carbon taxes and the impact of FEI's capital programs on the rates have negatively affected FEI's price competitiveness."
2	DBRS report for FEI (January 5, 2022 pg. 833/5621)	"Regulation Amendments to Greenhouse Gas Reduction Regulation (GGRR) In July 2020, the provincial government announced the following amendments to GGRR: • Increasing the amount of renewable gas FEI can acquire from 5% to 15% of system load. • Enabling FEI to acquire hydrogen, lignin, and synthesis gas. • Increasing the price cap for the acquisition of renewable gas to $31 per gigajoule, indexed to inflation. DBRS Morningstar notes that these amendments are not material from a credit perspective but will support the Company's transition to a lower carbon economy."

[72] Moody's Credit Rating Report for FEI dated August 29, 2019.
[73] Moody's Credit Rating Report for FEI dated November 25, 2021.

#	Reference	Excerpts
	2021	
3	Moody's report for FEI (November 25, 2021 pg. 888/5621)	"ESG considerations FEI has a very negative carbon transition risk because of the risks associated with carbon emissions targets. The Province of BC has legislated targets of reducing GHG emissions by 40% by 2030 and 80% by 2050, levels that exceed the company's own 30% reduction target by 2030 (all based on 2007 figures). The company intends to continue to increase its use of renewable natural gas as part of its effort to reach these goals, in addition to continuing its work on the use of hydrogen gas and other measures to achieve these aggressive targets. The company also expects to lead the transition to lower carbon fuels in marine transportation through LNG bunkering. (…) Regarding affordability, as emissions levels are reduced, there is a risk that this will increase costs making the company's services less affordable."
4	Moody's report for Fortis Inc. (August 31, 2021 pg. 1018/5621)	"Fortis's ESG Credit Impact Score is moderately negative (CIS-3), reflecting the moderately negative environmental and social risks balanced by a neutral-to-low exposure to governance risk. Environmental Fortis's moderately negative exposure to environmental risks (E-3 issuer profile score) is driven by its moderately negative physical climate risks mostly in the form of extreme weather patterns. These risks are offset by a neutral to low exposure to carbon transition, water management, waste and pollution and natural capital risks. (…) This is driven by the risk that public concern over environmental, social or affordability issues could lead to adverse regulatory political intervention."
	2020	
5	Moody's report for FBC (November 20, 2020) pg. 757/5621)	"We regard the coronavirus outbreak as a social risk under our ESG framework given the substantial implications for public health and safety."
6	Moody's report for FEI (November 20, 2020 pg. 877/5621)	"ESG considerations As a natural gas distribution company, FEI has a low carbon transition risk within the regulated utility sector. We generally consider T&D and LDC utilities to have low carbon transition risk because, unlike integrated utilities, they have no direct carbon emissions. The company intends to increase its use of renewable natural gas as part of its effort to support the Province of BC in achieving its legislated targets of reducing GHG emissions by 40% by 2030 and 80% by 2050 from 2007 levels. The company also expects to lead the transition to lower carbon fuels in marine transportation through LNG bunkering."
7	Moody's report for Fortis Inc. (August 27, 2020 pg. 1006/5621)	"ESG Considerations Fortis has a low carbon transition risk within the regulated utility sector. As primarily a T&D company, it has low exposure to carbon transition risk, and its diversity further reduces this exposure through, for example, the smaller impact of unfavorable policy and regulatory decisions in any given jurisdiction. About 11% of the company's net PP&E comes from generation, with the bulk of that located at TEP based in Arizona. TEP has elevated carbon transition risk based on its high coal generation ownership. About 50% of its generation currently comes from coal. TEP recently announced a new GHG reduction target to reduce emissions by 80% by 2035 from 2005 levels. Renewable generation is likely to grow toward more than 70% of the generation mix. Further, FEI also plans to reduce customers' greenhouse gas emissions by 30% and get 15% of its gas supply from renewables by 2030. Social risks are primarily related to demographic trends, safety, customer and regulatory relations. Key aspects of corporate governance include establishing the company's leverage policies and maintaining a straightforward organizational structure."

#	Reference	Excerpts
	2019	
8	Moody's report for FBC (August 29, 2019 pg. 751/5621 and appears in various other reports from 2020 and 2021)	"ESG considerations As a primarily electric T&D utility, FBC has low carbon transition risk as it does not have any direct exposure to fossil-fuel generation. While it is does have some vertical integration, its generation is hydro electric, with generation making up about 14% of rate base assets excluding capital leases. FBC owns four hydroelectric power facilities with a total capacity of 225 MW and provide about 45% of the total annual electricity needs of FBC's customers. CleanBC, the Province's climate action plan, has targets to increase the clean electricity delivery standard to 100% from 98% by 2030. However, we have not assumed that the company makes further generation investments but it will likely increase its power purchases to meet demand increases. Targets associated with increased electrification represent growth opportunities for the company."
9	Moody's report for FEI (August 29, 2019 pg. 866/5621)	"Low carbon transition risk within the regulated utility sector FEI has low carbon transition risk. The low designation is assessed based on a comparison with other companies within the regulated utility sector. We generally consider T&D and LDC utilities to have low carbon transition risk because, unlike integrated utilities, T&D utilities have no carbon emissions. Moody's framework for assessing carbon transition risk in the utility industry is discussed in "Prudent regulation key to mitigating risk, capturing opportunities of decarbonization"
10	Moody's report for Fortis Inc. (May 30, 2019 pg. 994/5621)	"Low carbon transition risk Fortis has a low carbon transition risk within the regulated utility sector. As primarily a T&D company it has low exposure to carbon transition risk, and its diversity further reduces this exposure through, for example, the smaller impact of unfavorable policy and regulatory decisions in any given jurisdiction About 12% of the company's net PP&E comes from generation, with the bulk of that located at TEP based in Arizona. TEP has an elevated carbon transition risk based on its high coal generation ownership. About 69% of its generation currently comes from coal. TEP plans to increase renewable resources' share in its energy mix to about 30% from 11% by 2030, which will exceed Arizona's current renewable energy standard of 15% by 2025. Moody's framework for assessing carbon transition risk in this industry is set out in "Prudent regulation key to mitigating risk, capturing opportunities of decarbonization" (2 Nov 2017)"
11	S&P report for Fortis Inc. (March 13, 2019 pg. 1060/5621)	"Environmental, Social, And Governance We consider Fortis' environmental footprint in the broader context of environmental, social, and governance (ESG) risk factors. Fortis is primarily a regulated gas and electric utility operator. Electricity poles, wires, and natural gas lines make up about 92% of Fortis' total assets, with the remaining 8% associated with generation, of which about 3% is renewable and 5% is fossil fuel-based generation that is primarily owned by Tucson Electric Power (TEP). As a result, TEP produces most of Fortis' fossil-based generation and associated greenhouse gas (GHG) emissions. In order to reduce Fortis' environmental footprint, TEP is focusing on reducing its GHG emissions by decreasing reliance on coal generation and replacing it with a mix of efficient natural gas and renewables generation. In 2014, gas and renewable generation represented about 9% of TEP's energy mix with coal representing about 79%. In 2018, gas and renewable energy represented about 40% of TEP's energy mix while coal represented about 43%. By 2030, the goal is to have gas and renewable represents about 57% of TEP's retail energy mix with coal representing only about 38%. Therefore, Fortis management is taking active steps to reduce its environmental footprint. From a social perspective, the company's long track record of providing safe and reliable gas and electric utility services to its customers could enable it to maintain social cohesion going forward. Governance factors are neutral to our ESG assessment. Fortis has an independent board of directors that, in our view, is capably engaged in risk oversight on behalf of all stakeholders."

(Emphasis added)

Equity Research Reports

Please note that FortisBC does not issue equity publicly and therefore equity research reports provided in Appendix D were for Fortis Inc. Because of the sheer volume of references to ESG

1 found in the equity research reports provided, FortisBC narrowed down the search to the most
2 recent year only – 2021:

#	Reference	Excerpts
1	RBC report (November 1, 2021 pg. 4084/5621)	"Roughly 80% of the plan focuses on energy delivery and on cleaner energy initiatives. Transmission and distribution spending makes up 63% of the total capex plan, with a further 19% aimed at cleaner energy investments, which Fortis defines to be investments that reduce air emissions, water usage and/or increase customer energy efficiency (…) Investment opportunities not only need to meet the company's risk-return profile, but also be considered in the context of Fortis' ESG profile, with the company highlighting that 93% of its assets are in transmission and distribution, and that it is on track to meet its target of reducing carbon emissions by 75% by 2035 using a 2019 base year."
2	RBC report (November 1, 2021 pg. 4087/5621)	"Central Hudson (general rate application): A joint proposal was filed with the New York Public Service Commission (NYPSC) in August 2021 in relation to the rate application that Central Hudson previously filed in August 2020. (…) The proposal also reflects the use of existing regulatory balances and other measures to reduce customer bill impacts, as well as initiatives to support New York State's climate goals. Fortis expects an order from the NYPSC in Q4/21."
3	TD report (November 1, 2021 pg. 5173/5621)	"2022–2026 Capital Plan FTS announced its updated five-year capital plan, which includes $20bln of investment between 2022 and 2026, representing a 6% rate-base growth for the period. A $1.0bln increase from the previous 2021–2025 capital plan is driven by forecast customer growth, enhancement in transmission reliability and capacity, investments in cleaner energy, as well as a reduction in foreign exchange rate assumptions from 1.32 U.S. dollar/Canadian dollar to 1.25 U.S. dollar/Canadian dollar. (…) Management noted that incremental opportunities beyond its capital plan and a push for accelerated clean-energy transition in the U.S. are potential tailwinds for the company and the magnitude of these opportunities as well as related financing will inform the dividend outlook beyond 2025"
4	TD report (November 1, 2021 pg. 5174/5621)	"Growing Opportunities Related to Energy Transition We note that the new five-year plan has an additional $500mm allocated towards cleaner-energy investments when compared with last year's plan, progressing FTS' transition into a lower-carbon future. Management anticipates using some sustainability-linked financing to support investments in cleaner-energy projects and is also weighting the merits of potentially locking-in finance costs in anticipation of rising interest rates, which can typically be passed on to utility customers. (…) Management emphasized that the appetite for investment opportunities is not limited to certain geographies, technologies, or types of energy-transition projects, but needs to meet an appropriate risk/return hurdle that would likely be comparable with the attributes embedded in utility investments."

#	Reference	Excerpts
5	CIBC report (October 31, 2021 pg. 2515/5621)	"FTS outlined a credible five-year capital plan with potential upside over time to both enhance and extend the current plan around required investments to support the electric transmission build-out and other decarbonization efforts. (…) Updated Five-year Plan Much Like The Prior Plan. The updated five-year, $20B capital plan provides an uptick in spending over the prior plan even with recent FX headwinds ($1B of additional capital offset by $0.6B of FX impacts). Incremental investments are related to typical utility needs (customer growth, reliability and capacity enhancements), and increasing focus on cleaner energy within FTS's electric and gas utilities. (…) Where There's Upside. FTS has multiple credible options to enhance and/or extend its current plan, including incremental electric transmission investments in the U.S. to facilitate the interconnection of new renewable energy. More specifically, its ITC utility should receive clarity on the MISO long-range plan by mid-next year; FTS noted discussions have been positive. The fully permitted Lake Erie Connector Project also seems increasingly likely with IESO negotiations to secure a contract ongoing (FTS seeks to contract 100% capacity). In BC, natural gas resiliency investments in pipeline and LNG infrastructure are accelerating, as are opportunities for cleaner energy infrastructure investments."
6	CIBC report (October 29, 2021 pg. 2509/5621)	"Upside to the current plan is largely in line with prior disclosures (Lake Erie project, UNS decarbonization, transmission buildout in the U.S., gas infrastructure in BC)."
7	RBC report (October 29, 2021 pg. 4082/5621)	"Additional opportunities to expand and extend growth include: further expansion of the electric transmission grid in the U.S. to facilitate the interconnection of cleaner energy, natural gas resiliency investments in pipelines and LNG infrastructure in B.C., the Lake Erie Connector electric transmission project in Ontario, and the acceleration of cleaner energy infrastructure investments across our jurisdictions."
8	Scotia report (October 29, 2021 pg. 4664/5621)	"There are also a variety of transmission projects at ITC that could help increase grid resiliency and connect additional renewables to the grid."
9	Scotia report (October 29, 2021 pg. 4678/5621)	"Potential areas of additional growth to this plan would be the $1.7b Lake Erie Connector, which is making progress (link), additional transmission at ITC to facilitate increased renewable investment, moving UNS away from coal generation, and a variety of other items."
10	RBC report (August 25, 2021 pg. 4078/5621)	Central Hudson filed a Joint Proposal with the NYPSC (…) "A total of 10 Earnings Adjustment Mechanisms (EAMs) will be implemented to incentivize Central Hudson to achieve outcomes that are aligned with the state's clean energy goals, such as: (1) increasing electric system efficiency through peak reduction and distributed energy resource utilization; (2) increasing achieved electric and gas energy efficiency; (3) efficiently reducing GHG emissions through increased penetration of environmentally beneficial electric technologies (e.g., air and ground-source heat pumps and EVs); and (4) promoting the acquisition of energy savings by the low-to-moderate income customer segment."
11	TD report (July 30, 2021 pg. 5165/5621)	"2021 Sustainability Update and Climate Financial Disclosure: Concurrent with the Q2/21 results, FTS released its 2021 Sustainability Update. Select highlights included a 15% reduction in Scope 1 emissions in 2020, largely the result of the closure of the Navajo Coal Generation Facility at Tucson Electric Power ("TEP"). The emission reduction reflects material progress towards reaching the previously established carbon emission reduction target of 75% by 2035 (using 2019 as a base year) (…) Furthermore, FTS announced the company has signed on to support the Task Force on Climate-Related Financial Disclosures ("TCFD"). With this commitment, FTS will fully implement TCFD recommendations, including a comprehensive climate scenario analysis and progress update planned for 2022."

#	Reference	Excerpts
12	RBC report (July 30, 2021 pg. 4067/5621)	"Arizona regulator finalizes renewable energy rules. In May, the Arizona Corporation Commission (ACC) voted to advance amended energy rules that would require the state's utilities to reach 100% carbon-free emissions by 2070, with interim standards beginning with a 50% reduction by 2032, a 65% reduction by 2040, an 80% reduction by 2050, and a 95% reduction by 2060. The proposed rules are subject to a comment period, an oral proceeding and a review by an administrative law judge prior to potentially being forwarded to the state legislature for review and certification."
13	RBC report (July 30, 2021 pg. 4066/5621)	"Clean energy and sustainability-related initiatives expected to headline Fortis' next update. Supported by the desires of its stakeholders to deliver clean, sustainable and affordable energy, as well as the goals of local governments to boost their respective economies and employment levels, we believe Fortis' next five-year plan update (which we believe may be published as early as this fall) will heavily feature decarbonization/clean energy and sustainability-related initiatives. Of note, Fortis previously estimated that that roughly US$400 billion of green infrastructure opportunities have been identified under the American Jobs Plan, including US$100 billion for electric grid resilience and US$174 billion for electric vehicles. We highlight the following as interesting topics to monitor in relation to Fortis' clean energy and sustainability-related initiatives: - Many electric transmission-related initiatives have been recently introduced, which can be a good thing for Fortis (specifically, for ITC). - Visibility on initial projects to expand and extend its electric grid in the U.S. could come around October. In March, the Midcontinent Independent System Operator (MISO) initiated a long-range transmission planning (LRTP) process with a focus on system constraints and configuration options. The MISO outlined conceptual maps that identify potential new transmission required to enable more renewable generation in the region. Fortis continues to expect the first group of potential projects to be made known by MISO around October, which potentially lead to the expansion and extension of ITC's electric transmission grid."
14	Morningstar report (July 29, 2021 pg. 3490/5621)	"Fortis is well positioned for the clean energy transition, with one of the lower ESG risks relative to its peers, as only 7% of Fortis' assets are generation. The company will transition this portfolio through its base capital investment program, with 1.1 GW of planned coal retirements, and the addition of 2.4 GW of renewable generation and 1.4 GW of battery storage. Fortis' goal to reduce carbon emissions by 75% by 2035 is in line with its utility peers. Regulators across its jurisdictions are supporting this transition"
15	Morningstar report (July 29, 2021 pg. 3492/5621)	"While FERC recently proposed eliminating the 50-basis-point adder currently given to regional transmission organization members, like ITC, we continue to believe transmission will receive favorable regulatory treatment given transmissions' role in the clean energy transition"
16	CIBC report (July 29, 2021 pg. 2494/5621)	"The sustainability update highlights good progress on emissions reductions and alignment with TCFD disclosures (…) * Sustainability Update. FTS reduced its Scope 1 emissions by 15% in 2020, largely on greening the generation at TEP. It also has adopted TCFD disclosures and made steady progress on other ESG objectives."
17	CIBC report (July 29, 2021 pg. 2500/5621)	"We continue to see modest potential upside to the current capex and growth plans around required investments to support the electric transmission build out and other decarbonization efforts. (…) Further, efforts in the U.S. by FERC and the federal government to debottleneck the electric transmission build out to support renewables growth should benefit ITC over time. And ongoing transmission in the MISO region could lead to tangible new investments within the next few quarters. Decarbonizing the gas utility in BC also offers further upside as RNG and hydrogen integration efforts continue. (…) Regulatory Updates: On the regulatory front, FTS has a few ongoing matters and proceedings, some of which might get resolved this year. These include the FERC's proposal regarding incentive adders that could see ITC's ROE come down by 75bps—FTS maintains the proposal is counter to current policy goals and the transition toward a clean energy future."

#	Reference	Excerpts
18	RBC report (July 29, 2021 pg. 4063/5621)	"While Q2/21 results were slightly below our estimate and consensus, we believe any potential negative share price reaction may be limited given the company's maintenance of its long term outlook, including relating to its rate base and dividend growth guidance, and its commitment (and progress, as disclosed through its 2021 Sustainability Update report released today) to delivering its corporate-wide carbon emissions reduction target of 75% by 2035 (compared to 2019 levels). (…) In conjunction with its earnings release, Fortis published its 2021 Sustainability Update, which included information on Fortis' progress to reduce emissions, updated sustainability key performance indicators and an announcement that Fortis is a supporter for the Task Force on Climate-Related Financial Disclosures (TCFD)."
19	Scotia report (July 29, 2021 pg. 4638/5621)	"2021 sustainability update. Fortis has been talking about ESG principals for years and continues to improve its profile. In 2020, it reduced its scope 1 emissions by 15% through the closure of the Navajo Coal Generation Facility at Tucson Electric Power (TEP) in late 2019. TEP expects to reduce its carbon emissions by 75% (relative to 2019 levels) through continued investment and adoption of clean power. Aside from TEP, Fortis' other assets are not meaningful carbon emitters, as overall, 93% of Fortis' assets are focused on the distribution and transmission of energy. The company has also further strengthened its linkage between sustainability and executive compensation. As we show on our ESG tearsheet on page 6, we view Fortis as leader in the field."
20	Scotia report (July 29, 2021 pg. 4643/5621)	"We view Fortis' ESG profile as strong, particularly with respect to governance. We expect to see continued focus on ESG initiatives across its utilities. Goals / Targets • Tucson Electric: 80% carbon emissions reduction by 2035 • Tucson Electric: 70% renewable power by 2035 • FortisBC: reduce customer GHG emissions by 30% by 2030 • Overall reduction in carbon emissions of 75% by 2035 Initiatives • Opportunities at ITC outside of capital plan to add renewable capacity, develop battery storage, and build transmission to facilitate increased demand for renewables • Transition to coal-free generation mix underway (done in 2032) Accomplishments • 250 MW Oso Grande wind project entered service in 2020 (…) • Consistent y/y decreases in Scope 1 GHG emissions associated with coal-fired generation at Tucson Electric (over last five years) • No company-specific ESG risks versus peers"

#	Reference	Excerpts
21	RBC report (May 20, 2021 pg. 4038/5621)	"Transition offers opportunities Our view: Across its U.S. utilities, we see Fortis benefitting from long-lasting themes relating to the 'greening' of generation and grid resiliency, and, further out, from the adoption of EVs as transport electrification improves grid utilization. Collectively, these opportunities should offer support (if not improvement) to Fortis' 6% rate base CAGR over the long-term. Overall, while we maintain our neutral rating on the stock due mainly to the market's positioning, we believe Fortis' growth potential associated with the energy transition will continue to attract investors seeking exposure to long-term, sustainable and ESG-friendly regulated cash flows and a growing dividend profile. (…) ITC: Building the grid of the future. We believe ITC's electric transmission assets, with a rate base of around $10 billion, are well-positioned to deliver solutions that improve reliability, expand market access and interconnect more clean generation resources to its system. A review of the MISO/SPP interconnection queues and MISO's Long Run Transmission Planning (LRTP) 2039 future scenarios suggests to us that the opportunity set over the next 15-20 years could range $10-30 billion for ITC (mostly based on its 20-25% market share in MISO and the US$30-100 billion of potential transmission capex related to MISO's LRTP). In addition, we note that MISO's most ambitious 2039 scenario (i.e., 50% renewables, 30% gas and 20% others) does not appear to keep pace with President Biden's climate ambition, suggesting there may be further upside to these estimates. (…) While we expect TEP's 2020 Integrated Resource Plan (IRP) will continue to support the growth of UNS Energy's $6 billion rate base beyond the 2021-2025 period, we believe President Biden's goal for a carbon free power sector in 2035 offers an opportunity for TEP and its Arizona stakeholders to redesign their decarbonization targets. (…) EV: Higher adoption increases grid utilization and may offer charging infrastructure opportunity. We believe investors can gain exposure to the electric vehicle (EV) theme by investing in regulated utility stocks, such as Fortis, without needing to pick a "winner" in terms of technology or vehicle manufacturer. We believe the utilities are well-positioned to support a rapid roll-out of EVs across their service areas and may benefit from the increased utilization of their grids."
22	RBC report (May 20, 2021 pg. 4039/5621)	"Within Fortis' 2021-2025 capital plan, the company expects to spend around $5.1 billion (of its $19.6 billion overall plan) in ITC, which includes infrastructure investments relating to reliability and resiliency upgrades, increased capacity, enhanced grid security (both physical and cyber) and importantly, interconnections to support 2,800 MW of cleaner energy (…) As shown in Exhibits 1 to 3, each of these major customers have, as part of their respective parent company's objectives, ambitions to achieve net zero carbon emissions by 2050, if not earlier. To realize these ambitions, their respective capital plans call for significant build out of renewable energy capacity to replace carbon emitting generation, such as coal."
23	RBC report (May 20, 2021 pg. 4044/5621)	"FERC: One step back, but potentially two steps forward on ROEs? With all of ITC's utilities being regulated by the FERC, we see the recent changes at the FERC as offering the company an opportunity to renew the utilities' role in the country's push toward sustainable infrastructure and clean energy."
24	RBC report (May 20, 2021 pg. 4045/5621)	"Following a broad stakeholder engagement process, Tucson Electric Power's (TEP) 2020 Integrated Resource Plan (IRP) aims to reduce its CO2 emissions by 80% by 2035 (versus 2005 levels), which is a key milestone in the company's journey to rapidly and responsibly transition to 100% clean energy resources. • Shut down of coal by 2032. Included in this plan is the exit of all of TEP's ownership interests in coal plants, with the last closures scheduled for 2027 and 2032 at the 793 MW Springerville units 1 and 2. • Replaced by renewables, storage and energy efficiency. As these fossil-fuel generation facilities close, TEP's IRP (under the Preferred Portfolio) aims to have 70% of its energy coming from renewable sources, around 1,400 MW of new energy storage, and 2.5 times more energy efficiency than originally planned by 2035. Timing wise, TEP expects to bring online 476 MW of new wind, solar and energy storage resources between 2020 and 2022, and an additional 2,000 MW of new renewables and roughly 1,400 MW of new energy storage resources between 2024 and 2035"

#	Reference	Excerpts
25	RBC report (May 20, 2021 pg. 4046/5621)	"Potential for an even more ambitious decarbonization plan TEP's Preferred Portfolio scenario in the IRP, which aims to have 70% of its energy coming from renewable sources (please see Exhibit 9), is already more ambitious than Arizona's current renewable energy standard, which is to serve 15% of the state's retail load with renewable energy by 2025. However, we highlight the following two climate change-related items that may lead to a more ambitious decarbonization plan ahead for TEP. • President Biden's goal to have a carbon-free electricity sector by 2035. We believe this goal opens the door for TEP to potentially deliver a more ambitious decarbonization plan than the Preferred Portfolio in its IRP. Federal incentives, for example, could be offered and used to support communities that may be impacted by a faster shutdown of coal generation in Arizona, or to make investments in renewable energy generation (including newer technologies like battery storage) more attractive. • Potential update to Arizona's current renewable energy standard. The state's current standard to serve 15% of the state's retail load with renewable energy by 2025 was set in 2006. In November 2020, the Arizona Corporation Commission (ACC) voted in favour of measures that included a goal to have 50% of the state's power to be carbon-free by 2035 and 100% carbon-free by 2050. However, in a follow-on vote and in spite of a number of amendments (including turning the requirements into voluntary goals instead), the ACC surprisingly voted down these measures in May 2021, which means the 2006 standard remains in effect. Amidst all this, there is an ongoing debate about the capacity of the ACC to set a clean energy mandate for the state, and there have been a number of bills introduced in the state legislature that served to limit the ACC's ability to do so. Overall, there is a lively discussion around the state's renewable energy standard and we would not rule out an update to the standard. As TEP noted following the ACC's May 2021 vote, the vote "will not slow our progress toward achieving the cleaner energy goals we've set for ourselves". Overall, we broadly view TEP's ability to take steps to achieve a more ambitious decarbonization plan as being guided by the goals set by the Arizona state government and the ACC."
26	RBC report (May 20, 2021 pg. 4047/5621)	"Measuring the opportunity set under President Biden's vision If Arizona adopts a target that is in line with President Biden's goal, one way to measure the initial opportunity set for TEP is finding replacement resources for the roughly 1,600 MW of natural gas generation capacity in the utility's 2035 generation mix. As discussed below, replacing this capacity with wind and solar resources, supplemented with battery storage, could lead to an opportunity of around US$1.7-3.6 billion (or $2-5 billion). • If replaced by wind and solar… Simplistically, if we assume construction costs of US$650/kW for fixed-tilted solar PV capacity and US$1,300/kW onshore wind capacity, the capital costs would range around US$1.0-2.5 billion. • … and supplemented with battery storage. However, in addition to the environmental attributes of wind and solar, TEP also needs to consider the dispatchability of the replacement resource, the availability of the resource to TEP, and whether the grid's reliability can be maintained (including during extreme weather events). As such, for this discussion, we assume the wind and solar resources will need to be supplemented with battery storage. (…) Carbon offsets may be utilized instead given gas generation's contribution to grid reliability. Given the potential for extreme weather events in the U.S., TEP and its stakeholders may choose to maintain a level of baseload gas generation capacity to provide support to the grid. If so, further lowering the utility's emission to net zero (admittedly, not "carbon-free" per Biden's goal) may require the use of carbon offsets. Along with recognizing that carbon costs are a pass-through to ratepayers, we also see a robust carbon pollution pricing framework as presenting an opportunity for new energy solutions and technologies to emerge in the future and be deployed by TEP."
27	RBC report (May 20, 2021 pg. 4050/5621)	"(1) Central Hudson: Supporting NY state's EV rollout as part of its infrastructure As part of New York state's plan to decarbonize the transportation sector and reduce overall statewide carbon emissions by 85% (versus 1990 levels) by 2050, the state aims to have 850,000 zero-emission vehicles (ZEV) on the road by 2025."

#	Reference	Excerpts
28	Scotia report (May 5, 2021 pg. 4610/5621)	"Overall, we see the U.S.'s push into renewable energy as requiring significant transmission investment, which is a positive for Fortis."
29	BMO report (May 5, 2021 pg. 2068/5621)	"The Q1/21 report supports our view that rate base expectations could rise and that the shares provide indirect leverage to the de-carbonization theme at a more inexpensive valuation than direct renewable power producers (~12x EV/EBITDA vs. ~15x renewables average). (…) Thoughts on the guidance. FTS reaffirmed its five-year outlook, with capex of $19.6B through 2025 ($3.8B in 2021), driving an attractive 6% rate base and dividend CAGR. FTS also newly disclosed that of total capex, about 17% is renewables-related, supporting its 2035 carbon reduction target (75% lower). At the same time, we detected optimism regarding further upside to the base plan: this includes new transmission projects at ITC (accelerated by President Biden's American Jobs Plan, and MISO LTRP), the $1.7B Lake Erie transmission project (recent announcement that Canada Infrastructure Bank funding ~40% of the project), and renewables through rate base (esp. at TEP where there is a $4-6B long-term investment opportunity)."
30	RBC report (May 5, 2021 pg. 4025/5621)	"The company maintains its positive long-term outlook, and continues to highlight additional opportunities to extend and expand its growth beyond its base plan, including further expansion of the electric transmission grid in the U.S. (Fortis noted "visibility on initial projects could be as early as this year"), LNG infrastructure in B.C. and the acceleration of cleaner energy infrastructure investments across its jurisdictions."
31	RBC report (May 5, 2021 pg. 4026/5621)	"Our view: The Q1/21 results and commentary reinforced our view that Fortis' shares offer not only defensive attributes to investor portfolios but also exposure to the positive energy transition trends in both the U.S. and Canada, particularly as it relates to expanding the electric transmission grid in the U.S. and the decarbonization of the energy its assets deliver across its jurisdictions. Whilst we maintain our Sector Perform rating primarily due to our offensive tilt towards stocks more geared to a recovery trade, we remain encouraged by Fortis' clean energy-oriented growth prospects and its ability to deliver growing dividends. (…) Fortis noted that roughly US$400 billion of green infrastructure opportunities have been identified under the American Jobs Plan, including US$100 billion for electric grid resilience and US$174 billion for electric vehicles initiatives."
32	RBC report (May 5, 2021 pg. 4027/5621)	"However, there appears to be upside to the capital expenditures budget. As noted in our previous report, we continue to keep a lookout for incremental energy transition opportunities, with the potential for an acceleration of expenditures, particularly in the U.S., stemming from President Biden's climate strategy. (…) In March, the Midcontinent Independent System Operator (MISO) initiated a long-range transmission planning (LRTP) process with a focus on system constraints and configuration options. The MISO outlined conceptual maps that identify potential new transmission required to enable more renewable generation in the region. (…) Fortis expects ITC's comments to be submitted to the FERC in relation to this Supplemental NOPR to touch on the benefits of having better connected power markets (such as improved cost allocation, reliability and integration of renewable energy) and its interpretation of the Federal Power Act on the legal requirement to provide incentives to each transmitting utility or electric utility that joins a transmission organization."
33	RBC report (May 5, 2021 pg. 4028/5621)	"Upside to transmission grid growth and from decarbonization initiatives remain positive. While much of recent investor focus has (rightfully) been on returns, we are encouraged by the potential growth upside for Fortis' utilities over the medium-to-long term stemming from the energy transition and job-creating infrastructure spending in both the U.S. and Canada. Fortis noted that roughly US$400 billion of green infrastructure opportunities have been identified under the American Jobs Plan, including US$100 billion for electric grid resilience and US$174 billion for electric vehicles."

#	Reference	Excerpts
34	RBC report (April 15, 2021 pg. 4023/5621)	"Further, he added the FERC is in discussion with the National Association of Regulatory Utility Commissioners (NARUC) and the states to discuss the role of building out the grid to accommodate the transmission of clean energy in the future, and that an announcement on this matter is expected soon."
35	BMO report (April 15, 2021 pg. 2063/5621)	"We believe the market will be surprised by this action especially in the context of recent directional positive language from the FERC (and U.S. President Biden) on the importance of electric transmission infrastructure to support the planned U.S. renewable power construction build-out."
36	BMO report (March 24, 2021 pg. 2058/5621)	"President Biden's US $3T Infrastructure Plan that should accelerate transmission requirements at ITC and renewables at UNS ($4-6B total opportunity). Every $1B add to the capex program is ~50bps rate base CAGR uplift or at least cumulative ~5c EPS power over five years."
37	Scotia report (March 2, 2021 pg. 4582/5621)	"OUR TAKE: Neutral. We recently hosted members of Fortis' senior management team for investor meetings. We believe the meetings highlighted the numerous reasons we like the shares, including: 1) strong and visible growth outlook; 2) stable balance sheet and easy-to-execute funding plan; 3) favourable ESG profile; and 4) what we view to be an attractive valuation. (…) Management sees various growth levers in front of it that are related to the longer-term energy transition theme. Its ITC transmission business should benefit from increasing development of wind in its territories. We could see FERC become more positive on transmission, which could speed up permitting of projects. In Arizona, there is a longer-term opportunity to replace legacy thermal generation with lower-carbon sources. (…) Strong ESG profile. Management noted that Fortis has been evaluating ESG factors for years, even before it became vogue. The company scores well on social and governance factors and its environmental profile is improving. While Fortis has some minor coal generation and relatively high emissions to assets, this is an area that we expect will improve in the coming years. The company has a plan to retire its thermal generation (largely in Arizona) and replace it primarily with renewables. This should improve its environmental scores while also generating EPS growth. Our ESG research team views Fortis as having top-quartile ESG characteristics on a one-year and five-year basis"

#	Reference	Excerpts
38	Scotia report (March 2, 2021 pg. 4584/562)	"Energy transition a tailwind for Fortis. President Biden's policy / platform is geared toward accelerating the build-out of renewable generation in the U.S. to further electrify and de-carbonize the economy. As such, Fortis believes it will see an acceleration of clean energy investment across the country that could benefit its businesses in many ways. An example of this would be at ITC where Fortis expects to invest $0.7b over the next five years to interconnect 2,800 MW of new renewables to its transmission system (Exhibit 3). We believe the accelerating energy transition occurring in both Canada and the U.S. will be a tailwind for Fortis' businesses and provide solid long-term upside for the company's growth outlook. (…) Transmission environment looking better under Biden, which is a positive for ITC. There has been a lot of talk lately among regulators and incumbent utilities regarding interconnecting renewables and regions. The new FERC Chairman has spoken very favourably about the key role that transmission will play in the U.S. clean energy transition. Fortis sees the Commissioner's comments regarding the need for additional transmission as positive for the company's business, as the current conversations should translate into policies and a regulatory structure that incent transmission going forward. The existing transmission companies (including Fortis) are ready, willing and able to deploy capital for transmission investment and infrastructure development in order to support growing renewable generation. Fortis is in the process of trying to figure out how to capture incentives in order to accelerate renewables development, and will actively participate in the FERC process of designing and implementing new policies. In addition, the Biden administration's push for a lower emissions profile has a significant focus on the build-out of wind in the U.S. Integrating these new wind projects would require a significant amount of additional transmission infrastructure. Working to lower carbon footprint of its gas distribution utilities. Fortis has gas distribution assets in BC, Arizona and New York. Management believes that these assets have very long useful lives, even in a world that is decarbonizing. It noted that its gas distribution utility in BC delivers more units of energy than BC Hydro. It views BC as a supportive region given the large heating demand, abundant local gas supply and favourable jurisdiction. FortisBC is also pursuing various LNG opportunities (e.g., fueling ships, bunkering) which should reduce overall GHG emissions and provide growth for Fortis. The company is also looking at opportunities to clean up its own fuel source, including integrating renewable natural gas into its system, using net zero cycle GHG and using hydrogen within the supply system. FortisBC is targeting a 30% reduction in its customers' GHG emissions by 2030; it also has a goal to have 15% of its portfolio supplied by renewable natural gas by 2030. In Arizona the regulator is supportive of natural gas and there is a pre-emption law in place that prevents towns/municipalities from restricting permits for new buildings to use gas. All in all, Fortis believes that natural gas does and will continue to have a long-term position as a clean, affordable energy source in North America. In BC specifically, management highlighted that even in a case where demand for natural gas declines, it has its electric utilities in the region acting as a natural hedge."
39	Scotia report (March 2, 2021 pg. 4586/5621)	"ESG has always been at the core of Fortis' operations. Fortis reiterated its view that despite ESG's recent emergence as a top priority for certain investors, its utilities have always conducted business with Environmental, Social and Governance issues in mind. On the "E" side, management highlighted its 75% GHG reduction target by 2035 as an important and substantial commitment that it has made to reduce its carbon footprint. By 2035, Fortis' assets will be 99% Transmission & Distribution and renewable energy. (…) All in all, management highlighted that Fortis is a high-growth / low-risk story, and in order to maintain the low-risk component, it needs to be a leader with respect to ESG. For this reason, ESG will continue to be at the core of Fortis' business. (…) We believe Fortis shares should warrant a premium to Hydro One given the company's strong growth outlook, high-quality business mix and improving ESG profile."

#	Reference	Excerpts
40	Morningstar report (February 17, 2021 pg. 3394/5621)	"Fortis faces ESG risk, although we consider its risk lower than its peers' since only 5% of Fortis' assets are fossil fuel. Across its service territories, regulators and politicians are embracing tighter policies on carbon emissions and greater restrictions on coal generation. Fortis is addressing this risk through its base capital investment program, 1.1 GW of planned coal retirements, and the addition of 2.4 GW of renewable generation and 1.4 GW of battery storage. Fortis' goal to reduce carbon emissions by 75% by 2035 is in line with its utility peers. Regulators across its jurisdictions are supporting this transition."
41	BMO report (February 15, 2021 pg. 2047/5621)	"As earnings rise, carbon emissions are declining (75% by 2035) on coal retirements (currently 5% of assets) and investment in regulated renewables at more attractive returns than the non-regulated renewable sector. With a 20% potential total return to our unchanged $60 target, we are maintaining our Outperform rating."
43	RBC report (February 14, 2021 pg. 4010/5621)	"Our view: We continue to view electric utilities, such as Fortis, as being from trends such as electrification and decarbonization, as well as drawing greater interest from generalist investors looking at ways to play secular growth from these trends while being technology-agnostic (i.e., it does not matter which electric car company "wins" or which EV charging provider "wins"). (…) Continuing its hallmark theme of low-risk regulated and predictable growth, while improving its already positive ESG profile. Along with the relatively in line Q4/20 results and the reiteration of the company's capex budget and funding plan, Fortis' management team (now led by its new CEO, David Hutchens) continues to deliver a message of low-risk and energy transition-driven regulated utility growth, which we believe will continue to be attractive to long-term focused investors. For Key ESG questions, please see page 6 of this report. Executing the organic growth in the base plan while pursuing incremental opportunities. While Fortis remains focused on delivering its $19.6 billion capital plan, which underpins its 6.0-6.5% rate base CAGR, we continue to view the company's utilities as being well-positioned to secure opportunities related to the ongoing transition toward cleaner energy and more resilient energy systems."
43	RBC report (February 14, 2021 pg. 4012/5621)	"Keeping a lookout for incremental energy transition opportunities; potential for acceleration, particularly in the U.S., stemming from President Biden's climate strategy. We continue to see regulated utilities, such as Fortis, as giving investors a lower-risk way to invest in the energy transition theme without needing to pick a "winner", be that from the perspective of technology, brand or otherwise. Opportunities beyond Fortis' base plan that aim to deliver cleaner energy and grid resiliency include: (1) investments as part of Tucson Electric Power's (TEP) 2020 Integrated Resource Plan (IRP) to achieve sustainability objectives, with the opportunity set sized at roughly $4-6 billion; (2) additional transmission projects at ITC to facilitate significant renewable energy and battery storage in the MISO and SPP queues, as well as the Lake Erie Connector Project; and (3) the Tilbury Phase 2 LNG expansion at FortisBC, which not only could improve the resiliency of the gas system, but also construct new liquefaction capacity to produce LNG for marine fuelling and/or overseas export."

#	Reference	Excerpts
44	RBC report (February 14, 2021 pg. 4015/5621)	"1. What are the most material ESG issues facing this company? Although generating electricity is only a small part (roughly 7%) of Fortis' business (i.e., 93% of its assets are associated with the delivery of electricity and natural gas), Fortis' Scope 1 GHG emissions through these power plants is an area of investor focus in relation to ESG. Fortis has a corporate-wide carbon emissions reduction target of 75% by 2035 compared to 2019 levels, with Tucson Electric Power (TEP), where 90% of these emissions are concentrated, targeting an 80% reduction in carbon emissions by 2035. Based on this target, Fortis projects its asset mix by 2035 will be 92% energy delivery, 7% renewable generation and 1% of other assets (predominantly natural gas generation). 2. Does the company integrate ESG considerations into its strategy? Fortis notes that sustainability is "front and centre" in all that it does, with the President and CEO (David Hutchens) being responsible for the long-term success of Fortis and its sustainability strategy, and with the Executive Vice President, Sustainability and Chief Human Resource Officer (Nora Duke) responsible for enterprise-wide sustainability and stewardship. For 2019, sustainability performance for safety and reliability had a 20% weighting in deriving the corporate performance factor used to calculate the annual incentives for Fortis executives. These annual incentives made up around 20-30% of the executives' total direct compensation for the year. Meanwhile, the Board of Directors, particularly the governing and nominating committee, provides sustainability oversight including reviewing programs designed to promote corporate citizenship and environmental and social responsibility. (…) 4. Beyond Scope 1 GHG emissions, how is the company managing its Scope 2 and 3 GHG emissions? Fortis has a number of initiatives aimed at reducing its Scope 2 and 3 GHG emissions. These efforts include: (1) the FortisBC 30BY30 goal, which aims to reduce customers' GHG emissions by 30% by 2030; (2) facilitating increased renewable energy connections, particularly at ITC; and (3) being a founding member of the Alliance for Transportation Electrification, a group that promotes the benefits of transportation electrification by focusing on the deployment of EV infrastructure."
45	Scotia report (February 12, 2021 pg. 4558/5621)	"We believe Fortis shares should warrant a premium to Hydro One given the company's strong growth outlook, high-quality business mix and improving ESG profile. (…) Any policies from the new Biden administration related to sustainable infrastructure, lower emissions and/or EV adoption are likely positive for earnings and rate base growth longer term."
46	Scotia report (February 12, 2021 pg. 4571/5621)	"Key questions for the call. We will look for Fortis' view on the proposed Arizona legislation that would limit the regulator's authority in setting energy policy. The proposed legislation could kill its zero-emission mandate by 2050. While a power fight between the regulator and policymakers in Arizona is not positive, we do note that Fortis' de-carbonizing investment in the state is not by the regulator's mandate but rather economics."
47	RBC report (January 5, 2021 pg. 4001/5621)	"Specifically, decarbonization of electricity generation and overall electrification are trends that we expect to result in attractive long-term growth for regulated utility stocks."

(Emphasis added)

On page 50 of Appendix B, FBC states:

> Operational risk resulting from cyber-attacks has increased as bad actors and their tools become more sophisticated, and operations has increased their reliance on technological systems and controls. Loss of control of any of these systems or ability to manage critical work is an increasing operational risk.

35.3 Please explain whether FBC's system has been subject to cyber attacks since 2013. If so, please explain the frequency and degree of system disruption that have occurred by these attacks.

Response:

FBC's systems are protected by layers of cybersecurity defenses. These layers of cybersecurity block millions of unauthorized access attempts, which could be considered attacks, to FBC's systems every day.

There have not been any cyber-attacks on FBC's systems since 2013 resulting in material or reportable system disruptions. However, there have been cases since 2013 where individual or small groups of company laptops or PCs have been infected by malware and needed to be taken offline. This has impacted the affected worker's ability to access the systems required to perform their duties and is an indicator of the potential disruption cybersecurity events have.

35.3.1 Please explain whether FBC estimates the frequency and degree of system disruptions from cyber attacks that are expected in the next ten years. If so, please discuss. If not, why not?

Response:

It is difficult to predict whether the frequency of cyber-attacks will change over the next 10 years; however, the sophistication of the unauthorized access attempts, or attacks, is increasing. Hacking tools and social engineering are becoming more advanced and readily available to bad actors. FBC's approach to cybersecurity is designed to adapt to the evolving capabilities of bad actors, but as technology continues to be used more widely for critical systems and operations, the impact of a successful attack increases.

35.4 Please provide evidence or reference to increased cyber attacks in the Equity and Credit Rating reports.

Response:

Concentric provides the following response:

The increased risk of cyber-attacks is being disclosed to investors in the 10-K reports filed with the U.S. Securities and Exchange Commission and in the companies' annual reports. Credit rating agencies and equity analysts are also aware of cyber-attacks being an increased risk factor

for regulated utilities. The following are excerpts from a sample of 10-K filings by utilities disclosing this risk.

Fortis, Inc.'s 2020 Management Discussion and Analysis, at 33:

> As operators of critical energy infrastructure, the Corporation's utilities face the risk of cybercrime, which has increased in frequency, scope and potential impact in recent years. Their ability to operate effectively is dependent upon developing and maintaining complex information systems and infrastructure that: (i) support the operation of electric generation, transmission and distribution facilities, including gas facilities; (ii) provide customers with billing, consumption and load settlement information, where applicable; and (iii) support financial and general operations.
>
> Information and operations technology systems may be vulnerable to unauthorized access due to hacking, viruses, acts of war or terrorism, acts of vandalism and other causes. This can result in the disruption of energy service and other business operations, system failures and grid disturbances, property damage, corruption or unavailability of critical data, and the misappropriation and/or disclosure of sensitive, confidential and proprietary business, customer and employee information.
>
> A material breach could adversely affect the financial performance of the Corporation, its reputation and standing with customers, regulators and financial markets, and expose it to claims for third-party damage. The resultant financial impacts may not be fully covered by insurance policies or, in the case of utilities, through regulatory cost recovery, and could have a Material Adverse Effect.

Consolidated Edison, Inc.'s 2020 10-K, at 47:

> A Cyber Attack Could Adversely Affect The Companies. The Companies and other operators of critical energy infrastructure and energy market participants face a heightened risk of cyber attack and the Companies' businesses require the continued operation of information systems and network infrastructure. See Item 1 for a description of the businesses of the Utilities, the Clean Energy Businesses and Con Edison Transmission. Cyber attacks may include hacking, viruses, malware, denial of service attacks, ransomware or other security breaches, including loss of data. Cyber threats to the electric and gas systems are increasing in sophistication, magnitude and frequency. There has been a growing use of COVID-19 related themes by malicious cyber actors and the significant increase in employees working remotely has increased the attack surface area for the Companies as well as their contractors and vendors. Interconnectivity with customers through advanced metering infrastructure, independent system operators, energy traders and other energy market participants, suppliers, contractors and others also exposes the Companies' information systems and network infrastructure to an increased risk of cyber incidents, including attacks,

> and increases the risk that a cyber incident or attack on the Companies could affect others. In the event of a cyber incident or attack that the Companies were unable to defend against or mitigate, the Companies could have their operations and the operations of their customers and others disrupted. The Companies could also have their financial and other information systems and network infrastructure impaired, property damaged, and customer and employee information stolen; experience substantial loss of revenues, response costs and other financial loss; and be subject to increased regulation, litigation, penalties and damage to their reputation. In December 2020, it was announced that updates from SolarWinds, a network monitoring tool used by CECONY, O&R and the Clean Energy Businesses, was compromised and facilitated a cyberattack against multiple private and public sector entities. The Companies have experienced cyber incidents and attacks, including the recent SolarWinds attack, although none of the incidents or attacks had a material impact.

Avangrid, Inc.'s 2020 10-K, at 31:

> Cyber breaches, acts of war or terrorism or grid disturbances resulting from internal or external sources could target our facilities or our information technology systems. In the ordinary course of business, we maintain sensitive customer, employee, financial and system operating information and are required by various laws to safeguard this information. Cyber or physical security intrusions could potentially lead to disabling damage to our facilities or to theft and the release of critical operating information or confidential customer or employee information, which could adversely affect our operations and/or reputation, and could result in significant costs, fines and litigation.

National Grid PLC's 2020 annual report, at 228:

> Malicious attack, sabotage or other intentional acts, including breaches of our cyber security, may also damage our assets (which include critical national infrastructure) or otherwise significantly affect corporate activities and, as a consequence, have a material adverse impact on our reputation, business, results of operations and financial condition.
>
> Unauthorised access to, or deliberate breaches of, our IT systems may also lead to manipulation of our proprietary business data or customer information. Unauthorised access to private customer information may make us liable for a violation of data privacy regulations. Even where we establish business continuity controls and security against threats to our systems, these may not be sufficient.

FortisBC provides the following additional response:

FBC did not find any references to cybersecurity in the Credit Rating reports. With respect to the Equity Analyst reports, FBC is not a public equity issuer and therefore is not covered by equity analysts. References to cybersecurity provided below are from Fortis Inc. Equity Analyst reports.

FBC noted primarily in the Equity Analyst reports multiple instances of cybersecurity considered as a key business driver at the Fortis Inc. level. Although there is no mention of specific instances of cyberattacks at the Fortis Inc. subsidiary levels, likely for the reason of avoiding mention of exact vulnerabilities in individual systems, FBC did find cybersecurity to be a pervasive theme, consistently covered in analyst reports published between 2017 and 2021.

Cybersecurity consistently merited attention as a key investment area in Fortis Inc.'s capital plans to align the company's activities with major industry trends. One Fortis Inc. subsidiary, Central Hudson, signed a joint proposal with the New York Public Service Commission to agree to increased funding levels for IT and cybersecurity investments with an aim to improve Central Hudson's ability to secure its IT systems.

In the US utilities context, it was mentioned that although the Federal Energy Regulatory Commission (FERC) does not currently provide basis points incentives on cybersecurity initiatives, it will "address incentives for this aspect of reliability in a future proceeding." This further evidences the importance of this issue at an industry-wide level.

And finally, cybersecurity was a standalone section in a 2020 TD Equity Analyst report where TD discussed Fortis Inc.'s sustainability report where cybersecurity disclosures were included. Commentary from Fortis Inc. executives was quoted in the analyst report specifically that "more metrics in this area are likely to come in the future."

36.0 Reference: FBC BUSINESS RISK

Exhibit B1-8-1, Appendix B - FBC Business Risk Assessment, pp. 51-52 and 54; Appendix C - Evidence of Mr. Coyne, pp. 104 and139–-140; Appendix D-2, "FBC - Moody's - 2021 Credit Rating Report dated November 25, 2021", p. 4; Appendix D-7, "D-7.2 - FBC List of Significant Deferral Accounts"

Regulatory Risk

On page 51 of Appendix B, FBC states:

> FBC has assessed its overall regulatory risk as higher than what was assessed in the 2013 Proceeding, […]
>
> The BCUC, as a statutory entity, acts pursuant to its power under the UCA but, within that framework, has significant discretion in the exercise of those powers. Regulatory discretion in approving or denying a utility's applications is the main cause of regulatory uncertainty. Regulatory oversight gives rise to the risk that the allowed return does not accord with the Fair Return Standard, that rates are set at a level that does not provide FBC with an opportunity to earn its fair return on and of invested capital, or that necessary investments are not approved.

Page 4 of "FBC - Moody's - 2021 Credit Rating Report" states:

> Decisions from the regulator tend to be predictable, consistent and transparent with a consultative approach to regulation. The regulatory framework established by the BCUC has a long track record of enabling the company to generate stable cash flow and earn its allowed returns, supporting our view that regulation is consistent and predictable.

On page 104 of Appendix C, Mr. Coyne states:

> In summary, BC is the most favorable Canadian jurisdiction in terms of "investor friendliness" or to attract investment.

36.1 Given that Moody's considers that BCUC's regulatory framework has enabled FBC to earn its allowed returns and Mr. Coyne ranks BC as the most "investor friendly" jurisdiction, please explain why FBC assesses regulatory risk from BCUC's oversight higher than in 2013.

36.1.1 Based on these assessments, could FBC's regulatory risk be considered low? Please discuss.

Response:

FBC's risk assessment its evidence is comprised of two separate analyses:

i. Consistent with past practice, a key reference point for assessing business risk is the previous BCUC assessment of FBC's business risk in the context of determining cost of capital (2013 Stage 2 GCOC Proceeding). FBC's business risk evidence (Appendix B) provides a detailed assessment of its risk from this perspective.

ii. A second way in which business risk comes into play in the determination of a Fair Return is through a comparison with other utilities. Concentric's evidence (Appendix C) compares FEI's and FBC's business and financial risk with their respective Canadian and U.S. proxy groups.

The regulatory ranking provided in Appendix C provides a relative comparison of regulatory risk in BC and other jurisdictions, with a focus on the utility regulator (as opposed to other forms of regulation applicable to utilities). From this perspective, FBC's regulatory risk is somewhat lower than most other jurisdictions. However, a comparison of FBC's regulatory environment today with what was assessed in 2013 points to higher regulatory risk. As explained in Section 10.1 of Appendix B, compared to 2013, there is an increased level of regulatory uncertainty driven by the BCUC's decision to review the financing of deferral accounts, and increased potential for regulatory uncertainty and lag around project approvals and increased requirements for environmental reviews, and consultation and engagement that extend to non-BCUC processes as well.

Further, as discussed in the 2016 GCOC decision (excerpts provided below), the ability to earn the allowed return in the past does not indicate a reduced risk:

> In the 2013 GCOC Decision, the Commission addressed the relevance of the disparity between allowed and actual ROE stating "the differences in actual and allowed ROE relate to revenue requirements and are influenced by management's ability first to forecast and then to control cost for each test period." The Commission also observed that the relevance of a disparity between allowed and actual ROE is a matter that is "entrenched in the regulatory compact, revenue requirements proceedings, and management's proactive approach.
>
> AMPC/BCOAPO take issue with FEI's position that in a given test year, the ability of a company to earn its ROE is short-term risk. Their collective concern seems to be with the fact that historically, FEI has managed to make and exceed its allowed ROE on a relatively consistent basis and at some point, the risk must be considered very limited or in Dr. Booth's words: "FEI's shareholders have not suffered any losses or experienced any risk."
>
> AMPC/BCOAPO's position is for a risk to remain a risk, it must at some point occur. The Panel is not persuaded that this interpretation of risk is reasonable or reflective of the prospective nature of risk. In the Panel's view, a risk does not disappear because it has not occurred over a period of time and non-occurrence of a risk in the past does not necessarily alter the probability of occurrence in the future.

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

The Panel accepts FEI's argument that risk is prospective. In the Panel's view, the risk of earning ROE does not disappear in any given test year because of a utility's success in achieving it in prior years. However, this does not mean that an investor does not consider historical performance when choosing to make an investment but in doing so must accept that there is no certainty that past performance will be repeated in the future. Given this, we agree with the parties and consider the attainment of ROE to be a short-term risk and if FEI fails to earn its approved ROE in a given test period, it has the capability to initiate actions to resolve the matter in a short time span.

On page 52 of Appendix B, FBC states:

> There has been no fundamental change in FBC's regulatory framework under the UCA since the 2013 Proceeding. However, the BCUC's decision to review the financing of deferral accounts as part of this Proceeding has introduced additional risk

On page 54 of Appendix B, FBC states:

> The decision to revisit deferral account financing costs itself creates uncertainty for FBC and investors. […] a more generic approach to deferral account financing can lead to approval of unfair and inappropriate financing treatment if a utility's specific circumstances are not fully recognized.

In "D-7.2 - FBC List of Significant Deferral Accounts" in Appendix D-7, FBC provides a list of its deferral accounts which has been reproduced in part below:

FBC Deferrals with Significant Activity	2012	2021
Margin Related		
Power Purchase Expense Variance [1]	X	
Revenue Variance [1]	X	
2012 Over Collection	X	
Energy Policy		
Demand Side Management (DSM)	X	X

36.2 Given that deferral account financing costs are typically a short-term debt rate or weighted average cost of capital (WACC), please explain how a more generic approach will affect the risk profile of FBC.

Response:

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. Please also refer to the response to BCUC IR1 22.2.

Ultimately, the implications for FBC (and other utilities) would depend on the outcome of the generic approach, and the mix of accounts assigned a WACC return vs. a debt-only return, but assigning a generic return to deferral accounts may also have unintended consequences. For example, BCUC Order G-110-12 relating to FBC's 2012-2013 RRA took a generic approach to deferral account financing, requiring FBC to finance deferral accounts with a debt-only return, resulting in these accounts needing to be held outside of rate base. One such account that was impacted by this decision was the Other Post Employment Benefits (OPEB) Liability account.

In its October 15, 2014 submission to the BCUC, FBC noted that assigning a debt only return to the OPEB account was incorrect:

> The amounts recorded in the OPEB deferred liability account are not deferred for rate smoothing purposes. They are accounting liabilities that exist due to the accrual of OPEB expenses for current employees that will not be paid out for many years. As long as FBC continues to hire employees, the liability is expected to grow and not reverse – these amounts are not current in nature.
>
> …
>
> There is no amortization of the OPEB deferred liability account, such that the interest will continue to compound. By requiring that a debt return be added into the balance in the account, the liability will continue to increase at an even greater rate than had it been held in rate base, as is the normal practice for these liabilities.

FBC then re-iterated and expanded on some of these arguments in its Annual Review for 2015 Rates, where the BCUC accepted FBC's position in Order G-107-15:

The Panel agrees with the submissions of FBC and is prepared to reconsider the Commission's previous decision regarding the Pension/OPEB Funding Liability account. This proceeding is an appropriate forum for the reconsideration, as the amounts at issue are material and the parties have had an opportunity to examine the issue and make recommendations and submissions.

Upon review, the Panel considers it appropriate that the Pension/OPEB Funding Liability account be returned to rate base. The Commission's clarification letter stated that financing costs are to be added to deferral accounts that are amortized. There is no amortization of this account. Therefore, while it is appropriate that the account attracts financing costs, these financing costs should not be accrued in the account, as this could potentially result in these costs being stranded. Adding the account to rate base allows the financing costs to be recovered from, or returned to, customers through their inclusion in the earned return component of FBC's revenue requirement, while leaving the account balance whole. This treatment is consistent with FBC's practice prior to the 2012 revenue requirements decision and also with the treatment by FortisBC Energy Inc. (FEI) of its analogous account.

The above example highlights how a generic approach to deferral financing may not work in all instances, and how a utility's individual circumstances, and the particulars of the deferral account itself, need to be considered during the approval of each individual deferral account.

36.3 Please explain what the years in row 2 of "D-7.2-FBC List of Significant Deferral Accounts" in Appendix D-7 represent.

Response:

The years in Row 2 of "D-7.2 – FBC List of Significant Deferral Accounts" in Appendix D represent the years for which FBC provided evidence on its deferral accounts in Cost of Capital filings; for comparison of current deferral accounts to that year.

36.4 Please provide any commentary from independent agencies, since the issuance of Order G-205-21 dated July 7, 2021, that they are concerned that the BCUC's review of deferral account financing costs would create uncertainty for FBC.

Response:

Please refer to the response to BCUC IR1 22.2.

On page 54 of Appendix B, FBC states:

> Regulatory lag, which can be associated with BCUC or other regulatory processes, can present a risk for FBC's return on and of capital.
>
> […] Risk arises in part because it can be necessary for the utility to conduct its operations based on interim rates, with no assurance that the interim rate will be confirmed in the final decision, or the risk that the costs incurred and projects contemplated and required to be undertaken will ultimately be approved. In the case of capital approvals, delays or non-approval can create obstacles for FBC completing projects on time and on budget

On page 139 and 140 of Appendix C, Mr. Coyne states with the following table:

> FBC has slightly more protection through regulatory mechanisms than the U.S. Electric proxy group companies, especially in terms of reducing regulatory lag through a fully forecast test year…

Figure 60: Regulatory Risk Assessment - Electric[214]

	U.S. Electric Proxy Group (% of operating companies in proxy group)	FortisBC, Inc.
Test Year	Fully Forecast – 35% Partially Forecast – 17% Historic – 48%	Fully Forecast

36.5 Please discuss how regulatory risk would change if FBC's test years were based on a partial forecast or historic information.

Response:

Historical and partially forecast test years involve higher regulatory risk. However, a common practice in most jurisdictions with historical test years is to adjust the test year for "known and measurable (i.e., forecast)" changes which will reduce the associated regulatory risk. The more cost items that are subject to "known and measurable" changes, the less incremental risk there would be from using historical or partially forecast test years. If FBC's test year were to be changed to historical and/or partially forecast test years, all else equal, the regulatory risk would increase. The magnitude of this increase would then depend on the extent of adjustment for known and measurable changes that the regulator would allow.

D. EVIDENCE OF MR. COYNE – METHODOLOGY

37.0 Reference: Proxy Groups

Exhibit B1-8-1, Appendix C - Evidence of Mr. Coyne, pp. 39–44, "Exhibit JMC-FEI-3", pp. 1–3, "Exhibit JMC-FBC-3", pp. 1–3, Exhibit JMC-FEI-10, Exhibit JMC-FBC-10; Exhibit A2-13, 2020 Brattle Group Report, p. 78

Proxy Groups

On pages 39 to 44 of Appendix C in Exhibit B1-8-1, Mr. Coyne describes the screening criterion for each proxy group and the resulting proxy groups. "Exhibit JMC-FEI-3" and "Exhibit JMC-FBC-3" of Exhibit B1-8-1 show general characteristics of each of the proxy companies, as shown below with the Canadian proxy group:

CANADIAN PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	S&P Rating	Pays Dividends (Yes/No)	Positive Earnings Growth by more than one Analyst (Yes/No)	Market Cap (C$ Million)	Total Electric Customers	Total Revenue (C$ Million)	Total Assets (C$ Million)	Regulated Income / Total Income (%)	Regulated Electric Income / Total Regulated Income (%)	Involved in Merger (Yes/No)
Algonquin Power and Utilities	AQN	BBB	Yes	Yes	12,276	306,000	2,249	16,850	86%	N/A	Yes
AltaGas Inc.	ALA	BBB-	Yes	Yes	7,651	NA	5,587	21,532	140%	N/A	No
Canadian Utilities Limited	CU	A-	Yes	Yes	9,878	260,552	3,233	20,296	64%	N/A	No
Emera Inc.	EMA	BBB	Yes	Yes	16,432	1,641,000	5,506	31,234	92%	N/A	No
Enbridge Inc.	ENB	BBB+	Yes	Yes	100,103	NA	39,087	160,276	16%	N/A	No
Hydro One, Ltd.	H	A-	Yes	Yes	19,687	1,400,000	7,290	30,294	100%	N/A	No

"Exhibit JMC-FEI-10" and "Exhibit JMC-FBC-10" of Exhibit B1-8-1 show the credit metric analysis of each of the proxy companies, as shown below with the Canadian proxy group:

Canadian Proxy Group							
AltaGas Utilities Inc	ALA	BBB-	56.3%	3.44	3.53	8.9%	7.90
Canadian Utilities Ltd.	CU	A-	61.1%	3.52	3.63	11.8%	6.05
Emera	EMA	BBB	61.8%	3.16	3.54	10.8%	7.10
Enbridge Inc.	ENB	BBB+	51.7%	4.31	4.57	14.5%	5.19
Algonquin Power and Utilities Corp.	AQN	BBB	42.6%	4.94	4.73	14.3%	5.46
Hydro One Inc.	H	A-	60.6%	4.46	4.59	11.3%	6.85
Canadian Proxy Group		BBB+	55.7%	3.97	4.10	11.9%	6.43

37.1 Please summarize the relative risk (higher, similar, lower) of FEI and FBC compared to each proxy company against which the utility is being measured and provide rationale to support the assessment. Please provide the response in a format similar to the following:

Table for FEI:

Proxy Company	**Relative risk to FEI**
One row for <u>each</u> company from the Canadian Proxy group	Higher/lower/similar risk to FEI (include brief rationale for the assessment)

One row for each company from the US Gas Proxy group	Higher/lower/similar risk to FEI (include brief rationale for the assessment)

Table for FBC:

Proxy Company	**Relative risk to FBC**
One row for each company from the Canadian Proxy group	Higher/lower/similar risk to FBC (include brief rationale for the assessment)
One row for each company from the US Electric Proxy group	Higher/lower/similar risk to FBC (include brief rationale for the assessment)

Response:

Concentric provides the following response:

Mr. Coyne's risk analysis is conducted at several levels, based on the availability of appropriate data. The first phase of the risk analysis is in the proxy group selection. He developed five proxy groups for the ROE analysis. The first proxy group is comprised of publicly traded, regulated Canadian electric and natural gas utility companies. Recognizing there are few publicly traded companies in the utility sector in Canada, the only screening criterion was an investment grade credit rating, which all companies in the sector have. The second proxy group is comprised of like-risk U.S. natural gas distribution companies. To obtain companies of like-risk, he performed a number of screens to determine a group of essentially pure-play gas utilities with similar risk profiles to FEI. The third proxy group is comprised of the three Canadian regulated utilities that have significant natural gas operations (i.e., AltaGas Utilities, Inc., Canadian Utilities Ltd., and Enbridge, Inc.) plus the four U.S. gas distribution companies. This group is referred to as the North American Gas proxy group. The fourth proxy group is comprised of like-risk U.S. electric utility companies. To obtain companies of like-risk, he performed a number of screens to determine a group of essentially pure-play electric utilities with similar risk profiles to FBC. The fifth proxy group is comprised of the four Canadian regulated utilities that are primarily electric companies (i.e. Algonquin Power, Canadian Utilities, Emera, and Hydro One) plus the ten U.S. Electric utility companies. This group is referred to as the North American Electric proxy group.

Proxy Groups are normally used as a surrogate for risk to estimate the cost of equity for the subject company. The data for each company is generally available and compiled at the holding company level which aggregate numerous operating companies in total. The specific risk comparisons, as requested in the question, would require assessment at the operating company level for all companies, which Mr. Coyne did not conduct. Mr. Coyne did provide an evaluation of regulatory risk of the operating companies and made these comparisons as summarized on pages 115 (FEI) and 140 (FBC) of his Report. He also made specific comparisons to the Canadian proxy group gas and electric utilities on pages 112 (FEI) and 138 (FBC).

37.2 Given that the North American gas (or electric) utilities proxy groups have overlap with the Canadian regulated utilities and the US gas (or electric) utilities proxy groups, please confirm if the North American gas (or electric) utilities proxy group is used in any aspect of the ROE calculations.

37.2.1 If yes, please clarify if this means that the companies, which appear in two proxy groups effectively have double the weight compared to the companies that appear only in one proxy group.

Response:

Concentric provides the following response:

Mr. Coyne presents ROE results for five proxy groups: Canadian, U.S. Gas, North American Gas, U.S. Electric, and North American Electric. As stated in Mr. Coyne's report, his ROE recommendations for FEI and FBC are based primarily on the results for the U.S Gas and U.S. Electric proxy groups because they he considers them most comparable to FEI and FBC in terms of business and financial risk. There is therefore no effect of double weighting companies in both the North American and U.S. proxy groups. Please also refer to the response to BCUC IR1 44.2.1.

On page 40 of Appendix C, Mr. Coyne lists the screening criteria for the US natural gas proxy companies. There is no criteria listed regarding the liquidity of the proxy company.

Page 78 of the 2020 Brattle Group report states:

> The ACM [regulator for energy networks and other infrastructure in the Netherlands] methodology requires that the stocks of the peers are sufficiently liquid to obtain a reliable beta estimate. Historically, the ACM required that the shares of the candidate peers were traded on at least 90% of the days over the reference period ("the number of trading days test") and that the company had annual revenues of at least € 100 million ("the annual revenue requirement"). More recently, in response to a court ruling related to the liquidity of one of the peers, the ACM abandoned these two criteria, and determined to apply a bid-ask spread threshold of 1% as its primary liquidity criterion.

37.3 Please discuss Mr. Coyne's views regarding including a liquidity criterion for selecting proxy companies.

Response:

Concentric provides the following response:

Mr. Coyne does not believe a liquidity criterion is necessary for selecting proxy companies. Attachment 37.3 shows the average daily volume in shares for each of the ten companies in the Value Line Gas universe over the most recent five quarters. Chesapeake Utilities is the only company in the Value Line Gas universe with average daily volume less than 100,000 shares, but this company was not included in Mr. Coyne's proxy group. The other nine companies have average daily volumes ranging from approximately 200,000 shares to almost 1.4 million shares. Further, each company's shares traded on every trading day from January 1, 2021 through March 9, 2022. As this analysis demonstrates, these U.S. companies are actively traded on the stock exchanges each day, and liquidity is not a concern for investors. A spot check of the electric companies in Mr. Coyne's electric proxy group, with trading data reported on March 14, 2022 on *Yahoo! Finance,* shows a similarly high level of liquidity. OGE, one of the smaller companies, had an average volume of 1,264,671 shares with a 2 basis point bid-ask spread; Portland General, another smaller company, had an average volume of 516,631 shares with a 3 basis point bid-ask spread. A larger company, such as NextEra Energy, had an average volume of 10,664,481 shares with a 0 basis point bid-ask spread.

37.3.1 If a bid-ask spread threshold of one percent were adopted as a primary liquidity criterion, please describe if this would eliminate any of the proxy companies.

Response:

Concentric provides the following response:

Please refer to the response to BCUC IR1 37.3, Mr. Coyne does not see any cause for concern with the liquidity of the companies in his U.S. Gas or Electric proxy groups, as measured by trading volume or representative bid-ask spreads. Further, the bid-ask spread changes continuously throughout the day, so it is not clear when this spread would be measured or what value it would have in selecting comparable companies.

38.0 Reference: CAPM

Exhibit B1-8-1, Appendix C - Evidence of Mr. Coyne, pp. 56–57; Exhibit A2-3, Continental Economics Inc.- Evidence of Dr. Lesser, pp. 45–48; Exhibit A2-15, Ofgem, RIIO-ED2 Sector Specific Methodology Decision: Annex 3 Finance, p. 21; Exhibit A2-13, 2020 Brattle Group Report, p. 121

Risk Free Rate of Return

On page 56 of Appendix C, Mr. Coyne states:

> Current bond yields remain near historical lows; consequently, adjustments are necessary to better reflect forward-looking circumstances. Use of forecast bond yields, as opposed to the current risk-free rate, reflects the current market reality that while bond yields remain near all time lows, investors are factoring higher interest rates into their longer-term expectations and required returns. My CAPM analysis relies on the 2022 through 2024 average Consensus Economics forecast of the Canadian 10-year government bond … plus the average spread between 10- year and 30-year government debt.

On page 45 of the Continental Economics Inc. report, Dr. Lesser states:

> One implementation issue that arises is whether to use the current yield on such bonds or a forecast of bond yields. Some regulators use current bond yields while others use forecasts of future bond yields […]
>
> The [Efficient Market Hypothesis] EMH explains why it is not appropriate to use a forecast of future government bond yields when applying the CAPM. Under the EMH, today's yield on long-term government bonds reflects investors' collective expectations about interest rates. Using a forecast of future yields on such bonds thus amounts to "double-counting" future expectations.

38.1 Under what circumstances does Mr. Coyne view that the use of forecast bond yields would no longer be appropriate? Would it depend on a certain threshold of the current bond yields, or a threshold of the difference between current and future bond yields?

Response:

Concentric provides the following response:

In Mr. Coyne's view, when current bond yields and projected bond yields are similar, there would be no need to use projected bond yields because current bond yields would be the same as future interest rate expectations. As we have seen recently, current average bond yields can change rapidly in response to economic data and investors' expectations of changes in monetary policy or inflation. In recent years, current interest rates have been heavily influenced by central bank

policy, and not just investors. As the economy recovers in both Canada and the U.S., and as central banks in both countries respond to inflationary pressure by moving toward a more neutral stance, average government bond yields increased rapidly between December 2021 and February 2022. This is an example of how current bond yields can change quickly. Since the Commission is setting the ROE for FEI and FBC for a future time period, it is best to use the interest rates that investors expect during that period, which aren't the same as current average interest rates.

38.2 Under what circumstances does Mr. Coyne view that the adjustment for the average spread between the 10-year and 30-year bond yield would no longer be appropriate?

Response:

Concentric provides the following response:

If the average spread were to significantly diverge from historic ranges, it would be cause for concern suggesting the calculated spread may not be appropriate. Absent forecast details for both 10 and 30 year bond yields, it is otherwise necessary to compute the average spread. Consensus Forecasts only provides projected interest rates on 10-year bonds. Mr. Coyne therefore adds the average spread to the 10-year forecast bond yield in order to derive the projected 30-year bond yield that is used in the CAPM analysis.

38.2.1 If, for example, this spread was negative due to an inverted bond yield, would Mr. Coyne view that it is appropriate to adjust the risk-free rate downward?

Response:

Concentric provides the following response:

If the spread happened to be negative, that would indicate that investors are expecting a recession, in which case Mr. Coyne assumes that central banks would intervene by making monetary policy more accommodative. Negative spreads between 10-year and 30-year bonds do not continue for long periods of time, and investors would likely not base their cost of equity requirements on the assumption that yields on 30 year bonds would be lower than yields on 10 year bonds over the long term. In such a circumstance, Mr. Coyne might look to a normalized spread calculated over longer than a one month period, perhaps 6 months or a year.

38.2.2 Please explain why Mr. Coyne does not simply use the 30-year bond yield, rather than the current approach of a 10-year bond yield adjusted for the spread between 10-year and 30-year.

Response:

Concentric provides the following response:

Consensus Economics does not provide a forecast of the 30-year bond yield, only for the 10 year bond yield. In the U.S, Blue Chip Financial Forecasts provides a 30-year government bond yield forecast, but does not provide economic projections for Canada. The use of a recent spread has been common regulatory practice in Canada (for example, the OEB's ROE formula relies on a Consensus forecast of 10 year government bond yield plus one month prior spreads between the 10 and 30 year government bond yield and the 10 year government bond yield and A-rate utility bonds).

38.2.2.1 Does the Consensus Economics report used by Mr. Coyne for the forecast 10-year government bond forecast yield also include a forecast for the 30-year government bond yield? If so, please provide the value.

Response:

Concentric provides the following response:

No, Consensus Economics does not provide a forecast of the 30-year government bond yield.

38.2.2.2 If available, please provide a copy of the Consensus Economics report associated with Mr. Coyne's CAPM analysis as noted on page 56 of his evidence in Appendix C.

Response:

Concentric provides the following response:

Please refer to Attachment 38.2.2.2.

38.3 What are Mr. Coyne's views on Dr. Lesser's assertion that "under the efficient market hypothesis, today's yield on long-term government bonds reflects investors' collective expectations about interest rates."?

Response:

Concentric provides the following response:

The Efficient Market Hypothesis ("EMH") does not take into consideration the current situation where long-term interest rates are being driven primarily by central bank policy rather than by investors' decisions. Under market conditions where current and projected interest rates are relatively similar, Mr. Coyne would agree that the use of current average bond yields is reasonable. However, that is not the case in the current market. Take for example the 30-year government bond yield. The U.S. 30-year yield was 1.175% on 4/26/20. It is trading today (3/14/22) at 2.462%, more than doubling over these two years. It was clear two years ago that market circumstances were extraordinary, as were central bank actions, and a current yield would not reflect forward market expectations. Therefore, Mr. Coyne believes that the use of projected interest rates best reflects investors' expectations and meets the requirement that an allowed rate of return be forward-looking.

38.4 Please provide evidence to show that there are jurisdictions in Canada that use a forecast yield (rather than current) and adjust for the spread between 10-year and 30-year bond.

Response:

Concentric provides the following response:

The Ontario Energy Board uses a forecast of government bond yields (1 quarter out and 4 quarters out) and the most recent month's spreads between government 10 and 30-year bonds and the 10-year government bond and A-rated utility bonds in updating its cost of capital parameters each year (see, for example: https://www.oeb.ca/sites/default/files/Appendix-1-2022-Cost-of-Capital-Parameter-Calculations-20211028-AODA.pdf).

The Newfoundland and Labrador Board of Public Utilities uses the projected yield on long Canada bonds as the risk-free rate in the CAPM. The Newfoundland Board's June 2016 decision (Order No. P.U. 18(2016) at pages 37-38) explains as follows:

> As stated in Order No. P.U. 13(2013) it is Canadian regulatory practice, and the practice of this Board, to use the forecast yield for the long-term Canada bond yield as the risk free rate in equity risk premium models, including CAPM. However, both Mr. Coyne and Dr. Booth agreed that capital market conditions continue to be abnormal. Mr. Coyne believes that the one-year forecast long-term Canada bond yield is too low and instead used the three-year forecast of 3.58%. Dr. Booth used a one-year forecast but explained that if he used a two-year forecast as he did during the last hearing the risk free rate would be 20 basis points higher, or 3.01%. The Board continues to believe that the risk free rate should be based on the long-term Canada bond yield. However, the Board believes that the one-year forecast of the long-term Canada bond yield may not appropriately reflect the risk free rate in the circumstances. Therefore the Board will accept a risk free rate of 3.0%, based on Dr. Booth's evidence of the forecast long-term Canada bond yields for 2016 and 2017, the two test years.

The BCUC has previously found that adjustments to current risk-free rates may be warranted. In 2016, the BCUC concluded:

> Although the expert witnesses differ in their approach, they both agree on the need for an adjustment in the CAPM to compensate for abnormal conditions in the bond markets resulting from the impact of global bond buying programs. While the expert witnesses differ in their approach and given there is no precise answer, the Panel takes comfort in the fact they end up with similar estimates. Accordingly, the Panel, using its best judgment, finds a risk-free rate plus an adjustment for abnormal conditions in the range of 3.8 to 4 percent is reasonable for use in the CAPM. (2016 Decision, G-129-16, pp. 59-60.)

On page 21 of its decision published on March 11, 2021, with respect to the risk-free rate, the Ofgem states:

> The bonds will have a higher yield due to their relative lack of liquidity. In addition, the index gives a nominal yield which must then be converted into a real yield. To correctly infer a Risk-Free Rate, we would need to estimate an inflation risk premium which is embedded in the yield of nominal bonds.

On page 121 of the 2020 Brattle Group Report, Table 17 shows a summary of Ofgem Authorised Return, which includes a -0.75% risk-free rate.

38.5 Using a similar methodology as Ofgem to consider the risk-free rate in real terms, please restate Mr. Coyne's calculated risk-free rate for his Capital Asset Pricing Model (CAPM) analysis.

Response:

Concentric provides the following response:

Using the projected interest rates from Consensus Economics in Mr. Coyne's CAPM analysis of 2.27% in Canada and 2.53% in the U.S., and subtracting the projected inflation rates from Consensus Economics of 2.0% in Canada and 2.3% in the U.S., the real risk free rates would be 0.27% in Canada and 0.23% in the U.S

Please also refer to the responses to BCUC IR1 21.3 and 21.4 where FortisBC explains the differences between Ofgem's and North American regulatory approach to cost of capital determination.

38.5.1 Please discuss whether it would be appropriate to adopt Ofgem's risk-free rate methodology in determining the fair rate of return for utilities in BC.

Response:

Concentric provides the following response:

No, it would not. In Mr. Coyne's view, it would complicate the model inputs and interpretation of the model results (which are all expressed in nominal dollars) and if done consistently should not produce a different result.

38.6 In Mr. Coyne's view, would it be appropriate to use the CAPM if the risk-free rate becomes negative? If so, why, and please explain how a negative risk-free rate should be interpreted in the CAPM? If not, please explain why not?

Response:

Concentric provides the following response:

Mr. Coyne would have some concerns with using the CAPM model if the risk-free rate was negative, and he would look for corroboration from the other ROE models to test the

reasonableness of the results. This circumstance would indicate an extraordinary financial market environment. Indicating how unusual, the Bank of England tracks its official interest rates back over the past 300 years, and it has always been positive. Nonetheless, the CAPM model's assumptions are not violated by a negative interest rate, so Mr. Coyne would still consider its results. In terms of interpreting the results, the existence of a negative interest rate most likely indicates a deflationary environment where central banks have taken extraordinary measures to promote spending and inflation, so he would consider this circumstance temporary.

39.0 Reference: CAPM

Exhibit B1-8-1, Appendix C - Evidence of Mr. Coyne, pp. 60–61, "Exhibit JMC-FEI-5", p. 1; Exhibit A2-3, Continental Economics Inc., Evidence of Dr. Lesser, pp. 49–52;

Forward-Looking Market Risk Premium (MRP)

On pages 60 and 61 of Appendix C, Mr. Coyne states:

> The FERC relies exclusively on a forward-looking market risk premium in the CAPM analysis and does not even consider a historical MRP. My approach to calculating the forward-looking MRP is consistent with FERC's methodology of using the Constant Growth DCF model to estimate the total return for the broad market and then subtracting the risk-free rate.

Figure 29: Market Risk Premia – Canada and U.S.

	Canadian MRP	U.S. MRP
Historical	5.54%	7.25%
Forward-Looking	9.10%	12.08%
Average	8.49%	

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

> FERC, for example, currently requires the use of a one-stage DCF model applied to the dividend paying firms of the S&P 500. FERC also excludes dividend-paying firms with negative earnings growth rate forecasts and forecasts greater than 20%. [emphasis added]

> … FERC has justified the use of a one-stage DCF model applied to the dividend-paying firms of the S&P 500 to estimate the market return and MRP because: (i) the S&P is updated regularly to remove slow-growing firms; and (ii) that even though an individual company cannot sustain high growth rates forever, a broad market index can do so.

> FERC's rationale is based on a misconception. Using the expected returns for the S&P 500 or the TSX represent a proxy for the entire market. Although the composition of the S&P 500 and S&P/TSX change over time as firms are added and dropped, that conclusion cannot apply to the market as a whole. In other words, a firm does not vanish from the "market" simply because it is no longer included in a broad market index... In the long run, the market cannot grow faster than the economy as a whole for the simple reason that the market, in effect, is the economy.

On page 45 of the Continental Economics Inc. report, Dr. Lesser also states:

> The [Efficient Market Hypothesis] EMH explains why it is not appropriate to use a forecast of future government bond yields when applying the CAPM. Under the EMH, today's yield on long-term government bonds reflects investors' collective expectations about interest rates. Using a forecast of future yields on such bonds thus amounts to "double-counting" future expectations.

39.1 Please confirm, or explain otherwise, that Mr. Coyne is aware that Federal Energy Regulatory Commission (FERC) excludes dividend-paying firms with negative earnings growth rate forecasts and forecasts greater than 20 percent in using the one-stage Discounted Cash Flow (DCF) model to determine a forward looking MRP.

Response:

Concentric provides the following response:

Yes, Mr. Coyne is aware that FERC excludes non-dividend paying firms and those with growth rates in excess of 20% or less than 0% in the calculation of the forward-looking MRP. However, Mr. Coyne does not agree with this approach because Beta in the CAPM is calculated using all companies in either the S&P 500 or the TSX index. If companies are excluded from the market return calculation but included in the Beta calculation, this creates a mismatch. Also, investors in the S&P 500 index are buying all the companies in the index, not just those that pay dividends and those that have growth rates < 20% and > 0%. In addition, several companies that traditionally paid dividends (e.g., Boeing, Disney, Marriott, Hilton, etc.) omitted them during the COVID period. The total return should not exclude companies such as Amazon, Google, Tesla, Netflix just because they do not pay dividends. Such companies contribute substantially to GDP growth and represent a significant portion of the market capitalization of the index.

Further, because Mr. Coyne averages the forward-looking MRP with the historical, he is using a more conservative (lower) MRP than that which would be produced by FERC's method.

39.1.1 If the forward-looking MRP provided by Mr. Coyne were to be adjusted to exclude dividend-paying firms with negative earnings growth rate forecasts and forecasts greater than 20 percent, please provide the resulting impact on the MRP values and impact on the final ROE.

Response:

Concentric provides the following response:

Please refer to the response to Attachment 39.1.1. The MRP values in Canada and the U.S. would be 7.61 percent and 9.62 percent, respectively. Taking the average produces a North

American MRP of 8.61 percent, which is higher than the 8.49 percent used in Mr. Coyne's analysis. Using the average of the forward-looking and historical MRP as Mr. Coyne did in the CAPM analysis in his report, the average CAPM estimates for the Canadian proxy group, US Gas proxy group, and North American Gas Proxy groups are 9.79 percent, 9.82 percent, and 10.14 percent, respectively.

39.2 Mr. Coyne stated that "FERC relies exclusively on a forward-looking market risk premium in the CAPM analysis". Please confirm that that the growth rates used in FERC's analysis are from S&P 500.

Response:

Concentric provides the following response:

FERC's forward-looking market risk premium is based on the total market return using projected EPS growth rates for the S&P 500 from I/B/E/S.

39.3 Please confirm, or explain otherwise, that utilities are generally lower risk than the broad market and have slower growth than the broad market.

39.3.1 If confirmed, then please explain why Mr. Coyne recommends that S&P 500 index is used in the constant growth MRP calculation, recognizing that S&P 500 removes slow growing firms.

39.3.1.1 If the S&P 500 index continues to be used in a constant growth model to compute the MRP, please describe if there is a need to adjust the MRP downwards to account for the difference in nature between utilities and the broad market.

39.3.2 If not confirmed, then please describe the general risk profile and growth profile of utilities compared to the broad market.

Response:

Concentric provides the following response:

Confirmed. Mr. Coyne agrees that regulated utilities are generally lower risk than the broad market and have slower EPS growth rates than the broad market, especially if limitations are not placed on the EPS growth rates for the broad market.

With regard to why it is appropriate to use constant growth DCF analysis of the companies in the S&P 500 Index, the purpose of this analysis is to derive an estimate of the expected **market** return, which is an input to the CAPM model. From this estimate of the market return, the beta for utilities adjusts the market return to the **utility** return. Beta distinguishes the market from the utility return. This approach is consistent with the method used by FERC to calculate the total market return for purposes of computing a forward-looking market risk premium for use in the CAPM analysis. In Opinion No. 531-B, FERC responded to intervenor arguments against this approach as follows:

> The required return on the overall market is determined by conducting a DCF study of "a representative market index, such as the Standard & Poor's 500 Index." [Para 113]

> The rationale for incorporating a long-term growth rate estimate in conducting a two-step DCF analysis of a specific group of utilities does not necessarily apply when conducting a DCF study of the companies in the S&P 500. That is because the S&P 500 is regularly updated to include only companies with high market capitalization. While an individual company cannot be expected to sustain high short-term growth rates in perpetuity, the same cannot be said for a stock index like the S&P 500 that is regularly updated to contain only companies with high market capitalization, and the record in this proceeding does not indicate that the growth rate of the S&P 500 stock index is unsustainable. [Para 113]

The market risk premium in the CAPM analysis is adjusted by first computing the total market return less the risk free rate, and then by multiplying that equity risk premium by the betas for the proxy group companies. Beta reflects the risk of regulated utilities relative to the broad market. In this way, the CAPM results already reflect the risk of utilities, and there is no need for a further adjustment to the MRP.

39.4 On page 52 of the Continental Economics Inc. report, Dr. Lesser challenges the reasoning behind FERC's use of a one-stage (constant growth) DCF model. Does Mr. Coyne have any response to Dr. Lesser's view that a constant growth DCF is not appropriate because "in the long run, the market cannot grow faster than the economy as a whole"?

Response:

Concentric provides the following response:

On pages 51-52 of his report, Mr. Coyne demonstrated that earnings per share and dividends per share for regulated utilities in Canada and the U.S. have grown faster than nominal GDP over the period from 2005-2019. If regulated utilities are generally slower growth companies, then it stands

to reason that the broad market can also increase by more than the level of GDP growth. In fact, the average annual return on large company stocks (per Duff & Phelps) has exceeded nominal GDP growth from 1929-2020 by 5.55 percent. It should be recognized that the S&P 500 represents among the most successful companies in the economy that have achieved the status of a publicly traded company on a major stock exchange, and these companies should not be expected to represent the economy overall, as implied by GDP.

39.5 If available, please provide the value and detailed calculation for the forward-looking multi-stage MRP for Canadian and US markets.

Response:

Concentric provides the following response:

Please refer to the response to Attachment 39.5. Using the Multi-Stage DCF model, the forward-looking MRP is 6.16% in Canada and 5.70% in the U.S.

39.6 Assuming that the EMH holds true in terms of "double-counting" because today's yield on bonds reflects investors' collective expectations about interest rates, please discuss whether the EMH (if accepted) would also apply to the use of a forward-looking MRP in the CAPM analysis.

Response:

Concentric provides the following response:

Mr. Coyne does not agree that the strict assumptions of the EMH always hold true. For example, not all investors have access to the same information at the same time, and not all investors react to that information in the same way. If they did, it would not be possible to explain the wide range of projected stock prices from equity analysts for a given stock. Further, the DCF model offers a view based on recent stock prices and dividend yield and projected earnings growth, so its inclusion in the analysis provides a perspective based on currently traded securities.

Page 1 of "Exhibit JMC-FEI-6" of Appendix C shows a derivation of the equity risk premium for the Canadian market. The first four rows of companies from the S&P/TSX Composite Index are shown below.

Canadian Market DCF Calculation as of December 31, 2021

		[1]	[2]	[3]	[4]			[13]	[14]
		Dividend Yield	Dividend Yield x (1 + 0.50g)	Expected Growth Rate (g)	Secondary Market Investor Required Return			Forecast Canadian Government Bond 30 Year	Equity Risk Premium
S&P/TSX COMPOSITE INDEX		**3.15%**	**3.28%**	**8.40%**	**11.68%**			**2.58%**	**9.10%**
		[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Shares Outstanding (million)	Price ($)	Market Capitalization ($million)	Percent of Total Market Capitalization	Current Dividend Yield	Long-Term Growth Estimate	Market Capitalization-Weighted Dividend Yield	Market Capitalization-Weighted Long-Term Growth Estimate
Sun Life Financial Inc	SLF	586.0	70.41	41,261	1.95%	3.12%	19.30%	0.0610%	0.3771%
Enghouse Systems Ltd	ENGH	55.6	48.43	Excl.	Excl.	1.32%	n/a		
H&R Real Estate Investment Trust	HR-U	286.9	16.25	Excl.	Excl.	4.25%	n/a		
Ivanhoe Mines Ltd	IVN	1209.6	10.32	Excl.	Excl.	n/a	31.40%		

Sources of the data are described as follows (Exhibit JMC-FEI-6, page 5).

Notes:
[1] Equals sum of Column [11]
[2] Equals [1] x (1 + 0.5 x [3])
[3] Equals sum of Column [12]
[4] Equals [2] + [3]
[5] Source: Bloomberg Finance L.P., as of December 31, 2021
[6] Source: Bloomberg Finance L.P., as of December 31, 2021
[7] Equals Column [5] x Column [6]. Excludes non-dividend paying companies and companies with no long-term growth estimates.
[8] Equals weight in index based on market capitalization. Excludes non-dividend paying companies and companies with no long-term growth estimates.
[9] Source: Bloomberg Finance L.P., as of December 31, 2021
[10] Source: Bloomberg Finance L.P., as of December 31, 2021
[11] Equals Column [8] x Column [9]
[12] Equals Column [8] x Column [10]
[13] Source: October 2021 Consensus Forecast Average 2022-2024 Forecasts 10-Year bond yield plus 30-day average spread ending December 31, 2021 between 10- and 30-year government bonds
[14] Equals Column [4] - Column [13]

The note pertaining to column 7 explains that non-dividend paying companies and companies with no long-term growth estimates are excluded. BCUC Staff note that 73 percent (175 out of 241) of companies are excluded from the overall Canadian market MRP DCF calculation because they are either non-dividend paying companies or are missing or a long-term growth estimate. For the US market, BCUC Staff note that 25 percent (129 out of 505) of companies in the S&P 500 Index are excluded from the MRP DCF calculation.

39.7 Given the significant portion of companies that are excluded from the MRP DCF calculations (73 percent and 25 percent of companies Canadian and US markets, respectively), please describe how Mr. Coyne views this may affect the final ROE results.

Response:

Concentric provides the following response:

Mr. Coyne agrees that excluding companies that do not pay dividends and those without a long-term growth rate significantly reduces the number of companies in this calculation. Mr. Coyne believes it is appropriate to include as many companies as possible in the analysis. In addition, limiting the sample size by removing companies with growth rates > 20% further exacerbates this problem.

39.8 Please explain, to the extent possible, how the long-term growth forecast for companies is determined. For example, does Bloomberg Finance L.P. calculate it internally or do they gather it from external analysts?

39.8.1 Does Bloomberg disclose a methodology used to determine the long-term growth values? If so, please provide.

39.8.1.1 Does the long-term growth rate methodology differ between Canada and the US? If so, please describe.

39.8.1.2 Does Bloomberg include a definition for the field "long-term growth estimate"? If so, please provide.

39.8.1.3 Does Bloomberg explain what period of time the long-term growth estimate pertains to? If so, please provide the description.

39.8.2 Please explain why Bloomberg does not report a long-term growth estimate for some companies. Are there certain characteristics of a company (such as market capitalization, trading volume, or other), that make it less likely to have a growth estimate on Bloomberg?

Response:

Concentric provides the following response:

Mr. Coyne's understanding is that the long-term earnings growth rate forecasts from Bloomberg are consensus estimates from equity analysts that cover each company. Specifically, Bloomberg provides the following explanation of its long-term growth forecasts:

> Long Term Growth Forecasts are received directly from contributing analysts, they are not calculated by BEst. While different analysts apply different methodologies, the Long Term Growth Forecast generally represents an expected annual increase in operating earnings per share over the company's next full business cycle. In general, these forecasts refer to a period of between three to five years.

Bloomberg does not differentiate its explanation of its Long-Term Growth Forecasts by country. Bloomberg's long-term growth estimates generally pertain to each company's "next full business cycle," which typically "refer to a period of between three to five years."

Bloomberg does not calculate long-term growth forecasts independently. Rather, Bloomberg's long-term growth forecasts are received directly from contributing analysts. Therefore, Bloomberg does not report a long-term growth estimate for companies that are not covered by contributing analysts.

39.9 As a sensitivity analysis, please determine the forward-looking, constant growth MRP using the average of Zacks, SNL, Value Line, and First Call as data sources (as opposed to Bloomberg Finance L.P.). As part of the response, please include a functional working spreadsheet, the detailed calculations, and the alternative ROE results.

Response:

Concentric provides the following response:

Please refer to Attachment 39.9 for the forward-looking MRP calculation using Value Line growth rates for the companies in the S&P 500. Value Line does not provide sufficient coverage of the companies in the S&P TSX Index to perform this calculation for Canada. The MRP using the constant growth DCF model and Value Line growth rates is 10.43% as of December 31, 2021.

Mr. Coyne is unable to provide this calculation using growth rates from Zacks, Thomson First Call and SNL. To do so, Mr. Coyne would need to manually download growth rates for each company in the S&P 500 and S&P TSX indexes. Those reports are only available with today's estimated EPS growth rate for each company; it is not possible to match the time period of the growth rates used in Mr. Coyne's report, which were as of December 31, 2021, because historical data is not available from these three sources.

40.0 Reference: CAPM

Exhibit B1-8-1, Appendix C - Evidence of Mr. Coyne, p. 60–61;
Exhibit A2-3, Continental Economics Inc., Evidence of Dr. Lesser, pp. 45 and48;

Historic Market Risk Premium (MRP)

On page 60 of Appendix C, Mr. Coyne provides the following information regarding the historical MRP:

> The historical MRP is based on the arithmetic mean of the average annual return on large company stocks less the income only return on long-term government bonds, based on historical data from Duff & Phelps... The BCUC has previously accepted the use of the income only return rather than the total return to calculate the historical MRP... Dr. Lesser also supports the use of the income-only return in computing the historical MRP, as implied by his statement that the historical MRP for the U.S. is 7.15 percent.

Figure 29: Market Risk Premia – Canada and U.S.

	Canadian MRP	U.S. MRP
Historical	5.54%	7.25%
Forward-Looking	9.10%	12.08%
Average	8.49%	

Page 48 of Dr. Lesser's report indicates a 7.15 percent US historical average MRP based on 1926–2019. His report does not explicitly contemplate the use of income only return versus total return to calculate the historical MRP. On page 45, Dr. Lesser acknowledges the price risk in long-term government bonds, as follows:

> Although the CAPM includes a risk-free asset, no truly "risk-free" asset exists. For example, although many long-term government bonds have no default risk priced into their yields, they are still subject to price risk because their value will generally change when interest rates change or expectations about future inflation change.

40.1 Please explain what time frame is used in Mr. Coyne's calculation of the historic Canadian and US MRP.

Response:

Concentric provides the following response:

The historical market risk premium for the U.S. is calculated over the period from 1926-2020, while in Canada, the historical market risk premium covers the time period from 1919-2020.

40.2 To the knowledge of BCUC Staff, the derivation of the historical MRP is not included in Mr. Coyne's Exhibits JMC-FEI-1 to 11 or Exhibits JMC-FBC-1 to 11. Please provide the detailed calculation for the Canadian and US historical MRPs (5.54 percent and 7.25 percent, respectively).

Response:

Concentric provides the following response:

Please refer to Attachment 40.2. The average historical MRP is shown in cell B112 for Canada and cell B105 for the U.S.

40.3 Please describe if Mr. Coyne is aware of any jurisdictions that use a total return on long-term government bonds in the historical MRP determination (rather than income-only return).

Response:

Concentric provides the following response:

Mr. Coyne is not aware of jurisdictions that use a total bond return for these purposes. Most jurisdictions in the U.S. that use a historical MRP typically use the income-only return reported by Duff & Phelps. Further, Morningstar (which published the Ibbotson historical return data before it was sold to Duff & Phelps) reports the historical market risk premium using the income-only return on government bonds rather than the total return.

40.4 Please describe if Mr. Coyne is aware of any jurisdictions that use a geometric mean in the historical MRP determination (rather than an arithmetic mean).

Response:

Concentric provides the following response:

Mr. Coyne is not aware of any jurisdictions that use a geometric mean in the historical MRP calculation.

On page 61 of Appendix C, Mr. Coyne states:

> In order to be consistent with my approach elsewhere in Canada, I have used an average of the historical and forward-looking MRP; however, given the low interest rate environment, I would tend to place more reliance on a forward-looking MRP in the CAPM analysis. The FERC relies exclusively on a forward-looking market risk premium in the CAPM analysis and does not even consider a historical MRP.

40.5 Please describe how much weight other jurisdictions, aside from FERC, place on historical versus forward-looking MRP. If possible, please provide examples for both ends of the spectrum (i.e., more than 50 percent weight on historical, and less than 50 percent weight on historical).

Response:

Concentric provides the following response:

Mr. Coyne has not conducted extensive research on this issue. He is aware that New York and Minnesota both rely on a forward-looking MRP, while Missouri implicitly relies on a historical MRP. Massachusetts has indicated that it is reasonable to consider both a historical and forward-looking MRP. Mr. Coyne has used an average of historical and forward-looking data for both Canada and the U.S. to compute his market return.

40.5.1 Please describe the strengths and weaknesses of placing more weight on historical versus forward-looking MRP.

Response:

Concentric provides the following response:

In the current market environment, the historical MRP does not reflect the low interest rate environment in both Canada and the U.S. and the inverse relationship between interest rates and the equity risk premium, as shown in my Bond Yield Plus Risk Premium analysis. In addition, as shown in the table below, the historical MRP in the U.S. declined during the financial crisis of 2008/2009 even though market volatility increased substantially during that period. This is counter-intuitive, as higher market volatility implies higher risk, which should coincide with a higher MRP.

Historical Market Risk Premium and Market Volatility

	Market Volatility	Historical Market Risk Premium[74]
2009	31.48	6.70%
2008	32.69	6.50%
2007	17.54	7.10%

By comparison, the forward-looking MRP takes into consideration the current and projected interest rate environment. However, the estimate of the projected total market return can be a source of controversy and requires care in the selection of growth rates for the broad market indexes such as the S&P 500 in the U.S. and the S&P TSX in Canada. Some also express concern for the sustainability of near-term earnings growth rates in the determination of the forward looking MRP.

40.6 Please clarify why Mr. Coyne appears to compensate the low interest rate environment with a higher forward-looking MRP in the CAPM. Please explain the relationship and whether this is symmetrical (e.g., in a high interest rate environment, would Mr. Coyne place more reliance on a historical MRP?).

Response:

Concentric provides the following response:

The historical MRP is based on government bond yields of around 4.9% in the U.S. and approximately 5.6% in Canada. As shown in Mr. Coyne's Bond Yield Plus Risk premium analysis (see Exhibits JMC-FEI-9 and JMC-FBC-9), there is an inverse relationship between interest rates and the MRP. That is, as interest rates decline, the market risk premium increases, and vice versa. If government bonds were well above the historical average levels in the U.S. and Canada, then the historical MRP might overstate the forward-looking MRP. Under current market conditions, however, with government bond yields well below historical average levels in both countries, the historical MRP understates the forward-looking MRP. As explained in Mr. Coyne's report, he relies on the average of the historical and forward-looking MRP, but under current market conditions, a forward-looking MRP is more appropriate.

[74] Morningstar Inc., 2008 Ibbotson Stocks, Bonds, Bills, and Inflation, Valuation Yearbook at 28. Morningstar Inc., 2009 Ibbotson Stocks, Bonds, Bills, and Inflation, Valuation Yearbook at 23. Morningstar Inc., 2010 Ibbotson Stocks, Bonds, Bills, and Inflation, Valuation Yearbook at 23. Historical Market Risk Premium equals total return on large company stocks less income only return on long-term government securities.

41.0 Reference: CAPM

Exhibit B1-8-1, Appendix C - Evidence of Mr. Coyne, pp. 57–59; Exhibit A2-3, Continental Economics Inc., Evidence of Dr. Lesser, p. 42; Exhibit A2-16, The Electricity Journal, Volume 26, Issue 9, "Public Utility Beta Adjustment and Biased Costs of Capital in Public Utility Rate Proceedings" dated November 2013, pp. 61–68; Exhibit A2-13, 2020 Brattle Group Report, p. 43

Beta

On page 57 to 59 of Appendix C, Mr. Coyne states:

> […] both Value Line and Bloomberg report adjusted Betas…
>
> […] numerous empirical studies have provided evidence that an individual company Beta is more likely than not to move toward the market mean of 1.0 over time.
>
> […] The common approach among investors and U.S. utility regulators including the FERC is to employ the widely utilized Blume adjusted betas.
>
> The Betas I have used in my analysis are consistent with Dr. Lesser's August 2021 report on cost of capital methodologies for the BCUC.
>
> […] Blume specifically studied four groups of betas, ranging from a very low beta group (averaging 0.50, and similar to the utility industry) to a very high beta group. Dr. Blume found that his adjustment best predicted future betas for each of the four risk groups over the next seven years. Dr. Blume found that a low beta portfolio that averaged 0.50 migrated towards the grand mean of all betas of 1.0 approximately in accordance with the Blume formula. The study makes obvious that betas migrate towards 1.0 and do indeed exceed their long-term unadjusted averages.

On page 42 of the 2021 Continental Economics Inc. report, Dr. Lesser briefly summarizes what a Blume adjustment is, and states:

> Because regulators establishing the allowed ROE for a regulated utility are basing that allowed ROE on expected market conditions over an indefinite future, adjusted beta values are typically considered to be more appropriate when applying the CAPM. [emphasis added]

In the "Public Utility Beta Adjustment and Biased Costs of Capital in Public Utility Rate Proceedings" article[75], the authors argue that:

[75] Public Utility Beta Adjustment and Biased Costs of Capital in Public Utility Rate Proceedings (irac.pe.ca).

> […] regulation affects the risk of public utility stocks and therefore the risk reflected in beta may not follow a time path toward one… (page 61)

> [The Blume adjustment] can only be appropriate for stocks with average betas, as a group, close to one. This is, however, hardly the case for public utility betas that are generally less than 1 […] (page 62)

> We have shown empirically that public utility betas do not have a tendency to converge to 1. […]

> During our nearly 45-year study period, the median beta ranged from 0.08 to 0.74. Therefore the Blume equation overpredicts utility betas and Blume-adjustments of utility betas are not appropriate. We are not suggesting that betas should not be adjusted for prediction. Rather, the measurement period and subjective adjustment to beta should be based upon the likely future trend in peer group or public utility betas, or the specific utility's beta, not the trend in betas for all stocks in general. (page 67)

41.1 Please confirm, or explain otherwise, if Value Line and Bloomberg both report raw Betas (in addition to adjusted Betas).

Response:

Concentric provides the following response:

Value Line does not report raw Betas. Bloomberg reports both raw and adjusted Betas.

41.2 Please confirm, or explain otherwise, that the referenced Dr. Blume study was conducted on the broad market, not specifically on utilities.

Response:

Concentric provides the following response:

Dr. Blume's study included all segments of the market, not just the broad market. His study segregated stocks into portfolios containing 100 stocks with like betas based on raw beta estimates ranging from a low of 0.50 to a high of 1.53. Several studies support the need to adjust Beta for its tendency to revert towards the market mean of 1.0. In 1971, Dr. Blume examined all common stocks listed on the NYSE and found a tendency for a regression of Betas towards 1.00. He concluded that:

> …there is obviously some tendency for the estimated values of the risk parameter to change gradually over time. This tendency is most pronounced in the lowest

> risk portfolios, for which the estimated risk in the second period is invariably higher than that estimated in the first period. There is some tendency for the high risk portfolios to have lower estimated risk coefficients in the second period than in those estimated in the first. Therefore, the estimated values of the risk coefficients in one period are biased assessments of the future values, and furthermore the values of the risk coefficients as measured by the estimates of βi tend to regress towards the means with this tendency stronger for the lower risk portfolios than the higher risk portfolios.[76]

In 1975, Dr. Blume revisited the topic, measuring the statistical significance of the regression tendency. He concluded:

> A comparison of the portfolio betas in the grouping period, even after adjusting for the order bias, to the corresponding betas in the immediately subsequent period discloses a definite regression tendency. This regression tendency is statistically significant at the five percent level for each of the last three grouping periods, 1940-47, 1947-54, 1954-61. Thus, this evidence strongly suggests that <u>there is a substantial tendency for the underlying values of beta to regress towards the mean over time</u>.[77] [Emphasis added.]

Dr. Blume's adjustment methodology does not support adjusting Beta to the long-term average beta of the industry or the sector being studied. Although Dr. Blume referred to Beta estimates across wide ranges of risk in the market, as mentioned, his study segregated stocks into portfolios containing 100 stocks with ***like*** betas based on raw beta estimates ranging from a ***low of 0.50*** to a high of 1.53. Four stock portfolios were analyzed, with beta estimates of 0.50, 0.85, 1.15, and 1.53. By grouping low beta stocks together, Dr. Blume could analyze how such low beta stocks changed over time. For example, the lowest beta portfolio, consisting of 100 stocks with betas averaging 0.50, when measured in the first subsequent period of seven years, had a beta estimate of 0.61 for the same 100 stocks, and in the next seven-year period, measured 0.73. In this Study, Dr. Blume found that <u>all</u> betas, low and high revert towards the grand mean of all betas, 1.0 over time.

Dr. Blume found that his adjustment best predicted future betas for <u>each</u> of the four risk groups over the next seven years. Dr. Blume also found that a low beta portfolio that averaged 0.50, migrated towards the grand mean of all betas of 1.0 approximately in accordance with the Blume formula. Given that the purpose of estimating the CAPM relying on these beta estimates is to estimate the forward-looking cost of capital, it is important to reflect a forward view of beta and its tendency to migrate towards the market mean over time, which is not limited to the long-term historic average of the company or industry betas.

[76] Marshall E. Blume, *The Journal of Finance*, Vol. 26, No. 1. (Mar., 1971), at p. 7-8 [emphasis added].
[77] Marshall E. Blume, *The Journal of Finance*, Vol. 30, No. 3. (Jun., 1975), at p. 794 [emphasis added].

41.3 Please provide, if available, any research known to Mr. Coyne regarding the applicability of Blume Beta adjustments specifically for regulated utilities, rather than the broad market.

Response:

Concentric provides the following response:

Mr. Coyne is not aware of research specific to regulated utilities on the applicability of the Blume method of beta adjustment. However, as indicated in Mr. Coyne's response to BCUC IR1 41.2, the Blume adjustment was tested by assembling stocks from a wide range of risk ranging from a ***low of 0.50*** (similar to the raw beta of regulated utilities) to a high of 1.53. Four stock portfolios were analyzed, with beta estimates of 0.50, 0.85, 1.15, and 1.53. The lower beta group (with estimates of 0.50) would be analogous to a group of regulated utilities and would be expected to perform similarly relative to the broader market. Dr. Blume found that all betas, low and high revert towards the grand mean of all betas, 1.0 over time. There is no reason to expect that regulated utilities would be an exception to this rule. The Blume study found that all betas revert towards the market mean of one over time in accordance with the Blume adjustment formula; and since it is the utility's regulated nature that allows its performance to deviate from that of the broader market thereby producing a lower beta estimate, it can be assumed that the effects of regulation are already taken into account in the utility's beta estimate.

41.4 BCUC Staff note that while Dr. Lesser acknowledges the work of Dr. Marshall Blume, Dr. Lesser does not specifically endorse the use of a Blume beta adjustment, rather he states that "adjusted beta values are typically considered to be more appropriate when applying the CAPM". However, Mr. Coyne states that, "the Betas I have used in my analysis are consistent with Dr. Lesser's August 2021 report". Please explain how Mr. Coyne interprets that Dr. Lesser's report specifically supports the use of a Blume adjusted Beta for utilities over an alternate adjustment.

Response:

Concentric provides the following response:

While Mr. Coyne agrees that Dr. Lesser's August 2021 report for the BCUC does not specifically endorse the use of the Blume adjustment method, Concentric is aware that Dr. Lesser has previously relied on Blume adjusted Betas in his U.S. evidence. For example, in his September 2002 rebuttal testimony on behalf of Arkansas Oklahoma Gas Corporation, Docket No. 02-024-U, Dr. Lesser used Value Line Betas for his gas proxy group in his CAPM analysis In addition,

sources that report adjusted betas such as Value Line and Bloomberg rely on the Blume adjustment method. In Mr. Coyne's experience, the Blume methodology is the only method widely accepted by U.S. regulators, although it has been a more contentious issue in Canada.

Dr. Lesser's response to the FBCU IR1 10.1 and 10.2 also confirms that the he is not aware of beta adjustment methodologies that adjust raw beta values towards a value other than one.

41.5 Please describe if Mr. Coyne is aware of any jurisdiction other than FERC that uses the Blume adjusted Beta in their CAPM calculations. Specifically, do any Canadian jurisdictions use the Blume adjusted Beta?

Response:

Concentric provides the following response:

Mr. Coyne is not aware of a single state or federal regulatory authority in the U.S. that takes exception to the use of Blume adjusted Betas, and this is not an area of dispute in cost of capital proceedings in the U.S. In other words, there are 51 U.S. regulatory agencies[78] plus the FERC, and none to Mr. Coyne's knowledge has expressed a concern with or relied on any adjustment mechanism to Beta other than the standard Blume methodology Mr. Coyne is not aware of any Canadian jurisdiction that has specifically endorsed the of use of Blume adjusted Betas. Rather, Canadian utility regulators tend to cite a range of estimated Betas in the ROE decision, but do not indicate whether those are adjusted or raw Betas. In Mr. Coyne's view, the lack of acceptance of the standard Blume methodology by Canadian regulators invites contentious debates on a topic that is well settled elsewhere. The use of raw betas or betas adjusted to a specific industry or sector have been shown to be an inferior estimate of actual returns for utilities, or any other segment of the market. Utilities, just because they are lower risk or have lower betas, are not otherwise unique from a capital market perspective. The use of raw betas or betas adjusted to an industry or sector average in the calculation of a fair return introduces an inherent bias without either academic or capital market support.

41.6 Please provide Mr. Coyne's views on the excerpts provided from the *Public Utility Beta Adjustment and Biased Costs of Capital in Public Utility Rate Proceedings* article, which note that Blume adjusted Betas are not appropriate for public utilities

[78] Texas has two regulatory agencies, the Public Utility Commission of Texas (for electric utilities) and the Texas Railroad Commission (for gas utilities).

because regulation affects the risk of public utility stocks, and as a group, public utility stocks do not have an average Beta close to 1.0.

Response:

Concentric provides the following response:

As discussed in Mr. Coyne's report, the current market data shows that Betas, both raw and adjusted, have increased substantially for gas and electric utilities since January 2020. Investors are aware of the regulatory risk of public utility stocks, and that risk is factored into the stock prices and the resulting Betas for these companies. On the referenced article, Mr. Coyne notes there are two observations and findings by the authors worth noting:

> The beta adjustment method most widely disseminated by the major beta vendors is the Blume adjustment. Therefore, our focus is on the Blume adjustment for public utility betas and the public utility cost of common equity capital. Occasionally, an expert witness in a public utility rate case estimates their own betas, but they are quickly repudiated in rate proceedings since these betas are not disseminated by influential stock analysts and presumed not to be reflected in the stock price.

And:

> We are not suggesting that betas should not be adjusted for prediction. Rather, the measurement period and subjective adjustment to beta should be based upon the likely future trend in peer group or public utility betas, or the specific utility's beta, not the trend in betas for all stocks in general. The time pattern of utility betas is obviously more complex than a smooth curvilinear adjustment, or for that matter, any adjustment toward one. Nor do we suggest as an alternative the use of raw or unadjusted betas in an application of the CAPM to estimate a public utility's cost of common equity.

Mr. Coyne concurs on both points, and he does not believe that a subjective adjustment to utility betas is superior to those broadly accepted by investors (the Blume adjustment) and therefore influencing stock prices. He also notes that this paper was authored in 2011, and he is not aware of any follow-on research or response that carried the authors' work any further. He also notes that since 2011 raw utility betas have moved closer to 1.0 than when they conducted their work (refer to the response to BCUC IR1 41.9) and a decade of additional data might change their conclusions.

On page 58 of Appendix C, Mr. Coyne gives the following argument to support adjusting Betas, and references Roger A. Morin, New Regulatory Finance, at 74.

> Because Betas are statistically estimated and have associated error terms, Betas greater than 1.0 tend to have positive estimated errors and thus tend to overestimate future returns. Betas below the market average of 1.0 tend to have negative error terms and underestimate future returns. Consequently, it is necessary to adjust forecasted Betas toward 1.0 in an effort to improve forecasts…

41.7 Please further explain, and if possible, provide evidence to support why it would be the case that Betas smaller than 1.0 tend to have negative error terms.

Response:

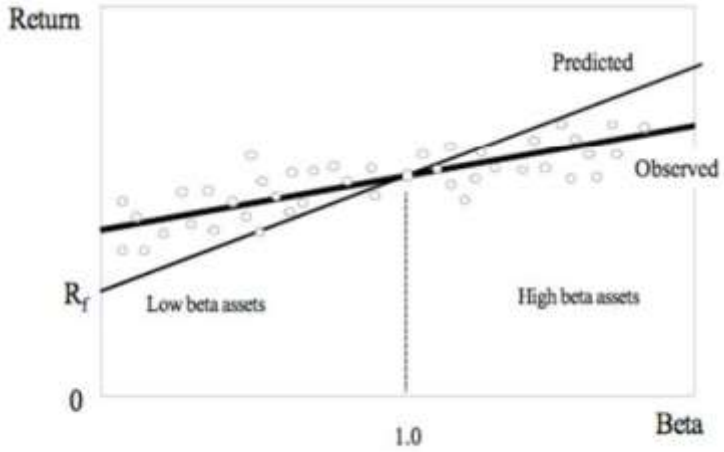
Concentric provides the following response:

Raw betas are highly unstable.[79] Their error terms tend to err on the high side for high beta securities (overestimate stock returns) and tend to err on the low side for low beta securities (or underestimate returns), or the slope of the predicted return is steeper than what is actually observed. Dr. Morin attributes a potential cause for this disparity in the case of regulated utilities to be due in part to the extra interest-sensitivity of regulated utilities relative to industrials. He asserts that beta does not capture this sensitivity and that betas would be higher if this relationship were properly captured.[80] Dr. Morin also addressed the propensity of the CAPM to underestimate returns in a recent SoCal Gas testimony. According to his testimony:

> [T]here have been countless empirical tests of the CAPM to determine to what extent security returns and betas are related in the manner predicted by the CAPM. This literature is summarized in Chapter 6 of my latest book, The New Regulatory Finance. The results of the tests support the idea that beta is related to security returns, that the risk-return tradeoff is positive, and that the relationship is linear. The contradictory finding is that the risk-return tradeoff is not as steeply sloped as the predicted CAPM. That is, empirical research has long shown that low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted.
>
> A CAPM-based estimate of cost of capital underestimates the return required from low-beta securities and overstates the return required from high-beta securities, based on the empirical evidence. This is one of the most well-known results in finance, and it is displayed graphically below.

[79] Morin, New Regulatory Finance at 78.
[80] Morin, New Regulatory Finance at 73-74.

CAPM: Predicted vs Observed Returns



A number of variations on the original CAPM theory have been proposed to explain this finding. The ECAPM makes use of these empirical findings. The ECAPM estimates the cost of capital with the equation:

$$K = RF + \alpha + \beta \times (M R P - \alpha)$$

where the symbol alpha, α , represents the "constant" of the risk-return line, MRP is the market risk premium (RM - RF), and the other symbols are defined as usual."[81]

Dr. Morin goes on to explain that the above equation with a long-term risk-free rate, an alpha term of between 1 and 2% and reasonable adjusted betas and MRP will provide a result that is indistinguishable from what he refers to as the "more tractable" ECAPM expression (below) which is known to provide formal recognition that the observed risk-return trade off is flatter than that predicted by the CAPM:

$$K = RF + 0.25 (RM - RF) + 0.75 \beta (RM - RF)$$[82]

41.7.1 Please provide any excerpt from Roger A. Morin, New Regulatory Finance, which can help support Mr. Coyne's assertion regarding the

[81] Morin Testimony, SoCal Gas Company (U 904 G) 2020, Application A. 19-04-XXX, Exhibit SCG-04, at p. 45-46.
[82] Ibid.

tendency for Betas below the market average of 1.0 to have negative error terms.

Response:

Concentric provides the following response:

Dr. Roger A. Morin discusses the issue of Betas below the market average of 1.0 having negative error terms. Specifically, Dr. Morin writes at pages 73-74 of New Regulatory Finance:

> There is statistical justification for the use of adjusted betas as well. Statistically, betas are estimated with error. High-estimated betas will tend to have positive error (overestimated) and low-estimated betas will tend to have negative error (underestimated). Therefore, it is necessary to squash the estimated betas in toward 1.00. One way to accomplish this is by measuring the extent to which estimated betas tend to regress toward the mean over time. As a result of this beta drift, several commercial beta producers adjust their forecasted betas toward 1.00 in an effort to improve their forecasts. This adjustment which is commonly performed by investments services such as Value Line, Bloomberg, and Merrill Lynch, uses the formula: $\beta_{adjusted} = \alpha(\beta_{raw} - 1.0)$" Each firm gives 66% weight to the raw beta and approximately 34% to the market mean of 1.0, such that $\beta_{adjusted} = 0.33 + 0.66\ \beta_{raw.}$

41.7.2 Please further explain what the magnitude of the potential negative statistical error associated with Betas under 1.0 might be.

Response:

Concentric provides the following response:

According to the two formulas put forward in Mr. Coyne's response to BCUC IRs 41.7 and 41.7.1, above, we would assume that the magnitude of the statistical error associated with Betas under 1.0 might be derived from those formulas as follows:

$$K = RF + \alpha + \beta_{adjusted} \times (M\ R\ P - \alpha)$$

$$\beta_{adjusted} = 0.33 + 0.66\ \beta_{raw.}$$

Where α is expected to be between 1% and 2%, and β_{raw} for utilities is typically in the range between 0.30 and 0.60. Given this, we would expect an average adjusted beta to be between 0.53 and 0.73 (though those beta estimates have been much higher recently). But for sake of example, we would expect a reasonable magnitude of the negative statistical error, represented by α to be somewhere between 47 bps (1% - 0.53 x 1%) and 54 bps (2% - 0.73 x 2%). The

impact of the adjustment to beta will depend on the MRP, but assuming that it ranges from 8.49% to 10.59%, as indicated in Mr. Coyne's testimony, the magnitude of the beta adjustment would be between 110 bps (0.73 – 0.60 = 0.13 x 8.49%) and 244 bps (0.53 – 0.30 = 0.23 x 10.59%), noting that as raw beta increases, the adjustment to beta decreases. So, adding both isolated adjustments together would result in an expected magnitude of 157 bps to 298 bps given the expected current level of parameters.

41.7.2.1 How much of an impact does the potential negative statistical error have on a raw Beta of 0.8?

Response:

Concentric provides the following response:

If raw beta were 0.80, the required adjustment would be 0.33 + 0.66 x 0.80 = 0.858 – 0.80 = 0.058. Applying the 0.058 beta adjustment to the range of MRP's Mr. Coyne uses in his testimony, yields an impact of between 49 bps (0.058 x 8.49%) and 61 bps (0.058 x 10.59%) for the adjustment to beta alone. If you also consider the α term identified in responses to BCUC IR1 41.7, 41.7.1, and 41.7.2, above, the impact would be between 14 bps (1% - 0.858 x 1%) and 28 bps (2% - 0.858 x 2%). Adding the two isolated adjustments together would yield a total impact of the negative statistical error associated with the CAPM of between 63 bps and 89 bps, depending on the value for α, and the MRP.

41.8 Please explain if it is possible to perform an alternative CAPM calculation that uses an MRP for the utility sector rather than a utility sector Beta multiplied by the MRP of the broad market. In other words, given the CAPM equation, Ke = rf + β(rm – rf), is it possible to substitute the term β(rm – rf) with an MRP specific to the utility sector, by taking data from the utility sector only, and thus, the Beta will be embedded in the calculation?

Response:

Concentric provides the following response:

Yes. This could be considered a form of the bond yield risk premium approach, where a utility specific risk premium is added to the prevailing bond yield. It is important that the bond yield used to calculate the risk premium, is the same bond yield that would be used as an adder to the risk premium in the formula. The problem with this approach is that it is not forward looking and is

based on historical utility risk premiums. It may be possible to develop a forward looking, utility specific MRP, using the S&P 500 utility index, which would eliminate the need to use a utility specific beta. However, note that the premise of the CAPM equation is to identify and quantify the systematic risk of a given stock or portfolio of stocks relative to the broader market. In order to perform the CAPM, beta is instrumental in identifying the relationship of the security with the broader market. If one were to select an MRP specific to the utility risk sector, an important part of the model would become static and unchanging. As such, the model would no longer represent the CAPM model but simply a risk premium approach.

On page 43 of the 2020 Brattle Group Report, the Brattle Group states:

> While the ACM [regulator for energy networks and other infrastructure in the Netherlands] relies on the Dimson and Vasicek adjustment and the FERC relies on the Blume adjustment to beta; neither the AER [Australian Energy Regulator] nor the other regulators undertake such adjustments.

Further, on page 79, the Brattle Group states:

> The first adjustment is the Dimson adjustment, which accounts for the fact that share prices may react to news the day before or the day after the market index. The Dimson adjustment regresses a company's daily returns using the market index returns one day before and one day after as additional regressors. The Dimson adjusted beta is given by the sum of the three coefficients calculated by the regression. The methodology selects the Dimson-adjusted beta estimate if it is statistically significantly different from the OLS [ordinary least squares] beta estimate.
>
> The second adjustment is the Vasicek adjustment, an adjustment designed to avoid extreme estimates of the beta by 'pulling' beta estimates towards a 'prior expectation' of the beta for the sector. The Vasicek adjustment moves the observed beta closer the prior expectation by a weighting based on the standard error of the beta and the standard error of the of the overall market, so that values with lower standard errors will be given a higher weighting relative to the prior.

41.9 Please discuss if Mr. Coyne has considered implementing a Vasicek or Dimson adjustment to the Beta, similar to ACM's approach, in order to address issues with statistical reliability of the Beta estimate. In the response, please include advantages and disadvantages of using each of these two adjustments.

Response:

Concentric provides the following response:

Mr. Coyne has not considered implementing a Vasicek or Dimson adjustment to Beta. This information is not widely available to investors in published Beta estimates.

As an alternative, Mr. Coyne has considered adjusted betas from Bloomberg calculated over a 10 year period (rather than the 5-year Betas used in his report) to smooth out the effect of the more recent period. However, in Mr. Coyne's view, that longer time period would not adequately take into consideration any changes in Beta for regulated utilities due to the Energy Transition, which is much more of an issue now than it was 10 years ago. For informational purposes, the table below provides the raw and adjusted Bloomberg betas calculated over 5-year and 10-year periods for each proxy group considered by Mr. Coyne.

Proxy Group	5-Year Betas		10-Year Betas	
	Raw	Adjusted	Raw	Adjusted
Canadian Proxy Group	0.84	0.89	0.83	0.88
US Gas Proxy Group	0.75	0.83	0.69	0.79
North American Proxy Group (Gas)	0.86	0.91	0.82	0.88
US Electric Proxy Group	0.86	0.91	0.74	0.83
North American Proxy Group (Electric)	0.82	0.88	0.73	0.82

On page 43 of the 2020 Brattle Group Report, the Brattle Group states:

> While the ACM [regulator for energy networks and other infrastructure in the Netherlands] relies on the Dimson and Vasicek adjustment and the FERC relies on the Blume adjustment to beta; neither the AER [Australian Energy Regulator] nor the other regulators undertake such adjustments.

Further, on page 79, the Brattle Group states:

> The first adjustment is the Dimson adjustment, which accounts for the fact that share prices may react to news the day before or the day after the market index. The Dimson adjustment regresses a company's daily returns using the market index returns one day before and one day after as additional regressors. The Dimson adjusted beta is given by the sum of the three coefficients calculated by the regression. The methodology selects the Dimson-adjusted beta estimate if it is statistically significantly different from the OLS [ordinary least squares] beta estimate.
>
> The second adjustment is the Vasicek adjustment, an adjustment designed to avoid extreme estimates of the beta by 'pulling' beta estimates towards a 'prior expectation' of the beta for the sector. The Vasicek adjustment moves the observed beta closer the prior expectation by a weighting based on the standard error of the beta and the standard error of the of the overall market, so that values with lower standard errors will be given a higher weighting relative to the prior.

41.9.1 Please describe the impact a Vasicek adjustment would generally have on the proxy group Betas, as compared to a Blume adjustment.

Response:

Concentric provides the following response:

Mr. Coyne has not done this analysis, nor has he experienced a regulatory proceeding which compared Blume vs. Vasicek vs. Dimson beta adjustments. These issues are preferably tackled in academic circles where research can be directed and evaluated with appropriate rigor and peer review.

41.9.2 Please describe the impact a Dimson adjustment would generally have on the proxy group Betas, as compared to a Blume adjustment.

Response:

Please refer to the response to BCUC IR1 41.9.1.

42.0 Reference: Multi-Stage DCF

Exhibit B1-8-1, Appendix C - Evidence of Mr. Coyne, "Exhibit JMC-FEI-5", p. 1, "Exhibit JMC-FEI-4", p. 1; Exhibit A2-3, Continental Economics Inc., Evidence of Dr. Lesser, p. 85

Growth Rate

On page 1 of "Exhibit JMC-FEI-5", Mr. Coyne's evidence shows that the multi-stage DCF uses an initial growth assumption for the first five years, followed by a five-year transition phase, levelling off to GDP growth in year 11.

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

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]
Company	Ticker	Annualized Dividend	Stock Price	Growth Rate Years 1-3	Year 6	Year 7	Year 8	Year 9	Year 10	GDP Growth (perpetuity)	ROE
Algonquin Power and Utilities	AQN	$0.68	$14.62	9.49%	8.55%	7.60%	6.66%	5.72%	4.78%	3.84%	10.92%
AltaGas Inc.	ALA	$1.00	$25.58	8.30%	7.56%	6.81%	6.07%	5.32%	4.58%	3.84%	9.39%
Canadian Utilities Limited	CU	$1.76	$35.23	2.58%	2.79%	3.00%	3.21%	3.42%	3.63%	3.84%	8.83%
Emera Inc.	EMA	$2.65	$59.27	5.81%	5.48%	5.15%	4.82%	4.49%	4.16%	3.84%	9.30%
Enbridge Inc.	ENB	$3.34	$50.45	6.98%	6.45%	5.93%	5.41%	4.88%	4.36%	3.84%	12.52%
Hydro One, Ltd.	H	$1.07	$30.93	4.52%	4.40%	4.29%	4.18%	4.06%	3.95%	3.84%	7.71%
MEAN				6.28%	5.87%	5.46%	5.06%	4.65%	4.24%	3.84%	9.78%
Flotation Costs [11]											0.50%
											10.28%

On page 1 of "Exhibit JMC-FEI-5", Mr. Coyne submits that the growth rate used in the above multi-stage DCF calculation is based on the average growth rate for each proxy company.

90-DAY CONSTANT GROWTH DCF -- CANADIAN PROXY GROUP

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Annualized Dividend	Stock Price	Dividend Yield	Expected Dividend Yield	Zacks EPS Growth	SNL EPS Growth	Value Line EPS Growth	First Call Growth	Average Growth Rate	Low DCF ROE	Mean DCF ROE	High DCF ROE
Algonquin Power and Utilities	AQN	$0.68	$14.62	4.67%	4.89%	8.70%	8.61%	n/a	11.15%	9.49%	13.48%	14.58%	16.08%
AltaGas Inc.	ALA	$1.00	$25.58	3.91%	4.07%	n/a	10.76%	n/a	5.84%	8.30%	9.86%	12.37%	14.88%
Canadian Utilities Limited	CU	$1.76	$35.23	4.99%	5.06%	n/a	4.00%	n/a	1.15%	2.58%	6.17%	7.63%	9.09%
Emera Inc.	EMA	$2.65	$59.27	4.47%	4.60%	n/a	6.45%	5.00%	5.98%	5.81%	9.58%	10.41%	11.06%
Enbridge Inc.	ENB	$3.34	$50.45	6.62%	6.85%	6.00%	5.00%	6.50%	10.40%	6.98%	11.79%	13.83%	17.37%
Hydro One, Ltd.	H	$1.07	$30.93	3.44%	3.52%	n/a	4.76%	n/a	4.28%	4.52%	7.80%	8.04%	8.28%
MEAN				4.68%	4.83%	7.35%	6.60%	5.75%	6.47%	6.28%	9.78%	11.11%	12.79%
Flotation Costs [13]											0.50%	0.50%	0.50%
											10.28%	11.61%	13.29%

Notes:
[1] Source: Bloomberg Professional
[2] Source: Bloomberg Professional, 90-day average as of December 31, 2021
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [10])
[5] Source: Zacks at December 31, 2021
[6] Source: SNL Financial Median Long-Term EPS Growth Rate as of December 31, 2021
[7] Source: Value Line
[8] Yahoo! Finance as of December 31, 2021
[9] Equals Average([5], [6], [7], [8])
[10] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7], [8])) + Minimum([5], [6], [7], [8])
[11] Equals [4] + [9]
[12] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7], [8])) + Maximum([5], [6], [7], [8])
[13] The Board has allowed 50 bps flotation adjustment for equity issuance costs, administrative costs, impact of underpricing, potential for dilution, and equity cushion for investors.

42.1 For each of the four sources of growth estimates (Zacks, SNL, Value Line and First Call), please provide the span of time that the growth estimate covers, according to the source. Does each source specify that the growth estimate is for five years, or does the duration vary by source?

Response:

Concentric provides the following response:

Growth rate estimates reported by both Zacks and Thomson First Call are for five years. Value Line growth rates are for 3-5 years. SNL does not specifically state the time period, but refers to them as long-term growth rates.

42.2 Please explain why the second stage of the model (transition from average growth to GDP growth) is a five-year stage, rather than some other length of time?

Response:

Concentric provides the following response:

There is no specific reason for Mr. Coyne's choice of a five year transition period, except to have a gradual transition from short-term growth to long-term growth over time instead of making an abrupt shift in Year 6. Mr. Coyne has seen other analysts use a transition period as long as 10 or 20 years in the multi-stage DCF model. A longer transition period typically causes the results of the multi-stage DCF model to increase when the long-term growth rate (i.e., projected GDP growth) is lower than the near-term growth rate (i.e., projected EPS growth). Mr. Coyne's five year transition period is therefore conservative.

42.3 Please explain why Zacks, SNL, Value Line and First Call were chosen as sources of growth rate.

Response:

Concentric provides the following response:

These sources are commonly relied on by investors and Zacks and First Call are available at no cost on the internet. Zacks, First Call and SNL all report consensus estimates of EPS growth. Value Line growth estimates are from a single analyst, but are also commonly used by investors, especially individuals.

42.3.1 Given that Bloomberg Finance L.P. was used as a source in other areas of Mr. Coyne's evidence (such as Beta values and long-term growth estimate for the equity risk premium), please explain why Bloomberg Finance L.P. was not included as a source for growth rate in the multi-stage DCF?

Response:

Concentric provides the following response:

There is no particular reason that Mr. Coyne did not include Bloomberg growth rates in his Constant Growth or Multi-Stage DCF models. Mr. Coyne typically uses growth rate estimates from Zacks, First Call, Value Line, and SNL (now S&P Capital IQ).

42.3.1.1 As a sensitivity analysis, please determine the (i) average and (ii) median growth rates and multi-stage DCF ROEs using Bloomberg Finance L.P. as a data source (as opposed to the average of Zacks, SNL, Value Line, and First Call). As part of the response, please include a functional working spreadsheet, the detailed calculations, the alternative ROE results, and discuss whether the average or median growth rates are appropriate.

Response:

Concentric provides the following response:

Please refer to Attachment 42.3.1.1. Bloomberg does not report median projected EPS growth rates from equity analysts; they only report the average consensus EPS growth rates. The average Bloomberg growth rates and DCF results (including flotation costs) for Mr. Coyne's proxy groups are shown in the table below.

Proxy Group	Bloomberg Growth Rate	Mean Constant Growth DCF	Median Constant Growth DCF	Mean Multi-Stage DCF	Median Multi-Stage DCF
Canadian	8.13%	13.75%	13.84%	11.17%	10.84%
U.S. Gas	5.53%	10.03%	9.77%	9.40%	9.53%
North American Gas	6.45%	11.45%	10.61%	10.15%	9.72%

42.4 Does Mr. Coyne have any views as to reasons why different sources might vary drastically in their growth rate estimates (such as with AltaGas Inc., where SNL ESP growth estimate is 10.76 percent and First Call growth estimate is 5.84 percent)?

Response:

Concentric provides the following response:

There are several possible reasons that projected EPS growth rates may vary across sources: 1) the growth rate may depend on which analysts are included in the consensus estimates; 2) the reported growth rate may cover a slightly different time period, or may have been last updated at a different time; 3) the growth rate may depend on whether the source makes any adjustments to analyst growth rates (such as using net income or operating earnings). For that reason, Mr. Coyne believes it is appropriate to rely on multiple sources for projected growth rates. All of this information is available to investors and presumably considered by them as they develop their stock price targets and return expectations.

43.0 Reference: RETURN ON EQUITY

Exhibit B1-8-1, Appendix C - Evidence of Mr. Coyne, pp. 69–72; Exhibit A2-3, Continental Economics Inc., Evidence of Dr. Lesser, pp. 80–85

Flotation Costs and Financing Flexibility

On page 85 of the 2021 Continental Economics Inc. report, Dr. Lesser states:

> First, many analysts make assumptions regarding flotation cost percentages, rather than basing their recommended allowances on actual flotation costs. Such assumptions will compensate a regulated utility for its actual flotation costs only by sheer chance. Second, an adjustment for flotation costs to allowed ROE will compensate the utility based on its rate base, not on the actual flotation costs incurred. As noted above, adding an arbitrary percentage to allowed ROE, such as the 50 bp adder used by many Canadian regulators including the BCUC, is likely to overcompensate the utility for flotation costs. Hence, it may be more reasonable to include actual flotation costs (or an estimate of those costs) as an expense to be recovered in the regulated utility's cost of service.
>
> […] FERC does not grant a flotation cost adjustment to allowed ROE unless the firm under review can demonstrate it issued stock and incurred flotation costs.

On pages 69 to 72 of Appendix C in Exhibit B1-8-1, Mr. Coyne states:

> The adjustment also allows a small cushion for financial flexibility such that the utility may continue to raise equity in challenging capital market conditions. (page 69)
>
> I have considered Dr. Lesser's position, but find that ROEs issued in Canada tend to be lower and Canadian utilities are more thinly capitalized and as a result, an adjustment for both flotation costs and financing flexibility is necessary. As such, I have adjusted my DCF and CAPM results by 50 basis points for flotation costs and financing flexibility. (page 72)

43.1 Please elaborate on what "financial flexibility" is intended to capture.

Response:

Concentric provides the following response:

In the August 2016 Order for FEI's cost of equity, the BCUC approved an adjustment of 50 basis points for flotation costs and financing flexibility. The Commission referred to page 79 of its previous 2013 Order where it explained financing flexibility as follows: "The decision referenced a definition of this allowance for financing flexibility as consisting of: (1) flotation costs comprising financing and market pressure costs arising at the time of the sale of new equity; (2) a margin, or

cushion, for unanticipated capital market conditions; and (3) a recognition of the "fairness" principle."

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.

As shown on pages 70-72 of Mr. Coyne's report and specifically in Figure 36, this adjustment for flotation costs and financing flexibility is common in jurisdictions across Canada.

43.2 Please provide a breakdown of the 50 bps adjustment separating flotation costs from financing flexibility.

Response:

Concentric provides the following response:

Mr. Coyne did not perform such an analysis in this proceeding. However, for an electric proxy group in the U.S., flotation costs are typically in the range of 10-15 basis points. This calculation is based on the flotation costs as a percentage of the two most recent equity issuances for a proxy group of companies. The remainder of the 50 basis points would be for financing flexibility.

43.3 Can Mr. Coyne demonstrate a close connection between the actual flotation costs incurred (or expected to be incurred) and the portion of the adjustment that is intended to cover flotation costs? If so, please provide a detailed flotation cost budget.

Response:

Concentric provides the following response:

Please refer to response to BCUC IR1 43.2. Mr. Coyne did not perform such an analysis in this proceeding. Actual flotation costs of electric and gas utilities in the U.S. are typically in the range of 10-15 basis points.

43.3.1 If available, please provide the historic annual flotation costs incurred by FEI and FBC, including the cost of preparation, filing, underwriting, and other costs associated with the issuance of common equity for the most recent five-year period available, or portion thereof. Please describe the costs as a dollar amount and as a percentage of issuance costs.

43.3.1.1 If not available, please describe the feasibility of tracking flotation cost data going forward.

Response:

FEI and FBC are not publicly traded and therefore do not issue equity and do not incur flotation costs. Fortis Inc. as the ultimate parent is the only source of equity for FortisBC.

Please see below the discrete Fortis Inc. equity issuances for the last 5 years:

Year	Shares issued (# in millions)	Gross Proceeds (millions of CAD)	Net Proceeds (millions of CAD)	Issue Costs, net of tax (millions of CAD)	Issue Costs, net of tax (basis points)
2017	12	500	500	1	10
2019	23	1,190	1,167	23	193
2019	4	212	209	3	142

The issuance costs included in the table above include direct costs associated with issuing equity, which are commissions paid to the underwriters, legal fees and assurance fees. These issuance costs do not include all other costs, for example, cost of preparation, filing, wages paid to investor relations department and other indirect costs associated with the issuance of common equity.

In addition to the issuance costs, flotation cost includes a “financial flexibility” component that is not reflected in the above issuance cost numbers. As explained in Concentric’s response to BCUC IR1 43.2, approximately 35 to 40 basis points of the proposed 50 basis points flotation cost relates to the financial flexibility. As discussed in Concentric’s evidence (Figure 36), the financial flexibility component of the flotation costs is used to adjust for things such as any impact of underpricing a new issue or the share dilution caused by the new issuance. Please refer to the response to BCUC IR1 43.1 for more detailed discussion of “financial flexibility”

It is important to note that Fortis Inc. is a large public company with an asset base of approximately $58 billion compared to FEI’s asset base of $8 billion and FBC’s asset base of $2.5 billion. Therefore, if FortisBC had to issue equity as standalone companies, they would incur higher flotation costs on a percentage basis than Fortis Inc. due to the economies of scale available to a larger issuer like Fortis Inc. compared to if FortisBC were to issue equity directly for its smaller financing requirements.

43.4 Please comment on the feasibility and merits of recovering future flotation costs as an expense through the cost of service, as FERC does.

Response:

Please refer to the response to BCUC IR1 43.3.1. FortisBC does not directly incur these costs as FEI and FBC are not public companies and do not issue equity, so there is no expense line item for this in the cost of service.

Under the standalone principle, FEI's and FBC's allowed ROE should be determined as if each company issues its own equity. If the companies were standalone utilities and issued their own equities, the associated flotation costs could have been recovered in cost of service. In the absence of this possibility, addition of flotation cost to the ROE is the only feasible approach. As explained in Concentric's evidence, the majority of the Canadian regulators add a 50 basis points premium to their allowed ROEs to account for the issuance costs and financial flexibility needed to be able to issue equity in various market conditions.

43.5 Please describe how much weight Mr. Coyne places on his finding that "ROEs issued in Canada tend to be lower and Canadian utilities are more thinly capitalized" in determining a 50 bps adjustment for flotation costs and financing flexibility.

43.5.1 In Mr. Coyne's view, why is it appropriate to compensate for a lower ROE or equity ratio through a flotation cost and financing flexibility adjustment?

Response:

Concentric provides the following response:

Mr. Coyne is not placing weight on lower Canadian ROEs and capitalization ratios in this determination. He is acknowledging the widely adopted practice in Canada, including the BCUC, recognizing that an adjustment to the authorized ROE for financing flexibility is warranted. Please also refer to the response to BCUC 43.1. Mr. Coyne has included such an adjustment to the results of his DCF and CAPM models.

44.0 Reference: RETURN ON EQUITY

Exhibit B1-8, pp. 23–24; Exhibit B1-8-1, Appendix C - Evidence of Mr. Coyne, p. 46; Exhibit A2-13, 2020 Brattle Group Report, p. 33

Proposed ROE for FEI

On page 23 of Exhibit B1-8, regarding the proposed ROE for FEI, FBCU states:

> Giving more weight to the U.S. Gas Utilities proxy group and considering the BCUC's findings in prior cost of capital decisions regarding the multi-Stage DCF and CAPM models, Concentric concludes that an appropriate ROE for FEI is 10.1 percent.

Table 5-1: Summary of Results of Concentric's evidence for FEI

	Canadian Regulated Utilities[36]	US Gas Utilities	North American Utilities - Gas	Average
CAPM	10.68%	10.67%	11.05%	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	10.5%	10.1%	10.6%	10.4%

44.1 Please provide the exact weights assigned to each of the ROE results in table 5-1 which led to a final proposed ROE of 10.1 percent for FEI.

Response:

Concentric provides the following response:

As indicated on page 4 of Mr. Coyne's report, he gave equal weight to the results of the Multi-Stage DCF model and the CAPM analysis. As shown in the table above, that results in an ROE estimate for the U.S. Gas proxy group of 10.1 percent, which is Mr. Coyne's recommendation for FEI.

On page 24 of the Exhibit B1-8, regarding the proposed ROE for FBC, FBCU states:

> Giving more weight to the U.S. electric Utilities proxy group and considering the BCUC's findings in prior cost of capital decisions regarding the multi-Stage DCF

and CAPM models, Concentric concludes that an appropriate ROE for FBC is 10.0 percent.

Table 5-2: Summary of Results of Concentric's Evidence for FBC

	Canadian Regulated Utilities[37]	US Electric Utilities	North American Utilities-Electric	Average
CAPM	10.68%	11.12%	10.80%	10.9%
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	10.9%	10.0%	10.0%	10.3%
Avg CAPM and Multi-Stage DCF	10.5%	10.0%	9.9%	10.2%

44.2 Please provide the exact weights assigned to each of the ROE results in table 5-2 which led to a final proposed ROE of 10.0 percent for FBC.

Response:

Concentric provides the following response:

Please refer to the response to BCUC IR1 44.1. Mr. Coyne applied the same equal weighting in deriving his ROE recommendation for FBC, as explained on page 5 of his report. The results of the individual models in the table above are rounded to two significant digits. The Multi-Stage and CAPM results for the U.S. Electric proxy group produce an average ROE of 10.0 percent. Any differences are due to rounding of the individual model results.

44.2.1 Given that the North American electric utilities proxy group has overlap with the Canadian regulated utilities and US electric utilities proxy groups, please confirm if the North American electric utilities proxy group is used in any aspect of the ROE calculations.

44.2.1.1 If yes, please confirm if this means that the companies, which appear in two proxy groups effectively have double the weight compared to the companies that appear only in one proxy group.

Response:

Concentric provides the following response:

Mr. Coyne presented the North American proxy groups as an alternative because investors in gas and electric utilities view the industry as an integrated North American industry. Mr. Coyne's North American Gas group only includes Canadian companies that are primarily focused on natural gas operations, while his North American Electric group only includes Canadian companies that are primarily electric utilities. While there is overlap between and amongst the groups, there is no double counting in the North American proxy groups. Canadian Utilities Ltd. is the only Canadian company included in both the North American Gas and North American Electric proxy groups. This is because Canadian Utilities Ltd. is a combination gas and electric utility that derives approximately equal percentages of net income and revenues from gas and electric utility service.

Page 33 of the 2020 Brattle Group Report states:

> All of the regulators rely on a version of the CAPM to estimate the cost of equity, although there are important differences of detail which we explore below. However, the two US regulators (FERC and STB) also estimate the cost of equity using one or two other models, and the final cost of equity determination is the simple average of the CAPM estimate and the estimate from the other model(s). This is a striking difference from the approach of the other regulators. All the other regulators either rely exclusively on the CAPM or very heavily on the CAPM, with some weight given to cross checks and other evidence. No reviewed regulator other than the FERC and the STB appears to put weight on other models beyond the CAPM.

On page 46 of Appendix C, Mr. Coyne summarizes that the BCUC has previously acknowledged the need to use multiple methodologies in determining a fair return on equity.

44.3 Please discuss Mr. Coyne's views regarding the appropriate weight to place on CAPM versus multi-stage DCF model.

Response:

Concentric provides the following response:

As stated in Mr. Coyne's report, he supports the BCUC's previous approach of using multiple methodologies and believe it is appropriate to place equal weight on the results of the CAPM and Multi-Stage DCF models. Mr. Coyne notes that FERC also considers multiple methods in

establishing the return for electric transmission companies. In particular, FERC also includes the risk premium model, in addition to the CAPM and Two-Stage DCF models, and gives equal weight to the results of those three approaches. He further points out that in volatile market conditions, such as those experienced over the last decade, there is additional value in using multiple models. All models have their strengths and weaknesses, so relying on an equal weighting of two (or more) improves both the reliability of the estimate and the confidence that stakeholders can place in the result.

44.4 If possible, please provide any insight Mr. Coyne may have as to why utility regulators outside of North America do not rely on models outside of CAPM (according to the 2020 Brattle Group Report) for the ROE determination.

Response:

Concentric provides the following response:

In markets outside North America, regulators do not have the same options of relying on multiple models. The DCF model, which is the primary alternative to the CAPM, requires substantial market data and earnings estimates for proxy companies not as readily available in all markets. Investors rely on multiple methods, and academic texts such as Brigham and Houston support use of multiple models to estimate cost of equity. The constant growth DCF model was developed by Professor Myron Gordon for the specific purpose of estimating cost of equity for public utilities, which operate in mature and stable industry and generally have stable, predictable growth rates. In Mr. Coyne's view, where the option and sufficient market data exists, multiple models convey important information to regulators and create greater confidence in the result.

E. EVIDENCE OF MR. COYNE – FEI

45.0 Reference: ENERGY TRANSITION RISK

Exhibit B1-8-1, Appendix A - FEI Business Risk Assessment, p. 19, Appendix C - Evidence of Mr. James Coyne, pp. 78 and 112; Exhibit B1-8, FBCU Evidence, p. 3

Energy Transition Risk – Canada and US

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

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

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

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

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

45.1 Considering that there are at least six US states that imposed restrictions on gas use in buildings but at least 19 other states prohibited gas bans, please discuss whether Mr. Coyne believes that Canada is more advanced or less advanced than the US in energy transition. Please provide supporting evidence where available.

Response:

Concentric provides the following response:

As discussed on page 78 of Mr. Coyne's report, the U.S. States that have imposed restrictions on natural gas use represent approximately 25% of total gas use in the country. As also noted, at least 19 U.S. states have passed laws prohibiting gas bans. Mr. Coyne observes on page 79 of his report: "While prohibitions on building gas bans in many U.S. states are a positive near-term development for natural gas distributors in certain jurisdictions, declining costs and government support for alternatives to gas space heating continue to pressure natural gas' long-term economic viability," citing a recent Brattle study. While the Energy Transition is accelerating

rapidly in the U.S., Mr. Coyne agrees that several jurisdictions in Canada, in particular British Columbia, are on the forefront of this movement.

45.2 Please discuss whether Mr. Coyne considers it is riskier to be at the forefront of energy transition or to be a laggard with prohibition on bans of natural gas.

Response:

Concentric provides the following response:

There is more risk for investors in jurisdictions that are at the forefront of changes in public policy, including the Energy Transition. In the case of regulated utilities, this is because future cost recovery is uncertain, no one knows exactly the extent to which the new carbon emissions policies will limit growth prospects for gas distribution companies, and there is the potential risk of stranded assets.

45.3 Please discuss whether any adjustments are warranted for the use of US Gas proxy to account for the difference in energy transition policies as compared to Canada. Please indicate whether these adjustments would increase or decrease the estimated allowed ROE and deemed equity component of a utility in Canada or in BC.

Response:

Concentric provides the following response:

As shown in Figure 49 of Mr. Coyne's report, 50 percent of the operating utilities held by the U.S. proxy group provide service in states with gas use restrictions, while 50 percent are in states that have prohibitions against gas bans. The 2021 CleanBC Roadmap in British Columbia is more aggressive and will happen sooner than in the U.S. states which have gas use restrictions, which means that FEI has greater Energy Transition risk than any of the companies in the U.S. Gas proxy group. This could support a higher recommendation than Mr. Coyne's recommended equity ratio of 45.0 percent for FEI, as well as an authorized ROE of 10.1 percent.

46.0 Reference: ENERGY TRANSITION RISK

Exhibit B1-8-1, Appendix C - Evidence of Mr. James Coyne, p. 94

Energy Transition Risk – European Case Study

On page 94 of Appendix C, Mr. Coyne states:

> The pace and status of the Energy Transition differs by region. Regions that are further along in the Energy Transition can serve as instructive examples of what is to come for regions that are further behind. We have examined Europe's gas utilities, which operate in a region that is ahead of many others in the Energy Transition, as a case study in the future of Canadian gas utilities if the Energy Transition continues.
>
> […]
>
> S&P further notes that, considering these limitations on growth, Europe's gas utilities will need to "reduce their financial leverage" (i.e., increase the equity ratio) to maintain their credit ratings despite "supportive and very predictable regulations."

46.1 Please discuss Mr. Coyne's views on how much gas utilities need to reduce their financial leverage (i.e., as a percentage of increase in equity ratio) given energy transition.

Response:

Concentric provides the following response:

Mr. Coyne has not attempted to quantify what reduction in financial leverage would be required due to the Energy Transition because that answer varies depending on the specific environmental policies of the jurisdiction in which the utility provides service. However, Mr. Coyne finds that increasing the common equity ratio for FEI to 45.0 percent is appropriate given the Company's higher business risk profile in part due to the Energy Transition. Without such an increase in the deemed equity ratio, natural gas companies such as FEI may not be able to maintain their current credit ratings or raise debt or equity on terms as favorable as those prior to the transition.

46.2 Please discuss if Mr. Coyne is aware of any credit agencies that have already downgraded gas utilities or any financial institutions that are denying lending to natural gas utilities.

Response:

Concentric provides the following response:

There have been credit downgrades for gas utilities in 2021 and 2022. The January 2022 S&P report provided as Attachment 13.3.1 in the response to BCUC 13.3.1 provides the following summary of credit downgrades and reduced credit outlooks related to ESG considerations and weakening credit metrics:

> During 2021 downgrades were primarily the result of weak financial measures and ESG-related credit risks. We downgraded Atmos Energy Corp. (A-/Negative/A-2), Duke Energy Corp. (BBB+/Stable/A-2), One Gas Inc. (BBB+/Negative/A-2), Entergy Louisiana (BBB+/Stable), and Entergy New Orleans LLC (BB/Developing/--) primarily because of rising environmental or physical risks. Conversely, downgrades to National Grid North America Inc. (BBB+/Stable/A-2), Southwest Gas Holdings Inc. (BBB-/Negative/--), Southern Co. (BBB+/Stable/A-2), and Pinnacle West Capital Corp. (BBB+/Negative/A-2) primarily reflected weak financial measures.
>
> ESG credit risks and weak financial measures similarly affected the outlooks on several utilities. We revised the outlook on OGE Energy Corp. (BBB+/Negative/A-2) to negative from stable reflecting physical risks while the outlooks for Algonquin Power & Utilities Corp. (BBB/Negative/--), American Electric Power Co. Inc. (A-/Negative/A-2), Cleco Corporate Holdings LLC (BBB-/Negative/--), and Evergy Inc. (A-/Negative/A-2) were all revised to negative from stable because of relatively weak financial measures for their current rating

As discussed in Mr. Coyne's report, the Energy Transition is a relatively new issue for the industry. Credit rating agencies have commented on the potential risks around this issue if it is not properly mitigated by regulatory policies that support utility credit quality, such as higher deemed equity ratios, accelerated depreciation, and shorter economic planning horizons. In general, S&P has noted that the median credit rating for utilities has recently declined to BBB for the first time ever.

46.3 Please discuss if Mr. Coyne is aware of any mitigation strategies that have been adopted by gas utilities to reduce their credit risk.

Response:

Concentric provides the following response:

In Mr. Coyne's view, increasing the deemed equity ratio or ROE is one of the ways to mitigate this increase in business risk for gas utilities such as FEI. Utilities might also consider accelerating

depreciation rates and shortening the economic planning horizon for capital investments. Equity investors will be looking for evidence that earnings growth can be sustained during and post-transition to a lower carbon future, so implementation of renewable gas programs, hydrogen, and related initiatives will also be important.

46.4 Please provide a summary of the European Case Study on gas utilities under energy transition. As part of the summary, please provide investors' sentiment on the impact to gas utilities.

Response:

Concentric provides the following response:

Please refer to Attachment 46.4 for a November 2020 S&P report titled "As Europe's Gas Markets Slowly Stall, Producers' and Utilities" Business Risks May Rise." S&P lists the key takeaways from the report as follows:

Key Takeaways

- Gas will remain a key European energy source for decades, but growth is likely now over and decline looks inevitable.
- S&P Global Platts Analytics expects demand for natural gas in Europe to decrease by 0.3% per year on average over the next decade.
- Even if large producers and well-diversified utilities are not downgraded because of the pandemic pressures in 2020, simply lowering debt and leverage may not offset increased longer-term business risks associated with these changes

In addition, the S&P report also observes:

> Demand for natural gas in Europe is extremely unlikely to expand over the next decade. S&P Global Platts Analytics expects accumulated demand decline of 11.5 billion cubic metres (bcm) in 2020-2030. Although carbon dioxide emissions from gas are about 50% lower than those from coal, this is not enough to make gas compatible with Europe's decarbonization targets and with the EU Green Taxonomy. Implementing the European Green Deal and rolling out green-focused, post-COVID-19 economic recovery packages will further constrain demand growth potential for gas, as will an increasing focus on energy security and the gradual development of energy storage.

That said, S&P Global anticipates that gas will remain an important part of the European energy mix during the next decade. Most countries plan to retire very large coal and nuclear generation capacity and their energy mix will still need options that complement intermittent renewables.

Although S&P Global Ratings considers that large players rated 'BBB-' or above will be able to manage the rating pressures specific to 2020, strategic shifts have been triggered. Europe is ahead of many regions in energy transition, which increases longer-term business risks for the gas industry.

European gas producers no longer view gas as a key part of their decarbonization strategies. For example, companies such as BP, Equinor, and Total are investing in renewables; hydrogen; and carbon capture, utilization, and storage (CCUS).

Meanwhile, emerging market gas producers such as Qatar Petroleum (QP), Gazprom, and Novatek increasingly seek to monetize their gas reserves by expanding in new and growing geographic markets, or into petrochemicals. QP and Novatek are developing their LNG projects and Gazprom plans to expand its pipeline gas exports to China. Middle Eastern countries and Russia plan to expand into petrochemicals.

Many large European power generation companies are already diversified into other types of fuel and hedge the risks associated with their exposure to gas. Their growth strategies typically focus on renewables and networks, and they are making only limited investments in gas-fired power generation.

At present, regulated gas transmission and distribution companies still benefit from supportive and very predictable regulations, which underpin their resilience. Despite this, we anticipate that they will need to reduce their financial leverage if they are to maintain ratings at the current level. There are limited growth prospects for gas infrastructure, and alternative growth paths, like diversifying into hydrogen, carry technological and regulatory uncertainties. Regulatory pressures in several countries, such as Spain and the U.K., are also rising.

46.5 Please discuss any quantifiable changes in ROE and equity ratios of regulated utility companies in the European Case Study conducted.

Response:

Concentric provides the following response:

The S&P article referenced in the response to BCUC IR1 46.4 discusses the outlook for European gas utilities as it relates to credit rating outlook, credit metrics, regulatory environment, financial policies, and declining growth prospects. Please see pages 10-15 of that report for details.

47.0 Reference: ENERGY TRANSITION RISK

Exhibit B1-8-1, Appendix C - Evidence of Mr. James Coyne, pp. 88 and 91, Appendix A - FEI Business Risk Assessment, p. 26

Energy Transition Risk – Stranded Asset Risk

On page 88 of Appendix C, Mr. Coyne states, "Even though the Energy Transition will play out over many decades, it is materially increasing FEI's risk profile today because of the long expected lives of most natural gas utility investments."

On page 91 of Appendix C, Moody's notes:

> Supportive regulation likely to help companies avoid stranded asset risk. State regulators and utilities will likely collaborate to avoid stranded asset risk as exposure to such risks increases. Adjusting the useful life of assets, accelerating depreciation rates of existing assets and securitizing the asset value of at-risk property, plant and equipment help ensure full investment recovery and support long term utility credit quality

On page 91 of Appendix C, Mr. Coyne states:

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

On page 26 of Appendix A, FEI states that it is unknown whether FEI's infrastructure will continue to be fully utilized.

47.1 Given the uncertainty of whether "FEI's infrastructure will continue to be fully utilized" and the "long expected lives of natural gas utility investments", please discuss whether FEI should adjust the useful life of its assets and/or accelerate its depreciation rates in order to improve the prospects of recovering investments and thus, support long term utility credit quality.

Response:

Please refer to the response to BCUC IR1 10.2.

As indicated in that response, a better approach for FEI at present is to develop alternative energy products and services that leverage existing assets while also reducing emissions. Early retirement of assets (such as accelerating depreciation) serves to increase costs for customers while also decreasing the competitiveness of the gas energy delivery system, whereas developing alternative energy products and services that leverage existing infrastructure offers a solution to reducing emissions.

47.2 Please discuss the pros and cons of accelerating depreciation rates or other ways to manage FEI's investments in major capital projects to address the concerns of allowing investors a fair "return of" their invested capital.

Response:

Accelerated depreciation is typically a type of mechanism used to limit losses when no other viable alternative exists to avoid asset impairment. Accelerated depreciation methods result in higher depreciation expenses for earlier years of the service life of an asset. The primary advantage of this approach is that, if estimates of service life are subject to wide possible error (for example due to stranded asset risk), only a small allocation of the initial asset value is left to the period near the end of the asset's life.

A major drawback of accelerated depreciation methods is that the annual depreciation expense would not represent the true consumption patterns of assets and may create intergenerational inequities. From the perspective of FEI and its customers, another drawback of this approach is that it will increase rates, reducing natural gas price competitiveness and energy affordability. The higher rates could then jeopardize FEI's ability to pursue initiatives that could reduce its customers' GHG emissions and could lead to a downward demand spiral. This is why FEI believes that increased investment to develop low-carbon energy products and services that leverage existing assets, while also reducing emissions, is the preferred approach.

Please refer also to the response to BCUC IR1 47.1.

47.2.1 In light of the risks that investors face due to stranded assets and the advent of Energy Transition as noted by Mr. Coyne, please discuss how the BCUC should choose to allow investors a fair "return of" their invested capital – either (i) increase the ROE or equity ratio; (ii) accelerate depreciation rates; or (iii) some combination of both or other solutions.

Response:

Please refer to the responses to BCUC IR1 47.1 and 47.2.

The "return on and of" capital is not an either/or issue as suggested in the question. In other words, having accelerated depreciation does not necessarily warrant a lower ROE. As explained in the response to BCUC IR1 47.2, accelerated depreciation may be a tool to consider in time, but should be based on further evidence and review of potential changes in useful lives of assets and any other relevant matter from depreciation experts. With no basis to adjust depreciation and

considering the current environment and uncertainty, at this time, using accelerated depreciation would not be appropriate.

Please further note that the ROE of a utility is set based on the return available to investors in similar risk enterprises. A utility with accelerated depreciation is still at risk of not being able to fully recover its invested capital and indeed may be at higher risk due to reduced price competitiveness, which could result in a demand death spiral. This situation may warrant an even higher ROE.

To properly consider the trade-offs between depreciation methods, FortisBC may evaluate whether the physical lives of assets have changed as a result of other factors (e.g., public policy). The Company has not proposed such an approach at this time but will monitor the evolution of depreciation approaches in the industry to determine if such an approach should be applied in the future.

48.0 Reference: RELATIVE RISK OF GAS AND ELECTRIC UTILITIES

Exhibit B1-8-1, Appendix C - Evidence of Mr. James Coyne, p. 99

Relative Risk of Gas and Electric Utilities – Value Line Electric Utility

On page 99 of Appendix C, Mr. Coyne states:

> I compared each of these measures [financial and valuation measures] for the natural gas LDC proxy group companies and the Value Line Electric Utility universe in 2021 vs. the same measure in 2016.

48.1 Please clarify what constitutes the "Value Line Electric Utility universe." As part of the response, please confirm, or explain otherwise, that the companies identified in the Value Line Electric Utility universe in 2021 are the same as in 2016.

Response:

Concentric provides the following response:

Mr. Coyne used the current Value Line Electric Utility universe of 36 companies and compared the financial and valuation measures of those companies in 2021 to the same 36 companies in 2016.

49.0 Reference: RELATIVE RISK OF GAS AND ELECTRIC UTILITIES

Exhibit B1-8-1, Appendix C - Evidence of Mr. James Coyne, p. 99

Relative Risk of Gas and Electric Utilities – Gas Utility Discount

On page 99 of Appendix C, Wells Fargo Securities January 2021 report on the outlook for the gas industry states:

> Taking into account the solid fundamental backdrop and the considerations around decarbonization and ESG risk, we think the gas utilities should trade at a modest discount to electric utilities, all else equal. We think a ~5% discount is reasonable and that anything beyond 10% would represent an attractive sub-sector entry point.

49.1 Please explain what constitutes "an attractive sub-sector entry point."

Response:

Concentric provides the following response:

Mr. Coyne interprets the Wells Fargo Securities report to mean that if the discount for gas utilities falls below 10% compared to electric utilities, Wells Fargo Securities views that as meaning that gas utility valuations are relatively low compared to electric utilities and are therefore attractive to investors.

49.2 Please explain whether Mr. Coyne agrees that natural gas utilities should trade at a discount to electric utilities.

49.2.1 If Mr. Coyne agrees, please explain why and whether 5 percent is appropriate.

49.2.2 If Mr. Coyne does not agree, please explain why.

Response:

Concentric provides the following response:

Mr. Coyne does not take a position on the relative valuation of gas and electric utilities. He quotes from the Wells Fargo Securities report because it provides evidence from equity analysts who provide coverage and research on the regulated utilities sector. Mr. Coyne, however, finds this evidence to be reasonable, given the challenges created by the Energy Transition.

49.3 Please explain how the "5% discount" suggested by Wells Fargo could be applied to the proposed ROE of FEI relative to FBC, if at all.

Response:

Concentric provides the following response:

The 5% discount reported by Wells Fargo was not intended to be applied to the proposed ROE or capital structure for FEI relative to FBC. Rather, it provides evidence that natural gas distributors are trading at a discount to electric utilities, and a principal reason for this discount is due to investor concerns with the Energy Transition and how it impacts the natural gas industry. Mr. Coyne emphasizes this is a fundamental shift in the perspective of investors regarding the relative risks of the gas and electric industries. In utilizing a gas specific proxy group, Mr. Coyne has picked up this risk perspective, at least for the gas utility business as whole, in his ROE analysis, so it requires no further adjustment. But the capital structure must also reflect those risks, as reflected in the recommended upward movement of FEI in relation to FBC that brings FEI closer, but still well below, most of its North American peers.

50.0 Reference: COMPARISON TO US GAS UTILITY

Exhibit B1-8-1, Appendix C - Evidence of Mr. James Coyne, pp. 112–114

Comparison of Canadian Regulation vs. US Regulation

On pages 112 and 113 of Appendix C, Mr. Coyne states, "Credit rating agencies such as Moody's previously published reports indicating that they viewed Canadian utility regulation as being generally more favorable than U.S. regulation, due primarily to lower regulatory lag in Canada and fewer cost recovery mechanisms for U.S. utilities." Mr. Coyne further states that in September 2013, Moody's issued a report discussing its evolving view of US utility regulation in which the credit rating agency states, "Based on our observations of trends and events, we propose to adopt a generally more favorable view of the relative credit supportiveness of the U.S. utility regulatory environment."

On page 114 of Appendix C, Mr. Coyne states:

> Concentric contacted Moody's to check if the agency has updated its 2013 report, and the lead utilities rating analyst indicated that 2013 remained its most recent assessment, although it anticipated publishing an update in mid-2022. More recently, a March 2019 report by equity analysts at Scotiabank indicated that they view the regulatory environments in Canada and the U.S. as being similar for regulated utilities.

50.1 Please discuss whether Mr. Coyne considers Canadian utility regulation as being generally more favorable than US utility regulation and explain why or why not.

Response:

Concentric provides the following response:

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. While there are differences between individual provinces and states, based on research supplemented by a series of interviews over the past several years, Mr. Coyne has found that credit rating agencies and equity investment analysts tend to view the Canadian and U.S. regulatory environments as more alike than different.

50.2 Please discuss whether Mr. Coyne contacted any other credit rating agency (e.g., S&P, DBRS, or Fitch) for a more recent report than Moody's 2013 Report, for an outlook on Canadian utility regulation and US regulation.

Response:

Concentric provides the following response:

Mr. Coyne has also spoken with the utility analysts at Standard and Poor's. S&P views all regulation as being supportive for the credit quality of regulated utilities, noting only slight variations or gradations between the jurisdictions in Canada and the U.S. DBRS has published a report comparing U.S. and Canadian jurisdictions that we found informative, but this report has not been updated to our knowledge. It was last published in 2014.

50.3 Please discuss whether Mr. Coyne is aware of any other Canadian banks apart from Scotiabank that view the utility regulatory environments in Canada and the US as being similar for regulated utilities. If so, please state the other Canadian banks and provide supporting material.

Response:

Concentric provides the following response:

Concentric is not aware of any public commentary by other banks on this topic. In the context of Concentric's financial advisory work, we routinely work with Canadian investment funds and banks on utility transactions in both the U.S. and Canada. In doing so, we focus on specific regulatory mechanisms and the overall business environment for the utilities and their unique risks and opportunities. In our experience, there is not a U.S. or Canadian perspective, but one that focuses on the specific circumstances of the utility, which we believe is appropriate.

50.4 Please provide the other Canadian banks' views on utility regulatory environments in Canada and the US, including whether any banks view Canadian utility regulators as being more, or less, supportive than US utility regulators.

Response:

Please refer to the response to BCUC IR1 50.3.

51.0 Reference: FINANCIAL RISK

Exhibit B1-8, p. 5; Exhibit B1-8-1, Appendix C - Evidence of Mr. James Coyne, pp. 120 and 148–149, Exhibit JMC-FEI-1 to 11

Capital Structure – Deemed Equity Ratio

On page 120 of Appendix C, Mr. Coyne provides the following table:

Figure 50: Comparison of Deemed Equity Ratios

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

Footnote 201: Source: S&P Global Market Intelligence. 2021 decisions through December 31, 2021.

On pages 148 and 149 of Appendix C, Mr. Coyne states that he finds FEI's proposed capital structure to be appropriate as it recognizes the "substantial increase in risks associated with the gas utility transition and the growing political opposition to fossil fuels and natural gas in particular" and "the greater risks of FEI relative to its Canadian investor-owned gas utility peer companies." Mr. Coyne also submits, "With respect to the U.S. Gas proxy group, FEI has greater financial risk but comparable business risk. FEI's proposed equity ratio would fall below the U.S. Gas proxy company average debt/capital ratio of 50-52 percent despite the higher level of financial risk and comparable level of business risk."

On page 149 of Appendix C, Mr. Coyne shows the following table:

Figure 64: Comparison of Authorized Equity Returns

Operating Utility	Equity Return	Equity Ratio	Weighted ROE
FortisBC Energy Inc. (existing)	8.75%	38.50%	3.37%
FortisBC Energy Inc. (proposed)	10.1%	45.00%	4.55%
ATCO Gas	8.50%	37.00%	3.15%
Enbridge Gas[224]	8.66%	36.00%	3.12%
Energir[225]	8.90%	38.50%	3.43%
Canadian Gas Average	8.69%	37.17%	3.23%
Canadian Gas Median	8.66%	37.00%	3.15%
U.S Gas LDC Average	9.48%	52.0%	4.93%
U.S. Gas Proxy Group Average	9.45%	53.4%	5.05%

In exhibit "JMC-FEI-10" attached to Exhibit JMC-FEI-1 to 11 of Appendix C, Mr. Coyne conducts credit metrics analysis, which has been reproduced in part below:

CREDIT METRICS ANALYSIS

Company Name	Ticker	Rating	Debt to Capital Ratio	EBITDA Interest Coverage	FFO to Cash Interest Coverage	FFO / Debt (%)	Debt to EBITDA
FortisBC Energy Inc. (1)		NR	62.9%	3.71	3.92	12.9%	6.13
U.S. Gas Proxy Group							
New Jersey Resources Corporation [3]	NJR	A-	46.9%	6.59	6.15	17.9%	4.67
Northwest Natural Gas Company	NWN	A+	61.8%	5.86	5.75	15.3%	5.26
ONE Gas, Inc.	OGS	A	47.4%	7.63	7.13	20.8%	3.90
Spire, Inc.	SR	A-	60.8%	4.31	5.01	12.5%	6.37
U.S. Gas Proxy Group		A	54.2%	6.10	6.01	16.6%	5.05

51.1 Please restate Figure 50 by providing the following:

a. the company names used for the US Gas LDC Average (2020/2021) and US Gas Proxy Group Average;

b. the ROE for the US Gas LDC Average (2020/2021) and US Gas Proxy Group Average;

c. the ROE for the Canadian operating utilities listed; and

d. the relative risk (higher, similar, lower) of FEI compared to each utility listed in Figure 50, and rationale to support the assessment. Please provide the response in a format similar requested in IR 37.1 above.

Response:

Concentric provides the following response:

a) The US Gas LDC average is based on all companies with a rate decision in 2020 and 2021. Please refer to CONFIDENTIAL Attachment 51.1 for the workpaper supporting that calculation. The U.S. Gas proxy group average is based on the most recent equity ratio for each of the operating gas utilities held by the U.S. Gas proxy group.

b) The average ROE for the U.S. Gas LDC and the U.S. Gas proxy group is provided in Figure 64, which appears in the table at the top of this page.

c) The authorized ROEs for the companies in Figure 50 are shown in Figure 35 of Mr. Coyne's report.

d) Mr. Coyne provides a relative risk assessment of three large investor-owned gas utilities in Canada (ATCO Gas, Enbridge Gas, and Energir) in his report. He does not include the remaining Canadian gas utilities shown in Figure 50 in that risk assessment because those companies are much smaller than FEI and therefore are not appropriate comparators.

Attachment 51.1 is being filed on a confidential basis with the BCUC, pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-15-19. Concentric advises that the information is proprietary and only available to subscribers who, under the terms of the license, are not to reproduce, redistribute or store in a public retrieval system without prior written consent, which has not been obtained. Therefore, Attachment 51.1 is being provided confidentially under separate cover to the BCUC only for the purposes of this proceeding, and cannot be provided to other parties under the terms of the license.

51.2 Please explain why Mr. Coyne considers the US Gas LDC Average (2020/2021) Proxy Group in Figure 50 in addition to the US Gas Proxy Group Average in the analysis of deemed equity ratio.

Response:

Concentric provides the following response:

Figure 50 of Mr. Coyne's report provides the average equity ratio for both the U.S. Gas proxy group and the U.S. Gas LDCs because both serve as benchmarks of what capital structure investors expect for U.S. gas distributors given the equity returns authorized for those same companies. Even though these companies did not pass Mr. Coyne's screening criteria at the holding company level, the allowed capital structures provide a broader perspective of allowed equity ratios. The evidence shows that the average authorized equity ratio for the U.S. Gas LDCs in 2020 and 2021 was generally consistent with the authorized equity ratios for the operating companies in the U.S. Gas proxy group. As discussed in Mr. Coyne's report, there is a correlation between the equity ratio and the authorized ROE. Both must be reasonable in order to meet the fair return standard.

51.3 Please clarify whether Mr. Coyne considers FEI to be more comparable in terms of risk to Énergir or to the US Gas proxy groups.

Response:

Concentric provides the following response:

Mr. Coyne considers the U.S. proxy group to be more comparable. Mr. Coyne included Energir in the section of his report that assesses the business risk of FEI against large gas distribution utilities in Canada, and he concluded that Energir has somewhat less energy transition risk than FEI and is smaller than FEI in terms of number of customers but comparable in terms of annual throughput and revenues, as shown in Figure 47 of his report. Please see pages 110-111 of Mr. Coyne's report for a more detailed comparison of Energir and FEI.

Energir is not included in Mr. Coyne's Canadian proxy group because it is not publicly traded and therefore does not have market data that can be used to estimate the cost of equity. Again, Mr. Coyne's overall conclusion is that the U.S. Gas proxy group is most comparable to FEI in terms of business and financial risk.

52.0 Reference: FINANCIAL RISK

Exhibit B1-8, p. 5; Exhibit B1-8-1, Appendix C - Evidence of Mr. James Coyne, p. 120, Exhibit JMC-FEI-1 to 11

Capital Structure – Deemed Equity Ratio

In "Exhibit JMC-FEI-10" attached to Exhibit JMC-FEI-1 to 11 of Appendix C, Mr. Coyne conducts credit metrics analysis, which has been reproduced in part below:

CREDIT METRICS ANALYSIS

Company Name	Ticker	Rating	Debt to Capital Ratio	EBITDA Interest Coverage	FFO to Cash Interest Coverage	FFO / Debt (%)	Debt to EBITDA
FortisBC Energy Inc. (1)		NR	62.9%	3.71	3.92	12.9%	6.13
U.S. Gas Proxy Group							
New Jersey Resources Corporation [3]	NJR	A-	46.9%	6.59	6.15	17.9%	4.67
Northwest Natural Gas Company	NWN	A+	61.8%	5.86	5.75	15.3%	5.26
ONE Gas, Inc.	OGS	A	47.4%	7.63	7.13	20.8%	3.90
Spire, Inc.	SR	A-	60.8%	4.31	5.01	12.5%	6.37
U.S. Gas Proxy Group		A	54.2%	6.10	6.01	16.6%	5.05

On page 120 of Appendix C, Mr. Coyne provides the following table:

Figure 50: Comparison of Deemed Equity Ratios

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

52.1 Please provide the Equity Ratio for the US Gas Proxy Group in "Exhibit JMC-FEI-10" attached to Exhibit JMC-FEI-1 to 11 of Appendix C in comparison to the "Debt to Capital" Ratio with an average of 54.2 percent provided.

Response:

Concentric provides the following response:

The equity ratios shown in Figure 50 are at the operating company level, whereas the equity ratios for the U.S. Gas proxy group in Exhibit JMC-FEI-11 are at the holding company level. That accounts for the difference. For his risk analysis, Mr. Coyne focused on the capital structure at the operating company level because that is where the risk comparison is appropriately

performed. However, credit metrics for the U.S. Gas proxy group are reported at the holding company level in Exhibit JMC-FEI-11. Since these companies derive most of their revenues and operating income from regulated operations, the holding company metrics should generally be similar to those for the operating utility.

52.2 Please confirm, or explain otherwise, if the US Gas Proxy Group Average in Figure 50 should align with the companies presented in Exhibit JMC-FEI-1 to 11.

52.2.1 If confirmed, please explain why the average equity ratio does not align.

52.2.2 If not confirmed, please explain how the two groups were used in the analysis.

Response:

Concentric provides the following response:

The U.S. Gas proxy group average equity ratio in Figure 50 is based on the most recent authorized equity ratio for each of the operating companies held by the U.S. Gas proxy group, as shown in Attachment 52.2. Exhibits JMC-FEI-1 to 11 do not provide equity ratios at the operating company level for the companies in Mr. Coyne's U.S. Gas proxy group.

53.0 Reference: FINANCIAL RISK

Exhibit B1-8-1, Appendix C - Evidence of Mr. James Coyne, p. 121

Financial Risk – Assessment of Credit Metrics

On page 121 of Appendix C, Mr. Coyne states

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

53.1 Please clarify why the S&P credit metrics for FEI for 2020 were considered "significantly weaker than the S&P credit metrics of the companies in the U.S. Gas proxy group", which differs by one notch from FEI's rating but considered "comparable" to the Canadian proxy group which also differs by one notch from FEI's rating.

Response:

Concentric provides the following response:

As shown in Figure 51 and discussed on page 121 of Mr. Coyne's report, the credit metrics for FEI in 2020 were significantly weaker than for the U.S. Gas proxy group. This is consistent with the fact that FEI's credit rating is one notch lower than the U.S. Gas proxy group. The credit metrics for FEI are similar to the Canadian proxy group as also shown in Figure 51. Credit ratings consider both business and financial risk. The fact that FEI's credit rating is one notch higher than the average for the Canadian proxy group suggests that FEI is considered to have somewhat lower regulatory risk than the Canadian proxy group, only three of which own gas distribution companies (Canadian Utilities – ATCO Gas; Enbridge Inc. – Enbridge Gas; and AltaGas – Washington Gas Light in the U.S.). Mr. Coyne's overall conclusion, as stated on page 122 of his report, is that FEI has greater financial risk than the U.S. Gas proxy group and similar financial risk as the Canadian proxy group.

54.0 Reference: FINANCIAL RISK

Exhibit B1-8-1, Appendix C, Evidence of Mr. James Coyne, p. 122

Financial Risk – Credit Metrics Trends Over Time

The following screenshot has been reproduced from page 122 of Appendix C:

> **4. Credit Metric Trends Over Time**
>
> **Error! Reference source not found.** evaluates the change in FEI's Moody's credit metrics from 2016 to 2020. The last column is the percent change in the most recent year (2020) relative to 2016.

54.1 Please provide the reference noted in the error above.

Response:

Concentric provides the following response:

The missing reference should be to Figure 52 on page 122 of Mr. Coyne's report.

F. EVIDENCE OF MR. COYNE – FBC

55.0 Reference: FBC RISK ANALYSIS

Exhibit B1-8-1, Appendix B - FBC Business Risk Assessment, p. 30–31; Appendix C - Evidence of Mr. Coyne, p. 128

Wholesale and Industrial Customers

On page 128 of Appendix C, Mr. Coyne states:

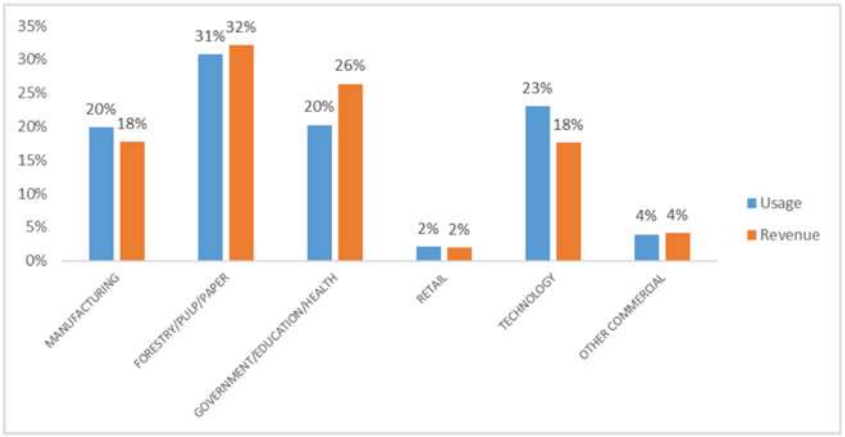
> In 2021, FBC reported that 6 of its 10 largest industrial customers were in the forestry industry, which is subject to a number of risk vulnerabilities, such as the strength of the Canadian dollar, competition and labor disputes. A significant downturn in that industry could eliminate a significant source of FBC's revenue.

On page 30 of Appendix B, FBC states:

> This is because the mix of load continues to be dominated by a small number of customers in a few industries, namely, those related to the forest sector, as has historically been the case, and now with technology-related load associated with cryptocurrency, the shift from one to the other increases the risk profile.

On page 31 of Appendix B, FBC provides the following graph to display the Industrial customers by load in 2020:

Figure B7-2: Industry of FBC's Top Twenty Industrial Customers by Load in 2020



55.1 Please explain whether the effects of cryptocurrency and Government/Education/Health industries were considered in Mr. Coyne's review of FBC's business risk.

55.1.1 If not, please explain whether including cryptocurrency and Government/Education/Health industries in FBC's Industrial Customer profile would amend your assessment of FBC's business risk.

Response:

Concentric provides the following response:

Mr. Coyne considered the Government/Education/Health sector to be a stabilizing element of FBC's risk profile. He did not focus on the emerging crypto-currency sector as a risk to FBC's business profile. More experience will be required to understand the demand profile of these customers and their relative stability to draw meaningful conclusions related to risk, Mr. Coyne did not alter his recommendation on ROE or equity ratio for FBC based on these factors.

56.0 Reference: FBC RISK ANALYSIS

Exhibit B1-8-1, Appendix C - Evidence of Mr. Coyne, p. 129–130, Appendix D-2, "FBC - DBRS – 2021 Credit Rating Report dated March 15, 2021", p. 3

Generation Risk

On page 129 and 130 of Appendix C, Mr. Coyne states:

> Utilities that own generation assets are considered to have higher business risk by credit rating agencies and equity investors… In summary, FBC's status as a vertically-integrated electric utility presents a riskier business profile than those without generation ownership.

On page 129 of Appendix C, Mr. Coyne quote's Moody's Rating Methodology: Regulated Electric and Gas Utilities," dated June 23, 2017: "We view power generation as the highest-risk component of the electric utility business, as generation plants are typically the most expensive part of a utility's infrastructure (representing asset concentration risk) and are subject to the greatest risks in both construction and operation."

On page 3 of DBRS 2021 Credit Rating Report, DBRS listed its Rating Considerations for FBC's Strengths as:

> *Vertically integrated utility/supply security*
>
> FBC is a vertically integrated regulated utility that owns generation, transmission, and distribution assets. The Company's four hydroelectric generation plants with 225 MW of capacity on the Kootenay River, which are insulated from annual hydrology risk as a result of the Canal Plant Agreement (CPA), represented approximately 45% of FBC's annual energy needs.

56.1 Given that DBRS considers FBC's vertically integration a strength, would Mr. Coyne please reconcile how FBC's vertically integrated utility presents a riskier business profile?

Response:

Concentric provides the following response:

According to DBRS's rating methodology for regulated utilities, the rating agency considers the generation mix of an electric utility, with those companies having a more diversified generation mix rated more favorably on this factor. Mr. Coyne interprets DBRS' comments to be focused on the benefits of FBC's diversity of supply. In Mr. Coyne's experience, rating agencies and equity investors more typically take the perspective expressed by Moody's.

More generally, as noted by Moody's rating methodology, integrated electric utilities have risk associated with generation ownership, which represents a significant portion of an electric utility's

rate base and which differentiates them from T&D utilities and gas distribution companies. Integrated electric utilities have historically received higher authorized ROEs than T&D only electric utilities to compensate investors for the unique risks of generation ownership.

Please also refer to the response to BCUC IR1 27.2.

56.2 In Mr. Coyne's view, please discuss the advantages and disadvantages of a vertically integrated electric utility against a Transmission- and Distribution-Only electric utility.

Response:

Concentric provides the following response:

The primary advantage of a T&D only company is the lack of technology, operating and capital investment risk associated with generation. Time has demonstrated that generation technology advances, shifts in fuels prices, and public policy initiatives often outpace the useful lives of generation assets, as currently demonstrated by the shift away from fossil-fuel based generation. These circumstances leave the utility and its customers exposed to stranded assets, whereas a T&D company is better able to navigate these shifts through reliance on contracts or wholesale markets. On the plus side, a vertically integrated utility controls its supply, and is somewhat less exposed to price spikes in wholesale markets, and is better positioned to make long-term investments in larger scale projects on behalf of its customers.

56.2.1 Please show examples of how the allowed ROE and equity thickness is higher for vertically integrated electric utilities than a Transmission- and Distribution-Only electric utility.

Response:

Concentric provides the following response:

Please refer to CONFIDENTIAL Attachment 56.2.1 for a comparison of the authorized ROEs and equity ratios for vertically integrated electric utilities as compared to T&D only electric utilities. 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.

Attachment 56.2.1 is being filed on a confidential basis with the BCUC, pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-15-19. Concentric advises that the information is proprietary and only available to subscribers who, under the terms of the license, are not to reproduce, redistribute or store in a public retrieval system without prior written consent, which has not been obtained. Therefore, Attachment 56.2.1 is being provided confidentially under separate cover to the BCUC only for the purposes of this proceeding, and cannot be provided to other parties under the terms of the license.

57.0 Reference: FBC RISK ANALYSIS

Exhibit B1-8-1, Appendix C - Evidence of Mr. Coyne, pp. 131–132 and 151

Equity Return

On page 131 and 132 of Appendix C, Mr. Coyne states:

> The Commission has previously determined that it was appropriate to compensate FBC's investors for the risk associated with this small size, among other risk factors, by increasing the authorized ROE by 40 basis points above the level set for the benchmark utility in BC, which has traditionally been FEI. In my view, FBC's business risk profile continues to be affected by this small size, and such an upward adjustment continues to be appropriate. [Emphasis added]
>
> FBC's business risk remains comparable to what it was in 2014 when the Commission last determined FBC's authorized ROE and equity ratio. There has been no material changes on most of these risk factors, and the ones that have changed generally offset each other.

On page 151 of Appendix C, Mr. Coyne provides the following table:

Figure 65: Comparison of Authorized Equity Returns

Operating Utility	Equity Return	Equity Ratio	Weighted ROE
FortisBC Inc. (existing)	9.15%	40.00%	3.66%
FortisBC Inc. (proposed)	10.0%	40.00%	4.00%
ATCO Electric	8.50%	37.00%	3.15%
Nova Scotia Power	9.00%	37.50%	3.38%
Hydro One Ltd.	8.66%	40.00%	3.34%
Newfoundland Power	8.50%	45.00%	3.83%
FortisAlberta	8.50%	37.00%	3.15%
Maritime Electric	9.35%	40.00%	3.74%
Canadian Electric Average	8.75%	39.42%	3.45%
Canadian Electric Median	8.50%	38.75%	3.36%
U.S. Electric Average	9.50%	49.64%	4.72%
U.S. Electric Proxy Group Average	9.59%	49.76%	4.77%

57.1 Given that FBC business risk remains comparable to what it was in 2014, please explain why an upward adjustment of 85 bps (Proposed ROE of 10 percent less existing ROE of 9.15 percent highlighted in blue above) is appropriate when compared to the 40 bps authorized in 2014.

Response:

Concentric provides the following response:

Mr. Coyne has not recommended an upward adjustment to FBC's authorized ROE for small size even though the BCUC has previously granted a premium of 40 bps above the benchmark return

to recognize small size and other risk factors. His 10.0% ROE recommendation for FBC is based on the average of the Multi-Stage DCF and CAPM results for the U.S. Electric proxy group. If Mr. Coyne were to make an explicit adjustment for FBC's small size similar to how the Commission made this adjustment in 2014, it would be relative to his ROE recommendation for FEI of 10.1%.

Please also refer to the response to BCUC IR1 24.1.

58.0 Reference: FBC RISK ANALYSIS

Exhibit B1-8-1, Appendix C - Evidence of Mr. Coyne, pp. 133, 138–139 and 141–142, "Exhibit JMC-FBC-1" and "Exhibit JMC-FBC-11"

Canadian and US Proxy Group Companies

On page 133 of Appendix C, Mr. Coyne provides a list of other investor-owned electric utilities in Canada:

Figure 57: Comparison of Canadian Investor-Owned Electric Utilities

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

In "Exhibit JMC-FBC 1" of Appendix C, Mr. Coyne provides a list of companies for Canadian Proxy Group for FBC:

CANADIAN PROXY GROUP

Company	Ticker
Algonquin Power and Utilities	AQN
AltaGas Inc.	ALA
Canadian Utilities Limited	CU
Emera Inc.	EMA
Enbridge Inc.	ENB
Hydro One, Ltd.	H
MEAN	
Flotation	
MEAN (including flotation)	

On page 138 of Appendix C, Mr. Coyne states:

Concentric concludes that FBC has comparable business risk compared to other Canadian electric utilities.

On page 139 of Appendix C, Mr. Coyne states:

> FBC derives 100 percent of its operating income from regulated electric utility service. As shown in Exhibit JMC-FBC-11, the U.S. Electric utility proxy group companies derive approximately 97 percent of regulated income and 96 percent of regulated revenues from electric utility service, and approximately 96 percent of regulated assets are dedicated to electric utility operations. For this reason, Concentric believes that the U.S. Electric utility proxy group is more representative of FBC's electric utility operations than the Canadian proxy group companies, which generally derive lower percentages of operating income and revenues from electric utility service and have a lower percentage of assets dedicated to electric utility operations. [emphasis added]

"Exhibit JMC-FBC-11" of Appendix C shows:

FortisBC Inc.
Exhibit JMC-FBC-11
Page 1 of 1

2018-2020 % Regulated

		[1]	[2]	[3]	[4]
		[1]	[2]	[3]	[4]
U.S. Gas Proxy Group		**% Regulated Income**	**% Electric Revenues**	**% Electric Income**	**% Electric Assets**
Alliant Energy Corporation	LNT	96%	86%	91%	86%
American Electric Power Company, Inc.	AEP	97%	100%	100%	100%
Duke Energy Corporation	DUK	99%	92%	91%	91%
Entergy Corporation	ETR	100%	99%	99%	99%
Exelon Corporation	EXC	79%	91%	91%	91%
Evergy Inc	EVRG	100%	100%	100%	100%
NextEra Energy Inc.	NEE	76%	100%	100%	100%
OGE Energy Corporation	OGE	100%	100%	100%	100%
Pinnacle West Capital Corporation	PNW	100%	100%	100%	100%
Portland General Electric Company	POR	100%	100%	100%	100%
U.S. Electric Proxy Group Average		**95%**	**97%**	**97%**	**97%**

On page 141 of Appendix C, Mr. Coyne states:

> Concentric concludes that FBC has slightly lower business risk than the U.S. Electric proxy due to FBC's lower generation risk.

58.1 Please clarify why the list of investor-owned Canadian utilities listed in Appendix C does not match the Canadian Proxy Group listed in "Exhibit JMC-FBC-1".

Response:

Concentric provides the following response:

Figure 57 of Mr. Coyne's report lists the electric utility operating companies that provide service in Canada (i.e., ATCO Electric, Hydro One Networks, and Nova Scotia Power). Each of these companies is held by one of the companies in Mr. Coyne's Canadian proxy group. For comparison purposes, Figure 57 of Mr. Coyne's report also includes the Fortis Inc's electric operating subsidiaries in Canada (i.e., FortisAlberta, Newfoundland Power, and Maritime Electric), even though Fortis Inc. is not included in the Canadian proxy group because it is the parent company of FEI and FBC. Although these Fortis subsidiaries are not part of the proxy group, Mr. Coyne included them to provide additional information and context for the BCUC's risk assessment of FBC.

58.2 Please confirm, or explain otherwise, whether the investor-owned Canadian utilities listed on page 133 of Appendix C have been used to compare against FBC's business risk and whether the Canadian Proxy group has been used in financial model calculations for DCF and CAPM.

58.2.1 If confirmed, please explain why the same group was not used for both assessments and why is having to separate comparison groups more reflective of FBC's situation.

Response:

Concentric provides the following response:

As explained in the response to BCUC IR1 58.1, Mr. Coyne's risk assessment compares FBC to the electric utility operating companies held by his Canadian proxy group. Mr. Coyne's risk assessment also includes information regarding the Canadian electric utilities held by Fortis Inc., even though Fortis Inc. is not included in his Canadian proxy group. Mr. Coyne's risk assessment for FBC does not include any subsidiaries that do not provide electric utility service in Canada, or that provide gas distribution service. Therefore, the risk assessment for FBC does not include any of the subsidiaries of Algonquin Power and Utilities Company, Enbridge Inc., and AltaGas Inc.

58.2.2 Please clarify which group of Canadian utilities was used to determine the proposed ROE and equity thickness for FBC. If both groups were used, please explain how much weight was given to each in the determination.

Response:

Concentric provides the following response:

Mr. Coyne's cost of equity analysis for FBC was performed on three proxy groups: Canadian Regulated, U.S. Electric., and North American Electric. His ROE recommendation was based primarily on the results for the U.S. proxy group. For the equity ratio, he again considered both U.S. Electric and Canadian proxy group companies, and an expanded sample of Canadian electric utilities that includes electric operating subsidiaries owned by Fortis Inc. as an additional point of comparison for the Commission. For the equity ratio recommendation, he placed more weight on the Canadian sample, as 40% is almost identical to FBC's Canadian peers company average, but almost 10% below that of its U.S. peers.

58.3 Please confirm, or explain otherwise, that the "US Gas Proxy Group" title in "Exhibit JMC-FBC-11" is a mislabelled and should read "US Electric Proxy Group" instead.

58.3.1 If not confirmed, please explain why US Gas Proxy Group includes Electric revenues, income and assets.

Response:

Concentric provides the following response:

Confirmed. Exhibit-JMC-FBC-11 should be labelled "US Electric Proxy Group."

58.4 Please provide "Exhibit JMC-FBC-11 - 2018-2020 % Regulated" as shown in the preamble for the investor-owned Canadian utilities listed on page 133 of Appendix C and the Canadian proxy group listed in "Exhibit JMC- FBC-1".

Response:

Concentric provides the following response:

The percentage of regulated income for the Canadian proxy group companies is shown in Exhibit JMC-FEI-3 and JMC-FBC-3. Several of the Canadian proxy group companies do not report business segment information in a way that would make it possible to provide the information in Exhibit JMC-FBC-11 for these companies. Further, as discussed on page 39 of Mr. Coyne's

report, the only screen he has applied in selecting the Canadian proxy group is that the company must have an investment grade credit rating.

58.5 Given Concentric concludes that FBC has comparable business risk to other Canadian Utilities and lower risk than US proxy group, please explain why US Electric utility proxy group is more representative of FBC's operations.

Response:

Concentric provides the following response:

Mr. Coyne concludes that FBC has greater financial risk than the U.S. proxy companies but slightly lower business risk, but not enough to cause an investor to assign a notably lower risk profile to FBC. Mr. Coyne's Canadian proxy group consists of only six companies, two of which are primarily electric utilities (Hydro One Ltd. and Emera, Inc.), one of which is a combination gas/electric company (Canadian Utilities Ltd.), two of which are primarily gas utilities (AtlaGas Utilities and Enbridge Inc.), and one of which owns utilities primarily in the U.S even though it is based in Canada (Algonquin Power and Utilities Company). As explained on pages 138-139 of his report, for purposes of his ROE analysis, Mr. Coyne believe it is more appropriate to rely on the U.S. Electric proxy group, which derives the majority of its operating income and revenues from regulated electric utility operations, rather than the Canadian proxy group which does not.

On page 142 of Appendix C, Mr. Coyne provides the following table:

Figure 61: Comparison of Allowed Equity Ratios

Operating Utility	Deemed Equity Ratio
FortisBC Inc. (existing)	40.0%
FortisBC Inc. (proposed)	40.0%
Alberta Electric Utilities	37.0%
Ontario Electric Utilities	40.0%
Maritime Electric	40.0%
Newfoundland Power	45.0%
Nova Scotia Power	37.5%
Canadian Electric Average	**39.9%**
US Electric Utility Average (20/21)[215]	**49.64%**
US Electric Proxy Group Average	**49.76%**

58.6 Please provide the following:

a. the company names used for the US Electric Utility Average (20/21) and US Electric Proxy Group Average; and

b. the ROE for the US Electric Utility Average (20/21) and US Electric Gas Proxy Group Average.

Response:

Concentric provides the following response:

The U.S. Electric average is based on all companies with a rate decision in 2020 and 2021. Please refer to CONFIDENTIAL Attachment 58.6, for the workpaper supporting that calculation. The U.S. Electric proxy group average is based on the most recent equity ratio for each of the electric operating utilities held by the U.S. Electric proxy group.

The average ROE for the U.S. Electric Utilities and the U.S. Electric proxy group is provided in Figure 35.

Attachment 58.6 is being filed on a confidential basis with the BCUC, pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-15-19. Concentric advises that the information is proprietary and only available to subscribers who, under the terms of the license, are not to reproduce, redistribute or store in a public retrieval system without prior written consent, which has not been obtained. Therefore, Attachment 58.6 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.

58.7 Please explain why Mr. Coyne considers the US Electric Utility Average (20/21) Proxy Group in Figure 61 in addition to the US Electric Proxy Group Average in the analysis of deemed equity ratio.

Response:

Concentric provides the following response:

Please refer to the response to BCUC IR1 51.2 for the same explanation applied to the gas utilities.

59.0 Reference: FBC RISK ANALYSIS

Exhibit B1-8-1, Appendix C - Evidence of Mr. Coyne, pp. 144–145, Appendix D-2, "FBC - Moody's - 2021 Credit Rating Report dated Nov. 25, 2021", pp. 5 and 8

Credit Metrics

On page 144 and 145 of Appendix C, Mr. Coyne states:

> CFO pre-working capital plus Interest/Interest has deteriorated by 32 percent, and CFO pre-working capital/Debt has deteriorated by 12 percent…
>
> This analysis suggests that FBC's Moody's credit metrics have generally deteriorated since 2016 and are toward the lower end of the range for the Baa1 rating category, providing little financial flexibility for the company in the event market conditions become more challenging.

On page 5 of "FBC - Moody's - 2021 Credit Rating Report", Moody states:

> […] We forecast CFO pre-W/C to debt in the 8-10% range for the next several years, a level that provides limited cushion at its current rating level. The utility has a long track record of earning its allowed return on equity and we have assumed that the company will continue to do so. […]

On page 8 of "FBC - Moody's - 2021 Credit Rating Report", Moody provides the following credit metrics:

Exhibit 10
Cash Flow and Credit Metrics [1]

CF Metrics	Dec-17	Dec-18	Dec-19	Dec-20	LTM Sept-21
As Adjusted					
FFO	111	110	109	112	117
+/- Other	3	4	-1	-5	5
CFO Pre-WC	114	114	108	107	122
+/- ΔWC	-10	14	-16	5	1
CFO	104	128	92	112	123
- Div	47	44	45	45	47
- Capex	105	106	107	136	140
FCF	-48	-22	-60	-69	-64
(CFO Pre-W/C) / Debt	9.9%	9.8%	8.8%	8.6%	9.6%
(CFO Pre-W/C - Dividends) / Debt	5.9%	6.1%	5.1%	5.0%	5.9%
FFO / Debt	9.7%	9.5%	8.8%	9.0%	9.2%
RCF / Debt	5.6%	5.7%	5.2%	5.4%	5.5%

59.1 Given Moody's assessment and the LTM credit metrics in September 2021, please discuss whether this would indicate that FBC's metrics are improving and may not be in the lower range for the Baa1 rating category.

Response:

Concentric provides the following response:

As shown in Figure 63 of Mr. Coyne's report and as discussed on pages 144-145, two of FBC's cash flow related credit metrics have deteriorated since 2016, while the other two Moody's credit metrics are approximately the same in 2020 as in 2016. While Mr. Coyne agrees that FBC's credit metrics for the 12-months ending September 2021 are improved as compared to year-end 2020, Moody's has indicated that FBC's cash flow to debt metrics for the next several years are expected to be in the 8-10% range, which provides limited cushion at the current rating level.

FortisBC adds the following response:

Please refer to the response to BCUC IR1 25.1. While LTM September 2021 credit metrics in Table 6-7 are indicating that FBC's financial metrics are improving slightly, they are still below the Baa rating thresholds as indicated in Table 6-7. In fact, three out of four financial metrics are still consistent with a non-investment grade credit rating of Ba.

59.2 Please explain the impacts, or lack of impact, COVID-19 has on FBC's credit metrics and liquidity.

Response:

Please refer to the response to BCUC IR1 7.5.

60.0 Reference: INTRODUCTION

Exhibit B1-8-1, Appendix C - Evidence of Mr. Coyne, p. 151; FEI 2016 ROE Application, Transcript Oral Hearing Vol. 1 dated March 9, 2016, pp. 29–30

Weighted ROE

On page 151 of Appendix C, Mr. Coyne provides the following table and states:

Figure 65: Comparison of Authorized Equity Returns

Operating Utility	Equity Return	Equity Ratio	Weighted ROE
FortisBC Inc. (existing)	9.15%	40.00%	3.66%
FortisBC Inc. (proposed)	10.0%	40.00%	4.00%
ATCO Electric	8.50%	37.00%	3.15%
Nova Scotia Power	9.00%	37.50%	3.38%
Hydro One Ltd.	8.66%	40.00%	3.34%
Newfoundland Power	8.50%	45.00%	3.83%
FortisAlberta	8.50%	37.00%	3.15%
Maritime Electric	9.35%	40.00%	3.74%
Canadian Electric Average	8.75%	39.42%	3.45%
Canadian Electric Median	8.50%	38.75%	3.36%
U.S. Electric Average	9.50%	49.64%	4.72%
U.S. Electric Proxy Group Average	9.59%	49.76%	4.77%

FBC's weighted equity return, at 3.66 percent [9.15% x 40%], is currently within the range of weighted equity returns in Canada, with Newfoundland Power at 3.83 percent having the highest weighted ROE. The proposed ROE and capital structure, resulting in a 4.00 percent weighted ROE, is more in line with FBC's current risk profile and current market data and moves the company closer, but not within the range, of its U.S. peers which have a weighted ROE of 4.72 to 4.77 percent. […]

Overall, my conclusion is that FBC's deemed equity ratio should be maintained at 40.0 percent at a minimum, and that the smaller size of FBC relative to the proxy group companies in both Canada and the U.S. could justify an increase in the Company's deemed equity ratio.

Pages 29 and 30 of the Transcript Oral Hearing Vol. 1 of the FEI 2016 ROE Application, show the following discussion:

MR. WALLACE: Q: Okay. You cannot point me to an example of a Commission in Canada or the United States that has commented on, or used, this formula, ROE times equity ratio.

MR. COYNE: A: I have not researched that. No, I have not seen it nor have I researched it. It's common practice to do this analysis. But I have not seen a Commission rely on it in this way.

MR. WALLACE: Q: It may be your common practice, but have -- you haven't seen a Commission do it.

MR. COYNE: A: I have not researched, but no, I have not.

60.1 Please confirm, or explain otherwise, whether Mr. Coyne has seen or researched regulators in Canada or the US that have relied on a weighted ROE to determine a fair return for a utility since the 2016 testimony.

Response:

Please refer to the response to BCUC IR1 60.2.

60.2 Please explain why this weighted ROE should be considered by the BCUC when setting a fair return.

Response:

Concentric provides the following response:

Mr. Coyne is not aware of regulators that have relied on a weighted ROE to determine a fair rate of return, but virtually all regulators apply a weighted return to the equity portion of the ratebase to establish the approved equity return. As discussed in Section VIII of Mr. Coyne's report, capital structure and the cost of common equity are closely linked in determining the fair return for regulated utilities. Other factors being equal, firms with lower common equity ratios require higher rates of return to compensate for the additional financial risks in the form of financial leverage to which their shareholders are exposed. Accordingly, regulators must consider capital structure and cost of common equity together to determine whether the Fair Return Standard has been met. The Commission adhered to this principle in its 2013 GCOC Decision:

> The Commission Panel confirms that the approval of rates to meet the FRS is not optional for the Commission. In other words, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital, which is consistent with the previous ROE decisions and the Regulatory Compact. In determining the fair return, this Commission Panel

examines the overall return, i.e., the ROE and the common equity component, allowed to the utility.[83]

Investors also consider both, and the return to the equity investor is a function of both the equity ratio and the authorized ROE. Mr. Coyne provides the information in Figures 64 and 65 to inform the BCUC of how FEI and FBC compare to other utilities on this basis. Mr. Coyne's ROE and equity ratio recommendations were developed independently, but bringing them together, as provided in Figures 64 and 65, demonstrates the overall impact of the combined recommendation. This is a tool which allows for consideration of the complete result, consistent with the requirement of setting a fair return which considers both the ROE and equity ratio.

60.3 Assuming the BCUC is to consider and accept FBC's proposal based on a weighted ROE, please clarify whether it would be appropriate for the BCUC to consider any combination of equity return and equity ratio to arrive at 4.00 percent. For example, would it be appropriate to set FBC's allowed ROE at 5.00 percent and the deemed equity ratio at 80 percent, would this combination still arrive at 4.00 percent weighted ROE?

60.3.1 If appropriate, please explain the implications and consequences of a (i) high ROE and low equity ratio and (ii) low ROE and high equity ratio.

60.3.2 If not appropriate, please explain how would the BCUC determine a reasonable range to offset the ROE with equity ratio, or vice versa.

Response:

Concentric provides the following response:

Both the authorized ROE and the deemed equity ratio should be reasonable by comparison to what is available to investors in companies with comparable risk. Extreme high and low values are not typically set by regulators.

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.

[83] GCOC Decision, May 10, 2013, at p. 12.

60.4 Please elaborate why and how a weighted ROE should be considered by the BCUC when setting a fair return.

Response:

Concentric provides the following response:

The BCUC has determined in previous cost of capital decisions that the overall rate of return (both the authorized ROE and the deemed equity ratio) must be consistent with the Fair Return Standard, as indicated in the response to BCUC IR1 60.1. Mr. Coyne provided this evidence to assist the BCUC in understanding how the authorized ROE and the deemed equity ratio are inter-related.

G. AUTOMATIC ADJUSTMENT MECHANISM

61.0 Reference: AUTOMATIC ADJUSTMENT MECHANISM

Exhibit B1-8, FBCU Evidence, pp. 56–61; Exhibit B1-8-1, Appendix C - Evidence of Mr. Coyne, p. 154, "Exhibit JMC-12 FortisBC Report", A Review of Automatic Adjustment Mechanisms for Cost of Capital dated August 3, 2012, pp. 10–13

Automatic Adjustment Mechanism

On pages 56 to 61 of Exhibit B1-8, FBCU states:

> FortisBC continues to believe that a regulatory proceeding is preferable to the use of a mechanical formula for setting the allowed ROE for a utility, and is the predominant approach in North America. FortisBC submits that attempts to mechanize the cost of capital may lead to ROE values that do not meet the Fair Return Standard, particularly in uncertain market conditions. In addition, AAMs do not create any significant regulatory efficiency, as there is still the need to periodically review the base ROE, formula parameters and their weightings. In Mr. Coyne's expert opinion the simple adjustment mechanisms cannot account for other changes that affect a regulated utility's opportunity cost and that historical relationships between equity returns and observable factors such as bond yields may not reflect the changes in the capital markets and investors' expected returns. (page 56)

> … the OEB re-set the base ROE and changed the formula model to a two-variable formula that considers both changes in [long Canada bond] LCB and utility bond spread. The OEB decision to refine and reset its formula-based ERP approach rather than abandon it was influenced by the large of number of utilities under the OEB's regulation… In 2013, the BCUC re-established the AAM approach adopting the OEB's two-variable model… conditional upon the actual LCB yield meeting or exceeding a threshold of 3.8 percent.… Finally, in 2016, BCUC Order G26 129-16 suspended the AAM formula indefinitely. (page 58)

> Nevertheless, if the BCUC determines that an AAM is appropriate then it should consider the criteria specified in Concentric's evidence [Appendix C, p. 154]. (page 61)

On page 154 of Appendix C, Mr. Coyne states:

> If the Commission should decide to reinstate an AAM, we recommended several criteria that should be considered to evaluate alternatives:
>
> 1. Tracks required utility equity returns
> 2. Easily administered

3. Based on commercially accessible inputs
4. Promotes regulatory transparency
5. Forward-looking
6. Exhibits stability
7. Insulated from the effects of anomalous and transitory market conditions
8. Includes a specified timetable for periodic review and/or rebasing of the formula
9. Reflects the capital market conditions faced by the utility.

On page 13 of "Exhibit JMC-12 FortisBC Report", Mr. Coyne states:

> Regulators across Canada have recognized that ROE cannot be reliably estimated through simple relationships to government bond yields. In response, provincial regulators and the NEB have either abandoned the formulaic approach or adjusted the formula. The revised Ontario formula uses forecast government bond yields while also incorporating utility bond spreads (over government bonds). Quebec has adopted a similar approach. Incorporating a term for the credit spread between the utility bond and the long Canada bond yield may mitigate one fatal weakness in the legacy formula: sole reliance on the variable Canadian long bond yield. We view this methodology as preferable to the prior models relying solely on government bond yields. A remaining concern we have with the revised Ontario formula is the lack of any specific link to the cost of equity, other than that conveyed by bond yields. To address this issue, Concentric recommended a potential alternative including an index of authorized U.S. and Canadian ROEs as a proxy for required equity returns.

61.1 Please discuss if and how the two-variable formula (that considers both changes in LCB and utility bond spread) would address the differences in the size, fuel source (i.e., natural gas or electricity), scope and business risk profile of the utilities in BC.

Response:

Concentric provides the following response:

The two-variable formula is limited to changes in government bond yields and utility credit spreads, which are not the only relevant factors in determining the cost of equity for regulated utilities. When the base ROE is established, the BCUC could take into consideration factors such as company size, fuel source, scope and business risk profile. However, to the extent any of those factors change, the two-variable formula would not reflect such a change. Rather those changes would need to be addressed in a subsequent proceeding to re-set the base ROE.

61.2 On page 56 of Exhibit B1-8, FBCU submits that "attempts to mechanize the cost of capital may lead to ROE values that do not meet the Fair Return Standard, particularly in uncertain market conditions". Please discuss if there is an economic environment that is more appropriate for establishing an ROE-AAM that does lead to allowed ROE values that would meet the Fair Return Standard.

Response:

Concentric provides the following response:

An ROE formula can perform reasonably well when economic and capital market conditions are relatively stable and predictable. However, when there are major disruptions to the economy and capital markets, such as the 2008-2009 financial crisis and the 2020-2022 COVID pandemic, extended periods of declining or increasing bond yields, or periods of high inflation, the ROE formula may not produce returns that meet the three elements of the fair return standard.

61.3 If the BCUC were to set FEI and FBC as the benchmark utilities in BC, would the same ROE-AAM apply for each utility or would the ROE-AAM vary depending on FEI and FBC?

Response:

Concentric provides the following response:

If FEI and FBC are set as the benchmark utilities in BC, Mr. Coyne agrees that it seems reasonable that the same ROE adjustment formula would be used for other companies, and any differentials in allowed returns would be established in the base year. The starting ROE should be established for each individual company based on its unique business and financial risks.

61.4 Please describe how, and to what extent an ROE-AAM considers changes in capital structure proportions, if at all.

Response:

Concentric provides the following response:

Mr. Coyne is not aware of an ROE formula that considers or adjusts for changes in capital structure. In Mr. Coyne's experience, the capital structure remains fixed until the next full rate case.

61.5 Please discuss if an ROE-AAM should be based on historic data or forward-looking projections. As part of the response, please comment on why the use of either historic or projected results is more or less reliable and appropriate information for use in an ROE-AAM.

Response:

Concentric provides the following response:

Where possible, a formula should be set based on forward-looking market data. Ontario, for example, resets its cost of capital parameters based on a forecast risk-free rate, and the most recent bond yield spreads. This would be a reasonable compromise under normal market circumstances, but central bank actions have rendered short term forecasts, such as those used by the OEB, a less reliable indicator of the cost of equity.

61.6 On page 154 of Appendix C, Mr. Coyne suggests nine criteria that should be considered in evaluating alternative ROE-AAM approaches. Please recommend a BC-specific ROE-AAM which appropriately considers and applies the nine criteria.

61.6.1 To the extent possible, please provide an ROE-AAM, which appropriately considers and applies changes in proxy companies' earnings growth, beta values, utility capital structure proportions, ESG investment considerations for the cost of debt and equity, and reliable historic and projected formula parameters. If this AAM is not possible or if Mr. Coyne views that these parameters are irrelevant, please explain why.

61.7 If the BCUC were to adopt an ROE-AAM, please discuss Mr. Coyne's views regarding whether the formula should be accompanied with specific trigger mechanisms for ROE adjustments or an ROE rate review.

61.7.1 If Mr. Coyne views that the ROE-AAM should be accompanied with specific trigger mechanisms, please discuss what the appropriate trigger mechanisms are (i.e., a specific time period, a threshold of change in LCB and utility bond interest rates, etc.).

61.8 Please discuss the merits of using an ROE-AAM as a mechanism to trigger an ROE determination or a cross-check against a proposed ROE determination. For example, could an ROE-AAM be applied as a test for each BC utility on an annual basis, where an ROE determination would be triggered if the spread between the current ROE and the ROE-AAM exceeded a certain threshold?

On page 10 of Exhibit JMC-12, Mr. Coyne identifies the formula parameters necessary to use an ROE-AAM methodology consistent with his formula design considerations and recommendations:

- Forecast Government Bond Yield
- Historical Government Bond Yield
- Corporate Bond Yield
- Utility Bond Yield
- DCF, Risk Premium and CAPM Inputs
- Formula Coefficients

61.9 Please discuss Mr. Coyne's views on how practical and efficient it is for the BCUC, directly or indirectly, to acquire the formula data necessary, and to use the formula and its parameters in a transparent and verifiable way.

61.10 On page 13 of Exhibit JMC-12, Mr. Coyne discusses the use of an "index of authorized U.S. and Canadian ROEs as a proxy for required equity returns" in the context of developing an ROE-AAM. Please provide a working example of an index of US and Canada ROEs, including how such an index would be used as a specific link to a market-based cost of equity in an ROE-AAM.

Response:

This response addresses BCUC IR1 61.6 through 61.10.

Concentric provides the following response:

If the BCUC determines that it wants to return to using an Automatic Adjustment Mechanism to set the ROE for regulated utilities in British Columbia, Mr. Coyne would recommend that the BCUC establish an additional process to determine the correct formula. In Mr. Coyne's view, developing an adjustment formula is a very detailed process that is better accomplished through input from both regulated utilities and other stakeholders, rather than through the limitations of a discovery process in this proceeding.

FortisBC adds the following response:

In Order G-281-21, the BCUC panel issued an amended scope which, among other things, includes:

> Whether re-establishment of a formulaic ROE automatic adjustment mechanism (AAM) is warranted. If a return to the use of a formulaic ROE AAM is warranted, then: a) The specifications of the ROE AAM formula. b) The frequency that the ROE AAM will apply (i.e. annually or some other frequency) and to whom the ROE AAM will apply. c) The date for which the ROE AAM will take effect.

Concentric's evidence (Appendix C) includes a jurisdictional review of AAMs in Canada which indicates that AAMs are not a common approach in Canada anymore and FortisBC's evidence provides some additional historical context for this issue and discusses the major drawbacks of an AAM approach. As discussed in its evidence, FortisBC concludes that a regulatory proceeding is preferable to the use of a mechanical formula for setting the allowed ROE for a utility and respectfully submits that the application of an AAM in BC is not warranted. As such, FEI's and FBC's evidence in this proceeding, has not considered the items (a) to (c) mentioned above. If the BCUC determines that an AAM formula is appropriate, FortisBC will require to perform more extensive research and consider the possible options and best practices (if any). This task would require additional time and resources and cannot be reasonably done in an IR process. As such, FortisBC respectfully requests that if the BCUC determines that AAM approach is appropriate, the consideration of the formula's specifications, frequency and effective date be considered in a further stage of the proceeding.

Attachment 13.3.1

For The First Time Ever, The Median Investor-Owned Utility Ratings Falls To The 'BBB' Category

January 20, 2022

Key Takeaways

- 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.
- During 2021, credit quality was primarily pressured by weak financial measures and Environmental, Social, and Governance (ESG) credit risks. We expect that these risks will continue to pressure the credit quality of the industry in 2022.
- Our outlook on the investor-owned North American regulated utility industry remains negative. We believe that 2022 could be the third consecutive year that downgrades outpace upgrades.
- Recently, several new credit risks have emerged, including inflation, higher interest rates, and rising commodity prices. Persistent pressure from any of these risks would likely lead to a further weakening of the industry's credit quality in 2022.

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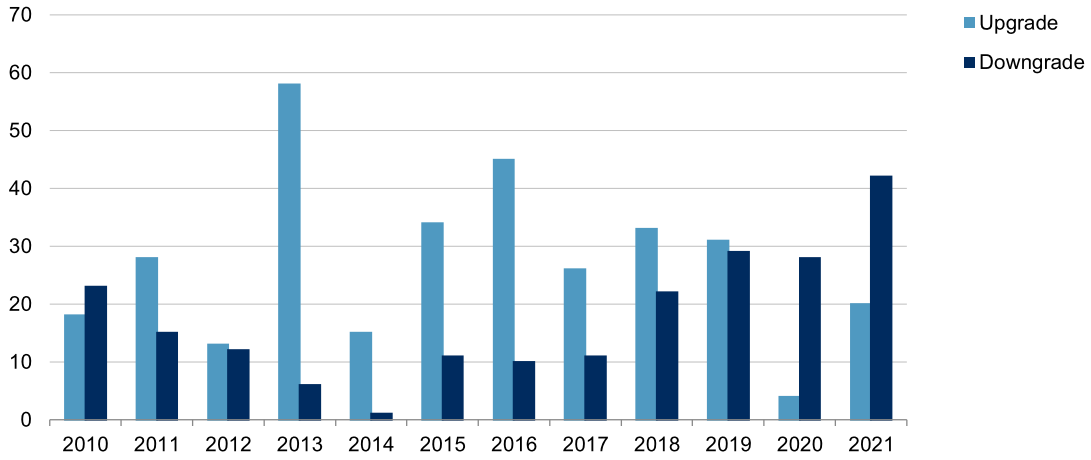
Credit quality again weakened in 2021 and represented the second consecutive year that downgrades outpaced upgrades. Prior to 2020, the last time downgrades outpaced upgrades was 2010, reflecting a near decade of consistent improvement to credit quality.

During 2021 downgrades were primarily the result of weak financial measures and ESG-related credit risks. We downgraded Atmos Energy Corp. (A-/Negative/A-2), Duke Energy Corp. (BBB+/Stable/A-2), One Gas Inc. (BBB+/Negative/A-2), Entergy Louisiana (BBB+/Stable), and Entergy New Orleans LLC (BB/Developing/--) primarily because of rising environmental or physical risks. Conversely, downgrades to National Grid North America Inc. (BBB+/Stable/A-2), Southwest Gas Holdings Inc. (BBB-/Negative/--), Southern Co. (BBB+/Stable/A-2), and Pinnacle West Capital Corp. (BBB+/Negative/A-2) primarily reflected weak financial measures.

ESG credit risks and weak financial measures similarly affected the outlooks on several utilities. We revised the outlook on OGE Energy Corp. (BBB+/Negative/A-2) to negative from stable reflecting physical risks while the outlooks for Algonquin Power & Utilities Corp. (BBB/Negative/--), American Electric Power Co. Inc. (A-/Negative/A-2), Cleco Corporate Holdings LLC (BBB-/Negative/--), and Evergy Inc. (A-/Negative/A-2) were all revised to negative from stable because of relatively weak financial measures for their current rating.

Chart 1

North American Regulated Utilities Rating Actions--Upgrades And Downgrades



Source: S&P Global Ratings and company data.

Because the industry has experienced such a significant weakening of credit quality over the past two years, the median and modale ratings for the industry fell for the first time ever to the 'BBB' category from the 'A' category. In 2021 the percentage of companies in the 'A' category dropped to 45% from 58% in 2020 and the percentage of companies in the 'BBB' category increased to 51% in 2021 from 34% in 2020. Despite the overall weakening of credit quality in 2021, there were some areas of improvement, specifically, the number of high-yield companies decreased in 2021 to about 2% from about 7% in 2020. However, this is mostly attributable to the multiple notch upgrades related to FirstEnergy Corp. (BBB-/Stable/--), which reflected the significant steps the company took to remediate the material weakness identified within its internal controls. We believe that this strengthening in credit quality is limited to FirstEnergy and is not reflective of the broader industry risks.

Chart 2

North American Regulated Utilities Year-End 2021 Ratings Distribution

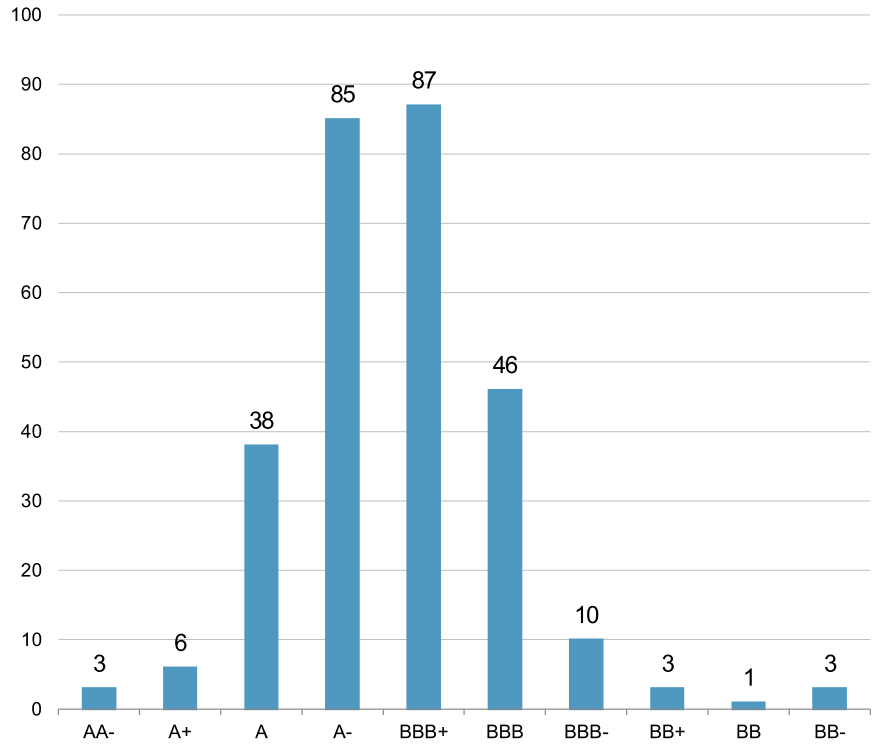
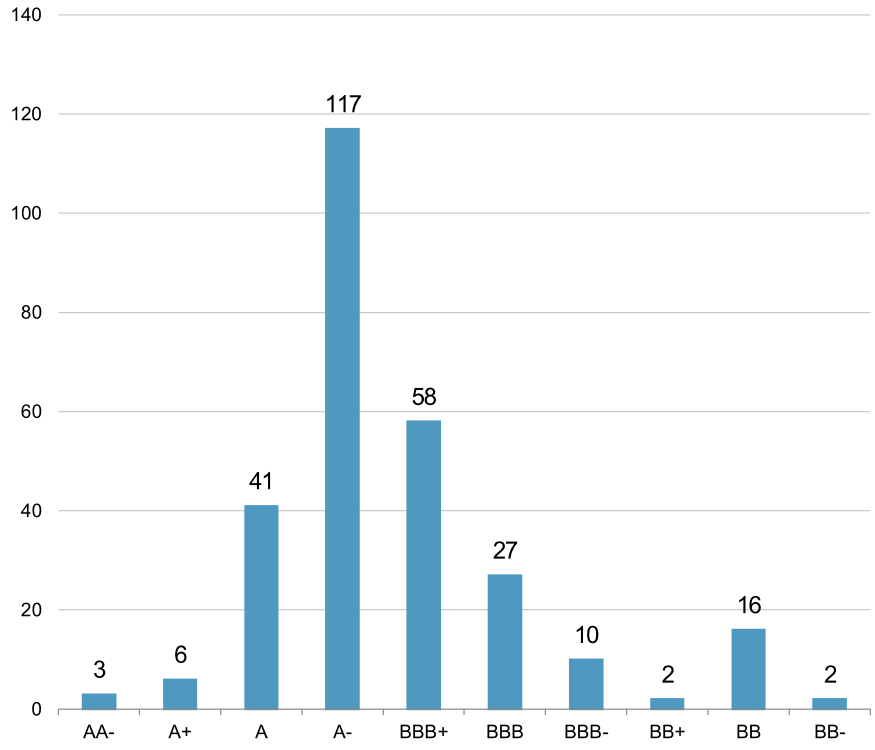


Chart 3

North American Regulated Utilities 2020 Year-End Ratings Distribution



Industry Credit Quality Will Likely Continue To Weaken in 2022

A relatively high percentage of the industry (about 20%) continues to have a negative outlook. While this is materially lower than the approximate 35% of the industry with negative outlooks at year-end 2020, it remains elevated compared to historical averages (approximately 10%). Conversely, the positive outlooks are at just about 5%. As such, we believe it is more likely that downgrades will continue to outpace upgrades in 2022.

Chart 4

North American Regulated Utilities Industry Year-End 2021 Outlooks

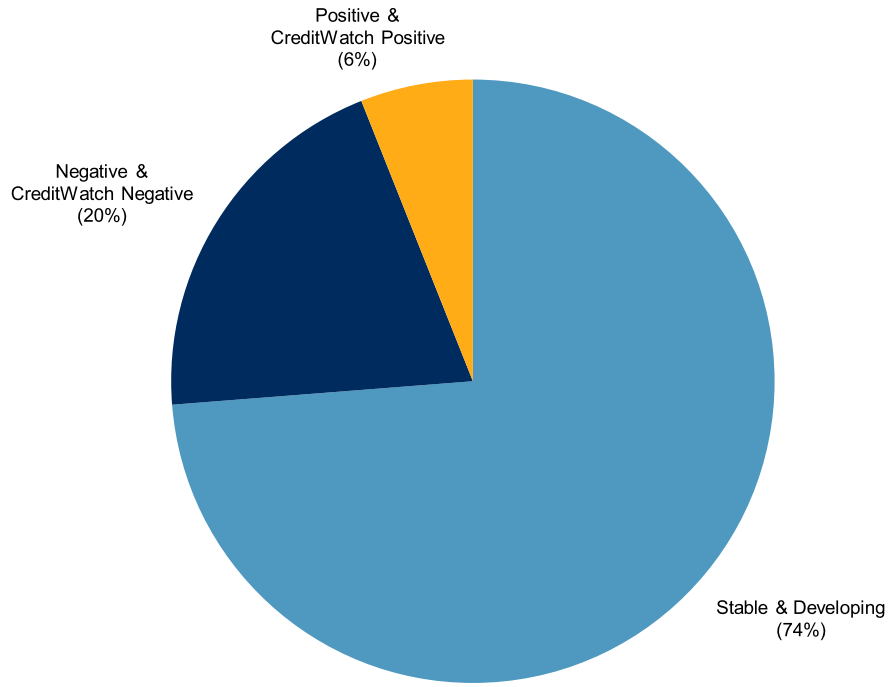
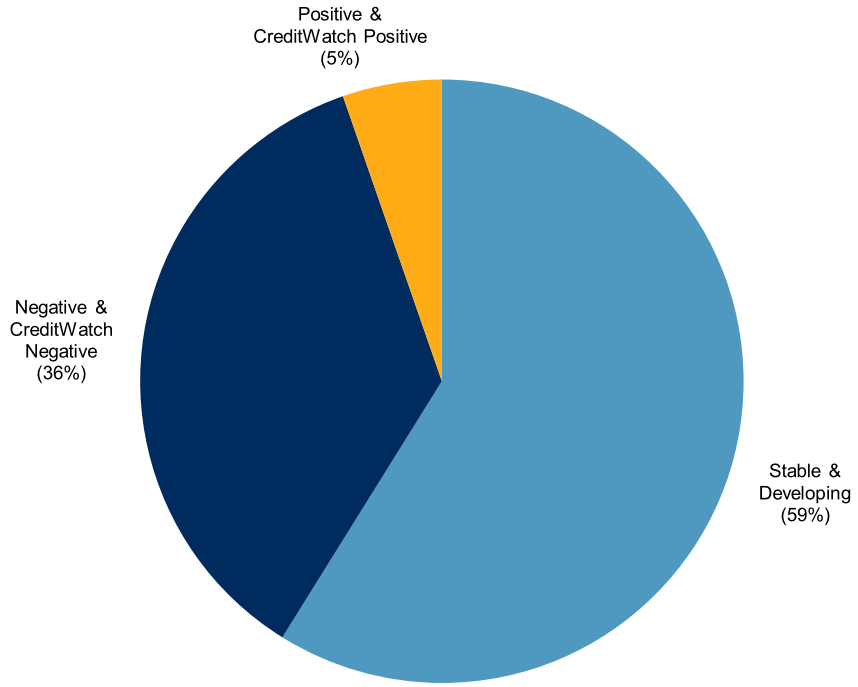


Chart 5

North American Regulated Utilities Industry Year-End 2020 Outlooks

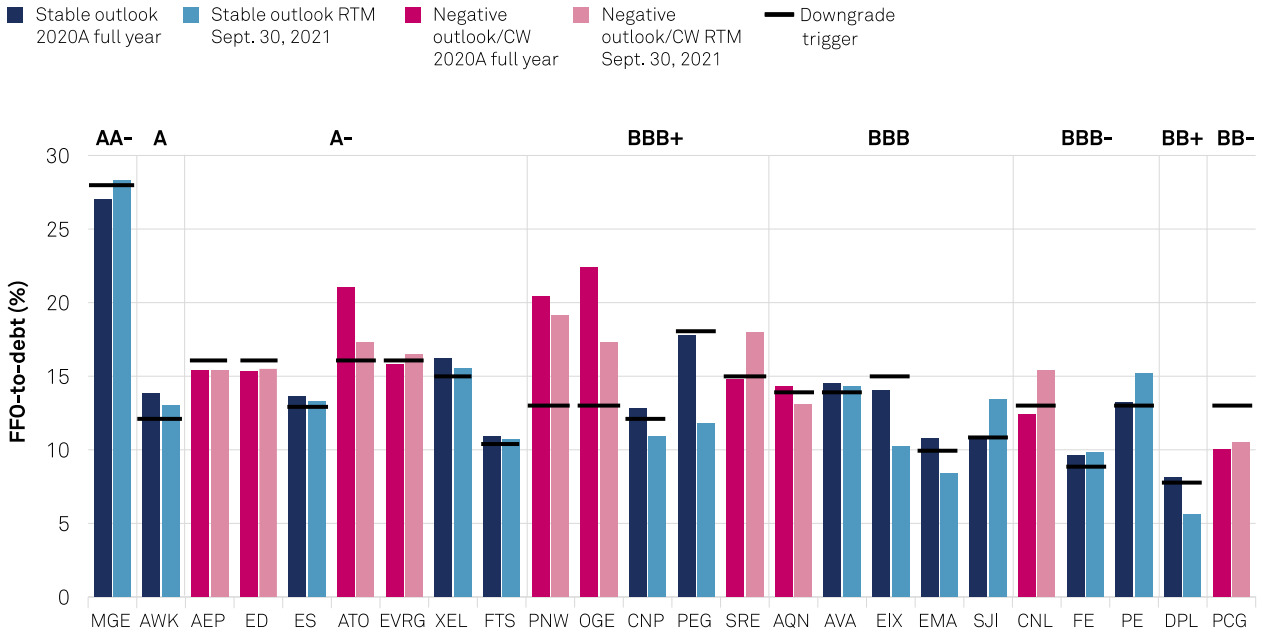


What's Behind This Fundamental Weakening Of Credit Quality?

Utility cash flows tend to be more stable and predictable than most other industries. Strategically, an increasing percentage of the industry has been managing their financial measures with only minimal financial cushion from their downgrade threshold. While this strategy of limiting excess credit capacity works well under ordinary conditions, when unexpected risks occur or base case assumptions deviate from expectations, the utility can become susceptible to a weakening of credit quality. This has been one of the primary drivers of the industry's weakening of credit quality over the past two years.

Chart 6

Minimal Financial Cushion



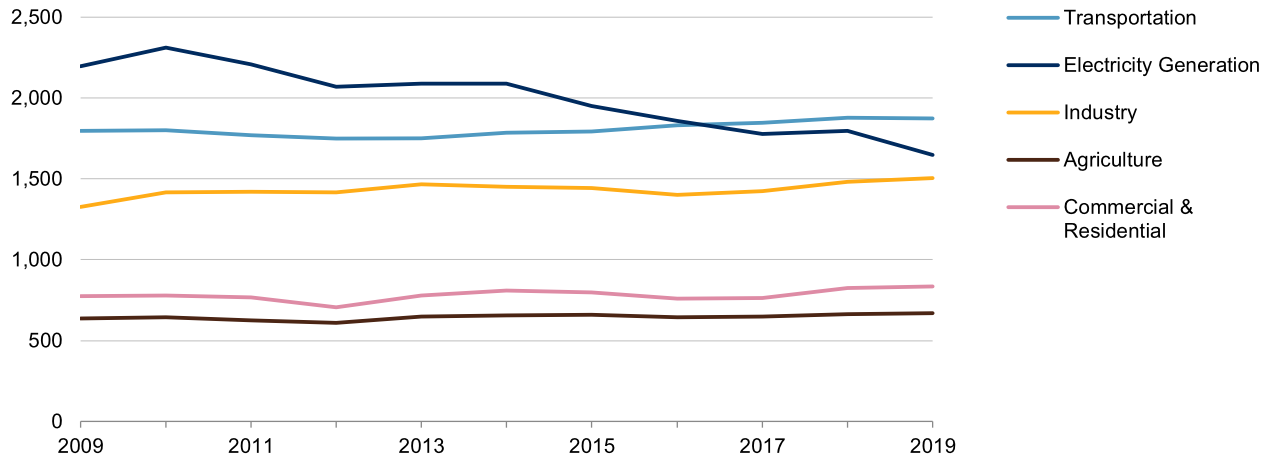
Source: S&P Global Ratings.

Dealing With Energy Transformation

The utility industry has already made significant progress towards reducing its greenhouse gas (GHG) emissions. Over the past decade, the industry reduced its reliance on coal-fired generation by more than 50% and more than doubled capacity from renewable energy. Because of these transformative trends, the industry's GHG emissions have decreased by more than 25%. Despite these milestones, the industry continues to invest heavily in renewable energy, which will further reduce its GHG emissions by about 40% over the next decade.

Chart 7

Total U.S. Greenhouse Gas Emissions By Economic Sector From 2009–2019
Million metric tons of CO2 equivalent

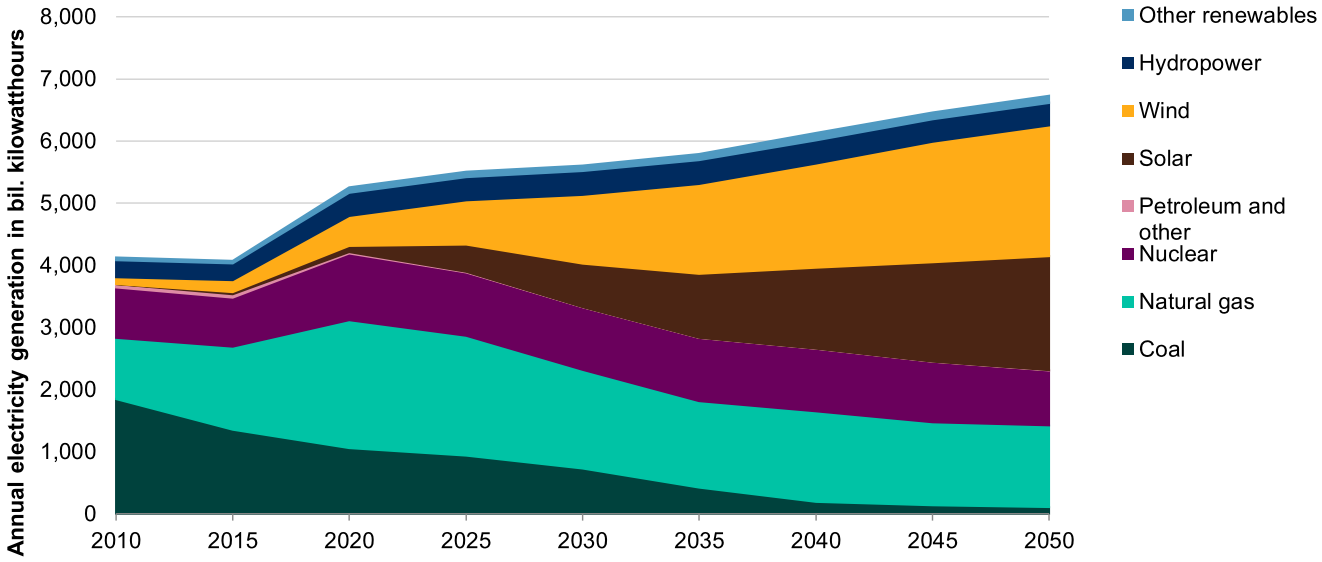


Source: U.S. Energy Information Administration.

We anticipate that it could take longer than a decade to transform the U.S. generation portfolio, increasing our reliance on renewable energy for more than 50% of total generation. As such, we expect that capital spending will remain robust for the foreseeable future, continuing to pressure the industry's financial measures. Because of the robust capital opportunities available to many companies within the industry, utilities will continue operate with only minimal financial cushion from their downgrade threshold.

Chart 8

U.S. Electricity Generation 2010-2050



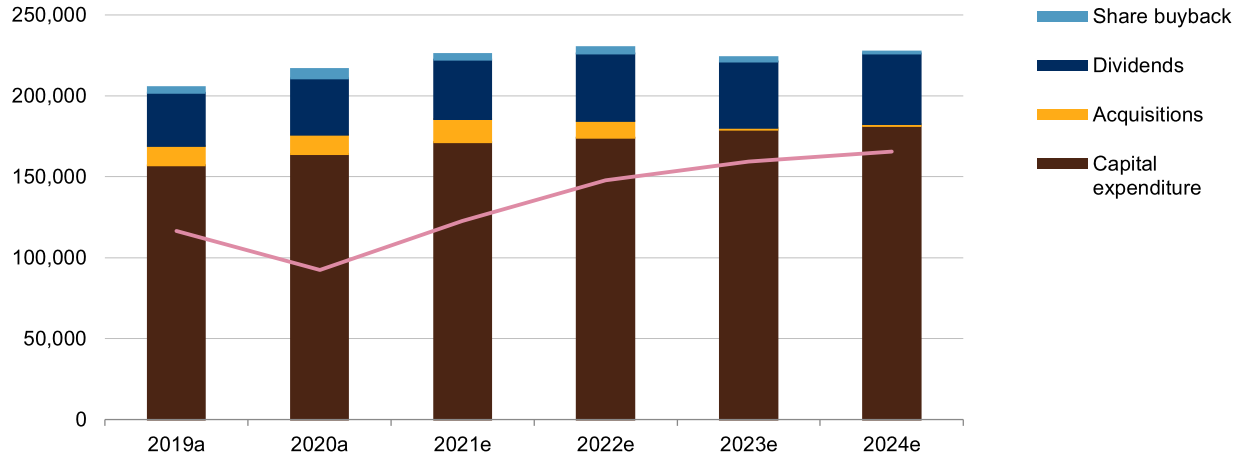
Source: S&P Global Platts.

Capital Spending

We expect 2021 capital spending to approximate $170 billion setting a new record for the sector. This is about 5% higher than the $164 billion spent in 2020 and about 9% higher than the $157 billion spent in 2019. Over the past fifteen years, the industry's capital spending has been growing at a compounded annual growth rate of about 9%. While we expect the growth rate will somewhat slow, we still expect that the industry will continue to grow its capital spending. Under our base case, we expect that by 2024 the industry's capital spending will exceed $180 billion. Because of the industry's continued robust capital spending, we expect that industry will continue to generate negative discretionary cash flow. This requires that the industry has consistent access to the capital markets to finance capital spending and dividends requirements.

Chart 9

North American Regulated Utilities Cash Flows And Primary Uses



Source: S&P Global Ratings and company data.

ESG Credit Risks

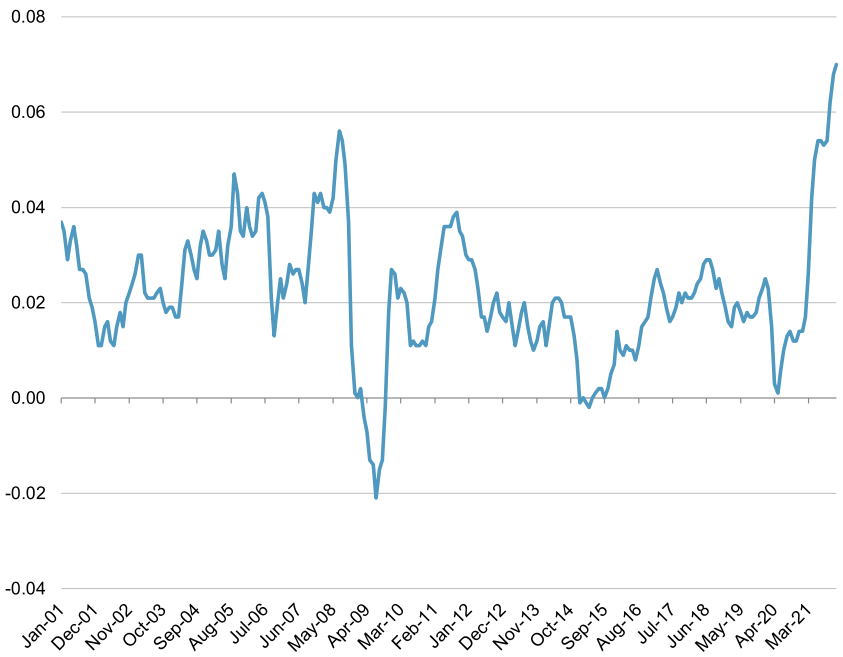
During 2020 and 2021 the industry credit quality was constrained by many ESG-related credit risks. Unexpectedly, the industry faced several governance-related credit risks in 2020. We view these governance events as isolated incidents and do not believe that they will have broader implications for the larger utility industry. However, we do expect that physical and environmental risks will continue to constrain the industry's credit quality. Wildfires, severe winter storms, hurricanes, and tornadoes lead to higher costs that are either partially disallowed by regulators or are deferred for future recovery. Similarly, higher environmental costs can also result in higher costs that are either partially disallowed by regulators or are deferred for future recovery. Either outcome for physical and environmental risks typically results in weaker financial measures until the utility fully recovers such costs from customers. Because of climate change, we believe that these risks will continue to negatively affect credit quality in 2022.

Other Developing Risks That May Affect Credit Quality

Inflation, higher interest rates, and rising commodity prices could all lead to higher customer bills, pressuring the industry's ability to effectively manage regulatory risk and its credit quality. Inflation recently spiked to its highest level in decades after rising for several consecutive months in 2021. Given the sustained increase to the U.S. consumer price index in 2021, inflation no longer appears to be just transitory and may have financial implications for the investor-owned North American regulated utility industry. Because of the regulatory lag within the industry, inflation, which causes prices to rise, typically leads to a weakening of financial performance. The regulatory lag is the timing difference between when costs are incurred and when regulators allow those costs to be fully recovered from ratepayers.

Chart 10

Inflation Risk
Consumer Price Index, 12-month percentage change (not seasonally adjusted)

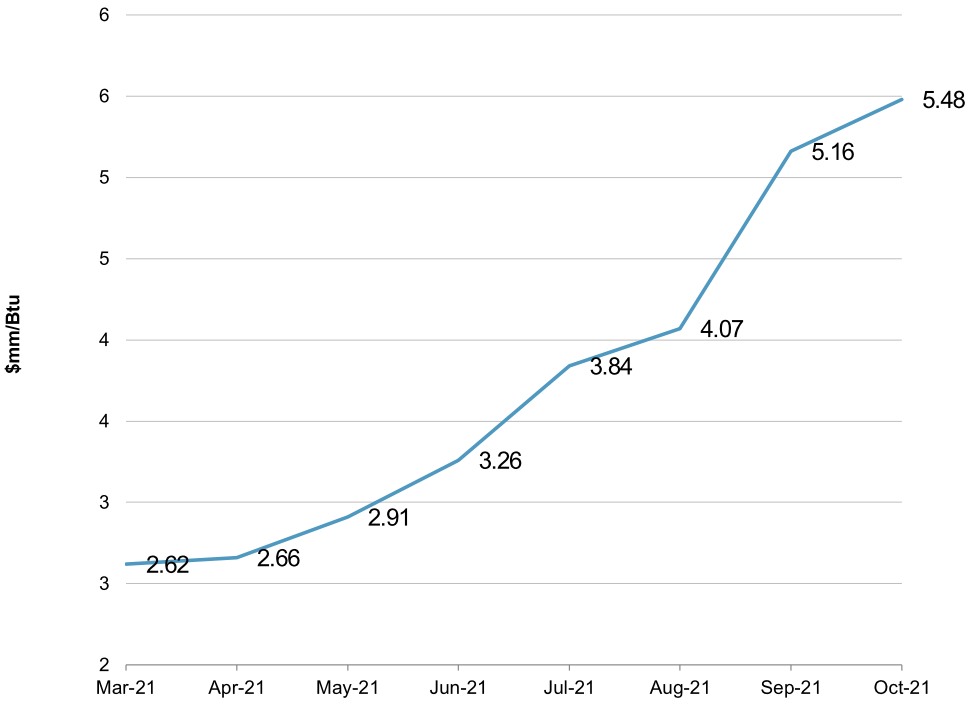


Source: U.S. Bureau of Labor Statistics, December 2021.

Similarly, when interest rates rise, the industry's finance measures also typically weaken because of regulatory lag. Commodity prices have also materially increased over the last several months, which could cause credit quality to weaken. While commodity costs are typically directly and fully collected from customers, high commodity costs increases the customer bill, which would likely make it more difficult for the industry to effectively manage regulatory risk. We believe persistently higher natural gas prices would pressure credit quality and the customer bill for natural gas distribution utilities. Furthermore, about 40% of the U.S. generation portfolio is from natural gas fired generation and therefore persistently higher natural gas prices would likely also pressure the credit quality of electric utilities.

Chart 11

Henry Hub Natural Gas Prices



Source: S&P Global Ratings and company data.

The Industry Outlook Remains Negative

Credit quality for the investor-owned North America regulated utility industry weakened during 2020 and 2021 with the median rating falling for the first time ever to the 'BBB' category. Given the relative high percentage of the industry with a negative outlook (about 20%), the strategic management of financial measures with only minimal cushion from the downgrade threshold, the industry's high capital spending, ESG credit risks, inflation, rising interest rates, and higher commodity prices, we expect that it is more likely that downgrades will again outpace upgrades in 2022. Should this occur, it would be the first time in more than 30 years that downgrades outpaced upgrades for three consecutive years.

This report does not constitute a rating action.

Attachment 18.4

1.0 Exhibit B-21, BCUC IR 81.1, 83.2

Future Changes in Gas Supply

In response to British Columbia Utilities Commission (BCUC) Information Request (IR) 81.1, FortisBC Energy Inc. (FEI) stated:

> There are several developments affecting the Lower Mainland region that could change natural gas use over time; however, those changes also increase the use of renewable and low carbon energy, such as RNG [renewable natural gas], which FEI expects to be an integral part of BC's clean energy future. Policies such as the Province's plan to cap greenhouse gas emissions from gas utility customers, or the transition of new buildings to zero emissions by 2030, are expected to result in less conventional natural gas use in the residential, commercial, and industrial sectors. However, FEI expects the continued development and expansion of renewable gas supply, such as RNG and hydrogen, will offset this impact.
>
> …
>
> To avoid the future uncertainties that will affect future peak demand, FEI believes sizing the TLSE [Tilbury Liquefied Natural Gas Storage] Project based on the 2019/20 design load forecast remains appropriate. Finally, the risk associated with the peak demand declining over time can be mitigated through the flexibility of FEI's contracted assets (i.e., off system storage at JPS or Mist). In particular, FEI's storage profile typically has contracts expiring once every three years. If the load duration curve changes over time (such that less supply is needed from the TLSE assets), FEI has the ability to de-contract a portion of its off-system storage resources.

In response to BCUC IR 83.2, FEI stated:

> FEI is enabled under the amended GGRR [Greenhouse Gas Reduction (Clean Energy Regulation] to acquire hydrogen to meet near term objectives including:
>
> …
>
> • Purchasing hydrogen that could be distributed through dedicated infrastructure (new or repurposed) to gas customers to displace conventional natural gas usage.
>
> …
>
> Over the longer term (assumed between 2030 and 2050), as demand for hydrogen grows, the existing gas system high pressure transmission pipeline corridors would be retrofitted, upgraded, and expanded to transport an increasing share of hydrogen and (bio)methane in a progressively decarbonized gas system.

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

a. The key assumptions underpinning the forecast scenario;

b. The volume of the proposed tank and regasification capacity that would need to be reserved for resiliency purposes.

Response:

FEI's long-term forecast of peak demand is based on a 20-year planning horizon consistent with the 2022 Long Term Gas Resource Plan (LTGRP) to be submitted to the BCUC at the end of March.

FEI's response to BCUC Panel IR1 1.2 also provides important context and background and should be read in conjunction with this response. Over the next 20 years and beyond, FEI's infrastructure needs to support multiple objectives, including:

- a transition to renewable and low carbon gas that includes methane, hydrogen, and smaller amounts of other resources;
- continuing to support the energy transition through delivery of conventional and renewable sources of methane supplies;
- maintaining and improving system resiliency to serve the need of customers and to reduce supply risk; and
- enabling innovative new energy solutions upstream, on-system, and near the end use to help reduce BC and global carbon emissions and to realize other benefits.

Over the timeframe from 2030 to 2050, the vast majority of energy molecules delivered by FEI's system will be methane, bio-methane and hydrogen. FEI's response to BCUC Panel IR1 1.2 discusses this transition further, indicating that the mix of these energy resources delivered to customers will change over time. FEI fully expects this mix to fall within a range of combinations of the various gas resources and that the expected range requires the TLSE Project to provide resiliency for the system throughout the LTGRP planning horizon and beyond. While the percentage of hydrogen delivered to customers on FEI's infrastructure will grow in the future, the resiliency benefits of the TLSE Project are upheld with on-system hydrogen mixes.

Forecast Descriptions and Assumptions

The rest of this response models a particular mix of methane, bio-methane and hydrogen over time that provides a conservative outlook on the need for the TLSE Project within this dynamic future. The derivation of the following forecasts developed in order to provide this response is explained in the paragraphs below:

- Traditional Peak forecast (used as the reference case in this response);
- High forecast – Traditional Peak forecast plus 10 percent;
- Low forecast – Traditional Peak forecast minus 25 percent; and
- Peak end use demand forecast (hypothetical low peak forecast based on exploratory peak demand method being examined in FEI's 2022 LTGRP)[1].

The above-noted **Traditional**, **High** and **Low** peak demand forecasts are associated with the **2022 LTGRP Diversified Energy Future scenario**; FEI uses the Diversified Energy Future scenario as its planning scenario.[2] Key planning assumptions underpinning the Diversified Energy Future scenario build upon a diversified approach to energy delivery and emissions reductions to British Columbians. Under this scenario, customer growth occurs for both the electric and gas utilities and growth in the use of natural and renewable gas as a transportation fuel is larger in the Lower Mainland than in other regions of the Province, particularly in the marine transportation sector. For the analysis requested in this information request, the total Diversified Energy Future scenario demand for the CTS has been adjusted to reflect only the customer demand in the Lower Mainland that would be supported by the TLSE Project under peak conditions that would be affected by a significant supply disruption. The peak demand for these firm customers is 865 MMcf/day in the winter of 2019-2020. Also for this analysis, FEI has not included system demand from Woodfibre LNG (WLNG) of 95 PJ annually in the calculations shown since the TLSE Project is neither designed nor intended to support WLNG demand, and WLNG demand is considered a flow-through load rather than an end-use for the purpose of assessing GHG emissions.

The **Traditional Peak Forecast** method is based on current customer peak consumption per account and future account forecasts and as such represents a "reference case" as it reflects the continuation of current system use; FEI uses this method today to plan for future infrastructure upgrades.

[1] In its 2022 LTGRP, FEI explores a potential alternative method for forecasting peak demand using end-use energy equipment information derived from FEI's long term end-use annual demand forecast results. This method remains hypothetical because empirical evidence linking changes to energy equipment and customer behavior to reductions in peak demand has not been identified but merits further investigation. Since this hypothetical or exploratory method results in a lower peak demand than the method FEI employs, FEI believes including it in this analysis offers a conservatively broad spectrum of peak demand forecasts with which to prepare this response.

[2] In the 2022 LTGRP, the Reference Case annual demand scenario is based on a future that is a continuation of current conditions at the time future scenarios were established (2020). As such, it does not include the actions that FEI needs to take, or anticipates will occur, in order to decarbonize energy supplies on behalf of customers. For this reason the Reference Case is not selected as FEI's long-term planning scenario. Instead, FEI uses the Diversified Energy Future scenario which uses the existing gas infrastructure to deliver low carbon energy solutions to customers as its planning scenario. The LTGRP also examines a number of other substantially different future scenarios which demonstrate that the Diversified Energy Future is the appropriate scenario to plan for.

FEI's forecasts currently extend to 2042 in the LTGRP. Therefore, FEI has extrapolated the above forecasts to 2050 by calculating the average peak growth in the forecast in the five-year period from 2038 to 2042 and applying that growth to the eight-year period from 2043 to 2050. This is a reasonable means of projecting the observed trajectory of the forecast in the absence of more detailed information.

In the TLSE Application, FEI uses units of volume (e.g., MMcf or Bcf) as measurements of peak demand as they are the most relevant to the proposed tank and increased regasification capacity. However, representing energy in standard volumes such as MMcf is inadequate to compare peak demand in future years where a portion of the demand will be supported by hydrogen. This is because hydrogen has approximately one-third the energy content of natural gas or renewable natural gas (RNG) per unit volume. Therefore, the tables below present much of the information in TJ/day rather than MMcf/day. The base year demand of 865 MMcf/day is represented in the tables as equivalent to 950 TJ/day. When appropriate, FEI has converted demand back to MMcf/day so that the results can be compared easily to the peak demand of 865 MMcf/day and regasification capacity of 800 MMcf/day presented in the Application. In the tables below, FEI has separated the peak demand associated with the future hydrogen system.

In preparing this response, FEI assumed that end-use gas equipment will evolve to be able to utilize hydrogen gas along different potential paths. Today, end-use equipment is assumed to be able to burn a blended mix of methane and low concentrations of hydrogen. The scenarios presented assume that equipment will evolve to 1) be able to utilize higher concentrations of hydrogen mixed with methane and 2) some gas equipment (industrial process equipment for example) could evolve to be able to fuel switch between hydrogen and methane and some customers may choose to install equipment that will be hydrogen dedicated. FEI assumes in these scenarios that all of these types of equipment except equipment that is solely dedicated to utilizing hydrogen will be able to benefit from the resiliency provided by the TLSE Project. The eventual mix of these types of equipment throughout FEI's service territory is yet to be determined. Therefore, in order to examine the implications of these alternatives on the need for and benefits of the TLSE Project, FEI has modelled this changing mix in two ways (as further illustrated in the tables below):

- Scenario A - FEI assumes that equipment is dedicated to using only hydrogen as a fuel, that none of the hydrogen used in the system is blended with natural gas and RNG, that a concentration of 100 percent hydrogen is provided to consumers, and that the TLSE Project may not be able to support the peak demand for this portion of the demand.
- Scenario B - FEI assumes that the equipment can use a varying blend of methane and hydrogen or can fuel switch between the two fuels, that about 50 percent of the hydrogen that is used in the CTS is blended with the natural gas and RNG and delivered to consumers. As such, methane/bio-methane from the TLSE Project can displace 50 percent of the on-system hydrogen during peak events.

While the planning for hydrogen is evolving in industry, and the ultimate mix is unknown, FEI expects Scenario B to be in the range of a more realistic outcome in the future because it demonstrates the compatibility of methane fuels with hydrogen within the network. However, Scenario A is useful to show a very conservative assumption for TLSE tank volume and regasification capacity.

Scenarios Demonstrate the Appropriateness of TLSE Tank Volume and Regasification

The following analysis will demonstrate the appropriateness of the TLSE tank volume and regasification capacity in the vast majority of scenarios in 2030, 2042, and 2050.

2030 Forecasts

FEI anticipates that in 2030 on an annual basis FEI will be providing approximately 24 percent[3] of its projected annual demand in the form of renewable and low carbon gases consisting of hydrogen and RNG, along with some syngas/lignin and some carbon capture and sequestration (CCS).

Approximately 50 to 55 percent of renewable and low carbon gases will be on-system and 45 to 50 percent will be supplied and consumed outside of FEI's service territory (as further explained in the response to BCUC Panel IR1 1.2). In the CTS, the hydrogen will be delivered via dedicated systems and blended into downstream distribution systems in larger volumes.

Accordingly, by 2030 in the Lower Mainland, FEI projects that approximately 3 to 4 percent of the demand would be served by hydrogen. Consequently, 96 to 97 percent of the peak demand in 2030 is expected to be provided by natural gas or RNG that is able to be supported by the TLSE Project storage and regasification in the event of a supply disruption.[4]

Table 1 below details the projected peak demand for the four forecasts in 2030. The second column from the right shows the send out requirement to support the natural gas and RNG demand (in MMcf/day) after subtracting the portion of the system demand supported by hydrogen.

The table demonstrates that:

- ***Regasification capacity (2030):*** The values are all very near or over the capacity of the 800 MMcf/day regasification, indicating that in all forecast scenarios the proposed regasification is needed on a peak day in 2030.
- ***Tank volume (2030):*** The last column shows the volume (in Bcf) of LNG storage required over the coldest three days of a design year in 2030. The forecast requirement for LNG inventory ranges from 2.1 to 2.4 Bcf.[5]

[3] 24 percent represents the renewable and low carbon gas required to meet Provincial emission reduction targets for the residential, commercial and industrial sectors and accounts for load growth from the use of natural gas and RNG as a transportation fuel, which also reduces carbon emissions in BC and globally.

[4] Natural gas and RNG used to produce LNG at Tilbury is removed from the percentages and peak demand presented in the table as this demand is curtailed when the TLSE send out would be required.

[5] As the proposed regasification capacity of the TLSE Project is 800 MMcf/day the volume able to be delivered each day is limited to 800 MMcf/day even on days where the peak demand may exceed 800 MMcf/day. The difference

Table 1

Diversified Energy Future Peak Demand Forecasts	2019	2030							
				Scenario A			Scenario B		
	Base Year Peak demand (TJ/day)	Total Peak Demand (TJ/day)	Hydrogen (TJ/day)	NG and RNG (TJ/day)	NG and RNG (MMcf/day)	Volume Required to Support Three Coldest Winter Days (Bcf)	NG, RNG & H2 (TJ/day)	NG, RNG & H2 (MMcf/day)	Volume Required to Support Three Coldest Winter Days (Bcf)
High (Traditional peak+10%)	950	1104	40.8	1063	**968**	**2.40**	1084	**987**	**2.40**
Traditional Peak	950	1048	38.8	1009	**919**	**2.37**	1029	**937**	**2.39**
Low (Traditional Peak-25%)	950	930	33.7	876	**798**	**2.20**	893	**813**	**2.26**
End Use Peak (theoretical method)	950	891	33.0	858	**781**	**2.11**	875	**796**	**2.19**

950 TJ/day is 865 MMcf/day

2042 Forecasts

FEI anticipates that in 2042 on an annual basis FEI will be providing just over 43 percent[6] of the projected annual demand as renewable or low carbon gases. Approximately 80 percent will be on-system and 20 percent will be supplied and consumed outside of FEI's service territory. In the CTS, the hydrogen will be delivered in dedicated systems and blended into the distribution systems in larger volumes.

By 2042 in the Lower Mainland, FEI expects that approximately 20 to 25 percent of the forecast peak demand would be served by hydrogen. The remaining 75 to 80 percent of the peak demand in 2042 will be provided by natural gas or RNG that could be supported by the TLSE Project storage and regasification.

Table 2 below details the projected peak demand for the four forecasts for 2042. This table demonstrates that:

- ***Regasification capacity (2042)***: The send-out requirements in the second column from the right show that after subtracting the portion of the system demand served by on-system hydrogen, the high, traditional, and low forecasts still require more than 600 MMcf/day of send-out. As such, the proposed regasification capacity would still be required in 2042 in each of the forecasts. Further, even using the theoretical end-use peak forecast method, 600 MMcf/day will be required to serve a peak day in the Lower Mainland until approximately 2038 in the lowest end-use peak forecast.
- ***Tank volume (2042)***: The last column shows the range of forecasts for the volume of LNG storage that would be required over the coldest three days of a design year in 2042. The forecast requirement for LNG inventory ranges from 1.6 to 2.4 Bcf. In all cases, the proposed TLSE tank sizing remains appropriate.

would need to be provided by curtailing the excess firm demand present in those future forecast scenarios.

[6] 43 percent represents the renewable and low carbon gas required to meet Provincial emission reduction targets for the residential, commercial and industrial sectors by 2050, interpolated to 2042, and accounts for load growth from use of natural gas and renewable/low carbon gas as a transportation fuel which also reduces carbon emissions in BC and globally.

Table 2

Diversified Energy Future Peak Demand Forecasts	2019	2042							
				Scenario A			Scenario B		
	Base Year Peak demand (TJ/day)	Total Peak Demand (TJ/day)	Hydrogen (TJ/day)	NG and RNG (TJ/day)	NG and RNG (MMcf/day)	Volume Required to Support Three Coldest Winter Days (Bcf)	NG, RNG & H2 (TJ/day)	NG, RNG & H2 (MMcf/day)	Volume Required to Support Three Coldest Winter Days (Bcf)
High (Traditional peak+10%)	950	1271	284.7	986	**898**	**2.39**	1129	**1028**	**2.40**
Traditional Peak	950	1156	258.9	897	**817**	**2.26**	1027	**935**	**2.40**
Low (Traditional Peak-25%)	950	867	194.2	673	**613**	**1.71**	770	**701**	**1.96**
End Use Peak (theoretical method)	950	794	177.9	616	**561**	**1.57**	705	**642**	**1.79**

950 TJ/day is 865 MMcf/day

2050 Forecasts

Based on an extrapolation of the 2042 forecasts, FEI anticipates that by 2050 on an annual basis it will be providing just under 60 percent[7] of the projected annual demand as renewable or low carbon gases. For this analysis, FEI assumes that 86 percent of this supply will be on-system and 14 percent will be supplied and consumed outside of FEI's service territory. In the CTS, the hydrogen will likely be primarily delivered in dedicated systems and blended into the distribution systems.

By 2050 in the Lower Mainland, FEI expects that approximately 35 percent of the forecast peak demand would be served by hydrogen. The remaining 65 percent of the peak demand in 2050 will be provided by natural gas or RNG that could be supported by the TLSE Project storage and regasification.

Table 3 below details the projected peak demand for the four forecasts for 2050. The table demonstrates:

- ***Regasification capacity (2050):*** The send-out requirements in the second column from the right show that, after subtracting the portion of the system demand supported by on-system hydrogen, the high and traditional peak forecasts still require more than 600 MMcf/day of send-out; thus the proposed regasification capacity would still be required in 2050 in these forecasts. The two lower forecasts may not require the full 800 MMcf/day vaporizer capacity at that time, but as indicated previously this capacity will be needed until 2038 to 2042.
- ***Tank volume (2050):*** The last column shows the range of forecasts for the volume of LNG storage that would be required over the coldest three days of a design year in 2050. The forecast requirement for LNG storage ranges from 1.2 to 2.4 Bcf. In all cases, the proposed TLSE tank storage remains appropriate.

[7] Since FEI has not prepared a forecast to 2050, this value is based on an extrapolation of the LTGRP 20-year forecast to 2050. 60 percent represents the approximate renewable and low carbon gas required to meet Provincial emission reduction targets of 80 percent for the residential, commercial and industrial sectors and accounts for load growth from use of natural gas and renewable/low carbon gas as a transportation fuel which also reduces carbon emissions in BC and globally.

Table 3

Diversified Energy Future Peak Demand Forecasts	2019	2050							
	Base Year Peak demand (TJ/day)	Total Peak Demand (TJ/day)	Hydrogen (TJ/day)	Scenario A			Scenario B		
				NG and RNG (TJ/day)	NG and RNG (MMcf/day)	Volume Required to Support Three Coldest Winter Days (Bcf)	NG, RNG & H2 (TJ/day)	NG, RNG & H2 (MMcf/day)	Volume Required to Support Three Coldest Winter Days (Bcf)
High (Traditional peak+10%)	950	1383	481.3	902	821	2.27	1142	1040	2.40
Traditional Peak	950	1230	428.0	802	730	2.04	1016	925	2.40
Low (Traditional Peak-25%)	950	838	291.6	546	497	1.39	692	630	1.76
End Use Peak (theoretical method)	950	738	256.8	481	438	1.22	610	555	1.55

950 TJ/day is 865 MMcf/day

Forecast Scenarios Support Project Need

FEI's forecast information above for a diversified energy future strongly supports a tank size of at least 2 Bcf (consistent with its analysis in Section 4.3.5.3 of the Application) and regasification capacity of 800 MMcf/day (consistent with its analysis in Section 4.4.2 of the Application) to meet the Minimum Resiliency Planning Objective. In particular:

- ***Tank volume:*** In all forecast scenarios, more than 2 Bcf is still required beyond 2030 to support demand on the coldest three days. In 2050, the Low (Traditional Peak forecast minus 25 percent) forecast volume remains close to 2 Bcf in scenario B, and even the theoretical end use peak forecast volume is above 1.2 Bcf.
- ***Regasification capacity:*** The forecasts also show that more than 600 MMcf/day of send-out would be needed until at least 2042 in all but the theoretical end-use forecast. This indicates the proposed 800 MMcf/day of regasification capacity is sized appropriately to meet forecast need until at least 2042. By 2050, both the traditional peak forecast and the high forecast support FEI's proposed 800 MMcf/day regasification sizing in order to meet the Minimum Resiliency Planning Objective.

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

Response:

As discussed in the response to BCUC IR2 80.1.2, FEI's framework to transition to a low carbon energy future is the Clean Growth Pathway to 2050. The Clean Growth Pathway is a diversified approach that is technology agnostic. At this point in the energy transition it is important to maximize the number of decarbonization pathways available and explore business models that meet energy demands and maximize the use of existing assets, thereby avoiding the costs that would come with the complete re-engineering of BC's energy sector. In the 2022 LTGRP, the Clean Growth Pathway to 2050 is represented by the Diversified Energy Future scenario.

With this in mind, FEI is planning for gas supply resources made up of increasing amounts of renewable and low carbon gas over the next 20 years and beyond. The components of this resource mix are expected to include renewable natural gas (RNG), hydrogen (H2), natural gas, and smaller amounts of syngas and lignin, supplemented later in the planning period by carbon capture, utilization or sequestration (CCUS). The amount of each resource to be acquired and delivered to customers throughout the planning period will ultimately be predicated on a number of a variables, including:

- **Quantity and Timing of Resource Availability**: Although FEI has modelled the mix of renewable and low carbon gases in certain proportions over time in the LTGRP planning scenario, the actual amount of each component that is acquired and delivered to customers could vary from the modelled amounts over the planning horizon based on a number of factors, including resource costs and supply project opportunities and development. Renewable and low-carbon gases with the highest volume potential over the planning horizon are RNG and H2. In particular, RNG is interchangeable[8] with natural gas and has wider availability so will make up a greater proportion of the resource mix in the near term. RNG will continue to be a large part of the resource mix throughout the planning horizon and beyond. While H2 resource development is underway, it is expected to become more widely available and make up an increasing proportion of the resource mix later in the planning horizon beyond 2030.
- **Resource Development and Delivery:** Many pathways exist for bringing the benefits of renewable and low carbon gas to FEI's customers; however, there are a number of ways in which these resources can be developed and delivered to customers which will ultimately impact the overall resource mix. For example, one means of incorporating more renewable and low carbon gas into the resource mix is through acquiring off-system supply, wherein FEI acquires renewable and low carbon gases in other regions and transports the gas by displacement to its system. While this process ultimately displaces conventional natural gas molecules, FEI customers physically receive conventional natural gas along with the environmental attributes associated with renewable and low carbon gas through displacement. The incorporation of these types of off-system supply will play an important role over the planning horizon as more on- or near-system resources are developed. FEI has also identified a number of ways to develop H2 supplies. These include, but are not limited to:
    - locating H2 production facilities that use RNG and natural gas as a feedstock near the end use;
    - blending H2 from physical production facilities on-system or upstream with natural gas on existing pipelines; and

[8] The physical properties of renewable natural gas, such as, specific gravity, viscosity and heating value, etc., falls with the range of the physical properties of FEI's conventional sources of natural gas. The capacity impacts and gas supply resource needs are comparable, and both sources of methane can utilize the same upstream and on-system infrastructure.

- developing dedicated delivery infrastructure over the longer term.

- **Location:** Given the length of the planning horizon, the geographic location where renewable and low carbon supply production is physically delivered to FEI's customers is not yet known in detail. Production facilities for RNG and H2 supplies are expected to be developed both on FEI's system and, over time, in locations where these low carbon gases can be injected into the existing upstream gas infrastructure. While many potential projects are in the concept and development stages, the location of all those that will proceed during the next 20 years is uncertain. In particular, the extent to which such resources are developed and delivered to customers on one portion of FEI's system will impact the amount of RNG and natural gas that will still need to be delivered on other portions of the system over the planning horizon.

FEI will discuss these resources and the range of quantities, timing of availability, modes of development and delivery and production location in greater detail as part of its 2022 LTGRP. However, as discussed in the response to BCUC Panel IR1 1.1, throughout the energy transition over the next 20 years and beyond to 2050, methane (both renewable and conventional natural gas) will continue to play a significant role in providing firm energy service to customers in the Lower Mainland. Therefore, the TLSE Project will be required to support the resilience of methane-based energy deliveries to customers well into the future.

FEI's modelling of supply resources over the next 20 years provides the following observations regarding supply resource mix in the future for FEI's 2022 LTGRP planning scenario. These observations apply to a moderate range of higher or lower demand forecasts. Note that the 2022 LTGRP modelling only extends to 2042; therefore, scenarios extending to 2050 are based on the trends regarding resource mix observed at the end of the LTGRP planning horizon, informed by the results of the Guidehouse report on *Pathways for British Columbia to Achieve its GHG Reduction Goals*[9] which considers a longer planning horizon. Table 1 below sets out the anticipated gas supply resource mix observations for annual and peak demand for the 2022 LTGRP Diversified Energy Future (Planning) Scenario over the planning horizon and to 2050. Below the table, FEI provides its observations on resource mixes under high and low demand scenarios as well.

[9] https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/guidehouse-report.pdf?sfvrsn=dbb70958_0.

1 **Table 1**

Year	Resource Mix Observations	
	Annual	Peak
2030	Off-system supplies of RNG and H2 will be relied on in the early stages of FEI's carbon reduction transition. Natural gas and RNG will continue to make up the majority of physical deliveries to customers during this period. For off-system supplies, carbon reductions are achieved through the displacement of conventional gas in favor of renewable and low carbon purchases. By way of displacement, FEI customers physically receive conventional gas in addition to the environmental attributes associated with the renewable and low carbon gas purchased in other jurisdictions. Physical flows of H2 on FEI's gas infrastructure are expected to be limited to smaller amounts and portions of FEI's system until around 2030 as the technologies and infrastructure needed to manage larger volumes are refined and implemented. One or more syngas and lignin projects will displace some industrial load, though natural gas may continue to provide firm back-up service for periods when syngas/lignin production is unavailable. CCUS is expected to still be in development stages, perhaps available in small amounts through pilot projects, in 2030.	The majority of FEI's firm customers, including those in the Lower Mainland, will continue to be using methane for space and water heating. Natural gas will provide firming service to on-system RNG resources during peak periods. As such, peak requirements for deliveries of methane molecules are expected to change little by 2030.
2042	This is the end of the planning horizon for the 2022 LTGRP and as such is subject to greater uncertainty with regard to the range of factors discussed above. The proportion of FEI customers using methane for space and water heating as opposed to other renewable and low carbon gas supplies will have decreased, but will still make up a majority of customers. While the development of on-system resources will have grown in the intervening years, FEI anticipates there will still be reliance on off-system supplies, and therefore, the need to flow physical molecules of RNG and natural gas to a majority of FEI's customers.	As a majority of FEI customers will still be using methane for space and water heating as opposed to other renewable and low carbon gas supplies, a large requirement for methane peaking services will remain. To the extent that a portion of customers have switched completely to H2 service, the TLSE Project will be able to provide resiliency benefits to the remaining "methane customers" over a longer period of time (i.e., a longer cold snap or potential pipeline outage).

Year	Resource Mix Observations	
	Annual	Peak
2050	The steps taken early in the planning horizon have set FEI on a pathway to deep decarbonization by 2050 and well on its way to carbon neutrality on an annual basis. RNG and H2 will both be an important part of FEI's resource mix.	A large portion of FEI's demand continues to be met via delivery of methane to customers and delivery of methane to H2 production facilities. As such, the resiliency benefits of the TLSE Project remain important, particularly as extreme weather events continue into the future.

Resource Mix Under Higher or Lower Demand Scenarios

FEI expects the mix of supply resources described in the table above to apply to a moderate range of possible higher or lower demand forecasts based on a diversified energy future, namely one in which both the electric and gas infrastructure systems are relied on to decarbonize BC's energy infrastructure.

If, however, substantially different futures unfolded, a different resource mix could also unfold. FEI anticipates that if a substantially higher demand scenario began to occur within the planning horizon, higher growth in demand for RNG and natural gas would ensue, creating greater dependence on the TLSE facility to provide resiliency for the system. In contrast, if a substantially lower demand scenario began to unfold such as deep electrification and a lack of support for renewable and low carbon gas development, FEI anticipates that unintended consequences to the electricity system would begin to emerge, creating at best an uncertain future for the reliability and performance of BC's energy infrastructure overall. Under such circumstances, the resiliency of BC's energy infrastructure could be expected to become strained, requiring costly and reactive responses.

1.2.1 Please discuss the extent to which FEI's reliance on the T-South system for supply would be expected to change compared to today based upon the expected resources supplied in the LML in 2030 and 2050. Where possible, please provide a quantitative estimate of the change in reliance on T-South.

1.2.1.1 If FEI's future reliance on T-South for LML supply were to reduce in future, please discuss how this would change FEI's utilization of the TLSE Project for resiliency purposes.

Attachment 23.1

FortisBC Energy Inc. Organization Areas & Communities

Fort Nelson
North Region
Mackenzie
Prince George
Quesnel
Williams Lake
One Hundred Mile House
Thompson
North Okanagan
Revelstoke
Central Okanagan
Kelowna
South Okanagan
Penticton
West Kootenay
East Kootenay
Cranbrook
Kimberley
Elkford
Sparwood
Fernie
Nelson
Castlegar
Trail - Fruitvale
Rossland
Grand Forks
Creston
Salmo
Okanagan Falls
Keremeos
Oliver
Osoyoos
Princeton
Summerland
Peachland
Duck Lake
Merritt
Logan Lake
Ashcroft
Rayleigh
Kamloops
Dallas
Chase
Blind Bay
Canoe
Salmon Arm
Enderby
Armstrong
Vernon
Lumby
Lower Mainland West
Lower Mainland East
North Island
Capital Region
Whistler
Squamish
Campbell River
Powell River
Puntledge Courtenay
Cumberland
Port Alberni
Parksville
Nanaimo
Cedar
Ladysmith
Crofton
Duncan
Cobble Hill
Shawnigan - Mill Bay
Victoria
Sooke
Welcome Beach Sechelt
Roberts Creek
Gibsons
Lions Bay
Miller's Landing
Fairwinds
Vancouver
Ladner
Aldergrove
White Rock
Tsawwassen
Abbotsford
Mission
Chilliwack
Cultus Lake
Kent
Rosedale
Harrison Hot Springs
Hope
Fort St John
Dawson Creek
Tumbler Ridge
Grande Prairie
Wonowon
Taylor
Hudson's Hope
Chetwynd
Dawson Creek
Tumbler Ridge
Mackenzie
Germansen Landing
Manson Creek
Nazko
Williams Lake
Blue River
Mica Creek
Revelstoke
Golden
Banff
Canmore
Cochrane
Rocky Mountain House
Red Deer
Sylvan Lake
Innisfail
Olds
Didsbury
Carstairs
Crossfield
Airdrie
Calgary
Cochrane
Strathmore
Chestermere
Drumheller
Three Hills
Trochu
Hanna
Oyen
Consort
Coronation
Provost
Lloydminster
Vermilion
Wainwright
Edmonton
St Albert
Spruce Grove
Leduc
Devon
Drayton Valley
Edson
Hinton
Whitecourt
Swan Hills
Barrhead
Westlock
Athabasca
High Prairie
Slave Lake
Peace River
Fairview
Grimshaw
Atikameg
Loon Lake
Peerless Lake
Chipewyan Lake
High Level
Rainbow Lake
Zama Lake
Utikuma Lake
Lesser Slave Lake
Calling Lake
Gull Lake
Pigeon Lake
Chip Lake
Wabasca-Desmarais
Trout Lake
Meander River
Fort Vermilion
La Crete
Fort Liard
Fort Simpson
Fort Nelson
Toad River
Muncho Lake
Liard River
Kwadacha
Tsay Keh Dene
Fort Ware
Prophet River
Trutch
Sikanni Chief
Pink Mountain
Kotcho Lake
Hay Zama Lake
Wildland Park
Chinchaga Wildland Park
Bison Lake
Peace Island Park
Dunvegan
Watino
Notikewin
Hotchkiss
Manning
Beaverlodge
Hythe
Dawson Creek
Chetwynd
Tumbler Ridge
Mackenzie
Germansen Landing
Manson Creek
Nazko
Quesnel
Williams Lake
Blue River
Mica Creek
Revelstoke
Golden
Banff
Canmore
Cochrane
Rocky Mountain House
Red Deer
Sylvan Lake
Innisfail
Olds
Didsbury
Carstairs
Crossfield
Airdrie
Calgary
Cochrane
Strathmore
Chestermere
Drumheller
Three Hills
Trochu
Hanna
Oyen
Consort
Coronation
Provost
Lloydminster
Vermilion
Wainwright
Edmonton
St Albert
Spruce Grove
Leduc
Devon
Drayton Valley
Edson
Hinton
Whitecourt
Swan Hills
Barrhead
Westlock
Athabasca
High Prairie
Slave Lake
Peace River
Fairview
Grimshaw
Atikameg
Loon Lake
Peerless Lake
Chipewyan Lake
High Level
Rainbow Lake
Zama Lake
Utikuma Lake
Lesser Slave Lake
Calling Lake
Gull Lake
Pigeon Lake
Chip Lake
Wabasca-Desmarais
Trout Lake
Meander River
Fort Vermilion
La Crete
Fort Liard
Fort Simpson
Fort Nelson
Toad River
Muncho Lake
Liard River
Kwadacha
Tsay Keh Dene
Fort Ware
Prophet River
Trutch
Sikanni Chief
Pink Mountain
Kotcho Lake
Hay Zama Lake
Wildland Park
Chinchaga Wildland Park
Bison Lake
Peace Island Park
Dunvegan
Watino
Notikewin
Hotchkiss
Manning
Beaverlodge
Hythe
Dawson Creek
Chetwynd
Tumbler Ridge
Mackenzie
Germansen Landing
Manson Creek
Nazko
Quesnel
Williams Lake
Blue River
Mica Creek
Revelstoke
Golden
Banff
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Cochrane
Rocky Mountain House
Red Deer
Sylvan Lake
Innisfail
Olds
Didsbury
Carstairs
Crossfield
Airdrie
Calgary
Cochrane
Strathmore
Chestermere
Drumheller
Three Hills
Trochu
Hanna
Oyen
Consort
Coronation
Provost
Lloydminster
Vermilion
Wainwright
Edmonton
St Albert
Spruce Grove
Leduc
Devon
Drayton Valley
Edson
Hinton
Whitecourt
Swan Hills
Barrhead
Westlock
Athabasca
High Prairie
Slave Lake
Peace River
Fairview
Grimshaw
Atikameg
Loon Lake
Peerless Lake
Chipewyan Lake
High Level
Rainbow Lake
Zama Lake
Utikuma Lake
Lesser Slave Lake
Calling Lake
Gull Lake
Pigeon Lake
Chip Lake
Wabasca-Desmarais
Trout Lake
Meander River
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Kwadacha
Tsay Keh Dene
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Prophet River
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Pink Mountain
Kotcho Lake
Hay Zama Lake
Wildland Park
Chinchaga Wildland Park
Bison Lake
Peace Island Park
Dunvegan
Watino
Notikewin
Hotchkiss
Manning
Beaverlodge
Hythe

Sources: Esri, HERE, Garmin, USGS, Intermap, INCREMENT P, NRCan, Esri Japan, METI, Esri China (Hong Kong), Esri Korea, Esri (Thailand), NGCC, (c) OpenStreetMap contributors, and the GIS User Community

Legend
- IP Pipes
- TP Pipes
- FEI Organization Areas

FORTIS BC
16705 Fraser Hwy,
Surrey, British Columbia, V4N 0E8
1-866-4FORTIS
http://www.fortisbc.com

1:1,500,000

10 5 0 10 20 30 40
Kilometers

Projection: BC Standard Albers - Datum: NAD83(CSRS98)

Attachment 33.6

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 35.2.2

Electric Grids and Gas & Water Utilities

ESG Evaluation
Key Sustainability Factors

Submit Your Feedback
Online | Email

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S&P Global
Ratings

Approach

Our key sustainability factors identify the most material environmental and social risks assessed in our ESG Evaluation. We assess the materiality[1] of those risks across the industry's value chain and reflect them in the weighting of our environmental and social factors. We also provide the quantitative indicators[2] used to assess a company's performance relative to its industry peers on each of those factors. For further information, please refer to our "Environmental, Social, And Governance Evaluation: Analytical Approach."

Scope

The electric grids sector comprises companies that operate regulated electricity transmission and distribution networks. Companies are typically regulated and include utilities operated by federal, state, or local governmental bodies and investor-owned companies.

The gas utilities sector comprises government-operated and public companies that deliver natural gas to residential, industrial, and commercial customers. Companies typically operate a network of distribution and transmission pipelines.

Water utilities include government-operated and public entities that deliver fresh water and provide sanitation services to residential, industrial, and commercial customers.

Material Environmental Risks

Electric grids, gas utilities, and water utilities are exposed to material environmental risks across their value chain:

- **Transition to a low-carbon economy**: Electric grids are materially exposed to the greenhouse gas (GHG) emissions of the power generators whose electricity flows through their grids. They are also exposed to risks related to the modernization of electric power infrastructure to accommodate new technologies and intermittent and decentralized renewable power supply. Gas utilities are exposed to risks from direct emissions from their networks (primarily methane) as well as upstream emissions in the oil & gas sector. Toughening climate-related regulations expose both subsectors to significant costs and operational impacts from the retirement of fossil-fuel-based assets. Water utilities are exposed to operating risks related to energy consumption.
- **Physical impacts of climate change**: Climate change and extreme weather events have material effects on electric grids and water and gas utilities. For example, acute risks such as flooding and storms can cause operational disruption, damage to assets (including reduced asset lifetimes), reduced capacity in the case of water networks, and increased capital and maintenance costs.
- **Land use impacts**: Construction and maintenance of electric and gas distribution and transmission corridors and water storage and transmission networks can harm endangered species and sensitive natural environments, potentially resulting in regulatory action or reputational damage for operators.
- **Waste and pollution**: Grid, water, and gas network upgrades and expansions require proper handling of materials and generate construction waste, which is a priority waste stream for some regulators. These aspects can result in waste management costs and potential reputational damage.

Environmental Factors: Weighting And KPIs

The weighting of our environmental factors varies by subsector. We also use different quantitative performance indicators to inform our opinion of an entity's management of its environmental impact relative to peers in the same subsector. Our opinion under the ESG Evaluation is also informed by qualitative indicators such as climate-related policy and commitments.

Electric Grids

We place the highest weighting on GHG emissions to capture risks related to the energy transition, which includes the indirect emissions from power generators and upgrades to infrastructure required to interconnect and reliably deliver low-carbon energy sources. We apply a moderate weighting to land use and biodiversity to reflect potential regulatory, operational, and reputational impact risks from wildfires and habitat destruction stemming from corridor maintenance and

construction. We assign a lower weighting to waste and pollution to reflect some exposure to costs and regulatory risk from the sector's use of resources for grid replacement and expansion. We apply the lowest weighting to water to capture the low water intensity of the sector, while reflecting some indirect exposure in the supply chain.

Factor	Weight	Key performance indicators	Other performance indicators
 **Greenhouse gas emissions**	40%	- Grid carbon emissions intensity (tonne of carbon dioxide equivalent [tCO2e] per kWh delivered) - SF6 emissions leakage (%) - Average annual transmission and distribution losses (%)	- % of energy that is sourced from renewable sources - % of electricity generation from fossil fuels - Regional renewable generation targets
 **Land use and biodiversity**	30%	- % of land area and sites assessed for biodiversity risks	- % of operational sites owned, leased, managed in, or adjacent to protected areas and areas of high biodiversity value outside protected areas
 **Waste and pollution**	20%	- Total waste (t) - % of waste that is recycled/reused/recovered - % of waste that is hazardous	- Proportion of suppliers assessed and audited on their waste and pollution performance - SOx, NOx, and PM intensity of generation (emissions per MWh)
 **Water**	10%	- % of operations exposed to high or extremely high water stress - Water consumption (cubic meter [m3])	- Water withdrawals (m3)

Gas Utilities

We apply the highest weighting to the GHG emissions factor due to financial and operating risks associated with the ongoing transition to low-carbon forms of energy, driven by global regulatory developments, economic factors, and societal pressure. We assign a lower equal weighting to the waste & pollution and land use & biodiversity factors due to potential regulatory and reputational impacts from hazardous waste generation and habitat impacts of pipeline corridors. These factors, while material, are less significant than carbon risk. We apply the lowest weighting to the water factor to reflect relatively low water intensity in the sector, while capturing some indirect exposure in the supply chain.

Factor	Weight	Key performance indicators	Other performance indicators
 **Greenhouse gas emissions**	50%	- Scope 1 GHG intensity (tCO2e per m3 of gas delivered) - Distribution gas leaks (tCO2e)	- Source and amount of material Scope 3 emissions (tCO2e)
 **Land use and biodiversity**	20%	- % of land area and sites assessed for biodiversity risks	- % of operational sites owned, leased, managed in, or adjacent to protected areas and areas of high biodiversity value outside protected areas
 **Waste and pollution**	20%	- Total waste (t) - % of waste that is recycled/reused/recovered - % of waste that is hazardous	- Proportion of suppliers assessed and audited on their waste and pollution performance
 **Water**	10%	- Water consumption (m3) - % of operations exposed to high or extremely high water stress	- Water withdrawals (m3)

Water Utilities

The higher weight on the water and waste and pollution factors primarily reflects the foreseen water scarcity induced by climate change and scrutiny on water preservation, water quality risks, and water recycling. We cover drinking water safety in the social profile since it relates to human consumption of water. Energy use is a significant portion of a water utility's cost and greenhouse gas emissions can be significant. Events that result in harm to biodiversity could warrant subsequent adjustment to the environmental profile.

Factor	Weight	Key performance indicators	Other performance indicators
 **Water**	40%	– Non-revenue water / leakage rates (%) – Exposure of supply to water stress	– Water withdrawals by source (m3) – Age of pipes – Water consumption: withdrawals less discharges (m3)
 **Waste and pollution**	30%	– % of samples passing effluent standards – Number of violations of effluent standards – Amount of wastewater treated (m3)	– Waste treatment path of sewage waste (% recycled, % energy recovery, % sent to landfill) – Water withdrawals by source (%)
 **Greenhouse gas emissions**	20%	– Scope 1 emissions intensity (tCO2e, by revenues and by volume) – Scope 2 emissions intensity (tCO2e, by revenues and by volume) – Energy intensity	– % of energy that is sourced from renewable sources – Estimated avoided carbon emissions from wastewater to energy
 **Land use and biodiversity**	10%	– % land managed to promote biodiversity – Number of violations of nutrient or biochemical oxygen demand (BOD) standards in effluent	– % catchments with management plans that cover ecosystem health – Natural capital valuation and accounts for land

Material Social Risks

Electric grids and gas and water utilities are exposed to material social risks across their value chain:

- **Network reliability and affordability**: Reliability, affordability, and accessibility can impact customer satisfaction, regulatory compliance, and company reputation. Electric, water, and gas network upgrades and expansions can put upward pressure on rates, while intermittent electric generation may influence grid reliability. Additionally, affordability and access to services, including for vulnerable populations, is an issue of growing regulatory and public scrutiny.
- **Safety Management**: Occupational safety risks, including electrical hazards and falls, are typically well-managed given stringent safety standards. Acute safety incidents including fires, gas explosions, and contaminated drinking water expose companies to material financial impacts, regulatory action, and reputational damage.
- **Communities**: The energy transition requires upgrading and expanding grids and gas network infrastructure, which can be disruptive to local communities and, in turn, can undermine regulatory support for operators. Water utilities must manage the use of shared water resources with local stakeholders.
- **Workforce & Diversity**: Recruiting and developing a diverse and skilled workforce is increasingly important to this sector, which is characterized by a relatively older and male talent pool. Moreover, shifting technologies and regulatory developments are rapidly reshaping the sector and require a new set of skills and attributes.

Social Factors: Weighting And KPIs

The weighting of our social factors varies by subsector. We use relatively similar indicators across the subsectors to inform our opinion of an entity's management of its social impacts relative to peers in the same subsector, although some may vary. Our opinion under our ESG Evaluation is also informed by qualitative indicators. Examples of qualitative indicators include the quality and effectiveness of an entity's policy on customer and community engagement.

Electric Grids

We place the highest weighting on customer engagement and safety to reflect that electric grid operators provide essential services that must meet strict reliability and affordability standards, while acute safety incidents including wildfires and worker fatalities can have material financial and reputational consequences. We place a moderate weighting on communities as grid upgrades and expansions could be disruptive to local communities and lead to strong local opposition if improperly managed, which could influence grid operators' social license to operate. We assign an equal weighting to workforce and diversity as entities are exposed to risks related to collective bargaining from largely-unionized workforces, succession planning for an aging workforce amid an industry transition, and a high proportion of contractors in the workforce.

Factor	Weight	Key Performance Indicators	Other performance indicators
 **Customer engagement**	30%	- Average retail electric rate for residential, commercial, and industrial customers - System Average Interruption Duration Index (SAIDI) - System Average Interruption Frequency Index (SAIFI)	- Customer satisfaction rate
 **Safety management**	30%	- Number of fatalities (employees and contractors) - Occupational injury frequency rate (OIFR) - Lost Time Injury Frequency Rate (LTIF) by contractors and employees)	- % of contractors assessed and audited on safety performance (%) - % of substations and line mileage in high-fire-risk areas
 **Communities**	20%	- Spend on engagement with local communities as a % of philanthropic spending - Cash contributions, employee volunteering, and in-kind giving converted into reporting currency	- % of operations with local community engagement, impact assessments, and development programs - Number and cost of project delays due to community opposition
 **Workforce and diversity**	20%	- Voluntary/involuntary turnover rate (%) - % of woman in total workforce, junior and senior management positions, and in revenue-generating functions - % of employees <30 years and >50 years	- % of part-time and temporary employees, and contractors in workforce - % of employees represented by an independent trade union or covered by collective bargaining agreements - Average amount spent per full-time equivalent on training and development

Gas Utilities

We apply the highest weighting on safety management to reflect exposure to elevated occupational hazards for maintenance workers, and low-probability, high-impact gas explosions that can affect local communities. We assign a slightly lower weighting to customer engagement as gas utilities provide essential services that must meet strict reliability, affordability, and access standards. We apply a lower weighting to communities because network upgrades and expansions could be disruptive to local districts and lead to opposition if improperly managed, which could influence gas utilities' social license to operate. We place an equal low weighting on workforce and diversity to reflect some exposure to an aging, low-diversity workforce and organized labor.

Factor	Weight	Key Performance Indicators	Other performance indicators
 **Safety management**	35%	– Number of fatalities (employees and contractors) – OIFR – Percentage of gas (1) transmission and (2) distribution pipelines inspected	– LTIF (by contractors and employees) – Gas emergency response time (minutes) –
 **Customer engagement**	25%	– Average gas prices for residential, commercial, and industrial customers (USD/mcf) – SAIDI – SAIFI	– Customer satisfaction rate
 **Communities**	20%	– Spend on engagement with local communities as a % of philanthropic spending – Cash contributions, employee volunteering, and in-kind giving converted into reporting currency	– % of operations with local community engagement, impact assessments, and development programs – Number of project delays as a result of community opposition
 **Workforce and diversity**	20%	– Voluntary/involuntary turnover rate (%) – % of employees <30 years and >50 years – % of woman and minority groups in total workforce, junior and senior management positions, and in revenue-generating functions	– % of employees represented by an independent trade union or covered by collective bargaining agreements – Average amount spent per full-time equivalent on training and development

Water Utilities

Water utilities have a relatively high weight on communities, where we capture water stewardship. Water basins can be geographically large and involve multiple stakeholder groups. Failure to manage these potentially complex relationships can result in disputes and litigation. It is our view that customers and safety are equally material to the social profile. In customer engagement we capture the utilities' ability to provide water at affordable rates and to limit service interruptions. In safety, regulatory fines can be levied against utilities that fail to meet standards, due to the health concerns from poor drinking water quality.

Factor	Weight	Key Performance Indicators	Other performance indicators
Communities	30%	– Frequency of interactions with basin stakeholders – Construction and maintenance project delays as a result of community opposition: number and cost	– Proportion of current construction and maintenance projects that require community consultation – Number of cases filed with courts from other water users
Safety management	30%	– Number of violations of drinking water quality standards	– Number of boil notices – Number of workplace fatalities LTIF
Customer engagement	30%	– Affordability of water tariffs: utility bill as a percentage of median disposable household income – Local poverty rates – Number and duration of supply interruptions – Number of customers affected by supply interruptions	– % satisfied customers (out of total customers responding to company's survey) – Customer complaints: number and average time to handle – Payment collection rate – Shut off rate (% accounts shut off) – Data privacy breaches: number and customers affected
Workforce and diversity	10%	– Voluntary/involuntary turnover rate (%) – Age demographics of workforce – % of women and minority groups per employee category	– % of operations and contractors assessed and audited for potential human rights breaches – Gender pay gap – Entry-level wage compare to local minimum wage

Submit Feedback

You can submit your feedback online or by email.

Please specify which sector you are commenting on when submitting feedback.

We would particularly like to hear from you regarding:

1. Which risks are missing or not relevant?
2. Which KPIs are missing, could be enhanced, or are not relevant?
3. What views do you have on the suggested factor weights for the environmental and social analysis?
4. Do you have additional feedback(s) on this document?

Endnotes

[1] Events and issues are material for the ESG Evaluation when in our view they could meaningfully affect the entity's business operations, cash flows, legal or regulatory liabilities, access to capital, reputation, or relationships with key stakeholders and society more generally, either directly or through its value chain (upstream or downstream).

[2] We are mindful that some may be produced using different methodologies and scopes.

Related Research

"The ESG Risk Atlas: Sector And Regional Rationales And Scores," published July 22, 2020

"Our Updated ESG Risk Atlas And Key Sustainability Factors: A Companion Guide," published July 22, 2020

"Environmental, Social, And Governance Evaluation: Analytical Approach," published June 17, 2020

"How We Apply Our ESG Evaluation Analytical Approach: Part 2," published June 17, 2020

"ESG Evaluation: TenneTholding B.V." published August 27, 2019

"ESG Evaluation: American Water Works Co. Inc." published April 7, 2020

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Attachment 37.3

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 38.2.2.2

CONSENSUS FORECASTS®

Surveys of International Economic Forecasts

- G-7 & Western Europe

Survey Date
December 6, 2021

Every month, Consensus Economics surveys over 250 prominent financial and economic forecasters for their estimates of a range of variables including future growth, inflation, interest rates and exchange rates. More than 20 countries are covered and the reference data, together with analysis and polls on topical issues, is rushed to subscribers by express mail and e-mail.

Our next issue of **Consensus Forecasts** will be available on **Thursday January 13** and will include forecasts for 2023, and our survey of **Forecast Probabilities.**

Survey Highlights

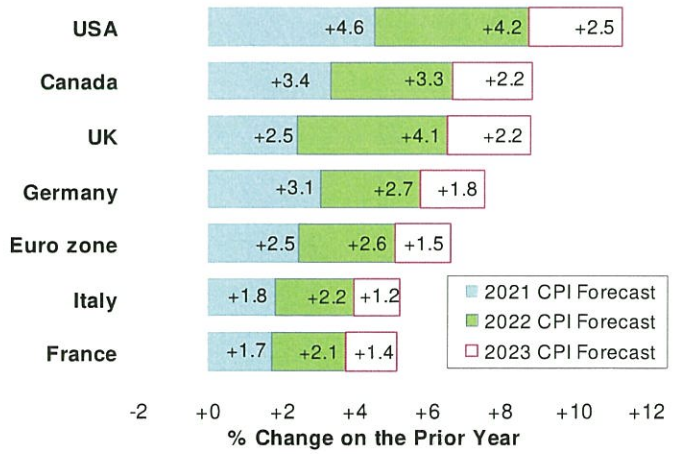
- **Inflation forecasts** – particularly for 2022 – have surged again in this month's survey (back page summary) due to blistering advances in energy costs reflected a combination of supply-led constraints and boisterous demand, as vaccine deployment and pared back restrictions fuelled a bounce-back in economic activity over Q3. **US Federal Reserve** chair Jay Powell recently admitted that inflation risks were no longer transitory and that a faster pace in QE tapering would likely be announced at next week's FOMC monetary policy meeting.

- In its latest Economic Outlook, the OECD warned that fresh Covid-related disruption, exacerbated by fears over the Omicron variant, could extend supply-chain stresses and push rising price pressures deeper into 2022.

- Olaf Scholz, who replaced Angela Merkel this week as **Germany's** long-standing chancellor, faces an economy struggling to overcome high inflation, supply-chain woes and Covid.

The results of our survey of quarter-by-quarter forecasts appear on pages 2,3,28,29 and 30. These include **Quarterly Forecasts** for **GDP Growth**, **Consumption**, **Industrial Production**, **Inflation** and **3-month Interest Rates** through to Q2 2023.

Total 2021 + 2022 + 2023 Consumer Price Inflation (CPI) Consensus Forecasts



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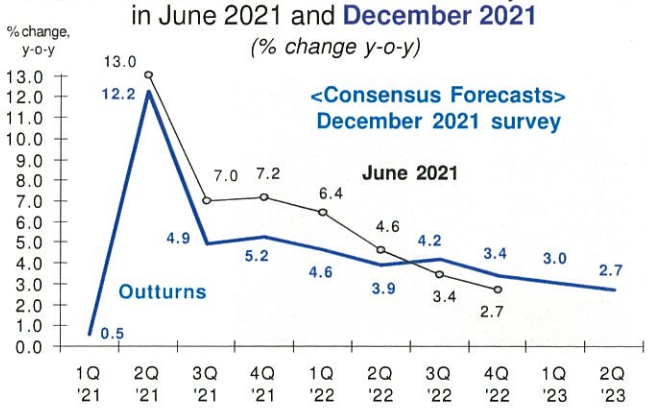
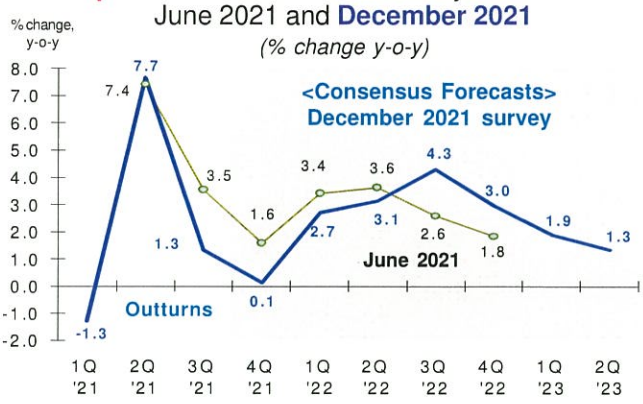
Deputy Editor: Luke N. George
Publisher: Philip M. Hubbard

The charts on this page show the evolution of **Quarterly Forecast Trends for GDP Growth** in four G7 economies. The GDP charts include consensus forecasts from our surveys in June 2021 (**grey line**) and from the current December 2021 survey (**blue**). The December 2021 quarterly forecasts for 14 countries are on pages 3, 28-30.

United States - GDP Growth - Quarterly Forecasts in June 2021 and **December 2021**



Japan - GDP Growth - Quarterly Forecasts in June 2021 and **December 2021**



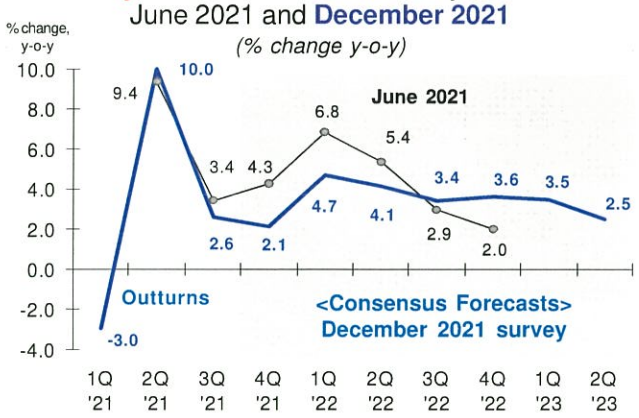
GDP Quarterly Consensus Forecasts – June 2021 and December 2021 (y-o-y, % change)

USA	2021 GDP		2022 GDP			
2 surveys:	Q3	Q4	Q1	Q2	Q3	Q4
June 14, 2021	*7.0*	*7.2*	*6.4*	*4.6*	*3.4*	*2.7*
Dec. 6, 2021	*4.9*	*5.2*	*4.6*	*3.9*	*4.2*	*3.4*
Difference	**-2.1**	**-1.9**	**-1.8**	**-0.7**	**+0.7**	**+0.6**

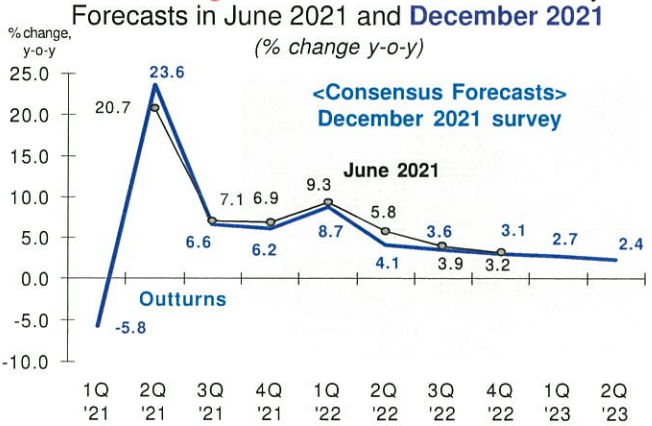
GDP Quarterly Consensus Forecasts – June 2021 and December 2021 (y-o-y, % change)

Japan	2021 GDP		2022 GDP			
2 surveys:	Q3	Q4	Q1	Q2	Q3	Q4
June 14, 2021	*3.5*	*1.6*	*3.4*	*3.6*	*2.6*	*1.8*
Dec. 6, 2021	*1.3*	*0.1*	*2.7*	*3.1*	*4.3*	*3.0*
Difference	**-2.2**	**-1.4**	**-0.7**	**-0.5**	**+1.7**	**+1.1**

Germany - GDP Growth - Quarterly Forecasts in June 2021 and **December 2021**



United Kingdom - GDP Growth - Quarterly Forecasts in June 2021 and **December 2021**



GDP Quarterly Consensus Forecasts – June 2021 and December 2021 (y-o-y, % change)

Germany	2021 GDP		2022 GDP			
2 surveys:	Q3	Q4	Q1	Q2	Q3	Q4
June 14, 2021	*3.4*	*4.3*	*6.8*	*5.4*	*2.9*	*2.0*
Dec. 6, 2021	*2.6*	*2.1*	*4.7*	*4.1*	*3.4*	*3.6*
Difference	**-0.8**	**-2.1**	**-2.1**	**-1.2**	**+0.5**	**+1.6**

GDP Quarterly Consensus Forecasts – June 2021 and December 2021 (y-o-y, % change)

UK	2021 GDP		2022 GDP			
2 surveys:	Q3	Q4	Q1	Q2	Q3	Q4
June 14, 2021	*7.1*	*6.9*	*9.3*	*5.8*	*3.9*	*3.2*
Dec. 6, 2021	*6.6*	*6.2*	*8.7*	*4.1*	*3.6*	*3.1*
Difference	**-0.5**	**-0.7**	**-0.6**	**-1.7**	**-0.4**	**-0.2**

In addition to their regular annual forecasts, country panellists were asked to provide individual quarterly estimates covering the period through Q2 2023. Figures in normal type are official, published data with consensus forecasts – based on the averages of our panels' forecasts – shown in ***bold italics***. Unless stated otherwise, all definitions correspond to those used on the individual country pages. As indicated, normal text numbers are percentage changes over the same quarter of the previous year; italics denote implied changes over the previous quarter (not annualised). **Readers should note that the quarterly (and monthly) consensus forecasts covering a year may not equate to the annual consensus forecast shown for the same variable on pages 4-24, since the groups of survey respondents may be different, or because of rounding.**

United States

* % change over previous year	2020		2021				2022				2023	
	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2
Gross Domestic Product*	-2.9	-2.3	0.5	12.2	4.9	***5.2***	***4.6***	***3.9***	***4.2***	***3.4***	***3.0***	***2.7***
% change, qtr/qtr	*7.5*	*1.1*	*1.5*	*1.6*	*0.5*	*1.4*	*0.9*	*0.9*	*0.8*	*0.6*	*0.6*	*0.6*
Personal Consumption*	-2.8	-2.4	2.1	16.2	7.0	***7.5***	***5.3***	***3.2***	***3.4***	***2.7***	***2.6***	***2.4***
% change, qtr/qtr	*9.1*	*0.8*	*2.7*	*2.9*	*0.4*	*1.2*	*0.7*	*0.8*	*0.6*	*0.6*	*0.5*	*0.6*
Industrial Production*	-6.7	-4.3	-1.6	14.7	5.6	***4.7***	***4.7***	***4.1***	***4.0***	***3.6***	***3.1***	***2.7***
Consumer Prices*	1.3	1.2	1.9	4.8	5.3	***6.4***	***6.3***	***4.9***	***3.9***	***2.8***	***2.6***	***2.5***
3 month Treasury Bill Rate, % [1]	0.1	0.1	0.0	0.1	0.1	***0.1***	***0.1***	***0.2***	***0.3***	***0.5***	***0.6***	***0.8***

[1] *End period*

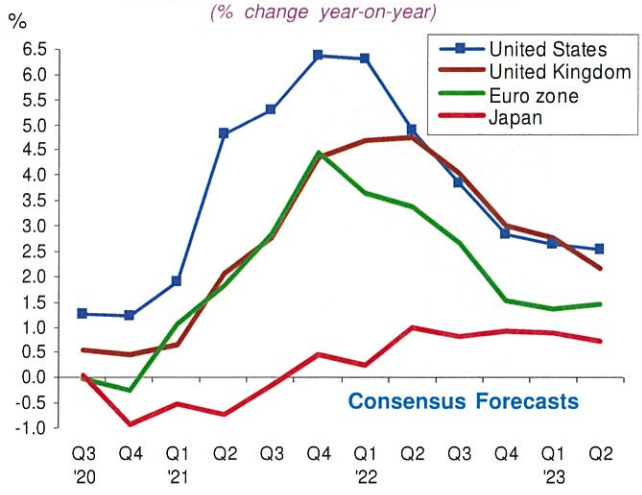
Many **Western European** economies regained momentum over the summer months, buoyed by a lifting of most social restrictions and higher mobility. A cautious rebound in overseas travel also helped to revive spending and job opportunities, enabling governments to pare back most emergency support measures implemented near the start of the pandemic to avert what may have otherwise been a catastrophic collapse in business activity and jobs. Increasingly, attention has shifted towards inflation and its erosion of household (and company) earnings, fuelled by hefty jumps in energy bills and food prices. For most economies, including the **US**, **quarterly inflation** is tipped to peak in Q4 2021 and Q1 2022 (charts below) before moderating thereafter as the weak base of comparison fades away. The **European** inflation surge is expected to dissipate even more rapidly – perhaps because of greater underlying disinflationary pressures in some of their countries. Uncertainty has risen, though, as the emergence of the Omicron variant and fresh Covid-based curfews risk extending supply bottlenecks which have contributed to sky-high raw materials costs and curbed companies' operating capacity. They have also complicated the policy plans of central banks whose job to preserve price stability is balanced by economic and employment considerations, especially following last year's collapse in GDP levels. The risk that premature tightening to tackle above-target inflation could unintentionally harm fledgling and uneven recoveries across the **G7 & Western Europe** remains delicately poised. The **UK** economy's improvement this year has been well supported by the vaccination programme, but concerns amid ongoing tensions with Brussels, alongside newly-announced restrictions prompted by Omicron cases, could shake the next few quarters. **Italy's** growth upturn has strengthened on accelerating investment linked in part to its access to EU recovery funds, of which it is the biggest beneficiary in the Euro zone. **Spain**, meanwhile, has seen its GDP forecasts slashed in recent months, attributed to weak spending and slow uptake of EU-funded investment. The minority government has pushed through its 2022 budget plan, however, which could support activity.

Tables continued on pages 28, 29 and 30

For our panel's Quarterly Forecasts underpinning these charts, see above and pp 28-30

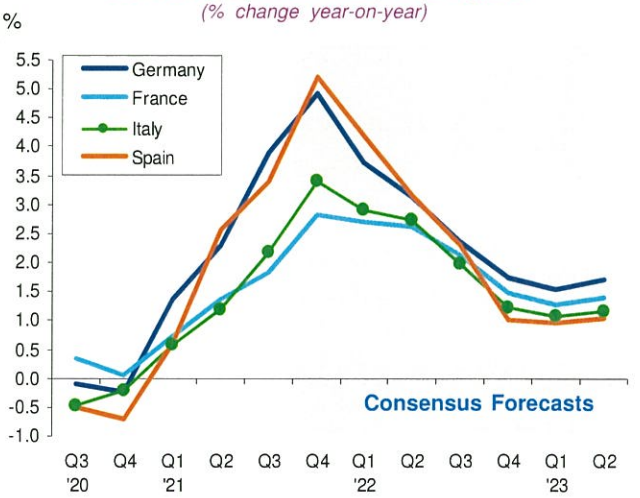
Quarterly Inflation (CPI) Consensus Forecasts – US, Japan, UK and Euro zone

(% change year-on-year)



Quarterly Inflation (CPI) Consensus Forecasts – Germany, France, Italy and Spain

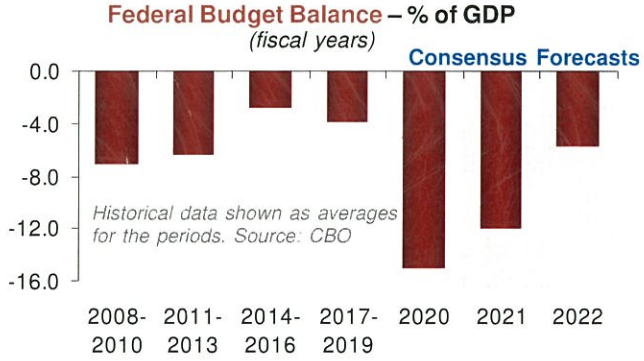
(% change year-on-year)



	Average % Change on Previous Calendar Year																		Annual Total	
	Gross Domestic Product		Personal Consumption		Business Investment		Pre - Tax Corporate Profits		Industrial Production		Consumer Prices		Core PCE Prices (ex. food & energy)		Producer Prices		Employment Costs		Auto & Light Truck Sales (inc. imports, mn units)	
Economic Forecasters	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022
Dynamic Econ Strategy	6.0	4.2	7.9	3.8	7.0	5.8	18.3	5.9	5.8	4.2	4.3	3.4	3.1	3.0	7.1	3.2	2.9	2.9	15.8	16.2
Robert Fry Economics	5.7	5.0	8.2	4.8	7.5	5.6	23.4	4.9	5.6	5.2	4.6	5.0	3.3	4.2	8.7	5.9	3.3	4.3	15.1	16.0
Oxford Economics	5.7	4.4	8.1	4.3	7.6	4.6	24.6	-5.9	5.5	3.3	4.6	4.0	3.3	3.1	8.7	4.8	3.3	3.5	15.2	15.7
First Trust Advisors	5.7	3.9	7.9	3.7	8.4	5.1	na	na	5.6	4.3	4.6	5.1	3.2	4.0	8.5	6.3	na	na	15.0	15.0
Wells Fargo	5.7	4.4	8.0	3.7	7.6	5.0	26.3	8.9	5.6	4.1	4.7	5.3	3.3	3.7	na	na	3.3	3.7	15.2	16.6
IHS Markit	5.7	4.3	8.1	3.8	7.4	6.1	23.1	1.7	5.6	4.5	4.6	3.7	3.2	3.2	8.8	5.5	na	na	15.0	15.4
JP Morgan	5.7	3.8	8.1	4.0	7.2	3.8	26.2	11.5	6.3	3.1	4.7	4.3	3.3	3.6	na	na	3.2	3.1	15.1	16.4
FedEx Corporation	5.6	4.2	8.0	3.9	7.4	4.3	23.9	4.4	5.6	4.4	4.6	4.2	3.3	3.2	na	na	na	na	15.3	16.3
Moody's Analytics	5.6	4.4	8.1	4.4	7.5	8.5	25.0	6.2	5.5	4.0	4.6	4.2	3.5	3.8	na	8.6	3.3	3.2	15.0	16.5
Goldman Sachs	5.6	3.8	8.0	3.2	7.5	4.5	na	na	5.8	5.2	4.6	4.8	3.3	3.3	na	na	na	na	na	na
BMO Capital Markets	5.6	3.5	8.0	4.0	7.5	4.0	25.6	8.9	5.5	3.5	4.6	4.7	3.2	3.3	na	na	3.6	4.5	15.1	16.0
The Conference Board	5.6	3.5	8.0	3.5	7.5	4.7	na	na	na	na	na	na	3.2	3.2	na	na	na	na	na	na
Bank of America - Merrill	5.6	4.0	8.1	3.7	7.5	4.3	na	na	5.6	4.0	4.7	5.0	3.3	3.5	na	na	na	na	15.0	15.6
Ford Motor Company	5.6	3.9	8.1	2.9	7.6	7.7	na	na	5.5	4.1	4.4	3.9	3.2	3.4	8.7	5.1	na	na	na	na
Inforum - Univ Maryland	5.6	4.0	7.9	3.6	7.5	5.0	23.1	2.8	5.5	3.8	4.5	3.9	3.2	3.1	8.3	5.0	3.3	3.6	15.0	15.9
Credit Suisse	5.5	3.8	8.0	3.6	7.7	5.4	na	na	5.6	na	4.7	4.8	3.3	3.4	na	na	na	na	na	na
CIBC Capital Markets	5.5	4.2	8.0	4.3	7.5	5.2	na	na	na	na	4.6	3.7	na	na	na	na	na	na	na	na
Swiss Re	5.5	3.7	na	na	7.5	5.2	37.4	9.3	5.5	3.2	4.7	5.0	3.3	4.0	6.9	8.3	3.3	4.3	15.1	13.3
Standard & Poor's	5.5	3.9	8.0	3.8	7.6	3.4	16.0	0.5	5.4	2.7	4.5	3.9	3.2	2.7	8.4	3.6	3.3	3.5	15.1	15.2
Citigroup	5.5	4.0	8.0	4.8	7.3	4.4	na	na	na	na	4.3	2.0	3.1	2.8	na	na	na	na	na	na
Econ Intelligence Unit	5.5	3.8	7.8	4.0	na	na	na	na	5.8	5.0	4.4	3.2	na	na	6.7	4.2	na	na	na	na
Fannie Mae	5.5	4.0	7.9	2.6	7.6	6.3	na	na	na	na	4.6	4.3	3.2	3.9	na	na	na	na	14.9	15.0
Nat Assn of Home Builders	5.5	3.9	8.0	2.5	na	na	na	na	na	na	4.6	5.1	3.2	3.4	8.8	8.5	na	na	na	na
Eaton Corporation	5.5	3.9	7.9	3.5	7.7	5.9	na	na	5.5	3.5	4.5	3.9	na	na	6.8	5.8	na	na	15.2	15.8
Royal Bank of Canada	5.5	3.5	7.8	2.5	7.3	3.6	26.4	11.4	na	na	4.6	3.9	na	na	na	na	na	na	15.1	15.3
PNC Financial Services	5.5	4.3	7.8	3.3	7.7	6.4	na	na	5.5	4.3	4.4	3.7	3.2	3.0	8.3	4.9	na	na	15.3	16.7
Univ of Michigan - RSQE	5.4	4.0	8.0	2.9	7.9	7.4	26.6	15.3	5.5	5.4	4.6	4.6	3.3	3.8	na	na	na	na	15.1	16.0
Georgia State University	5.4	3.3	8.0	2.9	7.5	4.8	24.9	-2.5	5.4	3.5	4.6	4.3	3.1	3.0	8.7	5.0	3.8	3.8	14.9	15.1
Consensus (Mean)	5.6	4.0	8.0	3.6	7.5	5.3	24.7	5.6	5.6	4.1	4.6	4.2	3.2	3.4	8.1	5.6	3.3	3.7	15.1	15.7
Last Month's Mean	5.5	4.0	7.9	3.6	7.6	5.4	20.2	5.7	5.6	4.0	4.4	3.7	3.2	3.1	7.7	4.7	3.3	3.5	15.3	16.1
3 Months Ago	5.9	4.3	7.9	3.7	8.1	6.0	21.2	6.4	5.8	4.3	4.3	3.1	3.2	2.8	7.1	3.0	2.9	2.9	15.9	16.6
High	6.0	5.0	8.2	4.8	8.4	8.5	37.4	15.3	6.3	5.4	4.7	5.3	3.5	4.2	8.8	8.6	3.8	4.5	15.8	16.7
Low	5.4	3.3	7.8	2.5	7.0	3.4	16.0	-5.9	5.4	2.7	4.3	2.0	3.1	2.7	6.7	3.2	2.9	2.9	14.9	13.3
Standard Deviation	0.1	0.3	0.1	0.6	0.3	1.2	4.6	5.7	0.2	0.7	0.1	0.7	0.1	0.4	0.8	1.7	0.2	0.5	0.2	0.8
Comparison Forecasts																				
CBO (July '21)	6.7	5.0	7.6	4.1	8.2	6.6					3.3	2.5	2.2	2.0			3.5	3.2		
IMF (Oct. '21)	6.0	5.2	8.2	3.9							4.3	3.5								
OECD (Dec. '21)	5.6	3.7	8.0	3.8							4.6	4.8	3.3	3.9						

Government and Background Data

President - Mr. Joseph R. Biden (Democrat). **Congress -** Democrats have retained a majority in the House of Representatives (lower house) and narrowly taken control of the Senate (upper house). **Next Elections -** November 2022 (congressional – half); November 2024 (presidential and congressional). **Nominal GDP -** US$20,937bn (2020). **Population -** 331.0mn (mid-year, 2020).



Historical Data

* % change on previous year	2017	2018	2019	2020
Gross Domestic Product*	2.3	2.9	2.3	-3.4
Personal Consumption*	2.4	2.9	2.2	-3.8
Business Investment*	4.1	6.4	4.3	-5.3
Pre - Tax Corporate Profits*	4.5	8.3	2.7	-5.2
Industrial Production*	1.3	3.2	-0.8	-7.2
Consumer Prices*	2.1	2.4	1.8	1.2
Core PCE Prices*	1.7	2.0	1.7	1.4
Producer Prices*	3.2	3.1	0.8	-1.3
Employment Costs*	2.4	2.8	2.7	2.6
Auto & Light Truck Sales (inc. imports), mn	17.2	17.2	17.0	14.5
Housing Starts, mn	1.21	1.25	1.29	1.40
Unemployment Rate, %	4.4	3.9	3.7	8.1
Current Account, US bn	-362	-438	-472	-616
Federal Budget Balance fiscal years, US bn	-665	-779	-984	-3132
3 mth Treasury Bill, %, end yr	1.4	2.4	1.5	0.1
10 Yr Treasury Yield, %, end yr	2.8	2.7	1.9	0.9

Annual Total Housing Starts (mn units)		Year Average Unemployment Rate (%)		Annual Total Current Account (US$ bn)		Fiscal Years (Oct-Sep) Federal Budget Balance (US$ bn)[1]		Rates on Survey Date 0.1% 3 month Treasury Bill Rate (%)		1.4% 10 Year Treasury Bond Yield (%)	
2021	2022	2021	2022	2021	2022	FY 20-21	FY 21-22	End Mar'22	End Dec'22	End Mar'22	End Dec'22
1.60	1.58	5.3	4.4	-786	-814	na	-1570	0.1	0.3	1.6	2.0
1.57	1.58	5.4	3.9	-800	-850	-2772	-1500	0.1	0.7	1.7	2.3
1.58	1.60	5.4	3.9	-787	-787	-2772	-1333	0.2	0.6	1.8	2.3
1.58	1.65	5.4	3.7	-795	-831	-2772	-1600	0.1	0.4	1.5	1.8
1.61	1.66	5.4	3.8	na	na	-2772	-1300	0.1	0.7	1.8	2.2
1.57	1.46	5.4	3.6	-777	-709	na	na	na	na	na	na
1.58	1.64	5.4	3.7	-774	-887	-2772	-1350	na	na	na	na
1.58	1.59	5.4	4.2	na	na	na	na	0.1	0.5	1.7	2.2
1.57	1.76	5.4	3.6	-847	-1121	na	na	na	na	na	na
1.61	1.68	5.4	3.7	na	na	na	-1200	0.1	0.1	1.8	2.0
1.58	1.63	5.4	3.8	-825	-960	-2772	-1400	0.1	0.4	1.7	2.0
na	na	5.4	4.0	na	na	na	na	na	na	na	na
1.58	1.60	5.4	3.7	-786	-862	na	-1300	na	na	na	na
1.57	1.52	5.4	3.3	na	na	na	na	0.1	0.3	1.5	1.8
1.57	1.56	5.4	4.0	na	na	na	na	0.1	0.3	1.7	2.0
na	na	5.4	3.9	na	na	na	na	na	na	1.6	2.0
1.57	1.60	5.4	3.7	na	na	na	na	0.1	0.7	1.8	2.1
1.57	1.52	5.4	4.0	na	na	na	na	0.1	0.5	1.5	1.6
1.58	1.55	5.4	4.0	-813	-749	-2772	-1378	0.1	0.4	1.8	2.4
na	na	5.3	3.9	-616	-628	na	-1450	0.3	1.0	2.1	2.3
na	na	5.5	4.5	-766	-851	-2772	-1836	na	na	na	na
1.59	1.59	5.4	3.9	na	na	na	na	0.2	0.6	1.5	1.6
1.58	1.55	5.5	3.9	na	na	na	na	na	na	na	na
1.57	1.50	5.3	3.7	na	na	na	na	na	na	na	na
1.57	1.41	5.5	4.2	-773	-818	na	na	0.1	0.7	1.9	2.2
1.59	1.62	5.5	3.9	na	na	na	na	0.1	0.7	1.7	2.0
1.57	1.67	5.4	4.0	na	na	na	na	0.2	0.7	1.8	2.2
1.57	1.37	5.5	4.2	-774	-763	na	na	0.0	0.1	1.4	2.2
1.58	1.58	5.4	3.9	-780	-831	-2772[1]	-1435	0.1	0.5	1.7	2.0
						[1]FY 20-21 = US$ -2,772 bn					
1.59	1.59	5.4	4.0	-789	-834	-2772	-1476				
1.58	1.58	5.5	4.2	-787	-815	-2977	-1512				
1.61	1.76	5.5	4.5	-616	-628	-2772	-1200	0.3	1.0	2.1	2.4
1.57	1.37	5.3	3.3	-847	-1121	-2772	-1836	0.0	0.1	1.4	1.6
0.01	0.09	0.1	0.3	52	116	0	172	0.1	0.2	0.2	0.2
		5.5	3.8			-3003	-1153				
		5.4	3.5	-796	-868						
		5.4	3.9	-817	-934						

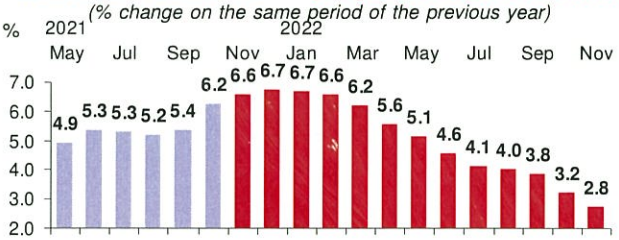
Hot Economy + Inflation = Fed Tightening

The second release of Q3 GDP was largely unchanged from the advance report, with growth up 2.1% (q-o-q annualized), in line with 2.0% in the first release. However, this was significantly down from a 6.7% annualized rate recorded in Q2 and 6.3% in Q1. Meanwhile, the marked acceleration in cost and price pressures (powered by supply-chain and labor disruptions, as well as pent-up demand) has forced a policy pivot from the Federal Reserve. Headline CPI went from an already-high 5.3% (y-o-y) in June to 6.2% in October, with our contributors projecting November and December outturns of 6.6% and 6.7% (monthly CPI chart below). The 2022 forecast for headline CPI has also been upgraded, from 3.7% to 4.2%, signaling that our forecasters do not expect inflation to reduce by much next year. Elsewhere, producer price inflation rose by12.5% (y-o-y) in October, with our panel's projection for PPI at 8.1% for 2021 and 5.6% for 2022. Global prices of raw materials and energy sources like gas, oil and coal have been soaring. The Fed's Beige Book of activity in all Fed districts in October and early November cited "wide-ranging input cost increases stemming from strong demand for raw materials, logistical challenges, and labor market tightness. But wider availability of some inputs, notably semiconductors and certain steel products, led to easing of some price pressures." Our panel's 2021 GDP outlook has edged up this month, although the pace of upgrades in the 2022 CPI consensus has now overtaken GDP (chart below).

The inflation environment prompted Fed chair Powell on 30 November to acknowledge that pressures could no longer be termed "transitory." While inflation should subside next year, Chair Powell announced a likely acceleration the tapering of asset purchases at the FOMC's December 14-15 meeting.

Monthly CPI Outturns and y-o-y Consensus Forecasts

(% change on the same period of the previous year)



Changes to 2023 GDP and CPI Consensus Forecasts

2023 Real GDP Growth:	**2.5**	**%**
last month's forecast:	2.5	%
2023 Consumer Price Inflation:	**2.5**	**%**
last month's forecast:	2.4	%

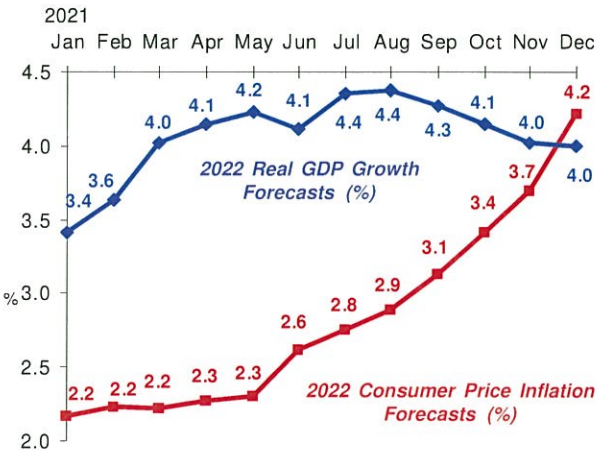
US Fed Funds Rate (Mid-Point of Target Range)
at Dec. 6, 2021: Mid-Point = 0.125%

Average probabilities of a change in the Funds Rate on **Dec. 15, 2021:**
Increase = 1.4% **No change =** 98.5% **Decrease =** 0.1%

Consensus Forecasts	End Dec. 2021	End Mar. 2022	End Jun. 2022	End Sep. 2022
Mean Average:	**0.136 %**	**0.139 %**	**0.171 %**	**0.308 %**
Mode (most frequent forecast):	**0.125 %**	**0.125 %**	**0.125 %**	**0.125 %**

2022 GDP Growth and Inflation Forecasts

Consensus Forecasts from Survey of:



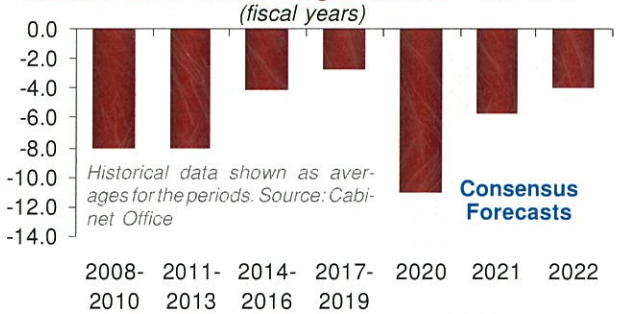
	Average % Change on Previous Calendar Year																Annual Total	
	Gross Domestic Product		Private Consump-tion		Business Investment		Industrial Production		Consumer Prices		Core-Core Consumer Prices (ex. food & energy)		Domestic Corporate Goods Prices		Total Cash Earnings (nominal)		New Car Registra-tions (mn)	
	国内総生産		民間消費		民間設備投資		鉱工業生産		消費者物価		消費者物価 生鮮食品及びエネルギーを除く		卸売物価		現金給与総額（名目）		新車登録台数（百万台）	
Economic Forecasters	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022
HSBC	2.2	1.8	1.8	2.6	na	na	7.9	0.4	-0.2	0.3	-0.2	0.3	na	na	0.5	0.7	na	na
Euromonitor Intl	2.1	2.8	1.6	3.1	na	na	5.7	1.0	-0.3	0.5	na	na	na	na	na	na	na	na
Econ Intelligence Unit	2.1	3.2	1.4	2.8	na	na	4.6	3.9	-0.2	1.3	na	na	4.8	3.5	na	na	na	na
Capital Economics	2.1	3.5	1.6	4.2	na	na	na	na	-0.2	0.8	na	na	na	na	na	na	na	na
Credit Suisse	2.0	2.0	1.3	1.8	-0.5	3.1	6.7	0.6	-0.2	0.5	-0.7	0.1	na	na	na	na	na	na
Japan Ctr for Econ Research	2.0	4.3	1.5	4.5	0.1	8.4	5.7	9.8	-0.2	0.2	-0.6	-0.8	4.2	3.9	1.4	1.2	na	na
JP Morgan - Japan	2.0	3.7	1.7	5.2	-0.4	4.7	6.0	7.3	-0.2	0.7	-0.8	-0.3	4.6	2.5	na	na	na	na
IHS Markit	2.0	3.5	1.5	3.7	-0.3	6.9	5.6	5.3	-0.3	0.8	-0.7	0.3	4.7	2.4	na	na	na	na
Goldman Sachs	1.9	2.5	1.5	3.5	-0.5	1.6	6.7	10.7	-0.3	0.9	-0.8	-0.4	na	na	na	na	na	na
Daiwa Institute of Research	1.8	4.0	1.6	5.2	-0.9	5.3	5.8	5.2	-0.3	0.5	-0.8	-0.7	4.6	4.0	na	na	na	na
Oxford Economics	1.8	3.2	1.2	2.9	-0.3	5.5	5.5	4.9	-0.2	0.6	na	na	4.6	1.2	0.5	-0.1	na	na
Barclays	1.8	3.4	1.3	4.4	-0.5	2.5	6.2	2.8	-0.2	0.6	na	na	na	na	na	na	na	na
MUFG Bank	1.8	3.6	1.4	4.5	-0.5	4.5	6.3	6.2	na	na	na	na	4.6	2.9	na	na	na	na
NLI Research Institute	1.8	2.3	1.4	2.2	-0.5	3.3	5.8	2.6	-0.3	0.8	-0.8	0.1	4.7	3.4	0.3	0.9	na	na
Moody's Analytics	1.8	2.7	1.1	2.4	-0.5	3.8	5.5	5.8	-0.2	0.8	na	na	na	na	na	na	na	na
Dai-Ichi Life Research	1.8	3.1	1.4	3.3	-0.5	3.4	5.6	5.7	-0.2	0.9	-0.8	-0.2	4.6	3.0	0.6	1.0	na	na
Nippon Steel Rsch Inst Corp	1.7	3.2	1.9	3.7	-0.2	5.0	6.1	3.6	-0.2	0.9	-0.6	1.0	4.4	2.7	1.2	2.7	2.41	2.78
Deutsche Securities	1.7	2.7	1.2	3.2	-0.3	3.9	6.4	3.7	-0.2	0.8	-0.5	0.2	4.4	3.7	0.6	1.1	na	na
Citigroup Japan	1.7	2.9	1.4	3.3	-0.4	3.6	5.9	2.7	-0.2	1.0	na	na	na	na	na	na	na	na
Morgan Stanley	1.7	2.9	1.2	2.1	-0.6	3.0	6.2	5.4	-0.3	0.8	na	na	na	na	na	na	na	na
ITOCHU Institute	1.6	3.6	1.3	4.7	-0.5	5.2	6.1	8.2	-0.2	0.4	-0.5	0.5	4.5	2.1	1.0	1.3	2.48	2.57
Mizuho Research Institute	1.6	3.1	1.1	3.7	0.0	3.9	5.5	4.0	-0.2	1.1	-0.7	0.0	4.0	0.7	0.4	0.3	na	na
Nomura Securities	1.5	4.4	1.5	5.1	-0.7	8.1	6.4	6.2	-0.3	1.1	-0.7	0.0	3.9	1.7	1.1	1.6	na	na
Toyota Motor Corporation	1.5	3.7	1.4	4.4	-0.7	8.0	na	na	0.1	0.5	0.2	0.5	na	na	na	na	na	na
Consensus (Mean)	1.8	3.2	1.4	3.6	-0.4	4.7	6.0	4.8	-0.2	0.7	-0.6	0.0	4.5	2.7	0.8	1.1	2.44	2.68
Last Month's Mean	2.2	3.0	1.7	3.3	1.3	4.5	6.9	4.9	-0.2	0.7	-0.5	0.1	3.8	1.8	0.7	1.1	2.44	2.68
3 Months Ago	2.3	3.0	1.7	3.1	1.7	4.7	8.4	5.2	-0.2	0.5	-0.4	0.1	3.3	1.1	0.7	1.3	2.54	2.58
High	2.2	4.4	1.9	5.2	0.1	8.4	7.9	10.7	0.1	1.3	0.2	1.0	4.8	4.0	1.4	2.7	2.48	2.78
Low	1.5	1.8	1.1	1.8	-0.9	1.6	4.6	0.4	-0.3	0.2	-0.8	-0.8	3.9	0.7	0.3	-0.1	2.41	2.57
Standard Deviation	0.2	0.7	0.2	1.0	0.2	1.9	0.6	2.7	0.1	0.3	0.3	0.5	0.3	1.0	0.4	0.7	0.05	0.14
Comparison Forecasts																		
IMF (Oct. '21)	2.4	3.2							-0.2	0.5								
OECD (Dec. '21)	1.8	3.4	1.3	4.2	-0.6	4.4			-0.2	0.8								

Government and Background Data

Prime Minister - Mr. Fumio Kishida of the Liberal Democratic Party of Japan (LDP). **Parliament -** The LDP won 261 of the 465 seats of the Lower House of Parliament at the October 2021 elections and has formed a coalition with the minority party, Komeito Party. **Next Elections** House of Representatives (31 October, 2025). **Nominal GDP -** ¥538.3tn (2020). **Population -** 126.5mn (mid-year, 2020). **Yen/$ Exchange Rate -** 106.75 (average, 2020).

General Government Budget Balance – % of GDP

(fiscal years)



Historical Data

* % change on previous year	2017	2018	2019	2020
Gross Domestic Product*	1.7	0.6	0.0	-4.7
Private Consumption*	1.1	0.2	-0.2	-5.9
Business Investment*	2.4	1.7	0.1	-6.2
Industrial Production*	2.8	1.0	-2.7	-10.6
Consumer Prices*	0.5	1.0	0.5	0.0
Core-Core Consumer Prices*	-0.1	0.1	0.4	0.0
Domestic Corp. Goods Prices*	2.3	2.6	0.2	-1.1
Total Cash Earnings (nominal)*	0.4	1.4	-0.4	-1.2
New Car Registrations, mn	2.9	2.9	2.8	2.5
Housing Starts, mn	0.96	0.86	0.91	0.82
Unemployment Rate, %	2.8	2.4	2.4	2.8
Current Account, ¥tn	23.1	19.6	18.9	15.7
General Govt Budget Balance, SNA basis, fiscal years[1], ¥tn	-16.3	-13.1	-17.1	-69.2 *e*
3 mth TIBOR, % (end yr)	0.1	0.1	0.1	0.1
10 Yr Govt Bond, % (end yr)	0.1	0.0	0.0	0.0

e = consensus estimate based on latest survey

Annual Total		Year Average		Annual Total		Fiscal Years (Apr-Mar)		Rates on Survey Date 0.1%		0.0%	
Housing Starts (mn)		Unemployment Rate (%)		Current Account (¥tn)		General Government Budget Balance (¥tn)		3 month Yen TIBOR Rate (%)		10 Year Govt Bond Yield (%)	
新設住宅着工（百万戸）		失業率		経常収支		一般政府財政収支（SNA ベース、兆円）		3ヵ月物円建譲渡性預金		10年物国債利回り	
2021	2022	2021	2022	2021	2022	FY 21-22	FY 22-23	End Mar'22	End Dec'22	End Mar'22	End Dec'22
na	na	2.8	2.7	21.6	21.5	-22.7	-16.8	0.0	0.0	0.0	0.0
0.89	0.89	2.8	2.8	19.3	20.1	na	na	na	na	na	na
na	na	2.9	2.6	18.6	19.6	na	na	na	na	na	na
na	na	2.7	2.4	16.7	20.6	na	na	na	na	na	na
na	na	2.9	2.8	20.4	22.2	-29.7	-22.0	na	na	na	na
0.86	0.86	2.8	2.8	15.9	12.6	-38.4	-22.7	na	na	0.0	0.0
na	na	2.8	2.4	15.2	19.3	na	na	na	na	0.1	na
0.87	0.91	2.8	2.8	16.4	10.5	na	na	0.1	0.1	0.1	0.1
na	na	2.9	2.7	15.8	10.9	na	na	0.1	0.1	0.1	0.2
na	na	2.8	2.6	17.2	15.9	na	na	na	na	na	na
0.87	0.92	2.8	2.6	15.8	17.2	-42.7	-34.8	0.0	0.0	0.1	0.1
na	na	2.9	3.0	15.5	15.6	na	na	na	na	0.1	0.2
na	na	na	na	16.7	14.2	na	na	0.1	0.1	0.1	0.2
0.86	0.85	2.8	2.8	14.0	10.0	-38.4	-26.1	0.1	0.1	0.1	0.1
0.87	0.89	2.8	2.7	15.7	17.7	na	na	na	na	0.0	0.0
0.86	0.87	2.8	2.6	17.0	19.0	na	na	na	na	0.1	0.1
0.86	0.87	2.7	2.2	16.0	18.2	na	na	0.1	0.1	0.1	0.1
na	na	2.8	2.4	14.8	11.7	-45.8	-33.7	0.0	0.0	0.2	0.1
na	na	2.8	2.6	12.0	9.7	na	na	na	na	na	na
na	na	2.8	2.6	na	na	na	na	na	na	0.2	0.3
0.87	0.89	2.8	2.6	14.8	10.9	-26.2	-20.2	0.1	0.1	0.2	0.3
0.86	0.87	2.8	2.8	16.2	16.2	na	na	na	na	0.1	0.1
na	na	2.8	2.4	16.3	17.8	na	na	na	na	0.1	0.1
na	na	2.7	2.5	na	na	na	na	na	na	na	na
0.87	0.88	2.8	2.6	16.5	16.0	-34.8	-25.2	0.0	0.0	0.1	0.1
0.87	0.88	2.8	2.7	18.2	18.3	-36.1	-24.0				
0.87	0.88	2.9	2.8	19.7	20.2	-37.9	-26.1				
0.89	0.92	2.9	3.0	21.6	22.2	-22.7	-16.8	0.1	0.1	0.2	0.3
0.86	0.85	2.7	2.2	12.0	9.7	-45.8	-34.8	0.0	0.0	0.0	0.0
0.01	0.02	0.0	0.2	2.1	4.0	8.7	6.8	0.1	0.1	0.0	0.1
		2.8	2.4								
		2.8	2.6	17.3	14.5						

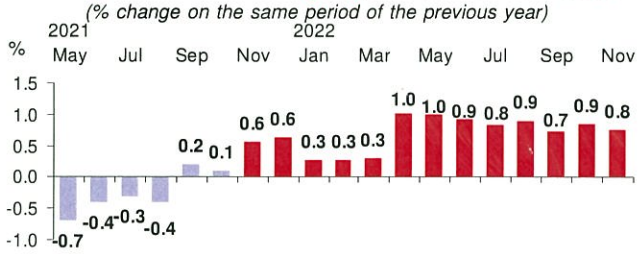
GDP Set to Rebound on Easing of Mobility Restrictions

Consensus expectations for 2021 GDP growth have been trimmed this month following a sharper-than-expected drag on Q3 GDP. Activity contracted by -0.8% (q-o-q) following a +0.4% increase in Q2. A rise in Delta-related infections and the resultant mobility restrictions hit consumption, which fell by -1.1% over the quarter, while supply-chain bottlenecks hit exports and reined in business investment by -3.8% (q-o-q). Our panel's 2021 forecast for business investment has fallen steeply into negative territory as a result. In spite of the Q3 slide, though, Q4 GDP growth is expected to show a rebound (see page 28) as domestic mobility restrictions have been eased on the back of stronger vaccination uptake. November services activity jumped at its fastest pace since August 2019 as more Japanese citizens took advantage of dining out, overnight stays and other spending. Moreover, the new Kishida government has submitted a draft supplementary budget of ¥36tn to parliament. ¥31.6tn of that will be used for stimulus measures, including cash handouts, allowances for furloughed workers, and subsidies for businesses, in order to pull the economy out of pandemic-related weakness. Meanwhile, industrial production rebounded by +1.1% (m-o-m) in October, ending three consecutive months of falls, while the November manufacturing PMI was revised higher to 54.5, well above the 50-mark, yet our panel's industrial production forecasts have continued to tumble.

Core-core CPI (excluding food and energy prices) fell in October by -0.7% (y-o-y), extending 7 consecutive months of deflation. As a result, the Bank of Japan is unlikely to budge from its current ultra-accommodative stance, despite higher energy prices pushing the headline CPI rate up a very modest +0.2% (y-o-y) in September and +0.1% in October.

Monthly CPI Outturns and y-o-y Consensus Forecasts

(% change on the same period of the previous year)



Changes to 2023 GDP and CPI Consensus Forecasts

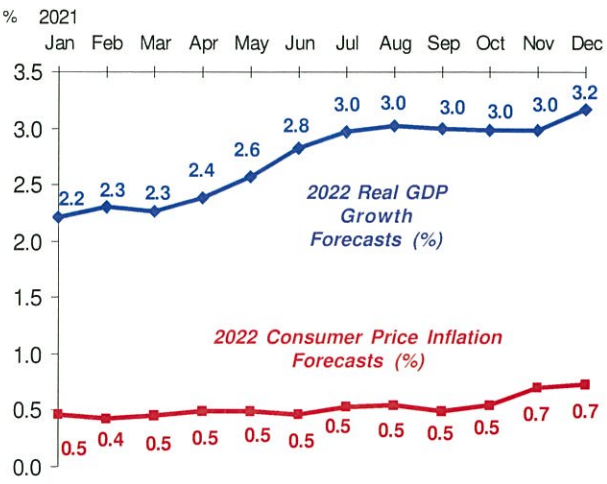
2023 Real GDP Growth:	1.4	%
last month's forecast:	1.6	%
2023 Consumer Price Inflation:	0.6	%
last month's forecast:	0.6	%

Real Growth and Inflation (2002-2026)

(% change over previous year)

2022 GDP Growth and Inflation Forecasts

Consensus Forecasts from Survey of:



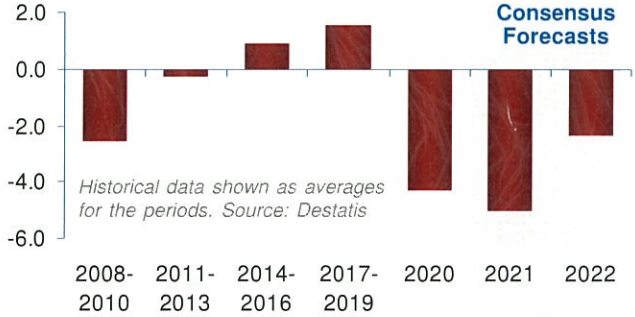
Average % Change on Previous Calendar Year

	Gross Domestic Product		Private Consumption		Machinery & Equipment Investment		Industrial Production		Consumer Prices		Producer Prices		Negotiated Wages and Salaries – Production Sector	
	Bruttoinlands-produkt		*Privater Verbrauch*		*Ausrüstungs-investitionen*		*Produktion im Produzierenden Gewerbe*		*Preisindex für die Lebenshaltung*		*Index für Erzeugerpreise*		*Tariflohn- und -gehaltsniveau*	
Economic Forecasters	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**
Morgan Stanley	3.1	4.4	-0.9	5.3	5.4	3.6	na	na	3.1	2.6	na	na	na	na
Bank Julius Baer	3.0	4.8	1.2	9.0	3.7	4.1	3.4	7.8	3.1	2.2	8.7	5.2	1.4	3.4
DWS	3.0	4.8	0.9	8.7	3.6	6.7	na	na	3.1	2.9	na	na	na	na
Swiss Life Asset Mgrs	3.0	3.6	1.0	8.1	2.5	10.9	na	na	3.1	2.5	na	na	na	na
Moody's Analytics	2.8	3.6	0.9	6.8	na	na	3.8	2.8	3.1	3.4	9.9	9.1	na	na
Berliner Sparkasse	2.8	3.6	0.5	6.6	4.0	4.9	2.5	-0.2	3.1	3.2	9.7	6.7	1.5	2.1
Helaba Frankfurt	2.8	3.9	0.8	5.5	5.0	5.5	2.5	5.5	3.1	2.7	10.0	7.0	1.5	2.5
NORD/LB	2.8	3.5	0.5	4.6	3.8	3.7	na	na	3.1	2.6	9.9	8.5	na	na
Goldman Sachs	2.8	4.0	-0.5	6.6	na	na	na	na	na	na	na	na	na	na
UBS	2.8	4.9	-0.2	5.8	na	na	3.1	2.4	na	na	na	na	na	na
Citigroup	2.8	3.5	-0.5	5.3	4.4	2.4	2.5	1.2	3.1	2.8	na	na	na	na
DZ Bank	2.8	4.8	-1.2	4.4	3.0	5.8	na	na	3.1	2.2	na	na	1.5	na
Capital Economics	2.8	3.5	0.9	7.4	na	na	na	na	3.3	3.5	na	na	na	na
IHS Markit	2.7	3.8	0.1	6.9	2.8	3.0	2.9	4.2	3.1	2.9	9.2	8.3	1.5	3.2
FERI	2.7	4.1	0.7	6.8	3.2	3.2	2.7	2.0	3.1	3.5	8.8	7.5	1.5	2.0
Allianz	2.7	3.7	0.7	6.0	3.5	4.4	na	na	3.1	2.4	8.8	5.0	na	na
Bank of America - Merrill	2.7	3.2	-1.2	4.4	na	na	3.6	4.6	3.1	2.6	na	na	na	na
MM Warburg	2.7	4.4	0.7	6.8	3.4	4.1	3.0	3.5	3.1	2.7	10.0	9.4	1.5	2.8
Zürcher Kantonalbank	2.7	3.0	1.2	8.3	5.8	5.8	3.3	4.4	3.1	2.5	9.9	5.5	1.7	2.7
Kiel Institute	2.6	5.1	-0.5	7.8	5.9	8.8	na	na	2.9	2.6	na	na	1.8	1.7
BayernLB	2.6	3.6	0.5	5.6	3.4	5.6	na	na	3.1	2.7	na	na	na	na
HSBC Trinkaus	2.6	3.5	na	na	na	na	na	na	3.1	2.8	na	na	2.0	2.6
DekaBank	2.6	3.4	0.4	5.5	3.4	4.1	4.4	3.2	3.1	2.7	9.4	10.0	1.6	2.4
Oxford Economics	2.5	4.0	0.4	8.2	na	na	3.9	5.1	3.1	2.3	10.1	3.0	2.0	4.6
Commerzbank	2.5	3.0	0.4	8.1	3.3	2.4	1.0	1.9	3.0	3.3	10.0	10.3	1.5	2.3
German Econ Inst (IW)	2.5	4.0	0.0	5.0	3.0	5.0	3.0	5.0	3.0	2.5	10.0	4.0	1.0	1.5
HWWI	2.5	3.5	0.0	4.7	3.6	4.3	3.0	4.0	3.1	2.3	8.0	4.5	1.5	2.2
IFO - Munich Institute	2.4	4.8	-0.1	7.8	4.9	7.3	na	na	3.0	2.5	na	na	na	na
IWH Halle Institute	2.4	4.8	-0.1	7.8	4.9	7.3	na	na	3.0	2.5	na	na	1.5	1.9
RWI Essen	2.4	4.8	-0.1	7.8	4.9	7.3	na	na	3.0	2.5	na	na	na	na
Consensus (Mean)	2.7	4.0	0.2	6.6	4.0	5.2	3.0	3.6	3.1	2.7	9.5	6.9	1.6	2.5
Last Month's Mean	2.7	4.3	-0.3	6.5	5.9	6.3	3.3	4.1	3.0	2.5	8.4	5.0	1.6	2.4
3 Months Ago	3.1	4.4	0.2	6.5	7.4	6.9	5.0	4.6	2.9	2.0	7.1	3.6	1.6	2.3
High	3.1	5.1	1.2	9.0	5.9	10.9	4.4	7.8	3.3	3.5	10.1	10.3	2.0	4.6
Low	2.4	3.0	-1.2	4.4	2.5	2.4	1.0	-0.2	2.9	2.2	8.0	3.0	1.0	1.5
Standard Deviation	0.2	0.6	0.7	1.4	1.0	2.1	0.8	1.9	0.1	0.4	0.6	2.3	0.2	0.8
Comparison Forecasts														
Bundesbank (Jun. '21)	3.7	5.1	0.6	8.9										
Government (Oct. '21)	2.6	4.1	0.3	6.6	5.5	4.5								
Eur Commission (Nov. '21)	2.7	4.6	0.0	6.7										

Government and Background Data

Chancellor - Olaf Scholz (Social Democrats or SPD). **Parliament -** The September 26, 2021 election saw the SPD win the most seats (206) in the 709-seat Bundestag (lower house). A coalition government has been formed between the SPD, Greens and Free Democratic Party. **Next Elections -** 2025. **Nominal GDP -** Euro 3,336bn (2020). **Population -** 83.8mn (mid-year 2020). **$/Euro Exchange Rate -** 1.141 (average, 2020).

General Government Budget Balance – % of GDP



Historical Data

** % change on previous year*	2017	2018	2019	2020
Gross Domestic Product*	2.7	1.1	1.1	-4.6
Private Consumption*	1.4	1.4	1.6	-5.9
Machinery & Eqpt Investment*	4.2	4.4	1.0	-11.2
Industrial Production*	3.3	0.9	-3.2	-8.2
Consumer Prices*	1.5	1.8	1.4	0.5
Producer Prices*	2.7	2.6	1.1	-1.0
Negotiated Wages & Salaries*	2.2	3.7	3.3	0.8
Unemployment Rate, %	5.7	5.2	5.0	5.9
Current Account, Euro bn	255	264	259	234
Budget Balance, net lending/borrowing, (ESA10, Maastrict), Euro bn	43.7	64.4	51.1	-145
3 mth Euro, % (end yr)	-0.3	-0.3	-0.4	-0.5
10 Yr German Govt Bond, % (end yr)	0.4	0.2	-0.2	-0.6

Year Average Unemployment Rate (%)		Annual Total Current Account (Euro bn)		General Govt Budget Bal (Maastricht) (Euro bn)		Rates on Survey Date -0.6% 3 month Euro Rate (%)		-0.4% 10 Year German Govt Bond Yield (%)	
Arbeitslosenquote, % der Erwerbspers. insgesamt		*Leistungsbilanz (€ bn)*		*Finanzierungssaldo des Staates (Maastricht) (€ bn)*		*3 Monate Euro (%)*		*Rendite von Bundesanleihen, 10 Jahre (%)*	
2021	2022	2021	2022	2021	2022	End Mar'22	End Dec'22	End Mar'22	End Dec'22
na	na	219	229	-207.5	-112.2	na	na	na	na
5.7	5.2	na	na	na	na	-0.5	-0.5	0.1	0.2
5.7	5.0	na	na	na	na	na	na	na	na
5.8	5.5	na	na	na	na	-0.6	-0.6	-0.3	-0.1
5.7	5.3	224	173	-147.0	-67.6	-0.5	-0.6	-0.4	-0.1
5.7	5.4	231	217	-214.0	-106.0	na	na	na	na
5.7	5.1	255	265	-160.0	-95.0	-0.5	-0.5	0.0	0.2
5.7	5.2	244	261	-175.0	-106.0	-0.6	-0.5	-0.2	0.0
na	na	na	na	-206.6	-97.9	na	na	0.0	0.3
na	na	248	250	na	na	-0.5	-0.5	0.1	0.3
5.8	5.6	259	249	-200.2	-145.6	na	na	-0.2	-0.1
5.7	5.0	na	na	na	na	-0.6	-0.5	-0.1	0.0
na	na	191	197	-127.1	-32.9	na	na	na	na
na	na	237	221	-165.4	-83.9	-0.5	-0.5	0.2	0.5
5.5	5.1	228	228	-177.5	-107.8	-0.5	-0.4	0.0	0.3
5.7	5.2	na	na	na	na	-0.5	-0.5	-0.1	0.0
na	na	244	212	na	na	na	na	na	na
5.7	5.0	245	252	-185.0	-100.0	-0.5	-0.4	-0.1	0.1
5.7	5.0	245	245	-190.0	-100.0	-0.5	-0.4	0.0	0.2
5.7	5.3	233	217	-173.2	-62.8	na	na	-0.2	-0.1
5.8	5.5	225	235	-175.0	-105.0	-0.6	-0.5	-0.1	0.2
5.7	5.2	243	247	-164.0	-78.0	na	na	na	na
5.7	5.4	229	244	-252.6	-105.4	-0.5	-0.5	-0.2	0.0
5.7	5.2	229	218	-138.7	-63.1	-0.6	-0.5	-0.2	0.2
5.7	5.1	240	250	-228.0	-107.0	-0.6	-0.5	-0.1	-0.2
5.8	5.3	na	na	-157.0	-79.0	-0.5	-0.5	-0.1	0.0
5.7	5.1	240	260	-160.0	-80.0	-0.5	-0.4	-0.2	-0.1
5.7	5.3	225	237	-173.7	-80.5	-0.6	-0.6	-0.3	-0.3
5.7	5.2	225	237	-171.2	-80.5	-0.5	-0.5	-0.3	-0.2
5.7	5.3	225	237	-173.7	-80.5	na	na	na	na
5.7	5.2	234	234	-179.2	-90.3	-0.5	-0.5	-0.1	0.1
5.7	5.2	238	239	-189.1	-95.4				
5.8	5.3	244	246	-189.9	-83.9				
5.8	5.6	259	265	-127.1	-32.9	-0.5	-0.4	0.2	0.5
5.5	5.0	191	173	-252.6	-145.6	-0.6	-0.6	-0.4	-0.3
0.1	0.2	14	22	28.9	22.7	0.0	0.1	0.1	0.2
5.8	5.2								
		238	257						

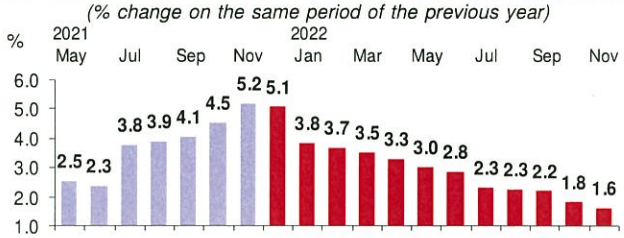
Fresh Restrictions to Counter Soaring Covid Cases

Record daily coronavirus-related deaths in recent weeks led to warnings over critical care capacity which may be amplified by the Omicron variant. Responding to the escalating crisis, the government barred unvaccinated individuals from many areas of public life, while new Chancellor Olaf Scholz suggested that he would favour a cross-party initiative to make vaccination mandatory from February 2022. Such a policy could incite significant public frictions, but could also shield economy from future hard restrictions. Most gauges of economic performance have slipped due to the virus and well-documented supply struggles in industry. Factory orders plunged by -6.9% (m-o-m) in October and have weakened noticeably after a strong first half of the year. Production finally saw a positive reading of +2.8% (m-o-m), yet the pickup comes from a very weak base and remains highly exposed to a dearth of inputs and chips, especially in automaking. A rebound in household consumption by +6.2% (q-o-q) spurred a 1.7% overall increase in Q3 GDP growth (and an uptick in our panel's consumption outlook), but spending could be set back by the health situation and restrictions. Coupled with the recent disappointment in exports, the economy is limping along as further highlighted by a fifth consecutive decline in the Ifo's business barometer. The downbeat assessment of the outlook was reinforced by our panel's downgrade to 2022 GDP and the machinery & equipment investment outlooks.

Inflation jumped 5.2% (y-o-y) in November, from 4.5% in October. Soaring prices are a feature across much of Europe, due to energy costs. ECB Governor Christine Lagarde has reiterated that premature monetary tightening could exacerbate the squeeze on purchasing power.

Monthly CPI Outturns and y-o-y Consensus Forecasts

(% change on the same period of the previous year)



Changes to 2023 GDP and CPI Consensus Forecasts

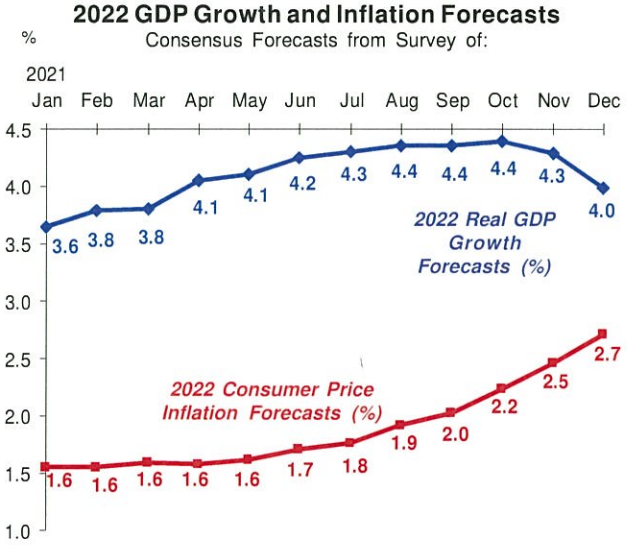
2023 Real GDP Growth:	**2.3**	**%**
last month's forecast:	2.1	%
2023 Consumer Price Inflation:	**1.8**	**%**
last month's forecast:	1.8	%

Real Growth and Inflation (2002-2026)

(% change over previous year)

2022 GDP Growth and Inflation Forecasts

Consensus Forecasts from Survey of:

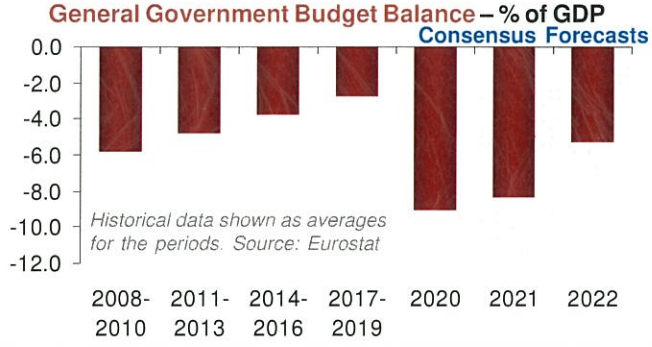


Average % Change on Previous Calendar Year

	Gross Domestic Product		Household Consumption		Business Investment		Manufacturing Production		Consumer Prices (INSEE)		Hourly Wage Rates	
	Produit Intérieur Brut		*Consommation des Ménages*		*Investissements des Entreprises*		*Production Manufacturière*		*Prix à la Consommation (INSEE)*		*Taux de Salaire Horaire*	
Economic Forecasters	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**
BIPE - BDO Advisory	7.0	4.2	5.0	4.8	12.2	3.7	na	na	2.0	2.2	na	na
Citigroup	6.8	3.9	4.6	4.2	11.8	2.0	7.7	4.7	2.0	2.8	1.8	2.0
Swiss Life Asset Mgrs	6.8	3.6	4.9	4.2	13.3	1.9	na	na	1.7	2.0	na	na
Credit Agricole	6.8	4.3	4.7	5.7	12.1	2.9	6.6	3.6	1.6	2.0	na	na
HSBC	6.8	4.1	4.8	5.9	12.1	3.8	6.4	1.3	1.6	1.9	2.0	1.7
Natixis	6.8	4.5	4.7	5.1	11.8	4.1	na	na	1.6	1.8	na	na
Zürcher Kantonalbank	6.8	3.9	4.8	5.4	12.0	4.5	6.5	3.6	1.6	1.8	na	na
Capital Economics	6.8	3.3	4.6	5.2	na	na	na	na	na	na	na	na
S&P Global Ratings	6.7	3.8	4.8	5.2	na	na	na	na	na	na	na	na
Bank of America - Merrill	6.7	3.3	4.6	4.1	na	na	na	na	1.6	1.8	na	na
Euler Hermes	6.7	3.6	4.7	4.1	11.9	5.0	na	na	1.7	1.9	1.8	2.3
UBS	6.7	3.8	4.8	5.5	11.6	3.5	6.4	2.9	na	na	na	na
Barclays	6.7	4.3	4.5	4.3	na	na	na	na	na	na	na	na
BNP Paribas	6.7	4.2	4.8	6.1	11.9	3.3	na	na	1.7	2.4	1.7	1.4
Econ Intelligence Unit	6.7	4.4	4.6	5.0	na	na	6.5	3.2	na	na	na	na
Exane BNP	6.7	3.9	4.7	6.6	11.9	2.9	8.6	4.7	1.7	2.1	na	na
Oddo BHF	6.7	4.4	4.6	5.3	12.2	3.3	6.4	3.2	1.7	2.4	1.5	1.7
Oxford Economics	6.7	3.7	4.6	5.2	11.5	1.9	6.1	4.2	1.7	2.0	na	na
Moody's Analytics	6.7	3.4	4.5	3.8	na	na	6.1	3.5	1.7	2.8	na	na
IHS Markit	6.6	3.4	4.4	3.4	11.0	2.7	6.8	3.4	1.7	2.0	na	na
GAMA - Paris-Nantere Univ	6.4	3.0	3.8	3.0	11.8	3.8	na	na	1.8	2.4	na	na
OFCE	6.3	4.1	4.3	5.9	12.4	3.8	na	na	1.5	1.5	1.6	1.9
Rexecode	6.3	3.5	4.6	5.3	13.3	4.0	na	na	1.9	2.2	1.7	2.1
PAIR Conseil	6.2	3.6	4.6	5.5	12.0	2.4	na	na	1.7	2.3	1.7	1.8
Fitch Ratings	6.1	3.8	3.5	4.5	na	na	na	na	1.9	1.7	na	na
Societe Generale	6.0	3.0	2.9	3.9	12.4	2.2	na	na	1.8	1.5	na	na
Consensus (Mean)	6.6	3.8	4.5	4.9	12.1	3.3	6.7	3.5	1.7	2.1	1.7	1.9
Last Month's Mean	6.5	3.8	4.3	4.8	12.2	3.5	7.0	3.5	1.7	1.8	1.6	2.0
3 Months Ago	6.1	3.8	3.9	4.8	12.2	4.0	7.6	4.1	1.6	1.5	1.6	1.6
High	7.0	4.5	5.0	6.6	13.3	5.0	8.6	4.7	2.0	2.8	2.0	2.3
Low	6.0	3.0	2.9	3.0	11.0	1.9	6.1	1.3	1.5	1.5	1.5	1.4
Standard Deviation	0.2	0.4	0.5	0.9	0.5	0.9	0.8	0.9	0.1	0.4	0.1	0.3
Comparison Forecasts												
Government (Sep. '21)	6.0	4.0										
Eur Commission (Nov. '21)	6.5	3.8	4.4	5.1								
IMF (Oct. '21)	6.3	3.9	4.1	6.0					2.0	1.6		
OECD (Dec. '21)	6.8	4.2	4.8	6.8								

Government and Background Data

President - Mr. Emmanuel Macron (LREM). **Prime Minister -** Mr. Jean Castex (LREM). **Parliament -** Mr. Macron's centrist *La République en Marche* (LREM) party currently has 271 out of the 577 seats in the National Assembly. **Next Elections -** Presidential (two rounds): April/ May 2022. **Nominal GDP -** Euro2,301bn (2020). **Population -** 65.3mn (mid-year, 2020). **$/Euro Exchange Rate -** 1.141 (average, 2020).



Historical Data

* % change on previous year	2017	2018	2019	2020
Gross Domestic Product*	2.4	1.8	1.8	-8.0
Household Consumption*	1.7	0.9	1.9	-7.2
Business Investment*	5.6	4.3	2.7	-8.1
Manufacturing Production*	2.8	0.6	0.7	-11.5
Consumer Prices (INSEE)*	1.0	1.9	1.1	0.5
Hourly Wage Rates*	1.2	1.5	1.7	1.4
Unemployment Rate (ILO), %	9.1	8.7	8.2	7.9
Current Account, Euro bn	-18.9	-19.9	-6.7	-44.0
General Govt. Budget Balance				
(Maastricht definition), **Euro bn**	-68.0	-54.1	-74.7	-209
3 mth Euro, % (end yr)	-0.3	-0.3	-0.4	-0.5
10 Yr French Govt Bond,				
% (end yr)	0.8	0.7	0.1	-0.3

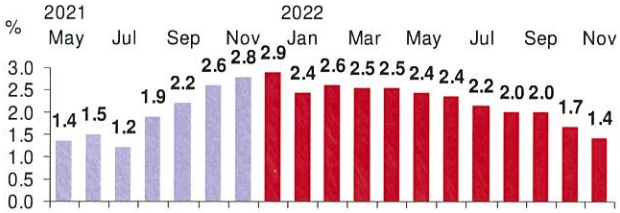
Year Average		Annual Total				Rates on Survey Date -0.6%		Rates on Survey Date 0.0%	
Unemployment Rate, ILO (%)		Current Account (Euro bn)		General Govt Budget Balance (Maastricht) (Euro bn)		3 month Euro Rate (%)		10 Year French Govt Bond Yield (%)	
Taux de Chômage, BIT (%)		*Solde Courant (€ md)*		*Balance Budgétaire (Maastricht) (€ md)*		*Taux d'intéret 3 mois Euro (%)*		*Rendement des obligations d'Etat, 10 ans (%)*	
2021	2022	2021	2022	2021	2022	End Mar'22	End Dec'22	End Mar'22	End Dec'22
7.6	8.0	-40.5	-30.0	-220.8	-157.9	na	na	na	na
7.7	7.5	-23.4	-23.1	-192.2	-131.2	na	na	0.3	0.4
7.8	7.6	na	na	na	na	-0.6	-0.6	0.0	0.2
7.8	7.8	na	na	-199.0	-129.0	-0.6	-0.6	0.5	0.1
na	na	-45.3	-78.8	-215.5	-150.5	na	na	0.0	-0.2
7.9	7.3	na	na	na	na	na	na	na	na
7.9	7.4	-34.0	-34.0	-210.0	-140.0	-0.5	-0.4	0.2	0.4
7.8	7.5	-11.4	-5.9	-194.7	-118.1	na	na	na	na
8.0	7.8	na	na	na	na	na	na	0.1	0.5
na	na	-24.8	-29.3	-201.0	-130.0	na	na	na	na
7.8	7.9	-38.0	-33.0	na	na	na	na	na	na
8.0	8.1	-23.5	-25.3	na	na	-0.5	-0.5	na	na
8.0	7.4	na	na	na	na	na	na	na	na
7.9	7.9	-23.0	-39.0	-202.0	-142.0	na	na	na	na
7.8	7.4	-32.9	-33.0	-221.1	-145.7	na	na	na	na
7.8	7.5	na	na	-210.0	-140.0	-0.5	-0.4	0.3	0.4
7.8	7.5	-28.8	-27.0	-200.7	-134.0	-0.5	-0.4	0.3	0.5
7.9	8.0	-29.2	-47.4	-186.2	-162.1	-0.6	-0.5	0.2	0.5
8.0	8.1	-29.9	-38.4	-197.6	-94.8	na	na	na	na
8.0	8.2	-25.1	-12.6	-200.7	-126.8	-0.5	-0.5	0.5	0.9
na	na	na	na	na	na	-0.4	-0.1	0.3	0.6
7.9	7.9	-30.0	-29.0	-207.0	-131.0	na	na	na	na
7.8	8.0	-28.5	-34.0	-210.0	-136.0	-0.5	-0.4	0.2	0.4
7.9	8.0	-47.1	-56.8	-220.2	-170.4	-0.5	-0.4	0.2	0.4
na	na	-40.9	-53.4	-204.0	-128.8	na	na	na	na
8.1	8.8	-29.7	-28.2	-222.6	-156.3	-0.5	-0.5	0.2	0.5
7.9	7.8	-30.8	-34.6	-206.1	-138.1	-0.5	-0.4	0.2	0.4
7.9	7.8	-33.0	-34.8	-210.7	-137.3				
8.0	8.0	-34.1	-36.5	-215.2	-141.6				
8.1	8.8	-11.4	-5.9	-186.2	-94.8	-0.4	-0.1	0.5	0.9
7.6	7.3	-47.1	-78.8	-222.6	-170.4	-0.6	-0.6	0.0	-0.2
0.1	0.4	8.7	16.2	10.5	17.2	0.1	0.1	0.2	0.3
				-197.4	-143.4				
8.0	8.0	-59.3	-56.5						
8.1	8.3			-219.9	-123.0				
7.8	7.6	-25.0	-53.2	-198.3	-128.7				

Q3 GDP Upbeat

Q3 GDP growth soared by 3.0% (q-o-q) following a 1.3% rise in Q2, powered by pent-up consumer demand following the lifting of Covid restrictions and increased vaccinations. Exports also contributed to activity, even though supply-chain issues remain a major factor in the outlook. Going into the final months of 2021, uncertainty has increased, although so far, our panel's GDP outlook remains upbeat, thanks to the stronger-than-anticipated Q3 national accounts report. The uncertainty stems from ongoing global supply disruptions and lagging delivery times, and these, along with labour shortages, have contributed to rising inflationary pressures. The November PMI for manufacturing, for example, cited improving output, new orders and job conditions, but material shortages and supply delays continued to push up input costs. In addition, gas prices accelerated in October and, consequently, our panel's expectations for monthly headline CPI, as published by national statistics office INSEE, have continued to trend higher (see chart, below). INSEE's flash estimate for the November CPI puts monthly inflation at 2.8% (y-o-y), up from 2.6% in October (the Eurostat indicator for harmonised consumer prices in France, which differs from INSEE's domestic CPI, puts its November rate at an even-higher 3.4%). Both the INSEE and Eurostat reports place energy as the major culprit behind the inflation surge: INSEE reported a 21.7% (y-o-y) surge in energy as opposed to other costs which were significantly lower. Not surprisingly, our panel has upgraded its CPI forecast for 2022 from 1.8% last month to 2.1%.

Manufacturing production managed only a +0.1% (y-o-y) advance in October, following a -0.3% fall in September, due to the ongoing low level of output in the auto industry.

Monthly CPI Outturns (INSEE) and y-o-y Consensus Forecasts *(% change on the same period of the previous year)*



Changes to 2023 GDP and CPI Consensus Forecasts

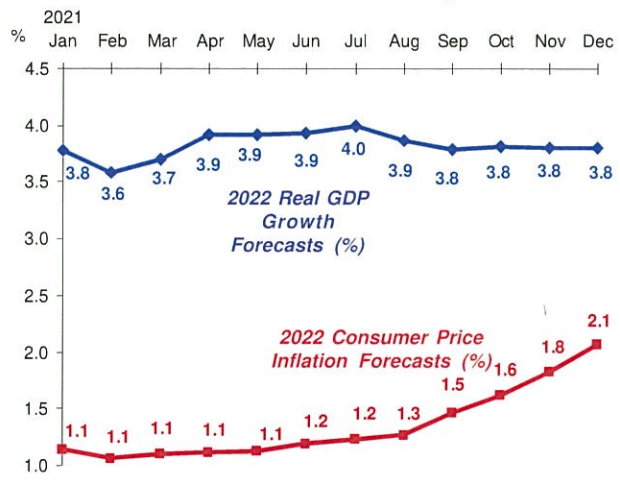
2023 Real GDP Growth:	**2.0**	**%**
last month's forecast:	2.0	%
2023 Consumer Price Inflation:	**1.4**	**%**
last month's forecast:	1.3	%

Real Growth and Inflation (2002-2026)

(% change over previous year)

2022 GDP Growth and Inflation Forecasts

Consensus Forecasts from Survey of:



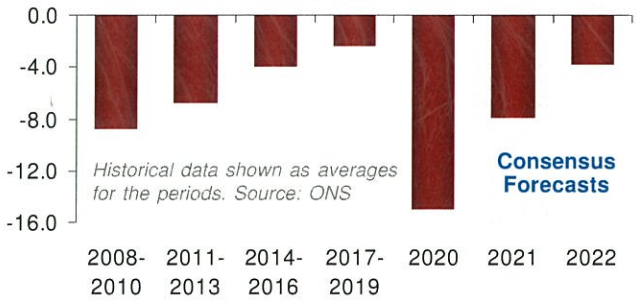
Average % Change on Previous Calendar Year

Economic Forecasters	Gross Domestic Product		Household Consumption		Gross Fixed Investment		Company Trading Profits		Manufacturing Production		Retail Prices (RPI-X, underlying rate)		Consumer Prices Index		Output Prices		Average Weekly Earnings	
	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022
Liverpool Macro Research	8.1	8.1	na	na	na	na	na	na	na	na	3.5	6.1	2.3	5.0	na	na	6.5	4.2
NatWest Markets	7.4	4.7	4.6	6.2	5.4	4.1	na	na	6.8	1.5	3.9	6.4	2.5	4.6	4.9	5.6	5.4	3.6
Deutsche Bank	7.1	3.6	3.9	5.7	na	na	na	na	na	na	na	na	2.5	4.3	na	na	na	na
HSBC	7.1	5.1	4.4	6.0	6.8	9.7	na	na	8.3	2.2	3.7	4.6	2.5	4.1	na	na	5.4	3.3
Societe Generale	7.1	5.3	4.2	5.6	4.9	8.0	9.4	4.5	na	na	3.9	5.6	2.5	4.0	na	na	5.7	4.4
UBS	7.0	4.6	3.7	6.0	4.2	2.3	na	na	na	na	na	na	2.5	3.6	na	na	5.3	3.7
Beacon Econ Forecasting	7.0	4.2	4.0	6.8	5.2	5.9	na	na	6.9	2.5	3.9	6.9	2.4	5.5	4.1	7.8	5.7	4.8
JP Morgan	7.0	4.8	3.9	6.8	na	na	na	na	na	na	na	na	2.5	4.1	na	na	na	na
TS Lombard	7.0	5.0	4.0	7.0	6.4	5.4	na	na	na	na	na	na	2.4	3.2	na	na	5.2	2.4
Goldman Sachs	7.0	5.1	3.7	7.9	na	na	na	na	na	na	3.6	4.9	2.4	3.9	na	na	na	na
Moody's Analytics	6.9	5.3	na	na	5.1	8.7	na	na	5.6	2.1	3.9	6.1	2.4	4.8	4.8	6.0	5.3	1.2
Citigroup	6.9	4.5	3.8	5.3	4.4	8.7	2.7	-4.7	na	na	4.1	6.2	2.5	4.8	na	na	5.4	5.4
NIESR	6.9	4.7	4.7	8.1	5.4	6.5	na	na	na	na	3.9	7.0	2.4	4.4	na	na	na	na
S&P Global Ratings	6.9	4.6	4.1	6.7	5.0	5.7	na	na	na	na	na	na	2.4	3.4	na	na	na	na
Bank of America - Merrill	6.9	4.1	3.6	5.5	4.5	5.1	na	na	6.9	2.4	3.8	5.2	2.5	4.0	na	na	na	na
Barclays	6.9	4.1	3.8	6.2	4.7	3.9	na	na	na	na	na	na	2.5	4.0	na	na	na	na
Fitch Ratings	6.9	5.0	3.7	6.2	4.5	4.3	na	na	na	na	na	na	2.5	4.5	na	na	na	na
Nomura	6.9	4.2	3.8	6.0	4.5	3.6	na	na	na	na	na	na	2.5	4.0	na	na	5.6	3.1
Schroders	6.9	5.2	3.8	5.9	4.9	6.5	na	na	6.8	2.0	4.1	5.5	2.5	3.8	na	na	5.0	3.5
Swiss Life Asset Mgrs	6.9	4.2	4.4	4.0	5.2	3.1	na	na	na	na	4.0	4.1	2.5	3.7	na	na	na	na
Confed of British Industry	6.9	5.1	3.8	7.6	4.7	4.8	na	na	na	na	3.9	4.7	2.5	4.0	na	na	5.5	3.3
Heteronomics	6.9	4.1	3.8	5.4	4.8	3.6	na	na	na	na	4.1	5.5	2.5	3.8	na	na	5.3	3.1
Experian	6.9	5.0	3.7	6.4	4.6	7.9	na	na	6.0	1.9	4.0	5.4	2.5	3.8	na	na	5.7	3.8
Capital Economics	6.8	4.8	4.3	7.8	4.9	5.5	na	na	na	na	4.0	5.1	2.5	3.8	na	na	5.5	3.1
Oxford Economics	6.8	5.0	4.1	6.9	5.2	7.8	3.5	8.2	6.8	3.5	3.9	5.4	2.5	3.8	4.8	4.5	5.2	3.0
Kern Consulting	6.8	5.0	4.4	6.4	6.0	6.4	6.0	4.5	6.3	3.0	na	na	2.4	3.9	na	na	5.0	3.7
IHS Markit	6.7	3.9	3.6	4.7	4.4	5.0	na	na	na	na	na	na	2.4	4.1	na	na	na	na
Allianz	6.7	4.4	3.5	6.3	7.0	5.8	na	na	na	na	na	na	2.5	3.8	na	na	5.1	3.5
Econ Intelligence Unit	6.7	4.0	3.4	4.0	5.4	8.7	na	na	na	na	na	na	2.4	3.6	4.3	3.0	na	na
KPMG	6.7	4.2	3.7	7.1	4.9	5.5	na	na	na	na	na	na	2.5	4.8	na	na	na	na
Consensus (Mean)	7.0	4.7	3.9	6.2	5.1	5.9	5.4	3.1	6.7	2.3	3.9	5.6	2.5	4.1	4.6	5.4	5.4	3.5
Last Month's Mean	6.9	4.7	4.3	6.2	5.8	6.3	7.1	1.5	7.0	2.5	3.7	5.1	2.4	3.7	4.2	4.6	5.2	3.6
3 Months Ago	6.7	5.4	4.0	6.8	6.5	6.3	7.1	3.7	6.8	2.5	3.5	4.3	2.2	2.8	3.6	3.6	4.8	3.1
High	8.1	8.1	4.7	8.1	7.0	9.7	9.4	8.2	8.3	3.5	4.1	7.0	2.5	5.5	4.9	7.8	6.5	5.4
Low	6.7	3.6	3.4	4.0	4.2	2.3	2.7	-4.7	5.6	1.5	3.5	4.1	2.3	3.2	4.1	3.0	5.0	1.2
Standard Deviation	0.3	0.8	0.3	1.0	0.7	2.0	3.0	5.5	0.7	0.6	0.2	0.8	0.1	0.5	0.4	1.8	0.3	0.9
Comparison Forecasts																		
OBR - Treasury (Oct. '21)	6.5	6.0	4.7	9.8	5.7	8.9					3.7	5.0	2.3	4.0				
Eur Commission (Nov. '21)	6.9	4.8	5.5	5.9	5.7	7.2							2.4	3.2				
IMF (Oct. '21)	6.8	5.0	4.0	7.1	6.0	5.5							2.2	2.6				
OECD (Dec. '21)	6.9	4.7	3.7	6.6	4.6	4.2							2.4	4.4				

Government and Background Data

Prime Minister - Mr. Boris Johnson (Conservative Party). **Parliament -** The Conservative party won 365 seats in the 650-seat House of Commons (lower house), in the December 2019 general election. **Next Election -** December 2024 (general election). **Nominal GDP -** £2,112bn (2020). **Population -** 67.9mn (mid-year, 2020). **$/£ Exchange Rate -** 1.284 (average, 2020).

Public Sector Net Borrowing – % of GDP
(fiscal years)



Historical Data

* % change on previous year	2017	2018	2019	2020
Gross Domestic Product*	2.1	1.7	1.7	-9.7
Household Consumption*	1.6	2.1	1.2	-10.5
Gross Fixed Investment*	3.3	-0.1	0.5	-9.1
Company Trading Profits*	2.7	3.0	3.9	1.8
Manufacturing Production*	1.4	4.0	3.1	-8.8
Retail Prices (RPI-X, underlying rate)*	3.8	3.3	2.5	1.7
Consumer Price Index*	2.7	2.4	1.8	0.8
Output Prices*	3.9	3.5	1.4	-1.0
Average Weekly Earnings*	2.3	2.9	3.4	1.8
Unemployment Rate (LFS), %	4.4	4.1	3.8	4.5
Current Account, £ bn	-76.2	-84.3	-60.2	-55.9
Public Sector Net Borrowing (excl. financial interventions)				
fiscal years, £ bn	55.1	43.3	55.3	323.1
3 mth Interbank, % (end yr)	0.5	0.9	0.8	0.0
10 Yr Gilt Yield, % (end yr)	1.2	1.3	0.8	0.2

Year Average Unemployment Rate (%) (Labour Force Survey)		Annual Total Current Account (£ bn)		Fiscal Years (Apr-Mar) Public Sector Net Borrowing (£ bn)		Rates on Survey Date 0.1% 3 month Interbank Rate (%)		0.8% 10 Year Gilt Yield (%)	
2021	2022	2021	2022	FY 21-22	FY 22-23	End Mar'22	End Dec'22	End Mar'22	End Dec'22
na	na	-48.3	-35.9	179.5	57.8	1.0	1.7	na	na
4.7	4.7	-40.0	-46.0	175.0	85.0	0.3	0.9	1.0	1.1
4.5	4.4	na	na	na	na	na	na	1.3	na
4.8	5.1	-57.0	-76.0	186.0	120.0	na	na	na	na
4.7	4.6	-43.6	-62.3	197.1	99.8	na	na	na	na
4.9	4.8	-61.1	-72.6	na	na	0.2	0.7	1.3	1.5
4.6	4.0	-60.7	-112.1	184.5	129.1	0.3	0.9	1.0	1.4
4.5	3.9	-38.6	-37.0	183.0	83.0	na	na	na	na
4.8	4.6	-77.0	-100.0	200.0	125.0	na	na	na	na
4.7	4.4	na	na	na	na	na	na	1.2	1.4
4.6	4.8	-42.4	-28.3	na	na	0.3	0.6	1.1	1.5
4.7	4.9	-65.2	-138.6	176.0	81.7	na	na	1.1	1.3
4.7	4.4	-40.7	-62.8	160.8	95.6	na	na	0.8	1.3
4.6	4.5	na	na	na	na	na	na	1.1	1.5
na	na	na	na	na	na	na	na	na	na
4.7	4.6	na	na	184.0	96.0	na	na	na	na
4.6	4.5	na	na	na	na	0.2	0.2	na	na
4.5	4.0	na	na	na	na	0.7	1.2	1.1	1.4
4.8	4.7	-72.0	-86.0	190.0	90.0	0.5	0.6	1.3	1.3
4.7	4.6	na	na	na	na	0.3	0.5	0.8	1.0
4.7	4.4	-55.2	-85.4	187.6	85.1	na	na	na	na
4.6	4.6	na	na	na	na	0.3	0.6	na	na
4.6	4.8	-59.7	-75.0	200.0	110.0	0.1	0.8	0.8	1.4
4.5	4.4	-48.9	-65.0	191.7	95.7	na	na	1.3	1.3
4.6	4.3	-56.2	-76.7	201.0	98.7	0.3	0.6	1.0	1.4
5.0	4.9	-75.0	-80.0	205.0	115.0	0.3	0.5	1.2	1.5
4.7	4.9	-33.8	-62.6	na	na	0.2	0.5	1.4	1.6
4.7	4.5	na	na	na	na	na	na	na	na
4.8	4.8	-66.6	-68.0	na	na	0.2	0.5	1.2	1.4
4.6	4.4	na	na	172.0	76.0	0.5	1.0	1.6	1.8
4.7	4.6	-54.8	-72.1	186.7	96.7	0.4	0.7	1.1	1.4
4.8	4.8	-58.6	-73.3	191.5	101.5				
5.0	5.0	-73.1	-83.1	200.8	109.2				
5.0	5.1	-33.8	-28.3	205.0	129.1	1.0	1.7	1.6	1.8
4.5	3.9	-77.0	-138.6	160.8	57.8	0.1	0.2	0.8	1.0
0.1	0.3	13.0	26.6	11.9	18.7	0.2	0.3	0.2	0.2
4.9	4.8	-76.2	-130.9	183.0	83.0				
4.9	4.7								
5.0	5.0								
4.5	4.3	-66.0	-87.7						

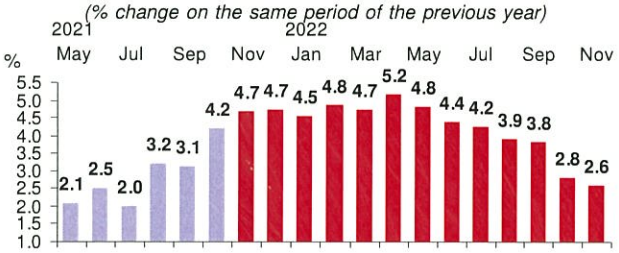
Price Rises Could Slow 2022 GDP Growth

While health experts believe that high rates of vaccination would prevent another lockdown, the government announced the start of "Plan B" measures just after our survey deadline which include a requirement for Covid passports in some social settings. A pause towards a full return to normality will frustrate businesses and services providers, who had hoped that such disruption had largely passed. Wide-ranging data highlighted steadily increasing mobility to cinemas, restaurants and retailers in recent weeks, as well as higher consumer confidence in November, supporting the view that consumer spending has been resilient despite alarming rises in household energy bills and food prices. That said, the CPI jumped 4.2% (y-o-y) in October – more than a percentage point above September's reading – and is expected to move even higher (chart below), perhaps reining in spending on non-essential goods and services. The Bank of England opted against tighter monetary policy last month, but all eyes are on the December 16 meeting as labour market strength suggests that domestic pressures are also contributing to loftier prices. The number of employees on company payrolls grew by 160,000 in October, implying no apparent deterioration in the jobs market following the removal of furlough support at the end of September.

Strains on businesses from bulging raw materials and energy costs are squeezing profits, as the OECD warned in its latest report that acute supply and labour shortages could more prominently affect firms' operating capacity. Upwardly-revising its 2021 GDP growth forecast to 6.9% this month, it trimmed its 2022 estimate to 4.7%. Our panel's own projections for GDP have been in this ballpark in recent months.

Monthly CPI Outturns and y-o-y Consensus Forecasts

(% change on the same period of the previous year)

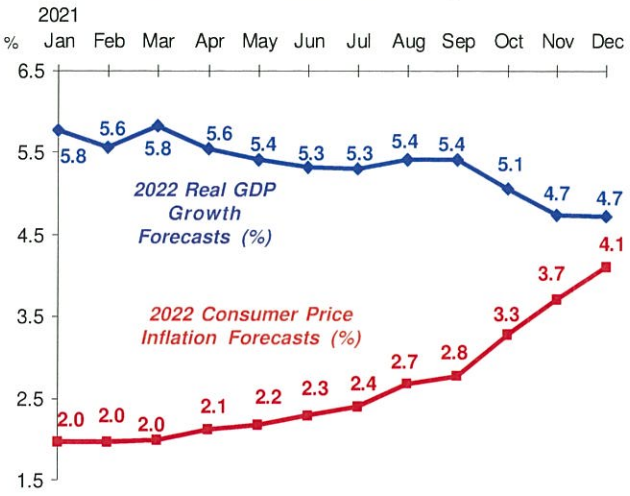


Changes to 2023 GDP and CPI Consensus Forecasts

2023 Real GDP Growth:	**2.1**	**%**
last month's forecast:	2.0	%
2023 Consumer Price Inflation:	**2.2**	**%**
last month's forecast:	2.5	%

2022 GDP Growth and Inflation Forecasts

Consensus Forecasts from Survey of:



UK Official Bank Rate – at Dec. 6, 2021 = **0.1%**

Average probabilities of a change in the Bank Rate on **Dec. 16, 2021**:
Increase = 40.0% **No change =** 59.5% **Decrease =** 0.5%

Consensus Forecasts	End Dec. 2021	End Mar. 2022	End Jun. 2022	End Sep. 2022
Mean Average:	**0.18 %**	**0.36 %**	**0.54 %**	**0.61 %**
Mode (most frequent forecast):	**0.25 %**	**0.25 %**	**0.50 %**	**0.50 %**

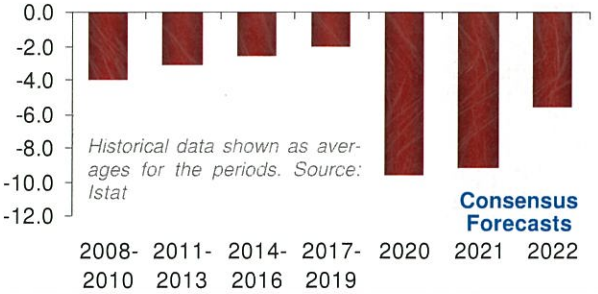
Average % Change on Previous Calendar Year

	Gross Domestic Product		Household Consumption		Gross Fixed Investment		Industrial Production		Consumer Prices (CPI)		Producer Prices		Contractual Hourly Earnings	
	Prodotto Interno Lordo		*Consumi delle Famiglie*		*Investimenti Fissi Lordi*		*Produzione Industriale*		*Prezzi al Consumo (NIC)*		*Prezzi alla Produzione*		*Retribuzione Oraria Contrattuali*	
Economic Forecasters	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**
Citigroup	6.6	3.8	5.5	4.0	17.5	7.1	na	na	1.9	2.8	na	na	na	na
Capital Economics	6.5	4.0	5.4	6.5	15.5	1.4	na	na	1.8	1.3	na	na	na	na
LC Macro Advisors	6.5	5.0	5.2	4.5	16.1	7.7	12.4	8.1	1.9	3.3	10.6	3.5	0.6	1.2
Zürcher Kantonalbank	6.5	4.2	5.4	5.7	15.7	3.6	11.2	3.6	1.9	2.3	11.0	5.5	0.8	1.0
Barclays	6.4	4.7	5.3	4.9	15.9	5.4	na	na	1.8	1.7	na	na	na	na
Centro Europa Ricerche	6.4	4.2	4.6	4.9	16.6	7.4	na	na	1.9	3.0	na	na	na	na
Societe Generale	6.4	4.3	5.3	5.2	15.6	3.9	na	na	1.8	1.9	na	na	na	na
S&P Global Ratings	6.4	4.7	5.7	6.1	16.3	6.9	na	na	1.7	1.7	na	na	na	na
Goldman Sachs	6.3	4.4	5.9	5.7	15.3	3.8	na	na	na	na	na	na	na	na
Banca Nzle del Lavoro	6.3	4.5	5.1	4.7	15.9	9.2	11.1	4.2	1.9	2.4	8.6	4.4	0.6	0.6
Econ Intelligence Unit	6.3	4.4	5.5	5.4	15.8	5.5	11.0	3.4	na	na	10.1	3.2	1.0	1.3
HSBC	6.3	4.0	5.2	4.7	15.8	4.3	11.2	2.7	2.0	2.9	na	na	na	na
ING Financial Markets	6.3	4.1	5.1	3.9	15.8	6.1	na	na	1.9	2.5	10.5	9.7	0.6	0.9
Natixis	6.3	4.5	5.0	3.7	16.3	7.4	na	na	na	na	na	na	na	na
Oxford Economics	6.3	4.5	5.2	6.1	16.4	6.4	11.1	3.4	1.9	2.3	12.2	6.1	na	na
Bank of America - Merrill	6.3	4.0	5.2	4.9	15.7	3.9	11.1	3.1	1.7	2.5	na	na	na	na
Moody's Analytics	6.3	4.2	na	na	16.5	6.3	11.3	3.2	1.8	2.8	9.7	8.9	na	na
IHS Markit	6.2	3.7	5.1	4.3	15.0	2.7	11.0	1.4	na	na	10.1	5.3	na	na
Intesa Sanpaolo	6.2	4.3	5.1	5.1	15.8	6.3	11.1	2.4	1.9	2.3	10.3	10.4	0.6	0.8
UBS	6.2	4.5	5.4	5.4	15.6	8.5	na	na	na	na	na	na	0.5	0.7
Allianz	6.2	4.5	5.5	6.1	16.0	6.4	11.8	3.4	1.9	1.8	11.2	5.1	0.7	0.4
Prometeia	6.2	4.0	5.0	3.9	16.0	9.0	11.1	2.5	1.9	1.9	10.2	3.6	na	na
REF Ricerche	6.2	4.2	5.5	5.6	14.0	9.0	11.0	1.5	1.9	1.9	na	na	0.5	1.0
Confindustria	6.1	4.1	4.3	3.5	18.3	9.6	11.2	4.3	1.8	1.4	na	na	na	na
Fitch Ratings	5.7	4.3	4.7	4.9	15.1	3.8	na	na	1.6	1.4	na	na	na	na
Deutsche Bank	5.7	4.0	4.9	4.4	na	na	na	na	1.7	2.0	na	na	na	na
Consensus (Mean)	6.3	4.3	5.2	5.0	15.9	6.1	11.3	3.4	1.8	2.2	10.4	6.0	0.7	0.9
Last Month's Mean	6.1	4.2	5.1	5.0	15.9	6.2	11.2	3.6	1.8	1.9	8.6	4.5	0.7	0.9
3 Months Ago	5.7	4.3	4.4	5.1	14.5	6.4	10.9	3.9	1.5	1.4	6.9	2.6	0.7	0.8
High	6.6	5.0	5.9	6.5	18.3	9.6	12.4	8.1	2.0	3.3	12.2	10.4	1.0	1.3
Low	5.7	3.7	4.3	3.5	14.0	1.4	11.0	1.4	1.6	1.3	8.6	3.2	0.5	0.4
Standard Deviation	0.2	0.3	0.3	0.8	0.8	2.2	0.4	1.6	0.1	0.6	0.9	2.6	0.2	0.3
Comparison Forecasts														
Banca d'Italia (Jul. '21)	5.1	4.4	3.3	5.6	15.2	8.7								
Government (Sep. '21)	6.0	4.7	5.2	5.0	15.5	6.8								
UPB (Oct. '21)	5.8	4.4	4.5	4.9	15.4	8.0								
Eur Commission (Nov. '21)	6.2	4.3	5.3	4.8	15.8	5.9								
IMF (Oct. '21)	5.8	4.2	4.2	5.0	15.0	5.1			1.7	1.8				
OECD (Dec. '21)	6.3	4.6	5.5	4.7	16.5	7.6								

Government and Background Data

Prime Minister - Mr. Mario Draghi. **Parliament -** Draghi was sworn in on February 13, 2021 after the previous coalition between the Five-Star Movement and the Democratic Party (since September 2019) collapsed in January 2021. **Next Elections -** 2022 (presidential); 2023 (parliamentary). **Nominal GDP -** Euro1,652bn (2020). **Population -** 60.5mn (mid-year, 2020). **$/Euro Exchange Rate -** 1.141 (average, 2020).

General Government Budget Balance – % of GDP



Historical Data

** % change on previous year*	2017	2018	2019	2020
Gross Domestic Product*	1.7	0.9	0.4	-8.9
Household Consumption*	1.5	0.9	0.2	-10.7
Gross Fixed Investment*	3.2	3.1	0.7	-9.2
Industrial Production*	3.6	0.9	-1.1	-11.4
Consumer Prices (CPI)*	1.2	1.2	0.6	-0.2
Producer Prices*	2.3	3.3	0.2	-3.3
Contractual Hourly Earnings*	0.5	1.5	1.0	0.6
Unemployment Rate,%	11.3	10.6	10.0	9.3
Current Account, Euro bn	44.9	44.8	57.9	62.1
General Govt. Budget Balance (Maastricht definition), **Euro bn**	-42.0	-38.8	-27.8	-158
3 mth Euro, % (end yr)	-0.3	-0.3	-0.4	-0.5
10 yr Italian Govt Bond, % (end yr)	1.9	2.8	1.4	0.5

Year Average		Annual Total				Rates on Survey Date			
Unemployment Rate (%)		Current Account (Euro bn)		General Govt Budget Bal (Maastricht) (Euro bn)		-0.6% 3 month Euro Rate (%)		0.9% 10 Year Italian Govt Bond Yield (%)	
Tasso di Disoccupazione (%)		*Partite Correnti (€ mld)*		*Indebitamento netto (Maastricht) (€ mld)*		*Interessi Euro Trimestrali (%)*		*Buoni del Tesoro Decennali (%)*	
2021	2022	2021	2022	2021	2022	End Mar'22	End Dec'22	End Mar'22	End Dec'22
9.6	9.4	60.6	48.6	-164.0	-109.3	na	na	1.1	1.2
9.5	8.8	50.2	52.2	-158.9	-95.7	na	na	na	na
9.6	8.5	68.1	76.4	-166.3	-110.2	-0.5	-0.4	1.0	1.3
9.6	9.1	64.0	60.0	-163.0	-95.0	-0.5	-0.4	1.2	1.4
9.6	9.3	na	na	na	na	na	na	na	na
9.5	8.9	59.9	49.6	-163.3	-96.7	-0.5	-0.3	1.1	1.3
9.7	9.1	60.1	53.9	-166.7	-119.4	na	na	na	na
9.6	9.1	na	na	na	na	na	na	1.0	1.4
na	na	na	na	-198.7	-108.7	na	na	na	na
9.7	9.4	na	na	na	na	na	na	na	na
9.7	9.2	68.2	67.3	-171.2	-109.0	-0.5	-0.5	1.1	1.5
9.5	8.9	62.8	62.8	-162.4	-109.7	na	na	0.7	0.4
9.6	9.7	61.0	55.6	-164.4	-105.9	-0.6	-0.5	1.4	1.1
9.5	8.6	na	na	na	na	na	na	na	na
9.5	9.1	52.5	33.7	-166.7	-105.3	-0.6	-0.5	1.2	1.7
9.7	9.5	65.5	51.5	-169.9	-112.6	na	na	na	na
9.7	9.5	57.6	42.8	-145.1	-74.3	-0.5	-0.6	0.9	1.1
10.1	10.2	67.2	67.7	-129.0	-83.7	-0.5	-0.5	1.6	2.1
9.6	9.3	51.9	33.3	-153.0	-102.0	-0.5	-0.5	1.2	1.8
9.7	9.6	46.2	50.8	na	na	-0.5	-0.5	na	na
9.6	9.0	52.3	33.1	-167.0	-102.0	-0.5	-0.5	1.1	1.2
9.5	9.6	52.6	45.1	-163.4	-108.0	-0.5	-0.4	1.0	1.3
9.7	8.9	55.7	39.1	-155.3	-105.0	-0.5	-0.5	0.9	0.9
9.9	9.6	53.8	60.0	-154.2	-150.7	na	na	na	na
10.0	9.7	49.6	44.9	-190.5	-132.2	na	na	na	na
10.1	9.7	na	na	na	na	na	na	na	na
9.7	9.3	58.0	51.4	-163.7	-106.8	-0.5	-0.5	1.1	1.3
9.8	9.5	57.8	53.1	-167.1	-99.4				
10.1	9.8	54.4	50.0	-183.6	-101.9				
10.1	10.2	68.2	76.4	-129.0	-74.3	-0.5	-0.3	1.6	2.1
9.5	8.5	46.2	33.1	-198.7	-150.7	-0.6	-0.6	0.7	0.4
0.2	0.4	6.7	12.0	14.4	15.9	0.0	0.1	0.2	0.4
10.5	10.3								
9.6	9.1								
9.8	9.5								
9.8	9.3	61.4	51.1						
10.3	11.6			-181.8	-88.0				
9.6	8.9	54.7	56.7	-167.4	-111.2				

Changes to 2023 GDP and CPI Consensus Forecasts

2023 Real GDP Growth:	**2.1**	**%**
last month's forecast:	2.1	%
2023 Consumer Price Inflation:	**1.2**	**%**
last month's forecast:	1.2	%

Real Growth and Inflation (2002-2026)

(% change over previous year)

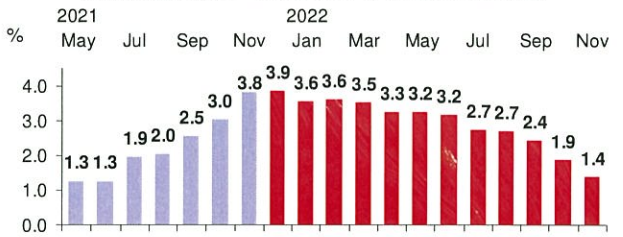
Outlook Upbeat Despite Omicron Threat

The resurgence in GDP growth was underpinned by the Q3 expansion of +2.6% (q-o-q), driven by increases of 3% and 1.6% in household consumption and gross fixed investment, respectively. Net exports also contributed, while from the production side, services output was buoyed by rising tourism. Solid growth, in addition to higher business optimism linked to investment from the EU Recovery Fund, pushed the 2021 GDP consensus to 6.3% this month, from 5.7% three months ago. Understandably, and largely due to the emergence of the Omicron variant, the outlook has clouded somewhat and brought uncertainty as to whether another round of national and regional lockdowns will occur. The government enforced its "super green pass" from December 6, meaning that many leisure and entertainment venues are only accessible to those either vaccinated or recently recovered from the virus. With borders tightened and less appetite for cross-border travel, the winter ski season could suffer disruption. Elsewhere, Istat's business sentiment index was marginally higher in November, influenced by manufacturing confidence hitting a new high despite ongoing supply bottlenecks. The manufacturing PMI indicator for November rose to a fresh high on the back of surging client demand and booming factory output.

Brussels has encouraged debt-ridden countries, including Italy, to focus on making a success of EU recovery funds and relying less on fiscal stimulus. Our panellists anticipate a 6.1% advance in fixed investment next year from an estimated 15.9% jump in 2021, while other schemes and tax breaks to revitalise the economy may keep the budget deficit elevated at -106.8bn next year (roughly -5.6% of GDP).

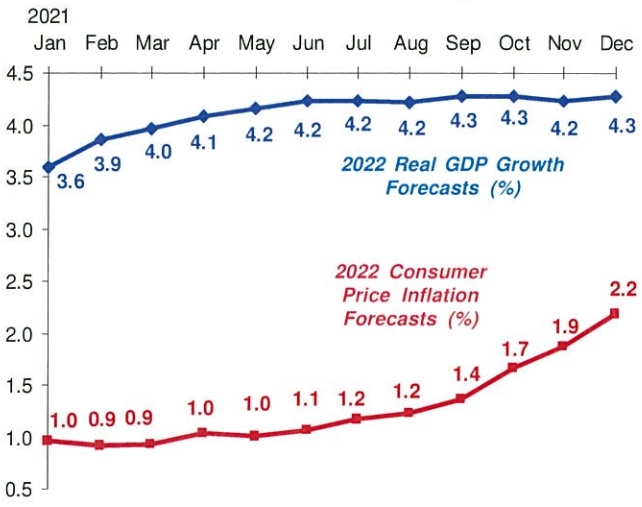
Monthly CPI Outturns and y-o-y Consensus Forecasts

(% change on the same period of the previous year)



2022 GDP Growth and Inflation Forecasts

Consensus Forecasts from Survey of:

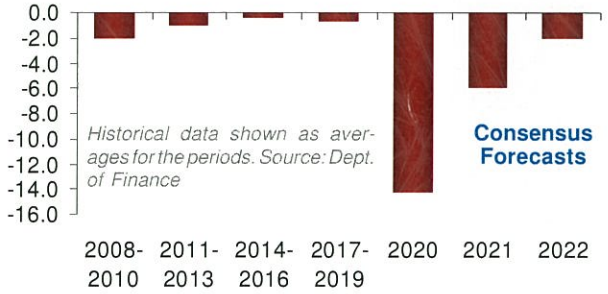


	Average % Change on Previous Calendar Year																Annual Total	
	Gross Domestic Product		Household Final Consumption Expenditure		Machinery & Equip-ment Investment		Net Operat-ing Surplus: Corporations		Industrial Production		Consumer Prices		Industrial Product Prices		Average Hourly Earnings		Housing Starts (thousand units)	
	Produit Intérieur Brut		*Dépenses de Consommation Finale des Ménages*		*Investissement de Machines et Matériel*		*Excédent d'exploitation net: sociétés*		*Production Industrielle*		*Prix à la Consom-mation*		*Prix des Produits Industriels*		*Rémunér-ation Horaire Moyenne*		*Construc-tion de Logements mises en chantier, milliers*	
Economic Forecasters	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**
Stokes Econ Consulting	5.7	4.5	6.0	4.9	13.1	13.6	na	na	na	na	na	na	na	na	na	na	262	236
Conf Board of Canada	5.1	4.4	4.8	5.9	5.9	7.4	na	na	na	na	3.3	2.7	11.2	-0.5	na	na	275	236
Econ Intelligence Unit	5.0	3.5	3.9	3.7	na	na	na	na	5.4	2.0	3.2	2.8	13.5	4.4	na	na	na	na
Citigroup	5.0	4.3	4.4	5.4	5.7	6.3	na	na	na	na	3.4	3.1	na	na	na	na	na	na
Economap	4.8	4.1	5.2	4.5	6.9	6.5	37.0	4.0	4.8	4.0	3.5	3.5	13.0	5.0	3.0	3.0	270	225
Informetrica	4.8	4.3	4.9	4.6	7.3	8.0	35.0	3.0	4.9	3.8	3.5	2.8	11.0	3.0	2.9	2.5	270	220
Royal Bank of Canada	4.7	4.3	5.4	6.0	6.2	6.4	31.9	2.0	na	na	3.4	3.3	na	na	na	na	277	236
National Bank of Canada	4.6	4.1	5.4	5.2	6.6	5.2	31.8	2.5	na	na	3.4	3.5	na	na	na	na	275	220
Desjardins	4.5	3.9	5.7	7.2	6.8	8.1	30.8	6.2	na	na	3.4	3.3	13.7	4.4	2.8	3.1	270	225
Oxford Economics	4.5	4.3	5.2	5.6	6.0	2.4	17.3	11.2	4.5	4.6	3.3	3.7	13.6	4.3	2.6	1.8	270	225
Moody's Analytics	4.5	3.5	na	na	13.2	7.2	29.2	-5.1	4.6	2.5	3.3	3.5	13.9	5.1	2.6	1.6	274	238
Inst Fiscal Studies	4.5	3.5	5.4	3.9	5.9	1.9	na	na	4.7	4.7	3.4	2.9	na	na	2.8	2.2	271	231
BMO Capital Markets	4.5	4.0	5.3	3.0	6.8	6.4	30.0	-5.0	4.5	4.0	3.4	3.5	14.0	3.0	3.0	3.5	270	230
Capital Economics	4.5	3.5	5.3	4.3	6.6	8.8	na	na	na	na	3.4	3.0	na	na	na	na	na	na
JP Morgan	4.5	3.5	5.3	5.4	6.1	2.5	na	na	na	na	3.4	3.3	na	na	na	na	na	na
Scotia Economics	4.5	4.2	5.3	7.9	6.3	3.5	30.6	0.6	4.5	4.1	3.4	4.5	na	na	na	na	na	na
University of Toronto	4.5	5.0	5.3	6.6	7.5	12.4	30.5	4.0	na	na	3.4	3.4	na	na	na	na	263	198
Consensus (Mean)	4.7	4.0	5.2	5.3	7.3	6.7	30.4	2.3	4.7	3.7	3.4	3.3	13.0	3.6	2.8	2.5	271	227
Last Month's Mean	5.0	4.1	4.3	5.0	7.0	7.2	36.9	4.9	5.5	3.6	3.3	2.9	13.2	3.7	2.8	2.6	271	226
3 Months Ago	5.4	4.2	4.7	5.1	7.6	7.9	36.1	4.0	5.9	4.0	3.0	2.5	12.4	3.2	2.9	2.4	269	226
High	5.7	5.0	6.0	7.9	13.2	13.6	37.0	11.2	5.4	4.7	3.5	4.5	14.0	5.1	3.0	3.5	277	238
Low	4.5	3.5	3.9	3.0	5.7	1.9	17.3	-5.1	4.5	2.0	3.2	2.7	11.0	-0.5	2.6	1.6	262	198
Standard Deviation	0.3	0.4	0.5	1.3	2.3	3.3	5.2	4.9	0.3	1.0	0.1	0.4	1.2	1.8	0.2	0.7	5	11
Comparison Forecasts																		
IMF (Oct. '21)	5.7	4.9	5.2	4.9							3.2	2.6						
OECD (Dec. '21)	4.8	3.9	4.3	6.3							3.3	3.3						

Government and Background Data

Prime Minister - Mr. Justin Trudeau (Liberals). **Government -** The Liberals hold 160 out of 338 seats in parliament (170 seats are needed for an outright majority). **Next Election -** by 20 October 2025 (Federal election). **Nominal GDP -** C$2,205bn (2020). **Population -** 37.7mn (mid-year, 2020). **C$/$ Exchange Rate -** 1.341 (average, 2020).

Federal Government Budget Balance – % of GDP



Historical Data

	2017	2018	2019	2020
Gross Domestic Product*	3.0	2.8	1.9	-5.2
Household Consumption Expenditure*	3.8	2.6	1.4	-6.2
Machinery & Eqpt. Invt*	7.5	7.4	0.1	-15.4
Net Operating Surplus: Corporations*	19.3	4.8	-0.6	-1.9
Industrial Production*	3.7	3.5	-0.2	-8.1
Consumer Prices*	1.6	2.3	1.9	0.7
Industrial Product Prices*	3.1	3.9	-0.1	-0.4
Average Hourly Earnings*	2.1	2.2	2.6	3.6
Housing Starts, '000 units	220	213	209	218
Unemployment Rate, %	6.4	5.9	5.7	9.6
Current Account, C$bn	-60.0	-53.1	-47.0	-39.4
Federal Govt Budget Balance, fiscal years, C$bn	-19.0	-11.8	-21.8	-314
3 mth Trsy Bills, % (end yr)	1.1	1.6	1.7	0.1
10 Yr Govt Bond, % (end yr)	2.1	2.0	1.7	0.7

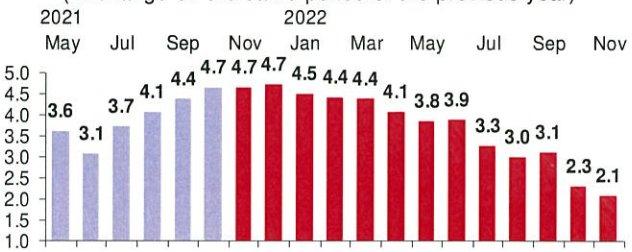
Year Average		Annual Total		Fiscal Years (Apr-Mar)		Rates on Survey Date 0.0%		Rates on Survey Date 1.5%	
Unemployment Rate (%)		Current Account (C$ bn)		Federal Govt Budget Balance (C$ bn)		3 month Treasury Bill Rate (%)		10 Year Government Bond Yield (%)	
Taux de Chômage (%)		*Balance Courante (C$ md)*		*Balance Budgétaire (C$ md)*		*Rendement sur les Bons du Trésor de 3 mois %*		*Rendement des Obligations d'État de 10 ans %*	
2021	2022	2021	2022	FY 21-22	FY 22-23	End Mar'22	End Dec'22	End Mar'22	End Dec'22
7.7	6.9	na	na	na	na	na	na	na	na
7.6	6.0	12.4	7.6	-122.0	-54.0	0.1	0.1	1.5	1.5
7.5	6.5	19.4	-10.1	na	na	na	na	na	na
7.5	6.2	22.0	28.8	-142.5	-50.9	0.3	1.0	1.9	2.3
7.4	5.8	5.0	0.0	-145.0	-50.0	0.2	0.5	1.8	2.0
7.5	6.1	15.0	15.0	-155.0	-55.0	0.2	0.6	1.9	2.1
7.5	6.1	8.9	22.2	na	na	0.3	1.1	1.7	1.9
7.5	5.8	-3.6	-34.0	na	na	0.4	1.4	1.8	2.1
7.5	5.7	-0.4	-51.0	-140.0	-50.0	0.4	0.9	2.0	2.3
7.4	6.2	0.0	-39.8	na	na	0.1	0.3	1.8	2.3
7.4	5.8	2.8	-43.2	na	na	na	na	na	na
7.5	6.1	na	na	na	na	0.1	0.2	1.7	1.8
7.4	5.7	5.0	0.0	-160.0	-60.0	0.1	0.9	1.7	2.0
7.4	5.6	na	na	na	na	na	na	na	na
7.5	6.0	na	na	na	na	na	na	na	na
7.5	5.2	7.9	-11.2	-138.2	-42.7	0.4	1.4	1.8	2.1
7.5	6.1	4.6	-13.1	na	na	0.2	0.8	1.8	2.4
7.5	6.0	7.6	-9.9	-143.2	-51.8	0.2	0.8	1.8	2.1
7.5	6.2	14.1	3.0	-144.0	-53.9				
7.6	6.3	0.4	-10.3	-144.0	-53.9				
7.7	6.9	22.0	28.8	-122.0	-42.7	0.4	1.4	2.0	2.4
7.4	5.2	-3.6	-51.0	-160.0	-60.0	0.1	0.1	1.5	1.5
0.1	0.4	7.7	25.7	12.3	5.4	0.1	0.4	0.1	0.3
7.7	5.7								
7.6	6.3	7.9	-0.6						

Despite Upbeat Q3 GDP Outturn, Outlook Pared Back

The release of the Q3 national accounts confirmed that after a Q2 beset by Covid restrictions – which dragged GDP down by -0.8% (q-o-q) – the economy advanced a solid +1.3%. Household expenditure and exports were the main drivers of activity, as pandemic regulations were loosened and operating conditions largely returned to normal. Pent-up consumer demand surged +4.2% (q-o-q) compared with a -0.1% fall in Q2, powered by a 14.0% (q-o-q) jump in semi-durables and 6.3% increase in services spending. By contrast, global supply-chain disruption hit machinery & equipment investment, by -0.2% (q-o-q), and in the absence of badly-needed materials and parts, producers drew down on existing inventories. These supply-chain issues have continued, with an energy price shock also adding to the current situation going into the current quarter. For industrialists, September was already a poor month: industrial production fell -0.6% (m-o-m) after a +0.7% gain in August, while manufacturing contracted -1.7% over the month. October's monthly survey of manufacturing did see sales rebound after a fall in September, including higher motor vehicle sales, which could suggest some semiconductor bottlenecks easing. Meanwhile, high prices will support natural resource industries. However, the emergence of the Omicron variant adds a note of caution. Our panel's GDP outlook has even been pared back.

By contrast, the Bank of Canada affirmed upside growth and inflation risks, highlighting recent surges in employment (up 153,700 in November) as a signifier of very solid activity. As a result, the Bank indicated that it would raise interest rates "in the middle quarters of 2022."

Monthly CPI Outturns and y-o-y Consensus Forecasts
(% change on the same period of the previous year)



Changes to 2023 GDP and CPI Consensus Forecasts

2023 Real GDP Growth:	**2.8**	**%**
last month's forecast:	2.7	%
2023 Consumer Price Inflation:	**2.2**	**%**
last month's forecast:	2.2	%

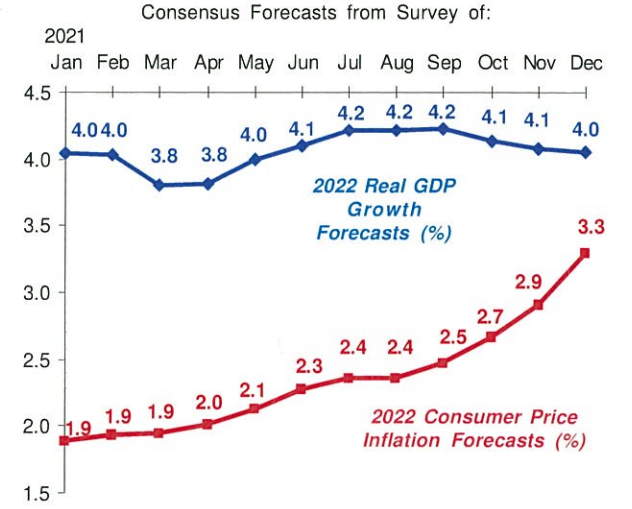
Canada Overnight Lending Rate – Dec. 6, 2021 = 0.25%

Average probabilities of a change in the Lending Rate on **Jan. 26, 2022:**

Increase = 13.3% **No change =** 86.4% **Decrease =** 0.2%

Consensus Forecasts	End Dec. 2021	End Mar. 2022	End Jun. 2022	End Sep. 2022
Mean Average:	**0.27 %**	**0.29 %**	**0.46 %**	**0.73 %**
Mode (most frequent forecast):	**0.25 %**	**0.25 %**	**0.50 %**	**0.75 %**

2022 GDP Growth and Inflation Forecasts
Consensus Forecasts from Survey of:



The EURO ZONE is: Austria, Belgium, Cyprus, Estonia, Finland, France, Germany, Greece, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Portugal, Slovakia, Slovenia and Spain.

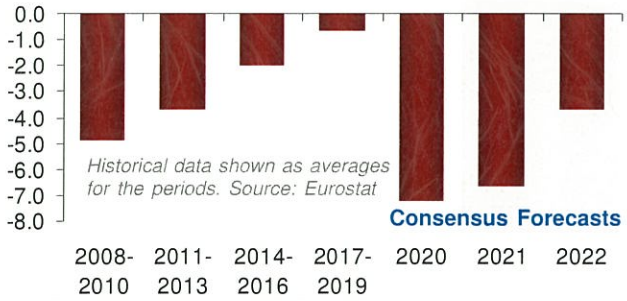
Average % Change on Previous Calendar Year

Economic Forecasters	Gross Domestic Product		Private Consumption		Govt Consumption		Gross Fixed Investment		Industrial Production		Harmonised Consumer Prices (HICP)		Core HICP (ex. energy, food, alcohol & tobacco		Industrial Producer Prices		Hourly Labour Costs – Total	
	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022
Morgan Stanley	5.2	4.6	3.0	5.5	3.2	1.0	4.4	4.7	na	na	2.5	2.3	1.4	1.7	na	na	na	na
Bank Julius Baer	5.2	5.0	3.4	6.7	3.4	2.2	4.2	4.9	7.7	5.5	2.6	2.7	1.5	2.1	10.7	7.6	1.6	3.8
Schroders	5.2	4.6	2.5	4.4	4.0	3.0	4.5	5.2	na	na	2.4	3.5	1.3	1.3	na	na	2.5	3.4
Credit Agricole	5.2	4.4	3.5	5.9	3.8	1.4	3.6	4.4	na	na	2.5	2.9	1.4	1.8	na	na	na	na
Swiss Life Asset Mgrs	5.2	3.7	3.9	4.5	3.5	2.0	5.0	3.2	8.3	1.9	2.6	2.8	1.4	2.1	na	na	na	na
Bank Vontobel	5.1	4.2	3.6	5.7	3.8	1.1	3.4	3.2	na	na	2.6	2.5	na	na	na	na	na	na
IHS Markit	5.1	3.7	3.0	4.7	3.5	1.6	4.2	3.6	6.7	2.9	2.5	2.6	1.4	1.9	9.4	6.3	na	na
Goldman Sachs	5.1	4.3	3.2	5.9	na	na	4.4	3.6	na	na	2.5	2.5	1.4	1.6	na	na	na	na
UBS	5.1	4.8	3.2	5.6	3.2	0.4	4.0	5.3	na	na	2.6	2.8	1.4	1.9	na	na	na	na
Barclays	5.1	4.3	3.0	5.0	3.7	1.6	4.2	4.5	na	na	2.5	2.5	1.4	1.7	na	na	na	na
Capital Economics	5.1	4.0	3.1	5.8	3.0	0.0	5.1	4.4	na	na	2.5	2.5	1.4	1.5	na	na	na	na
Natixis	5.1	4.3	3.1	4.7	3.3	1.9	4.0	4.3	na	na	2.5	2.3	1.5	2.1	na	na	na	na
Nomura	5.1	3.4	2.9	4.8	3.4	1.8	4.4	2.9	na	na	2.5	3.2	1.4	1.9	na	na	na	na
NORD/LB	5.1	4.0	2.8	4.1	3.8	3.3	4.6	4.5	na	na	2.6	2.9	1.4	1.9	na	na	na	na
Societe Generale	5.1	4.2	3.4	6.1	3.7	0.9	4.2	3.8	na	na	2.6	2.6	1.4	1.7	na	na	na	na
Citigroup	5.1	3.9	2.6	4.9	3.6	2.8	4.1	3.9	7.9	2.6	2.5	2.8	1.4	1.5	na	na	na	na
Moody's Analytics	5.0	3.8	na	na	3.1	0.6	3.5	4.4	7.6	3.1	2.4	3.2	na	na	10.9	8.5	na	na
Allianz	5.0	4.0	3.3	5.1	3.2	1.4	4.5	4.5	na	na	2.6	2.5	1.5	1.7	na	na	na	na
Bantleon Bank	5.0	5.1	3.2	6.2	3.5	1.8	3.4	4.0	7.5	8.0	2.5	2.8	1.4	1.8	11.9	11.5	na	na
Commerzbank	5.0	3.5	2.9	5.3	3.7	2.2	4.3	3.9	7.3	0.0	2.5	2.4	1.4	1.6	na	na	1.0	1.5
Deutsche Bank	5.0	4.0	na	na	na	na	na	na	na	na	2.6	3.0	1.5	2.0	na	na	na	na
Econ Intelligence Unit	5.0	4.2	3.5	5.1	3.5	1.6	8.2	7.7	7.0	3.6	2.3	2.3	na	na	10.6	5.2	na	na
Exane	5.0	4.0	3.2	5.4	3.1	1.8	3.6	5.1	na	na	2.5	2.7	1.4	1.7	na	na	na	na
FUNCAS	5.0	4.1	3.4	4.4	3.9	3.7	4.7	4.9	na	na	2.5	2.4	na	na	na	na	na	na
HSBC	5.0	4.0	3.5	5.8	3.6	1.4	4.4	4.8	7.9	3.2	2.5	2.6	na	na	na	na	na	na
IWH Halle Institute	5.0	4.6	3.3	6.7	3.4	1.6	4.3	4.1	8.0	2.1	2.3	2.0	na	na	na	na	1.2	3.0
JP Morgan	5.0	4.6	2.6	6.9	3.4	0.9	na	na	7.7	3.8	2.5	2.7	1.4	1.7	6.4	1.1	na	na
Zürcher Kantonalbank	5.0	3.6	3.0	5.1	3.5	1.9	5.0	4.0	7.4	4.0	2.6	2.5	1.5	1.8	12.0	8.8	1.8	2.9
Intesa Sanpaolo	5.0	3.9	3.4	5.4	3.2	0.8	4.4	5.3	7.3	2.5	2.6	2.7	1.5	1.6	11.8	12.6	1.2	2.6
Bank of America - Merrill	5.0	3.6	2.6	4.3	3.5	1.7	4.0	2.8	7.2	4.1	2.5	2.4	na	na	na	na	na	na
Oxford Economics	5.0	4.0	3.2	6.2	3.4	0.9	3.7	4.6	7.6	3.7	2.5	2.3	1.4	1.5	9.8	2.6	na	na
ETLA	4.5	4.4	4.2	4.3	2.0	1.0	6.0	5.0	6.0	4.0	2.5	2.2	na	na	na	na	na	na
Consensus (Mean)	5.1	4.2	3.2	5.4	3.4	1.6	4.4	4.4	7.4	3.4	2.5	2.6	1.4	1.8	10.4	7.1	1.6	2.9
Last Month's Mean	5.0	4.3	3.2	5.4	3.4	1.7	4.8	4.9	7.4	3.5	2.4	2.3	1.4	1.6	9.2	4.9	1.7	2.8
3 Months Ago	5.0	4.4	3.3	5.6	3.2	1.5	5.2	5.2	7.8	3.9	2.2	1.7	1.3	1.4	7.8	3.6	2.1	2.8
High	5.2	5.1	4.2	6.9	4.0	3.7	8.2	7.7	8.3	8.0	2.6	3.5	1.5	2.1	12.0	12.6	2.5	3.8
Low	4.5	3.4	2.5	4.1	2.0	0.0	3.4	2.8	6.0	0.0	2.3	2.0	1.3	1.3	6.4	1.1	1.0	1.5
Standard Deviation	0.1	0.4	0.4	0.8	0.4	0.8	0.9	0.9	0.5	1.7	0.1	0.3	0.0	0.2	1.8	3.8	0.5	0.8
Comparison Forecasts																		
Eur Commission (Nov. '21)	5.0	4.3	3.2	5.5	3.6	0.9	5.2	4.4			2.4	2.2						
ECB (Sep. '21)	5.0	4.6	3.6	7.0	3.4	-1.2	7.2	5.3			2.2	1.7						
IMF (Oct. '21)	5.0	4.3	3.2	5.9	3.3	0.3	5.2	4.9			2.2	1.7						
OECD (Dec. '21)	5.2	4.3	3.5	5.9	3.6	1.2	4.1	5.0			2.4	2.7	1.3	1.8				

European Monetary Union

Euro zone - The 19 European countries (listed at the top of this page) are united by a common currency (the euro), monetary policy and adherence to the Maastricht Treaty. **Monetary Policy** - is set by the European Central Bank's (ECB) governing board, headed by Christine Lagarde. **Nominal GDP -** Euro 11,318bn (2020). **Population -** 342.4mn (mid-year, 2020). **$/Euro** - 1.141 (average, 2020).

General Government Budget Balance – % of GDP



Historical Data

* % change on previous year	2017	2018	2019	2020
Gross Domestic Product*	2.8	1.8	1.6	-6.5
Private Consumption*	1.9	1.4	1.4	-8.0
Government Consumption*	1.1	1.0	1.8	1.3
Gross Fixed Capital Formation*	4.2	3.1	6.7	-7.3
Industrial Production*	3.0	0.8	-1.4	-8.4
Harmonised Consumer Prices (HICP)*	1.5	1.8	1.2	0.3
HICP ex. food, energy, alco. & tob.*	1.0	1.0	1.0	0.7
Industrial Producer Prices*	3.0	3.3	0.6	-2.6
Hourly Labour Costs – Total*	1.9	2.6	2.4	2.7
Unemployment Rate, (%)	9.1	8.2	7.6	7.9
Exports - Goods & Services*	6.0	3.6	2.7	-9.4
Imports - Goods & Services*	5.5	3.7	4.8	-9.3
Current Account, Euro bn	356	341	277	223
General Govt. Budget Balance (Maastricht definition), Euro bn	-104	-50.6	-77.1	-822
Money Supply, M3, end period*	4.7	4.2	4.9	12.2

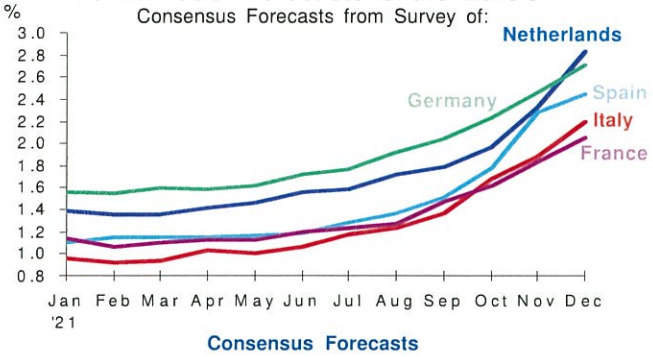
Year Average		Average % Change on Previous Calendar Year				Annual Total				Average % Change on Prev. Year	
Unemployment Rate (%)		Export of Goods & Services		Import of Goods & Services		Current Account (€ bn)		General Govt Budget Balance (Maastricht) (€ bn)		Money Supply, M3, end period	
2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022
7.8	7.0	9.9	6.8	7.5	6.2	332	339	-891	-521	na	na
7.8	7.5	10.3	9.0	8.7	9.2	na	na	na	na	na	na
7.8	7.4	10.3	6.5	7.7	6.4	na	na	na	na	na	na
8.0	7.9	9.6	5.9	7.1	6.0	232	261	-879	-496	na	na
7.8	7.4	na	na	na	na	na	na	na	na	na	na
7.7	7.5	9.6	5.9	7.2	5.3	na	na	na	na	na	na
7.8	7.6	9.6	4.7	7.2	4.6	455	435	-729	-459	6.6	4.5
7.5	7.1	9.7	4.4	7.1	4.4	na	na	-1046	-586	na	na
7.7	7.5	9.4	6.3	5.8	4.5	267	285	na	na	na	na
7.7	7.3	na	na	na	na	na	na	na	na	na	na
7.8	7.3	10.2	5.2	7.7	5.0	224	262	-671	-407	na	na
7.7	7.0	10.0	5.9	7.0	4.7	na	na	na	na	na	na
7.8	7.3	9.7	4.3	7.1	3.9	na	na	na	na	na	na
7.7	7.1	9.4	4.2	7.2	4.4	309	315	-861	-497	na	na
7.8	7.5	10.5	5.5	7.5	6.0	249	146	-878	-525	na	na
7.9	7.2	9.1	5.5	6.2	5.3	396	384	-842	-596	na	na
8.3	8.0	9.6	4.3	6.9	3.9	259	149	na	na	8.3	5.5
7.8	7.4	8.9	4.9	6.7	5.3	na	na	na	na	na	na
7.8	7.0	10.3	7.6	7.7	7.3	280	300	-900	-450	6.0	4.8
7.5	7.1	9.2	4.0	6.8	5.6	280	300	na	na	7.5	6.5
7.8	7.4	na	na	na	na	278	334	-922	-540	na	na
8.0	7.5	9.3	5.6	8.2	7.3	401	409	-889	-532	na	na
8.0	7.7	6.5	5.8	6.8	6.4	na	na	-860	-500	na	na
8.1	7.8	9.4	5.2	8.0	5.5	na	na	na	na	na	na
7.9	7.9	9.7	5.5	7.4	5.7	255	231	-798	-509	na	na
7.7	7.3	9.0	5.0	6.8	5.3	300	310	-840	-440	na	na
7.8	7.2	9.6	7.6	6.6	8.9	406	515	-769	-386	na	na
7.7	7.2	10.2	4.4	7.7	4.7	320	340	-830	-460	6.4	4.7
7.8	7.6	9.5	4.8	6.9	5.2	287	345	-809	-518	6.5	6.9
7.8	7.4	8.6	0.7	6.4	0.7	335	301	-865	-503	na	na
7.8	7.4	8.4	3.1	7.3	5.3	305	286	-723	-488	5.3	1.6
7.5	7.5	6.8	4.0	6.5	5.0	na	na	na	na	na	na
7.8	7.4	9.4	5.3	7.2	5.4	309	312	-842	-495	6.7	4.9
7.8	7.5	9.4	5.1	7.2	5.4	307	320	-847	-491	6.4	4.6
8.0	7.7	9.1	5.3	7.0	5.7	300	301	-868	-506	7.3	5.0
8.3	8.0	10.5	9.0	8.7	9.2	455	515	-671	-386	8.3	6.9
7.5	7.0	6.5	0.7	5.8	0.7	224	146	-1046	-596	5.3	1.6
0.2	0.3	0.9	1.5	0.6	1.6	63	86	83	54	1.0	1.7
7.9	7.5	9.7	7.3	8.2	7.2	380	409				
7.9	7.7	8.9	6.7	9.0	7.0						
8.0	8.1	9.3	6.6	7.2	6.9						
7.7	7.2							-821	-498		

Changes to 2023 GDP and CPI Consensus Forecasts

2023 Real GDP Growth:	**2.4**	**%**
last month's forecast:	2.2	%
2023 Consumer Price Inflation:	**1.5**	**%**
last month's forecast:	1.5	%

2022 Inflation Forecasts for the 'Euro 5'

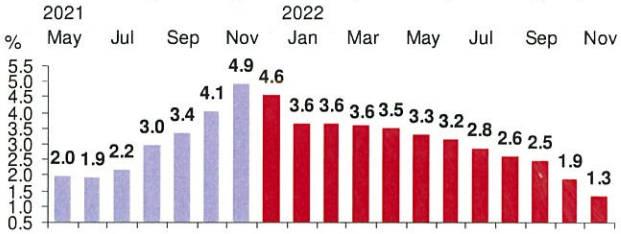
Consensus Forecasts from Survey of:



Dramatic Inflation Outturn in November

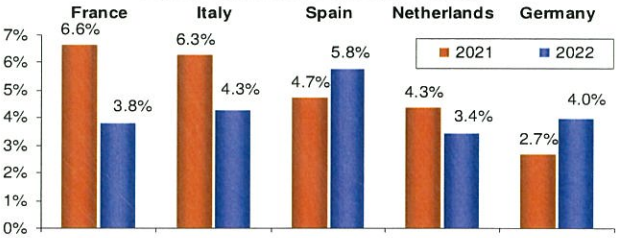
November harmonised inflation (HICP) for the Euro area hit 4.9% (y-o-y). It is worth noting that HICP for individual European countries shows higher rates of increase than the domestic CPI indices we survey for Germany, France, Italy, Netherlands, Spain and others, due to measure differences between Eurostat's HICP and local CPIs. The Eurostat HICP report showed stronger-than-average inflation in Belgium (7.1% y-o-y) and the Baltic states (on average 8.4%). German HICP hit 6.0%. Energy was by far the strongest contributor, surging 27.4% (y-o-y) as a result of the supply and price crunch in that sector. This has amplified pressure on the European Central Bank with regards to possible policy moves. Up until now, the ECB labelled price pressures as transitory and temporary, mindful of longtime disinflation pressures impacting activity. But now that the Fed has modified its tone regarding inflation (see page 5), the ECB is treading an even finer line between keeping inflation at bay while supporting a volatile economic and public health environment. Surging Covid cases, especially in Germany, and news of a new circulating variant are weighing on sentiment. Bundesbank chief Jens Weidmann is anxious to contain spiralling price pressures, especially if they lead to higher wage demands, although so far, wage pressures look to be modest. Headline and core inflation next year is expected to be even higher than in 2021.

Monthly HICP Inflation Outturns and y-o-y Consensus Forecasts (% change on same period of previous year)



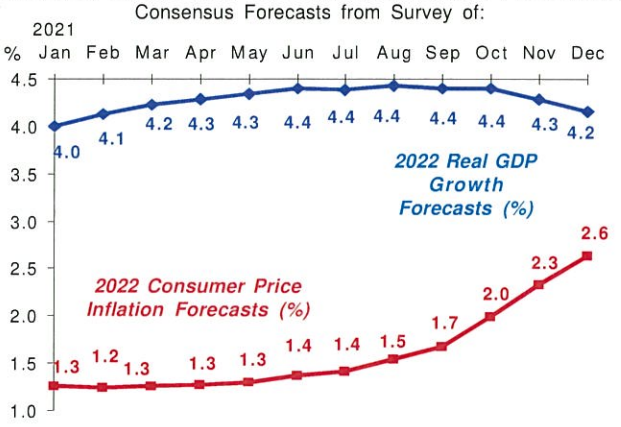
2021 and 2022 GDP Forecasts for the 'Euro 5'

Latest Consensus Forecasts Survey:



2022 Euro zone GDP Growth and Inflation Forecasts

Consensus Forecasts from Survey of:



	Average % Change on Previous Calendar Year												Annual Total				Rates on Survey Date			
	Gross Domestic Product		Private Consumption		Gross Fixed Investment		Manufacturing Production		Consumer Prices (CPI)		Hourly Wages (Manufacturing)		Current Account (€ bn)		General Govt Bud Balance (Maastricht) (€ bn)		-0.6%		-0.2%	
																	3 month Euro Rate (%)		10 Year Dutch Govt Bond Yield (%)	
Economic Forecasters	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	End Mar'22	End Dec'22	End Mar'22	End Dec'22
BNP Paribas	4.7	3.6	3.7	6.9	2.8	1.8	8.1	1.6	2.5	3.9	2.7	2.5	81.1	91.7	-45.0	-24.8	-0.6	-0.6	0.2	0.3
S&P Global Ratings	4.6	3.9	3.4	7.2	2.9	1.4	na	na	2.2	2.0	na	na	na	na	na	na	na	na	-0.2	0.2
Bank of America - Merrill	4.5	2.9	3.2	4.9	2.6	-0.9	4.9	3.9	2.3	2.2	na	na	84.5	77.8	-45.6	-21.7	na	na	na	na
Oxford Economics	4.5	3.5	3.4	6.3	2.8	2.5	na	na	2.6	3.2	3.3	3.7	92.9	98.3	-31.2	-22.3	-0.6	-0.5	0.0	0.3
Capital Economics	4.5	4.3	3.2	5.7	2.7	0.9	na	na	2.5	1.5	na	na	60.9	71.4	-38.0	-17.9	na	na	na	na
Rabobank Nederland	4.5	2.9	3.2	4.0	2.4	-0.3	na	na	2.5	3.5	na	na	na	na	na	na	-0.5	-0.4	-0.1	-0.1
Moody's Analytics	4.5	2.9	3.3	4.3	2.7	-0.7	na	na	2.5	3.9	na	na	90.8	91.7	-28.0	-8.4	-0.5	-0.6	-0.3	0.0
ING	4.4	3.6	3.2	5.1	2.5	1.3	7.5	2.5	2.6	2.7	2.2	2.4	87.0	80.7	-44.2	-23.5	-0.6	-0.5	0.0	0.3
FERI	4.4	3.6	3.4	5.7	3.4	4.3	9.1	5.0	2.5	3.6	2.2	2.3	73.4	77.3	-50.8	-16.6	-0.5	-0.4	0.0	0.2
ABN AMRO	4.4	3.8	3.1	5.7	2.5	-0.9	na	na	2.3	2.4	na	na	na	na	na	na	-0.6	-0.6	-0.2	-0.3
IHS Markit	4.2	3.3	1.9	3.4	4.8	2.5	6.1	0.7	na	na	na	na	100.1	92.3	-28.0	-8.8	-0.5	-0.5	0.4	0.7
Euromonitor Intl	4.0	3.3	2.7	4.7	4.7	2.3	na	na	2.2	2.0	na	na	82.2	81.9	-38.8	na	na	na	-0.4	-0.5
CPB	3.9	3.5	2.4	5.8	4.4	2.4	na	na	na	na	na	na	69.6	79.4	-45.6	-20.5	-0.5	-0.5	-0.3	-0.3
Econ Intelligence Unit	3.7	3.1	3.7	4.9	6.0	3.5	na	na	2.3	3.1	na	na	70.7	71.5	-42.9	-27.6	-0.5	-0.5	-0.3	0.0
Consensus (Mean)	4.3	3.4	3.1	5.3	3.4	1.4	7.1	2.7	2.4	2.8	2.6	2.7	81.2	83.1	-39.8	-19.2	-0.5	-0.5	-0.1	0.1
Last Month's Mean	4.2	3.4	2.8	5.1	4.7	2.4	7.4	2.8	2.2	2.3	2.5	2.7	79.1	82.0	-37.9	-19.6				
3 Months Ago	3.7	3.4	2.1	5.3	5.3	2.4	6.5	3.6	2.0	1.8	2.3	2.3	77.9	80.6	-37.9	-19.6				
High	4.7	4.3	3.7	7.2	6.0	4.3	9.1	5.0	2.6	3.9	3.3	3.7	100.1	98.3	-28.0	-8.4	-0.5	-0.4	0.4	0.7
Low	3.7	2.9	1.9	3.4	2.4	-0.9	4.9	0.7	2.2	1.5	2.2	2.3	60.9	71.4	-50.8	-27.6	-0.6	-0.6	-0.4	-0.5
Standard Deviation	0.3	0.4	0.5	1.1	1.1	1.6	1.6	1.7	0.2	0.8	0.6	0.6	11.6	9.0	7.8	6.4	0.0	0.1	0.2	0.3
Comparison Forecasts																				
DNB (Jun. '21)	3.0	3.7	0.5	7.2																
Eur Commission (Nov. '21)	4.0	3.3	2.7	5.8	4.0	2.6							71.9	80.2						
IMF (Oct. '21)	3.8	3.2							1.9	1.7					-51.8	-17.9				
OECD (Dec. '21)	4.3	3.2	2.8	4.9	2.3	2.0							72.7	80.4	-50.2	-24.6				

Changes to 2023 Consensus Forecasts

Real GDP Growth: **2.0** % (last month: 1.9 %)

Consumer Price Inflation: **1.8** % (last month: 1.7 %)

◈ After a 3.8% (q-o-q) surge in Q2, GDP climbed 1.9% in Q3, propelled by a 3.8% jump in consumption. Most sectors performed well amid the summer reopening and improving jobs market. Consumer confidence dived in November, though, as record Covid-19 transmission – resulting in fresh social distancing rules and shorter opening times for non-essential stores – threatens to overwhelm hospitals.

◈ Prices of manufactured products rose 20.2% (y-o-y) in October, driven by higher oil prices. At 5.2% (y-o-y) in November, meanwhile, consumer prices neared a 40-year high.

Real Growth and Inflation (2002-2026)

(% change over previous year)

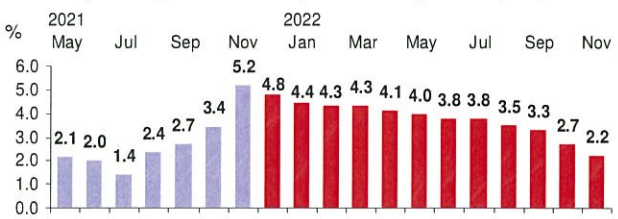
Historical Data

* % change on previous year	2017	2018	2019	2020
Gross Domestic Product*	2.9	2.4	2.0	-3.8
Private Consumption*	2.1	2.2	0.9	-6.6
Gross Fixed Investment*	4.2	3.6	6.2	-4.1
Manufacturing Production*	3.5	2.5	-0.7	-4.1
Consumer Prices (CPI)*	1.4	1.7	2.6	1.3
Hourly Wages (manufacturing)*	1.9	2.2	2.7	3.6
Current Account, transactions basis, Euro bn	79.9	83.9	76.2	55.8
General Govt. Budget Balance (Maastricht definition), **Euro bn**	9.7	11.1	14.0	-33.4
3 mth Euro, % (end yr)	-0.3	-0.3	-0.4	-0.5
10 Yr Dutch Govt Bond Yield, % (end yr)	0.5	0.4	-0.1	-0.5

Nominal GDP - Euro 800.1bn (2020). **Popn -** 17.1mn (mid-year, 2020). **$/Euro Exch. Rate -** 1.141 (average, 2020).

Monthly CPI Outturns and y-o-y Consensus Forecasts

(% change on the same period of the previous year)



	Average % Change on Previous Calendar Year												Annual Total				Rates on Survey Date			
	Gross Domestic Product (Mainland)		Private Consumption		Gross Fixed Investment		Manufacturing Production		Consumer Prices		Wages & Salaries		Current Account (Nkr bn)		General Govt Budget Balance (Nkr bn)		0.8%		1.4%	
																	3 month Interbank Rate (%)		10 Year Govt Bond Yield (%)	
Economic Forecasters	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**	**2021**	**2022**	End Mar'22	End Dec'22	End Mar'22	End Dec'22
HSBC	5.2	4.3	3.4	4.8	1.7	4.6	5.6	2.6	3.0	1.4	3.0	2.6	na	na	na	na	na	na	na	na
FERI	4.2	2.9	3.2	4.8	0.4	3.8	4.1	3.7	3.6	2.9	2.8	2.6	475	645	-165.4	36.0	1.0	1.5	1.8	2.0
Citigroup	4.2	4.3	4.2	7.2	0.6	3.3	na	na	3.2	2.2	na	na	227	231	na	na	na	na	1.9	2.1
Oxford Economics	4.1	4.3	4.0	6.0	-0.2	2.6	3.7	3.2	3.4	1.7	3.8	2.8	620	463	67.4	1.8	0.9	1.5	1.8	2.0
Statistics Norway	4.1	4.1	4.2	8.5	0.4	3.5	3.7	4.4	3.4	2.6	na	na	497	590	na	na	1.0	1.4	na	na
Capital Economics	4.0	3.6	4.1	5.5	0.0	2.3	na	na	3.5	3.5	na	na	na	na	-93.1	32.2	na	na	na	na
Swedbank	3.9	3.6	4.1	7.5	2.0	2.0	na	na	3.2	2.0	3.1	3.3	na	na	na	na	na	na	na	na
NHO Conf Nor Enterprise	3.8	3.4	4.4	7.8	1.2	3.0	na	na	na	1.8	na	na	na	na	na	na	na	na	na	na
Goldman Sachs	3.6	4.0	na	na	na	na	3.7	-0.5	3.3	1.5	na	na	na	na	na	na	na	na	1.7	1.8
Consensus (Mean)	4.1	3.8	4.0	6.5	0.8	3.1	4.2	2.7	3.3	2.2	3.2	2.8	455	482	-63.7	23.3	1.0	1.5	1.8	2.0
Last Month's Mean	3.8	3.9	3.7	6.9	0.9	3.1	4.3	2.9	3.2	1.8	3.2	2.7	318	308	60.0	49.7				
3 Months Ago	3.9	3.8	4.0	6.9	0.7	3.1	4.0	3.9	2.9	1.8	3.1	2.6	279	270	40.0	55.0				
High	5.2	4.3	4.4	8.5	2.0	4.6	5.6	4.4	3.6	3.5	3.8	3.3	620	645	67.4	36.0	1.0	1.5	1.9	2.1
Low	3.6	2.9	3.2	4.8	-0.2	2.0	3.7	-0.5	3.0	1.4	2.8	2.6	227	231	-165.4	1.8	0.9	1.4	1.7	1.8
Standard Deviation	0.5	0.5	0.4	1.4	0.8	0.8	0.8	1.9	0.2	0.7	0.4	0.3	165	184	119.1	18.8	0.0	0.1	0.1	0.1
Comparison Forecasts																				
Bank of Norway (Sep. '21)	3.9	4.5	3.6	9.6					3.2	1.5										
Min. of Finance (Oct. '21)	3.9	3.8																		
OECD (Dec. '21)	4.2	4.2	4.4	7.9	0.3	4.3			3.4	2.0			494	645	-97.9	-29.2				

Changes to 2023 Consensus Forecasts

Real GDP Growth: **2.0** % (last month: 1.9 %)

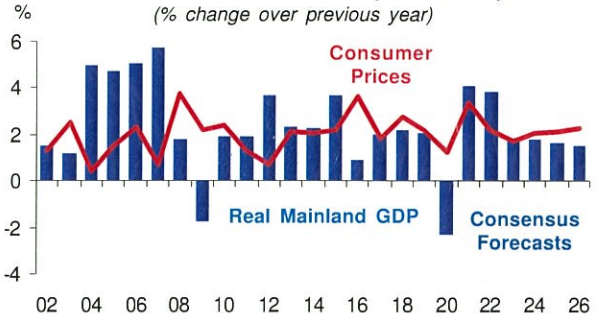
Consumer Price Inflation: **1.8** % (last month: 1.7 %)

- GDP growth raced up 2.6% (q-o-q) in Q3, from 1.1% in Q2, boosted by consumer spending which supported an output rebound in services. Government expenditure and exports also spurred the expansion. Sharp rises in natural gas prices contributed to a massive Nkr 129.7bn trade surplus in Q3, which in turn, led to a record current account surplus. Elsewhere, employment increased by an impressive 2.2% compared to Q2.

- While investor morale has been rocked by the omicron variant and weighed on oil prices, the Norges Bank is likely to proceed with a planned rate hike this month.

Real Growth and Inflation (2002-2026)

(% change over previous year)



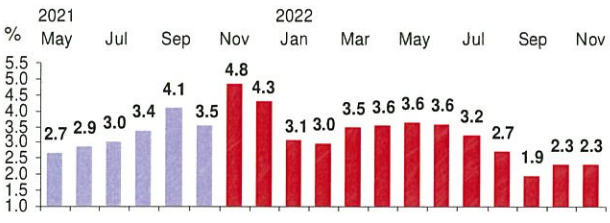
Historical Data

* % change on previous year	2017	2018	2019	2020
GDP (Mainland)*	2.0	2.2	2.0	-2.3
Private Consumption*	2.2	1.6	1.1	-6.6
Gross Fixed Investment*	2.6	2.2	9.5	-5.6
Manufacturing Production*	0.4	1.6	2.7	-3.1
Consumer Prices*	1.8	2.7	2.2	1.3
Wages & Salaries per Full-Time Employee (Total)*	3.0	3.0	3.5	2.7
Current Account, Nkr bn	180	283	102	67.2
General Govt. Bud Bal, Nkr bn	165	280	236	-115
3 mth Interbank Rate, % (end year)	0.8	1.3	1.8	0.5
10 Yr Govt Bond Yield, % (end year)	1.6	1.7	1.5	0.9

Nominal GDP (total) - Nkr 3,413bn (2020). **Population -** 5.4mn (mid-yr, 2020). **Nkr/$ Exchange Rate -** 9.398 (average, 2020).

Monthly CPI Outturns and y-o-y Consensus Forecasts

(% change on the same period of the previous year)



	Average % Change on Previous Calendar Year												Annual Total				Rates on Survey Date			
	Gross Domestic Product		House-hold Con-sumption		Gross Fixed Invest-ment		Industrial Produc-tion		Con-sumer Prices (CPI)		Salary Cost per Hour		Current Account (€ bn)		General Govt Bud Balance (Maastricht) (€ bn)		-0.6% 3 month Euro Rate (%)		0.3% 10 Year Spanish Govt Bond Yield (%)	
Economic Forecasters	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	End Mar'22	End Dec'22	End Mar'22	End Dec'22
Fitch Ratings	6.3	6.4	9.3	5.2	5.0	5.6	na	na	na	na	na	na	2.4	2.1	-104.0	-70.8	na	na	na	na
Econ Intelligence Unit	5.5	5.8	6.9	6.2	4.5	7.5	8.0	4.0	2.5	1.9	na	na	10.9	19.1	-107.8	-75.1	-0.5	-0.5	0.7	0.8
BBVA	5.2	5.5	7.1	6.4	2.2	12.3	na	na	2.6	1.8	na	na	8.5	-2.7	-83.9	-68.2	-0.5	-0.5	0.8	1.3
CEPREDE	5.2	6.7	4.6	5.0	5.3	8.2	8.2	2.7	3.1	2.1	-0.4	1.0	13.8	20.2	-89.2	-67.7	-0.2	0.1	0.8	1.2
Euromonitor Intl	5.2	6.2	6.7	6.1	3.4	8.4	8.4	5.4	2.9	2.2	na	na	14.8	20.8	na	na	na	na	0.3	0.3
FUNCAS	5.1	6.0	5.0	5.5	4.7	8.6	7.2	1.7	3.0	2.8	na	na	6.5	21.6	-94.5	-77.0	-0.6	-0.5	0.6	0.8
Inst. Klein-G. (UAM)	5.1	6.0	6.0	5.2	4.5	8.2	na	na	3.0	2.1	na	na	13.5	19.0	-97.5	-78.8	-0.5	-0.5	0.7	0.9
CEOE	4.8	5.0	4.4	5.9	3.7	4.5	na	na	3.0	2.3	na	na	14.3	18.9	-95.4	-78.4	-0.4	-0.3	na	na
Natixis	4.7	6.2	4.5	4.9	3.3	2.3	na	na	2.8	1.2	na	na	na	na	na	na	na	na	na	na
Repsol	4.7	5.2	5.3	3.3	4.4	6.0	7.0	3.9	3.0	2.4	0.2	1.8	11.3	13.5	-89.0	-64.2	-0.5	-0.4	0.7	0.9
Bank of America - Merrill	4.6	6.0	4.6	5.6	3.5	5.2	7.1	2.4	2.9	2.7	na	na	7.7	7.3	-99.3	-76.6	na	na	na	na
Grupo Santander	4.6	5.8	4.5	4.0	4.0	10.6	na	na	3.0	3.3	na	na	na	na	na	na	-0.5	-0.5	na	na
UBS	4.6	6.1	4.6	5.1	3.9	5.9	na	na	na	na	na	na	10.7	19.2	na	na	-0.5	-0.5	na	na
AFI	4.5	6.0	6.2	4.9	3.6	8.2	na	na	2.8	2.1	na	na	12.0	18.0	-88.6	-54.9	-0.5	-0.4	0.7	1.1
Capital Economics	4.5	6.5	4.8	6.2	3.4	4.9	na	na	3.0	3.5	na	na	8.4	35.6	-100.2	-71.2	na	na	na	na
Societe Generale	4.5	4.9	4.3	5.9	3.5	5.4	na	na	3.0	3.1	na	na	16.4	28.3	-103.6	-76.1	na	na	na	na
S&P Global Ratings	4.5	7.0	4.5	7.3	3.8	8.7	na	na	2.8	2.2	na	na	na	na	na	na	na	na	0.5	0.9
Goldman Sachs	4.5	6.4	4.5	5.4	3.5	9.2	na	na	na	na	na	na	na	na	-119.5	-72.1	na	na	na	na
La Caixa	4.4	5.9	4.6	5.7	3.6	7.1	7.9	2.6	2.9	2.6	0.0	0.9	18.6	20.7	-91.9	-68.0	-0.5	-0.5	0.5	0.6
HSBC	4.4	5.6	4.4	4.9	3.7	6.9	7.2	1.9	2.9	3.4	na	na	5.7	15.1	-97.3	-74.3	na	na	na	na
Oxford Economics	4.4	5.4	4.3	5.3	3.5	8.2	7.1	2.6	3.0	2.5	2.2	3.0	12.1	19.0	-86.3	-67.0	-0.6	-0.5	0.6	1.1
Moody's Analytics	4.4	5.6	4.4	6.9	3.2	6.3	7.1	3.8	2.9	3.2	na	na	9.8	-6.5	-86.6	-82.6	-0.5	-0.6	0.3	0.6
Citigroup	4.3	4.9	5.3	4.0	4.6	7.1	na	na	2.9	3.1	na	na	8.5	20.6	-104.2	-77.5	na	na	0.7	0.7
Barclays	4.3	4.7	4.3	3.8	3.4	5.2	na	na	2.9	2.7	na	na	na	na	na	na	na	na	na	na
IHS Markit	4.3	4.1	4.3	3.3	3.4	4.2	7.1	1.7	na	na	na	na	19.6	18.3	-82.8	-71.6	-0.5	-0.5	1.1	1.6
Consensus (Mean)	4.7	5.8	5.2	5.3	3.8	7.0	7.5	3.0	2.9	2.5	0.5	1.7	11.3	16.4	-95.9	-72.2	-0.5	-0.4	0.6	0.9
Last Month's Mean	5.0	5.9	5.9	5.6	4.3	7.8	8.0	3.2	2.8	2.3	0.3	1.5	10.2	13.9	-96.7	-71.7				
3 Months Ago	6.1	6.0	8.2	5.7	6.2	8.8	8.3	3.7	2.3	1.5	1.5	1.4	9.1	14.5	-99.4	-73.1				
High	6.3	7.0	9.3	7.3	5.3	12.3	8.4	5.4	3.1	3.5	2.2	3.0	19.6	35.6	-82.8	-54.9	-0.2	0.1	1.1	1.6
Low	4.3	4.1	4.3	3.3	2.2	2.3	7.0	1.7	2.5	1.2	-0.4	0.9	2.4	-6.5	-119.5	-82.6	-0.6	-0.6	0.3	0.3
Standard Deviation	0.5	0.7	1.2	1.0	0.7	2.2	0.5	1.2	0.1	0.6	1.2	1.0	4.3	9.8	9.4	6.4	0.1	0.2	0.2	0.3
Comparison Forecasts											Changes to 2023 Consensus Forecasts									
Banco de Espana (Sep. '21)	6.3	5.9	9.6	4.3	5.8	10.5					Real GDP Growth:				3.5 % (last month: 3.2 %)					
Government (Oct. '21)	6.5	7.0	8.0	6.9	7.2	12.3					Consumer Price Inflation:				1.3 % (last month: 1.4 %)					
Eur Commission (Nov. '21)	4.6	5.5	4.8	5.2	3.7	7.4														
IMF (Oct. '21)	5.7	6.4	5.9	5.1	6.4	9.9			2.2	1.6					-104.0	-65.3				
OECD (Dec. '21)	4.5	5.5	4.4	4.5	3.8	8.1							7.2	12.8	-96.7	-69.4				

- A disappointing economic performance over the summer held back the growth rebound, meaning that 2021 GDP may recover less than half of the -10.8% output loss seen in 2020. Soaring inflation, which accelerated to 5.6% in November, high transmission of Covid-19 and supply shortages are all exposing the economy to greater risks and delaying a return to pre-crisis norms.

- The absorption of EU recovery funds next year could help to partly offset the aforementioned headwinds, as could a more robust labour market as labour ministry figures showed unemployment falling again in November.

Real Growth and Inflation (2002-2026)

(% change over previous year)

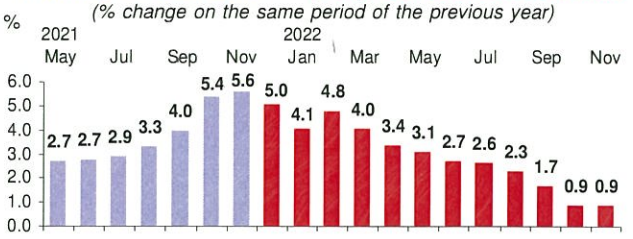
Historical Data

* % change on previous year	2017	2018	2019	2020
Gross Domestic Product*	3.0	2.3	2.1	-10.8
Household Consumption*	3.0	1.8	0.9	-12.2
Gross Fixed Investment*	6.8	6.3	4.5	-9.5
Industrial Production*	2.9	0.7	0.7	-9.2
Consumer Prices (CPI)*	2.0	1.7	0.7	-0.3
Salary Cost per Hour*	0.1	1.2	2.2	6.0
Current Account, Euro bn	32.2	23.2	26.6	7.7
General Govt. Budget Balance (Maastricht definition), Euro bn	-35.3	-30.0	-35.8	-122.9
3 mth Euro, % (end yr)	-0.3	-0.3	-0.4	-0.5
10 Yr Spanish Govt Bond Yield, % (end yr)	1.5	1.4	0.5	0.0

Nominal GDP - Euro 1,120bn (2020). **Popn -** 46.8mn (mid-year, 2020). **$/Euro Exch. Rate -** 1.141 (average, 2020).

Monthly CPI Outturns and y-o-y Consensus Forecasts

(% change on the same period of the previous year)



	Average % Change on Previous Calendar Year												Annual Total				Rates on Survey Date			
	Gross Domestic Product		House-hold Con-sumption		Gross Fixed Invest-ment		Mining & Manu-facturing Produc-tion		Con-sumer Prices (CPI)		Hourly Earnings (Mining & Manuf.)		Current Account (SEK bn)		General Govt Budget Balance (SEK bn)		-0.1%		0.1%	
																	3 month Interbank Rate (%)		10 Year Govt Bond Yield (%)	
Economic Forecasters	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	End Mar'22	End Dec'22	End Mar'22	End Dec'22
HSBC	6.0	4.1	5.3	3.6	7.8	5.8	8.1	2.1	1.8	1.9	2.0	1.5	na	na	na	na	na	na	na	na
National Institute - NIER	4.7	3.9	4.9	4.7	5.8	4.8	8.0	4.1	2.1	2.0	2.7	2.4	311	268	-51.0	2.0	na	na	0.4	0.7
Oxford Economics	4.7	3.2	5.4	4.2	6.5	3.6	7.4	3.4	2.1	2.2	na	na	278	255	-71.3	-43.2	0.0	0.1	0.3	0.6
SE Banken	4.6	3.6	4.7	3.7	6.0	7.0	na	na	2.0	2.5	na	na	na	na	na	na	-0.1	-0.1	0.4	0.5
Moody's Analytics	4.6	3.2	na	na	6.5	4.2	na	na	2.1	2.1	na	na	260	245	-37.6	23.1	0.0	0.1	0.2	0.3
Svenska Handelsbanken	4.5	3.8	4.8	5.1	5.7	4.9	na	na	2.1	2.3	na	na	na	na	-73.0	0.0	0.0	-0.1	0.4	0.5
Swedbank	4.4	3.3	4.4	4.0	5.9	4.2	na	na	2.0	2.4	na	na	na	na	na	na	na	na	na	na
Citigroup	4.2	3.9	3.9	2.8	5.8	5.4	na	na	2.3	2.8	na	na	237	190	-141.6	-47.4	na	na	0.3	0.6
Euromonitor Intl	4.2	3.5	4.4	4.1	5.3	4.5	na	na	1.9	1.7	na	na	308	292	-122.9	na	na	na	0.3	0.3
Goldman Sachs	4.2	3.5	na	na	na	na	9.2	3.0	2.3	2.3	na	na	na	na	na	na	na	na	0.7	1.2
Econ Intelligence Unit	4.1	2.8	3.9	2.8	3.5	2.8	8.0	3.1	2.2	2.0	na	na	252	230	-97.1	-35.5	0.1	0.2	0.4	0.5
IHS Markit	4.1	3.5	4.0	3.6	6.2	4.2	na	na	na	na	na	na	270	197	-85.8	-77.1	-0.1	-0.1	0.6	0.8
Capital Economics	3.5	2.5	3.7	3.0	5.8	3.8	na	na	2.3	1.5	na	na	309	290	-128.9	-52.8	na	na	na	na
Consensus (Mean)	4.4	3.5	4.5	3.8	5.9	4.6	8.1	3.1	2.1	2.1	2.4	2.0	278	246	-89.9	-28.9	0.0	0.0	0.4	0.6
Last Month's Mean	4.4	3.5	4.2	4.0	5.3	4.4	8.4	3.1	2.0	1.9	2.4	2.0	299	303	-96.4	-32.6				
3 Months Ago	4.3	3.5	4.2	3.9	3.9	4.3	8.4	2.7	1.8	1.6	2.6	2.0	297	302	-112.6	-39.3				
High	6.0	4.1	5.4	5.1	7.8	7.0	9.2	4.1	2.3	2.8	2.7	2.4	311	292	-37.6	23.1	0.1	0.2	0.7	1.2
Low	3.5	2.5	3.7	2.8	3.5	2.8	7.4	2.1	1.8	1.5	2.0	1.5	237	190	-141.6	-77.1	-0.1	-0.1	0.2	0.3
Standard Deviation	0.6	0.4	0.6	0.7	1.0	1.1	0.7	0.7	0.2	0.4	0.5	0.6	29	39	35.8	33.7	0.1	0.1	0.1	0.3
Comparison Forecasts																				
Riksbank (Nov. '21)	4.7	3.8	4.8	4.8	6.3	3.1			2.1	2.3										
Government (Sep. '21)	4.4	3.5	4.2	4.9	2.4	3.6			1.6	1.4										
Eur Commission (Nov. '21)	3.9	3.5	3.7	3.5	6.1	6.1														
IMF (Oct. '21)	4.0	3.4							2.0	1.6					-139.0	-46.7				
OECD (Dec. '21)	4.3	3.4	4.5	4.2	6.2	5.6			2.0	2.6			334	353	-68.5	-8.9				

Changes to 2023 Consensus Forecasts

Real GDP Growth: **2.1** % (last month: 2.1 %)

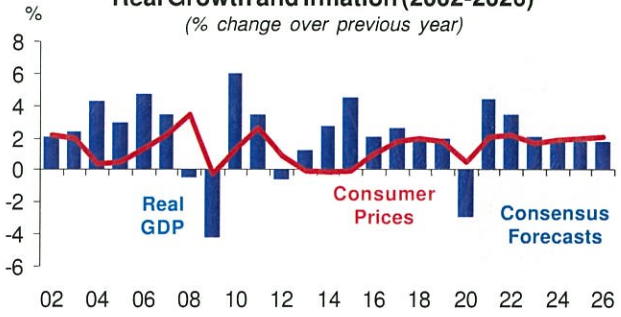
Consumer Price Inflation: **1.7** % (last month: 1.6 %)

- GDP growth accelerated 2.0% (q-o-q) in Q3, building on the 1.2% (Q1) and 1.0% (Q2) expansions. This marked a fifth straight positive quarterly GDP outturn, underpinned by consumption and investment. Having contracted -2.9% in 2020, the economy has recaptured pre-crisis levels of GDP, supported by upbeat developments in manufacturing and services. Sweden has introduced Covid passes for large indoor gatherings, but has maintained few curbs on everyday freedoms despite virus cases edging higher.

- Employed numbers jumped in Q3 as firms' output recovered and improved business conditions fuelled demand for labour.

Real Growth and Inflation (2002-2026)

(% change over previous year)



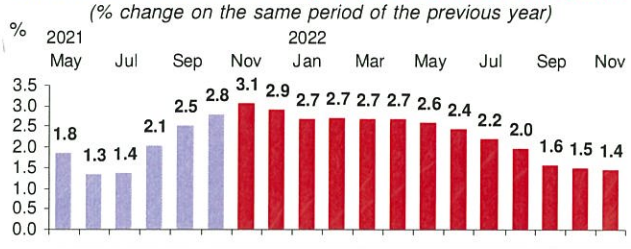
Historical Data

* % change on previous year	2017	2018	2019	2020
Gross Domestic Product*	2.6	2.0	2.0	-2.9
Household Consumption*	2.6	1.8	0.7	-4.7
Gross Fixed Investment*	5.5	1.4	-0.3	-0.3
Min. & Manufacturing Prodn*	4.1	2.8	2.0	-3.9
Consumer Prices (CPI)*	1.8	2.0	1.8	0.5
Average Hourly Earnings (Mining & Manufacturing)*	2.0	2.9	2.4	1.1
Current Account, Skr bn	137	127	276	284
General Govt. Bud Bal, Skr bn	65.8	39.5	28.5	-141
3 mth Interbank Rate, % (end yr)	-0.5	-0.1	0.1	0.0
10 Yr Govt Bond Yield, % (end yr)	0.8	0.5	0.2	0.0

Nominal GDP - Skr 4,952bn (2020). **Population** - 10.1mn (mid-year, 2020). **Skr/$ Exchange Rate** - 9.193 (average, 2020).

Monthly CPI Outturns and y-o-y Consensus Forecasts

(% change on the same period of the previous year)



	Average % Change on Previous Calendar Year										Annual Total						Rates on Survey Date			
	Gross Domestic Product		Private Consump-tion		Gross Fixed Invest-ment		Industrial Produc-tion		Con-sumer Prices		Merchan-dise Exports (SwFr bn)		Current Account (SwFr bn)		General Govt Budget Balance (SwFr bn)		-0.8% 3 month Euro-Franc Rate (%)		-0.3% 10 Year Govt Bond Yield (%)	
Economic Forecasters	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	2021	2022	End Mar'22	End Dec'22	End Mar'22	End Dec'22
Credit Suisse	4.0	2.5	3.1	2.5	na	na	na	na	0.5	0.5	na	na	na	na	na	na	-0.8	-0.8	na	na
Zürcher Kantonalbank	4.0	3.0	2.8	3.3	2.9	2.0	8.0	6.5	0.6	1.0	251	261	21.4	38.1	-21.9	-3.1	-0.7	-0.7	-0.1	0.1
Bank Julius Baer	3.6	3.6	2.6	4.2	3.1	4.3	10.3	2.3	0.6	0.7	na	na	na	na	na	na	-0.7	-0.7	0.0	0.1
Bantleon Bank	3.6	2.8	2.6	4.3	2.9	1.5	na	na	0.6	1.0	na	na	na	na	na	na	-0.7	-0.7	na	na
Econ Intelligence Unit	3.6	3.0	2.6	3.3	2.5	2.0	7.0	4.8	0.5	0.9	249	262	38.7	41.7	-27.2	0.7	-0.7	-0.8	-0.1	-0.1
Pictet & Cie	3.6	2.6	na	na	na	na	na	na	0.6	0.8	na	na	na	na	na	na	-0.7	-0.7	-0.2	0.1
Moody's Analytics	3.6	2.8	2.6	3.7	2.7	0.4	9.6	4.5	0.6	1.4	na	na	na	na	na	na	na	na	-0.3	-0.2
Fitch Ratings	3.6	3.4	3.4	4.5	3.8	3.0	na	na	0.6	0.6	na	na	na	na	na	na	na	na	na	na
Allianz	3.5	3.0	3.0	3.5	4.0	3.5	na	na	0.5	0.8	na	na	na	na	na	na	-0.7	-0.7	-0.2	-0.1
Capital Economics	3.5	3.0	2.6	4.0	3.0	2.4	na	na	0.5	0.3	na	na	44.3	57.0	-11.1	-3.8	na	na	na	na
Luzerner Kantonalbank	3.5	3.3	2.5	4.2	2.9	2.2	na	na	0.5	0.7	na	na	na	na	na	na	-0.7	-0.7	-0.1	0.1
Swiss Life Asset Mgrs	3.5	2.3	2.7	3.4	3.1	2.2	9.3	2.4	0.6	0.8	na	na	na	na	na	na	-0.7	-0.7	-0.2	-0.2
UBS	3.5	2.9	2.6	3.5	2.9	1.8	na	na	0.6	0.8	na	na	na	na	na	na	-0.8	-0.8	-0.1	-0.1
IHS Markit	3.5	3.3	2.2	3.4	3.7	3.5	9.4	1.7	0.6	1.2	245	262	57.9	74.6	-18.2	-6.6	-0.8	-0.8	0.2	0.3
Oxford - BAK	3.5	3.1	2.5	4.1	2.8	3.6	9.9	3.4	0.5	0.7	na	na	46.3	71.6	-17.2	0.1	-0.8	-0.8	-0.1	0.1
WPuls	3.4	2.8	3.4	3.0	3.3	2.2	na	na	0.5	0.6	252	265	na	na	na	na	na	na	na	na
S&P Global Ratings	3.3	3.3	3.0	4.7	4.0	3.5	na	na	0.5	0.7	na	na	na	na	na	na	na	na	-0.1	0.2
KOF Swiss Econ Inst	3.2	3.6	2.8	6.2	3.5	2.3	na	na	0.5	0.6	256	277	na	na	-16.1	2.5	-0.7	-0.7	-0.4	-0.3
HSBC	3.2	2.8	2.2	3.3	4.2	4.3	9.8	3.6	0.5	0.4	na	na	54.4	52.9	-7.0	0.5	-0.7	-0.7	-0.2	-0.1
Citigroup	3.2	2.5	2.5	3.5	3.8	2.5	na	na	0.6	1.2	na	na	40.7	40.0	na	na	-0.8	-0.8	-0.1	0.1
Goldman Sachs	2.7	3.3	na	na	na	na	9.3	5.5	0.5	0.8	na	na	na	na	-28.1	0.0	-0.8	-0.8	-0.1	0.1
Consensus (Mean)	3.5	3.0	2.7	3.8	3.3	2.6	9.2	3.9	0.5	0.8	251	265	43.4	53.7	-18.4	-1.2	-0.7	-0.7	-0.1	0.0
Last Month's Mean	3.4	3.0	2.7	3.8	3.7	3.0	9.9	4.0	0.5	0.7	250	265	42.1	48.7	-18.1	-0.7				
3 Months Ago	3.5	3.0	2.9	3.7	3.8	3.1	10.0	3.7	0.5	0.6	249	261	53.6	58.0	-20.7	-2.9				
High	4.0	3.6	3.4	6.2	4.2	4.3	10.3	6.5	0.6	1.4	256	277	57.9	74.6	-7.0	2.5	-0.7	-0.7	0.2	0.3
Low	2.7	2.3	2.2	2.5	2.5	0.4	7.0	1.7	0.5	0.3	245	261	21.4	38.1	-28.1	-6.6	-0.8	-0.8	-0.4	-0.3
Standard Deviation	0.3	0.4	0.3	0.8	0.5	1.0	1.0	1.6	0.0	0.3	4	7	11.9	15.0	7.3	3.0	0.0	0.0	0.1	0.2
Comparison Forecasts																				
IMF (Oct. '21)	3.7	3.0							0.4	0.6										
SECO (Sep. '21)	3.4	3.6	2.6	4.2	3.5	2.9			0.5	0.8										
OECD (Dec. '21)	2.9	3.0	1.7	3.8	4.8	3.6			0.6	1.0										

Changes to 2023 Consensus Forecasts

Real GDP Growth: **1.9** % (last month: 1.8 %)

Consumer Price Inflation: **0.5** % (last month: 0.5 %)

- The economy could soften in the final months of 2021 amid tighter Covid-related measures domestically and abroad, in addition to production delays caused by supply chain blockages. Still, GDP growth advanced by 1.7% (q-o-q) in Q3, from 1.8% in Q2, on the back of rising consumer spending. The energy price crunch has been contained so far and had only a modest impact on household bills, partly due to less dependence on imported gas and oil.

- Safe haven demand – reignited by a surge in the spread of Covid-19 – pushed the Swiss franc to a six-year high against the euro.

Real Growth and Inflation (2002-2026)

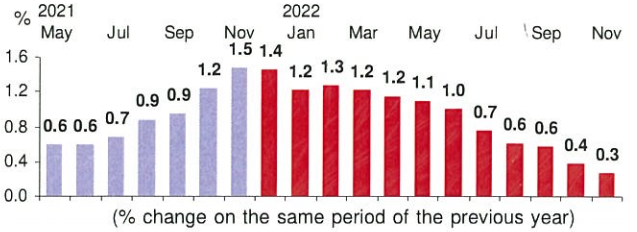
(% change over previous year)

Historical Data

* % change on previous year	2017	2018	2019	2020	
Gross Domestic Product*	1.6	2.9	1.2	-2.4	
Private Consumption*	1.2	0.7	1.4	-3.7	
Gross Fixed Investment*	3.6	1.3	0.6	-1.8	
Industrial Production*	5.4	5.9	4.4	-3.2	
Consumer Prices*	0.5	0.9	0.4	-0.7	
Merch Exports, SwFr bn	221	233	242	225	
Current Account, SwFr bn	41.3	38.5	36.0	8.5	
General Govt. Bud. Bal. SwFr bn	5.4	8.1	2.6	-15.4	e
3 mth Euro-Franc Rate, % (end yr)	-0.8	-0.8	-0.9	-0.7	
10 Yr Govt Bond Yield, % (end yr)	-0.1	-0.2	-0.5	-0.5	

e = consensus estimate based on latest survey **Nominal GDP** - SwFr 703bn (2020). **Population** - 8.7mn (mid-year, 2020). **SwFr/$ Exchange Rate** - 0.938 (average, 2020).

Monthly CPI Outturns and y-o-y Consensus Forecasts



(% change on the same period of the previous year)

Forecasts for the countries in Western Europe, the Middle East and Africa shown on the next two pages were provided by the following leading economic forecasters, among others:

Akava Works
Bank Leumi
Capital Economics
Economist Intelligence Unit
Fitch Ratings
Handelsbanken
Nedbank
Allianz
Bank of America Merrill
Citigroup
ETLA
Forecaster ECOSA
IHS Markit
Oxford Economics
Universidade Catolica Portuguesa
Banco BPI
Barclays
Danske Bank
Euromonitor
Goldman Sachs
Moody's Analytics
S&P Global Ratings

AUSTRIA

Population - 9.0mn (2020, mid-year)

Nominal GDP - US$428.3bn (2020)

	Historical Data				Consensus Forecasts	
	2017	2018	2019	2020	2021	2022
Gross Domestic Product *(% change on previous year)*	2.3	2.5	1.5	-6.7	**4.6**	**4.0**
Industrial Production *(% change on previous year)*	5.1	4.7	0.4	-6.0	**9.3**	**3.5**
Consumer Prices *(% change on previous year)*	2.1	2.0	1.5	1.4	**2.7**	**2.5**
Current Account *(US Dollar bn)*	5.7	4.1	9.3	8.2	**1.7**	**5.6**

BELGIUM

Population - 11.6mn (2020, mid-year)

Nominal GDP - US$512.8bn (2020)

	Historical Data				Consensus Forecasts	
	2017	2018	2019	2020	2021	2022
Gross Domestic Product *(% change on previous year)*	1.6	1.8	1.8	-6.3	**5.9**	**3.1**
Industrial Production *(% change on previous year)*	2.6	1.4	4.8	-3.5	**15.5**	**1.5**
Consumer Prices *(% change on previous year)*	2.1	2.1	1.4	0.7	**2.3**	**2.2**
Current Account *(US Dollar bn)*	3.5	-4.5	0.9	4.4	**9.6**	**1.8**

DENMARK

Population - 5.8mn (2020, mid-year)

Nominal GDP - US$356.1bn (2020)

	Historical Data				Consensus Forecasts	
	2017	2018	2019	2020	2021	2022
Gross Domestic Product *(% change on previous year)*	2.8	2.0	2.1	-2.1	**3.7**	**3.0**
Manufacturing Production *(% change on previous year)*	2.8	4.0	4.3	-3.7	**7.4**	**3.9**
Consumer Prices *(% change on previous year)*	1.1	0.8	0.8	0.4	**1.7**	**1.7**
Current Account *(US Dollar bn)*	26.6	26.0	30.6	29.0	**28.9**	**29.0**
					Mar '22	Dec '22
3 month Interbank Rate, *End period %*	-0.3	-0.3	-0.4	-0.2	**-0.3**	**-0.3**

EGYPT

Population - 102.3mn (2020, mid-year)

Nominal GDP - US$369.3bn (2020)[1]

	Historical Data				Consensus Forecasts	
	2017	2018	2019	2020	2021	2022
Gross Domestic Product *(% change on previous year)*[1]	4.2	5.3	5.6	3.6	**3.3**[2]	**5.0**
Industrial Production *(% change on previous year)*	7.1	3.1	1.7	-10.1	**6.5**	**6.4**
Consumer Prices *(% change on previous year)*	29.6	14.4	9.4	5.1	**5.3**	**6.8**
Current Account *(US Dollar bn)*	-7.9	-7.7	-10.2	-14.2	**-17.3**	**-16.2**

[1] *year(s) ending June 30* [2] *Actual outturn*

FINLAND

Population - 5.5mn (2020, mid-year)

Nominal GDP - US$270.8bn (2020)

	Historical Data				Consensus Forecasts	
	2017	2018	2019	2020	2021	2022
Gross Domestic Product *(% change on previous year)*	3.2	1.1	1.3	-2.9	**3.4**	**2.7**
Industrial Production *(% change on previous year)*	3.2	3.5	1.6	-2.9	**3.4**	**2.9**
Consumer Prices *(% change on previous year)*	0.7	1.1	1.0	0.3	**2.0**	**1.9**
Current Account *(US Dollar bn)*	-2.0	-5.1	-0.8	2.1	**1.5**	**-0.1**

GREECE

Population - 10.4mn (2020, mid-year)

Nominal GDP - US$189.1bn (2020)

	Historical Data				Consensus Forecasts	
	2017	2018	2019	2020	2021	2022
Gross Domestic Product *(% change on previous year)*	1.3	1.6	1.9	-8.2	**7.6**	**3.9**
Industrial Production *(% change on previous year)*	3.9	1.6	-0.7	-2.0	**8.6**	**3.8**
Consumer Prices *(% change on previous year)*	1.1	0.6	0.3	-1.2	**0.6**	**2.0**
Current Account *(US Dollar bn)*	-3.8	-6.2	-3.1	-12.5	**-11.5**	**-6.8**

IRELAND	Population - 4.9mn (2020, mid-year)	Historical Data				Consensus Forecasts	
	Nominal GDP - US$418.0bn (2020)	2017	2018	2019	2020	2021	2022
Gross Domestic Product *(% change on previous year)*		8.9	9.0	4.9	5.9	14.4	4.5
Industrial Production *(% change on previous year)*		-2.3	-4.9	2.9	4.2	17.5	1.0
Consumer Prices *(% change on previous year)*		0.4	0.5	0.9	-0.3	2.1	2.6
Current Account *(US Dollar bn)*		1.6	18.9	-79.2	-11.3	65.5	67.3

ISRAEL	Population - 8.7mn (2020, mid-year)	Historical Data				Consensus Forecasts	
	Nominal GDP - US$403.4bn (2020)	2017	2018	2019	2020	2021	2022
Gross Domestic Product *(% change on previous year)*		4.4	4.0	3.8	-2.2	6.2	4.7
Industrial Production *(% change on previous year)*		4.2	2.8	2.4	5.4	5.8	4.0
Consumer Prices *(% change on previous year)*		0.2	0.8	0.8	-0.6	1.5	1.7
Current Account *(US Dollar bn)*		12.8	10.6	14.3	22.2	21.9	22.0
						Mar '22	Dec '22
3 Month Interbank Rate, *end period %*		0.1	0.3	0.2	0.1	0.1	0.3

NIGERIA	Popn - 206.1mn (2020, mid-year)	Historical Data				Consensus Forecasts	
	Nominal GDP - US$404.2bn (2020)	2017	2018	2019	2020	2021	2022
Gross Domestic Product *(% change on previous year)*		0.8	1.9	2.3	-1.9	2.6	2.9
Consumer Prices *(% change on previous year)*		16.5	12.1	11.4	13.3	16.7	13.0
Current Account *(US Dollar bn)*		12.7	6.3	-14.6	-17.0	-6.3	-1.9

PORTUGAL	Population - 10.2mn (2020, mid-year)	Historical Data				Consensus Forecasts	
	Nominal GDP - US$231.2bn (2020)	2017	2018	2019	2020	2021	2022
Gross Domestic Product *(% change on previous year)*		3.5	2.8	2.7	-8.4	4.4	5.0
Industrial Production *(% change on previous year)*		3.9	0.1	-2.3	-7.0	3.9	2.8
Consumer Prices *(% change on previous year)*		1.4	1.0	0.3	0.0	1.0	1.6
Current Account *(US Dollar bn)*		2.9	1.3	1.0	-2.5	-2.7	-1.9

SAUDI ARABIA	Popn - 34.8mn (2020, mid-year)	Historical Data				Consensus Forecasts	
	Nominal GDP - US$700.1bn (2020)	2017	2018	2019	2020	2021	2022
Gross Domestic Product *(% change on previous year)*		-0.7	2.4	0.3	-4.1	2.8	5.6
Consumer Prices *(% change on previous year)*		-0.8	2.5	-2.1	3.4	3.3	2.2
Current Account *(US Dollar bn)*		10.5	72.0	38.2	-21.6	40.1	55.9

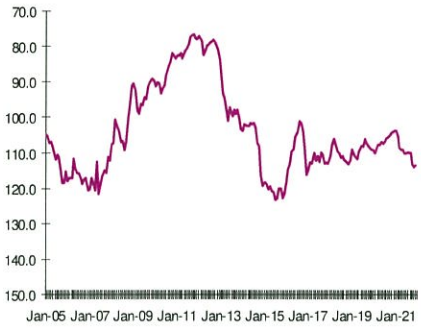
SOUTH AFRICA	Popn - 59.3mn (2020, mid-year)	Historical Data				Consensus Forecasts	
	Nominal GDP - US$303.0bn (2020)	2017	2018	2019	2020	2021	2022
Gross Domestic Product *(% change on previous year)*		1.2	1.5	0.1	-6.4	5.2	2.3
Manufacturing Production *(% change on previous year)*		-0.4	1.2	-0.9	-11.0	8.0	2.6
Consumer Prices *(% change on previous year)*		5.3	4.7	4.1	3.3	4.4	4.5
Current Account *(US Dollar bn)*		-9.0	-12.0	-10.0	6.7	14.4	3.2
						Mar '22	Dec '22
3 Month Interbank Rate, *end period %*		7.2	7.2	6.8	3.6	4.1	4.6

Foreign Exchange Rates

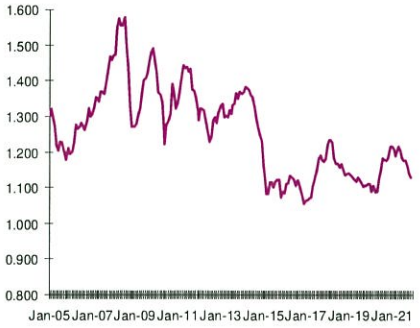
**All US$ rates are amounts of currency per dollar, except the UK pound and the euro which are reciprocals. A positive (+) sign for the % change implies an appreciation of the currency against the US Dollar and vice versa.*

	Historical Data: Rates at end of:				Latest Spot Rate (Dec. 6)	Consensus Forecasts					
	2017	2018	2019	2020		Forecast End Mar. 2022	Percent Change	Forecast End Dec. 2022	Percent Change	Forecast End Dec. 2023	Percent Change
Rates per US Dollar*											
Canadian Dollar	1.259	1.364	1.297	1.274	1.279	1.252	2.2	1.240	3.1	1.238	3.3
Egyptian Pound	17.68	17.87	15.99	15.70	15.71	15.86	-1.0	16.10	-2.4	16.74	-6.2
European Euro	1.199	1.143	1.123	1.224	1.127	1.138	1.0	1.151	2.1	1.170	3.8
Israeli Shekel	3.467	3.748	3.454	3.211	3.167	3.135	1.0	3.137	1.0	3.159	0.3
Japanese Yen	112.9	110.8	108.7	103.2	113.5	113.7	-0.2	113.2	0.2	111.3	1.9
Nigerian Naira	360.0	363.5	362.9	394.8	413.8	422.3	-2.0	430.9	-4.0	446.8	-7.4
Saudi Arabian Riyal	3.750	3.750	3.750	3.752	3.751	3.750	0.0	3.750	0.0	3.750	0.0
South African Rand	12.34	14.39	13.98	14.69	15.88	15.27	4.0	15.53	2.3	15.82	0.4
United Kingdom Pound	1.351	1.270	1.325	1.367	1.324	1.340	1.2	1.363	3.0	1.375	3.9
Rates per Euro											
Danish Krone	7.445	7.465	7.473	7.444	7.436	7.446	-0.1	7.447	-0.1	7.457	-0.3
Norwegian Krone	9.846	9.950	9.864	10.48	10.278	9.899	3.8	9.729	5.6	9.558	7.5
Swedish Krona	9.844	10.25	10.51	10.05	10.262	10.04	2.2	9.903	3.6	9.680	6.0
Swiss Franc	1.170	1.127	1.087	1.082	1.044	1.058	-1.3	1.069	-2.3	1.090	-4.2

Yen per US$



US$ per Euro[1]



US$ per UK Pound

Brent, US$ per barrel

Range 1990-2021	US$9.10 - US$143.95
Spot Rate (Dec. 6)	US$ 73.38

Brent December Survey	Forecast for End Mar. '22	Forecast for End Dec. '22
Mean Forecast	75.1	71.6
High	95.0	85.0
Low	63.0	55.0
Standard Deviation	6.0	5.5
No. of Forecasts	54	54

Prices Drop US$10 on Omicron and OPEC+ Supply Hike

After soaring to US$83.43 on November 23, Brent slumped to US$69.53 on December 1, as markets were roiled by the emergence of a new Covid variant, Omicron. The energy supply crunch had pushed up oil prices in recent months, to the concern of the US administration and other major energy importers. On December 2, following negotiations with the US, Saudi Arabia and OPEC+ agreed to raise crude supply next year by 400,000 barrels a day, in a bid to cool prices. However, Saudi Arabia countered this decision on December 5 by hiking its January selling prices of Saudi Aramco crude to Asia and the US. This triggered a modest rebound in Brent to US$73.38 per barrel on December 6. Omicron may be prompting fears of economic retrenchment, but Saudi Arabia's price hike signals the Kingdom's expectation that oil demand is going to remain strong.

Tables continued from page 3

Japan

* *% change over previous year*

	2020		2021				2022				2023	
	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2
Gross Domestic Product*	-5.4	-0.8	-1.3	7.7	1.3	***0.1***	***2.7***	***3.1***	***4.3***	***3.0***	***1.9***	***1.3***
% change, qtr/qtr	*5.4*	*2.8*	*-1.1*	*0.4*	*-0.8*	*1.6*	*1.5*	*0.8*	*0.4*	*0.3*	*0.4*	*0.2*
Private Consumption*	-7.2	-2.1	-2.5	7.2	0.7	***0.8***	***3.7***	***3.5***	***4.9***	***2.9***	***1.6***	***1.1***
% change, qtr/qtr	*5.3*	*2.2*	*-1.3*	*0.9*	*-1.1*	*2.3*	*1.5*	*0.7*	*0.2*	*0.4*	*0.3*	*0.2*
Industrial Production*	-12.7	-4.2	-1.4	19.9	6.0	***1.7***	***2.5***	***2.8***	***7.7***	***6.9***	***4.4***	***3.5***
Consumer Prices*	0.0	-0.9	-0.5	-0.7	-0.2	***0.4***	***0.2***	***1.0***	***0.8***	***0.9***	***0.9***	***0.7***
3 month Yen (TIBOR) rate, % [1]	0.1	0.1	0.1	0.1	0.1	***0.1***	***0.1***	***0.1***	***0.1***	***0.1***	***0.1***	***0.1***

[1] *End period*

Germany

* *% change over previous year*

	2020		2021				2022				2023	
	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2
Gross Domestic Product* [2]	-3.7	-2.9	-3.0	10.0	2.6	***2.1***	***4.7***	***4.1***	***3.4***	***3.6***	***3.5***	***2.5***
% change, qtr/qtr	*9.0*	*0.7*	*-1.9*	*2.0*	*1.7*	*0.3*	*0.6*	*1.5*	*1.0*	*0.4*	*0.5*	*0.5*
Private Consumption* [2]	-3.4	-6.1	-9.2	6.6	1.6	***4.3***	***10.8***	***8.7***	***3.8***	***3.9***	***3.7***	***2.4***
% change, qtr/qtr	*11.5*	*-2.7*	*-5.3*	*3.8*	*6.2*	*0.0*	*0.6*	*1.8*	*1.4*	*0.0*	*0.5*	*0.5*
Industrial Production*	-8.6	-1.5	-2.0	16.1	2.6	***-3.7***	***-1.4***	***1.7***	***6.0***	***7.7***	***7.5***	***6.0***
Consumer Prices*	-0.1	-0.3	1.4	2.3	3.9	***4.9***	***3.7***	***3.1***	***2.4***	***1.7***	***1.5***	***1.7***
3 month Euro Rate, % [1]	-0.5	-0.5	-0.5	-0.5	-0.5	***-0.5***	***-0.5***	***-0.5***	***-0.5***	***-0.5***	***-0.4***	***-0.4***

[1] *End period* [2] *Quarterly data (source: Bundesbank) are working-day & seasonally adjusted. Annual figures on page 8 (source: FSO) are not adjusted.*

France

* *% change over previous year*

	2020		2021				2022				2023	
	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2
Gross Domestic Product*	-3.6	-4.3	1.5	18.8	3.3	***4.9***	***5.7***	***5.1***	***2.7***	***2.7***	***2.5***	***2.2***
% change, qtr/qtr	*18.5*	*-1.1*	*0.1*	*1.3*	*3.0*	*0.5*	*0.8*	*0.7*	*0.7*	*0.5*	*0.6*	*0.4*
Household Consumption*	-1.1	-6.8	-1.1	13.3	0.5	***7.0***	***7.8***	***7.0***	***2.6***	***2.5***	***2.4***	***2.2***
% change, qtr/qtr	*18.3*	*-5.4*	*-0.2*	*1.4*	*4.9*	*0.8*	*0.6*	*0.7*	*0.6*	*0.6*	*0.5*	*0.5*
Manufacturing Production*	-7.9	-4.7	2.1	23.8	2.5	***0.5***	***1.5***	***4.4***	***3.7***	***3.9***	***3.6***	***2.8***
Consumer Prices*	0.3	0.1	0.7	1.4	1.8	***2.8***	***2.7***	***2.6***	***2.1***	***1.5***	***1.3***	***1.4***
3 month Euro Rate, % [1]	-0.5	-0.5	-0.5	-0.5	-0.5	***-0.5***	***-0.5***	***-0.5***	***-0.5***	***-0.4***	***-0.4***	***-0.4***

[1] *End period*

United Kingdom

* *% change over previous year*

	2020		2021				2022				2023	
	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2
Gross Domestic Product*	-8.1	-7.1	-5.8	23.6	6.6	***6.2***	***8.7***	***4.1***	***3.6***	***3.1***	***2.7***	***2.4***
% change, qtr/qtr	*17.4*	*1.1*	*-1.4*	*5.5*	*1.3*	*0.7*	*1.0*	*1.1*	*0.7*	*0.3*	*0.7*	*0.7*
Household Consumption*	-7.5	-8.5	-10.3	20.7	2.7	***6.3***	***12.2***	***5.8***	***4.3***	***3.4***	***3.0***	***2.5***
% change, qtr/qtr	*19.9*	*-1.8*	*-4.4*	*7.2*	*2.0*	*1.7*	*0.8*	*1.1*	*0.6*	*0.9*	*0.4*	*0.6*
Manufacturing Production*	-6.3	-2.7	-1.4	27.8	4.5	***1.1***	***1.9***	***1.4***	***1.6***	***1.7***	***2.0***	***1.6***
Retail Prices (underlying rate)*	1.3	1.4	1.6	3.5	4.6	***5.9***	***6.2***	***6.2***	***5.5***	***4.5***	***4.2***	***3.6***
Consumer Prices*	0.6	0.5	0.6	2.1	2.8	***4.4***	***4.7***	***4.7***	***4.1***	***3.0***	***2.8***	***2.2***
3 month Interbank Rate, % [1]	0.1	0.0	0.1	0.1	0.1	***0.2***	***0.4***	***0.6***	***0.6***	***0.8***	***1.1***	***1.2***

[1] *End period*

Italy

* % change over previous year	2020		2021				2022				2023	
	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2
Gross Domestic Product* [2]	-5.4	-6.6	-0.6	17.1	3.9	*6.4*	*6.8*	*4.9*	*2.9*	*2.8*	*2.5*	*2.1*
% change, qtr/qtr	*15.6*	*-1.6*	*0.3*	*2.7*	*2.6*	*0.7*	*0.7*	*0.8*	*0.7*	*0.5*	*0.4*	*0.4*
Household Consumption* [2]	-7.7	-9.9	-4.0	14.2	4.0	*7.9*	*9.6*	*5.1*	*2.7*	*2.3*	*2.1*	*1.9*
% change, qtr/qtr	*13.0*	*-2.7*	*-1.1*	*5.0*	*3.0*	*0.9*	*0.6*	*0.6*	*0.6*	*0.5*	*0.4*	*0.4*
Industrial Production*	-5.2	-2.5	9.9	32.0	4.4	*4.0*	*4.5*	*3.4*	*2.9*	*3.0*	*3.0*	*2.8*
Consumer Prices*	-0.5	-0.2	0.6	1.2	2.2	*3.5*	*3.0*	*2.9*	*2.1*	*1.3*	*1.0*	*1.1*
3 month Euro Rate, % [1]	-0.5	-0.5	-0.5	-0.5	-0.5	*-0.5*	*-0.5*	*-0.5*	*-0.5*	*-0.5*	*-0.5*	*-0.4*

[1] *End period* [2] *Quarterly data are seasonally adjusted. Annual figures on page 14 are not adjusted.*

Canada

* % change over previous year	2020		2021				2022				2023	
	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2
Gross Domestic Product*	-4.9	-3.1	0.3	11.8	4.0	*2.8*	*2.7*	*4.7*	*4.4*	*4.0*	*3.5*	*3.0*
% change, qtr/qtr	*9.0*	*2.2*	*1.2*	*-0.8*	*1.3*	*1.1*	*1.1*	*1.1*	*1.1*	*0.6*	*0.7*	*0.6*
Household Consumption*	-4.3	-4.7	-2.0	13.7	5.0	*5.1*	*5.6*	*6.9*	*4.6*	*4.1*	*3.8*	*3.1*
% change, qtr/qtr	*12.9*	*0.3*	*0.6*	*-0.1*	*4.2*	*0.3*	*1.1*	*1.1*	*2.0*	*-0.1*	*0.8*	*0.5*
Industrial Production*	-7.9	-5.0	-1.5	12.8	5.1	*2.7*	*2.8*	*4.7*	*4.2*	*3.8*	*2.9*	*2.6*
Consumer Prices*	0.3	0.8	1.4	3.3	4.1	*4.7*	*4.4*	*3.8*	*3.1*	*2.4*	*2.3*	*2.2*
3 month Treasury Bill Rate, % [1]	0.1	0.1	0.1	0.2	0.1	*0.1*	*0.2*	*0.4*	*0.6*	*0.8*	*1.0*	*1.2*

[1] *End period*

Euro zone

* % change over previous year	2020		2021				2022				2023	
	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2
Gross Domestic Product*	-4.1	-4.4	-1.1	14.4	3.9	*4.7*	*5.7*	*4.6*	*3.3*	*3.3*	*3.3*	*2.7*
% change, qtr/qtr	*12.6*	*-0.4*	*-0.2*	*2.2*	*2.2*	*0.4*	*0.7*	*1.2*	*0.9*	*0.5*	*0.7*	*0.6*
Household Consumption*	-4.6	-7.6	-5.6	12.2	2.5	*5.8*	*9.0*	*6.5*	*3.7*	*3.4*	*3.3*	*2.6*
% change, qtr/qtr	*14.1*	*-3.0*	*-2.3*	*3.9*	*4.1*	*0.2*	*0.6*	*1.5*	*1.4*	*-0.1*	*0.5*	*0.8*
Industrial Production*	-6.6	-1.2	3.1	22.5	5.6	*1.3*	*1.2*	*2.5*	*3.7*	*4.6*	*5.6*	*4.8*
Consumer Prices*	0.0	-0.3	1.1	1.8	2.8	*4.4*	*3.6*	*3.4*	*2.7*	*1.5*	*1.4*	*1.4*

[1] *End period*

Netherlands

* % change over previous year	2020		2021				2022				2023	
	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2
Gross Domestic Product* [2]	-2.6	-3.1	-2.3	10.7	5.0	*4.8*	*6.0*	*3.0*	*2.0*	*2.5*	*2.5*	*2.0*
% change, qtr/qtr	*7.5*	*0.0*	*-0.8*	*3.8*	*1.9*	*-0.2*	*0.4*	*0.8*	*1.0*	*0.2*	*0.4*	*0.4*
Private Consumption* [2]	-5.2	-7.0	-8.1	10.3	5.0	*6.4*	*11.0*	*5.0*	*2.4*	*2.5*	*2.5*	*2.2*
% change, qtr/qtr	*8.9*	*-1.4*	*-3.5*	*6.4*	*3.8*	*-0.1*	*0.7*	*0.7*	*1.2*	*0.0*	*0.6*	*0.4*
Manufacturing Production*	-4.2	-1.6	0.8	15.3	11.2	*7.3*	*6.9*	*2.7*	*2.0*	*2.2*	*2.1*	*2.4*
Consumer Prices*	1.2	1.0	1.8	2.0	2.2	*3.8*	*3.9*	*3.6*	*3.2*	*2.0*	*2.4*	*1.9*
3 month Euro Rate, % [1]	-0.5	-0.5	-0.5	-0.5	-0.5	*-0.5*	*-0.5*	*-0.5*	*-0.5*	*-0.5*	*-0.4*	*-0.4*

[1] *End period* [2] *Quarterly data are seasonally adjusted. Annual figures on page 20 are not adjusted.*

Norway

* % change over previous year	2020		2021				2022				2023	
	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2
Gross Dom. Prod. (Mainland)*	-3.0	-1.2	0.0	7.4	4.9	*4.8*	*5.8*	*5.1*	*2.6*	*1.8*	*2.7*	*2.3*
% change, qtr/qtr	*5.0*	*1.9*	*-0.7*	*1.1*	*2.6*	*1.7*	*0.3*	*0.4*	*0.2*	*0.9*	*1.2*	*0.0*
Private Consumption*	-6.1	-4.7	-4.6	8.9	6.3	*4.7*	*9.5*	*7.0*	*1.9*	*2.3*	*3.1*	*2.9*
% change, qtr/qtr	*8.7*	*1.1*	*-3.6*	*2.9*	*6.0*	*-0.4*	*0.8*	*0.5*	*1.0*	*0.0*	*1.5*	*0.3*
Manufacturing Production*	-4.0	-1.7	2.2	6.8	3.7	*3.5*	*1.3*	*2.0*	*2.3*	*2.0*	*1.3*	*1.0*
Consumer Prices*	1.6	1.3	3.0	2.8	3.5	*3.9*	*2.5*	*2.6*	*1.5*	*1.3*	*1.5*	*1.7*
3 month Interbank Rate, % [1]	0.3	0.5	0.4	0.2	0.6	*0.8*	*1.0*	*1.2*	*1.3*	*1.4*	*1.6*	*1.7*

[1] *End period*

Spain

* % change over previous year	2020		2021				2022				2023	
	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2
Gross Domestic Product*	-8.7	-8.8	-4.2	17.5	2.7	*4.8*	*6.4*	*6.5*	*5.5*	*4.3*	*4.3*	*3.8*
% change, qtr/qtr	*16.8*	*0.2*	*-0.6*	*1.1*	*2.0*	*2.3*	*0.9*	*1.1*	*1.1*	*1.0*	*0.9*	*0.6*
Household Consumption*	-9.0	-10.1	-6.2	23.4	1.1	*4.2*	*7.1*	*4.1*	*5.4*	*4.1*	*4.2*	*3.6*
% change, qtr/qtr	*21.5*	*-0.9*	*-2.2*	*4.7*	*-0.5*	*2.3*	*0.5*	*1.7*	*0.7*	*1.1*	*0.6*	*1.1*
Industrial Production*	-4.2	-2.3	1.3	27.6	1.8	*1.9*	*2.7*	*2.0*	*3.5*	*3.1*	*2.1*	*2.1*
Consumer Prices*	-0.5	-0.7	0.6	2.6	3.4	*5.2*	*4.1*	*3.1*	*2.2*	*1.0*	*0.9*	*1.0*
3 month Euro Rate, % [1]	-0.5	-0.5	-0.5	-0.5	-0.5	*-0.5*	*-0.5*	*-0.5*	*-0.4*	*-0.4*	*-0.5*	*-0.5*

[1] *End period*

Sweden

* % change over previous year	2020		2021				2022				2023	
	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2
Gross Domestic Product* [2]	-2.1	-2.0	0.0	9.6	4.5	*4.9*	*4.6*	*4.4*	*2.8*	*2.5*	*2.5*	*2.2*
% change, qtr/qtr	*6.9*	*0.3*	*1.2*	*1.0*	*2.0*	*0.6*	*0.9*	*0.8*	*0.4*	*0.3*	*1.0*	*0.4*
Household Consumption* [2]	-4.6	-4.7	-0.8	9.0	6.6	*5.5*	*5.5*	*5.2*	*3.4*	*2.9*	*3.1*	*2.8*
% change, qtr/qtr	*4.7*	*0.5*	*2.2*	*1.4*	*2.4*	*-0.5*	*2.2*	*1.1*	*0.6*	*-1.0*	*2.4*	*0.9*
Mining & Manuf. Production*	-3.9	0.6	2.8	21.5	5.3	*4.8*	*4.1*	*3.6*	*2.4*	*2.1*	*na*	*na*
Consumer Prices*	0.6	0.3	1.5	1.8	2.0	*2.8*	*2.6*	*2.4*	*1.8*	*1.4*	*1.0*	*1.5*
3 month Interbank Rate, % [1]	-0.1	0.0	0.0	0.0	-0.1	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*	*0.0*

[1] *End period* [2] *Quarterly data are seasonally adjusted. Annual figures on page 23 are not adjusted.*

Switzerland

* % change over previous year	2020		2021				2022				2023	
	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2	Qtr 3	Qtr 4	Qtr 1	Qtr 2
Gross Domestic Product* [2]	-1.3	-1.8	-0.5	8.0	3.3	*3.7*	*4.5*	*3.3*	*2.2*	*2.2*	*2.1*	*1.8*
% change, qtr/qtr	*6.3*	*-0.1*	*-0.1*	*1.8*	*1.7*	*0.4*	*0.6*	*0.6*	*0.6*	*0.3*	*0.5*	*0.4*
Private Consumption* [2]	-0.9	-2.9	-3.3	8.4	1.8	*4.0*	*7.9*	*4.4*	*2.2*	*2.0*	*1.9*	*1.7*
% change, qtr/qtr	*9.3*	*-1.6*	*-3.1*	*4.0*	*2.7*	*0.4*	*0.5*	*0.6*	*0.6*	*0.3*	*0.4*	*0.5*
Industrial Production*	-3.9	-1.5	4.3	16.4	8.2	*9.4*	*3.3*	*2.2*	*2.9*	*2.9*	*3.2*	*2.9*
Consumer Prices*	-0.8	-0.7	-0.5	0.5	0.8	*1.4*	*1.2*	*1.0*	*0.7*	*0.4*	*0.5*	*0.5*
3 month Euro-Franc Rate, % [1]	-0.7	-0.7	-0.7	-0.7	-0.7	*-0.7*	*-0.7*	*-0.7*	*-0.7*	*-0.7*	*-0.7*	*-0.7*

[1] *End period* [2] *Quarterly data are seasonally adjusted. Annual figures on page 24 are not adjusted.*

- **GDP** - Gross Domestic Product
  IMF - International Monetary Fund
  na - not available
  Emu - European economic and monetary union
  OECD - Organisation for Economic Co-operation and Development
  ECB - European Central Bank
  BoE - Bank of England
  PMI - Purchasing Managers Index
  y-o-y - year-on-year
  q-o-q - quarter-on-quarter
  m-o-m - month-on-month

- Measures of GDP, Consumption, Business Investment and Industrial Production are expressed in real (i.e. inflation-adjusted) terms. These variables, and certain others as indicated, are expressed as percentage changes over the previous year.

- All individual country forecasters on pages 4-24 are listed in descending order of their 2021 real GDP estimates. Consensus forecasts are mean arithmetic averages of the listed individual estimates.

CONSENSUS FORECASTS: WORLD ECONOMIC ACTIVITY

↑ Consensus Forecast **Increase** From Prior Month ↓ Consensus Forecast **Decrease** From Prior Month

December Survey	Real GDP % increase			Consumer Prices % increase			Current Account Balance, US$bn		
	2020	2021	2022	2020	2021	2022	2020	2021	2022
Belgium	-6.3	5.9 ↑	3.1 ↓	0.7	2.3 ↑	2.2 ↑	4.4	9.6	1.8
Canada	-5.2	4.7 ↓	4.0 ↓	0.7	3.4 ↑	3.3 ↑	-29.4	6.1	-7.9
France	-8.0	6.6 ↑	3.8	0.5	1.7	2.1 ↑	-50.2	-36.5	-39.6
Germany	-4.6	2.7	4.0 ↓	0.5	3.1 ↑	2.7 ↑	267.3	276.7	267.4
Italy	-8.9	6.3 ↑	4.3 ↑	-0.2	1.8	2.2 ↑	70.8	68.6	58.8
Japan	-4.7	1.8 ↓	3.2 ↑	0.0	-0.2	0.7	146.6	150.0	140.9
Netherlands	-3.8	4.3 ↑	3.4	1.3	2.4 ↑	2.8 ↑	63.7	96.0	95.0
Norway	-2.3	4.1 ↑	3.8 ↓	1.3	3.3 ↑	2.2 ↑	7.2	52.8	55.8
Spain	-10.8	4.7 ↓	5.8 ↓	-0.3	2.9 ↑	2.5 ↑	8.8	13.3	18.7
Sweden	-2.9	4.4	3.5	0.5	2.1 ↑	2.1 ↑	30.9	32.5	28.1
Switzerland	-2.4	3.5 ↑	3.0	-0.7	0.5	0.8 ↑	9.1	47.5	57.9
United Kingdom	-9.7	7.0 ↑	4.7	0.8	2.5 ↑	4.1 ↑	-71.7	-75.4	-97.2
United States	-3.4	5.6 ↑	4.0	1.2	4.6 ↑	4.2 ↑	-616.0	-779.9	-830.7
North America[1]	-3.5	5.5	4.0	1.2	4.5	4.1	-645.4	-773.8	-838.6
Western Europe[2]	-6.5	5.2	4.1	0.4	2.3	2.6	353.2	568.5	539.7
European Union[2]	-5.9	5.1	4.1	0.6	2.5	2.6	426.1	532.3	512.6
Euro zone[2]	-6.5	5.1 ↑	4.2 ↓	0.3	2.5 ↑	2.6 ↑	254.3	364.9	356.9
Asia Pacific[3]	-0.9	6.0	4.8	2.0	1.5	2.2	766.2	796.8	687.4
Eastern Europe[4,7]	-2.5	5.4	3.7	5.3	8.0	6.8	5.5	59.5	53.4
LatAm ex Venezuela[5,7]	-6.7	6.6	2.4	6.4	11.3	8.3	5.7	-27.7	-48.6
Other Countries[6]	-2.4	3.8	4.4	4.8	5.9	5.2	-23.9	52.8	62.9
Total[7]	-3.2	5.6	4.2	1.9	3.5	3.5			

*Regional totals and the grand totals for GDP growth and inflation, are weighted averages calculated using **2020 GDP weights, converted at average 2020 US$ exchange rates.** These weights and rates were last updated in July 2021. Due to annual updates in exchange rates and GDP weights in July-September of each year, there will be differences in the Regional and World Aggregates in those months. Therefore, some aggregates may not be comparable to the aggregates from previous months. Current account forecasts given in national currencies on pages 7-24 have been converted using consensus exchange rate forecasts for the purposes of comparison. [1] USA and Canada. [2] The Euro zone aggregate is taken from our panel's latest forecasts (pages 18-19). The Euro zone current account data and forecasts are based on extra-euro zone data, i.e., an aggregate of the Euro zone member states' transactions with nonresidents of the Euro zone. The European Union data includes the Euro zone countries listed on page 18 plus Denmark and Sweden, as well as the Czech Republic, Hungary, Poland, Romania, Bulgaria and Croatia (data taken from Eastern Europe Consensus Forecasts). Western Europe comprises the six Euro zone countries listed in the table above, plus Austria, Denmark, Finland, Greece, Ireland, Norway, Portugal, Sweden, Switzerland and the United Kingdom. [3] Survey results for Japan plus sixteen other countries taken from **Asia Pacific Consensus Forecasts**. [4] Twenty-seven countries, including twelve European Union countries taken from the latest issue of **Eastern Europe Consensus Forecasts.** [5] Seventeen countries taken from the latest issue of **Latin American Consensus Forecasts** (inflation figures are on a December/December basis). Venezuela is excluded beginning in April 2018. [6] Egypt, Israel, Nigeria, Saudi Arabia and South Africa. [7] The **Eastern Europe** and **Latin American** components of the **World Total** are taken from prior months surveys.*

Attachment 39.1.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 39.5

REFER TO LIVE SPREADSHEET MODEL

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(accessible by opening the Attachments Tab in Adobe)

Attachment 39.9

REFER TO LIVE SPREADSHEET MODEL

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Attachment 40.2

REFER TO LIVE SPREADSHEET MODEL

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Attachment 42.3.1.1

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Attachment 46.4

As Europe's Gas Markets Slowly Stall, Gas Producers' And Utilities' Business Risks May Rise

November 16, 2020

*(**Editor's Note:** This report on the European gas market, by S&P Global Ratings and S&P Global Platts Analytics, is a thought leadership report that neither addresses views about ratings on individual entities nor is a rating action. S&P Global Ratings and S&P Global Platts are separate and independent divisions of S&P Global.)*

Key Takeaways

- Gas will remain a key European energy source for decades, but growth is likely now over and decline looks inevitable.
- S&P Global Platts Analytics expects demand for natural gas in Europe to decrease by 0.3% per year on average over the next decade.
- Even if large producers and well-diversified utilities are not downgraded because of the pandemic pressures in 2020, simply lowering debt and leverage may not offset increased longer-term business risks associated with these changes.

Demand for natural gas in Europe is extremely unlikely to expand over the next decade. S&P Global Platts Analytics expects accumulated demand decline of 11.5 billion cubic metres (bcm) in 2020-2030. Although carbon dioxide emissions from gas are about 50% lower than those from coal, this is not enough to make gas compatible with Europe's decarbonization targets and with the EU Green Taxonomy. Implementing the European Green Deal and rolling out green-focused, post-COVID-19 economic recovery packages will further constrain demand growth potential for gas, as will an increasing focus on energy security and the gradual development of energy storage.

That said, S&P Global anticipates that gas will remain an important part of the European energy mix during the next decade. Most countries plan to retire very large coal and nuclear generation capacity and their energy mix will still need options that complement intermittent renewables.

Although S&P Global Ratings considers that large players rated 'BBB-' or above will be able to manage the rating pressures specific to 2020, strategic shifts have been triggered. Europe is ahead of many regions in energy transition, which increases longer-term business risks for the gas industry.

European gas producers no longer view gas as a key part of their decarbonization strategies. For example, companies such as BP, Equinor, and Total are investing in renewables; hydrogen; and carbon capture, utilization, and storage (CCUS).

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Meanwhile, emerging market gas producers such as Qatar Petroleum (QP), Gazprom, and Novatek increasingly seek to monetize their gas reserves by expanding in new and growing geographic markets, or into petrochemicals. QP and Novatek are developing their LNG projects and Gazprom plans to expand its pipeline gas exports to China. Middle Eastern countries and Russia plan to expand into petrochemicals.

Many large European power generation companies are already diversified into other types of fuel and hedge the risks associated with their exposure to gas. Their growth strategies typically focus on renewables and networks, and they are making only limited investments in gas-fired power generation.

At present, regulated gas transmission and distribution companies still benefit from supportive and very predictable regulations, which underpin their resilience. Despite this, we anticipate that they will need to reduce their financial leverage if they are to maintain ratings at the current level. There are limited growth prospects for gas infrastructure, and alternative growth paths, like diversifying into hydrogen, carry technological and regulatory uncertainties. Regulatory pressures in several countries, such as Spain and the U.K., are also rising.

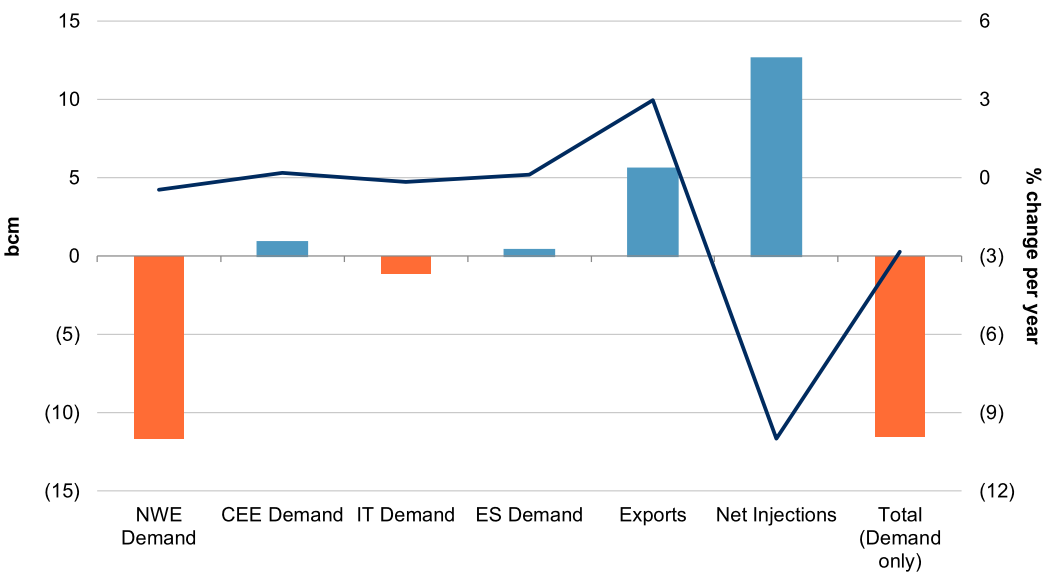
Europe: The World's First, Last Gas Market

The following market view comes from Ira Joseph, Head of Global Gas and Power, S&P Global Platts Analytics. S&P Global Platts is a division of S&P Global, as is S&P Global Ratings. Therefore, what follows are the sole views of S&P Global Platts, subject to its citation policy, available upon request.

Europe is a mature gas market, which is a euphemistic way of saying that its growth prospects are extremely limited. No need to blame or finger point; it's just that the market is saturated in terms of infrastructure, and gas is entering a future when it will need to stave off the competition from the new kids on the block, rather than replace what was there before it. Given this harsh reality, S&P Global Platts Analytics expects natural gas to see its topline regional demand decrease by 12 billion cubic metres (bcm)through 2030. More importantly, while gas will continue to play a central role in European energy security, Europe's storage and regasification capacity for liquefied natural gas (LNG) will take on a growing role in global security of supply, as seasonal demand swings grow in intensity.

Chart 1

How European Demand Will Change In The Next Decade
2030 versus 2020



Source: S&P Global Platts. NWE--North Western Europe. CEE--Central and Estern Europe. IT--Italy. ES--Spain. Bcm--Billion cubic metres of natural gas.

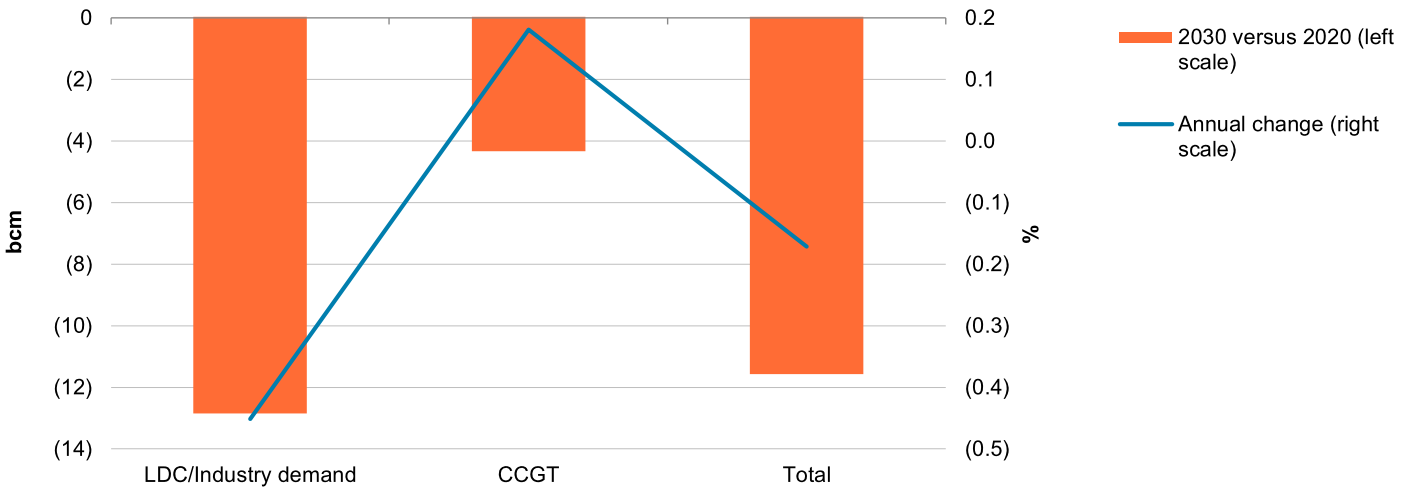
Europe is still a vast gas market at over 500 bcm a year and will remain the second-largest traded market in the world after North America for decades. Even China's gas market is still only at 300 bcm. Europe will remain critical as a pricing point and is replete with infrastructure that is taking on global significance. The more LNG that Europe imports over the next decade--38 bcm more by 2030--the more gas balances in Europe will influence pricing in the rest of the world. Yet the outlook for a decline in European gas demand over the next decade is a major issue. The decline will be fairly minor in terms of volume--just under 0.3% per year--but the opportunities for gas demand growth are well past their prime. Europe is becoming a larger and larger net importer, facing unprecedented levels of competition. Save a major policy decision immediately banning coal and lignite use in power generation or an enormous gas find somewhere on the European continent, the only questions are how rapid the demand decline will be, and which sectors will suffer the most?

Most gas markets around the world are still growing due to lower prices (North America), decarbonization policies and air-quality concerns (China and India), or use as a fuel or feedstock for underlying economic growth. But even

North America, which has untold volumes of low-cost gas reserves, is struggling to find a way to burn it at the lowest of prices. The added cost of moving gas to a market like Europe only makes the demand growth equation more difficult to solve. Short-term supply-side shortages (as we occasionally expect in the next 12 months) do not negate the longer-term oversupply reality relative to potential incremental demand creation.

Chart 2

Which Sectors Will Drive European Demand Changes In The Next Decade



Source: S&P Global Platts. LDC--Local distribution company. CCGT--Combined cycle gas turbine.

The European gas market has, more or less, been essentially mature since 2005, save a few years like 2010, when abnormal temperatures caused a demand spike. Somewhat amazingly, the true tipping point demise of growth in the European gas market can actually be traced to a single moment. It began on New Year's Day in 2006, when Russia decided to cut gas flows to and through Ukraine. This prompted Europe to reconsider security of supply, and eventually, adopt the Third Energy Package, and in turn, Russia to invest in Nord Stream and TurkStream to mitigate transit risks. On that day, the renewables business we see today was born in earnest, as a legitimate case emerged in Europe for renewables as both a security and an environmental counterweight to the ever-expanding reliance on imported volumes of gas from the broader gas market.

Europe's subsequent vast investments in gas supply diversification, LNG terminals, storage, and interconnectors, as well as Russia's investments in new supply routes, have massively reduced the physical risks of a gas supply disruption. Nevertheless, customer perceptions of gas security are still shaped by memories of supply disruptions in 2006 and in 2009-2010. Meanwhile, Russia remains largely reliant on Europe, a gas market that is not growing and is more competitive than ever, for most of its gas sales. In retrospect, the incident in 2006 also became the moment that Russia understood the value of Europe in terms of security of demand as much as the moment when Europe became concerned with security of supply, and the idea of Nord Stream was born in order to avoid future Ukrainian complications. Even the Fukushima disaster five years later in 2011, which triggered an accelerated schedule for German nuclear retirements, did nothing to reverse the decline of gas use in power generation, which remains 40 bcm-60 bcm below its 2008 peak. A slower growing population, combined with policy measures promoting renewables and more efficient electricity use, undermined the ability of gas to find its mojo once again.

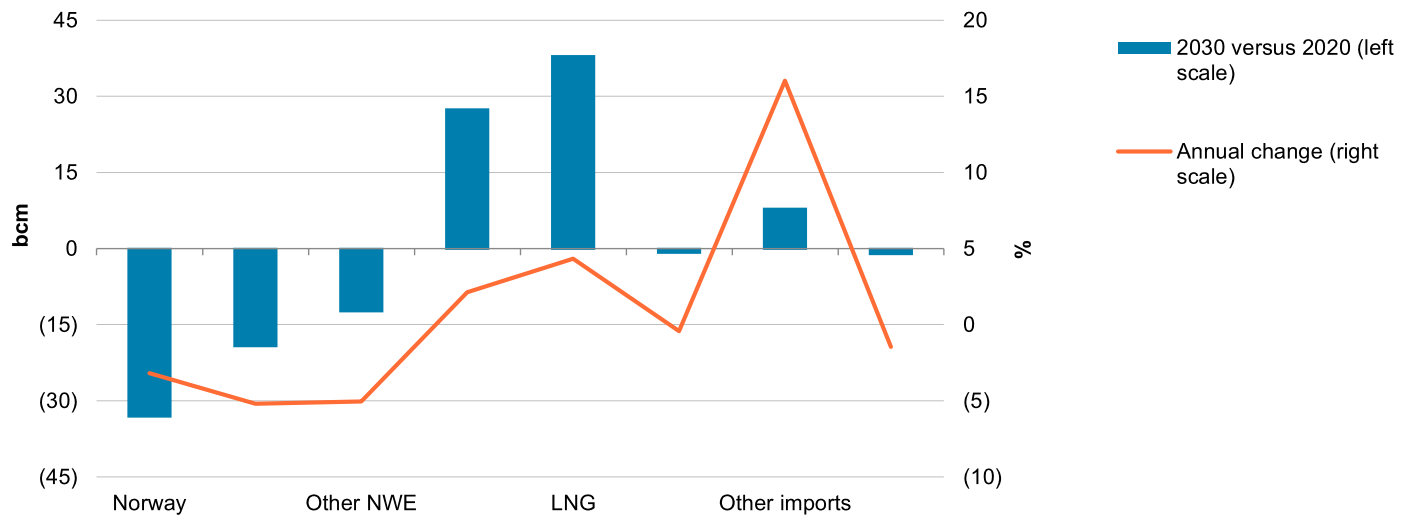
At its core, the issue for gas will remain that the cost of importing from other countries and regions is rising, while the cost of renewables and batteries are falling, and coal prices are chronically weak. In particular, LNG is the costliest form of incremental gas supply trying to compete in the most price-sensitive form of demand: power generation. Europe is in the process of replacing low-cost gas supply from the U.K., the Netherlands, and Norway with either lower-cost gas supply from Russia or much higher-cost gas supply from the LNG market. Neither option is an optimal solution: the former presents a political problem and the latter an economic one. Imported gas, particularly LNG, does not compete well with the emergence of several alternatives in power generation for most hours of the day. As renewables continue to scale, gas risks seeing its position deteriorating as an intermittency solution. More

cost-effective batteries are emerging, and Europe can still rely on more traditional sources of flexibility, such as hydro storage and power interconnectors.

Does gas have a long and sustainable role in the European energy mix? Absolutely it does. The role of gas as a stable and flexible source for power generation cannot currently be challenged from either a commercial or operating perspective, although predators are certainly at the gate. The flexibility of gas use to meet hourly loads was a primary driver in its ability to overtake coal use in the prior generation. That conquest is not entirely complete, even as other competitors to replace coal attempt to outflank gas. The gas-to-coal switching channel still provides another 75-125 million cubic meters per day of sustainable demand potential, and most of it can be generated using existing gas-fired infrastructure, even as the risk grows of committing capital to a new combined cycle gas turbine (CCGT) in this day and age. Additionally, large retirements of nuclear plants, because of age or political opposition, does create room for gas units to operate. These large retirements are taking place, while the EU is targeting a fast ramp-up of hydrogen production, especially from renewable sources.

Chart 3

How Key Supply Sources For European Gas Will Change In The Next Decade



Source: S&P Global Platts. LNG--Liquified natural gas. NWE--Northwestern Europe.

Europe's greatest gas asset going forward will be its storage capacity, which has rapidly evolved from a regional to a global asset. Once again, the 2006 disruption played a central role, as European storage capacity roughly doubled thereafter as a response to the greater perceived risk to imported gas that was emerging. Now Europe is not only storing gas for Europe, but also for Asia and every other LNG-importing country with a winter demand peak and nowhere to put the LNG during the summer. The additional availability of Ukraine's sizable 31 bcm of storage capacity for broad commercial use significantly boosts the relevance of Europe's storage assets.

Platts Analytics' 10-year forecast shows gas demand dropping another 12 bcm (0.3% per year) by 2030 in total, including a 12 bcm (0.45% per year) decrease in northwestern Europe. The drop in Europe will emerge as a 65 bcm drop in production within the region--Norway, the Netherlands, and the U.K.--will need to be replaced by higher imports, either from within Europe or abroad. Higher imports mean higher delivered costs, which will cut into demand due to competitive threats in the power sector and drive greater efficiencies in the local distribution zone (LDZ), where residential/commercial demand is the primary driver. LDZ demand will also drop if normal weather conditions for winter continue to warm.

As my friend Patrick Heren, Europe's revolutionary pricing architect, has so eloquently put it, no one speaks for gas. It is the foster child of fossil fuels; politically and economically, it is an orphan. In Europe it used to be broadly run by Big Oil, but around the Millennium it was sold off to Big Power. And Big Power is now in the grip of Big Green and doesn't necessarily want gas living at home much longer.

Gas In Europe Provides A Short Bridge

S&P Global Ratings still views gas as a bridge fuel, and a part of the energy transition process. However, in Europe, the bridge could be shorter than in other regions. Although greenhouse gas emissions from natural gas power stations are lower than those from coal-powered stations, unabated gas (that is, fossil gas used without carbon capture or storage technology) is not compatible with the EU's long-term decarbonization goals. Under the EU's Green Taxonomy, gas is an intermediary solution only, because it is a fossil fuel and emits more than 100g of carbon dioxide per kilowatt-hour.

The EU has created an economic stimulus plan to help European economies recover from the COVID-19 pandemic, comprising a Next Generation EU Fund and additional funding at the national level. Of the $750 billion fund, 30% focuses on sizable financial support for climate-friendly projects, especially renewables, energy efficiency, and hydrogen.

Europe also leads the way in environmental, social, and governance (ESG) investment. European exchange-traded funds already held ESG assets of €1,663 billion in 2019, and PricewaterhouseCoopers LLP projects that this will increase to €5.5 trillion by 2025. Investor pressure increases the cost of capital for projects related to fossil fuels.

Nevertheless, we believe gas will be needed to offset the large mandatory retirements of coal-fired and nuclear power generation capacity. In 2019, 21.5% of the EU's power generation fuel mix came from gas. The exact amount varied widely from country to country. In the Netherlands, the U.K., and Italy, gas provided over 40% of power, but only 15% in Germany, and a mere 9% in coal-dependent Poland.

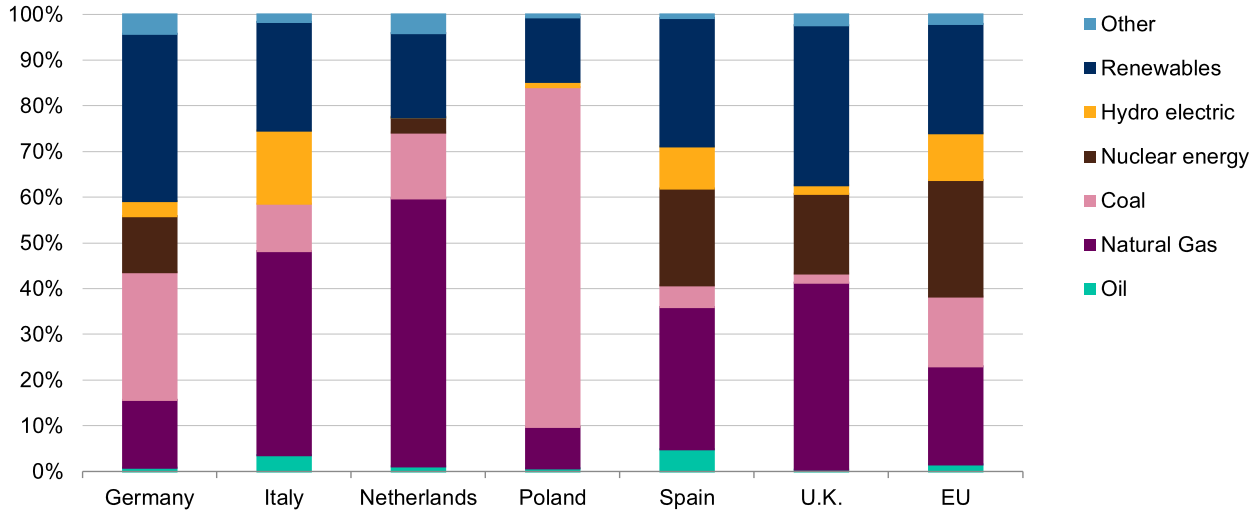
Replacement options are not ready yet

The potential for renewable energy varies across Europe. Existing gas-fired facilities offer a lower-cost option than investing in new nuclear facilities, and a lower-carbon option than coal. The shortage of energy storage solutions currently makes gas the key "insurance policy" against renewable intermittency, although future developments in energy storage capacity and technology could change this.

Hydrogen is a promising energy storage option, but the EU target for green hydrogen is still very low at 6 gigawatt (GW), in the context of Europe's energy system. We don't expect hydrogen to offer a new life for gas because Europe's hydrogen policy explicitly favors green hydrogen, produced via water electrolysis using renewable electricity, over blue hydrogen, produced from methane. That said, the recent lockdown shows that existing grids can probably cope with a higher share of renewables.

Chart 4

Shares Of Gas In European Countries' Power Mix Vary Significantly

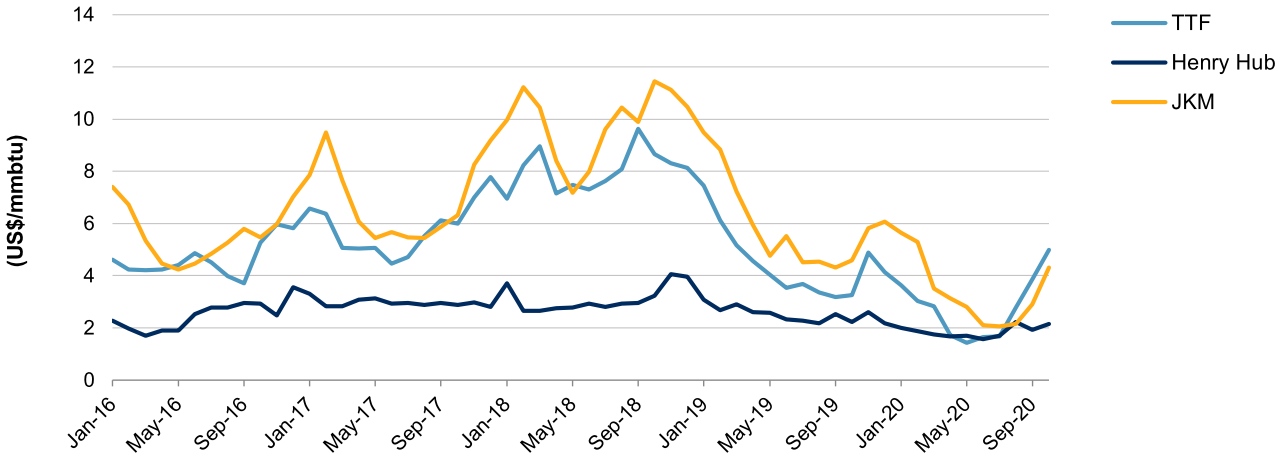


Source: BP

Gas demonstrated extreme price volatility in 2020. Title Transfer Facility (TTF) spot prices fell below $1.5 per million British thermal units (mmbtu) in May-June, but reverted to about $5/mmbtu in October, as the heating season began. A massive increase in LNG capacity was commissioned in 2019, making the global gas markets oversupplied, even before the lockdown. Thanks to its location and ample storage capacities, Europe often acts as a swing market.

Chart 5

Gas Price Is Highly Volatile



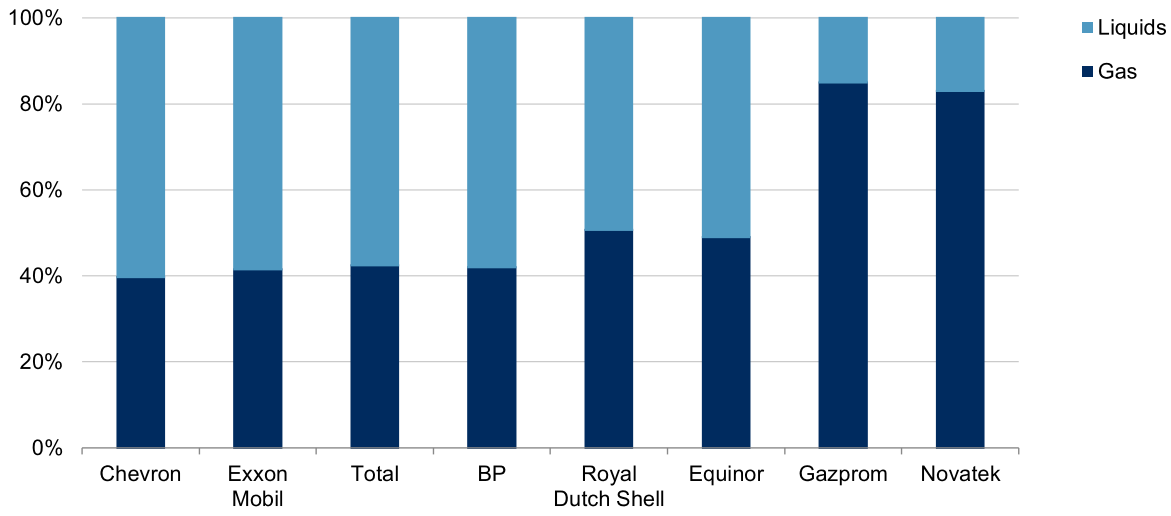
Source: S&P Global Platts. TTF--Title Transfer Facility. JKM--Japan-Korea market.

The Pressures Of 2020 Herald Longer-Term Problems

For most producers, gas remains generally supportive to their business risk profile, because gas provides diversification. Gas prices have become delinked from oil prices, and peak gas is likely to be further away than peak oil. In addition, LNG often allows producers to have longer-term contracted volumes, even if it does not guarantee stable revenue.

Chart 6

European Hydrocarbon Producers Have Large Shares Of Gas



Source: Companies' reports.

European gas producers increasingly look at diversification into renewables

Until recently, many producers viewed gas as part of a global decarbonization solution. They invested in gas, especially LNG, to match the global growth in gas demand. Given increasing uncertainty about the trajectory of global gas demand and future gas prices, many are now changing strategy. BP, Equinor, and Total, among other large global gas producers are now aiming to become diversified energy companies through investments in renewables. They also want to establish early positions in hydrogen and CCUS.

For example, BP's new strategy is to achieve net zero emissions by 2050 or sooner. It is increasing its investments in sustainable energy and its energy partnerships and using active portfolio management to reduce hydrocarbon production. This, combined with stopping exploration in new countries, should result in a 40% hydrocarbon production decline by 2050. Over the next decade, BP aims to reduce the carbon intensity of its operations by 30%-35% and build about 50GW of renewable capacity. Equinor aims to make its operations carbon-neutral by 2030. Its interim goals are to have 4GW-6GW of renewable capacity by 2026 and 12GW-16GW by 2035.

Many gas producers are also looking at CCUS opportunities. For example, Equinor has a CCUS project in the North Sea. Currently, policy support for CCUS is less pronounced than for renewables, but we anticipate that attractive financial mechanisms may emerge in the future because CCUS are important for long-term decarbonization.

Although many large exploration & production (E&P) players have cut their oil and gas capital expenditure (capex), they continue to invest in renewables. As the price of oil and gas has fallen and investment in renewables attracts strong policy support, the difference between potential returns on oil and gas projects and those on renewables is likely to shrink.

Today's investments in both gas and renewable developments could perform for years, even decades. Therefore, the nature of and balance between these different investments is critical. We consider a range of energy activities is likely to be more resilient over time, even if higher returns might be achieved at different times from a more-focused portfolio. In reality, for many years, the cash generated from oil and gas activities will fund or support other investments. Nonetheless, players will need to focus on low-cost, flexible developments to minimize the risk of holding stranded assets, if the energy transition advances rapidly over the coming decade.

Russian and Middle Eastern producers look at growing Asian markets

Russian and Middle Eastern gas producers have tended to focus on monetizing their massive gas reserves by targeting markets that have higher demand growth potential, such as LNG, gas pipeline export to Asia, and petrochemicals. Although the European gas market is set to stagnate, gas demand in China and other Asian countries is set to grow.

The Russian Energy Strategy aims to increase pipeline gas exports to 255 bcm-300 bcm a year, from 200 bcm in 2018 and LNG exports to 108 bcm-189 bcm a year, mostly to Asia-Pacific. Russia's largest capex projects across all sectors include Novatek's Arctic LNG-2, an LNG production project estimated to cost $21.3 billion; Gazprom's LNG export and chemical project in the Baltic port of Ust-Luga, which is estimated to cost Russian ruble (RUB) 750 billion and is being built through a 50:50 joint venture; and Sibur's new petrochemical plant. Novatek's unique location in the north of Russia makes it possible to ship LNG to both Europe and Asia via the Northern Sea Route.

Gazprom's CEO has unveiled plans to increase exports to China to 130 bcm. That said, we view these plans as very ambitious, long-term, and subject to massive capex. The first stage of the Power of Siberia project, commissioned in December 2020, involves a 2,200 km pipeline from the Chayanda gas field in Eastern Siberia to China. After that, considerable investments will be needed to build a 800 km pipeline link to the Kovykta gas field, construct the Amur gas processing plant, and ramp up exports to the 38 bcm of already-contracted volumes by 2024. And 38 bcm is far short of the 130 bcm target.

Expanding exports further would require a new multibillion pipeline from Gazprom's core production area in Western Siberia to China. In our view, this will only be possible if Gazprom manages to sign a new offtake contract with China. Therefore, for now, we expect Europe to remain the key market for Russian gas. Similarly, large Middle Eastern producers like QP are aiming to expand their LNG production and making vast investments in domestic petrochemicals.

On the ESG side, Russian gas producers Gazprom and Novatek focus on reducing emissions from their core operations, rather than on making a shift away from fossil fuel entirely. They will also play a major role in Russia's hydrogen strategy, which has a 2 million metric tonnes target by 2035.

Several Outlooks Have Turned Negative

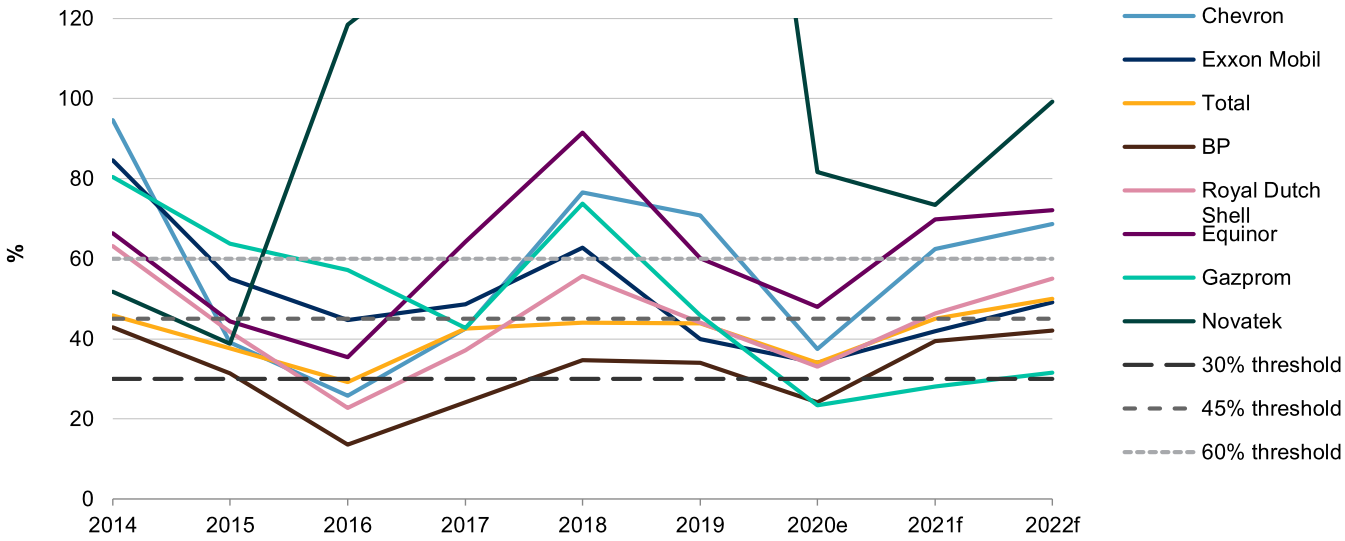
In the short term, the challenge for many gas producers will be to restore their credit metrics post-2020. Our ratings analysis considers multiyear averages. Thus, a rebound in credit measures in 2021 takes on greater important.

The record low prices of mid-2020 were below full costs and even below marginal costs for most gas producers. Gas storages were already full by year-end 2019, and the pandemic also hit sales volumes through demand destruction. Because prices were very low, Gazprom cut its exports to

Europe and many LNG producers faced cargo cancellations. Financial metrics were also hit by the oil price collapse and decline in liquids volume on the back of lockdowns, the economic recession, and changes in demand patterns. As the metrics fell below the level we consider compatible with our ratings, we revised to negative our outlooks on a number of players, including Shell, Equinor, and Gazprom. We will be monitoring how quickly the metrics recover in 2021-2022 to determine the effect on ratings.

Chart 7

2020 Packed Quite A Punch
We expect European gas producers' funds flow from operations-to-debt to rebound after 2020 trough



Source: S&P Global Ratings. e--Estimated. f--Forecast.

Financial policies make a difference

All the European gas producers have announced capex cuts of up to 30%. Some, like Shell and BP, also cut dividends. Other factors that may affect gas producers credit metrics include:

- The significant price recovery since August 2020. TTF prices rose to around $5/mmbtu in October-November from below $1.5/mmbtu in May, enabling most European producers to cover their costs.
- Financial headroom before the crisis. This was stronger at some producers, such as Equinor and Novatek.
- Diversification into oil. Gas prices are essentially decoupled from oil. It is particularly relevant for those producing associated gas. If liquid prices cover joint production costs, the cost of producing associated gas essentially falls to zero. Oil prices have recovered, reaching a level close to many producers' full costs more quickly than gas prices did.

- Contract structures. Legacy oil-linked contracts or forward-linked prices enable many gas producers to realize gas prices well above the spot price. For example, Gazprom's average export price to Europe and Turkey in the second quarter of 2020 was $110 per million cubic meters (/mcm)--the spot price at that time was well below $100/mcm. Management's guidance for full 2020 is $133/mcm. In 2019, only 33% of Gazprom's exports were under spot prices. The remainder comprised 17% oil-linked, 16% hybrid, 23% forwards, and 11% electronic sales platform and trading.
- Competitive costs and tax hedges. For example, we understand that Equinor's cost of gas delivered to European markets is about $1.6/mmbtu. We also estimate that Gazprom's full cash costs to Europe are about $2.1-$2.8/mmbtu, and its marginal costs are even lower, closer to $1.6/mmbtu, depending on the destination. Equinor's high corporate tax at 78% and Gazprom's 30% export duty act as partial natural hedges. Novatek's management estimates all-in costs for its Yamal LNG at $1.50-1.75/mmbtu for Europe.
- Regulated or quasiregulated domestic prices (for example, in Russia and Azerbaijan). Although regulated domestic prices in Russia have historically been well below export prices at about $60/mcm, they still cover operating expenditure, and the 2020 fall in export prices made domestic netbacks relatively attractive, when adjusted for transportation costs and export duty. Domestic sales remain low-margin, but profitable, and provided stable EBITDA contributions for Gazprom, Novatek, and Russian oil companies.
- In addition, we assume that national players such as Gazprom will receive ongoing and exceptional government support, which limits rating downside for these entities.

Utilities Ratings Are Supported By Diversification

Large integrated utilities had already moved away from significant exposure to gas operations because of reduced merchant gas activities. Increasingly, they prefer to expand their power network to the detriment of gas. Most rated large European utilities are diversified by fuel type and integrated. Their high EBITDA contribution from regulated and service activities helps offset the high volatility of gas-fired generation on their business risk profiles (see charts 1, 2, and table 1). The rated companies most exposed to gas-fired generation are Engie, Uniper, Fortum, A2A, Edison, and Naturgy. Many players hedge a high proportion of their power generation. For example, Uniper hedges 100% of 2020 production and 55% of 2021; Engie hedges 80% of 2020 production and 54% of 2021. Another alternative is to enter into long-term gas purchase contracts. This improves profit visibility, even if it sometimes locks-in unfavorable prices for electricity or gas under legacy contracts.

In European markets like the U.K. and France, gas-fired generation can receive capacity payments, but typically, their contribution to EBITDA is quite small at 5%-10%). Where companies are expanding their regulated network activities in Europe and abroad, they generally focus on power networks, rather than gas infrastructure (examples include Enel or Iberdrola). Some diversified utilities--including Engie, Naturgy and SSE--have also reduced their exposure to gas infrastructure as part of their asset rotation policy, either to lock in high valuations or to focus on faster growing segments.

Table 1

Europe's Largest Utilities' Exposure To Gas Is Manageable

Utility name	Exposure to gas generation/transportation*	Business risk profile	Rating
Gasunie	89%	Excellent	AA-/Stable/A-1+ (SACP 'a')
Engie	Gas networks about 38% EBITDA. Gas-fired generation about 49% of production (considering net ownership)	Strong	BBB+/Stable/A-2
Enel	Less than 2%	Strong	BBB+/Stable/A-2
Fortum (without consolidating Uniper)	Less than 15% (excluding Russia)	Satisfactory	BBB/Negative/A-2
Iberdrola	About 10%	Strong	BBB+/Stable/A-2
CEZ	2%-3% gas-fired generation	Strong	A-/Negative
Naturgy	Less than 58%	Strong	BBB/Stable/A-2
SSE	16%	Strong	BBB+/Stable/A-2
EP Infrastructure	About 75%	Strong	BBB/Stable

*Defined as percentage of EBITDA related to gas generation plus percentage of EBITDA related to gas transportation.

Growth Prospects Are Flagging

We believe gas generation growth prospects have been most affected by the market developments. Although utilization rates may remain high in the coming years, supported by the phasing out of coal and nuclear power, Europe is unlikely to build much new CCGT capacity. The economics of gas generation assets will gradually weaken as carbon prices rise and the cost of renewables falls further.

Much of the 2019-2020 uptick in European gas-fired generation comes from higher utilization of existing gas-fired capacity. The record low gas prices, combined with relatively high carbon dioxide prices, created an economic advantage for gas compared with coal. For the same reason, the pandemic-inspired decline in electricity volumes hit coal harder than gas.

At this stage, we don't expect to see massive new investments in gas infrastructure in Europe in the next five years. There has been massive construction in previous years, so that interconnectors, underground storage, and LNG terminals already support a sufficient degree of diversification and security of supply, in our view.

New investments in EMEA gas-fired generation remain limited. There were only a few projects, such as the 0.7 GW CCGT built in Italy and several relatively small coal-to-gas switching projects that have short payback times in northwestern Europe. For most rated companies, their strategy is to focus on growth in renewables generation. Companies aim to avoid having stranded assets, given Europe's decarbonization focus, technology development, and the weakening in clean spark spreads as gas prices rebound from the record lows of mid-2020.

Regulation Is Supportive But Tightening

Decarbonization targets mean uncertain times for gas, particularly compared with electricity networks. Its current monopolistic position and the very slow decline in natural gas consumption

still provides gas generators with earnings stability for the coming decade. These factors support the credit ratings, for now, but if long-term uncertainties are not clarified, companies will struggle to maintain their current ratings without reducing their financial leverage.

For regulated gas utilities in Western Europe, solid and predictable regulatory regimes remain the key factor that supports ratings. Regulated gas utilities in Europe have generally proved resilient to the downturn triggered by the pandemic. The regulations ensured that they had adequate coverage of operating expenditure as well as capex and, in most cases, also protected them from volume swings. Therefore, we typically demand less from them in terms of leverage metrics, and use low or medial volatility tables to assess their financial risk profile.

That said, in the longer term, uncertainty about the role of gas in each country's energy mix poses risk for gas infrastructure. We see weaker growth prospects and a higher risk of stranded assets materializing over time. We believe this may well start to weigh on regulatory returns and investments in gas over future regulatory periods.

Regulatory pressures have already emerged in several countries, leading to weaker projected financial metrics and weighing on outlooks. For example, recent regulatory resets in Spain and in the U.K. led to lower remunerations for gas utilities because regulators do not see the need for higher capex and because they allowed for lower interest rates. This has already triggered outlook revisions for several European gas utilities, including Wales & West Utilities' notes and Scotia Gas Network in April 2020.

Regulated gas utilities in Western Europe are increasingly looking to reinvent their business models by growing into activities aligned with the EU decarbonization focus, such as hydrogen. That said, this is an area subject to technological uncertainty and requires the adaptation of regulatory frameworks. It also involves massive capex and will still result in some stranded assets, given that in many cases the routes needed for hydrogen and for methane are different. Therefore, this switch could still heighten future business risk.

New Infrastructure Projects Face Risks

Several large European gas infrastructure projects in progress still face uncertainties. Completion of NordStream 2 will largely depend on U.S. sanction risks, for instance. That said, the pipeline was 94% complete by the end of 2019, meaning that most costs are sunk. Even if NordStream 2 is not completed, we don't see any material risks for gas flows to Europe from Russia and we expect the project's 100% shareholder Gazprom and European energy companies Shell, Engie, Uniper, and OMV (which provided debt funding for it) to be able to manage the rating impact of a failure to finish building the pipeline. Broad sanctions on large parts of the gas value chain are not part of the base-case scenarios in our ratings analysis for the European energy sector.

EP Infrastructure's subsidiary Eustream, a gas transit operator in Slovakia, gains revenue visibility--and therefore rating support--from its lucrative legacy long-term ship-or-pay contracts. These include a contract for 50 bcm per year, until 2028. That said, we don't necessarily expect such contracts to be renewed at the same lucrative terms when they expire. The risk of contract renegotiation remains key to our analysis, given the long-term uncertainty about gas transportation volumes and potential competition with NordStream 2.

The most recent new gas pipeline into Europe, Trans-Adriatic Pipeline (TAP), was completed in November 2020. It brings gas to Italy, Bulgaria, and Greece from Azerbaijan's Shah Deniz field. We expect other gas pipeline projects already in progress to be completed. These include the Baltic pipeline, which is due to complete in October 2022, and several interconnectors. The Baltic pipeline will carry 10 bcm to Poland from Norway.

Both TAP and the Baltic pipeline are relatively small in terms of impact on Europe's energy security, but could influence gas pricing and competition in specific countries, such as Italy or Poland. The recent military conflict between Azerbaijan and Armenia in Nagorno-Karabakh highlights TAP's political risks. Although oil and gas assets are relatively remote, the pipeline that eventually feeds TAP runs only 30-40 kilometers from the conflict zone. We understand that the conflict has not yet affected oil and gas assets or operations. Despite the ceasefire in November 2020, some political uncertainty remains. We forecast that TAP will make only a limited EBITDA contribution because of the high cost of gas and its gradual ramp-up.

Gas-Supportive Policies Boost Utilities' Margins In CIS

In contrast to Western Europe, in the Commonwealth of Independent States (CIS), governments' energy policies are generally supportive of gas. Therefore, we expect gas-fired generation to remain profitable and stable. Nevertheless, growth potential for gas in Russia is limited by existing overcapacity and stagnant energy demand. The following rated companies in the region are heavily exposed to gas:

- Mosenergo, a Russian power generating company (almost 100% of generation volumes);
- TGC-1, a regional power company in northwest Russia (two-thirds of generation volumes);
- Georgian Oil and Gas Corporation (100% of generation volumes); and
- Azerenerji, an electrical power producer in Azerbaijan.

For European companies operating in Russia (such as Fortum and Uniper), the key risk relates to foreign exchange volatility (the ruble weakened in 2020). Fortum and Uniper have a material presence in Russia of about 25%, including gas-fired power generation.

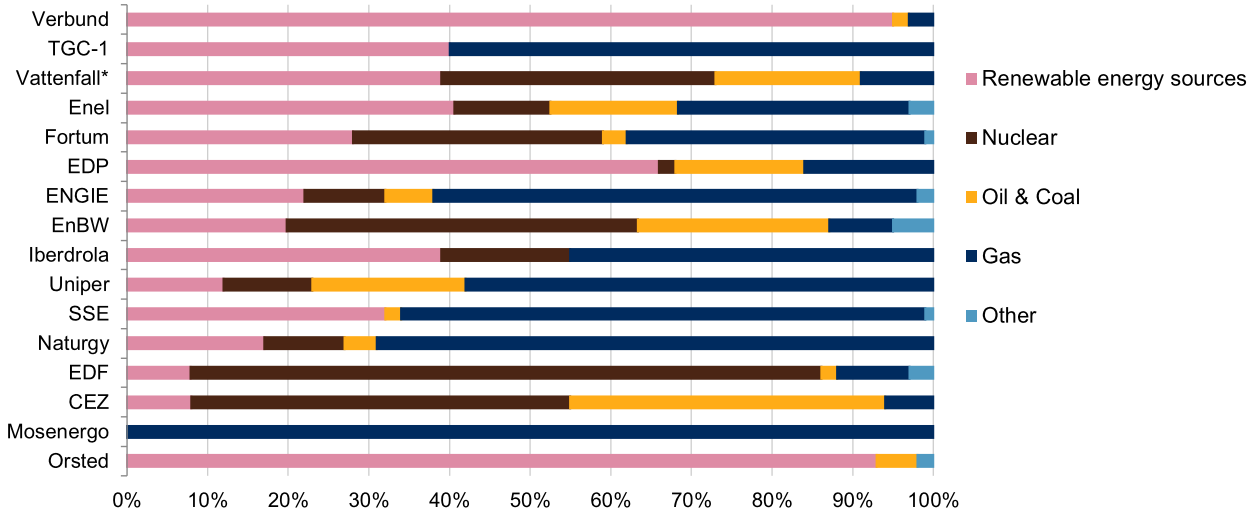
In the CIS, we view gas as positive because it doesn't carry near-term exposure to regulatory risks or to gas price volatility. In Russia, gas-fired generation benefits from lucrative capacity supply agreements (CSAs). About 15%-20% of revenue at TGC-1 and Mosenergo comes through CSAs, which guarantee return on historical investments.

Domestic gas prices are also stable as Russia's largest producer, Gazprom, is regulated, electricity prices are less volatile than in many large European markets, and competition with renewables other than hydro is limited. Even though capacity revenue is set to decline as first-round CSAs expire and the second round of CSAs will be considerably smaller, solid EBITDA has enabled Mosenergo and TGC-1 to repay most of their legacy debt. This means that funds from operations (FFO) to debt is above 60% for both companies.

Russia's Energy Strategy, approved in 2020, aims at 2%-5% growth in domestic gas consumption by 2030, compared with an increase of up to 3% in primary energy consumption. We expect investments in gas-fired generation to focus on modernization, increasing the efficiency of the existing fleet, and import substitution for turbine manufacturing. There is unlikely to be significant capacity expansion. Georgia is also a gas-supportive environment because the government promotes construction of all types of new electricity generation, to reduce dependency on energy imports and ensure security of supplies. As a result, GOGC's gas-fired plants enjoy attractive power sales agreements that have stable U.S. dollar-denominated prices or guaranteed returns on investment. These agreements resemble some of the Western European companies' arrangements for renewables and have contributed 70% of GOGC's EBITDA since Gardabani-2 was commissioned in early 2020. The company's operations remain resilient--its main risk is now related to refinancing of its 2021 bond.

Chart 8

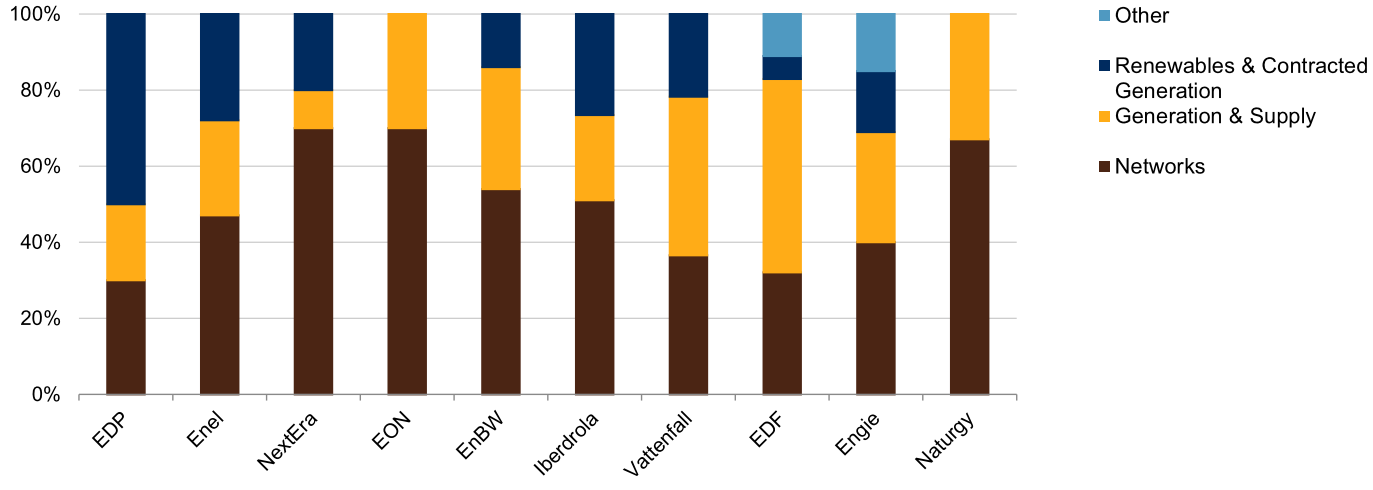
Large European Utilities Have A Diversified Fuel Mix
2019 electricity generation by sources



*Pro rata figures. Source: S&P Global Ratings.

Chart 9

Europe's Largest Utilities Are Diversified Between Regulated And Unregulated Activities



Source: S&P Global Ratings.

This report does not constitute a rating action.

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Attachment 51.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

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(accessible by opening the Attachments Tab in Adobe)

Attachment 52.2

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 56.2.1

REFER TO LIVE SPREADSHEET MODEL

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(accessible by opening the Attachments Tab in Adobe)

Attachment 58.6

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

FILED CONFIDENTIALLY

(accessible by opening the Attachments Tab in Adobe)