Sarah Walsh
Director, Regulatory Affairs

Gas Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

Electric Regulatory Affairs Correspondence
Email: electricity.regulatory.affairs@fortisbc.com

FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (778) 578-3861
Cell: (604) 230-7874
Fax: (604) 576-7074
www.fortisbc.com

September 6, 2024

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

Attention: Patrick Wruck, Commission Secretary

Dear Patrick Wruck:

Re: FortisBC Energy Inc. (FEI) and FortisBC Inc. (FBC) (collectively FortisBC)

Application for Approval of a Rate Setting Framework for 2025 through 2027 (Application)

Response to the British Columbia Utilities Commission (BCUC) Information Request (IR) No. 1

On April 8, 2024, FortisBC filed the Application referenced above. In accordance with the regulatory timetable established in BCUC Order G-165-24 for the review of the Application, FortisBC respectfully submits the attached response to BCUC IR No. 1.

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

If further information is required, please contact the undersigned.

Sincerely,

on behalf of FORTISBC

Original signed:

Sarah Walsh

Attachments

cc (email only): Registered Interveners.

Table of Contents **Page No.**

A. OVERVIEW

1.0 Reference: OVERVIEW

Exhibit B-1 (Application), Section A1.3.2, p. A-5, Section B2.3.1, p. B-35

Proposed Rate Setting Framework (Rate Framework) – Approach to Base Operations and Maintenance (O&M)

On page A-5 of the Application, FortisBC states:

> For the Rate Framework, both FEI and FBC established the 2024 Base O&M using the same method used to establish the 2019 Base O&M in the Current MRP [FortisBC 2020—2024 Multi-Year Rate Plan]. […] The starting point for determining the O&M per customer amount is the 2024 Base O&M, which is the adjusted actual O&M expenditures for 2023 expressed over the average number

of customers for 2023, escalated by the approved formula indexing factors for 2024, and includes expected spending for 2024 and incremental funding proposed for the term of the Rate Framework.

On page B-35 of the Application, FortisBC states: "the MRP term for both Enbridge Gas and Ontario's electric utilities typically includes a one-year cost of service for establishing the going-in base rates."

1.1 Please explain why it is appropriate for FortisBC to establish its 2024 Base O&M as described on page A-5 of the Application as opposed to based on its cost of service for the first year of the proposed Rate Framework as done by Enbridge Gas and Ontario's electric utilities.

1.1.1 Please discuss the advantages and disadvantages of both approaches for setting the Base O&M as described in the preceding information request (IR).

Response:

FortisBC notes that, except for the Companies' formula O&M and FEI's Growth capital, all the other components of the Rate Framework are set based on a cost-of-service methodology. Further, as discussed below, the approach used to set the 2024 Base O&M is similar to a cost-of-service approach and therefore, the result would not be materially different.

FortisBC's approach to setting the 2024 Base O&M for the proposed Rate Framework is consistent with its approach taken to set the 2019 Base O&M for the Current MRP from 2020 to 2024. Using the 2023 Actual Base O&M per customer as the starting point reflects FortisBC's most recent full year of actual costs to serve its customers, which incorporates all of the productivity savings achieved over the term of the Current MRP. The 2023 Actual O&M (as well as the 2019 to 2022 Actual O&M) has been provided in detail in Appendices C2-1, C2-2 and C2-3 to the Application, and the detailed explanations for the adjustments to 2024 and the incremental O&M funding starting in 2025 are presented in Sections C2-2 and C2-3 of the Application. Therefore, both the historical and forecast O&M are available for examination, similar to the detail that would be available in a cost-of-service rebasing application. The result of the proposed 2024 Base O&M for FEI and FBC and the resulting 2025 O&M funding envelope would therefore generally be the same as a new O&M forecast for 2025 developed on a cost-of-service basis.

Ultimately, FortisBC's approach to setting the 2024 Base O&M is reflective of its cost-of-service, while also allowing rebasing in the same way that a cost-of-service application or an O&M forecast on a cost-of-service basis would provide, but with improved regulatory efficiency. This was agreed and accepted by the BCUC as part of the MRP Decision:[1]

> The Panel agrees with FortisBC and BCOAPO that it is reasonable to use the 2018 Actual O&M as the starting point for determining FEI and FBC Base O&M for the

[1] Decision and Orders G-165-20 and G-166-20, p. 107.

> MRP. Regarding the concerns expressed by the CEC and ICG that a full review of costs should be developed prior to implementing another different formula or that a BCUC- approved COS for 2020 is necessary, <u>the Panel is persuaded by FortisBC's submission that there is no material difference between what FortisBC has proposed and having a 2020 forecast of O&M. As FortisBC points out, the 2018 Actual O&M and all adjustments were available for review and scrutiny in this proceeding</u>. [Emphasis added]

As discussed in Section 3 of Appendix B2-2 to the Application, utilities in Ontario can choose an Incentive Rate-setting Plan approach that is suited to their specific circumstances, including setting going-in rates based on cost-of-service or other approaches in the first year of the rate-setting term. The requirements for going-in rates for each Incentive Rate-setting Plan for utilities in Ontario are shown in Table 7 of Appendix B2-2 to the Application and summarized below:

- **Price-cap model:** The utilities adopting this approach are directed to file a one-year cost-of-service application for setting their going-in rates.
- **Custom approach:** Under this option, setting the going-in rates is not subject to a common prescribed model. Rebasing can be based on a traditional cost-of-service model or a hybrid methodology (e.g., using a combination of actual costs and cost-of-service forecasts similar to the approach used by FEI and FBC).
- **Annual indexing:** Under this option, there is no need to periodically set base rates using a cost-of-service application. Distributors with relatively steady state investment needs (i.e., primarily sustainment) may prefer this approach.

In addition to the rebasing approaches above, the Ontario Energy Board (OEB) established a policy to encourage consolidation that allowed entities undergoing consolidation to defer rebasing for up to 10 years. Prior to Enbridge Gas' (EGD) 2024 Rebasing Application for its 2024 to 2028 rate-setting plan, EGD deferred rebasing for their 2019 to 2023 rate-setting plan, which was under the Price Cap model, given their amalgamation with Union Gas in 2019.[2]

This highlights that utilities in Ontario have wide flexibility to choose from a number of options for setting going-in rates, recognizing that the appropriate rate-setting approach may be different based on the specific circumstances of each utility.

The OEB's Incentive Rate-setting Plan differs from the Companies' proposed Rate Framework in that rates are subject to indexing whereas only FortisBC's O&M and Growth capital (FEI only) are subject to indexing. For example, under the OEB Price-cap model, rates are indexed to inflation less the productivity factor (i.e., I-X), meaning that there is no separately defined O&M or capital funding envelope (i.e., no itemized costs) and utilities can arbitrage between capital and O&M expenditures during the Incentive Rate-setting Plan term. Therefore, the OEB and interveners will

---

[2] Despite proposing a deferred rebasing period, Union Gas and EGD's application included four specific adjustments to their base rates. All four proposed adjustments were approved.

not have access to the utility's detailed O&M or capital expenditure data until the cost-of-service rebasing application is filed, which further supports the approach taken in Ontario.

FortisBC also notes that its rebasing approach is similar to the approach taken by the Alberta Utilities Commission (AUC), who recognized the improved efficiency achieved with a more streamlined review. The AUC determined that utilities should be able to adopt the rebasing approach that fits their needs and shall not prescribe a specific methodology for developing the 2023 revenue requirement forecasts. As a result, the AUC adopted a hybrid methodology for assessing the 2023 forecasts. Under this hybrid methodology, the extent to which expenditures are examined is guided by the nature, size or complexity of the associated cost to facilitate a streamlined review:[3]

> The Commission agrees with the majority of parties and will adopt a hybrid methodology under which the review of expenditures is guided by the nature, size or complexity of the associated cost, allowing the Commission to focus on certain cost categories, while other costs could be assessed in a more streamlined manner. The Commission finds that using this methodology to establish a revenue requirement on a COS basis best achieves the objectives set out in Bulletin 2021-04, while allowing for a streamlined and efficient regulatory process. The Commission agrees with ENMAX's view that each DFO should be allowed to develop its 2023 forecast on its own accord with an understanding that the utility bears the onus of demonstrating and supporting the reasonableness of the elements comprising its revenue requirement. The Commission finds that adopting a hybrid methodology permits DFOs to both streamline their submissions pertaining to costs that are routine or less controversial, and to tailor and focus their 2023 COS applications on complex issues. <u>The Commission further considers that a hybrid methodology achieves an appropriate balance between regulatory efficiency and providing an adequate opportunity for interveners and the Commission to test a utility's case</u>. [Emphasis added]

1.2 Please explain, in FortisBC's view, what differences exist between FEI/FBC and Enbridge Gas/Ontario's electric utilities that would necessitate different approaches to setting the Base O&M for a multi-year rate plan or rate setting framework.

<u>Response:</u>

Please refer to the response to BCUC IR1 1.1.

---

3 AUC Decision 26354-D01-2021, para. 13.

2.0 Reference: OVERVIEW

Exhibit B-1, Section B1.6.1.2, p. B-12

Climate Change Operational Adaptation Plan

On page B-12 of the Application, FortisBC states:

> […] FortisBC's Climate Change Operational Adaptation (CCOA) work aims to <u>improve asset and operational resilience to climate change risks</u> and to maintain safe and reliable energy supply to customers. In 2023 and 2024, as part of its initial CCOA development work, FortisBC is evaluating the risk of climate-related events to its various asset types. These events include wildfires, flooding, sea-level rise, windstorms, snowstorms, extreme temperature, landslides, lightning, and freeze-thaw events. […] [*Emphasis added*]

2.1 Please confirm, or explain otherwise, that the CCOA plan as described in the preamble above relates only to FBC.

2.1.1 If confirmed, please discuss whether FEI has a similar CCOA plan or a plan under a different name that accomplishes the same objective. Please explain how the associated costs are handled for FEI.

<u>Response:</u>

The CCOA development work described in the preamble to this IR is referring to FBC. However, FEI also considers the need to improve asset and operational resilience to climate change risks to be of high importance and is undertaking similar CCOA development work. FEI is funding its work on climate change operational adaptation through formula O&M.

3.0 Reference: OVERVIEW

Exhibit B-1, Appendix E3 (Draft Final Order – FBC), p. 3

FBC – Approvals Sought

In the Draft Final Order – FBC, Directive 4 states that FBC is seeking "Approval of Exogenous Factor treatment for the 2021 Flood costs, as described in Section C1.6.1."

3.1 Please confirm, or explain otherwise, that Directive 4 in the Draft Final Order – FBC is a typographical error, as the flooding costs discussed in Section C1.6.1 of the Application pertain only to FEI.

<u>Response:</u>

Confirmed. FortisBC inadvertently copied over the wording from Directive 6 of FEI's Draft Final Order (Appendix E2) to FBC's Draft Final Order (Appendix E3). FortisBC is only seeking exogenous factor treatment of the flooding costs for FEI. Please refer to the Errata to the Application filed concurrently with these IR responses for a revised Appendix E3.

B. RATE SETTING FRAMEWORK CONSIDERATIONS

4.0 Reference: RATE SETTING FRAMEWORK CONSIDERATIONS

Exhibit B-1, Section B1.3.1, p. B-3, Section B1.3.5, p. B-5, Section B1.3.7, p. B-6 to B-7

Policies Guiding the Energy Transition in BC

On page B-3 of the Application, FortisBC states:

> As described in the CleanBC Roadmap to 2030, the Greenhouse Gas Reduction Standard (GHGRS) will establish an obligation for natural gas utilities to reduce GHG [Greenhouse Gas] emissions from energy delivered to the buildings and industrial sectors by way of an annual cap of approximately 6 Mt CO2e [million tonnes of carbon dioxide-equivalent] on gas customer emissions. The GHGRS cap is a significant part of the Province's CleanBC 2030 Roadmap, considering that more than half of the buildings in BC are heated with natural gas. The provincial government has indicated that enabling legislation for the GHGRS will be introduced to the provincial legislature in 2024. [*Footnote omitted*]

On page B-5 of the Application, FortisBC discusses how the federal government issued an initial draft of the Clean Electricity Regulations (CER) under the Canadian Environmental Protection Act, 1999 with the objective of reaching net-zero emissions from Canada's electricity grid by 2035. FortisBC states that these changes in the industry will drive significant investment beyond generation, including major upgrades to distribution networks and deployment of smart grid technology. As these proposed regulations are still in the early consultation stages, the impact to FortisBC is uncertain.

On pages B-6 and B-7 of the Application, FortisBC also discusses building codes including (i) the BC Energy Step Code which will move towards net-zero ready performance for new buildings by 2030; (ii) the Zero Carbon Step Code which is a further advancement in building standards that focuses on reducing GHG emissions; and (iii) the City of Vancouver Building Code which allows the City of Vancouver to accelerate the timeline of the BC Energy Step Code or implement further energy performance requirements.

4.1 Please provide FEI's historical and forecast annual GHG emissions from energy delivered to the buildings and industrial sectors for each year from 2018 through 2030.

<u>Response:</u>

Please refer to the table below.

Table 1: Actual and Forecast GHG Emissions [1,2]

Year	Actual / Forecast	GHG Emissions from the Building and Industrial Sector (million tCO2e)
2018	Actual	10.5
2019	Actual	11.2
2020	Actual	10.8
2021	Actual	11.2
2022	Actual	11.4
2023	Actual	10.5
2024	Forecast	9.2
2025	Forecast	8.8
2026	Forecast	8.4
2027	Forecast	8.0
2028	Forecast	7.5
2029	Forecast	7.1
2030	Forecast	6.6

Notes to Table:

[1] Actuals from 2018-2022 do not account for reductions in GHG emissions from the use of RNG. Combustion emission factors are based on those provided in FEI's 2022 Long Term Gas Resource Plan (LTGRP).

[2] Forecasts are based on the Diversified Energy Planning (DEP) Scenario in FEI's 2022 LTGRP.

4.2 Please provide FEI's share of the approximately 6 Mt CO2e annual cap on gas customer emissions as described in the CleanBC Roadmap to 2030.

Response:

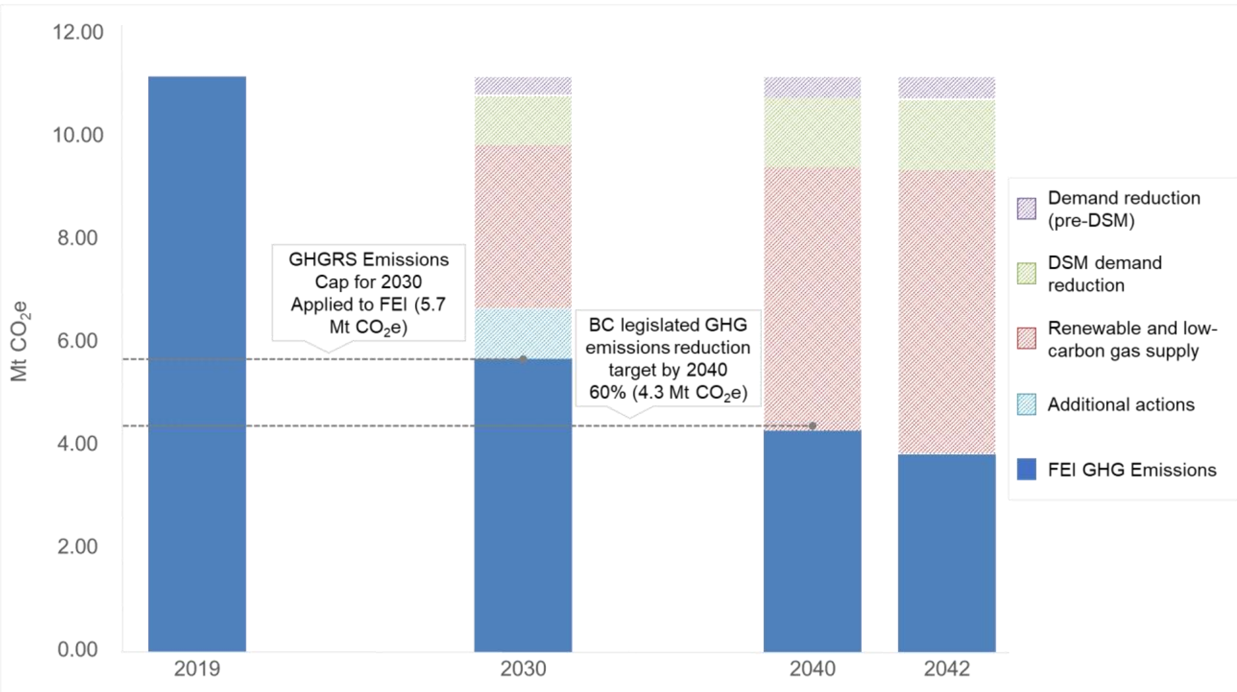
At this time, the allocation of the annual cap on gas customer emissions in accordance with the CleanBC Roadmap to 2030 has not been established by the BC Government and no additional guidance has been provided. However, as set out in the response to BC Hydro and Power Authority (BC Hydro) IR2 2.6 in FEI's Revised Renewable Gas Program Application – Stage 2, FEI estimated its portion of the 6.1 Mt CO2e cap to be approximately 5.8 Mt CO2e.

4.2.1 Please discuss FEI's progress and plan during the proposed term of the Rate Framework and beyond towards meeting its share of the proposed annual cap including, but not limited to, current and planned initiatives in reducing customer GHG emissions and challenges faced by FEI.

Response:

FEI described its plan to meet the proposed annual cap in GHG emissions, also known as the Greenhouse Gas Reduction Standard (GHGRS), in its 2022 LTGRP. The plan was illustrated in Figure 9-1 of the 2022 LTGRP, which is reproduced below.

Figure 9-1: GHG Emission Reductions for Residential, Commercial and Industrial Customers Meets the GHGRS for the Diversified Energy (Planning) Scenario



However, as explained in the response to BCUC IR1 4.2, the GHGRS has not yet been established by the Province. Therefore, FEI's primary challenge at this time is the lack of any details on the GHGRS and, in particular, the lack of any guidance on acceptable GHG emission reduction compliance pathways. For example, while FEI plans to reduce emissions through the utilization of carbon capture and storage, the necessary legislative framework to facilitate and recognize such emission reductions has not been established.

4.3 Please elaborate on how FortisBC has incorporated government policies that are not yet government regulations (such as the CleanBC Roadmap to 2030, the draft CER, and various building codes) into the components of the proposed Rate

Framework. Please provide a separate discussion for each of FEI and FBC as applicable.

Response:

Please refer to the response to BCUC Panel Supplemental IR 1 for details on how FortisBC has designed the Rate Framework to incorporate the growing impacts of the energy transition into rates each year through the Annual Review process and other approved mechanisms, as well as to provide incentives to achieve cost savings. This includes:

- Mechanisms such as the flow-through treatment of Clean Growth Initiatives to enable FEI to acquire renewable and low carbon fuels;
- The ways in which FBC has incorporated increased O&M and capital spending to address the increased pressure of electrification on its system and the need to adapt to climate change impacts on its above-ground assets; and
- The continuation of a formulaic approach to FEI's Growth capital so that investments in Growth capital are directly tied to changes in annual customer attachments.

Further, and as explained in the responses to the BCUC Panel Supplemental IRs, the energy transition is having and will continue to have an impact on rates, and both FEI and FBC continue to evolve the rate-setting frameworks to help manage the impacts. In particular, as explained in the response to BCUC Panel Supplemental IR 1, FortisBC's substantive actions in response to policies and regulations will largely be addressed in separate proceedings, through applications such as the Companies' long term resource plans, demand side management (DSM) expenditure plans, rate design applications, major project applications, and energy supply agreements and plans.

While FortisBC has considered current and future policies in the development of the Rate Framework, it is not able to incorporate specific adjustments to the Rate Framework mechanisms for policies that are not yet finalized or enacted in government regulation. The timing and specific details of government policies, regulations and legislation that remain under development are uncertain until they are enacted, and it is FortisBC's experience that until legislation is enacted, it can be difficult to know exactly how it will affect the Companies or how the Companies will need to adapt to meet any requirements that legislation may impose on the utilities. Further, in many cases, FortisBC requires enacted legislation to implement responses to the energy transition (for instance, changes to the DSM Regulation impact the programs that FEI can offer, which was the case with FEI's most recent 2024-2027 DSM Plan).

Regardless, FortisBC has put forward a Rate Framework with features that make it inherently flexible and able to respond to significant changes in the operating environment, just as FortisBC's Current MRP has proven able to adapt to significant events such as the COVID-19 pandemic. As discussed in the response to BCUC Panel Supplemental IR 2, FortisBC has identified how the Rate Framework has been designed to manage rate impacts associated with increased costs facing both FEI and FBC, decreased load/revenue facing FEI, and extraordinary/unforeseen events affecting both FEI and FBC. Therefore, while the specific impacts of future policies are difficult to predict, the Rate Framework puts FortisBC in a position to be able to respond and adapt as needed.

4.4 Please explain how the components of the proposed Rate Framework would be flexible to changes in legislation (e.g. if enabling legislation for the GHGRS were introduced to the provincial legislature in 2024 or if the CER were codified into legislation before 2027, or if municipalities were to voluntarily take up compliance with various building codes prior to established deadlines).

Response:

Please refer to the response to BCUC IR1 4.3.

C. PROPOSED RATE SETTING FRAMEWORK – COMPONENTS OF THE RATE FRAMEWORK

5.0 Reference: PROPOSED RATE SETTING FRAMEWORK – COMPONENTS OF THE RATE FRAMEWORK

Exhibit B-1, Section B1.3.1, p. B-3, Section C1.2, p. C-3

Term

On page B-3 of the Application, FortisBC states: "The provincial government has indicated that enabling legislation for the GHGRS [Greenhouse Gas Reduction Standard] will be introduced to the provincial legislature in 2024."

On page B-45 of the Application, FortisBC states: "Three years is a shorter term compared to the Current MRP and the previous 2014-2019 PBR [Performance-based regulation] Plan, and it reflects the uncertainty inherent in the operating environment due to the energy transition."

5.1 Please discuss the advantages and disadvantages of a Rate Framework term that is shorter than three years given both the uncertainty in FortisBC's current operating environment due to the energy transition and the enabling legislation for the GHGRS that may be introduced to the provincial legislature in 2024.

Response:

FortisBC does not consider there to be any advantages to shortening the Rate Framework term to be less than three years, while there are material disadvantages to doing so. FortisBC considers that a three-year term strikes a reasonable balance between managing the uncertainty inherent in the energy transition, while also providing a long enough timeframe to find some efficiencies in the regulatory process and provide certainty on the rate mechanisms in place.

First, a shorter term would offer no advantages. A three-year term is already materially shorter than the Current MRP and the previous 2014-2019 PBR Plan, as well as the common term of rate frameworks in other jurisdictions. The jurisdictional summary in Section B2.3.1 of the Application demonstrates that, with the exception of Energir's plan, all other jurisdictions have a five-year term. FortisBC considers that reducing the term from the typical five years to three years sufficiently addresses the uncertainty caused by the energy transition. In three years (in 2027), further policy developments may have occurred, with further clarity provided on what roles the gas and electric utilities play in the future, and on how gas and electric utilities can work together to accommodate the energy transition. A three-year term therefore provides an opportunity to evaluate whether a change to the Rate Framework is needed once policy has had time to develop.

A shorter term is also not needed because, as set out in Section B of the Application and in greater detail in the responses to the BCUC Panel Supplemental IRs, the Rate Framework provides a flexible and efficient approach to rate-setting that supports both Companies' abilities to adapt to the energy transition and manage the energy transition's impacts on the provision of affordable, reliable and resilient service to customers. Further, as explained in the response to BCUC Panel Supplemental IR 3, the Companies have been actively adapting to the changing energy landscape and continue to evolve their energy services and operations in response to the energy transition. While some of these changes are reviewed and approved through the rate-setting process, many of the changes are reviewed and approved/accepted through separate regulatory processes, such as DSM expenditure applications, rate design applications, acquisitions of renewable gas through filings pursuant to section 71 of the *Utilities Commission Act* (UCA), annual contracting plans, and long-term resource plans. Accordingly, the proposed Rate Framework incorporates flexibility to support the Companies' efforts to adapt to changing policies/legislation and shortening the term of the Rate Framework would offer no advantage in this regard.

Second, a shorter term would come with material disadvantages, as it would create regulatory inefficiency and uncertainty. As explained in the response to BCUC Panel Supplemental IR 4, FortisBC spent close to a year developing this Rate Framework Application, which included consultation with the BCUC staff and interveners, the retention of subject matter experts, and a jurisdictional review of how other utilities are setting rates. Based on the timetable established by Order G-165-24, a decision on the Application will be issued sometime in 2025. Thus, if the Rate Framework were only two years or less, the length of the Rate Framework would be shorter than the process to develop, file and review the Application, and FortisBC would need to commence preparing the next application immediately after receiving the decision on the current Application. For this reason, FortisBC considers that a three-year term is the minimum time required to enable efficiencies in the regulatory process and provide certainty on the rate mechanisms in place. Creating regulatory efficiency is vital, as it allows the Companies to focus more time and resources on other regulatory applications (such as the development of the next long term resource plans) and on responding to the energy transition and the complex operating environment. FortisBC therefore considers that a shorter term for the Rate Framework would actually detract from its ability to respond to the energy transition.

6.0 Reference: PROPOSED RATE SETTING FRAMEWORK – COMPONENTS OF THE RATE FRAMEWORK

Exhibit B-1, Section C1.3, pp. C-4 to C-5

Inflation Factor (I-Factor)

On page C-4 of the Application, FortisBC proposes to return to fixed labour and non-labour weightings based on the average of the 2019 to 2023 actual labour and non-labour weightings to calculate the I-Factor for the duration of the proposed Rate Framework.

On page C-5 of the Application, FortisBC states that it “considers the benefits of regulatory efficiency outweigh the potential for decreased accuracy.”

Further, on page C-5 of the Application, FortisBC states:

> FortisBC has observed during the Current MRP term that there may be less acceptance of the approach directed in the MRP Decision [also referred to as Current MRP Decision in this BCUC IR No. 1] of recalculating the labour and non-labour ratios annually based on the number and types of information requests received during the Annual Reviews. While FortisBC appreciates that the intent is generally to understand how the weightings are being calculated and why they are changing annually, the requests ultimately result in additional time and effort for the Companies to prepare these responses and do not have a bearing on the approvals being sought in the Annual Reviews, because the method for calculating the weightings was established in the MRP Decision and is not subject to change during the term of the Current MRP. […]

6.1 For each of FEI and FBC, please calculate the fixed labour and non-labour weightings for the Current MRP using the same methodology as proposed in the Application (i.e. five-year average of the 2015 to 2019 actual labour and non-labour weightings).

Response:

Please refer to Table 1 below for the actual labour and non-labour weightings from 2015 to 2019 for both FEI and FBC. The five-year average of the 2015 to 2019 actual labour and non-labour weighting for FEI is 51 percent and 49 percent, respectively. For FBC, the five-year average of 2015 to 2019 actual labour and non-labour is 60 percent and 40 percent, respectively.

Table 1: Five-Year Average of the 2015-2019 FEI and FBC Actual Labour and Non-Labour Weightings

	FEI		FBC	
	Labour	Non-Labour	Labour	Non-Labour
2015	51%	49%	62%	38%
2016	50%	50%	59%	41%
2017	48%	52%	57%	43%
2018	52%	48%	60%	40%
2019	52%	48%	62%	38%
Average	51%	49%	60%	40%

6.1.1 Under a scenario where the I-Factor in the Current MRP had been approved using the fixed labour and non-labour weightings calculated in the preceding IR, please quantify what the difference would have been in FEI's and FBC's formula O&M and FEI's growth capital compared to the approved amounts for each year from 2020 through 2024.

Response:

Please refer to Tables 1, 2, and 3 below for FEI's formula O&M, FBC's formula O&M, and FEI's Growth capital, respectively, for the Current MRP term if the I-Factor was calculated using a fixed labour and non-labour weighting based on the five-year average from 2015 to 2019. As calculated in the response to BCUC IR1 6.1, FortisBC has used a fixed labour weighting of 51 percent for FEI and 60 percent for FBC, and a fixed non-labour weighting of 49 percent for FEI and 40 percent for FBC.

Table 1: FEI's Formula O&M Calculated Using Fixed Labour and Non-Labour Weightings Compared to Approved Inflation Indexed O&M

	2020	2021	2022	2023	2024	Total
FEI Fixed Weighting Inflation Indexed O&M ($000s)	261,820	272,197	284,837	298,497	311,533	1,428,883
FEI Approved Inflation Indexed O&M ($000s)	261,798	272,463	285,219	299,302	312,561	1,431,343
Difference ($000s)	22	(266)	(382)	(805)	(1,028)	(2,460)
Difference (%)	0.01%	-0.10%	-0.13%	-0.27%	-0.33%	-0.17%

Table 2: FBC's Formula O&M Calculated Using Fixed Labour and Non-Labour Weightings Compared to Approved Inflation Indexed O&M

	2020	2021	2022	2023	2024	Total
FBC Fixed Weighting Inflation Indexed O&M ($000s)	59,682	62,116	65,897	70,070	72,529	330,294
FBC Approved Inflation Indexed O&M ($000s)	59,752	62,261	66,200	70,318	72,823	331,354
Difference ($000s)	(70)	(145)	(303)	(248)	(294)	(1,060)
Difference (%)	-0.12%	-0.23%	-0.46%	-0.35%	-0.40%	-0.32%

Table 3: FEI's Growth Capital Calculated Using Fixed Labour and Non-Labour Weightings Compared to Approved Inflation Indexed Growth Capital

	2020	2021	2022	2023	2024	Total
FEI Fixed Weighting Inflation Indexed Growth Capital ($000s)	68,203	62,576	80,898	67,273	65,507	344,457
FEI Approved Inflation Indexed Growth Capital ($000s)	68,199	62,593	80,920	67,280	65,550	344,542
Difference ($000s)	4	(17)	(22)	(7)	(43)	(85)
Difference (%)	0.01%	-0.03%	-0.03%	-0.01%	-0.06%	-0.02%

As shown in Table 1, for FEI, using a fixed labour/non-labour weighting of 51 percent/49 percent would have reduced formula O&M by approximately $2.460 million in total over the five-year period, which is equivalent to approximately $491.9 thousand per year or 0.17 percent. The reduction to FEI's Growth capital shown in Table 3 of approximately $85 thousand over the five-year period is equivalent to only $17 thousand per year or 0.02 percent.

For FBC, as shown in Table 2, using a fixed labour/non-labour weighting of 60 percent/40 percent would have reduced formula O&M by approximately $1.060 million in total over the five-year period, which is equivalent to approximately $212 thousand per year or 0.32 percent.

6.2 Please quantify, both in dollars and percentage points, the forecasted "decreased accuracy" under the proposed method versus the previously approved method for calculating the I-Factor during each year of the proposed term of the Rate Framework (i.e. 2025 to 2027).

Response:

While responding to this information request, FortisBC discovered an inconsistency between the labour/non-labour percentages provided in Table C1-2 of the Application and its actual O&M results for each year. As noted on page C-4 of the Application, Table C1-2 provides the labour and non-labour splits that were presented in each year of the Annual Reviews. However, as approved in the MRP Decision and explained in each Annual Review, the actual O&M results used to determine the labour and non-labour weightings are the most recent full year of actuals, resulting in two-year lagged actual O&M results being used to determine the I-Factor weightings.[4]

Please see Table 1 below for the revised version of Table C1-2 of the Application with the actual labour and non-labour weightings for FEI and FBC from 2019 to 2023. The revised five-year average split from 2019 to 2023 is 50 percent labour and 50 percent non-labour for FEI, and 60 percent labour and 40 percent non-labour for FBC. FortisBC accordingly proposes to revise its approvals sought for the I-Factor to reflect the corrected labour/non-labour weightings for FEI and FBC. Please refer to the Errata to the Application filed concurrently with these IR responses for

4 For example, in FEI's Annual Review for 2024 Delivery Rates, the I-Factor weightings were based on the 2022 Actual O&M results.

the revisions to the labour/non-labour weightings and the revised approvals sought for FEI and FBC.

Table 1: Revised Table C1-2 of the Application with the History of Labour and Non-Labour Splits for FEI and FBC from 2019 to 2023

	FEI		FBC	
	Labour	Non-Labour	Labour	Non-Labour
2019	52%	48%	62%	38%
2020	51%	49%	63%	37%
2021	51%	49%	60%	40%
2022	49%	51%	57%	43%
2023	48%	52%	59%	41%
Average	50%	50%	60%	40%

FortisBC's reference to the potential for decreased accuracy on page C-5 of the Application was intended to acknowledge that fixed labour/non-labour weightings for the duration of the proposed three-year Rate Framework term would not be tied to actual annual labour/non-labour weightings each year. However, even under the approach used in the Current MRP, there is a degree of misalignment because the weightings are based on the most recent full year of actual O&M results, whereas the formula is being used to establish the upcoming year's O&M spending (or Growth capital) envelope.

FortisBC is unable to quantify the difference in misalignment for the years' 2025 to 2027 between the proposed approach and the approach used in the Current MRP for calculating the I-Factor because FortisBC does not have actual O&M and capital data for these years, including actual labour and non-labour weightings available for 2025 to 2027. However, FortisBC expects the impact to FEI's and FBC's formula O&M due to the changes would be similar to those presented in the response to BCUC IR1 6.1.1.

6.3 Please demonstrate, both quantitatively and qualitatively, how fixed labour and non-labour weightings would improve regulatory efficiency for FortisBC (e.g. provide how much time FortisBC would save drafting information and replying to IRs during Annual Reviews, discuss the associated cost savings for that time, etc.)

Response:

FortisBC does not have direct cost and time savings quantified for changing from the currently approved approach to the proposed approach of fixing the labour and non-labour weightings for calculating the I-Factor.

FortisBC expects that some additional time and effort to respond to IRs each year justifying how the annual labour and non-labour weightings were calculated would be saved. However, FortisBC's main point on page C-5 of the Application was that there seemed to be a lower level of acceptance of the approach approved in the Current MRP, as evidenced by the IRs received in the Annual Reviews questioning the reasonableness of the labour/non-labour weightings. FortisBC previously used fixed labour/non-labour weightings to calculate the I-Factor in the 2014-2019 PBR Plan, and in consideration of the potential reduced level of acceptance with the approach used in the Current MRP, the Companies considered that reverting back to the 2014-2019 PBR Plan approach for the Rate Framework may be more efficient and may increase acceptance of the I-Factor calculation.

FortisBC considers that the use of fixed labour and non-labour weightings, or the approach approved in the Current MRP where the weightings are based on the most recent year of actual O&M results, are appropriate and that neither option is more or less beneficial than the other from a customer or shareholder standpoint. FortisBC is ultimately amenable to either approach, and both approaches have been previously approved by the BCUC. However, FortisBC continues to propose the fixed labour/non-labour weighting approach for this Rate Framework term for the reasons described above and in the Application.

6.3.1 Please discuss how setting fixed labour and non-weightings would benefit FortisBC's ratepayers and shareholders.

Response:

Please refer to the response to BCUC IR1 6.3.

7.0 Reference: PROPOSED RATE SETTING FRAMEWORK – COMPONENTS OF THE RATE FRAMEWORK

Exhibit B-1, Section C1.4, pp. C-6 to C-8, C-10, C-66; FortisBC Multi-Year Rate Plan Application for 2020 to 2024 (Current MRP Application), Exhibit B-1, pp. B-48 to B-58, Exhibit B-1-1, Appendix C2-1, Figure 33, p. 36, Exhibit B-1-1, Appendix C2-2, Figure 36, p. 37; Current MRP Application, Decision and Order G-165-20 and G-166-20 (Current MRP Decision), pp. 52–55

Productivity Improvement Factor (X-Factor)

On page C-6 of the Application, FortisBC states that its proposed X-Factor for FEI is 0.38 percent, inclusive of a 0.10 percent stretch factor, and 0.20 percent for FBC, inclusive of a 0 percent stretch factor.

On page C-66 of the Application, FortisBC explains that during the term of the Current MRP, FortisBC has prioritized and managed its overall O&M expenditures to deliver savings of $28.0 million and $11.8 million to FEI and FBC customers, respectively.

On pages C-8 and C-10 of the Application, for FEI and FBC, respectively, FortisBC states that Dr. Kaufmann concludes each utility has either likely or almost certainly generated significant cost savings for customers that have since been rebased into customer rates and thereby benefits customers.

7.1 Please elaborate on the relationship between the historical actual O&M savings and the proposed X-Factor which consists of an O&M partial productivity factor (PFP) and a stretch factor. Please provide a separate discussion for each of FEI and FBC.

Response:

The following response was provided by Dr. Kaufmann:

There is no conceptual or empirical relationship between FEI's and FBC's historical actual O&M savings and the proposed O&M partial factor productivity (PFP) component of the X factor. As explained in Part 2 of Dr. Kaufmann's report (LKC Report), the productivity factor is an industry-based measure that uses indexing logic and economic reason to identify appropriate external metrics for rate adjustment formulas. The aim of incentive regulation is to replicate the behavior and outcome of competitive markets, so the formulas used to adjust utility rates in index-based regulation are designed to be consistent with how prices change in competitive markets.

However, both rebased cost savings and the stretch factor are similar in that they create benefits for customers beyond the rebasing year of the Rate Framework. As the previous year formula O&M has been reduced by rebased cost savings, the application of the indexing formula will lead to less O&M growth, compared with the scenario where there was no rebasing of cost savings. This will also be true for each subsequent year of the Rate Framework. The stretch factor similarly creates benefits for customers in each year of the plan by directly reducing annual growth in formula O&M by the amount of the stretch factor. Thus, because rebased cost savings and stretch factors both lead to customer benefits throughout the term of the Rate Framework, there are some similarities between rebased cost savings and stretch factors.

The LKC Report concludes that the Current MRPs for both FEI and FBC have generated cost savings that will be rebased into customers' updated rates. This is a tangible and significant source of benefit for both Companies' customers. It should also be recognized that customers will benefit immediately from these cost savings in the Companies' proposed Rate Framework, since the savings are reflected in lower rates from the outset of the new plan.

While the stretch factor is based on expected incremental savings, the potential to realize incremental savings depends on the Companies' previous cost performance. Companies that have been more successful in realizing cost efficiencies in prior years, have less potential to realize incremental cost savings going forward.

7.2 Given the O&M savings during the term of the Current MRP as noted in the preamble above, please explain why the X-Factor should be reduced to 0.38 percent and 0.20 percent for FEI and FBC, respectively, for the proposed Rate Framework as compared to the 0.5 percent X-Factor for both utilities in the Current MRP.

Response:

The following response was provided by Dr. Kaufmann:

The proposed X factor for FEI is comprised of an O&M PFP productivity factor of 0.28 percent and a 0.10 percent stretch factor. FEI's recommended O&M PFP factor was based on an estimate of O&M PFP growth in the gas distribution industry, which has no conceptual or empirical relationship with FEI's own cost savings.

FEI's proposed stretch factor is based on a consideration of:

1. the BCUC's previously approved X factors (and implicit stretch factors) for FEI;
2. cost benchmarking evidence relative to the gas distribution industry; and
3. the cost savings FEI achieved during its current and previous incentive regulation plans, which have been rebased into lower year-one rates for FEI customers.

Based on the BCUC's previously approved stretch factors, benchmarking evidence indicating that FEI is an average cost performer in the gas distribution industry, and the cost savings it has generated, which will be reflected in rebased, lower rates at the outset of the new Rate

Framework, in Dr. Kaufmann's opinion, all of this evidence supports a 0.1 percent stretch factor for FEI's proposed X-factor.

A nearly identical analysis applies to FBC. FBC's O&M PFP productivity factor of 0.20 percent was based on O&M PFP trends in the electricity distribution industry. This productivity factor has no conceptual or empirical relationship to the Company's own cost savings.

FBC's proposed stretch factor is based on a consideration of:

1. the BCUC's previously approved X factors (and implicit stretch factors) for FBC;
2. cost benchmarking evidence relative to the electric distribution industry; and
3. the cost savings FBC achieved during its current and previous incentive regulation plans, which have been rebased into lower year-one rates for FBC customers.

Based on the BCUC's previously approved stretch factors, benchmarking evidence indicating that FBC is a superior cost performer in the electricity distribution industry, and the cost savings it has generated, which will be reflected in rebased, lower rates at the outset of the new Rate Framework, in Dr. Kaufmann's opinion, all of this evidence supports a zero stretch factor for FBC's proposed X-factor.

7.3 With consideration to the O&M savings achieved by each of FEI and FBC above the embedded formula O&M savings, please discuss whether FortisBC considers that both the inclusion of, and the quantum of, the 0.5 percent X-Factor to have been a reasonable and successful component of the Current MRP. Please provide a separate discussion for each of FEI and FBC.

Response:

The following response was provided by Dr. Kaufmann:

Dr. Kaufmann believes that the 0.5 percent X factor in the Current MRPs was reasonable given the evidence on the record at that time. He also believes the O&M savings achieved by both FEI and FBC is evidence that the plans are "successful."

However, it should be noted that the decision to approve a 0.5 percent X factor was based on the BCUC's experience and judgement. It was not based on rigorous evidence of O&M PFP trends, since there was no explicit, O&M PFP evidence on the record at the time for the BCUC to consider. Recommendations for FEI's and FBC's proposed Rate Framework include industry O&M PFP evidence and therefore improve on the information on the record in the 2020-2024

MRP Application proceeding. The BCUC articulated clear concerns regarding the establishment of the X factors for FEI's and FBC's Current MRPs. In particular, the BCUC found that:[5]

> …if the X-Factor is to apply to a utility's entire operation, it would be reasonable for the TFP studies to be applicable to FortisBC. However, this is not the case with the Proposed MRPs where the X-Factor applies only to O&M expenses and a small part of the capital expenditures…the Panel finds that TFP studies are not sufficiently relevant to be applied to FEI and FBC's MRPs…[and] the Panel is not persuaded that productivity studies from other jurisdictions can be applied or are relevant in this instance.

Dr. Kaufmann's recommendations for the Companies' proposed Rate Framework respond directly to the BCUC's stated concerns. Instead of drawing on TFP evidence applied elsewhere, Dr. Kaufmann developed new evidence on O&M productivity growth that is more relevant to be applied to FEI's and FBC's Rate Framework. This evidence is a better fit for rate-setting frameworks where "the X factor applies only to O&M expenses and a small part of the capital expenditures." Further, by focusing his analysis more directly on the services provided by FEI and FBC, Dr. Kaufmann's recommendations provide more carefully tailored and accurate productivity evidence to the BCUC.

Notwithstanding the reasonableness of the X-factor findings in 2019, Dr. Kaufmann believes the Companies' current analysis responds to the BCUC's previously expressed concerns. He accordingly believes he has provided more refined, accurate, and appropriately tailored evidence for the BCUC's review.

7.4 Other than the passage of time impacting the stretch factor,[6] please discuss the operational circumstances, if any, that have changed since the beginning of the Current MRP term (i.e. 2020) to warrant a reduction in the proposed Rate Framework of the 0.5 percent X-Factor approved for the Current MRP.

Response:

The following response was provided by Dr. Kaufmann:

FEI's and FBC's "operational circumstances" are not relevant to the calculation of appropriate productivity factors for the Companies' Rate Framework. Instead, these productivity factors should be based on industry-wide trends in O&M PFP for the gas distribution and electricity distribution industries. In response to concerns stated by the BCUC in the MRP Decision, Dr.

[5] Decision and Orders G-165-20 and G-166-20, at p. 59.

[6] Where on page 7 of Appendix C1-1 to the Application, Dr. Kaufmann states: "[a]ll else equal, it is increasingly difficult for a utility to achieve incremental cost performance gains for each subsequent iteration or "generation" of an incentive regulation."

Kaufmann has provided X-factor recommendations grounded in a rigorous theoretical and empirical framework that utilized industry trends in O&M PFP as the basis for the Companies' productivity factors. Please refer to the responses to BCUC IR1 7.1, 7.2 and 7.3 for additional details regarding the proposed stretch factors.

FortisBC adds the following response:

Changes in the "operating environment" that can impact FEI's and FBC's O&M are reflected in the Companies' proposed 2024 Base O&M amounts.

On page C-6 of the Application, FortisBC states that it "retained the services of Dr. Lawrence Kaufmann, an expert in the field of productivity studies, to conduct two separate productivity studies for FEI's and FBC's respective industries and recommend an appropriate, evidenced based X-Factor (including any stretch factor, if appropriate) for their indexing formulas."

On pages C-7 and C-9 of the Application, FortisBC states that Dr. Kaufmann's Report is based on a sample of 54 United States (US) natural gas distributors over the 2007 to 2022 period for FEI, and 82 US electric utility industry companies over the same period for FBC.

On pages B-48 to B-58 of Exhibit B-1 in the Current MRP Application proceeding, FortisBC provided the results of benchmarking studies for the years of 2012 to 2017 prepared by Concentric for both FEI and FBC.

On page 52 of the Current MRP Decision, a summary of FEI and FBC's benchmarking study results was provided as follows:

> FortisBC states that the analysis can be used to estimate the relative cost-efficiency of FEI and FBC as compared to their peer group consisting of five Canadian and eight Pacific Northwest U.S. Natural Gas companies for FEI, and nine Canadian and five Pacific Northwest U.S. electric Utilities for FBC. The metrics were chosen in consultation with FortisBC and stakeholders and measure the utilities' financial efficiency, reliability and customer service performance.

On page B-52 of Exhibit B-1 in the Current MRP Application proceeding, FortisBC stated that the criteria used to select the companies included the companies' types of operations and geographical location, and whether or not the companies were rate regulated.

7.5 Please confirm the criteria used by Dr. Kaufmann to select the sample of 54 US natural gas distributers for FEI and 82 US electric utility industry companies for FBC over the 2007 to 2022 period.

Response:

The following response was provided by Dr. Kaufmann:

Dr. Kaufmann's main task was to estimate the industry O&M PFP trends for FEI's and FBC's Rate Framework. To estimate O&M PFP trends, it is necessary to compile and utilize industry-wide datasets for both the gas distribution and electric distribution industries. Industry-wide datasets require the compilation of extensive cross-sectional data (i.e., data on utilities across the entire US) and extensive time series data (i.e., long series of data across time for each selected utility). His criteria for selecting the companies in each of these samples were:

1. To select companies with sufficient, high-quality data, across multiple years, for estimating productivity trends;
2. To develop industry samples that reflect the economic and geographic diversity across the US; and
3. Simultaneously, to develop industry samples that reflect the diversity in company size across each of the respective utility industries.

Concentric's work for FortisBC was somewhat different. Concentric's analysis focused on benchmarking the Companies' cost and service quality at a given point in time. Accordingly, it compared the Companies' unit costs and service quality indicators to analogous metrics for a group of utilities that Concentric believed operate under broadly similar circumstances. Concentric did not estimate industry productivity trends for rate adjustment mechanisms. It therefore did not need to develop or use industry-wide databases. Instead, it constructed a dataset comprised of selected peer groups for FEI and FBC.

It should be noted, however, that Concentric also said that expanding the number of peers in its analysis reduces the risk that the peer company data will be incompatible with the Companies' data (e.g., due to differences in capitalization policies) and thereby distort comparisons between FEI and FBC and their selected peers. Concentric's sample was comprised of 13 gas distributors for FEI (5 Canadian and 8 US) and 14 electricity distributors for FBC (8 Canadian and 6 US).

7.5.1 If any criterion identified in the above response differs from the criterion noted on page B-52 of Exhibit B-1 in the Current MRP Application proceeding in the preamble above, please explain why and whether the differences may yield different results to FEI's and FBC's industry O&M PFP and resulting proposed X-Factor.

Response:

The following response was provided by Dr. Kaufmann:

Many criteria are similar for the Concentric and Dr. Kaufmann's studies. However, as discussed in the response to BCUC IR1 7.5, it was necessary for Dr. Kaufmann to compile a dataset that included both a larger cross-section of utilities, and a longer time series of data for each selected utility, in order to calculate industry-wide O&M PFP trends. Dr. Kaufmann also utilized publicly-available data on US gas and electric utilities compiled and provided by Standard&Poor's (S&P); he did not survey any other utilities.

7.6 Please explain why a sample period from 2007 to 2022, or 16 years, was chosen by Dr. Kaufmann for the FEI and FBC productivity studies and how FEI's and FBC's industry O&M PFP and resulting proposed X-Factor would differ if only the most recent five years were included (i.e. 2019 to 2023).

Response:

The following response was provided by Dr. Kaufmann:

To clarify, while the 2007-2022 period involves 16 years of data, in Dr. Kaufmann's work, this is typically described as a 15-year sample period since his work focuses on growth rates (e.g., growth in inflation or productivity which requires an additional year of data). Dr, Kaufmann therefore addresses this IR by referring to the datasets as comprising 15 years of growth rates, rather than the 16 years of data necessary to calculate those growth rates.

The issue of the sample period used to estimate O&M PFP trends was addressed in the LKC Report. On page 10 of this report, Dr. Kaufmann states that: "LKC will develop O&M PFP measures for the Companies for two distinct and relevant sample periods. The first period is 2014-2022. The second period is 2007-2022." Most of the subsequent analysis focused on the 2007-2022 period.

Using a 15-year period to estimate productivity trends has become widespread in incentive regulation. This period is long enough to average out the annual "ebbs and flows" in utility expenditures and thereby minimize the impact of year-to-year volatility, and the experience of a small number of years, on estimated productivity growth. At the same time, this period is recent enough to reflect the industry's current, long-run conditions rather than dated, obsolete experience. By balancing these objectives, a 15-year sample period is likely to provide a reliable measure of long-run productivity trends (partial or total-factor). LKC therefore uses a 2007-2022 period to estimate long-run O&M PFP trends for FEI and FBC.

To provide context for the 15-year sample period used to estimate productivity trends, Dr. Kaufmann examined the sample periods used to estimate productivity trends for approved incentive regulation plans in three important jurisdictions:

1. Massachusetts;
2. Alberta; and
3. Ontario.

Other than British Columbia, these are the three most active incentive regulation jurisdictions in North America.

The sample periods used in these jurisdictions over the 2014-2024 period are itemized below.

	Jurisdiction	Proceeding/Approved Plan	Period Used to Estimate Productivity Trends
1.	Massachusetts	D.P.U. 17-05	14 years, 2001-2015
2.	Massachusetts	D.P.U. 18-150	14 years, 2002-2016
3.	Massachusetts	D.P.U. 19-120	14 years, 2003-2017
4.	Massachusetts D.	D.P.U. 19-120	14 years, 2004-2018
5.	Alberta	“PBR1”	37 years, 1972-2009
6,	Alberta	“PBR2”	An average of three different studies • NERA, 1972-2014, 42 years • Brattle, 2000-2014, 14 years • PEG, 1997-2014, 17 years Unweighted average, 24.3 years
7.	Alberta	“PBR3”	An average of two studies • Christensen, 2007-2021, 14 years • PEG, 2006-2021, 15 years Unweighted average, 14.5 years
8.	Ontario	Fourth Generation IRM	2002-2012, 10 years Note: the Ontario Fourth Generation IRM has been in effect since 2014.

The average sample period used to estimate productivity for each of these eight incentive regulation plans is 17.7 years. This is somewhat longer than Dr. Kaufmann’s recommended 15-year period for estimating O&M productivity growth.

The IR also asked what the industry productivity trends would be if they were measured over the last five years of the sample (i.e., average O&M PFP growth over the 2017-2022 period for both the gas distribution and electricity distribution industries). The data necessary to compute these hypothetical growth rates are available in the LKC Report in Tables 3.1 (for gas distribution) and 3.4 (for electricity distribution).

The annual, and average, growth rates in O&M PFP for the 2017-2022 period are provided below for both the gas distribution and electricity distribution industries.

Year	% Change Gas Distribution O&M PFP	% Change Electricity Distribution O&M PFP
2018	-4.52%	-1.47%
2019	2.07%	6.86%
2020	3.07%	-3.83%
2021	-0.84%	5.94%
2022	3.79%	-0.45%
Average	0.72%	1.41%

The average PFP growth between 2017 and 2022 was 0.72 percent per annum for the gas distribution industry and 1.41 percent for the electricity distribution industry.

These results show that industry MFP data are quite volatile from year to year. For the gas distribution industry, annual O&M PFP growth ranged from 3.79 percent to -4.52 percent within this short, five-year period. O&M PFP data was even more volatile for the electricity distribution industry, with industry PFP expanding by 6.86 percent in 2019, followed by a rapid 3.83 percent decline in 2020, followed by a 5.94 percent increase in 2021.

The LKC Report addressed this issue in some detail. After examining FEI's and FBC's own O&M PFP trends, Dr. Kaufmann writes[7]:

> The data also show that O&M PFP measures can be volatile. This is evident in the divergent estimates of O&M PFP growth for the 2014-2022 and 2007-2022 periods, for both companies. This is an important finding, because it supports the view that changes in O&M PFP can be affected by a wide range of factors, including the timing of relatively large O&M expenditures, changes in inflationary pressures, and other exogenous factors that impact output growth, O&M growth, or both. As discussed above, these ebbs, flows, and transitory developments in business operations tend to balance out over longer sample periods. Longer-term measures of O&M PFP growth therefore provide more reliable estimates of underlying O&M PFP trends for utility industries. This, in turn, implies that longer-term measures of O&M PFP are generally a more appropriate basis for productivity factors in index-based incentive regulation plans than O&M PFP measured over relatively short intervals.

In sum, this IR confirms the findings in the LKC Report that five years is far too short to estimate reliable, long-run trends for O&M PFP growth. The previous evidence shows that, in practice, experts typically select sample periods for measuring productivity growth that are three to four times greater than five years.

[7] LKC Report, Appendix C1-1, p. 12.

7.7 Please explain why Dr. Kaufmann's productivity studies focused on US utilities as the comparators to FEI and FBC and why no Canadian utilities were included in the studies as compared to what was done for the benchmarking analysis previously provided by FortisBC in the Current MRP Application proceeding. As part of this response, please discuss the advantages and disadvantages of applying only US data to FEI's and FBC's operations.

Response:

The following response was provided by Dr. Kaufmann:

Please refer to the responses to BCUC IR1 7.5 and 7.5.1. Dr. Kaufmann's work was focused on estimating long-run O&M PFP trends, and this task requires industry-wide data for the gas distribution and electricity distribution industries, reported consistently for at least 16 consecutive, recent years. As Concentric indicates in its reports, the cross-sectional and time series data necessary to estimate these trends are not available in Canada. Dr. Kaufmann therefore focused on using US datasets to estimate long-run O&M PFP growth rates.

Another valuable aspect of the US datasets is they enabled Dr. Kaufmann to compare FEI's and FBC's unit costs to the average unit costs of their respective industries. Benchmarking against "industry standards" is both informative and relevant for assessing a utility's potential to achieve incremental gains in cost performance, which in turn is important for developing recommendations for stretch factor values. Because the US databases shed light on both the productivity factor and stretch factor components of the Companies' X factors, Dr. Kaufmann focused its analysis on US industry data.

However, Dr. Kaufmann also benchmarked FEI against a sample of six Canadian gas distributors. He did not include this analysis in his report because the Canadian data were not as complete across the sample. The six Canadian gas distributors are Apex Gas (Alberta), Atco Gas (Alberta), Centra Gas (Manitoba), Eastward Gas (Nova Scotia), Enbridge Gas (Ontario), and Liberty Utilities (New Brunswick). Eastward and Centra data were available for the 2018-2020 period, while all other utilities' data were available for 2020-2022. Average O&M unit costs for each company were calculated by averaging O&M costs per customer over the three most recent years for which data were available. Average unit costs for the six Canadian gas distributors, as well as FEI, are provided below. These results are ranked from the highest to the lowest O&M unit cost values.

Company	Average O&M/Customer	Time Period
Liberty Utilities	$1,182.8	2020-2022
Eastward	$1,158.0	2018-2020
Apex Gas	$539.0	2020-2022
Atco Gas	$386.9	2020-2022

Company	Average O&M/Customer	Time Period
FEI	$306.2	2020-2022
Enbridge Gas	$217.3	2020-2022
Centra	$197.4	2018-2020
Sample Average	$569.6	
FEI/Sample Average $	-46.3%	

The sample average for the seven utilities (FEI plus the six Canadian peers) was C$569.6. FEI's average O&M costs per customer were $306.2 for 2020-2022, which was 46.3 percent below the Canadian sample average. FEI's unit costs were fifth lowest among the seven sampled Canadian gas distributors. Viewed in isolation, the Canadian benchmarking results support the view that FEI is an above average O&M cost performer in the Canadian gas distribution industry.

7.8 Please discuss the differences in US policy and legislation regarding the energy transition as compared to in British Columbia. Where there are differences, please explain how FortisBC views that these differences should be taken into account in its proposed X-Factor for FEI and FBC given the US comparators provided in the productivity studies.

<u>Response:</u>

The following response was provided by Dr. Kaufmann:

It is difficult to summarize the differences between US policy and legislation regarding the energy transition as compared to British Columbia. The reason is that there are 50 autonomous and diverse states largely charting their own paths. There is accordingly a wide range of reactions towards energy transition policies across the country.

Broadly speaking, there are two general approaches towards energy transition issues. One group actively supports policies that discourage the use of natural gas. A second group has implemented legal prohibitions against energy transition initiatives.

The following states have enacted or proposed legislation which limits the future use of natural gas:

- California
- Oregon
- Washington
- Massachusetts

- New York

In contrast, a number of other states have enacted legislation which prohibits municipal governments from enacting bans on the use of natural gas. As of 2023, the states which have enacted these prohibitions are:

- Tennessee—NB1838 / SB1934[8]
- Missouri—HB 734
- Iowa—House File 555[9]
- Kansas—S.B. 24[10]
- Arizona—HB 2686[11]
- Utah—H.B. 19[12]
- Texas—H.B. 17[13]
- Louisiana—Act Number 46[14]
- Indiana—H.B. 1191[15]
- Ohio—H.B. 201[16]
- Kentucky—H.B. 207[17]
- West Virginia—H.B. 2842[18]
- Mississippi—H.B. 632
- Alabama—H.B. 446[19]
- Georgia—H.B. 150[20]
- Louisiana—Act No. 42[21]

---

8 https://publications.tnsosfiles.com/acts/111/pub/pc0591.pdf.
9 https://www.legis.iowa.gov/legislation/BillBook?ga=89&ba=HF%20555.
10 http://www.kslegislature.org/li_2022/b2021_22/measures/documents/sb24_enrolled.pdf.
11 https://www.azleg.gov/legtext/54leg/2R/bills/HB2686P.pdf.
12 https://le.utah.gov/~2021/bills/hbillenr/HB0017.pdf.
13 https://capitol.texas.gov/tlodocs/87R/billtext/html/HB00017F.htm.
14 https://www.legis.la.gov/legis/ViewDocument.aspx?d=1179929.
15 https://iga.in.gov/legislative/2021/bills/house/1191#document-7140b902.
16 https://search-prod.lis.state.oh.us/solarapi/v1/general_assembly_134/bills/hb201/EN/05/hb201_05_EN?format=pdf.
17 https://apps.legislature.ky.gov/recorddocuments/bill/21RS/hb207/bill.pdf.
18 http://www.wvlegislature.gov/Bill_Status/bills_text.cfm?billdoc=HB2842%20INTR.htm&yr=2021&sesstype=RS&i=2842.
19 https://legiscan.com/AL/text/HB446/id/2383964.
20 https://www.legis.ga.gov/legislation/59025.
21 https://www.legis.la.gov/legis/ViewDocument.aspx?d=1179929.

- Florida—S.B. 28[22]

Nearly all these efforts either supporting or opposing the energy transition have been implemented in the last two or three years. Support for the energy transition is concentrated in California (the most populous state), the northwest, and the northeast. Opposition appears to be more common across the rest of the US, including the second and third most populous states of Texas and Florida, respectively. Since the energy transition issue is relatively new, and fluid, it is difficult to identify any developments in US policy that may or may not be relevant to the proposed X-factor.

FortisBC adds the following response:

FortisBC agrees with Dr. Kaufmann's assessment of energy transition related policies in the US and BC and notes that this assessment is aligned with Concentric's assessment provided recently in the Stage 1 Generic Cost of Capital (GCOC) Proceeding:[23]

> In British Columbia, climate change initiatives are at the forefront, and the use of fossil fuels for water heating and space heating is discouraged. BC already had one of the most aggressive greenhouse gas reduction targets in Canada, requiring reductions of 40 percent below 2007 levels by 2030 and 80 percent below 2007 levels by 2050 even before the Canadian federal government passed the Canadian Net-Zero Emissions Accountability Act, which sets into law the commitment to achieve net-zero carbon emissions by 2050. This sets an even more aggressive target for 2050 than had previously been legislated in BC. There will be significant pressure for all provinces to find ways to curb greenhouse gas emissions.
>
> … The Energy Transition is accelerating rapidly in the U.S. as well. The Biden administration is targeting a 50 percent reduction in GHG emissions relative to 2005 by 2030, and net zero emissions economy-wide by 2050. As shown in Figure 39, at least a dozen states have committed to net zero or 100 percent renewable power targets by 2050 or earlier.
>
> 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

---

22 https://www.flsenate.gov/Session/Bill/2021/1128/BillText/c2/PDF.

23 FortisBC's Evidence in the 2023 Stage 1 GCOC Proceeding; Appendix C, Evidence of Mr. James Coyne, Concentric Energy Advisors Inc.

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.

7.9 For the productivity studies conducted by Dr. Kaufmann, please provide comparative benchmarking information, if available, that sets out each of FEI's and FBC's ranking relative to the total number of utilities in each respective sample, similar to the format and methodology as provided to the BCUC by FortisBC in Figure 33 of Exhibit B-1-1 on page 36 of Appendix C2-1 in the Current MRP Application proceeding for FEI and in Figure 36 of Exhibit B-1-1 on page 37 of Appendix C2-2 in the Current MRP Application proceeding for FBC.

Response:

The following response was provided by Dr. Kaufmann:

The "Electricity Distribution Unit Cost Rankings" below summarizes the ranked position of each sampled electricity distributor's average O&M costs per customer over the 2020-2022 period, as well as providing FBC's average ranked position on the same O&M cost per customer metric for the 2020-2022 period.

FBC ranked 5th among the 83 sampled electricity distributors (i.e., the 82 sampled US utilities plus FBC) with respect to O&M cost performance. FBC's cost performance therefore exceeds the top decile standards. This evidence bolsters the data provided in the LKC Report, which found that FBC's cost performance was well above average.

Electricity Distribution Cost Rankings

Rank	Company
1	Florida Power & Light Company
2	NextEra Energy, Inc.
3	Nevada Power Company
4	Duke Energy Carolinas, LLC
5	FortisBC Inc.
6	Versant Power
7	The Potomac Edison Company
8	Pennsylvania Power Company
9	Pennsylvania Electric Company
10	Kingsport Power Company
11	Duke Energy Progress, LLC
12	Arizona Public Service Company
13	Metropolitan Edison Company
14	West Penn Power Company

Rank	Company
15	Virginia Electric and Power Company
16	Tampa Electric Company
17	Commonwealth Edison Company
18	Duquesne Light Company
19	Jersey Central Power & Light Company
20	Duke Energy Florida, LLC
21	The Dayton Power and Light Company
22	Georgia Power Company
23	PacifiCorp
24	El Paso Electric Company
25	Duke Energy Indiana, LLC
26	Kentucky Utilities Company
27	Ohio Edison Company
28	Evergy Metro, Inc.
29	Public Service Company of New Mexico
30	Entergy Mississippi, LLC
31	Idaho Power Company
32	PPL Electric Utilities Corporation
33	OGE Energy Corp.
34	Potomac Electric Power Company
35	AES Indiana
36	The Cleveland Electric Illuminating Company
37	Alabama Power Company
38	Public Service Company of New Hampshire
39	Tucson Electric Power Company
40	Oklahoma Gas and Electric Company
41	Atlantic City Electric Company
42	DTE Electric Company
43	Evergy Missouri West, Inc.
44	The Connecticut Light and Power Company
45	Alaska Electric Light and Power Company
46	Southwestern Electric Power Company
47	Ohio Power Company
48	Appalachian Power Company
49	Entergy Arkansas, LLC
50	Black Hills Colorado Electric, Inc.
51	Maui Electric Company, Ltd.
52	Cleco Power LLC
53	Public Service Company of Oklahoma

Rank	Company
54	The Empire District Electric Company
55	Portland General Electric Company
56	Indiana Michigan Power Company
57	The Toledo Edison Company
58	Hawaiian Electric Company, Inc.
59	Monongahela Power Company
60	Upper Peninsula Power Company
61	Central Maine Power Company
62	NSTAR Electric Company
63	Unitil Energy Systems, Inc.
64	Evergy Kansas Central, Inc.
65	Mississippi Power Company
66	Green Mountain Power Corporation
67	Kentucky Power Company
68	Evergy Kansas South, Inc.
69	UIL Holdings Corporation
70	The United Illuminating Company
71	Rockland Electric Company
72	Southwestern Public Service Company
73	Liberty Utilities (Granite State Electric) Corp.
74	Southern California Edison Company
75	Massachusetts Electric Company
76	Otter Tail Corporation
77	Minnesota Power Enterprises, Inc.
78	Black Hills Power, Inc.
79	Northwestern Wisconsin Electric Co Inc
80	Wheeling Power Company
81	Lockhart Power Company
82	Hawaii Electric Light Company, Inc.
83	Consolidated Water Power Company

A similar analysis is presented below for FEI. The “Gas Distribution Unit Cost Rankings” table summarizes the ranked position of each sampled gas distributor’s average O&M costs per customer over the 2020-2022 period, as well as providing FEI’s average ranked position on the same O&M cost per customer metric for the 2020-2022 period.

Gas Distribution Unit Cost Rankings

Rank	Company
1	The East Ohio Gas Company
2	Questar Gas Company

Rank	Company
3	Atlanta Gas Light Company
4	Public Service Electric And Gas Company
5	Wisconsin Gas LLC
6	Ohio Gas Company
7	Northern Illinois Gas Company
8	Public Service Company of North Carolina, Incorporated
9	Consumers Energy Company
10	Northern States Power Company
11	Puget Sound Energy, Inc.
12	Virginia Natural Gas, Inc.
13	Avista Corporation
14	Cascade Natural Gas Corporation
15	Delta Natural Gas Company, Inc.
16	Black Hills Energy Arkansas, Inc.
17	South Jersey Gas Company
18	Southern California Gas Company
19	Duke Energy Ohio, Inc.
20	Northern Indiana Public Service Company
21	Southern Indiana Gas and Electric Company
22	Boston Gas Company
23	North Shore Gas Company
24	Pacific Gas and Electric Company
25	Rochester Gas and Electric Co
26	Louisville Gas and Electric Company
27	Washington Gas Light Company
28	Niagara Mohawk Power Corporation
29	Madison Gas and Electric Company
30	Peoples Gas System
31	FortisBC Energy Inc.
32	Bluefield Gas Company
33	New Jersey Natural Gas Company
34	National Fuel Gas Distribution Corporation
35	DTE Gas Company
36	Consolidated Edison Company of New York, Inc.
37	Mountaineer Gas Company
38	The Southern Connecticut Gas Company

Rank	Company
39	Superior Water, Light and Power Company
40	Baltimore Gas and Electric Company
41	Wisconsin Power and Light Company
42	The Peoples Gas Light and Coke Company
43	The Berkshire Gas Company
44	New York State Electric & Gas Corporation
45	Yankee Gas Services Company
46	Brooklyn Union Gas Company
47	St. Joe Natural Gas Co, Inc.
48	Columbia Gas of Maryland, Incorporated
49	Connecticut Natural Gas Corporation
50	Columbia Gas of Kentucky, Incorporated
51	Orange and Rockland Utilities, Inc.
52	Central Hudson Gas & Electric Corporation
53	St. Lawrence Gas Company, Inc.
54	Corning Natural Gas Corporation

FEI ranked 31st among the 54 sampled gas distributors.[24] This ranking is consistent with Dr. Kaufmann's finding that FEI exhibits average cost performance relative to the US gas distribution industry.

7.10 Please discuss whether FortisBC retained the services of any other expert(s) for the purposes of determining an appropriate X-Factor for FEI's and FBC's indexing formulas for the proposed Rate Framework.

7.10.1 If yes, please provide the other expert(s)'s recommendation(s) and explain why FortisBC did not ultimately move forward with the other expert(s)'s advice.

Response:

Dr. Kaufmann is the only expert FortisBC retained for the purpose of recommending the appropriate X-Factor values for FEI's and FBC's indexing formulas and commenting on the

[24] Colonial Gas was one of the 54 gas distributors used to estimate O&M PFP growth for the 2007-2022 period, but it was fully absorbed by Boston Gas in 2021 and therefore did not provide any 2021 or 2022 data. Accordingly, it was not included in the gas distribution benchmarking sample. The sample presented here therefore includes 53 US gas distributors plus FEI.

appropriateness of the 0.75 adjustment currently applied to growth factors in the Companies' O&M indexing formulas. Dr. Kaufmann is among a small handful of qualified experts in the field of productivity studies with extensive Canadian experience representing both regulators and utilities.

8.0 Reference: PROPOSED RATE SETTING FRAMEWORK – COMPONENTS OF THE RATE FRAMEWORK

Exhibit B-1, Section C1.5, pp. C-10, C-14, C-15

Growth Factor

On page C-10 of the Application, FortisBC proposes to eliminate the 0.75 discount factor currently applied to the growth factor for the O&M formulas.

On pages C-14 to C-15 of the Application, FortisBC discusses how Dr. Kaufmann agrees with its proposed elimination of the 0.75 discount factor currently applied to the growth factor in FEI's and FBC's O&M formulas as outlined in Dr. Kaufmann's report.

8.1 Other than for the reasons provided in Dr. Kauffmann's report, please discuss the circumstances (i.e. operationally), if any, that have changed for FEI or FBC since the beginning of the Current MRP term (i.e. 2020) going into the proposed term of the Rate Framework to warrant the elimination of the 0.75 discount factor that is currently applied to the growth factor in FEI's and FBC's O&M formula.

Response:

Changes in circumstances, such as operational changes, are not relevant to the consideration of the elimination of the 0.75 discount factor.

In the 2020-2024 MRP Application and proceeding, FortisBC explained that the application of a discount factor to the growth factor used in the indexing formulas is not warranted and amounts to double counting of the effects of economies of scale on costs' growth trends since the economies of scale are already reflected in the productivity growth factors calculated as part of the TFP or PFP studies conducted by experts. This continues to be FortisBC's position, and in this proceeding has provided the expert evidence of Dr. Kaufmann showing that a discount factor is not appropriate, which was not part of the evidence considered by the BCUC when approving FortisBC's Current MRP. As explained by Dr. Kaufmann, applying a discount factor to the growth factor in FEI's and FBC's O&M formulas is inappropriate due to its fundamental inconsistencies with cost theory and the theory behind the indexing formulas and productivity analysis, not because of FEI's and FBC's specific operational circumstances:[25]

> In other words, an important element of a "consistent cost-based treatment of output growth" is recognizing that changes in output (i.e. customer numbers) do not measure or reflect "the effect of output growth on cost." Instead, "these are captured in the productivity trend."
>
> … Cost theory shows that economies of scale is one of several sources of productivity growth. A rigorous mathematical derivation of this fact is presented (along with similar findings) in Appendix Two of this report. Since economies of

[25] Appendix C1-1, p. 29.

scale is a component of productivity change, a properly constructed productivity index will by definition capture the impact of scale economies.

In short, economies of scale are already captured in the productivity factor and cannot be reasonably used to justify a discount in the growth factor.

8.2 Please discuss whether other utilities on PBR plans in Canada or the US have a discount factor applied to the growth factor in their O&M formulas. If yes, please provide the discount factor(s) used by the other utilities and explain what differences exist between the other utilities and FEI and FBC such that a similar discount factor(s) is not appropriate for FEI or FBC.

Response:

Among the jurisdictions that FortisBC studied, Énergir is the only other utility that has a discount factor applied to its indexing formula; however, as explained in Appendix B2-2 to the Application, Énergir's O&M formula does not include an X-Factor value and the 0.75 discount factor to the growth factor implicitly acts as an X-Factor. Therefore, unlike FEI's and FBC's O&M formulas, Énergir's O&M formula does not lead to the double counting of the effects of economies of scale. In contrast, in FEI's and FBC's unique cases, the effects of economies of scale are currently counted first in the X-Factor and then again in the discount factor to the growth factor.

8.3 Please discuss how FEI's and FBC's number of customers, as well as customer growth, from 2007 to 2022 compare to the utilities used in the productivity studies conducted by Dr. Kaufmann.

Response:

The following response was provided by Dr. Kaufmann:

In general, it should be recognized that in O&M PFP studies, customer growth rates are more important to utilities' measured cost performance than customer numbers. The reason is that customer growth is used to measure output growth in Dr. Kaufmann's work, and O&M PFP growth is equal to output growth minus the growth in O&M input quantity. Changes in customer numbers therefore enter directly into calculations of O&M PFP growth.

In 2022, FEI served 1,067,191 customers, which is consistent with being a large gas distributor, but not one of the largest in the industry. In 2022, FBC served 147,112 customers, which is consistent with being a relatively small electricity distribution utility. Data on customer growth rates for FEI, FBC, and the US gas and electricity samples are provided in the LKC Report. Over the 2007-2022 period, Table 1 of the LKC Report shows that FEI's customer numbers grew at an average annual rate of 1.08 percent per annum. For the same 2007-2022 period, Table 4 shows customer numbers in the US gas distribution sample grew an average rate of 0.67 percent per annum. For the same 2007-2022 period, Table 2 shows that FBC's customers grew at an average annual rate of 1.32 percent. Over the same period, customer numbers grew by 0.91 percent per annum for the US electricity distribution sample. Therefore, for both the US samples and the FortisBC Companies, the growth in electricity distribution customers has exceeded the growth in gas distribution customers.

8.3.1 If there are significant differences in the number of customers and customer growth between FEI and FBC when compared to the utilities used in the productivity studies conducted by Dr. Kaufmann, please explain why those utilities are relevant comparables to support the proposed elimination of the discount factor.

Response:

The following response was provided by Dr. Kaufmann:

The appropriate treatment of the discount factor depends on indexing logic and incentive regulation principles, not on differences in measured customer growth. Under the proposed Rate Framework, the approved O&M PFP factor acts as a kind of O&M cost "target" that the Companies compete against. In doing so, the Companies must manage a variety of unpredictable factors that can impact O&M costs, including customer growth that may be above or below the levels reflected in the O&M PFP target. If the Companies are successful in keeping their costs below the O&M PFP target, they retain those savings throughout the term of the Rate framework. When the plan expires, the Companies pass accumulated cost savings onto customers via rebased rates, regardless of the sources of those cost savings.

8.4 Please provide a table showing the actual annual customer additions and attritions for each of FEI and FBC over the term of the Current MRP (i.e. 2020 to 2024), as well as FortisBC's forecast of annual customer additions and attritions over the proposed term of the Rate Framework (i.e. 2025 to 2027).

Response:

Please refer to Tables 1 and 2 below for the breakdown of actual annual customer additions and attritions from 2020 to 2023, and the projected/forecast net customer additions from 2024 to 2027 for FEI and FBC, respectively. Customer additions are made up of move-ins and new customer connections/attachments, while customer attritions are made up of move-outs and disconnections (voluntary and involuntary).

FortisBC notes that its forecasting methods do not separately forecast customer additions and attritions (i.e., the forecast is on a net basis). As such, only the projected/forecast net customer additions are shown for 2024 to 2027 in Tables 1 and 2 below. Please refer to Appendix C4-1 and C4-2 for FEI's and FBC's forecasting methods.

Table 1: Actual Annual Customer Additions and Attritions for FEI from 2020 to 2023, and Net Customer Additions Projected for 2024 and Forecast for 2025 to 2027

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Projected	2025 Forecast	2026 Forecast	2027 Forecast
Customer Additions (New Additions/Move-ins)	114,575	134,703	115,603	107,045	N/A	N/A	N/A	N/A
Customer Attritions (Move-outs/Disconnection (Vacant))	101,814	122,240	105,498	93,857	N/A	N/A	N/A	N/A
Net Customer Additions	**12,761**	**12,463**	**10,105**	**13,188**	**10,712**	**10,982**	**10,561**	**10,139**

Table 2: Actual Annual Customer Additions and Attritions for FBC from 2020 to 2023, and Net Customer Additions Projected for 2024 and Forecast for 2025 to 2027

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Projected	2025 Forecast	2026 Forecast	2027 Forecast
Customer Additions (New Additions/Move-ins)	25,609	28,500	26,326	25,048	N/A	N/A	N/A	N/A
Customer Attritions (Move-outs/Disconnection (Vacant))	23,096	25,944	24,091	22,558	N/A	N/A	N/A	N/A
Net Customer Additions	**2,513**	**2,556**	**2,235**	**2,490**	**2,360**	**2,285**	**1,980**	**1,915**

8.4.1 With reference to the net customer additions provided in response to the preceding IR, please provide the correlation coefficient of net customer additions to O&M for each of FEI and FBC over the Current MRP term (i.e. 2020 to 2024). Please provide all supporting calculations and explain all inputs and assumptions.

Response:

FortisBC understands the question as requesting the correlation coefficient of actual *average customer count* to formula O&M over the Current MRP term, not the correlation coefficient of actual *net customer additions* to actual formula O&M, since FEI's and FBC's formula O&M is based on average customer count, not net customer additions.

However, in order to be responsive, please refer to Tables 1 and 2 below for the correlation coefficient of actual/projected net customer additions to actual/projected formula O&M for FEI and FBC, respectively, over the Current MRP term. Please also refer to Tables 3 and 4 for the correlation coefficient of actual/projected average customer count to actual/projected formula O&M for FEI and FBC, respectively, from 2020 to 2024. FortisBC notes that the correlation coefficients are calculated using the excel function "CORREL".

As shown in Tables 1 and 2, there is little correlation between net customer additions and formula O&M. However, Tables 3 and 4 show there is a significant correlation between the actual/projected average customer count to actual/projected formula O&M for both FEI and FBC.

Table 1: Correlation Coefficient of Actual/Projected Net Customer Additions to Actual/Projected Formula O&M for FEI over the Current MRP Term

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Projected
Actual/Projected Formula O&M ($000s)	259,533	268,272	281,732	294,980	309,600
Actual/Projected Net Customer Additions	12,761	12,463	10,105	13,188	10,712
Correlation Coefficient					**(0.39)**

Table 2: Correlation Coefficient of Actual/Projected Net Customer Additions to Actual/Projected Formula O&M for FBC over the Current MRP Term

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Projected
Actual/Projected Formula O&M ($000s)	58,234	58,880	63,569	66,083	70,800
Actual/Projected Net Customer Additions	2,513	2,556	2,235	2,490	2,360
Correlation Coefficient					**(0.51)**

Table 3: Correlation Coefficient of Actual/Projected Average Customer Count to Actual/Projected Formula O&M for FEI over the Current MRP Term

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Projected
Actual/Projected Formula O&M ($000s)	259,533	268,272	281,732	294,980	309,600
Actual/Projected Average Customer Count	1,044,623	1,057,086	1,067,191	1,080,379	1,091,091
Correlation Coefficient					**0.99**

Table 4: Correlation Coefficient of Actual/Projected Average Customer Count to Actual/Projected Formula O&M for FBC over the Current MRP Term

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Projected
Actual/Projected Formula O&M ($000s)	58,234	58,880	63,569	66,083	70,800
Actual/Projected Average Customer Count	142,321	144,877	147,112	149,602	151,962
Correlation Coefficient					**0.98**

8.5 With consideration to FEI's and FBC's operating environments currently and over the next three years, please explain what new factors might impact customer growth and O&M costs and thus lead to variances between formula and actual costs during the proposed MRP term. As part of the response, please discuss how FEI or FBC has mitigated or could mitigate these factors.

Response:

As explained in the response to BCUC IR1 8.1, changes in circumstances, such as operational changes, are not relevant to the consideration of the elimination of the 0.75 discount factor.

FortisBC explained in the response to BCUC Panel Supplemental IR 2 that the impacts to the Companies from changes in the operating environment due to the energy transition generally fall within three categories:

(1) Increased costs facing both FEI and FBC;

(2) Decreased load/revenue facing FEI; and

(3) Extraordinary/unforeseen events affecting both FEI and FBC.

The Rate Framework includes mechanisms to manage the rate impacts of these factors. Please refer to the response to BCUC Panel Supplemental IR 2 for a detailed explanation of the impacts and mitigations.

Specifically with regard to the formula O&M, the unit cost of O&M is adjusted annually for the change in the average customer count. As explained in the response to BCUC IR1 8.4.1, FEI's and FBC's formula O&M is based on average customer counts, not net customer additions. Therefore, FEI's and FBC's formula O&M will move up or down in alignment with any change in the average customer counts. Additionally, to the extent that actual average customer counts vary from forecast, the variances will be trued up (based on a two-year lag); thus, ultimately, both Companies' formula O&M will adjust to reflect the actual changes in average customers.

Further, the unit cost of O&M is also adjusted for inflation minus a productivity factor, and any variances between approved and actual formula O&M will be shared 50/50 with customers. The inclusion of a productivity improvement factor (i.e., X Factor) and the ability to retain 50 percent of any achieved savings creates an incentive to focus on cost control and efficiency.

Finally, although the number of new customer additions is expected to decrease annually for FEI during the term of the proposed Rate Framework (i.e., the growth in the number of customers connecting to the system is slowing), there is no evidence to suggest that customer additions will cease completely over the three-year term of the Rate Framework. In fact, as shown in the response to BCUC IR1 8.4.1, the average customer count for both utilities (which the formula O&M is based on) has been increasing annually, with FEI adding more customers in 2023 than in previous years of the Current MRP.

Accordingly, FEI and FBC expect the formulaic approach will continue to provide adequate funding envelopes for O&M during the Rate Framework term.

8.6 Please discuss whether FortisBC retained the services of any other expert(s) for the purposes of determining an appropriate growth factor for FEI's and FBC's indexing formulas for the proposed term of the Rate Framework.

8.6.1 If yes, please provide the other expert(s)'s recommendation(s) and why FortisBC did not ultimately move forward with the other expert(s)'s advice.

Response:

Please refer to the response to BCUC IR1 7.10.

9.0 Reference: PROPOSED RATE SETTING FRAMEWORK – COMPONENTS OF THE RATE FRAMEWORK

Exhibit B-1, Section C1.8, p. C-19

Efficiency Carry-Over Mechanism (ECM)

On page C-19 of the Application, regarding the ECM for the proposed Rate Framework, FortisBC states:

> […] Given a more limited (three-year) term for this Rate Framework, the focus in the coming three years on managing through the energy transition, and the complexities involved in designing an ECM [Efficiency Carry-Over Mechanism] tailored to its specific Rate Framework elements, FortisBC does not believe that an ECM is required at this time.

9.1 Please confirm whether FortisBC intends to apply for an ECM at any time during the proposed three-year term of the Rate Framework.

Response:

FortisBC does not intend to apply for an ECM during the proposed three-year term of the Rate Framework. FortisBC will evaluate the design of a future ECM and may propose to re-instate an ECM as part of a future rate framework application (i.e., subsequent to the proposed three-year term of this Rate Framework).

10.0 Reference: PROPOSED RATE SETTING FRAMEWORK – COMPONENTS OF THE RATE FRAMEWORK

Exhibit B-1, Section C1.10, pp. C-21 to C-22, Section B1.6.3, p. B-15, Exhibit B-2 (Supplemental Information), pp. 12, 14

Annual Review Process

On page C-21 of the Application, FortisBC states that it is "seeking clearer parameters at the outset of this Rate Framework on topics that are out of scope in the Annual Reviews [...]"

On page C-22 of the Application, FortisBC proposes to scope out, among other things, the methods used to forecast demand and load each year for FEI and FBC. FortisBC clarifies that it considers the demand/load forecast (e.g. the drivers of each year's demand increase or decrease) is within the scope of the Annual Review process, but the methods used to develop each forecast should remain out of scope as they will not change during the term of the Rate Framework.

10.1 Please discuss how FortisBC would propose to delineate between the methods used to forecast demand and load each year for FEI and FBC (proposed to be scoped out per FortisBC) versus the demand/load forecast itself including drivers of each year's demand increase or decrease (proposed to be scoped in per FortisBC). As part of the response, please provide an example of an IR that would be in scope and out of scope.

<u>Response:</u>

Unlike questions about the load forecast itself, including the drivers of demand, questions about load forecasting methods ask about the appropriateness of the forecasting method or the availability of, or results of using, alternative forecasting methods. For example, FortisBC is routinely asked to justify the appropriateness of using different time periods of actual results, the appropriateness of the ETS[26] method, and the use of the CBOC forecast by dwelling type (FEI) or the use of BC-Stats for population data (FBC). These types of questions would be out of scope based on FortisBC's proposed scoping. Additionally, IRs asking FortisBC to run load forecast scenarios based on hypothetical alternative forecasting methods or asking FortisBC to make adjustments to its forecasts to try to take into account certain future events would be out of scope. These are methodology-focused IRs and would be more appropriate when evaluating the forecasting method at the end of each multi-year rate framework period, instead of during the Annual Review process.

However, the BCUC and interveners would still have the opportunity to examine the drivers behind the changes and variances in the demand forecasts. For example, IRs that ask about why demand increased or decreased for the test year (which might be due to increased customer count or decreases in use rates) would be considered driver-focused and would be in scope.

[26] Exponential Smoothing Time Series.

Other examples of driver-focused IRs would be whether the increase in industrial load was due to a single large industrial customer or for other reasons, and why there is a significant change in the demand forecast for FBC wholesale customers.

Please refer to Attachment 10.1a for examples of specific IRs from the Annual Reviews for 2024 Rates for both FEI and FBC that FortisBC considers to be methodology-focused (and therefore out-of-scope during the proposed Rate Framework) and Attachment 10.1b for examples of specific IRs that FortisBC considers to be driver-focused (and therefore in-scope during the proposed Rate Framework). FortisBC notes the examples provided in Attachments 10.1a and 10.1b are only a subset of IRs from the 2024 Annual Reviews and considerations on whether certain IRs are in- or out-of-scope should not be limited by these examples.

On page B-15 of the Application, FortisBC states:

> With the implementation of CleanBC, dependence on FBC's system is expected to increase, particularly at peak demand times. As a result, the entirety of the FBC system, from generation to local distribution infrastructure and the necessary support systems, will require investment to address both the ability to accommodate load growth (through growth capital expenditures), and the ability of the existing infrastructure to support current and increasing levels of demand. […] [*Emphasis added*]

On page 12 of the Supplemental Information, FortisBC states:

> […] Electrification of heating demand in particular poses a significant challenge to the electric grid which lacks the capacity to shoulder peak heating demand on its own. Electrification demands from all sectors of the economy would therefore exceed what the grid is currently designed for and challenge FBC to maintain reliability, resiliency, and affordability. [*Emphasis added*]

On page 14 of the Supplemental Information, FortisBC provides several impacts of energy transition on its rates during the proposed term of the Rate Framework. FortisBC describes one of the impacts on FBC as follows:

> **Unexpected projects needed to address new load.** […] The pace of the energy transition could result in additional projects being required during the Rate Framework term which FBC has not forecast. Should such a situation arise, the Rate Framework has the flexibility to accommodate both increases and decreases in expenditures. […] [*Emphasis added*]

10.2 Please explain why FortisBC views it appropriate to scope out the methods used to forecast the peak demand (megawatt (MW)) and load (gigawatt hour (GWh)) each year for FBC during the proposed term of the Rate Framework given the significant challenges to its electric grid and a potential requirement for unexpected additional projects to address new loads as described in the preambles above. As part of the response, please explain whether FortisBC anticipates the pace and scope of energy transition over the proposed term of the Rate Framework to pose greater uncertainty in the timing of load, energy consumption trends and electricity demand as compared to the Current MRP term.

Response:

For clarity, while FBC includes a peak demand forecast in the Annual Review applications, the peak demand forecast is informational and is not used to set rates annually. Further, FortisBC has not proposed to scope this topic out of the Annual Review.

However, FortisBC has proposed that the methods used to forecast demand/load each year should be scoped out of the Annual Reviews for the following reasons:

- Demand/load forecast methods can be efficiently reviewed and tested in this proceeding. Through this Application, FortisBC has presented the details of its demand/load forecast to facilitate such a review, thus avoiding the need to retest demand/load forecast methods each year over the term of the Rate Framework and, instead, focusing on reviewing the drivers and results of the forecast.
- There is no evidence to suggest that the methods require annual modification at this time. The demand/load forecasts included in the Annual Reviews are near-term forecasts used to set rates for one year and have continued to work well and are producing reasonably accurate results, as demonstrated in Sections C4.2.1 and C4.2.2 of the Application. Further, this Rate Framework is proposed to be in place for only three years and FortisBC expects that the methods will continue to work as intended.
- Even if demand/load forecasts were to become less accurate over time, customers are not exposed to variances due to forecast error. The demand/load is re-forecast each year and the variances (positive and negative) to revenue are trued up and flowed through to customers.
- A thorough review of the performance of the load/demand forecast methods over multiple years to determine whether the variances between forecast and actual load/demand have been increasing should occur at the end of the three-year term once there is more data to perform such an evaluation.

While there is the potential for increases in load and peak demand for FBC, the pace of these increases is not expected to have a significant impact on the upcoming three years' load forecasts. Further, as new loads materialize, they are incorporated into the annual load forecast each year when setting rates (i.e., the prior year actuals are included in the upcoming year's forecast).

Regarding unexpected growth-driven projects, FBC's proposal to scope load forecasting methods out of the Annual Reviews has no impact on the Company's ability to respond to growth-driven projects. FBC is seeking approval of its three-year forecast of Growth capital expenditures, which includes growth-driven projects, as part of this Application, so the issue of how FBC is forecasting/planning for these projects is appropriately considered in this Application (not in the Annual Reviews). Regular Growth capital is not reviewed during the Annual Reviews, and the forecasts are not adjusted during the three-year term. However, if an unexpected growth-driven project does arise during the term of the Rate Framework, FBC would assess whether it would need to seek separate approval of the project through a CPCN or as a capital expenditure schedule pursuant to section 44.2 of the UCA, or if FBC could accommodate the project within its existing approved regular capital forecasts.

Finally, the annual demand/load forecasts are not intended to be used for capital planning purposes or for long-term forecasting, which are best addressed in the long-term resource plans. Please also refer to the response to BCUC IR1 27.4 for a discussion of the differences between short-term demand forecasts for rate-setting, long-term peak demand forecasts for system planning, and long-term scenario modelling for resource planning.

10.3 In the event that FortisBC's proposed Annual Review scoping is implemented, please explain whether FortisBC would nevertheless monitor the out-of-scope items and propose to scope them back in to any Annual Review where a significant variance or change has occurred that might warrant further analysis in that Annual Review.

Response:

Confirmed. If approved, FortisBC would continue to monitor out-of-scope items and propose to scope them back in if a significant variance or change arose.

10.4 In the event that FortisBC's proposed Annual Review scoping is implemented, please explain whether FortisBC would be amenable to re-deploying regulatory resources to include additional information in Annual Review applications and workshops that would monitor FEI's and FBC's progress towards meeting the targets for the CleanBC Roadmap to 2030, or other aspects of the energy transition. If yes, please propose the additional reporting that FortisBC views would add value to the Annual Review processes.

Response:

FortisBC wishes to clarify the intent of the proposed scoping of the Annual Reviews.

With the exception of the demand/load forecast methods, all of the proposed items in Section C1.10 of the Application were implicitly scoped out of the Current MRP as they are items that were either approved as part of the MRP Decision (for example, the formula O&M and formula Growth capital (for FEI), the three-year regular capital forecasts, the I-Factor, and the growth factor), or approved in other applications. The purpose of explicitly identifying out-of-scope items in this Application is to provide greater clarity for the Annual Reviews as to what is appropriately examined through IRs and at the Workshops, similar to the BCUC's intent with scoping IRs which was implemented as part of the BCUC's Regulatory Efficiency Initiative's Final List of Efficiencies.[27]

Providing greater scoping clarity for the Annual Reviews is expected to improve the efficiency of the process; however, it is not expected to free up regulatory resources for re-deployment. While FortisBC would redeploy available resources elsewhere within the Companies, the regulatory team works on all regulatory filings, and the magnitude of these total filings (including applications, IRs, compliance filings and progress reports, among others) requires the full use of all the Regulatory department's resources.

Further, the proposed scoping of the Annual Reviews is intended to reduce the time spent by other departments within the Companies on the Annual Review process, as the process is time-intensive for many areas of the Companies. Any efficiencies gained from the proposed Annual Review scope by other departments would simply enable those resources to focus more fully on their responsibilities which, in many cases, includes working towards meeting the challenges of the energy transition.

FortisBC also notes that it will already be reporting on energy transition activities through the Annual Review process, including through the following:

- The energy transition informational indicators proposed for FEI;
- Flow-through O&M and capital forecasts related to Clean Growth Initiatives for both FEI and FBC; and
- The Clean Growth Innovation Fund for FEI.

[27] https://docs.bcuc.com/documents/other/2023/doc_75555_bcuc-regulatory-efficiency-initiative-final.pdf.

D. PROPOSED RATE SETTING FRAMEWORK – OPERATIONS AND MAINTENANCE

11.0 Reference: PROPOSED RATE SETTING FRAMEWORK – OPERATIONS AND MAINTENANCE

Exhibit B-1, Section C2, Tables C2-1 and C2-10, pp. C-26 and C-49

2024 Base O&M – General

11.1 Please provide the total number of employee retirements and resignations by year for each of FEI and FBC which occurred during the Current MRP term (i.e. 2020 to 2024) and the associated decrease in labour costs attributable to each utility.

Response:

Tables 1 and 2 below show the total number of employee retirements and resignations that have occurred during the Current MRP term for FEI and FBC, respectively, and an estimate of the associated decrease in O&M labour costs, not accounting for offsetting costs such as overtime or contractors to backfill positions.

As the calculation of FEI's and FBC's proposed 2024 Base O&M starts with the 2023 Actual O&M expenditures, any decrease in O&M labour costs that occurred during these years due to employee retirements and resignations is already reflected in the proposed 2024 Base O&M (i.e., the savings are being passed onto customers in the 2024 Base O&M).

FortisBC notes the following regarding the estimates in Tables 1 and 2:

- FortisBC has used the average Time to Fill a position as an overall proxy for the amount of time the positions remain unfilled.
- FortisBC does not track the specific employee retirements and resignations with corresponding rehires by position. Instead, as part of an overall productivity focus and prudent cost management, departments generally review vacancies as they occur to validate their need to refill (i.e., review department requirements and priorities, job duties and responsibilities). Employee retirements and resignations are then refilled if needed in order to support the ongoing operating needs of the Company.
- The decreases in O&M labour spending presented in the tables are only an estimate of the approximate lower labour spending attributable to O&M based on an approximate O&M cost per employee per day value.
- Factors such as the actual higher/lower allocation of labour to O&M, Capital and Other (Deferral) activities will affect the actual O&M labour savings achieved.
- FortisBC has not factored in the offsetting cost of consultants and overtime used to temporarily backfill for vacancies.
- FortisBC has not factored in the cost of hiring certain positions prior to anticipated retirements to allow for cross training and transfer of knowledge.

Table 1: Estimated Decrease in Labour O&M Costs Due to FEI Retirements and Resignations During the Current MRP Term

FEI	Current MRP Term				As of July 31
	2020	2021	2022	2023	2024
Employee retirements and resignations	98	163	223	225	125
Time to fill	57	57	55	59	56
Decrease in labour costs ($M)	1.0	2.0	3.0	3.0	N/A

Table 2: Estimated Decrease in Labour O&M Costs Due to FBC Retirements and Resignations During the Current MRP Term

FBC	Current MRP Term				As of July 31
	2020	2021	2022	2023	2024
Employee retirements and resignations	24	38	44	46	19
Time to fill	55	49	54	53	53
Decrease in labour costs ($M)	0.2	0.3	0.4	0.4	N/A

11.2 Please estimate the number of employees that each of FEI and FBC is expecting to retire during the proposed term of the Rate Framework and the associated decrease in labour costs related to those retirements. Please include a discussion on the methodology that was used for this estimation.

11.2.1 Please confirm whether the amounts identified in response to the IR above have been removed from each of FEI's and FBC's 2024 Base O&M prior to any adjustments for required 2024 spending or net incremental funding required for the proposed term of the Rate Framework. If not, please explain why not.

11.2.2 Please discuss whether any adjustment to FEI's and FBC's 2024 Base O&M has been made for each of FEI's and FBC's expectation for other voluntary employee attritions, such as resignations, over the proposed term of the Rate Framework based on historical employee attrition rates. If not, please explain why not.

Response:

FortisBC does not have an estimate of the number of employees expected to retire during the Rate Framework term. FEI and FBC are proposing an index-based formula approach based on total O&M per customer to determine overall O&M funding for the Rate Framework term. As discussed below, FortisBC's approach to rebasing takes into account the level of resignations and retirements experienced.

Since FEI and FBC started with Actual 2023 O&M when determining the Companies' respective Base O&M funding for the Rate Framework term, any reductions in costs related to the time required to fill positions vacated due to retirements, resignations or other voluntary employee attritions are already embedded in the 2024 Base O&M. It is therefore not necessary or reasonable to forecast an additional level of employee attrition over and above the level already embedded in the 2024 Base O&M, as doing so would double count the impact of such attrition.

Additionally, as explained in the response to BCUC IR1 11.1, while the total number of vacant positions due to retirements and resignations may contribute to a change in labour costs from the prior year, all else equal, there will be other impacts on total O&M costs from retirements and resignations. These include utilization of contractors, overtime costs, training and other transition-related costs, and the impact on productivity associated with new, less experienced staff.

11.3 Please clarify the total number of employees that each of FEI and FBC intends to hire during the proposed term of the Rate Framework (i.e. 2025 to 2027) as provided for in the 2024 Base O&M and provide a breakdown of the number of employees by department by year.

Response:

A breakdown of the requested total number of new incremental employees that FEI and FBC intend to hire in 2025 by the categories described in Sections C2.2.4 and C2.3.4 of the Application is provided in Table 1 below. As FEI and FBC have predominately filled the required resources for 2024 (described in Sections C2.2.3 and C2.3.3 of the Application), these required 2024 positions are not included in the below table. Please refer to the response to BCUC IR1 11.5 for the breakdown of the required 2024 incremental employees.

Table 1: Breakdown of Incremental Employees for FEI and FBC by Category

Company	Business Driver Category	Sub Category	Shared	Quantity
FEI	Government, Indigenous and Community Engagement	Government Relations and Public Policy	Yes	1
FEI	Government, Indigenous and Community Engagement	Community Engagement	No	3
FEI	Government, Indigenous and Community Engagement	Indigenous Relations Engagement	No	4
FEI	Government, Indigenous and Community Engagement	Customer Engagement	No	2
FEI	Environment and Sustainability	Environment and Sustainability	No	6
FEI	Corporate Security	Corporate Security	Yes	2
FEI	Technology	Patching	No	14
FEI	System Operations and Adaptation	Operate and Maintain LNG Plants	No	1
FEI	System Operations and Adaptation	Workforce Development	No	3
	FEI Total			36
FBC	Government, Indigenous and Community Engagement	Government Relations and Public Policy	Yes	1
FBC	Government, Indigenous and Community Engagement	Indigenous Relations Engagement	No	3
FBC	Government, Indigenous and Community Engagement	Customer Engagement	No	1
FBC	Environment and Sustainability	Environment and Sustainability	No	2
FBC	Corporate Security	Corporate Security	Yes	1
FBC	Technology	Patching	No	7
FBC	System Operations and Adaptation	Engineering	No	7
FBC	System Operations and Adaptation	Workforce Development	No	2
	FBC Total			24

11.4 Please clarify whether any of the new positions that either FEI or FBC intends to hire in 2024 are because of vacancies experienced in 2023.

Response:

The new positions required in 2024 are not to support vacancies in 2023; they are net new positions and are required for the reasons described in Sections C2.2.3 and C2.3.3 of the Application.

11.5 Please provide an update on the hiring status for each of the incremental positions that each of FEI and FBC expect to hire in 2024.

Response:

An update on the hiring status of the new positions identified as a required adjustment to the 2024 Base O&M is provided below.

FEI Department	New Positions	Hiring Status
LNG Operations	4	Filled
LTRP (shared with FBC)	2	2 filled, 1 in progress
Decarbonization & Sustainability	2	Filled
Total	8	

FBC Department	New Positions	Hiring Status
LTRP (shared with FEI)	1	2 filled, 1 in progress
Power Supply	4	Filled
Total	5	

In Tables C2-1 and C2-10 of the Application, FortisBC outlines the 2024 Base O&M calculations for the Rate Framework for each of FEI and FBC, respectively.

11.6 Please explain whether there are any areas of non-labour O&M spending that can be removed from FEI's 2023 Approved Base O&M of $299.302 million and FBC's 2023 Approved Base O&M of $70.318 million that would be in addition to the 2023 savings achieved ($4.322 million and $4.235 million respectively) and the FEI adjustment for exogenous factor and flow through items ($18.007 million). If not, please explain why not.

Response:

As explained in Sections C2.2.1 and C2.3.1 of the Application, FEI and FBC used the 2023 Actual expenditures as the starting point for calculating the 2024 Base O&M, as 2023 Actual results provide the most recent representation of the level of O&M funding required to operate FortisBC's system safely and reliably and maintain its overall service quality. Starting with the Actual 2023 results also ensures that the 2023 O&M savings achieved are reflected in the 2024 Base through a reduction to the O&M. As such, FortisBC confirms that there are no further areas of O&M spending that can be removed from FEI's and FBC's 2023 Approved O&M that would be in addition to the 2023 savings achieved.

Regarding non-labour spending, the amounts included in the 2024 Base O&M represent FEI's and FBC's expectation of its overall funding needs for the Rate Framework term. While the nature of non-labour activities, such as the work undertaken by contractors, may vary in type and amount, overall, at the Company level, the non-labour O&M included in the 2024 Base for FEI and FBC represents the Companies' expected, required level of spending. Further, many non-labour costs are related to permitting, auditing and compliance costs, as well as membership fees and other ongoing required costs. In many cases, particularly regarding permitting, auditing and compliance, the costs for FEI and FBC are expected to increase, not decrease during the Rate Framework term, and both Companies have accordingly sought incremental funding to address these expected increases.

12.0 Reference: PROPOSED RATE SETTING FRAMEWORK – OPERATIONS AND MAINTENANCE

Exhibit B-1, Sections C2.2.3.1 to C2.2.3.4, pp. C-30 to C-32

FEI – Adjustments to 2024 Base O&M for Required 2024 Spending

On page C-30 of the Application, FEI explains that it has entered into a lease for a new contact centre facility in Prince George and states that it is "currently evaluating options for the existing facility, including selling or leasing the property."

12.1 Please explain why a new contact centre facility in Prince George is required.

Response:

FEI determined that a new customer service facility in Prince George was necessary to mitigate risks related to crime and to the safety of its employees at the previous Prince George office location.

Over the past seven years, there has been an increase in crime and social disorganization at or around the customer service office location in Prince George. In response, FEI engaged with multiple community organizations and implemented further security enhancements to improve the environment around the office and reduce incidents. Despite these additional security measures and actions taken, crime and social disorganization continued to deteriorate, and employees continued to experience negative and/or unsafe interactions around the office, particularly while on break and when leaving/entering the office from the overflow parking area. The situation became so severe that routine activities, such as taking a walk on a break, going out for lunch, or visiting their vehicles (particularly those in the overflow parking lot), raised significant safety issues, negatively impacting employee mental and physical well-being. The site has also experienced recurring vandalism, break and enters, and on various occasions, staff have witnessed crimes, including serious assaults, and major medical incidents.

FEI is committed to the safety and well-being of its employees and given the number of security enhancements and safety measures that FEI explored over the years with no material improvement, FEI determined that relocating the Prince George customer service office was the most reasonable and appropriate option.

12.2 Please confirm whether FEI has experienced any employee attrition due to the decision to relocate the Prince George contact centre. If yes, please provide the number of employees and the associated cost savings.

Response:

FEI is not aware of any employee attrition due to the decision to relocate the Prince George customer service office. Overall, the employee response to the office relocation has been positive, given the concerns and issues encountered at the previous location, as explained in the response to BCUC IR1 12.1.

12.3 Under a scenario where the existing facility is sold or leased during the proposed term of the Rate Framework, please discuss how each of these options would impact FEI's rate base and/or be reflected in delivery rates during the proposed term of the Rate Framework.

Response:

If FEI sells the existing facility in Prince George, the value of the assets including the land will be retired from FEI's rate base, thus reducing FEI's revenue requirement in terms of depreciation expense, earned return and income tax associated with the existing facility, which will be reflected as credits in FEI's delivery rates set as part of the Annual Review process. FEI will also save on property tax expenses associated with the existing facility which will also be reflected as a credit in FEI's delivery rates. With regard to the O&M currently embedded in the formula for the existing facility, it will remain within formula O&M as FEI expects to incur a similar level of O&M at the new facility for building services such as utilities, security and cleaning (approximately $200 thousand annually). This O&M is separate from the incremental lease costs for the new facility of $0.850 million.

If FEI sells the existing facility in Prince George, depending on the final selling price of the existing facility, there may either be a gain or loss on the sale. As explained in the response to BCUC IR1 12.4, FEI is currently in negotiations with a potential purchaser and will seek approval of the disposition and treatment from the BCUC in a separate application which it expects to file in Q4 2024. Given the selling price is not yet known, the impact on overall delivery rates due to the sale of the existing facility is unknown at this time.

If FEI leases the existing facility in Prince George instead of selling it, there will be no change to FEI's rate base and therefore no change in its revenue requirement and the delivery rates in terms of depreciation expense, earned return, and income tax expense. FEI will continue to incur property tax for the existing facility and there will continue to be some level of O&M expenses required to maintain the existing facility. Depending on the lease, the cost of service of the existing facility might be offset to a certain extent, thus reducing the delivery rate impact associated with the existing facility.

12.4 Please provide a status update on the existing facility, including whether it has been sold or leased, and if not, please provide FEI's estimated timeline for either option.

Response:

FEI is currently in negotiations with a potential purchaser which, if terms are agreed to, would result in the existing facility being sold. If an agreement is reached, FEI anticipates submitting an application to the BCUC in Q4 2024, pursuant to section 52(1)(a) of the UCA, for approval of the disposition.

On page C-30 of the Application, FEI explains that a total of four incremental operator positions are required for operational support at the Tilbury and Mt. Hayes facilities (two at each facility) in 2024.

12.5 Please explain whether there have been instances where operational support has been inadequate at either the Tilbury or Mt. Hayes facilities during the Current MRP term such that FEI identifies that incremental operator positions are now needed. If yes, please explain how FEI has managed in such instances during the Current MRP term and why FEI cannot manage in the same way for the proposed term of the Rate Framework.

Response:

FEI has been able to maintain an adequate level of operational support during the Current MRP term. The incremental operator positions are needed to enhance the safe and reliable operations of FEI's facilities and were identified based on the following:

1. The findings from an emergency response exercise conducted at the Mt. Hayes facility where FEI determined that additional operators are needed to improve safety related to emergency response. For example, FEI made the following findings from the emergency response exercise:

> With only two plant operators on duty during after-hours operations, should one become incapacitated in the field, the remaining plant operator cannot leave the control panel to offer assistance. This is a potential safety issue. In addition, responding Fire Department will not enter the active area of the site unless accompanied by a FortisBC plant operator. Currently this would require an additional plant operator to be contacted and dispatched to the site. Only then would North Oyster Volunteer Fire Department proceed into the active area.

The recommendation resulting from the findings was as follows:

Need to ensure that there are adequate resources at the site to safely and efficiently respond to any incident that may occur during after-hours. In addition to resources at the site, there should also be a dedicated support mechanism to immediately assist the site should the incident escalate.

2. An assessment of staffing levels at Tilbury required to manage incremental maintenance, increased unforeseen repairs, and other operational requirements that have increased beyond what was planned for in the Current MRP.

Over the Current MRP term, FEI gained experience operating the new T1A facility. Through its experience, FEI identified that additional support was required to ensure all required maintenance and operating activities could be adequately supported. For example, the requirement to recertify pressure safety valves (PSVs) every two years requires operators to create "lock out, tag out to ensure zero energy" plans and issue work permits for over 200 valves every year. Creating "lock out tag out to ensure zero energy" plans are often a complex and time-consuming task to ensure safety when working on plant equipment. Increasing requirements for maintenance, unforeseen repairs, and other operational activities have placed similar demands on operators' time, and additional operators are therefore needed to meet these requirements.

Accordingly, FEI has identified the need for two additional operators at each facility to address these issues.

On page C-31 of the Application, FortisBC explains that it has identified an immediate need for three additional positions in 2024 to support its long-term resource planning activities in consideration of the recent BCUC decision on FEI's 2022 Long-Term Gas Resource Plan. FEI states that the total cost of these three positions, including supporting costs, is $0.552 million, with the costs being allocated approximately two-thirds to FEI and one-third to FBC (FEI's share of the costs is equal to $0.382 million).

12.6 Please provide a breakdown of the $0.552 million referenced in the preamble immediately above by labour costs for each incremental position and identify the relevant supporting costs. As part of the response, please explain whether the labour costs and supporting costs are reflective of current market rates.

Response:

Please refer to the table below for the breakdown of the $0.552 million. The labour and supporting costs are reflective of current market rates. As shown in the table below, the supporting costs include $20 thousand for consulting costs and $5 thousand for employee expenses.

Cost ($M)	Amount
IRP Special Projects Manager	0.200
IRP Policy and Engagement Specialist	0.175
IRP Data Analyst	0.152
Consulting costs	0.020
Employee expenses	0.005
Total	0.552

On pages C-31 to C-32 of the Application, FEI explains that it requires additional resources to support reporting and compliance requirements to comply with the growing requirements related to decarbonization and sustainability. FEI states that it "requires $0.800 million starting in 2024 for two new positions, as well as costs related to membership dues, external audit fees and consulting costs."

12.7 Please provide a breakdown of the $0.800 million funding that is required as referenced in the preamble above by cost component (i.e. two new positions, membership dues, external audit fees, consulting costs). As part of the response, please explain whether the labour costs for the two new positions are reflective of current market rates.

Response:

A breakdown of the $0.800 million in additional funding is provided below. The labour costs are reflective of current market rates.

Cost ($M)	Amount
Director, Decarbonization & Sustainability	0.210
Senior Manager, Carbon Management	0.180
Membership dues	0.100
Consulting fees	0.175
External audit fees	0.085
Departmental travel and course fees	0.050
Total	0.800

13.0 Reference: PROPOSED RATE SETTING FRAMEWORK – OPERATIONS AND MAINTENANCE

Exhibit B-1, Sections C2.2.4.1 to C2.2.4.2, pp. C-33 to C-42, Section C2.2.4.5,

pp. C-46 to C-47

FEI – Net Incremental Funding for the Term of the Rate Framework

On pages C-33 to C-39 of the Application, FEI provides a breakdown of the $2.748 million in net incremental funding for government, Indigenous and community engagement required for the term of the Rate Framework. BCUC staff understand that the $2.748 million is comprised of approximately $1.549 million for 11 new positions, $0.500 million for community support, and $0.700 million for advancing reconciliation; of the 11 new positions, two positions will be shared between FEI and FBC, and nine positions are exclusively for FEI.

13.1 Please confirm, or explain otherwise, that FEI is seeking approval of $2.748 million in net incremental funding as summarized in the preamble above.

Response:

FEI is seeking approval of the overall 2024 Base O&M per customer.

FEI notes the net incremental O&M funding for Government, Indigenous and Community Engagement has been updated to $2.499 million due to the changes related to the Community Support funding, which FEI has reduced from $0.500 million to $0.250 million as discussed in the response to BCUC IR1 16.2. Please also refer to the Errata to the Application filed concurrently with these IR responses. All other items for the net incremental funding are as summarized in the preamble above.

13.2 Please provide a tabular breakdown by position and year of the $1.549 million of net incremental funding referenced in the preamble above. As part of the response, please indicate the year(s) in which the 11 positions are intended to be hired and explain whether the labour costs for each of the positions are reflective of current market rates.

Response:

A breakdown of the 11 positions is provided below. The labour costs are reflective of FEI's estimate of the current market rates to recruit employees for the requested positions. FEI intends to hire the new positions in 2025.

Description of Position	# of Positions	Labour Costs ($ millions)
Manager, Climate Action Policy[1]	2	0.234
Community Relations and Public Policy Manager	3	0.480
Community and Indigenous Relations/Initiatives Manager	4	0.560
Events and Outreach Coordinator	1	0.125
Digital Content Designer	1	0.150
Total	**11**	**1.549**

Note to Table:

[1] These two positions are being shared between FEI and FBC. The total labour cost is $0.300 million, and FEI's allocated share is $0.234 million.

13.2.1 To the extent that the 11 new positions are not hired by the start of the Rate Framework term, please explain why it is appropriate for the full cost to be added to the 2024 Base O&M.

Response:

As has been the case with the Current MRP and the 2014-2019 PBR Plan, FortisBC considers it reasonable to include the full labour costs of these positions when setting the Base O&M, regardless of whether all the positions are able to be filled at the start of the Rate Framework. The inclusion of full year labour costs is required to provide for sufficient funding for each of the years of the Rate Framework term, and there is always expected to be some variability in the timing of new hires despite FortisBC's best efforts.

Further, to the extent that positions are not able to be filled immediately in 2025, and depending on the degree of urgency of the required work to be undertaken, FortisBC may need to pursue short-term solutions such as contractors or consultants to assist with necessary work, which would increase non-labour O&M costs above what FortisBC has proposed in the 2024 Base O&M. As the extent of potential savings in 2025 (and the causes of those savings) cannot be known at this time, FortisBC considers it reasonable and appropriate for the full net incremental funding for 2025 to be added to the 2024 Base O&M.

13.3 Please explain whether FEI anticipates any challenges in filling the 11 new positions in government, Indigenous and community engagement roles.

Response:

No, FEI does not anticipate any challenges in filling these positions.

On page C-26 of the Application, FEI provides Table C2-1 which shows how the proposed FEI 2024 Base O&M is calculated, including an adjustment to multiply the 2024 Base O&M (in 2023 dollars) by the 2024 formula inflator. The 2024 formula inflator of 1.0443 is defined by FEI in footnote 67 on page C-25 of the Application as "inflation less productivity, and customer growth."

On page C-40 of the Application, FEI provides Table C2-6 which summarizes the actual expenditures for environment and sustainability that includes 2023 actual expenditures of $2.910 million, the projected base funding for 2024 ($3.839 million), and the proposed net incremental funding to be added to the 2024 Base O&M ($1.800 million).

13.4 Please provide a detailed calculation of how FEI arrived at the 2024 Projected Base of $3.839 million from the 2023 Actual Expenditure of $2.910 million for environment and sustainability expenditures. As part of the response, please identify the 2024 formula inflator that is used and if it differs from 1.0443, please explain why and discuss what it is comprised of.

Response:

A detailed calculation of the 2024 Projected Base is included below. FEI started with the 2023 Actual O&M amount of $2.910 million and confirms that it inflated (multiplied) the 2023 Actuals by 1.0443. FEI then added the required $0.800 million incremental O&M to the 2024 Projected Base. Please refer to the response to BCUC IR1 12.7 for a breakdown of the $0.800 million.

	2023 Actual	Formula Inflator	2024 Base	Required 2024 Adjustment	Projected 2024 Base
Environment and Sustainability	2.910	1.0443	3.039	0.800	3.839

On pages C-39 to C-42 of the Application, FEI provides a breakdown of the $1.800 million in net incremental funding for environment and sustainability required for the proposed term of the Rate Framework. Of the total $1.800 million, FEI states that $0.700 million is estimated for ongoing requirements and $1.100 million is estimated to be attributable to implementing new codes and regulations required or anticipated in six areas of labour and three areas of non-labour, which FEI lists on pages C-41 to C-42 of the Application.

13.5 Please clarify whether the $1.100 million in incremental funding is a one-time cost in 2025 or expected to be a recurring cost for each year from 2025 through 2027.

13.5.1 If the $1.100 million in incremental funding is a one-time cost, please explain why it is appropriate to add this amount to the FEI 2024 Base O&M for the proposed term of the Rate Framework.

13.5.2 If the $1.100 million is a recurring cost, please provide further details regarding the nature of the cost for each year from 2025 through 2027.

Response:

The $1.100 million in incremental funding is a recurring cost for each year from 2025 to 2027; therefore, the nature of the costs remains the same in each year of the Rate Framework term. The breakdown of the $1.100 million is provided below. The labour costs are reflective of current market rates.

Description of Cost	Amount ($ million)
Environmental Program Lead (Contaminated Sites Regulation) to support increased requirements/activities (new labour position)	0.150
Environmental Program Lead (Transportation of Dangerous Goods/Hazardous Waste Regulation) to support increased requirements/activities (new labour position)	0.150
Archaeologist to support increased requirements/activities (new labour position)	0.150
Carbon Accounting Lead (GHG) to support new compliance reporting requirements (new labour position)	0.150
Carbon Accounting Technician (GHG) to support new compliance reporting requirements (new labour position)	0.125
Additional Sustainability Program Manager to support increased sustainability progress and reporting (new labour position)	0.150
Non-labour: Increased archaeology permits/compliance costs	0.125
Non-labour: Increased Contaminated Sites Regulation compliance costs/consulting	0.050
Non-labour: Increased GHG emissions/carbon accounting costs	0.050
	1.100

13.6 Please clarify whether the six listed labour areas on pages C-41 to C-42 of the Application correspond to six incremental positions which FEI intends to hire during the proposed term of the Rate Framework. If not confirmed, please explain what the labour costs relate to.

Response:

Confirmed. The six labour areas discussed on pages C-41 and C-42 of the Application are related to six new incremental positions.

13.6.1 To the extent that the six new positions are not hired by the start of the proposed term of the Rate Framework, please explain why it is appropriate for the full cost to be added to the 2024 Base O&M.

Response:

Please refer to the response to BCUC IR1 13.2.1.

13.7 Please provide a detailed breakdown of the $1.100 million in incremental funding being requested by FEI by cost component/driver, including, but not limited to, labour costs of any new positions. As part of the response, please explain whether the labour costs are reflective of current market rates.

Response:

Please refer to the response to BCUC IR1 13.5.

On page C-46 of the Application, FEI provides Table C2-9 which summarizes the actual expenditures for system operations and adaptation from 2020 to 2023, the projected base funding for 2024, and the net incremental funding to be added to the FEI 2024 Base O&M. This table includes the following two line items: “Operate and Maintain LNG [liquified natural gas] Plants” and “Workforce Development”.

13.8 Please provide a detailed calculation of how FEI arrived at the 2024 Projected Base of $14.578 million from the 2023 Actual Expenditure of $13.385 million for the “Operate and Maintain LNG Plants” line item. As part of the response, please identify the 2024 formula inflator that is used and if it differs from 1.0443, please explain why and discuss what it is comprised of.

Response:

A detailed calculation of the 2024 Projected Base is included below. FEI started with the 2023 Actual O&M amount of $13.385 million and confirms that it inflated (multiplied) the 2023 Actuals by 1.0443. FEI then added the required $0.600 million incremental O&M to the 2024 Projected Base. As explained in Section C2.2.3.2 (page C-30) and in the response to BCUC IR1 12.5, the additional funding is required in 2024 to hire two operator positions at the Mt. Hayes facility and two operator positions at the Tilbury facility.

	2023 Actual	Formula Inflator	2024 Base	Required 2024 Adjustment	Projected 2024 Base
Operate and Maintain LNG Plants	13.385	1.0443	13.978	0.600	14.578

On pages C-46 to C-47 of the Application, FEI provides a breakdown of the $0.800 million in net incremental funding for system operations and adaptation required for the proposed term of the Rate Framework. Of the $0.800 million, FEI states that $0.400 million is required to "add a warehouse position" and "manage ongoing maintenance requirements," and the remaining $0.400 million "provides for three additional positions focused on recruitment, corporate employee skills, and competencies development for all employees."

13.9 Please provide a breakdown of the $0.400 million of net incremental funding required to add a warehouse position and to manage ongoing maintenance requirements.

Response:

A breakdown of the $0.400 million of net incremental funding required is provided below.

Cost ($M)	Amount
Warehouse position (labour)	0.150
Capital spares maintenance (non-labour)	0.250
Total	0.400

13.10 Please indicate the year(s) in which the three positions are intended to be hired and explain whether the labour costs for each of the three positions are reflective of current market rates.

Response:

FEI intends to hire the three positions in 2025 once a BCUC decision on the Application is issued (please also refer to the response to BCUC IR1 13.2.1). Labour costs for the three positions are reflective of current market rates.

13.10.1 To the extent that the three new positions are not hired by the start of the Rate Framework term, please explain why it is appropriate for the full cost to be added to the 2024 Base O&M.

Response:

Please refer to the response to BCUC IR1 13.2.1.

14.0 Reference: PROPOSED RATE SETTING FRAMEWORK – OPERATIONS AND MAINTENANCE

Exhibit B-1, Section C2.3.3.3, p. C-51

FBC - Adjustments to 2024 Base O&M for Required 2024 Spending

On page C-51 of the Application, FBC explains that "[t]o support the management of its power supply portfolio and the development of new supply side resources, four additional positions, as well as funding for external consultants are being added in 2024 at a total cost of $1.200 million."

14.1 Please provide a detailed breakdown of the $1.200 million of funding in 2024 by component discussed in the preamble above (i.e. each of the four additional positions, funding for external consultants). As part of the response, please explain whether the labour costs for the four new positions are reflective of current market rates.

Response:

Please refer to the table below for the breakdown of the $1.200 million. The labour costs are reflective of current market rates.

Description	Amount ($ million)
Energy Supply Data Analysis Manager	0.185
Power Supply Planning Specialist	0.150
Energy Supply Resource Specialist	0.150
Power Supply Operations Manager	0.175
External Consultants	0.540
Total	**1.200**

Managing added complexity is a cost driver for all of the requested incremental spending, as FBC not only requires more resources to manage and optimize its existing supply portfolio given the increasingly tight power market, but also requires resources to plan and model future supply options.

The activities of contract analysis, design and updates, which include both BC Hydro and other power supply contracts, are driving the need for the new Power Supply Operations Manager, as well as the need for increased external consultants due to the specialized nature of these contracts.

The development of new power supply resources is driving the need for the Power Supply Resource Specialist as well as the need for increased external consultants.

14.2 Please provide a detailed breakdown of the $1.200 million of funding in 2024 by cost driver (i.e. managing added complexity, development of new power supply resources, development of new framework under which FBC operations will be coordinated with BC Hydro).

Response:

Please refer to the response to BCUC IR1 14.1.

On page C-51 of the Application, FortisBC also states: “As highlighted at the Annual Review for 2024 Rates workshop, the power supply market is changing and has become more complex and dynamic as the region experiences higher wholesale prices and tighter market conditions.”

14.3 Given the increased complexity of the power supply market that was discussed in FBC’s 2024 Annual Review, please explain how power supply costs were managed within the formula for the Current MRP term.

14.3.1 Please elaborate on the changes in circumstances, if any, going into the proposed term of the Rate Framework (i.e. 2025 to 2027) that necessitates the additional resources to support FBC’s power supply activities.

Response:

FortisBC assumes the question is asking about formula O&M costs related to managing the power supply portfolio as opposed to “power supply costs” which are not included in formula O&M.

The power supply market has become increasingly constrained year-over-year, but these constraints have become particularly notable in the last two years of the Current MRP term. Given the increasing constraints on the power supply market being created by the move towards electrification and the increased pressure on peak demand in particular, FBC considers that the need to strategize and proactively respond to these changes, as well as continue to effectively manage its existing supply portfolio, will only become more challenging and resource intensive. Thus, while FBC was able to manage with increasing difficulty in the latter years of the Current MRP term, FBC must increase its resourcing in the area of power supply and resource development in order to ensure that it is responding to the changing environment to continue reliably serving customers as cost-effectively as possible.

Further, and as explained in the response to BCUC IR1 14.1, a key driver of the additional resources is related to obtaining new supply resources, which was not an area of focus when FBC was considering its resourcing for the Current MRP, but is now an area of high importance for FBC given the costs, complexity and evolving impacts of the energy transition.

As the need for increased electric supply in the region grows in response to the move to electrification, the pressures placed on FBC's power supply and resource development group will continue to grow. This requires adequate resourcing and specialized skillsets, and therefore cannot be accommodated by placing greater workloads on existing staff, or cross-training employees from other departments. Further, the increased need for external consultants is required because there are areas of specialization that would be very difficult to obtain internally. For example, while FBC has internal legal resources which can be used for work on contracts, FBC must also seek assistance from external legal due to the complexity of some contracts (as well as the breadth of experience which some legal firms have in highly technical areas). Utilizing specialized experts in highly technical fields ensures that FBC is developing strategies, plans and models that are producing the best reasonably-possible results, which is important for the long-term provision of reliable and affordable service for its customers.

FBC has identified the level of increased funding that it considers to be required in 2024 and for the duration of the three-year Rate Framework term.

14.4 Please discuss whether the activities required to support the management of FBC's power supply could be addressed by current FBC employees (either already working in power supply, or by cross-training employees from other departments) as opposed to adding additional positions and engaging external consultants. If not, please explain why not.

Response:

Please refer to the response to BCUC IR1 14.3.

15.0 Reference: PROPOSED RATE SETTING FRAMEWORK – OPERATIONS AND MAINTENANCE

Exhibit B-1, Sections C2.3.4.1 to C2.3.4.2, pp. C-52 to C-57, Section C2.3.4.5,

pp. C-58 to C-61

FBC – Net Incremental Funding for the Term of the Rate Framework

On pages C-52 to C-55 of the Application, FBC provides a breakdown of the $1.356 million in net incremental funding for government, Indigenous and community engagement required for the proposed term of the Rate Framework. BCUC staff understand the $1.356 million is comprised of approximately $0.696 million for six new positions, $0.100 million for non-labour costs, $0.250 million for community support, and $0.310 million for advancing reconciliation. Further, of the six new positions, two positions will be shared between FEI and FBC, and four positions are exclusively for FBC.

15.1 Please confirm, or explain otherwise, that FBC is seeking approval of the $1.356 million in net incremental funding as summarized in the preamble above.

Response:

FBC is seeking approval of the overall 2024 Base O&M per customer.

FBC notes the net incremental funding for Government, Indigenous and Community Engagement has been updated to $1.231 million due to the changes related to the Community Support funding FBC has reduced from $0.250 million to $0.125 million as discussed in the response to BCUC IR1 16.2. Please also refer to the Errata to the Application filed concurrently with these IR responses. All other items for the net incremental funding are as summarized in the preamble above.

15.2 Please provide a breakdown of the $0.696 million of net incremental funding referenced in the preamble above, by position in a table. As part of the response, please indicate the year(s) for which the six positions are intended to be hired and explain whether the labour costs for each of the positions are reflective of current market rates.

Response:

A breakdown of the six positions is provided below. The labour costs are reflective of FBC's estimate of the current market rates for the requested positions. FBC intends to hire the new positions in 2025.

Description of Position	# of Positions	Labour Costs ($ million)
Manager, Climate Action Policy[1]	2	0.066
Community and Indigenous Relations/Initiatives Manager	3	0.480
Communications Manager	1	0.150
Total	**6**	**0.696**

Note to Table:

[1] These two positions are being shared between FEI and FBC. The total labour cost is $0.300 million, and FBC's allocated share is $0.066 million.

15.3 Please discuss whether FBC anticipates any challenges in filling the six new positions in government, Indigenous and community engagement roles during the proposed term of the Rate Framework.

Response:

No, FBC does not anticipate any challenges in filling these positions.

15.3.1 To the extent that the six new positions are not hired by the start of the proposed term of the Rate Framework, please explain why it is appropriate for the full cost to be added to the 2024 Base O&M.

Response:

Please refer to the response to BCUC IR1 13.2.1.

On pages C-55 to C-57 of the Application, FBC provides a breakdown of the $0.500 million in net incremental funding for environment and sustainability required for the proposed term of the Rate Framework. FBC states that $0.200 million is estimated for increasing regulatory requirements and $0.300 million is estimated for implementing new codes and regulations required or anticipated in two areas of labour and four areas of non-labour, which FBC lists on pages C-56 to C-57 of the Application.

15.4 Please clarify whether the two listed labour areas on page C-56 of the Application correspond to two incremental positions which FBC intends to hire during the proposed term of the Rate Framework. If not confirmed, please explain what these labour costs relate to.

Response:

Confirmed. The two listed labour areas on page C-56 of the Application correspond to two incremental positions.

15.4.1 To the extent that the two new positions are not hired by the start of the Rate Framework term, please explain why it is appropriate for the full cost to be added to the 2024 Base O&M.

Response:

Please refer to the response to BCUC IR1 13.2.1.

15.5 Please provide a detailed breakdown of the $0.500 million in incremental funding being requested by FBC by cost component, including, but not limited to, labour costs of any new positions. As part of the response, please explain whether the labour costs are reflective of current market rates.

Response:

A detailed breakdown of the $0.500 million in incremental funding is provided below. The labour costs are reflective of current market rates.

Description of Cost	Amount ($ million)
Environmental Technician to support increased activities (new labour position)	0.125
Environmental Program Lead to support increased activities (new labour position)	0.150
Non-labour: Increased fisheries assessment work (*Fisheries Act*)	0.100
Non-labour: Additional invasive species (mussel) prevention	0.050
Non-labour: Additional terrestrial resource management (migratory birds/species at risk; invasive plants)	0.025
Non-labour: Increased archaeology permits/compliance costs	0.050
Total	**0.500**

On pages C-58 to C-61 of the Application, FBC provides a breakdown of the $2.273 million in net incremental funding for system operations and adaptation required for the proposed term of the Rate Framework, of which $0.345 million is for seven new positions in engineering and $0.190 million is for related support costs (telecommunications fees and licencing fees to support the Mandatory Reliability Standards (MRS) process), $0.260 million is for two new positions in workforce development, $0.478 million is for vegetation management, and the remaining $1.000 million is for generation and system control.

Concerning the seven additional positions in engineering, FBC states on page C-59 of the Application, "[w]hile two of these positions are associated with asset management and have significant O&M allocations, the majority of the positions' salaries are to support the proposed growth in FBC's capital over the upcoming period, with most of the salaries charged to capital activities and the remaining 10 to 15 percent allocate to O&M."

Concerning the two new positions in workforce development, FBC states on page C-61 of the Application that the net incremental funding supports the increasing volume of recruitment and employee movements (retirements and voluntary turnover) which it has experience since 2018.

15.6 Please provide a breakdown of the $0.345 million and $0.260 million of net incremental funding referenced in the preamble above, specifying the labour costs of each incremental position. As part of the response, please indicate the year(s) in which each of the nine positions are intended to be hired and explain whether the labour costs for each position are reflective of current market rates.

Response:

A breakdown of the $0.345 million for the seven Engineering positions and related costs is provided below. Total O&M labour costs are estimated at $0.275 million, with the labour costs for each position based on current market rates and after capital allocations (i.e., the labour costs in the table for each position represent the amount allocated to O&M). All of the positions are planned to be filled in 2025.

Engineering Positions	Amount ($ million)
Engineer In Training (EIT)	0.010
Technologist (Distribution Design)	0.012
Technologist (Protection & Control/Communications Design)	0.034
Technologist Data Integrity	0.098
Protection & Control Engineer	0.015
Technologist (Station Design)	0.012

Engineering Positions	Amount ($ million)
Asset Assistant (Asset Maintenance)	0.094
Employee-related Expenses (non-labour)	0.070
Total	**0.345**

A breakdown of the $0.260 million for Workforce Development is provided below. The estimated labour costs for each position are reflective of current market rates. Both positions are planned to be filled in 2025.

Workforce Development Positions	Amount ($ million)
Talent Acquisition Associate	0.130
Workforce Development Indigenous Business Partner	0.130
Totals	**0.260**

15.6.1 For any positions which are not expected to be hired at the start of the proposed term of the Rate Framework, please explain why it is appropriate for the full anticipated cost to be added to the FBC 2024 Base O&M.

Response:

Please refer to the response to BCUC IR1 13.2.1.

15.7 Given the net incremental funding in engineering to support the proposed growth in FBC's capital, please provide a comparison of the percentage increase in FBC's proposed capital expenditures compared to the percentage increase in O&M costs related to engineering and discuss the results.

Response:

Please refer to Table 1 below which shows the percentage increase in FBC's gross Growth and Sustainment capital (for which engineering labour is required) from 2024 Approved to 2025 Forecast.

Table 1: Percentage Increase in FBC's Growth and Sustainment Capital Requiring Engineering Labour from 2024 Approved to 2025 Forecast

	2024 Approved ($000s)	2025 Forecast ($000s)	Incremental ($000s)	% Increase
Growth Capital (Gross)	24,568	41,349	16,781	68.3%
Sustainment Capital (Gross)	51,652	75,664	24,012	46.5%
Total	**76,220**	**117,013**	**40,793**	**53.5%**

Please refer to Table 2 below which shows the percentage increase in the proposed incremental engineering O&M for FBC from the 2024 Projected Base (as shown in Table C2-17 of the Application).

Table 2: Percentage Increase in FBC's Proposed Engineering O&M from 2024 Projected Base

	2024 Projected Base O&M ($000s)	2024 Base O&M w/ Incremental Funding ($000s)	Incremental Funding ($000s)	% Increase
Engineering O&M	**6,553**	**7,088**	**535**	**8.2%**

FBC notes that, as discussed on page C-59 of the Application, two of the new positions in engineering will support asset management and will charge approximately 95 percent of their labour to O&M. The other five new positions, which represent $345 thousand of the incremental O&M funding, will support capital projects and the majority of the labour costs associated with these five new capital supporting positions will be direct charged to capital. The above results demonstrate that increases in Growth and Sustainment capital expenditures are not well correlated with Engineering O&M, which is primarily driven by the maintenance of FBC's existing assets.

15.8 Please provide the expected percentage increase in telecommunication fees and licensing costs to support the MRS process, respectively, and provide the historical fee increases during the Current MRP term by way of comparison to explain how FBC estimated the net incremental funding that is needed.

Response:

Please refer to Table 1 below for the 2020 to 2023 Actual expenditures, the 2024 Projected Base amounts, the proposed incremental funding amounts for 2025, and the percentage increase in each support activity compared to the 2024 Projected Base.

Table 1: Other Engineering Support Activities ($ million)

	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Projected	Proposed Incremental	% Increase
Telecommunications Fees	0.210	0.213	0.215	0.238	0.240	0.050	20.8%
Support the MRS Process (licensing fees)	0.147	0.104	0.129	0.121	0.130	0.140	107.7%

The increase in Telecommunications Fees for the Rate Framework term is based on the expected increase in the cost of new telecommunications contracts. FBC is currently in negotiations with vendors on new contracts.

Of the $0.140 million increase in O&M to support the MRS process, approximately $0.050 million is due to licenses that were part of initial capital purchases and are now going to be renewed annually under O&M fees, as the terms of the agreements have ended and are being renewed. Of the remaining $0.090 million, approximately $0.060 million is due to Virtual Machines (VM) licensing which is seeing an approximate increase of 500 percent. The percentage increase is largely due to the VM vendor being purchased and thus changing their licensing model. The MRS infrastructure and architecture is relatively small in scale and has fewer applications, but the key applications being used are seeing higher increases.

15.9 Please explain what actions FBC is taking to manage the operational impacts of retirements and voluntary turnover, and to mitigate the impacts.

Response:

FBC strives to proactively address the operational impact of retirements and turnover. Key positions are identified and whenever possible, filled before employees leave with new hires or existing employees, and include a transition period to enable training and a smooth knowledge transfer. Succession planning is discussed across all departments to mitigate risk in upcoming years due to retirements and turnover, including promotions. FBC actively develops talent, including employees with high potential for future leadership roles, and provides support for employees that are new to the Company or new to their positions with relevant training. Leaders may also consider other tools to address changes in their workforce such as department restructuring or, for shorter periods, overtime and external consultant support.

15.10 Given that FBC has managed recruitment and employee training activities within formula O&M since 2018, please explain why the two additional positions in workforce development are needed at this time.

Response:

The environment in which FBC operates has changed dramatically over the last five years, and existing workloads are increasing. Recruitment volumes due to retirements and resignations have increased since 2018 with a critical need to fill these positions through both employee succession and external recruitment, creating an increased volume of posting, interviewing, and filling. Additionally, new hires require onboarding support, and employees moving into leadership roles (or new roles) require support with the transition.

While these activities have been performed in previous years, FBC's metrics and industry trends show a sustained increase in the volume of retirements and turnover. The workforce development team also leads the work to advance long-term Indigenous employment strategies and to support commitments to Partnership Accreditation in Indigenous Relations (PAIR[28]) certification. Indigenous employment requires dedicated resources to support relationship building and engagement. Finally, workforce development supports the workforce planning needs for major projects, including staffing for projects. The Company must fill these positions and provide onboarding support and training in a timely manner to ensure that the Company is meeting its ongoing operational requirements for its projects.

On pages C-59 to C-60 of the Application, FBC provides a breakdown of the $1.000 million net incremental funding for general and system control into four categories: compliance activities to meet BC dam safety regulations, compliance activities to meet evolving WorkSafe BC regulations, increased dam and plant maintenance work, and additional major unit inspections and maintenance.

15.11 Please clarify whether the compliance activities to meet BC dam safety and WorkSafe BC regulations, respectively, relate to new requirements from these entities and are therefore new compliance activities during the proposed term of the Rate Framework as compared to the Current MRP term. If not, please explain why these new compliance activities and funding amounts are required.

[28] PAIR certification was formerly known as Progressive Aboriginal Relations (PAR) certification.

Response:

The compliance activities to meet BC dam safety and WorkSafe BC regulations relate to the implementation of new activities to meet the regulations, not to new requirements from these entities. These new activities are explained below.

The dam safety reviews completed during the Current MRP term recommended that a seismic capacity withstand study be undertaken for all dams. FBC plans to complete the studies at the South Slocan (SLC), Lower Bonnington (LBO) and Upper Bonnington (UBO) dams during the Rate Framework term. The reviews also identified the need for increased vegetation management at various locations at FBC's dams; therefore, FBC has included increased funding for vegetation removal on dam surfaces and in drains. FBC plans to undertake a dam drainage inspection at its Corra Linn (COR) and SLC dams to assess their functionality and condition and to determine if dam drainage maintenance, including sediment removal or flushing is required. These activities are new activities that were not performed during the Current MRP term and are incremental to the existing activities that FBC has been undertaking during the Current MRP term.

Further, FBC performs spillway gate testing annually with most of the spillway gates being opened partially. Based on operational learnings, FBC plans to implement full spillway gate opening tests which require increased internal resources.

FBC performs annual powerhouse cranes inspections as required by the Operational Health & Safety (OHS) Regulation Part 14. Based on operational learnings, in addition to the annual inspections, powerhouse crane runway span and elevation surveys need to be performed during the Rate Framework term.

15.12 Please elaborate on, and quantify where possible, how the condition/age of FBC's assets have or are expected to change during the proposed term of the Rate Framework, resulting in increased dam and plant maintenance activities as well as major unit inspections and maintenance, as compared to the Current MRP term. As part of the response, please explain how FBC estimated the additional funding that is needed related to changing assets condition/age.

Response:

As FBC's generation assets continue to age, increased maintenance activities are expected to be required. FBC's assessment of the activities required to be performed in the upcoming three years are informed by the dam safety reviews completed during the Current MRP term (as explained in the response to BCUC IR1 15.11) and by FBC's ongoing review of the condition of its generation assets. The amount of funding required to undertake the additional work during the Rate Framework term is based on quotes from contractors, historical costs of similar activities, and evaluation of the costs of internal resources needed.

As explained in the response to BCUC IR1 15.11, the dam safety reviews have identified various activities that need to be performed to address age and condition-related issues. Beyond these activities, FBC has discovered concrete surface deterioration at the SLC and UBO dams, and FBC plans to commence a project during the Rate Framework term which includes applying concrete sealing and performing localized minor repairs to protect the concrete from surface damage, thereby extending the service life of the assets. This project is in addition to the concrete work described in Section C3.4.2.1 of the Application.

Other activities which FBC plans to undertake during the Rate Framework term which are tied to age and condition-related issues are as follows:

- The log boom at the Corra Linn dam protects the units' intake from debris and FBC cleans it approximately every two years depending on the amount of debris observed. FBC has noted an increase in the deterioration of the debris boom and plans to undertake various maintenance activities to ensure its continued functionality during the term of the Rate Framework.
- The dewatering, unit cooling water, fire water and domestic water systems at FBC's generation plants use pressurized pipes that in most cases are original. FBC plans to start a condition assessment of all the pipe systems.
- The air-cooling of the generating units and powerhouses at FBC's plants is done by an air wash system. While FBC performs regular inspections and maintenance of these systems, FBC plans to undertake an overhaul program of the air wash systems that will start in 2025 and will include removal, inspection, and overhaul of the major components: motors, fans, bearings, journals, impellers, plenums, pulleys, motors, piping, nozzles, and baffles.
- FBC plants have a water passageway dewatering system that includes pipes, valves and other components, which are original. In addition to their regular maintenance, FBC plans to undertake an overhaul program for these original systems that will include dewatering pump system disassembly, inspection and refurbishing of components.
- FBC performed an evaluation of each plant's electrical auxiliary system maintenance plan and determined that increased maintenance activities are required for certain components of the 2,300 V and 600 V station service systems.

Finally, during the term of the Rate Framework, FBC will start a 160,000 hours Major Unit Inspection (MUI) program, as it has been approximately 20 years since the upgrades to generators were completed during the Unit Life Extension program. The 160,000 hours MUI program will include a more extensive inspection and condition assessment of unit components than the 80,000 hours (10 year) MUI program that was performed during the Current MRP term. The 160,000 hours MUIs will include more hours of work due to the increased scope and FBC plans to complete a detailed inspection and a finite element analysis of the original unit headcovers that are made from cast iron and critical to the units' integrity.

16.0 Reference: PROPOSED RATE SETTING FRAMEWORK – OPERATIONS AND MAINTENANCE

Exhibit B-1, Section C2.2.4.1.2, p. C-36, Section C2.3.4.1.2, p. C-54

Community Investment

On page C-36 of the Application, FortisBC explains that through the community investment program, it currently provides $1.100 million in donation funding to support grassroots initiatives to more than 126 municipalities and regional districts and 58 First Nations communities. FEI requests incremental funding of $0.500 million to extend support for the communities it serves, stating that there has been an increase in the business development requests to connect with local politicians and business leaders, which accounts for approximately 25 percent of the overall Community Investment spending.

On page C-54 of the Application, FBC explains that similar to the need identified for FEI, FBC requires new community investment funding of $0.250 million to support the communities that FBC serves and operates in.

16.1 Under a scenario in which the $0.750 million in incremental funding for community support is approved ($0.500 million for FEI and $0.250 million for FBC), please confirm, or explain otherwise, that a total of approximately $0.463 million[29] would be meant to fund the business development requests of local politicians and business leaders.

<u>Response:</u>

FortisBC clarifies that the words “business development requests to connect with local politicians and business leaders” was meant to describe the portion of the community investment funding for conferences, forums and workshops related to topics such as economic development, energy, environment, climate change, and net zero. FortisBC further clarifies that this funding is not to support the business interests of local politicians and business leaders. FortisBC describes its community investment in more detail below.

Through the Community Investment Program, FortisBC partners with a range of leaders from local initiatives, non-profits and social giving groups who have creative insights into the specific needs of their communities. As discussed in the Application, FortisBC invests in four key areas because the Companies believe that they help contribute to the well-being of BC’s communities:

- Safety: projects that promote natural gas and electrical safety, personal safety, and accident avoidance.
- Education: projects that promote natural gas and electrical trades, literacy, and leadership.

[29] Calculated as $1.100 million + $0.750 million = $1.850 million x 25 percent = $0.463 million.

- Indigenous initiatives: projects that meet the unique needs of Indigenous groups, organizations, or communities.
- Environment: projects that directly benefit the environment.

FortisBC's support generally involves the sponsorship of conferences or events that offer strategic value to particular sectors of FortisBC's business or the Companies as a whole through, in particular, supporting local economic development and climate change strategies in the communities FortisBC serves. This funding allows the Companies to participate in conferences for local governments and Indigenous economic development with local chambers of commerce and business associations, enabling FortisBC to provide input and support to these activities. This includes partnership and speaking opportunities, conference booths, and/or access to engage within the community, including local politicians, Indigenous leaders, community and business leaders.

The table below provides examples of the types of sponsorships provided in 2023.

Type	Organization	Event Details
Indigenous economic development	BC First Nations Energy and Mining Council	First Nation Hydrogen initiative workshop including over 40 First Nation communities. A two-day energy workshop that discussed the hydrogen and electricity sectors, featuring sessions on BC's changing electricity landscape, BC Hydro's UNDRIP implementation, and promising hydrogen market opportunities.
Indigenous economic development	Greater Vancouver Board of Trade	Indigenous Opportunities Forum that brought together local First Nations and the region's business and economic development leaders to connect, discuss, and learn about projects, partnerships, and opportunities for shared growth in the region.
Local economic development	Vancouver Island Economic Alliance Society	A two-day event for business owners, community leaders, and aspiring entrepreneurs in the region which included action lab workshops, breakout sessions and dynamic networking opportunities. The event involved collaboration with industry leaders, visionaries, and change-makers to ignite change and pave the way toward a more prosperous future for Vancouver Island and the rural islands.
Climate economic development	City of Maple Ridge	Climate Action Summit which is a process to gather input from local, regional and provincial elected officials, Indigenous partners, experts and academics, community leaders, stakeholders and members of the public as Climate leadership and environmental stewardship as one of Council's strategic priorities.

Sponsorship costs for conferences and events have increased significantly over the Current MRP term, resulting in FortisBC being unable to fund the same number of initiatives at the same level year-over-year, and driving the need for additional funding to support the same number of sponsorships.

These conferences and events are organized or attended by key community and business leaders and provide an opportunity for FortisBC to demonstrate its commitment to the health and development of communities within its service area. Through participation in these conferences and events, the Companies' profiles are raised with key stakeholders and business objectives are advanced within communities. Further, FortisBC is able to directly learn about issues and challenges impacting the communities it serves.

As discussed further in the response to BCUC IR1 16.2 below, the Community Investment funding in this information request is shared equally with FortisBC's shareholder. As such, FortisBC expects that the amount of funding used to support "business development requests" is up to approximately $0.180 million for FEI and $0.075 million for FBC.

16.2 Please explain the benefits to ratepayers and FortisBC's shareholders, respectively, from the community investment program including community support requests, and provide support to substantiate these benefits from FortisBC's experience in the Current MRP.

Response:

The Community Investment program enables FortisBC to actively demonstrate its support and commitment to the communities where it operates, which allows the Companies to positively impact the communities they serve. Benefits of the program include:

- Creating community partnerships that improve both FortisBC's ability to work in these communities and the effectiveness of those activities;
- Supporting FortisBC's commitment to Reconciliation with Indigenous Peoples and Indigenous communities that FortisBC serves;
- Improving the pride that FortisBC employees take in working for FortisBC and thus increasing productivity and attracting high quality employees;
- Increasing or maintaining the pride and trust that customers have in FortisBC's business through knowing that FortisBC is actively engaged in the improvement of the communities they live in; and
- Sharing information about the energy services FortisBC offers and activities FortisBC conducts in the communities it serves, which can include information about programs and safety.

Further, the program has helped create operational certainty and improved relationships between the Companies and Indigenous communities, interested parties and the public and, as such, is beneficial for the Companies and their customers.

As regional utilities, FEI and FBC seek to connect with and support community leaders, Indigenous leaders, businesses, and other local organizations that are working to improve the region's economic and social well-being. FortisBC also seeks to support community-driven programs that benefit the greatest number of people within the communities FortisBC operates. The Community Investment program typically focuses on funding local initiatives within FortisBC's service areas to reach as many organizations and communities as possible. The application criteria to obtain funding from the program align with each Company's business objectives in the areas of safety, education, environment and Indigenous initiatives.

The Community Investment program provides benefits to FortisBC's customers by:

- promoting natural gas and electrical safety and avoiding safety incidents;
- supporting Indigenous communities on projects for the benefit of customers;
- supporting local environmental causes in which customers live and work; and
- helping FEI and FBC to proceed with projects in communities for the benefit of customers.

In addition, FortisBC participates in and supports regional events in partnership with community and Indigenous leaders, which raises FortisBC's profile in a positive manner with local interested parties, community members and employees. Regional events and support for community initiatives helps develop support for the Companies' projects and operations. Attendance at local government conferences across the province, regional First Nations Annual General Assemblies, Powwow events and business opportunities conferences allows for interaction with Indigenous communities, stakeholders and the public to build and strengthen FortisBC's relationships in the community. These relationships allow FortisBC to move projects forward, which in turn benefits customers by providing greater support and operational certainty for FortisBC's operations and projects.

Examples of the investments in the community during the Current MRP term are provided below.

Safety

Organization	Description
Kaleden Community Association and the Kaleden Volunteer Fire Department	FortisBC supports their annual Community "Chipping" event. This annual event reduces fire/fuel load in the community, including around FortisBC's infrastructure (power lines). It is volunteer-based and led by local community members.
Town of Creston	Funding toward the new Creston Valley Fire Training facility.
Castlegar Society for Search and Rescue (SAR)	Support towards fenced storage facility and maintenance of SAR headquarters.
Nelson Search and Rescue	Support search and rescue outdoor exercises/training for teams from the East and West Kootenays.
First Nations Emergency Services Society	BC Fire Expo – Safety training for First Nation firefighters from across the province.
Silver Star Property Owners Association	FireSmart event. Chip and remove 50 tons of fire debris around Silver Star's community.
Coquitlam Search and Rescue	Purchase First Aid supplies.

1 ***Environment***

Organization	Description
Creston Valley Chamber	Community clean-up day – gather trash in the communities for Earth Day – Creston, Canyon, Lister, Erickson, West Creston, Wynndel.
Friends of Kootenay Lake Stewardship Society	Kootenay Lake Kokanee Salmon Research and Restoration Project.
OWL (Orphaned Wildlife) Rehabilitation Society	Rescue and rehabilitate raptors.
Lazy Lake Environmental Association	Education and outreach initiative including many volunteers, with a focus on the painted turtle (endangered species), and includes the invasive species volunteers.
Vancouver Avian Research Centre Society	Fall Migration Monitoring project within ƛ̓éxətəm (tla-hut-um) Regional Park.
Powell River Salmon Foundation	Support long term sustainability of Pacific Salmon in BC.
Slocan River Stream keepers	Protect and restore the aquatic and riparian ecosystems of the Slocan River through education, outreach, restoration, enhancement, monitoring and research.

2 ***Education***

Organization	Description
West Kootenay Watershed Collaborative	Four public education sessions on wildfires and watersheds in Taghum, Nelson, Wyndel and Kaslo.
Agassiz Harrison Community Services	Story Time in the Park program.
Osoyoos Desert Society	Free school education and environmental tour programs for local schools in the region.
Boys and Girls Club of South Coast BC	Academic Enhancement and Raise the Grade programs for kids in need.
Kootenay Association for Science and Technology – GLOWS	Growing learning opportunities with science and engaging youth in science school programs.
Surrey Public Library	Tree of Giving, children's literacy programming.
BCIT - Pathways to Success	Indigenous student support for breaking down barriers to access education.

3 ***Indigenous Initiatives***

Organization	Description
Indigenous Partnership Success Showcase	First Nations, Métis and Inuit communities and enterprise partners conference regarding how to work together, for shared success.
Surrey Hospitals Foundation	Support the Indigenous Maternal Child Health liaison.
BC First Nations Energy and Mining Council	First Nation Hydrogen initiative workshop - 60 communities.
BC Achievement Foundation	BC Indigenous Business Awards Sponsorship.

Organization	Description
Prince George Nechako Aboriginal Employment and Training Association	Trade Access Program Funding.
YWCA Metro Vancouver	Early childhood literacy program that welcomes Indigenous caregivers and children under six years old.

In addition to the initiatives above, FortisBC has also used funding from the Community Investment program to support local communities where its customers live during emergencies, including the COVID-19 pandemic. In response to the fires and floods that took place in the Interior of BC over the Current MRP term, FortisBC contributed to the Central Okanagan Foodbank, BC SPCA, Red Cross BC Fires and Floods Appeal Campaign, Chase Hamper Society and United Way BC Wildfire recovery, in addition to directly funding local governments and First Nations communities impacted by the emergency weather events. In 2020, FortisBC also supported a number community projects and programs, including food relief programs across the province and support for the Downtown Eastside Women's Centre and the United Way.

In its Decision on the FortisBC Energy Utilities (FEU) 2012-2013 Revenue Requirements Application, the BCUC found the following benefits to shareholders associated with community investment (then described as community involvement spending):[30]

- An increase in the goodwill of the Company or Companies that may be reflected in the share value or value if sold;
- The use of community involvement to differentiate the FEU and provide it with a competitive advantage over other energy providers; and
- The ability for the FEU to promote activities outside their traditional monopoly business role, expanding the scope and revenue base of the companies benefiting the shareholder, but not necessarily benefitting the traditional company ratepayer.

Also, in the 2012-2013 revenue requirement decisions for both FEU[31] and FBC[32], the BCUC directed that all Community Involvement Spending be allocated 50 percent to the customer and 50 percent to the shareholder in recognition of these potential benefits. While some of the benefits to the shareholder have decreased over time (i.e., customer choices are increasingly shaped by climate policy), FEI and FBC continue to share community investment (community involvement spending) costs equally between shareholders and customers.

Finally, in preparing this response, FEI and FBC discovered an error in the 2025 net incremental funding amounts included in the Application. The Companies inadvertently included the full amounts of the funding and did not account for the portion of community investment that is to be

[30] FEU 2012-2013 Revenue Requirements & Natural Gas Rates Application, Decision and Order G-44-12, p. 73.

[31] FEU 2012-2013 Revenue Requirements & Natural Gas Rates Application, Decision and Order G-44-12, p. 73.

[32] FBC 2012-2013 Revenue Requirements and Review of 2012 Integrated System Plan Application, Decision and Order G-110-12, p. 69.

paid by the shareholder. Accordingly, FEI and FBC have revised the net incremental funding and 2024 Base O&M for the Rate Framework as per the table below. FortisBC has filed an Errata to the Application concurrently with these IR responses reflecting the corrections noted in the IR responses.

Table 1: Revised Calculation of Net Incremental Funding for Rate Framework ($ millions)

Company	Incremental Community Investment		Total Net incremental Funding for Community and Indigenous Relations	
	Amount included in Application	Corrected Amount	Amount included in Application	Corrected Amount
FEI	0.500	0.250	2.240	1.990
FBC	0.250	0.125	1.140	1.015

E. PROPOSED RATE SETTING FRAMEWORK – CAPITAL EXPENDITURES

17.0 Reference: PROPOSED RATE SETTING FRAMEWORK – CAPITAL EXPENDITURES

Exhibit B-1, Section A1.3.3.2, Table A1-2, p. A-9, Section A1.3.3.3, Tables A1-4 and

A1-5, p. A-10

Contributions in Aid of Construction (CIAC)

In Table A1-2 on page A-9 of the Application, FortisBC provides approved and forecast sustainment capital expenditures for FEI. The table includes both total gross figures and total figures net of CIAC.

In Table A1-4 on page A-10 of the Application, FortisBC provides approved and forecast growth capital expenditures for FBC. The table includes both total gross figures and total figures net of CIAC.

In Table A1-5 on page A-10 of the Application, FortisBC provides approved and forecast sustainment capital expenditures for FBC. The table includes both total gross figures and total figures net of CIAC.

17.1 Please confirm, or explain otherwise, that FortisBC is seeking approval, for 2025 through 2027, of the gross sustainment capital expenditures only for FEI and the gross growth capital expenditures and gross sustainment capital expenditures only for FBC.

Response:

Confirmed. To clarify, FEI is seeking approval of a 2024 Base Unit Cost Growth Capital which is net of CIAC (i.e., includes CIAC) as well as gross Sustainment capital expenditures and Other capital expenditures. FBC is seeking approval of gross Growth capital expenditures, gross Sustainment capital expenditures and Other capital expenditures.

17.2 For each of FEI and FBC, please discuss the relationship between the gross capital expenditure forecasts and the CIAC forecasts.

Response:

FEI and FBC forecast their CIAC based on historical trending of actual CIAC and future expectations of third-party driven requests and customer growth. Typically, increases in gross capital expenditures related to third-party driven work and Growth capital are positively correlated with CIAC.

The CIAC amounts shown in Tables A1-2, A1-4, and A1-5 and in Section C3 of the Application are FortisBC's forecasts based on the current information available. However, the timing of when contributions are received can vary widely and can be difficult to predict. At times, CIAC does not fall in the same fiscal year as the construction costs for third-party receivables or Growth capital projects. Further, the percentage of contribution amounts can differ depending on the type and location of each project (the contribution amounts can fall anywhere between zero to 100 percent of the total gross capital spend).

Therefore, consistent with the approach taken during the Current MRP, FortisBC is not requesting approval of the CIAC forecasts shown in Tables A1-2, A1-4, and A1-5 of the Application. Instead, FortisBC is proposing to review the CIAC forecasts annually and update the forecasts if appropriate. This approach was discussed in the FBC Annual Review for 2024 Rates[33] and was accepted by the BCUC in their decision.[34]

FortisBC considers its proposed approach to be preferrable because it allows for adjustments to be made based on the most up-to-date information, including FEI's and FBC's most recent expectations of third-party requests and customer growth. The current approach is more likely to improve the accuracy between actuals and forecasts, thus reducing the cost-of-service impact due to the variances between forecast and actual results, which are shared with customers through the earnings sharing mechanism.

However, FortisBC is amenable to seeking approval of the CIAC forecasts from 2025 to 2027 in this Application. If this approach is directed by the BCUC, FortisBC would not make adjustments to the CIAC forecasts during the Annual Reviews, and the cost-of-service variances between the approved forecasts and actuals would be shared 50/50 with customers (consistent with the treatment of annual variances in FortisBC's regular Sustainment, Growth and Other capital). The potential disadvantage of this approach (compared to the current/proposed approach) is that the variances between actual and forecast results each year may be higher since the forecasts would not be adjusted to incorporate any new information available, such as changes in the amount of third-party requests being experienced each year.

17.3 For each of FEI and FBC, please discuss the pros and cons of reviewing and approving the CIAC forecasts for 2025 through 2027 in tandem with the gross capital expenditures in this proceeding as opposed to in the Annual Reviews and explain whether the utilities would be amenable to this approach.

---

[33] Exhibit B-8, CEC IR1 5.1.

[34] FBC Annual Review for 2024 Rates Decision and Order G-340-23, p. 15.

Response:

Please refer to the response to BCUC IR1 17.2.

18.0 Reference: PROPOSED RATE SETTING FRAMEWORK – CAPITAL EXPENDITURES

Exhibit B-1, Section C3.2.1.1, pp. C-70 to C-71; FEI 2022 Long-Term Gas Resource Plan, Decision and Order G-78-24 (2022 LTGRP Decision), p. 33

FEI – Capital Planning Process – Energy Transition

On pages C-70 to C-71 of the Application, FortisBC states:

> The energy transition impacts on capital planning differ for FEI and FBC. For FEI, given the uncertainty over future gas demand levels driven by climate policy, capacity driven projects have been reviewed to ensure they meet the needs of the shorter-term system demand forecast. While the need for an upgrade is determined through normal capacity planning processes, FEI has reviewed the size of the upgrade (length/size of system improvement or capacity of station) with a view to shorter timelines. Typically, a longer-term capacity forecast (20 years) is utilized to ensure any upgrades can address the requirements of the system without having to upgrade again in the near future, with the goal of ensuring investments are as efficient as possible and costs are minimized. With the development of this capital plan, and with the recent pressures of decarbonization and electrification in local communities, FEI has reviewed the proposed capacity driven projects to assess if they can be re-scoped into multiple smaller capacity upgrades so that FEI can proceed with only the portions that meet the underlying need for the near term. FEI expects this process to be iterative over the coming years.

On page 33 of the 2022 LTGRP Decision, the BCUC discusses the impact of hydrogen on FortisBC's infrastructure requirements, stating:

> FEI considers that integration of hydrogen supply into its transmission systems has the most complex requirements from a system planning perspective. The planning of the production and delivery of hydrogen is in its early phases, and FEI states in the [2022 LTGRP] Application that it does not yet have sufficient definition to provide projections on the specific impact hydrogen integration will have on the capacity of FEI's system. [*Footnote omitted*]

18.1 Please discuss how FEI determines which capacity-driven projects, if not all, can be effectively re-scoped into smaller, incremental upgrades. As part of the response, please include an explanation of any criteria or metrics used in the evaluation process.

<u>Response:</u>

For clarity, FEI's capacity driven projects can fall into either Growth or Sustainment capital, depending on the type of work being undertaken. For example:

- System reinforcements to the distribution system are included in Growth capital (i.e., DP System Improvements), which are required to maintain capacity for meeting existing and forecast loads;
- System reinforcements to FEI's transmission system (both intermediate and transmission pressures) are included in Sustainment capital (or are filed as a CPCN if the materiality threshold is met); and
- New stations are included as Sustainment capital.[35]

Given the uncertainty over future gas demand levels due to changes in policy, and in consideration of the BCUC's findings and determinations in the Okanagan Capacity Upgrade CPCN Project Decision and Order G-361-23, FEI has reviewed the scope of capacity-driven projects with a focus on meeting near-term capacity requirements (pre-2030). FEI provides a discussion of capacity-driven projects below, including where projects can be effectively re-scoped or staged to meet near-term demand.

System Reinforcements – "Bottlenecks"

When considering pipeline additions to serve new or growing load within the existing system, there is often a specific system constraint or "bottleneck" which the project is designed to alleviate. This may be a portion of the existing pipeline system in which there is only a single, smaller diameter pipe through which a relatively large quantity of gas must flow, thereby creating excessive pressure drop downstream of the bottleneck. In such a case, there is no opportunity to re-scope the project into smaller, incremental upgrades as the entire length of the bottleneck must be replaced or "looped" (i.e., additional new line added in parallel) to achieve the required capacity. Any portion of the bottleneck that remains causes enough pressure drop to negate the benefit of the system improvement. Conversely, adding a pipeline loop beyond the extent of the existing bottleneck often provides diminishing benefits in terms of incremental capacity. In these scenarios, the projects cannot effectively be re-scoped into smaller upgrades.

System Reinforcements – No "Bottlenecks"

In cases where a system improvement is added along parts of the system without specific constraints (i.e., without bottlenecks), variations in the length and diameter of the pipe produce related variations in incremental capacity. Such projects can be sized to meet a range of capacity requirements which can be measured in terms of downstream delivery pressure during peak day conditions, or conversely, the quantity of incremental load that can be delivered to locations where future growth is forecast to occur. Such projects can be sized to meet the requirements of the longest-term forecast scenario available, or they can be re-scoped to meet either the immediate or near-term system needs, maintaining only the minimum delivery pressures in that shorter timeframe. This is an example of where projects can be effectively re-scoped into smaller staged

[35] FEI-FBC 2020-2024 MRP Application, Section C3.3, page C-55.

upgrades. However, in such cases, if system growth continues, subsequent projects will be required to continue to facilitate the growth.

New Stations and Station Upgrades

Stations can similarly be re-scoped to meet varying degrees of flow requirements. FEI assesses overall system capacity requirements annually, including an annual assessment of each of its station flows relative to their capacities. There are a few courses of action that can be taken when considering projects to increase station capacity, ranging from minor modifications to existing stations, replacement of existing stations, or the addition of a completely new station.

Small amounts of incremental capacity can sometimes be achieved by replacement of specific components within the stations runs. For example, if hydraulic simulation of the station indicates excessive pressure drop through a heater or certain fittings, they can sometimes be replaced at relatively low cost to achieve relatively small increments to capacity. Alternatively, the size of the station's piping and regulators can be changed entirely. These are examples of smaller projects that can provide smaller amounts of incremental capacity to serve a shorter-term need.

Stations versus System Reinforcements

In cases where a new station is considered to feed an area, FEI also evaluates, where practicable, the addition of pipeline system improvements to supplement the constrained area in lieu of a new station addition. This can often result in the need for multiple pipeline projects over the long term, sometimes with higher total capital costs, to replace a new station addition. However, this approach has the benefit of allowing for incremental additions and project spending over time, as opposed to the larger up-front capital costs for the stations.

18.2 Please specify whether the potential for hydrogen integration is considered in the re-scoping process as discussed in response to the preceding IR.

18.2.1 If yes, please discuss how the potential need for hydrogen integration affects the cost and scope of the smaller projects.

18.2.2 If no, please explain why not and discuss the potential long-term implications of not having considered the potential for hydrogen integration.

Response:

The potential for hydrogen integration is not explicitly considered in the re-scoping process described in the response to BCUC IR1 18.1. All else equal, the incorporation of the assumption of future hydrogen blends would cause FEI to upsize its system improvements to account for the additional pressure loss associated with meeting the same demand requirements with hydrogen blends (as opposed to natural gas). Given that the quantity, location, and timelines for hydrogen integration are not yet known, incorporation of hydrogen blends at this point in time could drive expenditures that may or may not provide future benefit. Conversely, by not incorporating the assumption of future hydrogen blends into the long-term designs, there is a possibility that new future projects, or an upsizing of otherwise required future projects, would be required. FEI's approach of re-scoping projects to meet the needs of shorter timelines allows for more frequent re-evaluation of system needs and planning for hydrogen blends as applicable, thus ensuring efficient and timely spending.

FEI is currently undertaking the British Columbia Gas System Blending Study and Technical Assessment project to better understand how hydrogen integration will affect FEI's legacy system. The results of this study will inform how FEI's system can accommodate hydrogen. Until this work is done, FEI does not have the required information to incorporate the impacts of hydrogen integration at the project level. However, FEI utilizes modern materials for all new gas infrastructure installations, so the compatibility of new gas infrastructure with hydrogen is inherently improved.

18.3 Please discuss whether the re-scoping of capacity-driven projects into smaller upgrades could result in individual projects falling below the Certificate of Public Convenience and Necessity (CPCN) threshold.

18.3.1 If yes, please clarify the approval process for these smaller projects to ensure regulatory compliance and transparency within the proposed Rate Framework.

18.3.2 If yes, please provide a list of the projects, if any, where re-scoping has led to or is expected to lead to projects being below the CPCN threshold.

<u>Response:</u>

Over the proposed Rate Framework term, none of the capacity-driven projects affected by FEI's re-scoping approach has resulted in projects falling below the CPCN threshold. All of the re-scoped projects were already well below the CPCN threshold both before and after the re-scoping process, and any projects being considered that were above the CPCN threshold continue to be above the threshold. The majority of system improvements are additions or modifications to distribution pipeline systems, and the costs are generally well below the CPCN threshold.

However, if the situation arose where a CPCN project was re-scoped and fell below the CPCN threshold, FEI would likely apply for acceptance of the project pursuant to section 44.2 of the UCA as part of the Annual Review process. For example, during FEI's Annual Review for 2023 Delivery Rates, FEI filed for acceptance of the Gibsons Capacity Upgrade project and included a detailed business case with project alternatives, a capital cost estimate, and other information for review within the Annual Review process.

18.4 Please discuss how the iterative nature of re-scoping capacity upgrades either influences or will influence FEI's capital planning and budgeting processes during the proposed term of the Rate Framework.

Response:

FEI regularly confirms that the scope of projects is appropriate in its capital planning process and seeks to optimize the timing of projects in order to use available capital funds in the most effective manner. As a result, FEI does not expect major changes during the proposed Rate Framework term.

FEI notes that the next LTGRP could lead to changes in FEI's forecasting methodologies which could influence FEI's capital planning and budgeting processes, but FEI expects that any changes to the capital planning and budgeting processes that may result would be subsequent to this three-year Rate Framework term.

18.5 Please discuss how FEI ensures that its capital plan remains adaptable to changing demand forecasts and the CleanBC Roadmap to 2030.

Response:

FEI's approach to capital is adaptable to changes to the current policy environment. First, FEI is proposing a formulaic approach to Growth capital that adjusts funding levels based on Gross Customer Additions. Second, FEI is proposing a three-year capital forecast for Sustainment and Other capital and does not expect significant changes to occur during this three-year time period. Third, FEI has carefully scoped its capacity-driven projects.

18.6 Please provide a detailed breakdown of all capacity-driven projects included in the forecast capital expenditures during the proposed term of the Rate Framework. As part of the response, please specify (i) the associated costs for each project: (ii) the cost category for each project (growth, sustainment, other, major projects); and (iii) the system served by each project (Coastal, Interior, Vancouver Island).

18.6.1 For each capacity-driven project, please explain how it is supported by FEI's near-term demand forecast on the particular system served by the project and clarify whether the project has been adjusted or re-scoped to better meet near-term demand while maintaining flexibility for future needs.

Response:

The table below provides a detailed breakdown of all capacity-driven projects included in the forecast capital expenditures during the proposed term of the Rate Framework. FEI notes that the Okanagan Capacity Mitigation CPCN project has been excluded as it is currently under separate review with the BCUC. Additionally, since FEI has proposed to continue with a formulaic approach for Growth capital, there are no individual projects forecast for this category.

While FEI has provided the full breakdown of capacity-driven projects in the table below, FEI notes that it is not seeking approval of each individual project/expenditure in this Application; rather, FEI is seeking approval of the annual level of Sustainment and Other regular capital for the three-year Rate Framework term. It is reasonable, appropriate and expected that expenditures will vary during the three-year term, and FEI will manage those variations within the approved levels of spending, with the cost-of-service impacts of variances between approved and actual amounts shared 50/50 with customers.

Project Description	Total Forecast Costs 2025-2027 ($000s)	Cost Category	System Served
Projects			
New Station – 1900/420 Downes/Bradner	2,512	Sustainment Distribution Stations NEW	Coastal
	Residential and commercial growth in the Townline area of Abbotsford has significantly impacted the DP network in the area. The driver for this new station is new commercial loads that are expected to come online in 2026, and the new station will enable minimum service pressure to be met throughout the network. This project is scoped to meet the near-term demand.		
Colwood New IPDP Station	5,246	Sustainment Distribution Stations NEW	Vancouver Island
	A new IP/DP station is proposed to address growth in demand and capacity constraints in the Colwood area on Vancouver Island. A number of new commercial customers are expected to come online in 2026, and the new station will enable minimum service pressure to be met throughout the network. This project is scoped to meet the near-term demand.		
System Improvement – 1050m x 323IP/ST Riverside St, Abb	3,140	Sustainment Distribution System Capacity Alterations	Coastal
	A large new commercial customer is planned to come online in 2025 in the north Mission area of the Lower Mainland. This system improvement is required to provide adequate station inlet pressure for two existing stations in Mission. This project is scoped to meet the near-term demand.		

Project Description	Total Forecast Costs 2025-2027 ($000s)	Cost Category	System Served
Projects <$2 million			
152 St & 64 Ave Station – Upgrades	868	Sustainment Distribution Stations Capacity Alterations	Coastal
	This project is required to increase station capacity to meet near-term demand and to upgrade the station to current FEI design standards. According to the 2023/2024 system capacity model, peak flow through the station exceeds the single run capacity and there is a probability of a capacity shortfall. FEI plans to rebuild the station in place using a standard pit station layout, allowing increased station capacity and a safer working environment for field personnel.		
1700 Begbie St Station Capacity Upgrade	113	Sustainment Distribution Stations Capacity Alterations	Vancouver Island
	According to the 2022/2023 system capacity model, peak flow through the station exceeds the single run capacity and there is a probability of a capacity shortfall. FEI plans to upsize the station regulators to increase station capacity to meet near term demand.		
208 St & 24 Ave Station – Capital Upgrade	60	Sustainment Distribution Stations Capacity Alterations	Coastal
	According to the 2022/2023 system capacity model, peak flow through the station exceeds the single run capacity and there is a probability of a capacity shortfall. FEI plans to upsize the orifice plate to increase station capacity to meet near term demand.		
272 St & 40 Ave Station – TP/IP Capacity Upgrade	1,373	Sustainment Distribution Stations Capacity Alterations	Coastal
	According to the 2023/2024 system capacity model, peak flow through the station is 95 percent of single run capacity and there is a probability of a capacity shortfall. FEI plans to upsize the TP/IP station to increase station capacity to meet near term demand.		
4280 Mostar Station Install Line Heater	692	Sustainment Distribution Stations Capacity Alterations	Vancouver Island
	Recent pressure increases on the IP system to meet capacity demands in the Nanaimo area have worsened the occurrence of ice-up of IP/DP station components, hindering the operation of station equipment and increasing the risk of service disruption due to regulator freeze-off. FEI plans to install a line heater at 4280 Mostar Station to mitigate this risk.		
8277 Central Saanich Rd Stn Capacity Upgrade	133	Sustainment Distribution Stations Capacity Alterations	Vancouver Island
	According to the 2022/2023 system capacity model, peak flow through the station exceeds the single run capacity and there is a probability of a capacity shortfall. FEI plans to upsize the station regulators to increase station capacity to meet near term demand.		

<table>
<tr><th>Project Description</th><th>Total Forecast Costs 2025-2027 ($000s)</th><th>Cost Category</th><th>System Served</th></tr>
<tr><td rowspan="2">Chilliwack Station – Capacity Upgrade</td><td>110</td><td>Sustainment
Distribution Stations Capacity Alterations</td><td>Coastal</td></tr>
<tr><td colspan="3">According to the 2023/2024 system capacity model, peak flow through the station is 99 percent of single run capacity and there is a probability of a capacity shortfall. FEI plans to upsize the station regulators to increase station capacity to meet near term demand.</td></tr>
<tr><td rowspan="2">Duncan Gate Station Capacity Upgrade & Reg Run Modifications</td><td>384</td><td>Sustainment
Distribution Stations Capacity Alterations</td><td>Vancouver Island</td></tr>
<tr><td colspan="3">According to the 2022/2023 system capacity model, peak flow through the station is 90 percent of the single run capacity and there is a probability of a capacity shortfall. FEI plans to upsize the station regulators to increase station capacity to meet near term demand.</td></tr>
<tr><td rowspan="2">Henderson Ave & Jackson St – Station Upgrade</td><td>938</td><td>Sustainment
Distribution Stations Capacity Alterations</td><td>Coastal</td></tr>
<tr><td colspan="3">This project is required to increase station capacity and to upgrade the station for improved drainage and employee safety. According to the 2023/2024 system capacity model, peak flow through the station is 87 percent of the single run capacity. Demand on the station is forecast to increase by 50 percent in the near term. FEI plans to rebuild the station using a standard district station layout, allowing increased station capacity and a safer working environment for field personnel.</td></tr>
<tr><td rowspan="2">Jacklin Rd Gate Station Capacity Upgrade</td><td>15</td><td>Sustainment
Distribution Stations Capacity Alterations</td><td>Vancouver Island</td></tr>
<tr><td colspan="3">According to the 2022/2023 system capacity model, peak flow through the station is 73 percent of the single run capacity and there is a probability of a capacity shortfall. FEI plans to upsize the station regulators to increase station capacity to meet demand. Project construction is forecast to occur after the proposed term of the Rate Framework. The forecast capital expenditure is for project planning in 2027.</td></tr>
<tr><td rowspan="2">Keating Install Line Heater</td><td>630</td><td>Sustainment
Distribution Stations Capacity Alterations</td><td>Vancouver Island</td></tr>
<tr><td colspan="3">Recent pressure increases on the Victoria IP system to meet capacity demands have worsened the occurrence of ice-up of IP/DP station components, hindering the operation of station equipment and increasing the risk of service disruption due to regulator freeze-off. FEI plans to install a line heater at Keating Station to mitigate the risk of ice-up.</td></tr>
<tr><td>Nelson Rd – Heater Capacity</td><td>1,125</td><td>Sustainment
Distribution Stations Capacity Alterations</td><td>Coastal</td></tr>
</table>

Project Description	Total Forecast Costs 2025-2027 ($000s)	Cost Category	System Served
	New industrial loads on the system in the Richmond area have significantly increased demand at the station. According to the 2022/2023 system capacity model, peak flow through the station exceeds the single run capacity and there is a probability of a capacity shortfall when all downstream customers are online. FEI plans to upsize the station piping, regulators, line heater and meter to increase station capacity to meet near term demand.		
Parksville Gate Station IPDP Capacity Upgrade	115	Sustainment Distribution Stations Capacity Alterations	Vancouver Island
	According to the 2023/2024 system capacity model, peak flow through the station is 96 percent of the single run capacity and there is a probability of a capacity shortfall. FEI plans to upsize the station regulators to increase station capacity to meet near term demand.		
Port Alberni Station Capital Upgrade	102	Sustainment Distribution Stations Capacity Alterations	Vancouver Island
	According to the 2023/2024 system capacity model, peak flow through the station is 90 percent of the single run capacity and there is a probability of a capacity shortfall. FEI plans to upsize the station regulators to increase station capacity to meet near term demand.		
Riverside Rd & Vye Rd – Station Capital Upgrade	1,607	Sustainment Distribution Stations Capacity Alterations	Coastal
	According to the 2023/2024 system capacity model, peak flow through the station is 95 percent of the single run capacity and there is a probability of a capacity shortfall. FEI plans to upsize the station regulators, piping, and line heater to increase station capacity to meet near term demand.		
Royal Oak Install Line Heater	650	Sustainment Distribution Stations Capacity Alterations	Vancouver Island
	Recent pressure increases on the Victoria IP system to meet capacity demands have worsened the occurrence of ice-up of IP/DP station components, hindering the operation of station equipment and increasing the risk of service disruption due to regulator freeze-off. FEI plans to install a line heater at Royal Oak Station to mitigate the risk of ice-up.		
Trail Ave Gate Station Capacity Upgrade	129	Sustainment Distribution Stations Capacity Alterations	Vancouver Island
	According to the 2022/2023 system capacity model, peak flow through the station is 84 percent of the single run capacity and there is a probability of a capacity shortfall. FEI plans to upsize the station regulators to increase station capacity to meet demand.		

Project Description	Total Forecast Costs 2025-2027 ($000s)	Cost Category	System Served
University Station Capacity Upgrade	15	Sustainment Distribution Stations Capacity Alterations	Vancouver Island
	According to the 2022/2023 system capacity model, peak flow through the station is 80 percent of the single run capacity and there is a probability of a capacity shortfall. FEI plans to upsize the station regulators to increase station capacity to meet demand. Project construction is forecast to occur after the proposed term of the Rate Framework. The forecast capital expenditure is for project planning in 2027.		
Wilkinson Rd Install Line Heater	21	Sustainment Distribution Stations Capacity Alterations	Vancouver Island
	Recent pressure increases on the Victoria IP system to meet capacity demands have worsened the occurrence of ice-up of IP/DP station components, hindering the operation of station equipment and increasing the risk of service disruption due to regulator freeze-off. FEI plans to install a line heater at Wilkinson Road Station to mitigate the risk of ice-up. Project construction is forecast to occur ahead of the proposed term of the Rate Framework. The forecast capital expenditure is for project close-out in 2025.		
5224 88 St Station – New Station	13	Sustainment Distribution Stations NEW	Coastal
	A new station is required to support the Parkwood Business Park in Delta. Project construction has occurred ahead of the proposed term of the Rate Framework. The forecast capital expenditure is for project close-out in 2025.		
David St Station Capacity Upgrade	133	Sustainment Distribution System Capacity Alteration	Vancouver Island
	According to the 2022/2023 system capacity model, peak flow through the station is 133 percent of the single run capacity and there is a probability of a capacity shortfall. FEI plans to upsize the station regulators to increase station capacity to meet demand.		
Hilliers Rd Gate Station Capacity Upgrade	115	Sustainment Distribution System Capacity Alteration	Vancouver Island
	According to the 2023/2024 system capacity model, peak flow through the station is 93 percent of the single run capacity and there is a probability of a capacity shortfall. FEI plans to upsize the station regulators and piping to increase station capacity to meet near term demand.		
SI 1000m x 168 IPST on Jingle Pot Rd (Phase 1)	84	Sustainment Distribution System Capacity Alteration	Vancouver Island
	Based on the 2023/2024 system capacity model, 1,000 metres of the IP main along Jingle Pot Road in North Nanaimo requires upsizing to boost inlet pressure for the North and South Shenton Stations. Project construction is forecast to occur after the proposed term of the Rate Framework. The forecast capital expenditure is for project planning in 2027.		

Project Description	Total Forecast Costs 2025-2027 ($000s)	Cost Category	System Served
SI 1000m x 168 IPST on Labieux Rd (Phase 2)	83	Sustainment Distribution System Capacity Alteration	Vancouver Island
	Based on the 2021/2022 system capacity model, 1,000 metres of the IP main along Labieux Road in North Nanaimo requires upsizing to boost inlet pressure for the North and South Shenton Stations. Project construction is forecast to occur after the proposed term of the Rate Framework. The forecast capital expenditure is for project planning in 2027.		
SI 800m x 168 IPST on Labieux Rd (Phase 3)	83	Sustainment Distribution System Capacity Alteration	Vancouver Island
	Based on 2021/2022 system capacity model, 800 metres of the IP main along Labieux Road in North Nanaimo requires upsizing to boost inlet pressure for the North and South Shenton Stations. Project construction is forecast to occur after the proposed term of the Rate Framework. The forecast capital expenditure is for project planning in 2027.		
SOK IP 700m x 168 IPST Installation	70	Sustainment Distribution System Capacity Alteration	Vancouver Island
	Installation of approximately 700 metres of 168 mm IP main from Langford/Jacklin Station to the start of Sooke IP pipeline. Project construction is forecast to occur after the proposed term of the Rate Framework. The forecast capital expenditure is for project planning in 2027.		
VIC IP System Upgrade	98	Sustainment Distribution System Capacity Alteration	Vancouver Island
	Upgrade approximately 3 kilometres of IP pipeline upstream of David Street Station from NPS 8 to NPS 12. Project construction is forecast to occur after the proposed term of the Rate Framework. The forecast capital expenditure is for project planning in 2027.		

19.0 Reference: PROPOSED RATE SETTING FRAMEWORK – CAPITAL EXPENDITURES

Exhibit B-1, Section C3.2.1.1, p. C-94

FEI – Other Capital – Trail Operations Centre Replacement

On page C-94 of the Application, FEI states:

> FEI has completed an assessment of the Trail Operations Centre to determine the required size of the replacement property and has developed a project plan. […]
>
> Based on FEI's assessment, the current property size is too small to re-build. Accordingly, FEI plans to relocate and construct a new facility. The project is expected to be completed over three years, from 2024 through 2026, and the forecast cost is approximately $13 million. […]

19.1 Please discuss any alternative sites considered during the assessment process conducted for the Trail Operations Centre and discuss any key factors that led to the selection of the final site.

Response:

FEI is currently undergoing the land assessment process and has therefore not yet identified alternative sites or selected the final site. The key criteria for the selection process are property zoning, sizing, and the location of the land in consideration of operational requirements, employee impacts and costs. FEI anticipates this process will be complete by the end of Q3 2024.

19.2 Please provide a breakdown of the estimated project cost for the Trail Operations Centre Replacement.

Response:

Please refer to Table 1 below for the breakdown of the estimated costs for the Trail Operations Centre Replacement.

Table 1: Trail Operations Centre Replacement Estimated Costs

Item	Estimated Cost ($ millions)
Land Purchase	0.9
Building Construction	9.3
Other (office furniture & equipment, industrial equipment like racking, security)	1.0
Contingency (design, construction, and escalation)	1.8
Total	**13.0**

20.0 Reference: PROPOSED RATE SETTING FRAMEWORK – CAPITAL EXPENDITURES

Exhibit B-1, Section C3.3.3.3, Table C3-23, pp. C-95, C-97

FEI – Other Capital – Expenditures Related to Business Technology Applications

Table C3-23 on page C-95 of the Application shows the 2023 and 2024 approved and 2025 through 2027 forecast information systems (IS) capital expenditures for FEI as follows:

Table C3-23: FEI Approved and Forecast IS Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
IS Sustainment	10,808	10,913	14,800	15,200	15,800
Application Enhancements	2,850	2,850	2,000	2,100	2,200
Business Technology Applications	10,800	10,800	8,500	8,500	8,500
Total Information Systems	**24,458**	**24,563**	**25,300**	**25,800**	**26,500**

On page C-97 of the Application, FortisBC states that the rapid pace of technology changes necessitates more frequent replacement of information systems due to obsolescence, loss of technical support and maintenance, risk of cyber threats, or to leverage the benefits of new functionality.

20.1 Please explain whether the forecast 2025 through 2027 capital expenditures for business technology applications in Table C3-23 includes the physical (or virtual) hardware, operating software and/or other computing, storage and network infrastructure.

20.1.1 If not, please explain how the planned business technology applications for 2025 through 2027 will be implemented and managed.

Response:

Projects identified under Business Technology Applications include the initial cost and setup of new physical (or virtual) hardware, operating systems, and/or other computing, storage and network infrastructure as required.

IS Sustainment includes the capital cost for replacing/upgrading existing physical and virtual infrastructure, upgrading applications, and other capital investments required to sustain both applications and infrastructure.

The costs to replace information systems due to obsolescence, loss of technical support and maintenance, risk of cyber threats, or to leverage the benefits of new functionality are included in both categories.

20.2 Please discuss how FEI has provided for sufficient IS / IT resources for the ongoing administration of the above business technology applications; including but not limited to, patch management, business continuity management and security management.

Response:

To assess ongoing and future business needs anticipated over the Rate Framework term, FEI's Information Systems department engaged with other departments within the Company, including Business Continuity and Cybersecurity, to understand their changing technology needs. FEI also gathered insights from relevant studies and research to consider general technology trends. This information was then considered in the context of FEI's current resourcing and capacity, and the lifecycle of existing products and systems to develop its resourcing needs for the Rate Framework term. The resources identified, including the tools and staffing levels, are necessary to safeguard critical systems and operations and meet capital and sustainment requirements.

20.3 Please confirm, or explain otherwise, that any associated software licensing costs for the new 2025 through 2027 forecast business technology applications are included in formula O&M.

Response:

Confirmed. Ongoing software licenses for Business Technology Applications are included in formula O&M.

20.4 Please explain how FEI plans to mitigate the risk of rapid obsolescence and optimize costs to operate its business technology applications.

Response:

FEI mitigates the risks associated with technology obsolescence and optimizes the cost of technology during a period of rapid technological change in three main ways:

- Carefully choosing technologies that meet both current and future needs, as well as reputable vendors who offer appropriate future development plans for their technology. This helps FEI maximize the useful life of a system and minimizes the risk of early replacement.

- Leveraging as many potential benefits of new technologies as possible to offset the cost of implementing these systems. Although technology is rapidly changing, it is also providing new and improved opportunities for benefits that can offset costs, such as increased efficiency or improved services for customers.
- Ensuring strong project governance and controls during implementation, which helps ensure that the desired benefits and outcomes are met within expected costs and timelines.

20.5 Please discuss how the 2025 through 2027 forecast business technology applications capital expenditures align with FEI's future load forecasts (i.e. Is the customer base increasing in line with the increase in these costs?)

Response:

Business Technology Applications capital expenditures are not driven by FEI's load or customer forecasts. As explained in the response to BCUC IR1 20.1, the costs to upgrade and replace systems can fall into various IS capital categories depending on their nature (e.g., new versus existing systems); therefore, trends in expenditures should be considered at the overall level.

IS capital expenditures are forecast based on expected system requirements, which are driven by changing business needs, increased security requirements and by the normal software/hardware support lifecycle, which includes regular upgrades and replacements. IS capital costs are also impacted by inflationary pressures. Overall, IS capital expenditures are forecast to increase at approximately 2 to 3 percent on average as compared to the Current MRP.

21.0 Reference: PROPOSED RATE SETTING FRAMEWORK – CAPITAL EXPENDITURES

Exhibit B-1, Section C3.3.3.4, Table C3-25, pp. C-97 to C-98

FEI – Other Capital – Expenditures Related to Corporate Security

Table C3-25 on page C-97 of the Application shows the 2023 and 2024 approved and 2025 through 2027 forecast corporate security capital expenditures for FEI as follows:

Table C3-25: FEI Approved and Forecast Corporate Security Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Corporate Security	3,100	3,100	8,887	7,720	7,741

On page C-98 of the Application, FortisBC states that in recent years, FEI has increased capital expenditures for patching to respond to evolving security risks and to reduce the threat landscape and vulnerabilities. FEI forecasts an increase of $3.589 million in 2025 in capital costs for its patch management program, which is a component of corporate security.

21.1 Please provide a breakdown of the 2025 through 2027 forecast corporate security capital expenditures in Table C3-23 by major driver(s) for each year (e.g. patch management, physical security, mobile incident command units, etc.).

21.1.1 Please provide a breakdown of the major sub-components of the total patch management capital expenditure amount for each forecast year from 2025 to 2027.

Response:

Please refer to Table 1 below for the breakdown of FEI's forecast of corporate security capital expenditures from 2025 to 2027.

Table 1: Breakdown of FEI's Forecast Corporate Security Capital Expenditures from 2025 to 2027 ($000s)

	2025 Forecast	2026 Forecast	2027 Forecast
Cyber Security	2,090	1,770	1,908
Mobile Incident Command Units	800	0	0
Physical Security	408	361	244
Patch Management	5,589	5,589	5,589
Total	**8,887**	**7,720**	**7,741**

The Patch Management costs of $5.589 million are made up of $2.799 million in Labour and $2.790 million in Managed Services for each year of the Rate Framework term.

21.2 Please explain why patch management is a capital expenditure as opposed to an operating expenditure.

Response:

The patch management costs included as capital expenditures in Table C3-25 (for FEI) and Table C3-54 (for FBC) of the Application are for the installation and testing of upgrades that would extend the life of hardware and software assets in FEI's and FBC's systems, thus making them eligible to be capitalized. This treatment is consistent with the Current MRP.

22.0 Reference: PROPOSED RATE SETTING FRAMEWORK – CAPITAL EXPENDITURES

Exhibit B-1, Section C3.4.3.4, Table C3-51, pp. C-135 to C-136

FBC – Other Capital – Expenditures Related to Corporate Security

Table C3-51 on Page C-135 of the Application shows the 2023 and 2024 approved and 2025 through 2027 forecast corporate security capital expenditures for FBC as follows:

Table C3-51: FBC Approved and Forecast Corporate Security and Business Continuity Capital Expenditures 2023-2027 ($000s)

	2023 Approved	2024 Approved	2025 Forecast	2026 Forecast	2027 Forecast
Corporate Security	1,008	1,028	2,668	2,536	2,544

Further on Page C-135 of the Application, FortisBC states, in recent years, FBC has increased capital expenditures for patching to respond to evolving security risks and to reduce the threat landscape and vulnerabilities. FBC forecasts an increase of $1.196 million in 2025 in capital costs for its patch management program.

22.1 Please provide a breakdown of the 2025 through 2027 forecast corporate security capital expenditures in Table C3-51 by major driver(s) for each year (e.g. patch management, physical security, mobile incident command units, etc.).

22.1.1 Please provide a breakdown of the major sub-components of the total patch management capital expenditure amount for each forecast year from 2025 to 2027.

Response:

Please refer to Table 1 below for the breakdown of FBC's forecast of corporate security capital expenditures from 2025 to 2027.

Table 1: Breakdown of FBC's Forecast Corporate Security Capital Expenditures from 2025 to 2027 ($000s)

	2025 Forecast	2026 Forecast	2027 Forecast
Cyber Security	709	603	613
Physical Security	110	84	82
Patch Management	1,849	1,849	1,849
Total	**2,668**	**2,536**	**2,544**

The Patch Management costs of $1.849 million are made up of $1.099 million in Labour and $0.750 million in Managed Services for each year of the Rate Framework term.

22.2 Please explain why patch management is a capital expenditure as opposed to an operating expenditure.

Response:

Please refer to the response to BCUC IR1 21.2.

23.0 Reference: PROPOSED RATE SETTING FRAMEWORK – CAPITAL EXPENDITURES

Exhibit B-1, Section B1.6.3.1, p. B-15, Section C3.4.1, Table C3-27, pp. C-104 to C-109, Section C3.4.2, p. C-118; FBC Kelowna Bulk Transformer Addition Project Certificate of Public Convenience and Necessity (KBTA CPCN), Exhibit B-2, BCUC IR 6.1; FBC 2021 Long-Term Electric Resource Plan (2021 LTERP), Exhibit B-2, BCUC IR 22.2.1

FBC – Growth Capital

On page B-15 of the Application, FortisBC states:

> FBC supports load growth through capital expenditures categorized as either Growth – consisting of new infrastructure required <u>to increase system capacity</u>, or Sustainment – […] [*Emphasis added*]

On page C-104 of the Application, FortisBC provides Table C3-27 which summarizes the 2025 to 2027 forecast regular gross capital expenditures for FBC.

23.1 Please provide an estimate of the portion of the annual revenue requirement ($) and annual rate increase (%) attributable to growth in rate base for each year of the proposed term of the Rate Framework if forecast gross capital expenditures for Growth capital projects were to be approved as proposed.

<u>Response:</u>

Table 1 below provides the estimated incremental annual revenue requirement and rate impact from 2025 to 2027 (when compared to the 2024 Approved revenue requirement and rates) for the forecast FBC gross Growth capital expenditures from Table C3-27 of the Application. In calculating the revenue requirement impact, the incremental offsetting revenue attributable to the load from new customers and/or attachments was excluded from this calculation.

Table 1: Annual Revenue Requirement and Rate Impact of Forecast Growth Capital Expenditures

	2025	2026	2027
Gross Growth Capital ($000s)	41,349	45,035	46,357
Incremental Revenue Requirement ($000s)	479	4,330	8,489
2024 Approved Revenue Requirement ($000s)	457,247	457,247	457,247
Rate Impact Compared to 2024 Approved (%)	0.10%	0.95%	1.86%

Note: Depreciation is calculated based on the opening balance of plant-in-service. As such, depreciation for capital expenditures forecast in 2025 begins in 2026, which is why the rate impact in 2025 is small.

23.2 Please provide the total planned system capacity increase (in MW) under Growth capital expenditures for the FBC service area during the proposed term of the Rate Framework.

Response:

FBC notes that the BCUC references Table C3-27 in the preamble to this IR; however, the applicable component of Growth capital expenditures for planned system capacity projects is only the Transmission Growth capital category. Accordingly, FBC provides the following two tables which set out the planned system capacity increases from each Transmission Growth capital project included in Table C3-30 of the Application. Table 1 contains the transmission line projects within Table C3-30 and Table 2 contains the station projects within Table C3-30. To respond to BCUC IR1 23.3, the tables also indicate whether the projects align with the system peak demand forecasts and FBC's 2021 LTERP.

Table 1: Capacity Increases from Transmission Line Projects Planned During the Rate Framework Term

Project	Line/Area Capacity After Increase (MVA)	Increase (MW)	Aligns with System Peak Demand Forecasts during Rate Framework?	Aligns with 2021 LTERP?	Comments
Reconductor 52L & 53L	142.2	68.6	Yes	Yes	
Princeton 138 kV Capacitor Bank	188	11	Yes	No	Project was not required at the time of the 2021 LTERP. FBC is no longer able to rely on the BC Hydro system in the event of an outage (see response to BCUC IR1 23.8).
Reconductor 51L & 60L	311.4	150.1	Yes	Yes	
Total		**229.7**			

Table 2 below sets out the station growth projects provided in Table C3-30 of the Application. The existing and future nameplate ratings (Summer Normal) of each transformer for the distribution substations are provided below. Some transformers are currently limited below their nameplate rating due to other equipment constraints. Stations with a two-transformer configuration cannot be loaded to the total installed capacity as the purpose of the second transformer is to provide redundancy. Furthermore, substations that are interconnected may provide redundancy to each other; therefore, the available capacity at these substations is not static and will depend on system conditions.

Table 2: Capacity Increases from Station Projects Planned During the Rate Framework Term[36]

Project	Installed Capacity (MVA)	Future Installed Capacity (MVA)	Aligns with System Peak Demand Forecasts during Rate Framework?	Aligns with 2021 LTERP?	Comments
Glenmore Low Voltage Bus Capacity and Equipment Upgrades	• 1 x 40 MVA (limited to 32 MVA) • 1 x 32 MVA (limited to 28 MVA)	• 1 x 40 MVA • 1 x 32 MVA	Yes. However, it also considers non-coincident peaks and large new distribution connections.	Yes. However, distribution substations are not specifically identified in the 2021 LTERP.	Addresses equipment constraints
Duck Lake Second Distribution Transformer Addition	• 1 x 28 MVA	• 1 x 28MVA • 1 x 40 MVA	Yes. However, it also considers non-coincident peaks and large new distribution connections.	Yes. However, distribution substations are not specifically identified in the 2021 LTERP.	Provides redundancy
Christina Lake Station Upgrade	• 1 x 5 MVA	• 2 x 15 MVA	Yes. However, it also considers non-coincident peaks and large new distribution connections.	Yes. However, distribution substations are not specifically identified in the 2021 LTERP.	Addresses equipment constraints and condition issues
Saucier Second Distribution Transformer Addition	• 1 x 32 MVA (limited to 26 MVA)	• 1 x 32 MVA • 1 x 50 MVA	Yes. However, it also considers non-coincident peaks and large new distribution connections.	Yes. However, distribution substations are not specifically identified in the 2021 LTERP.	Addresses equipment constraints
DG Bell Second Distribution Transformer Addition	• 1 x 32 MVA	• 1 x 32 MVA • 1 x 40 MVA	Yes. However, it also considers non-coincident peaks and large new distribution connections.	Yes. However, distribution substations are not specifically identified in the 2021 LTERP.	Provides redundancy

23.3 Please discuss how the planned system capacity increase that is addressed by Growth capital projects over the proposed term of the Rate Framework aligns with (i) system peak demand forecasts during the proposed term of the Rate Framework; and (ii) FBC's 2021 LTERP.

[36] The Glenmore Station Capacity Upgrade project is planned to commence initial development work in 2027; however, the majority of the project will not be undertaken until after the conclusion of the Rate Framework term, as explained on page C-108 of the Application. Accordingly, this project has been excluded from Table 2 since it will not provide a capacity increase during the Rate Framework term.

Response:

Please refer to the response to BCUC IR1 23.2.

On page C-106 of the Application, FortisBC states:

> […] several of the Transmission Growth projects are required to address the resulting increase in demand in the City of Kelowna, which is one of the fastest growing cities in Canada.

23.4 For the City of Kelowna, please provide the annual forecast summer peak and winter peak loads in MW for 2025 through 2027, and actual summer peak and winter peak loads for 2020 through 2023.

Response:

Please find below the actual summer and winter peaks for the years 2020 to 2023, the projected 2024 peaks, and the forecast peaks for 2025 to 2027 for the City of Kelowna and surrounding area (which includes the Joe Rich, Big White and Lake Country areas).

	Historical					Forecasted		
Season	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Summer Peak (MW)	320	379	352	339	354	376	379	382
Winter Peak (MW)	325	314	346	366	359	378	381	387

23.5 Please describe the new load conditions, including a breakdown of new customers (i.e. residential, commercial) that have caused the increase in demand in the City of Kelowna as discussed on page C-106 of the Application.

Response:

FBC does not forecast customers at the city or regional level and therefore is not able to provide a breakdown of new customers by rate class that is driving increased demand in the City of Kelowna; however, FBC anticipates most of the new customers to be residential. Load growth in the City of Kelowna, and specifically the downtown, is driven by multiple factors of which the number of new customers is only one. These factors include:

1. **Population Growth:**
    - Kelowna is one of the fastest-growing cities in British Columbia. Downtown Kelowna is experiencing a significant influx of residents, contributing to increased demand for housing, services, and infrastructure.
    - The Provincial Housing Target for Kelowna is 8,774 units over the next five years as per the news released by the BC Government on June 28, 2024: https://news.gov.bc.ca/releases/2024HOUS0113-001012
2. **2024 Planning Legislation Changes:**
    - At the end of 2023, the BC Government passed several new pieces of legislation that apply across the province and impact the City of Kelowna's land use planning:
        - Suburban Areas: Up to 4 units permitted on one lot.
        - Core Areas: Up to 5 or 6 units permitted on one lot.
        - Transit Oriented Areas: Within 200 metres of the Transit Exchange, maximum building heights will be 10 storeys. Within 400 metres, 6-storey buildings are permitted.
        - No required parking for residential land uses within Transit Oriented Areas.
    - The legislation changes are currently affecting the City of Kelowna's zoning. Several adjustments that are being recommended but not currently in place will increase electrical demand beyond the City's current unit forecasts in all the study areas.
3. **Electrification of Heating Loads:**
    - Policy is expected to accelerate the shift towards electric heating systems in residential, commercial, and industrial buildings. This shift is part of a broader effort to reduce GHG emissions and increase energy efficiency. FBC anticipates increased enhancements to electric infrastructure to enable greater adoption of electric heating over time as contemplated by policies such as the BC Energy Step Code and in the future, the Zero Carbon Step Code.
4. **Electric Vehicle Loads:**
    - The adoption of electric vehicles is rising rapidly in Kelowna, and as of April 1, 2024, bylaws require that all new builds must be EV ready. As more residents and businesses opt for EVs, the demand for charging infrastructure increases. This growing demand places additional pressure on the electrical grid, requiring upgrades to ensure reliable and adequate power supply as all new residential services in Kelowna are designed to serve a higher capacity.

5. **Planning Legislation Changes Resulting in Redevelopment and Densification of Existing Buildings:**
   - Downtown Kelowna, particularly the north end, is seeing a trend towards the redevelopment of existing structures and densification. In the last five years, new developments including new high-rise residential and commercial buildings have been built in downtown Kelowna. In addition, older buildings are being renovated or replaced with higher-density residential and commercial properties. This trend is in response to a growing population and the need for more efficient use of urban space. These developments are expected to transform downtown Kelowna, attracting businesses, residents, light industrial, and visitors, thereby boosting economic activity and increasing the demand for utilities, including electricity.
   - Refer to Attachment 23.5 for a map providing the projected residential unit counts from the City of Kelowna up to 2040.

On pages C-106 to C-109 of the Application, FortisBC provides a list of all projects in the Transmission Growth Capital category with forecast capital expenditures of $1 million or greater that FBC plans to deliver during the proposed term of the Rate Framework. These projects include the Reconductor 52L & 53L project and Princeton 138 kV Capacitor Bank Addition project. FortisBC states both projects will be undertaken to maintain the N-1 system reliability criteria, which will be exceeded by the forecast load growth over the proposed term of the Rate Framework.

23.6 For each of the Transmission Growth Capital projects with forecast expenditures of above $1 million, please confirm that the planned peak loads are either expected to violate the N-1 criteria or exceed the facility rating limits over the proposed term of the Rate Framework.

23.6.1 If not confirmed, please discuss, with rationale, whether a portion of the forecast capital expenditures for Transmission Growth Capital over the proposed term of the Rate Framework could be deferred to beyond 2027.

Response:

Confirmed.

23.7 Please discuss whether all transmission facilities of FBC's interconnected system currently achieve N-1 planning criteria.

23.7.1 For each of those facilities that do not achieve N-1 planning criteria: (i) please provide any system adjustments FBC uses to alleviate the N-1 contingency events; and (ii) please discuss whether FBC intends to meet the N-1 system reliability criteria during the proposed term of the Rate Framework.

Response:

All parts of FBC's transmission interconnected system achieve N-1 planning criteria with the exception of 52L and 53L, and 40L and BEN T1. FBC has included projects to address these N-1 contingencies in the 2025-2027 Growth capital expenditure forecasts.

Regarding 52L and 53L, in the case of an outage on either line, the flow on the remaining line would violate its thermal rating. FBC utilizes post contingency manual load shedding of 47L to reduce flows on 52L or 53L to alleviate the N-1 contingency events.

Regarding 40L and BEN T1, if an outage occurs on either 40L or BEN T1, the resulting voltages are well below acceptable limits in the Princeton area. If an outage occurs, FBC would seek to transfer load to BC Hydro through 56L, depending on BC Hydro's system availability throughout the year (as discussed in BCUC IR1 23.8), or would shed load on 43L.

23.8 Please discuss, with rationale, whether FBC has considered other system adjustments (e.g. use of operational procedures and remedial schemes) to achieve the N-1 reliability criteria during the proposed term of the Rate Framework as opposed to undertaking the Reconductor 52L & 53L project or Princeton 138 kV Capacitor Bank Addition project.

Response:

Yes, FBC has considered the use of pre-contingency operational procedures to either avoid or defer both the Reconductor 52L & 53L project and Princeton 138 kV Capacitor Bank Addition project, as follows:

- **Reconductor 52L & 53L project:** Opening 42L between Huth station and Kaleden Station would reduce the loadings along 52L and 53L; however, this procedure is not sufficient to bring loadings within the emergency limits.
- **Princeton 138 kV Capacitor Bank Addition project:** Princeton load along 43L can be transferred to BC Hydro through 56L depending on BC Hydro's system availability throughout the year. However, during peak winter and summer times this transfer is no longer available due to increased load from customers on BC Hydro's system.

23.9 Please discuss how FBC determined the forecast capital expenditures for the Reconductor 52L & 53L and Princeton 138 kV Capacitor Bank Addition projects during the proposed term of the Rate Framework.

Response:

FBC undertook the following analyses to determine the forecast capital expenditures for the referenced projects.

52L & 53L Reconductoring Project:

FBC determined that significant upgrades are required to increase capacity by 2026 based on forecast load growth. FBC evaluated three possible options to address the need:

1. Reconductoring to a higher-capacity conventional conductor type with a complete rebuild of the existing circuits to accommodate the increased weight of the conductor.
2. Adding capacity with a new line connection, which involves construction of a new transmission line and major substation-related infrastructure at the substation.
3. Reconductoring the existing circuits using a light weight and higher capacity High Temp Low Sag (HTLS) conductor, which allows for reuse of existing infrastructure as much as possible (i.e., minimizing replacement costs).

FBC obtained high level cost estimates for the possible options and determined that Option 3 achieves significant cost savings compared to Options 1 and 2 while still increasing capacity by implementing a specialty conductor (HTLS conductor), thus avoiding as many full structure replacements as possible. Additionally, Option 3 (and Option 1) can be completed within the existing Statutory Right of Way (SRW) and lands, whereas Option 2 requires the acquisition of land rights, which increases costs, time and potential environmental impacts. Wherever possible, FBC endeavors to minimize incremental land requirements and the associated costs, schedule delays and potential environmental impacts.

FBC progressed Option 3 to an AACE Class 3 level of definition and more detailed estimates and scoping were consolidated to ensure schedule, constructability, material, and design costs were accounted for. As noted in the Application, the estimated total cost of this project is $6.6 million, with the majority of expenditures to be incurred in 2025 and 2026.

The project will be staged, with purchasing of material to begin first due to the long lead time for the conductors and accessories. Civil construction will occur ahead of the installation of the overhead line, and environmental and archeological studies are needed to obtain permits to begin civil construction. In addition, due to the location of these lines, FBC cannot undertake construction during the summer season due to heavy traffic.

Princeton 138 kV Capacitor Bank Addition Project:

FBC determined that the addition of reactive compensation at the Princeton Station is required to maintain compliance with BC Mandatory Reliability Standard TPL-001-4 regarding low voltage. FBC evaluated five options using estimates at an AACE Class 5 level of definition, as described below.

1. **13 kV Open Rack Capacitor Bank:** Consists of a 13 kV open rack capacitor bank externally fused grounded-wye capacitor bank. This option was dismissed because it would require derating of the transformer nameplate, limiting its capacity to supply customers at the distribution level and adding an operational constraint in a transmission contingency of 40L or BEN T1.
2. **138 kV Open Rack Capacitor Bank:** Consists of a 138 kV open rack fuseless double wye grounded capacitor bank. This is FBC's selected option because it is the most cost-effective solution, it directly supports the transmission voltage requirement, and it is a proven application within the FBC system.
3. **13 kV Mobile Capacitor Bank:** Consists of a 13 kV mobile trailer. This option was dismissed because it would require derating of the transformer nameplate, limiting its capacity to supply customers at the distribution level and adding an operational constraint in a transmission contingency of 40L or BEN T1. This option was also dismissed due to being the highest cost, having long lead times, and potentially requiring a transportation permit. There is also a permanent need for reactive compensation at the Princeton Station, and therefore a mobile option is not a suitable solution.
4. **138 kV Mobile Capacitor Bank:** Consists of a 138 kV mobile trailer. This option was dismissed for the same reasons as Option #3.
5. **13 kV Metal Enclosed Capacitor Bank:** Consists of a 13 kV outdoor rated capacitor bank. This option was dismissed because it would require derating of the transformer nameplate, limiting its capacity to supply customers at the distribution level and adding an operational constraint in a transmission contingency of 40L or BEN T1.

As explained above, FBC determined that Option 2 was the best option because it is the most cost-effective, and directly supports the transmission voltage requirement.

As noted in the Application, FBC obtained high level cost estimates based on manufacturer information (an AACE Class 5 level of definition), and FBC is currently developing an AACE Class 3 level estimate. The estimated total cost of the project is $2.2 million with expenditures forecast to be incurred in 2026 and 2027.

On pages C-108 of the Application, FortisBC forecasts capital expenditures of $11.2 million for the Reconductor 51L & 60L project in Kelowna, which includes reconductoring of 138 kilovolt (kV) transmission lines 51L and 60L to provide adequate capacity during an N-1-1 event. FortisBC explains that an N-1-1 event can be caused by an outage to more than one F.A. Lee terminal substation transformer and constitutes a violation of BC Mandatory Reliability Standard TPL-001-5.

In response to BCUC IR 6.1 in the KBTA CPCN proceeding, FBC stated:

> FBC's 138 kV Kelowna system is not subject to MRS [Mandatory Reliability Standards], as explained in the Application. FBC notes that prior to March 2016 (at which time the BCUC formally confirmed the exclusion methodology for Local Networks), the Kelowna 138 kV system was considered part of the Bulk Electric System and hence was subject to the BC MRS. The statement provided in the Multi-Year Rate Plan proceeding was inadvertently included based on this previous requirement which was no longer in effect.

In response to BCUC IR 22.2.1 of Exhibit B-2 in the FBC 2021 LTERP proceeding, FBC stated:

> The 60L and 51L upgrade project is required to maintain compliance with Mandatory Reliably Standard TPL-001-4, 2.1.5. FBC does not plan for double contingencies (N-2) other than to fulfill the TPL-001-4 requirement.

On page C-118 of the Application, FortisBC states that it is undertaking a new Spare Parts program commencing in 2025 to comply with Section 2.1.5 of Transmission System Planning Performance Requirements (TPL-001-5), which states:

> When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2 categories […]

23.10 Please discuss whether the new Spare Parts program and the 51L and 60L upgrade project are both required to maintain compliance with TPL-001-4 2.1.5.

Response:

While the new Spare Parts program is required to maintain compliance with TPL-001-4 2.1.5, FBC confirms that the 138 kV Kelowna system, which includes 51L and 60L, is not subject to Mandatory Reliability Standards, including TPL-001-4 2.1.5, at this time due to the Local Network exclusion. TPL-001-5.1, as referenced on pages C-106 and C-108 of the Application, is not currently effective in BC and the statement made in the response to BCUC IR1 22.2.1 in the FBC 2021 LTERP proceeding (referenced in the preamble to this IR) was made in error. Please refer to the Errata to the Application filed concurrently with these IR responses which corrects the reference to TPL-001-5.1 in the Application.

The 51L and 60L upgrade projects are required to maintain compliance with the N-1-1 planning requirements as set out in FBC's Transmission System Planning Criteria. As per Section 5.2 of FBC's Transmission System Planning Criteria, N-1-1 multiple contingencies are defined as follows:

- Loss of any single element (line, transformer, generator unit or power conditioning unit) followed by system adjustments to compensate for the outage, then the loss of another element.

After the loss of the second element, the system will be within emergency facility ratings and within emergency voltage limits and no loss of load shall occur. The reconductoring of 60L and 51L must be completed to re-configure the Kelowna 138 kV network to prevent exceeding line and transformer emergency ratings to satisfy this N-1-1 requirement and to satisfy FBC's Transmission System Planning Criteria.

23.11 Please confirm that the Kelowna 138 kV system is not subject to MRS as stated in the preamble above from the response to BCUC IR 6.1 in the KBTA CPCN proceeding.

23.11.1 If confirmed, please explain the need to undertake the proposed Reconductor 51L & 60L project in the context of compliance with Mandatory Reliability Standard TPL-001-5.

23.11.2 If not confirmed, please clarify whether transmission lines 51L and 60L are now considered part of the Bulk Electric System and hence subject to BC MRS.

Response:

Please refer to the response to BCUC IR1 23.10.

24.0 Reference: PROPOSED RATE SETTING FRAMEWORK – CAPITAL EXPENDITURES

Exhibit B-1, Section C3.4, Table C-3-27, p. C-104, Section C3.4.2.3, pp. C-118 to C-121, Section C3.5, p. C-139, Section B2.2.1, p. B-18

FBC – Sustainment Capital

On page C-104 of the Application, FortisBC provides Table C3-27 which summarizes the 2025 to 2027 forecast regular gross capital expenditures for FBC.

24.1 Please provide an estimate of the portion of the annual revenue requirement ($) and annual rate increase (%) attributable to growth in rate base for each year of the proposed term of the Rate Framework if forecast gross capital expenditures for Sustainment capital projects were to be approved as proposed.

Response:

Table 1 below provides the estimated incremental annual revenue requirement and rate impact from 2025 to 2027 (when compared to the 2024 Approved revenue requirement and rates) for the forecast FBC gross Sustainment capital expenditures from Table C3-27 of the Application.

Table 1: Annual Revenue Requirement and Rate Impact of Forecast Sustainment Capital Expenditures

	2025	2026	2027
Gross Sustainment Capital ($000s)	75,664	72,116	71,310
Incremental Revenue Requirement ($000s)	877	7,699	14,229
2024 Approved Revenue Requirement ($000s)	457,247	457,247	457,247
Rate Impact Compared to 2024 Approved (%)	0.19%	1.68%	3.11%

Note: Depreciation is calculated based on the opening balance of plant-in-service. As such, depreciation for capital expenditures forecast in 2025 begins in 2026, which is why the rate impact in 2025 is small.

On page C-118 of the Application, FortisBC states that it has added a new category titled “Spare Parts” to its Sustainment Capital portfolio to ensure compliance with Transmission System Planning Performance Requirements (TPL-001-4), which became effective in BC on July 1, 2020. FBC states that TPL-001-4 contains the following requirement:

> 2.1.5. When an entity’s spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. […]

Further, on page C-118, FortisBC states that it has identified 500/230 kV, 250 megavolt amperes (MVA) transformers as having a delivery time longer than one year and that a spare 500/230 kV, 250 MVA transformer would be needed to correct system issues in 2029.

On page C-119 of the Application, FortisBC states that it intends to comply with TPL-001-4 requirements by purchasing spares for several pieces of transmission equipment (e.g. 500/230 kV, 250 MVA transformer; 230/161/138/63 kV, 200 MVA transformer) during the proposed term of the Rate Framework term.

24.2 Please discuss the frequency, or under what circumstances, FBC will perform and update the studies outlined under the TPL-001-4 requirement.

Response:

The FBC Power Flow and Transient Stability Analysis Report is completed annually to satisfy TPL-001-4 requirements.

24.3 For each transmission equipment spare listed on page C-119 of the Application that FBC is planning to purchase, please briefly describe any impacts on system performance conditions otherwise arising from equipment unavailability over the proposed term of the Rate Framework.

24.3.1 Please briefly describe the system performance conditions that would trigger the need to employ an equipment spare.

Response:

FBC performed studies as required by TPL-001-4, R2.1.5 for any major transmission equipment that was determined to have a lead time of one year or more to determine the impact on system performance if this equipment was unavailable. These studies were completed as N-1-1 contingencies which are defined as follows:

- Loss of any single Element[37] followed by system adjustments to compensate for the outage, then the loss of another Element.

[37] Element is any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An Element may be comprised of one or more components.

After the loss of the second Element, acceptable system performance is that the system shall be within emergency facility ratings and within emergency voltage limits and no Non-Consequential Load Loss[38] shall occur.

The impacts on system performance conditions otherwise arising from equipment unavailability due to each of the transmission equipment spares are as follows:

- **500/230 kV, 250 MVA Transformer:** For the loss of one Vaseux Lake Substation (VAS) 500/230 kV, 250 MVA transformer followed by system adjustments to compensate for the outage, then the loss of the other VAS 500/230 kV, 250 MVA transformer, the unacceptable impact on system performance is load shedding in the Oliver region to prevent exceedance of emergency low voltage limits. Without a spare transformer, customers in the Oliver region could experience rotating power outages until a replacement transformer can be purchased and installed onsite, which is currently estimated to be approximately three years.
- **230/161/138/63 kV, 200 MVA Transformer:** For the loss of one of this class of transformer followed by system adjustments to compensate for the outage, then the loss of another parallel transformer, the unacceptable impact on system performance is load loss or shedding to prevent exceedance of emergency facility ratings or emergency low voltage limits. Without a spare transformer, customers in the applicable region could experience rotating power outages until a replacement transformer can be purchased and installed onsite, which is currently estimated to be approximately three years.
- **245 kV, 2000 A Circuit Breaker:** For the loss of one of this class of circuit breaker, then the loss of another circuit breaker which is connected in series, the unacceptable impact on system performance is load loss or shedding to prevent exceedance of emergency facility ratings or emergency low voltage limits. Without a spare circuit breaker, customers in the applicable region could experience rotating power outages until a replacement circuit breaker can be purchased and installed onsite, which is currently estimated to be approximately four years.
- **145 kV, 30 MVAR Capacitor Bank:** For the loss of one of this class of capacitor bank with an outage to a second Element, the unacceptable impact on system performance is load shedding to prevent exceedance of emergency low voltage limits in the Kelowna 138 kV system. Without a spare capacitor bank, customers in the Kelowna area could experience rotating power outages until a replacement capacitor bank can be purchased and installed onsite, which is currently estimated to be approximately two years. 145 kV capacitor banks connected in the Kelowna 138 kV system are part of the Bulk Electric System (BES) as per inclusion I5 of the BES definition and are not subject to the Local

[38] Non-Consequential Load Loss is Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment. Consequential Load Loss is all load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Network[39] exclusion and, therefore, are required to comply with TPL-001-4 spare parts requirements.

- **145 kV, 2000 A Point-On-Wave (POW) Circuit Breaker:** This type of circuit breaker is used to connect 145 kV, 30 MVAR capacitor banks to the system, and a failure of this type of circuit breaker will result in the outage of its associated capacitor bank, resulting in the same system issues as described in the previous bullet point. Current delivery estimates from manufacturers for a 145 kV, 2000 A POW circuit breaker are approximately two years.

24.4 Please explain why FBC plans to purchase a 500/230 kV, 250 MVA transformer during the proposed term of the Rate Framework if it will not be needed to correct system issues until 2029.

Response:

As explained in the response to BCUC IR1 24.3, the current delivery time estimates from power transformer manufacturers are approximately three years, which means the 500/230 kV, 250 MVA transformer will need to be purchased during the proposed Rate Framework term to ensure it is delivered by 2029.

24.5 Please discuss whether, in addition to long lead delivery times, FBC considers other spare requirements for new technologies and end-of-life equipment to manage its spare inventory.

---

39 Local Network (LN): A group of contiguous transmission Elements operated at less than 300 kV that distribute power to Load rather than transfer bulk power across the interconnected system. LN's emanate from multiple points of connection at 100 kV or higher to improve the level of service to retail customers and not to accommodate bulk power transfer across the interconnected system. The LN is characterized by all of the following:

a) Limits on connected generation: The LN and its underlying Elements do not include generation resources identified in Inclusions I2, I3, or I4 and do not have an aggregate capacity of non-retail generation greater than 75 MVA (gross nameplate rating);
b) Real Power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN; and
c) Not part of a Flowgate or transfer path: The LN does not contain any part of a permanent Flowgate in the Eastern Interconnection, a major transfer path within the Western Interconnection, or a comparable monitored Facility in the ERCOT or Quebec Interconnections, and is not a monitored Facility included in an Interconnection Reliability Operating Limit (IROL).

Response:

FBC considers delivery times, availability of manufacturer support, technology obsolescence, and alternative equipment compatibility when determining spare equipment requirements.

Further on page C-119 of the Application, FortisBC states:

> Station Sustainment Programs include new and existing programs required to replace or refurbish obsolete or aging equipment, maintain or improve reliability of the substations, and/or improve legacy designs. […]
>
> The forecast increase in expenditures during the Rate Framework term is the result of FBC implementing certain new programs which will support an all-inclusive approach to station condition assessment. The new programs will upgrade legacy distribution transformer high voltage protection, replace porcelain fused cut-outs at legacy stations, implement station security upgrades, and enhance station transformer monitoring.

On page C-117 of the Application, FortisBC provides Table C3-36, showing a breakdown of Station Sustainment capital expenditures, including 2023 approved and 2024 approved capital expenditures and forecast capital expenditures for each year of the proposed term of the Rate Framework under five categories (e.g. Spare Parts, Station Sustainment Programs, Station Upgrade/Replacement Projects, etc.).

24.6 Please elaborate on what FBC means by an "all-inclusive approach" to station condition assessment and provide the difference(s) between such an approach and FBC's current practice for station condition assessments.

Response:

FBC's existing station condition assessment approach occurs on a six-year cycle and focuses on the as-found condition of major electrical apparatus (i.e., transformers, circuit breakers, switches, and relays) and recommends necessary investments. Due to changing market conditions resulting in longer delivery and project development timelines, FBC is evolving its Station Condition Assessment program. This is necessary to provide comprehensive insight on the overall station health and sustainment needs, including critical information such as health indices, probability of failure, and rate of change.

The new Station Condition Assessment program will perform an all-inclusive condition assessment of each FBC owned station on a six-year cycle. This all-inclusive approach will include all electrical equipment/apparatus in addition to foundations, above-ground structures, and buildings in the substation. The deliverables of the all-inclusive approach will include:

1. Defining the condition/health indices, probability of failure, and rate of change for the electrical apparatus, automation, protection and controls, and communication equipment;
2. Providing an overall assessment of the station's collective health;
3. Identifying station rehabilitation needs (replacements, retrofits, additions, equipment/operational deficiencies, etc.) and a timeline for fulfillment;
4. Recommending alternatives for sustaining the station and/or meeting the identified needs; and
5. Advising on intermittent sustainment actions to prolong asset health until a more comprehensive solution can be implemented.

The deliverables produced from this program will be used to allocate resources to ensure the sustainment of the station in the short-term and long-term through rehabilitation, remediation, replacement, and upgrade work. FBC will use this information to develop rehabilitation strategies, mitigate risk, and prioritize investments according to cost, criticality, reliability, safety, and risk.

24.7 Please provide a breakdown of the capital expenditures for new versus existing programs under the "Stations Sustainment Programs" category for each year of the proposed term of the Rate Framework.

Response:

The following table below provides a breakdown of the capital expenditures for new versus existing programs under the Station Sustainment Programs category for each year of the proposed term of the Rate Framework.

Table 1: Breakdown of Existing vs New Stations Sustainment Programs ($000s)

Stations Sustainment Programs	2025	2026	2027
Existing Programs			
Generating Stations Switchyard	361	544	563
Transmission Transformer Sustainment	431	467	412
Distribution Transformer Sustainment	442	447	452
Minimum Oil Circuit Breaker Replacement	1,890	1,235	1,240
Switchgear Sustainment Program	176	185	197
Outdoor Isolating Switch Replacement	1,098	1,155	1,217
Transformer Oil Containment	733	740	789
Ground Grid Upgrades	283	283	251
Station Oil Recloser Replacements	538	0	0

Stations Sustainment Programs	2025	2026	2027
Existing Programs Subtotal	**5,952**	**5,056**	**5,121**
New Programs			
Station Security Enhancements	431	435	441
Station Transformer Monitor Enhancements	296	300	319
Station Condition Assessments	242	245	261
Station High Voltage Protection Upgrades	379	653	662
Station Porcelain Fuse Cut-out Replacements	54	54	55
New Programs Subtotal	**1,402**	**1,687**	**1,738**
Stations Sustainment Programs Total	**7,354**	**6,743**	**6,859**

24.8 Please explain how FBC determines the level of capital investments necessary for new programs under the "Stations Sustainment Programs" category during the proposed term of the Rate Framework.

Response:

For each of the new programs proposed under the Station Sustainment Programs category, FBC has developed the scope of deliverables and forecast of capital expenditures.

The annual forecasts for Station Transformer Monitor Enhancements, Station Condition Assessments, High Voltage Protection Upgrades, and Porcelain Fuse Cut-out Replacements are based on historical spending on similar past projects. Contractor or vendor quotes are obtained to verify estimates for any new work that cannot accurately rely on historical cost data. A prioritized list of investment needs is maintained for each program and updated annually. The average annual project execution rate is targeted at a certain number of projects per year, ranging from one per year to multiple per year, depending on project costs and the investment level proposed.

The annual forecast for Station Security Enhancements is based on the preliminary planning work completed by the FBC security team to install new equipment or to upgrade existing outdated equipment to enhance substations' physical and electronic security systems.

On page C-120 of the Application, regarding Station Upgrade/Replacement Projects, FortisBC states:

> To maintain adequate levels of reliability, FBC will replace transmission and distribution station transformers and/or associated equipment based on condition

assessments, which consider asset health, reliability, age, risk of failure, loading, outdated load tap changers, and the impact to the FBC system.

On page C-121 of the Application, FortisBC states that the third-party condition assessment for the Castlegar Switchgear Replacement project found major equipment to be in very poor condition and recommended that this equipment be replaced.

24.9 Please confirm the classifications within the range of asset health ratings (e.g. very poor, poor, good, etc.) that FBC uses to evaluate a piece of equipment's suitability for use.

Response:

FBC has relied on the expertise of METSCO (a third-party contractor specializing in asset analytics, forecasting and failure analysis, project scoping and evaluation, risk-based investment planning, and maintenance strategies) to determine the health of a particular asset. METSCO prepared the Medium-Voltage, Metal-Clad Switchgear Strategic Plan (Switchgear Plan), included as Attachment 24.9. Table 0-1 from the Switchgear Plan is reproduced below and shows the classifications for ranking the assets' health and suitability for use.

Table 0-1: Health Index Ranges and Corresponding Implications for the Asset Condition

Health Index Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of aging or minor deterioration of a limited number of components	Normal Maintenance
[70-85)	Good	Significant Deterioration of some components	Normal Maintenance
[50-70)	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
[30-50)	Poor	Widespread serious deterioration	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
[0-30)	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

24.10 Please elaborate on FBC's asset health rating methodology and discuss how it considers various factors (e.g. age, risk of failure, condition assessments, codes and standards, etc.) in determining the health rating of an asset.

Response:

As explained in the response to BCUC IR1 24.9, FBC used METSCO to assess the health of its assets, including its switchgears. Section 3 of Attachment 24.9 sets out how METSCO applied their asset health rating methodology to determine a health index. METSCO's methodology considers the following factors to calculate a health index:

- Breaker Condition;
- Control and Operating Mechanism Condition;
- Maintenance Test Results;
- Operations Count;
- Insulating Medium Integrity;
- Equipment Failure History; and
- Obsolescence.

The health indices and the age for each asset were used by METSCO to the determine the asset effective age, which is used to determine an asset's failure probability.

24.11 Please discuss what factors inform the ranking of the risk of failure as worse or different than expected.

Response:

As described in Section 3.9 of Appendix A to the Switchgear Plan, provided as Attachment 24.9 in the response to BCUC IR1 24.9, the factors that lead to a Castlegar switchgear risk of failure ranking as worse or different than expected include:

- Excessive corrosion found inside the switchgear enclosure;
- Visible signs of previous arc-flash (insulation failure) events;
- Partial discharge measured during operation; and

- Major temperature differences in excess of 40°C of the switchgear unit above ambient.

24.12 Please explain how condition assessments are used to inform investment decisions with respect to risk of failure, reliability, asset health, age, and other factors. As part of the response, please provide thresholds for asset health ratings, risk of failure, or any other factors that trigger the need to replace an asset.

24.12.1 Please provide the dollar value of assets or percentage of number of assets that fall below FBC's allowable thresholds over the proposed term of the Rate Framework for each of the following categories: (i) station assets; (ii) distribution assets; (iii) transmission assets; and (iv) generation assets.

Response:

Section 3 of Attachment 24.9 describes the Asset Condition Assessment which determines the Health Index (HI) of an asset. The threshold for these asset health ratings is shown in the response to BCUC IR1 24.9.

At a high level, the Asset Condition Assessment collects information on the asset, such as the level of degradation of an asset, its configuration within the system, and its corresponding likelihood of failure to determine the HI. The age and HI of an asset is then used to determine an effective age which determines the asset's failure probability. As detailed in Section 4 of Attachment 24.9, METSCO quantifies a risk cost based on the calculation of probability of failure and the following failure impact factors: total customer impact; financial impact; environmental damage impact; and collateral impact. METSCO uses this information to calculate a total cost of ownership which is then used to determine the Optimal Intervention Time (OIT) for the asset (as detailed in Section 5 of Attachment 24.9).

FBC uses these condition assessments to inform its investment decisions during the capital planning process as described in Section C3.2 of the Application. The HI, probability of failures, and impact factors are used by FBC as inputs in the optimization process of the Asset Investment Planning (AIP) tool.

Although condition monitoring is performed on an on-going basis, comprehensive condition assessments are performed only on a case-by-case basis and therefore FBC is not able to provide the dollar value or percentage of number of assets that fall below allowable thresholds for all of its station, distribution, transmission and generation assets. Assets are selected for comprehensive condition assessment based on: (i) deteriorating condition/failure history; (ii) test results; (iii) obsolescence; and (iv) asset age.

On page B-45 of the Application, FortisBC states that it has a strong track record of cost control and savings while operating under successive PBR plans, and this will continue to be a major focus of FortisBC. To respond to rate pressures, FortisBC will continue to focus on rate smoothing approaches, and on the affordability strategies.

24.13 Given the rate pressures described in the preamble over the proposed term of the Rate Framework, please explain whether FortisBC is able to defer a portion of capital expenditures to beyond 2027 for its electric operations.

Response:

FBC continues to focus on managing rate pressures and customer affordability; however, deferring capital investments beyond 2027 will only put greater pressure on customers in future years. Given the increasing operating challenges utilities are facing with climate change, security risks, supply chain management, aging infrastructure, regulatory requirements, and load growth due to electrification, FBC does not expect the level of capital expenditures to decrease beyond 2027.

FBC has carefully reviewed its required level of Growth, Sustainment and Other capital expenditures for the three-year term to optimize spending and gain efficiencies in design, procurement, construction, and operation through the timing of expenditures (for example, some Growth and Sustainment expenditures have been timed together so that the work can be done in tandem, thus achieving efficiencies in the design and execution of the projects).

Further, deferring needed projects is not acceptable from a safety or reliability standpoint. If FBC defers a project that has been identified as necessary to address a system need such as aging infrastructure, it increases system risk, reducing safe and reliable operations as the probability of equipment failure increases with time. Deferring a project needed for system growth could result in FBC not being able to provide adequate electric service to existing and new customers in a timely manner. Deferring investments can also increase project and operational costs. Maintenance activities will need to increase to prolong the life of the existing equipment. Additional projects will have to be created at a future date when opportunities for project efficiencies may no longer be available.

25.0 Reference: PROPOSED RATE SETTING FRAMEWORK – CAPITAL EXPENDITURES

Exhibit B-1, Section B1.5, p. B-10, Section C3.4, p. C-104

FBC – Climate Change Adaptation and Resilience

On page B-10 of the Application, FortisBC identifies significant costs associated with energy transition that negatively impact affordability, including increased costs related to investments in climate adaptation and resilience.

On page C-104 of the Application, FortisBC summarizes 2025–2027 Forecast regular gross capital expenditures for FBC under three categories: Growth, Sustainment, and Other Capital.

On page 7 of the FortisBC Supplemental Information, FortisBC states:

> […] In all likelihood, the projects that will be required to address climate change adaptation will require a CPCN or Major Project approval. However, in the event that smaller projects are identified during the three-year Rate Framework term, the Rate Framework is flexible enough to accommodate the necessary expenditures. […]

25.1 Please provide FBC's 2025 to 2027 forecast capital expenditures relating to investments in climate adaptation and resilience within each category of regular capital (Growth, Sustainment and Other Capital).

Response:

FBC is currently working with a consultant to finalize the Climate Change Risk Assessment (CCRA), which assesses the risks of climate change on FBC's asset categories at a high level and identifies potential adaptation strategies. FBC is beginning to apply the CCRA results to specific assets, which requires additional climate hazard studies. Once the Asset-Specific Assessments are complete, FBC will be able to develop plans to mitigate and adapt to climate hazard risks. FBC will then consider the results and what applications might be necessary to implement the plan. Forecast expenditures for adaptation strategies related to this work are not included in the 2025 to 2027 forecast capital expenditures (or formula O&M) as this work is still underway.

Nonetheless, climate adaptation and improved resilience are often one of many drivers of projects within FBC's forecast regular capital expenditures (i.e., regular Growth and Sustainment capital). Generally, Sustainment projects and programs can build resiliency and harden the system by rehabilitating, upgrading, or replacing infrastructure. Growth projects enable FBC to meet higher customer demands while providing a more reliable supply by increasing system capacity and redundancy. Examples in FBC's 2025-2027 forecast capital expenditures of investments with climate adaptation and resiliency benefits include the following:

- As part of the Transmission Rehabilitation program, grounding and bonding will be repaired, and insulators replaced on transmission lines to aid in wildfire mitigation. The transmission condition assessment reports were used to determine the capital expenditures required to complete this rehabilitation work.
- As part of the Station Smart Device and Recloser Upgrades program, FBC will implement distribution field recloser controller upgrades with SCADA control addition. This is a new addition to the program and is required to aid FBC's overall Wildfire Mitigation Plan (WMP). The capital expenditures required to complete this work are based on historical project costs to upgrade distribution field reclosers with SCADA control addition and are planned to be completed for all distribution field reclosers over a four-year period.
- FBC recently updated the transformer cooling specifications to consider higher ambient temperatures and FBC also recently updated the design criteria for transmission and distribution to account for higher wind and snow loadings.

25.2 Please explain how FBC forecasted the amount of capital investments required for climate adaptation and resilience over the proposed term of the Rate Framework.

Response:

Please refer to the response to BCUC IR1 25.1.

F. PROPOSED RATE SETTING FRAMEWORK – ANNUAL CALCULATION OF THE REVENUE REQUIREMENT

26.0 Reference: PROPOSED RATE SETTING FRAMEWORK – ANNUAL CALCULATION OF THE REVENUE REQUIREMENT

Exhibit B-1, Section C4.2.1.1, p. C-143

FEI – Natural Gas for Transportation (NGT) and Non-NGT Demand Forecasts

On page C-143 of the Application, FEI states:

> FEI considers that forecasting non-NGT LNG [Liquified Natural Gas] demand consistent with its current practice continues to be the best approach at this time. FEI forecasts its non-NGT LNG demand by including a forecast of volume for which FEI has firm contract demand plus demand associated with customers that have spot purchase contracts. The spot purchase customer demand is derived from direct conversations with those customers. This approach is similar to FEI's method for forecasting Industrial customer demand, where FEI circulates a survey to its Industrial customers requesting them to forecast their own expected usage. […]

26.1 Please provide a table showing the annual variance ($ and %) between actual and forecast non-NGT LNG demand from 2015 through 2023.

26.1.1 Please compare the accuracy of non-NGT LNG demand forecasts to the accuracy of industrial customer demand forecasts over the same period (2015 to 2023).

<u>Response:</u>

Please refer to Table 1 below for the annual variances (in TJ and %) between forecast and actual non-NGT LNG demand under RS 46 from 2015 to 2023, compared against the annual variances (in TJ and %) for industrial customers (RS 4, 5, 6, 7, 22, 25, 27) over the same period. FEI notes the comparison between non-NGT customers and industrial customers in Table 1 below is based on TJ, not dollars as requested. A comparison based on dollars would not be meaningful or instructive given the wide range of rates set for industrial customers depending on the rate schedule, and the RS 46 rate under which LNG is sold.

Table 1: Demand Forecasts for Non-NGT LNG Customers and Industrial Customers

		Non-NGT LNG Volume & Customers					Industrial Volume & Customers				
Line No.	Year	Approved (TJs)	Actual (TJs)	Variance (TJs)	Variance (%)	Actual Average Customers	Approved (TJs)	Actual (TJs)	Variance (TJs)	Variance (%)	Actual Average Customers
	(1)	(2)	(3)	(4) = (3) - (2)	(5) = (4) / (3)	(6)	(7)	(8)	(9) = (8) - (7)	(10) = (9) / (8)	(11)
1	2015	236	147	(89)	-60%	5	49,219	51,038	1,819	4%	957
2	2016	107	212	105	50%	8	50,027	54,492	4,465	8%	958
3	2017	166	318	152	48%	11	52,287	55,555	3,268	6%	967
4	2018	210	189	(21)	-11%	13	54,091	56,122	2,031	4%	980
5	2019	170	305	135	44%	4	59,490	58,920	(570)	-1%	999
6	2020	922	245	(677)	-277%	5	59,132	56,849	(2,283)	-4%	1,048
7	2021	3,685	190	(3,495)	-1,839%	4	55,648	57,296	1,648	3%	1,076
8	2022	3,083	125	(2,958)	-2,370%	5	56,789	56,815	26	0%	1,099
9	2023	3,691	223	(3,468)	-1,554%	7	57,132	56,136	(996)	-2%	1,128
Average (2015-2023)					**-663%**	**7**				**2%**	**1,024**

FEI notes that the forecasting methods for industrial demand and non-NGT LNG demand are fundamentally the same, as both involve gathering demand forecasts directly from customers. For industrial customers, FEI sends an online survey to each individual industrial customer and requires the customers to forecast their own expected usage for the coming year (please refer to Section 7 of Appendix C4-1 to the Application for further details on the Industrial forecast). For non-NGT LNG customers, FEI's LNG Business Development team directly contacts existing and prospective customers to ask for their best estimation of future demand (please also refer to the response to BCUC IR1 26.5). While FEI's LNG Business Development team manages the process directly with the non-NGT LNG customers, the process for Industrial customers is mostly automated with the use of the online survey. Ultimately, the methodologies are substantively the same as both rely on the customer to provide their estimation of demand based on their own information.

The primary reason for the high degree of forecast variance in non-NGT LNG demand is that most of the volume is from spot purchases, which FEI was directed to include as part of its demand forecast since 2016 pursuant to Order G-86-15. Spot non-NGT LNG customers are served via ISOtainers and operate internationally in rapidly changing business environments as well as having alternative market options at various price points, unlike FEI's industrial customers who operate facilities in BC and are generally only able to receive their gas through FEI's system. Fluctuations in economic factors, such as LNG price, foreign exchange rates, and logistics costs as well as other unforeseen events, such as logistical difficulties, geopolitical instability, and regulatory changes, can lead to sudden changes in spot customer demand. These dynamics make spot purchases difficult to forecast.

FEI recognizes the difficulties in forecasting non-NGT LNG demand. As discussed in the response to BCUC IR1 26.6, FEI's LNG Business Development team has developed and is improving its procedures for verifying and validating the demand forecasts from spot LNG customers. FEI has also conducted market research and studies to gain deeper insight into market trends and is engaging with existing and prospective spot customers to explore firm contracts with take-or-pay commitments, which can improve the demand forecast certainty.

As shown in Table 2 below, FEI's non-NGT LNG demand forecast for 2025 has been reduced to be more closely aligned with the actuals from recent years.

Table 2: 2024 Approved, 2024 Projected, and 2025 Forecast for NGT and Non-NGT LNG Demand (TJ)

	2024 Approved	2024 Projected	2025 Forecast
CNG	1,762.1	1,672.4	1,689.3
LNG	1,562.6	1,533.8	1,540.9
Total NGT Demand (TJ)	**3,324.7**	**3,206.2**	**3,230.2**
Non-NGT LNG (export)	1,471.0	168.5	216.5
Total NGT and Non-NGT Demand (TJ)	**4,795.7**	**3,374.6**	**3,446.7**

Finally, FEI is amenable to reverting back to the pre-2016 forecasting method for RS 46 LNG demand, in which FEI did not include any spot purchases from non-NGT LNG customers. By excluding spot purchases, the accuracy of the non-NGT LNG forecast demand may improve. Further, if actual spot purchases ultimately ended up being higher than forecast, the revenue would still be accounted for, as the variances will be captured in the Flow-through deferral account (for the variance in RS 46 revenue between forecast and actual) and will be returned to customers in the subsequent year through amortization of the deferral account.

26.2 Please explain in what ways the methodology for forecasting industrial customer demand (using surveys) differs from the approach for non-NGT LNG demand.

Response:

Please refer to the response to BCUC IR1 26.1.

Further on page C-143 of the Application, FEI states:

> FEI's non-NGT LNG demand is typically not backed by firm take-or-pay commitments as most are spot purchases, with the majority of this demand being for the ISOtainer LNG business. FEI's ISOtainer LNG demand is affected by factors such as LNG market price, foreign exchange, and logistics costs, making the non-NGT LNG forecast more uncertain. Therefore, FEI considers that its own customers are best able to forecast their own demand.

26.3 Please provide the percentage of FEI's total non-NGT LNG demand that is from "ISOtainer" LNG customers for each year from 2015 through 2023.

Response:

Please refer to Table 1 below for the percentage of FEI's total non-NGT demand from ISOtainer (spot) LNG customers from 2015 through 2023.

Table 1: Non-NGT LNG Demand from ISOtainer (Spot) LNG Customers

Line No.	Year (1)	Non-NGT Actual (TJs) (2)	ISO Actual (TJs) (3)	% of ISO to non-NGT Demand (4) = (3) / (2)
1	2015	147	17	11%
2	2016	212	20	9%
3	2017	318	51	16%
4	2018	189	133	70%
5	2019	305	305	100%
6	2020	245	184	75%
7	2021	190	17	9%
8	2022	125	91	73%
9	2023	223	221	99%

26.4 Please explain where FEI's "ISOtainer" LNG customers are located.

Response:

As discussed in the response to BCUC IR1 3.4 in FEI's Annual Review for 2024 Delivery Rates proceeding, all RS 46 sales to ISOtainer (spot) LNG customers occur in BC, with the transfer of title of the LNG occurring at the outlet flange of the Tilbury LNG Facility and the customer responsible for transportation and delivery of the LNG to the end user. Most of FEI's ISOtainer LNG customers are located in Asia, particularly in China, while some are located in the US. While the LNG is ultimately consumed in the Asian or US markets, FEI's sales occur in BC.

26.5 Please discuss how FEI engages with "ISOtainer" LNG customers to gather demand forecasts.

Response:

Due to the timing of filing the Annual Review materials, LNG Business Development staff reach out directly to existing and prospective ISOtainer (spot) LNG customers in June of each year to gather their estimated demand for the upcoming year. LNG Business Development staff communicate regularly with ISOtainer (spot) LNG customers to track any adjustments to their forecast and include the customers' estimated demand in the non-NGT LNG forecast demand.

26.6 Please discuss how FEI verifies and validates the demand forecast collected from "ISOtainer" LNG customers.

Response:

As discussed in the response to BCUC IR1 26.1, spot demand is difficult to forecast; however, FEI has developed the following procedures to verify and validate the ISOtainer (spot) demand forecasts:

- Analyzing historical sale volumes to identify the customers' consumption pattens and trends;
- Engaging in detailed discussion with customers to understand the rationale behind their usage estimates;
- Collaborating on shipment planning, including conversations on estimated delivery schedules and container quantities; and
- Maintaining consistent communication with customers, to remain apprised of any shifts in their operations and market dynamics.

Additionally, FEI works to develop close business relationships, not only with ISOtainer LNG customers, but also with brokerage agents, port authorities, and shipping companies. These proactive approaches allow FEI to obtain first-hand and critical knowledge on LNG markets, which ultimately helps FEI to verify and validate forecast demand.

26.7 Please discuss any measures FEI currently takes, or could take in the future, to account for the inherent uncertainty in "ISOtainer" LNG demand forecasts.

Response:

Please refer to the response to BCUC IR1 26.1.

27.0 Reference: PROPOSED RATE SETTING FRAMEWORK – ANNUAL CALCULATION OF THE REVENUE REQUIREMENT

Exhibit B-1, Section B1.4.2, p. B-9, Section B1.6.3, p. B-15, Section C4.2.2, p. C-144, Appendix C4-2 (FBC's Forecast Methods), p. 2, Exhibit B-2 (Supplemental Information), p. 14; FBC 2024 Annual Review of Rates, Exhibit B-2, p. 15, Appendix A2, pp. 2, 9, 12; FBC 2021 LTERP, Decision and Order G-280-22, p. 4

FBC – Energy and Demand Forecasts

On page 2 of FBC's Forecast Methods, FBC provides the following description of its Seed and Forecast Years:

- […] for this Application the Seed Year is 2024 (2024S) and the Seed Year forecast is based on the latest actual 9 years, including 2023. As such, the 2024 Seed Year forecast in this Application will differ from the 2024 Forecast presented in the Annual Review for 2024 Rates, for which 2023 actual data was not available.
- Forecast Year(s): This is the year or years for which the forecast is being developed. This can be one year (in the case of the Annual Review) or a range of two or more years depending on the filing. In this Application, 2025 is the Forecast Year (2025F).

Exhibit B-2 in the FBC 2024 Annual Review of Rates proceeding contains the following information:

- On page 15, FBC forecasted a decrease in consumption in the 2024 Forecast Year (2024F) compared to the 2023 Approved;
- On page 2 of Appendix A2, FBC provided forecast before-savings and after-savings gross load of 3,829,838 megawatt hours (MWh) [3,830 gigawatt hours (GWh)] and 3,772,679 MWh [3,773 GWh] respectively for 2024F;
- On page 9 of Appendix A2, FBC provided its forecast after-Savings Summer Peak and Winter Peak load of 697.3 MW and 785.0 MW for 2024F.
- On page 12 of Appendix A2, FBC provided a forecast total customer count of 153,063 for 2024F.

On page B-15 of the Application, FBC states:

> With the implementation of CleanBC, dependence on FBC's system is expected to increase, particularly at peak demand times. As a result, the entirety of the FBC system, […] will require investment to address both the ability to accommodate load growth (through growth capital expenditures), and the ability of the existing infrastructure to support current and increasing levels of demand. […] [*Emphasis added*].

27.1 Please complete the following table for the FBC service area:

Year	Aggregate Gross Load – Before-Savings (GWh)	Aggregate Gross Load – After-Savings (GWh)	After-Savings Peak Demand -Summer (MW)	After-Savings Peak Demand - Winter (MW)	Forecast Year-End Aggregate Customer Count
2024F	3,830	3,773	697.3	785.0	153,063
2024S					
2025F					
2026F					
2027F					

27.1.1 Please provide estimates of the annual percentage increase in forecast gross load (before-savings) for each year of the proposed term of the Rate Framework (2025-2027).

27.1.2 Please provide and compare an estimate of the forecast average annual customer growth (in percent) from 2024 through 2027 to the actual average annual customer growth (in percent) from years 2020 through 2023.

Response:

Please refer to Table 1 below for the forecast aggregate before- and after-savings gross load, the forecast after-savings summer and winter peak demands, and the forecast year-end aggregate customer counts for FBC's service area for 2024 through 2027. The increase in 2024S aggregate gross load from 2024F is predominantly due to a forecast increase in industrial loads, which are interruptible and therefore do not impact peak demand. The difference in 2024S and 2024F is also impacted by small increases in residential and commercial loads.

Table 1: Aggregate Gross Load (Before- and After-Savings), After-Savings Peak Summer and Winter Demands, and Year-End Aggregate Customer Counts for 2024F, 2024S and 2025-2027F

Year	Aggregate Gross Load – Before-Savings (GWh)	Aggregate Gross Load – After-Savings (GWh)	After-Savings Peak Demand - Summer (MW)	After-Savings Peak Demand - Winter (MW)	Forecast Year-End Aggregate Customer Count
2024F	3,830	3,773	697	785	153,063
2024S	3,955	3,928	673	745	153,233
2025F	4,183	4,127	677	750	155,201
2026F	4,318	4,233	682	753	157,076
2027F	4,340	4,223	682	752	158,944

Please refer to Table 2 below for an estimate of the annual percentage change in forecast gross load (before-savings) for each year of the proposed Rate Framework term (2025-2027). The estimated increase in the gross load growth rate is predominantly due to an increase in forecast Industrial interruptible loads.

Table 2: Annual Forecast Change in Gross Load (Before-Savings) during Rate Framework Term

Year	2025-2027 Gross Load (before-savings) Growth Rate (%)
2024S	3.9%
2025F	5.8%
2026F	3.2%
2027F	0.5%

The actual average annual customer growth from years 2020 through 2023 was 1.7 percent while the forecast average annual customer growth from 2024 through 2027 is 1.3 percent.

The short-term residential regression is sensitive to the population forecast from BC STATS. The BC STATS population forecast is affected by a number of inputs, including housing prices, mortgage rates, housing market changes in the service territory and elsewhere, and provincial economics and demographics, among other factors. The short-term forecast is updated each year to make use of the latest data from BC STATS.

27.2 Given that FBC had forecasted a decrease in load for 2024 compared to 2023 in the 2024 Annual Review of Rates proceeding, please compare FBC's assumptions for load growth between the Current MRP term and the proposed term of the Rate Framework as a result of each of the following potential drivers: (i) changes in government and climate policies; (ii) rate of customer growth; and (iii) the pace of energy transition in relation to fuel-switching and adoption of electric vehicles.

Response:

FBC's forecast methods for short-term rate setting, for both the Current MRP term and the proposed term of the Rate Framework are not based on assumptions of drivers such as government or climate policies or the pace of any energy transition-related activities that may develop. Any impact to actual load as a result of fuel-switching, electric vehicles, or other drivers is embedded in historical loads and is then captured within the forecast each year. The methods used to develop the forecasts used to set rates are detailed in Appendix C4-2 to the Application. In the response to BCUC IR1 27.4, FBC provides additional explanation of the difference between scenario forecast modelling (for long-term planning) and demand forecasting (for short-term rate setting).

On page B-9 of the Application, FBC states:

> […] FBC is focused on keeping pace with the growing demand for electricity in a constantly evolving operating environment. Policies are increasingly promoting the use of electricity, including in home heating, light duty transportation and industrial processes. Electrification of heating demand in particular poses a significant challenge to the electric grid which lacks the capacity to shoulder peak heating demand on its own. Electrification demands from all sectors of the economy would therefore exceed what the grid is currently designed for and challenge FBC to maintain reliability, resiliency, and affordability.

On page C-144 of the Application, FBC states:

> FBC proposes to continue the use of the existing forecasting methods from the Current MRP for the one-year forecast in each Annual Review over the term of the Rate Framework. […]

On page 14 of the Supplemental Information, FortisBC states that the pace of the energy transition could result in additional projects being required during the Rate Framework term which FBC has not forecast. FortisBC also states that load-driven projects are always subject to some timing uncertainty, whether due to the energy transition or other factors.

On page 4 of Decision and Order G-380-22 for the 2021 LTERP proceeding it is stated:

> […] FBC has taken the additional step of developing a range of alternative load scenarios to explore the impact of emerging technologies, policies, climate change and changes in how customers use energy that could impact load drivers that are not captured in the Reference Case load forecast.

27.3 Please describe the methodology used by FBC to forecast the grid impacts of electrification in its service area over the proposed term of the Rate Framework.

Response:

FBC completes power flow studies to identify future system upgrades in its transmission and distribution systems. These power flow studies are based on the long-term peak demand load forecast (as described in the response to BCUC IR1 27.4), which intrinsically reflects the full impact of changes in load drivers, including electrification. In addition, this load forecast is adjusted further to include any highly certain large new load customers and an incremental electric vehicle forecast.

27.4 Please discuss, with rationale, whether FBC has considered alternative load scenarios to forecast the increase in demand from electrification of loads over the proposed term of the Rate Framework.

27.4.1 If yes, please describe each scenario, including the level of electrification considered under each scenario and the key assumptions, policies, and metrics for electrification loads (i.e. electric vehicles, electric heating installations, etc.).

27.4.2 Please discuss, with supporting rationale, which electrification load scenario will be used to inform the proposed capital expenditures and the annual load and peak demand forecasts for the proposed term of the Rate Framework.

Response:

FBC has not considered the alternative load scenarios, as set out in its most-recent Long-Term Electric Resource Plan (LTERP), to forecast the increase in demand from electrification of loads over the proposed term of the Rate Framework. FBC discusses its forecasts and their respective purposes below.

Short-Term Demand Forecast for Rate Setting

FBC uses short-term demand forecasting developed using the methods set out in Appendix C4-2 to the Application for setting rates, and is proposing to continue to use short-term demand forecasting to set rates for the term of the Rate Framework. FBC considers short-term demand forecasting to be the most accurate and appropriate approach to year-over-year forecasting for rate setting as the demand trends in the most recent years intrinsically reflect the full impact of policy (such as building energy codes), technology, and all other changes in the service territory – including those driven by demand from electrification of loads. Since this short-term forecast will be updated annually during the Rate Framework term (i.e., in each Annual Review), any acceleration or deceleration of these trends will be reflected in the actual data used to prepare the upcoming year's demand forecast for rate-setting purposes.

Also, sustained changes to demand due to changes in policies, regulation, or technology are expected to happen gradually over time, rather than a one-year step change. As such, the changes due to policies, regulation, or technology between the historical actual and the single one-year forecast are expected to be incremental and are well within the capabilities of the single year load and peak forecast methods to forecast accurately for rate-setting purposes, which is reflected in the relatively small forecasting variances shown in Tables C4-3 and C4-4 of the Application.

Therefore, short-term rate-setting and peak demand forecasts are not, and cannot be, based on the electrification load scenarios and future impacts developed for the purposes of FBC's most-recent LTERP.

Long-Term Peak Demand Forecast for System Planning

FBC uses long-term peak demand forecasting (generally referred to as a "1-in-20" year load forecast) for the purposes of system planning and in the development of its capital expenditure forecasts, including the capital expenditure forecasts for 2025 to 2027 (these forecasts include the station projects as set out in the response to BCUC IR1 23.2).

FBC takes the long-term peak demand load forecast (which is a Business as Usual (BAU) forecast) and adds any highly certain large new load customers and an incremental electric vehicle forecast. Peak forecasts for each of the areas within FBC's service territory are created by allocating the "1-in-20" year peak demand forecast for FBC's system among FBC's substations. This is done by scaling the Distribution Planning forecast, which is the sum of the non-coincident substation peak forecasts to the system peak (the coincident peak). As is the case with the short-term peak demand forecasts, demand trends are intrinsically reflected within the "1-in-20" year load forecast as it is updated annually to incorporate actual data.

Long-Term Scenario Modeling for Resource Planning

In contrast to short-term demand forecasting and long-term peak demand forecasting, long-term future scenario modelling, as presented in FBC's LTERPs, involves identifying load drivers or critical uncertainties and modelling alternative long-term outcomes for those drivers to create a range of scenarios. Modelling a range of long-term scenarios in this way is beneficial because of the inherent uncertainties in how future energy and peak demand use trends may unfold over the LTERP's long-term planning horizon due to the energy transition. While the resulting range of possible values and plausible outcomes are useful for resource planning purposes, they cannot be appropriately applied to rate setting where a *single* forecast value is necessary.

The scenario modelling in the 2021 LTERP is distinct from the short-term demand forecasting used for the proposed Rate Framework in the following ways. First, short-term demand forecasting captures the trends that are occurring in the planning environment as they occur by utilizing actual demand trends from the most recent years. Second, unlike scenario modelling which produces a range of values, short-term demand forecasting produces a single value.

Ultimately, using LTERP forecast scenarios is also not appropriate for system planning and the development of capital expenditures within the Rate Framework while, in contrast, using the "1-in-20" year peak demand forecast ensures that FBC's capital planning only includes expenditures that are necessary and cost-effective because they are based on the pace at which growth is anticipated to occur and on new highly certain loads within each area of its service territory.

27.5 Please compare the forecast incremental electrification load (GWh) for each year of the proposed term of the Rate Framework to: (i) the actual average incremental electrification load from years 2020 to 2023 inclusive; and (ii) annual energy impacts of load scenarios between 2025 and 2027 in the 2021 LTERP.

Response:

The metered load data used to prepare the forecasts for the proposed Rate Framework term are captured at the customer level (i.e., not broken out by end-use), and the actual data recorded by FBC does not include a measurement of the incremental electrification load in any year.

Year-over-year changes are impacted by many drivers, including:

- Natural growth from migration into the service territory;
- Changes in commercial loads due to changes in demand for products and services;
- Increased energy efficiency of building envelopes and end uses;
- Changes to the mix of new home construction (i.e., more or less multi-family construction);
- Demolition of existing buildings and replacement of new building construction; and
- Electrification of building, industrial, and transportation load.

While year-over-year changes to FBC actual and forecast load data can be calculated, the changes cannot be proportioned or attributed to electrification or any other load driver.

27.6 Please clarify, with justification, whether FBC anticipates a greater number of unexpected projects over the proposed term of the Rate Framework compared to the Current MRP term.

Response:

FBC does not anticipate there will be more unexpected projects in the next three years as compared to the five-year Current MRP term, over which there was only one unexpected project (i.e., the Playmor Substation Upgrade project, which was included in FBC's Annual Review for 2020-2021 Rates application). FBC considers this to be evidence that its capital planning processes accurately capture needed projects over the planning period. The excerpted quote in the preamble to the question, from page 14 of the responses to the BCUC Panel Supplemental IRs, was meant to indicate that, even if the pace of the energy transition were to accelerate, FBC's proposed Rate Framework is able to accommodate those unexpected projects. However, it is more likely that identified load-driven projects will be subject to timing changes due to the pace of load growth, rather than entirely new and unexpected projects materializing.

Section C3.2 of the Application describes in detail FBC's and FEI's capital planning processes, and that the resulting capital plan contains a mix of investments, some of which are time-sensitive and others that have some flexibility in timing. As conditions change, FBC's capital plan must be capable of adapting. FBC has continued to use its AIP process to optimize its capital portfolio using Copperleaf C55 software along with methodologies and processes that support the consistent quantification of benefits and risk mitigation associated with each proposed investment. Once investments are evaluated using the value framework, the AIP tool provides the ability to optimize the capital planning portfolio for a given period of time to achieve the greatest benefit within a set of financial constraints.

In Section C3.2.1.3 of the Application, FBC explains how land acquisition is becoming increasingly more challenging, particularly in the City of Kelowna. This is one area where the timing is more uncertain but the need for land appears to be accelerating. Land has been difficult to procure in a timely manner to support execution of projects, adversely impacting project timelines. This is especially true for the City of Kelowna where a new substation is required to support rapid load growth, as discussed in the response to BCUC IR1 23.5. FBC is aware of this project but has not included it in the forecast capital expenditures for the Rate Framework term due to unknowns around cost and timing; however, should the timeline need to be advanced as these load drivers are realized, FBC would file for approval of the necessary expenditures, likely as part of the Annual Review process, pursuant to section 44.2 of the UCA.

27.7 Please explain whether FBC anticipates greater uncertainty in accurately forecasting load and peak demand due to the impacts of energy transition over the proposed term of the Rate Framework compared to the Current MRP term.

27.7.1 If yes, please explain how the use of existing demand forecasting methods continues to be appropriate for the proposed term of the Rate Framework.

Response:

FBC does not anticipate any changes to the accuracy of the annual load and peak demand forecasts due to the impacts of the energy transition over the proposed Rate Framework term.

All forecast components are updated every year with the latest data so any changes due to the energy transition will be captured. FBC does not expect changes due to the energy transition in any single year to materially affect the performance of the forecast methods. Notable, sustained changes to the annual actual load and capacity are expected to happen gradually over time, rather than as a one-year step change, and are well within the capabilities of the annual load and peak forecast methods to model accurately. The longer-term implications of the energy transition are more appropriately examined as part of the Long-Term Electric and Gas Resource Plans.

28.0 Reference: PROPOSED RATE SETTING FRAMEWORK – ANNUAL CALCULATION OF THE REVENUE REQUIREMENT

Exhibit B-1, Appendix C4-3 (FEI's Review of CMAE Forecast and Regulatory Process), Sections 3.1 and 3.2, pp. 5–7, Section 4.2, p. 10

FEI – Review of Core Market Administration Expense (CMAE) Forecast and Regulatory Process

On page 10 of FEI's Review of CMAE Forecast and Regulatory Process, it states:

> […] FEI conducted an internal survey of its staff that are involved with the gas supply activities to determine whether the allocation of CMAE costs for 2025 should be changed. Based on the survey results, FEI determined that the allocation between the CCRA [Commodity Cost Reconciliation Account] and MCRA [Midstream Cost Reconciliation Account] should shift to 25 percent and 75 percent, respectively [from 30 percent and 70 percent, respectively]. The change is primarily driven by additional gas supply resources, related to growth in the RNG [Renewable Natural Gas] supply and in resiliency resources, being managed through the midstream portfolio. FEI anticipates the shift in the allocation from CCRA to MCRA will continue if conventional natural gas supply within the commodity portfolio decreases and the supply of off system renewable gas increases. FEI will re-evaluate the allocation at the end of the Rate Framework term.

28.1 Please explain how FEI calculated that the allocation of CMAE costs to the MCRA should increase by five percent from the internal survey results as opposed to some other percentage.

Response:

As discussed in the preamble to this IR, FEI conducted a survey of its gas supply staff to determine the proportion of their time spent on the commodity (CCRA) portfolio and the proportion on the midstream (MCRA) portfolio and RNG. The resulting time spent on MCRA, CCRA and RNG activities was averaged across all staff and showed that 25 percent of staff time is spent on CCRA activities, 70 percent is spent on MCRA activities, and 5 percent is spent on RNG activities. Rather than making an accounting entry to move 5 percent of Gas Supply costs to the RNG account,[40] for which costs are recovered through a rate rider on FEI's Storage & Transport charges (Storage & Transport charges are used to recover MCRA costs), FEI considered it more efficient to amend the allocation between CCRA and MCRA so that the cost of RNG activities undertaken by FEI's Gas Supply staff formed part of the MCRA allocation of costs which is aligned with how FEI recovers much of its RNG costs through the aforementioned rate rider.

[40] The RNG Account is approved to capture RNG costs.

28.1.1 Please discuss and quantify how the change in the allocation between the CCRA and MCRA will affect each customer class's rates.

Response:

Directionally, the shift in cost allocation from the CCRA to the MCRA will decrease the Cost of Gas charges and increase the Storage and Transport charges.

For illustrative purposes, FEI provides a comparison below between the current BCUC-approved 70/30 (MCRA/CCRA) allocation and the proposed 75/25 (MCRA/CCRA) allocation using FEI's approved 2024 CMAE costs, including how using a different allocation affects FEI's January 1, 2024 Cost of Gas (tested rate) and Storage and Transport (proposed and approved) charges as filed in its 2023 Fourth Quarter Gas Cost Report (2023 Q4 Gas Cost Report), dated November 22, 2023.

FEI's approved 2024 CMAE is $6.050 million.[41] Table 1 below shows the cost allocation between the MCRA and CCRA when changing the allocation from the currently approved 70/30 split to the proposed 75/25 split, resulting in a decrease in allocated costs to the CCRA of $302.5 thousand, with an offsetting increase to the MCRA.

Table 1: Difference in CCRA / MCRA Allocation

2024 CMAE ($000)		**70/30**		**75/25**		**Difference**
		$ 6,050.0		$ 6,050.0		
CCRA	30%	$ 1,815.0	25%	$ 1,512.5	-5%	$ (302.5)
MCRA	70%	$ 4,235.0	75%	$ 4,537.5	5%	$ 302.5

Table 2 below shows how the CMAE allocated to the CCRA is included in FEI's 2023 Q4 Gas Cost Report. The CMAE, among other costs, is divided by FEI's CCRA baseload volume of 148,171 TJ.[42] As shown in Table 2, using a 75/25 (MCRA/CCRA) allocation results in a reduction to the Cost of Gas of $0.002 per GJ.

[41] FEI Annual Review for 2024 Delivery Rates Decision and Order G-334-23.

[42] 2023 Q4 Gas Cost Report, Tab 2, Page 3, Line 1.

Table 2: CCRA Allocated Cost and Difference

	70/30	75/25	Difference
% CCRA	30%	25%	-5%
$000	$ 1,815.0	$ 1,512.5	$ (302.5)
TJ	148,171	148,171	-
$/GJ	**0.012**	**0.010**	**(0.002)**

Table 3 below shows that the tested Cost of Gas rate applicable to all FEI Sales Service customers (excluding Customer Choice customers) in Rate Schedules 1, 2, 3, 4, 5, 6 and 7 would decrease by $0.002 per GJ if FEI had used the 75/25 split in its 2023 Q4 Gas Cost Report.

Table 3: Cost of Gas Recalculated Using 75/25 MCRA/CCRA Allocation[43]

Cost of Gas	2023 Q4 Calculated using 70/30	Change	Calculated using 75/25
($/GJ)	$ 2.520	$ (0.002)	$ 2.518

FEI's Storage and Transport charges are determined by allocating MCRA costs based on a rate schedule's load factor, which means that the $302.5 thousand increased allocation to the MCRA (from Table 1 above) would be allocated across FEI's rate schedules on a load factor adjusted volume basis (this is not a change in methodology).

Table 4 below shows the difference in the Storage & Transport allocated costs to the various Sales customer rate schedules that were included in the 2023 Q4 Gas Report when comparing the MCRA allocation at 70 percent to the allocation at 75 percent. In the table below, the "Allocated Cost ($000)" columns are divided by the "MCRA Volume (TJ)" to derive the "Cost per GJ ($/GJ)". The results (i.e., the last column of Table 4) show that the allocated cost per GJ is in the range of $0.000 per GJ to an increase of $0.002 per GJ.[44]

---

[43] $2.520 can be found in the 2023 Q4 Gas Cost Report, Tab 2, Page 3, Line 31.

[44] In Table 4, "All Other" includes Rate Schedules 1, 2 and 3 in the Fort Nelson Service Area, and Rate Schedule 6 NGV. For these customers the incremental increase in allocated cost rounds to $0.1 thousand and does not change the Storage and Transport charge when rounded to the third decimal place.

Table 4: CMAE Costs Included in MCRA from Table 1, Allocated to Customers[45]

	Allocated Cost ($000)				Cost per GJ ($/GJ)		
Rate Schedules	Approved 70% Allocation	Comparative 75% Allocation	Difference	MCRA Volume (TJ)	Approved 70% Allocation	Comparative 75% Allocation	Difference
RS-1	$ 2,334.3	$ 2,501.0	$ 166.7	83,144	$ 0.028	$ 0.030	$ 0.002
RS-2	$ 852.9	$ 913.8	$ 60.9	29,518	$ 0.029	$ 0.031	$ 0.002
RS-3	$ 655.5	$ 702.3	$ 46.8	26,900	$ 0.024	$ 0.026	$ 0.002
RS-5	$ 391.5	$ 419.5	$ 28.0	23,898	$ 0.016	$ 0.018	$ 0.001
All Other	$ 0.9	$ 0.9	$ 0.1	517	$ 0.002	$ 0.002	$ 0.000
Total CMAE in MCRA	**$ 4,235.0**	**$ 4,537.5**	**$ 302.5**	**163,977**	**$ 0.026**	**$ 0.028**	**$ 0.002**

Finally, Table 5 below shows that the BCUC approved Storage and Transport Charges[46] in the Mainland and Vancouver Island Service Area would increase between $0.001 per GJ and $0.002 per GJ for Rate Schedules 1, 2 ,3 and 5 when using a 75/25 MCRA/CCRA allocation for CMAE costs.

Table 5: Storage & Transport Charges Recalculated Using 75/25 MCRA/CCRA Allocation

	$ / GJ		
Rate Schedules	Approved Rates	Change	Calculated Using 75/25
RS-1	$ 1.102	$ 0.002	$ 1.104
RS-2	$ 1.134	$ 0.002	$ 1.136
RS-3	$ 0.957	$ 0.002	$ 0.959
RS-5	$ 0.643	$ 0.001	$ 0.644

Overall, the summary provided in Table 6 below shows that RS 1 (Residential) and RS 2 (Small Commercial) customers, who purchase commodity from FEI, would have an equal offsetting change in the Cost of Gas and Storage and Transport charges of $0.002 per GJ, with RS 3 (Large Commercial) and RS 5 (General Service) customers experiencing a small net decrease of $0.001 per GJ.

Table 6: Net Change to Customer Cost of Gas and Storage & Transport Charges

Rate Changes	RS-1	RS-2	RS-3	RS-5
Cost of Gas rate change $ / GJ	$(0.002)	$ (0.002)	$ (0.002)	$ (0.002)
Storage and Transport rate change $ / GJ	$ 0.002	$ 0.002	$ 0.001	$ 0.001
Net Change in Rates $ / GJ	$ -	$ -	$ (0.001)	$ (0.001)

[45] The "MCRA Volume (TJ)" includes Customer Choice customer volumes so it is not equal to the baseload volume used to derive the cost of gas charges in Table 3.

[46] Storage and Transport Charges are used to recover MCRA related costs.

On pages 5 to 7 of FEI's Review of CMAE Forecast and Regulatory Process, FEI states that CMAE costs are not conducive to a formulaic approach. Instead, FEI proposes a simplified forecasting and flow-through approach with streamlined variance reporting.

28.2 Please discuss how, if at all, the proposed continuation of flow-through treatment of CMAE costs incentivizes FEI to be cost efficient. As part of this response, please discuss any instances of CMAE cost efficiencies realized by FEI in the past five years.

Response:

FEI has always managed its CMAE budget in an efficient and cost-effective manner, and will continue to do so; therefore, continuing to treat the CMAE costs as flow-through will not have any impact on FEI's efforts and ability to be cost efficient. As explained in the CMAE Budget Reviews filed in the Annual Reviews during the Current MRP term, the increases to costs are primarily driven by inflation (both labour and non-labour inflation). FEI's CMAE cost is small in comparison to FEI's overall O&M (i.e., approximately $6 million in 2024 compared to total approved net O&M of $305 million) and compared to the total gas costs it manages (approximately $940 million in 2023) and mitigation savings it achieves (approximately $311 million in 2023). There is little opportunity to find efficiencies within this small cost area. For instance, the staffing requirements and other resource requirements have generally remained unchanged from year to year. As previously noted, FEI endeavours to limit increases to the annual CMAE to be within inflation.

Variations in the actual CMAE costs each year (beyond inflationary impacts) are primarily related to external legal and consulting costs which can fluctuate year-to-year depending on the degree of FEI's involvement in upstream regulatory matters (and the complexity of the matters). FEI utilizes external legal and consultants to help respond to upstream proponents' applications before the Canadian Energy Regulator or the Federal Energy Regulatory Commission (United States). FEI's costs related to upstream proponent applications can vary from year to year and from forecast to actual for any given year. For example, as shown in Table 1 of Appendix C4-3 to the Application, in 2018 the Actual CMAE costs were higher than the years' 2019-2022. The higher costs were primarily due to one-time incremental costs related to the Enbridge T-South incident, which required the use of additional external resources.

29.0 Reference: PROPOSED RATE SETTING FRAMEWORK – ANNUAL CALCULATION OF THE REVENUE REQUIREMENT

Exhibit B-1, Section C4.4.1, pp. C-149 to C-150; FEI 2024 Annual Review of Delivery Rates Decision, p. 11

FEI – Methodology for Forecasting Late Payment Charges

On page 11 of the FEI 2024 Annual Review of Delivery Rates Decision, the BCUC directed FEI to evaluate the impacts of alternative methodologies for forecasting Late Payment Charges, including forward-looking approaches and backward-looking approaches as part of its next revenue requirements application.

On page C-150 of the Application, FortisBC states:

> FortisBC also considered a forward-looking approach such as using a percentage of the projected revenue for the forecast year to forecast the late payment charges, as suggested by the FEI 2024 Annual Review Decision. However, FortisBC could not find an observable trend between the actual late payment charges and the projected revenue that would suggest this method is reasonable.
>
> Considering the above, FortisBC considers its current forecasting approach for late payment charges continues to be the most reasonable. […]

29.1 Please confirm whether FortisBC has considered alternative forward-looking and backward-looking methodologies for forecasting Late Payment Charges (i.e. aside from the forward-looking approach based on projected revenue as mentioned above).

29.1.1 If yes, please explain what methodologies were considered by FortisBC and why they were rejected.

29.1.2 If no, please explain how FortisBC has met the BCUC's directive from the FEI 2024 Annual Review of Delivery Rates Decision for forecasting FEI's Late Payment Charges as referenced in the preamble above.

Response:

FortisBC considers it has met the BCUC directive from the FEI Annual Review for 2024 Delivery Rates Decision as it has considered both forward- and backward-looking approaches to forecasting late payment charges.

The options for backward-looking approaches are essentially varying the number of years of actual historical results used in determining the upcoming year's forecast, as well as either including or excluding the most recent year of projected results. FortisBC's long-standing approved approach to forecasting late payment charges prior to the Annual Reviews for 2023 Rates was to use the most recent three years of actual results. However, due to the impact of the COVID-19 pandemic and other factors, which resulted in a departure from the level of actual late payment charges historically experienced, FortisBC proposed (and was approved) to revise the approach to include only the most recent full year of actual results and the projected results from the current year.

While FortisBC did not evaluate using the average of two previous years of actuals in the Application, this is another backward-looking option that could be used, though FortisBC does not consider it would be a superior method to FortisBC's proposed approach. For FEI, using the average of two previous years of actuals would have produced a 2023 Forecast of $3.137 million, which is significantly lower than 2023 Actuals (i.e., $3.863 million). However, FortisBC considers that using two years of actuals (or a combination of two years of actuals and the most recent year of projected results) could also be used. FortisBC would not be supportive of using more than three years of actual historical results, because historical results older than three years would likely be less reflective of current and forecast expectations of late payment charges.

FortisBC considered the forward-looking approach suggested by the BCUC in the FEI Annual Review for 2024 Delivery Rates Decision (i.e., FEI performed a linear regression between revenue/customer bills and late payment charges) but there was no observable trend between late payment charges and revenue or late payment charges and customer bill sizes that would suggest these methods would be a reasonable approach to forecasting late payment charges. There are various reasons behind late payment charges, and it depends on the circumstances of the individual customers. Therefore, FortisBC considers that using just one or two parameters, such as revenue or customer bill size, to forecast late payment charges would not produce a reasonable result. FortisBC is not aware of any other forward-looking approaches that would be suitable for the purposes of forecasting annual late payment charges.

Regardless of the method used, it is expected that variances in late payment charges will occur and FortisBC considers its proposed approach to be reasonable. Using a backward-looking approach appropriately balances the desire for accuracy with the requisite level of effort. Late payment charges are only one component of Other Revenue, which is only a small component of the overall revenue requirement subject to earnings sharing. As Tables C4-5 and C4-6 of the Application show, variances between actual and forecast late payment charges have been both positive and negative, indicating that there is no bias in results being created by the method. Further, the use of the backward-looking approach is simple and grounded in recent historical actual/projected results, which FortisBC considers to be more appropriate than attempting to assign a correlation between projected revenue or customer bills (or other trends in revenue or customer activity) where none has been identified.

Further, on page C-149 of the Application, FortisBC states:

> The current forecasting approach, which uses the most recent information available, will ensure the latest upward or downward trends in the late payment charge revenue is accounted for. […] [*Emphasis added*]

29.2 Please discuss whether an alternate backward-looking approach to forecasting Late Payment Charges (such as using previous two years' or previous three years' actual Late Payment Charges) was considered by FortisBC. As part of the response, please discuss whether such an approach would be based on "most recent information" as well as satisfy the BCUC's directive from the FEI 2024 Annual Review Decision.

Response:

Please refer to the response to BCUC IR1 29.1.

30.0 Reference: PROPOSED RATE SETTING FRAMEWORK – ANNUAL CALCULATION OF THE REVENUE REQUIREMENT

Exhibit B-1, Section C4.13.2, Table C4-7, p. C-155; Current MRP Application,

Exhibit B-1, Section C4.13, Table C4-1, p. C-118

Flow-Through Deferral Account

Table C4-7 on page C-155 of the Application shows FortisBC's proposed treatment of variances in revenue requirement items from forecast for the Rate Framework.

Table C4-1 on page C-118 of Exhibit B-1 of the Current MRP Application proceeding showed FortisBC's proposed treatment of variances in revenue requirement items from forecast for the Current MRP.

30.1 Please complete the following table using the information in Table C4-7 of the Application, Table C4-1 of Exhibit B-1 to the Current MRP Application, and additional analysis provided by FortisBC.

	Current MRP Application (Table C4-1 of Exhibit B-1 to the Current MRP)		Proposed Rate Framework (Table C4-7 of the Application)		Change in treatment? (Y/N)	Reason for change or reason why no change is needed
Item	FEI	FBC	FEI	FBC		
Delivery Revenues (FEI):						
Residential and commercial use rate variances	Revenue Stabilization Adjustment Mechanism (RSAM)	N/A	RSAM	N/A	N	
Customer variances	Flow-through deferral	N/A	Flow-through deferral	N/A	N	
…						

<u>Response:</u>

Besides including additional clarification on the flow-through treatment for CPCN-approved projects or approved exogenous costs which are identified in Table 1 below, there are no changes in terms of items or change in treatment between the proposed Rate Framework and the Current MRP.

	2020-2024 MRP Application (Table C4-1)		2025-2027 Rate Framework Application (Table C4-7)		Change in treatment? (Y/N)	Reason for change or reason why no change is needed
Item	FEI	FBC	FEI	FBC		
Delivery Revenues (FEI):						
Residential and commercial use rate variances	RSAM	N/A	RSAM	N/A	N	Refer to Note 1
Customer variances	Flow-through deferral	N/A	Flow-through deferral	N/A	N	Refer to Note 2
Industrial and all other revenue variances	Flow-through deferral	N/A	Flow-through deferral	N/A	N	Refer to Note 2
Revenues and Power Supply (FBC):						
Revenue variances	N/A	Flow-through deferral	N/A	Flow-through deferral	N	Refer to Note 2
Power supply variances	N/A	Flow-through deferral	N/A	Flow-through deferral	N	Refer to Note 2
Gross O&M:						
Index-based O&M variances	Subject to earnings sharing	Subject to earnings sharing	Subject to earnings sharing	Subject to earnings sharing	N	Refer to Note 3
BCUC fees variances	BCUC variances deferral	BCUC variances deferral	BCUC variances deferral	BCUC variances deferral	N	Refer to Note 1
Pension & OPEB variances	Pension/ OPEB variances deferral	Pension/ OPEB variances deferral	Pension/ OPEB variances deferral	Pension/ OPEB variances deferral	N	Refer to Note 1
All other O&M variances	Flow-through deferral	Flow-through deferral	Flow-through deferral	Flow-through deferral	N	Refer to Note 2
Capitalized Overhead:						
Capitalized Overhead variances	No variance	No variance	No variance	No variance	N	N/A
Depreciation and Amortization:						
Depreciation rate variances	No variance	No variance	No variance	No variance	N	N/A
Depreciation on Clean Growth Projects	Flow-through deferral	Flow-through deferral	Flow-through deferral	Flow-through deferral	N	Refer to Note 2

	2020-2024 MRP Application (Table C4-1)		2025-2027 Rate Framework Application (Table C4-7)		Change in treatment? (Y/N)	Reason for change or reason why no change is needed
Item	FEI	FBC	FEI	FBC		
Depreciation on CPCNs / Exogenous items	-	-	Flow-through deferral	Flow-through deferral	N	Consistent with the previously approved approach, the cost-of-service impact related to CPCN projects and exogenous costs have been afforded flow-through treatment. While not included in Table C4-1 of the 2020-2024 MRP Application, it has been added to this table for clarity.
Other depreciation variances	Subject to earnings sharing	Subject to earnings sharing	Subject to earnings sharing	Subject to earnings sharing	N	Refer to Note 3
Amortization of deferrals	No variance	No variance	No variance	No variance	N	N/A
Property Tax:						
Property tax variances	Flow-through deferral	Flow-through deferral	Flow-through deferral	Flow-through deferral	N	Refer to Note 2
Other Revenues:						
SCP mitigation revenues variances	SCP revenues deferral	N/A	SCP revenues deferral	N/A	N	Refer to Note 1
CNG/LNG recoveries variances	CNG/LNG recoveries deferral	N/A	CNG/LNG recoveries deferral	N/A	N	Refer to Note 1
Revenues from Clean Growth Projects	Flow-through deferral	Flow-through deferral	Flow-through deferral	Flow-through deferral	N	Refer to Note 2
Revenues from CPCNs / Exogenous items	-	-	Flow-through deferral	Flow-through deferral	N	Consistent with the previously approved approach, the cost-of-service impact related to CPCN projects and exogenous costs have been afforded flow-through treatment. While not included in Table C4-1 of the 2020-2024 MRP Application, it has been added to this table for clarity.
All other Other Revenue / income variances	Subject to earnings sharing	Subject to earnings sharing	Subject to earnings sharing	Subject to earnings sharing	N	Refer to Note 3

	2020-2024 MRP Application (Table C4-1)		2025-2027 Rate Framework Application (Table C4-7)		Change in treatment? (Y/N)	Reason for change or reason why no change is needed
Item	**FEI**	**FBC**	**FEI**	**FBC**		
Interest Expense/Cost of Debt:						
Interest on RSAM/ CCRA/ MCRA/Gas storage	Interest on RSAM/ CCRA/ MCRA/Gas storage	N/A	Interest on RSAM/ CCRA/ MCRA/Gas storage	N/A	N	Refer to Note 1
Interest rate variances	Flow-through deferral	Flow-through deferral	Flow-through deferral	Flow-through deferral	N	Refer to Note 2
Interest on Clean Growth Projects	Flow-through deferral	Flow-through deferral	Flow-through deferral	Flow-through deferral	N	Refer to Note 2
Interest on CPCNs / Exogenous items	-	-	Flow-through deferral	Flow-through deferral	N	Consistent with the previously approved approach, the cost-of-service impact related to CPCN projects and exogenous costs have been afforded flow-through treatment. While not included in Table C4-1 of the 2020-2024 MRP Application, it has been added to this table for clarity.
Other interest variances	Subject to earnings sharing	Subject to earnings sharing	Subject to earnings sharing	Subject to earnings sharing	N	Refer to Note 3
Income Tax:						
Income tax variances due to changes in tax rates / laws	Flow-through deferral	Flow-through deferral	Flow-through deferral	Flow-through deferral	N	Refer to Note 2
Income tax on Clean Growth Projects	Flow-through deferral	Flow-through deferral	Flow-through deferral	Flow-through deferral	N	Refer to Note 2
Income tax on CPCNs / Exogenous items	-	-	Flow-through deferral	Flow-through deferral	N	Consistent with the previously approved approach, the cost-of-service impact related to CPCN projects and exogenous costs have been afforded flow-through treatment. While not included in Table C4-1 of the 2020-2024 MRP Application, it has been added to this table for clarity.
Other income tax variances	Subject to earnings sharing	Subject to earnings sharing	Subject to earnings sharing	Subject to earnings sharing	N	Refer to Note 3

Notes to Table:

(1) No change in the treatment of variances in specific deferral accounts. Consistent with the Current MRP, specific deferral accounts are used to capture the variances for costs and expenditures that are re-forecast each year as part of the Annual Review process based on updated information.

(2) No change in the treatment of these variances. As approved in the Current MRP, the Flow-through deferral account will continue to capture the annual variances between the approved and actual amounts for those costs and revenues which are included in rates on a forecast basis, and which do not have a separately approved deferral account. This type of mechanism is used for non-controllable costs and revenues to mitigate customer risk by ensuring that customers pay actual costs in circumstances where the Company does not control the level of expenditures or revenues.

(3) No change in the treatment of these variances. As approved in the Current MRP, these variances will continue to be subject to the earnings sharing mechanism, which aligns with customer and Company interests as both parties share the risks and benefits.

G. PROPOSED RATE SETTING FRAMEWORK – FEI CLEAN GROWTH INNOVATION FUND

31.0 Reference: PROPOSED RATE SETTING FRAMEWORK – FEI Clean Growth Innovation Fund (CGIF)

Exhibit B-1, Section C5.2.2, pp. C-160 to C-161, Section C5.2.4, p. C-169 to C-170, Section C5.3.2, p. C-174

Unused 2020 CGIF Funds and Proposed 2025 CGIF Rider

On page C-161 of the Application, FortisBC proposes to return the projected $5.810 million ending balance in the CGIF deferral account to FEI customers through amortization of the deferral account over one year (i.e. in 2025). FortisBC notes that this is consistent with the Current MRP Decision, which directed FEI to return any unused balance in the CGIF deferral account at the end of the Current MRP term through a disposal mechanism subject to approval by the BCUC.

On pages C-169 to C-170 of the Application, FortisBC discusses an overall increase in innovations related to the energy transition that has increased the opportunities available to use the CGIF funding over the Current MRP term. FortisBC states that to build on the momentum gained during the Current MRP term, there is an opportunity for the CGIF to expand support for innovative technology pilots, particularly as some of the innovative technologies supported by the CGIF approach commercialization.

31.1 Please provide the estimated 2025 bill impact for the average FEI customer of returning the projected $5.810 million ending balance in the CGIF deferral account to FEI customers through amortization of the deferral account over one year (i.e. in 2025).

31.1.1 Please provide the estimated administrative costs of returning the projected ending balance in the CGIF deferral to FEI customers and explain how those costs would be accounted for.

Response:

The delivery rate impact of returning the projected $5.810 million in the CGIF deferral account to FEI's customers in 2025 is a credit of approximately 0.70 percent when compared to the 2024 Approved delivery rates. Please refer to Table 1 below for an example of the 2025 bill impact to an average residential (RS 1), commercial (RS 2 and 3) and industrial (RS 5) customer.

Table 1: 2025 Bill Impact for the Average FEI Customer (RS 1, RS 2, RS 3, and RS 5)

	RS 1	RS 2	RS 3	RS 5
2025 Annual Bill Impact ($)	(3.33)	(12.98)	(147.78)	(694.14)

There are no additional administrative costs to return the projected ending balance in the CGIF deferral account to FEI's customers.

31.2 Please discuss the pros and cons of returning the projected $5.810 million ending balance in the CGIF deferral account to FEI customers through amortization of the deferral account over one year (i.e. in 2025) versus retaining that amount for future CGIF investments during the proposed term of the Rate Framework (e.g. impact to ratepayers, investment continuity, etc.).

Response:

FEI notes that its proposal to return the ending balance in the CGIF deferral account to customers in 2025 is in response to the BCUC's directive in the MRP Decision:[47]

> The Panel directs any used balance in the deferral account to be returned to customers at the end of the Proposed MRP term through a disposal mechanism subject to approval by the BCUC.

As such, FEI did not consider retaining the unused balance for the proposed term of the Rate Framework for investment continuity purposes.

However, irrespective of the BCUC's directive in the MRP Decision, FEI considers it most appropriate to return the ending balance in the CGIF deferral account to customers in 2025, as proposed in the Application, as FEI considers the estimated funding that FEI proposes to collect in the CGIF deferral account for the proposed Rate Framework term (i.e., approximately $5.2 million per year) will be adequate to fund innovative projects during the term and enable FEI to make actionable progress in the innovative areas described in Section C5 of the Application.

Returning the ending balance in the CGIF deferral account to customers in 2025 has the following advantages:

1. The credit amortization in 2025 will help to offset other revenue requirement pressures on delivery rates, thus reducing the overall rate increase to customers in 2025;
2. Given that the amounts were collected from customers over the 2020 to 2024 time period, returning the unused funds immediately in 2025 reduces intergenerational inequity issues; and
3. FEI will still have adequate funding during the proposed Rate Framework term through the continuation of the CGIF rider to fund innovation.

Retaining the unused balance in the CGIF deferral account to be used during the proposed Rate Framework term would have the advantage of increasing the funding available for potential

[47] MRP Decision and Order G-165-20, p. 156.

projects; however, for the reasons described above, FEI considers returning the funds in 2025 to customers to be the best approach.

On page C-174 of the Application, FortisBC states:

> FEI proposes to continue utilizing the innovation rider and to continue to collect $0.40 per month from FEI's customers' bills. Although this funding was in excess of requirements in the Current MRP, […] approved funding amounts steadily increased from 2020 to 2024. FEI expects this to continue now that the CGIF is an established source of funding. Portfolio approvals totalled $4.169 million in 2023 which came close to the $5.230 million in funding collected from customers through the existing rider in that year. In 2024, FEI is forecasting approved funding of $7.5 million which is expected to significantly exceed CGIF rate rider collections. FEI has also proposed to expand the scope of funding activities […] which will increase potential funding opportunities. The $0.40 per customer monthly rate rider would collect approximately $5.2 million in 2025, similar to the levels in 2023 and 2024. At the end of the Rate Framework, the unused balance in the deferral account will be returned to customers.

On page C-170 of the Application, FortisBC discusses its proposed evaluation criteria for the 2025 CGIF, including a criterion that is the energy cost mitigation potential for FEI customers.

31.3 If FEI did not have to return the projected $5.810 million ending balance in the CGIF deferral account, please discuss whether FortisBC would change its proposed 2025 CGIF Rider amount of $0.40 and provide the revised proposed amount. Please justify any revised proposed amount or explain why no revision would be needed.

Response:

As explained in the response to BCUC IR1 31.2, FEI considers returning the ending balance in the CGIF deferral account to customers in 2025 to be the most reasonable approach, as it is consistent with the BCUC's directive in the MRP Decision. However, if the BCUC Panel in this proceeding decided to vary the MRP Decision directive, FEI considers there to be two potential options, each with pros and cons.

Option 1: Continue the Existing Rider Amount

Under this option, FEI would retain the ending balance in the CGIF deferral account and maintain the CGIF rider at $0.40. The advantages to this approach are that more funding would be available during the Rate Framework term for innovation, and the rider amount would be consistent with the existing amount, which customers are accustomed to. The disadvantage is that the increased balance in the deferral account may not be spent (i.e., there may not be an increase in the level of innovative projects seeking funding), which would result in a further balance accruing in the CGIF deferral account for three more years.

Option 2: Reduce the CGIF Rider

Under this option, FEI would retain the ending balance in the CGIF deferral account but reduce the CGIF rider so the amount of annual funding (when including the carried over ending balance from the Current MRP term) would still average out to approximately $5.2 million per year. This would reduce the CGIF rider from $0.40 to $0.25 per month per customer (based on the current forecast of the 2025 average non-bypass customer count and the current projection of the 2024 ending balance in the CGIF of $5.810 million).[48] The advantage to this approach is that customers will be paying a lower rider each year. The disadvantage is that the same outcome could essentially be achieved by returning the ending balance in the CGIF deferral account to customers immediately in 2025, which has the advantages described in the response to BCUC IR1 31.2 and allows for the rider to continue at the current, accepted level.

31.4 Please discuss the funds needed for FEI to make actionable progress towards meeting the targets for the CleanBC Roadmap to 2030 and the GHGRS for the proposed term of the Rate Framework.

31.4.1 If the funds needed are significantly different from the funds that would be obtained through the proposed $0.40 2025 CGIF rate rider, please explain how FEI will address the gap.

31.4.2 Please discuss whether changes to the evaluation criteria or an increase in the amount of the rate rider may help address the gap, if any.

Response:

The level of funding approved by the BCUC for the Current MRP term has allowed FEI to make actionable progress towards accelerating the adoption of clean technologies, which supports CleanBC's goal of decarbonization.

FEI is recommending continuing with the CGIF and its existing level of funding for the term of the Rate Framework. FEI considers the existing level of annual funding from the $0.40 per customer per month CGIF rider to strike a reasonable balance between rate impacts to FEI's customers and supporting FEI's ability to advance the adoption of innovative technologies that will help it reduce GHG emissions, while optimizing the use of its gaseous energy delivery system for the

[48] FEI expects to file for approval of interim 2025 delivery rates in the fourth quarter of 2024, which will include updated forecasts for the 2025 average customer count and projected 2024 ending balance of the CGIF deferral account.

benefit of its customers. Therefore, based on FEI's experience administering the fund and the funding requests it has received, FEI considers that the estimated $5.2 million per year – which would be collected through the proposed $0.40 CGIF rider – will provide adequate funding for the Rate Framework term.

As explained in Section C5.3.1 of the Application, FEI is proposing enhancements to the CGIF to expand the scope of funding to address other impacts of climate adaptation and the energy transition. This enhanced scope will allow FEI to support technologies which are vital to BC's clean energy transition, will help achieve performance breakthroughs and cost reductions on emerging technologies, and will provide greater access to cost effective, safe, and resilient solutions for FEI's customers. FEI has accordingly proposed one addition to the 2020 CGIF evaluation criteria – energy system resilience benefits, as well as some amendments to the evaluation criteria, as explained in Section C5.3.1 of the Application. Based on the revised criteria, FEI is recommending that the CGIF expand its focus to help address the following additional categories: (1) Cost Mitigation (investment in technological solutions that reduce costs for customers); and (2) Resilience (investment in technological solutions that will improve the resiliency of the gas delivery systems in response to adverse climatic events).

32.0 Reference: PROPOSED RATE SETTING FRAMEWORK – FEI CGIF

Exhibit B-1, Section C5.3, pp. C-170 to C-171

Proposed Enhancements to the 2025 CGIF

On page C-170 of the Application, FEI states that the clean energy transition is well underway and the need for innovation and technology solutions is becoming increasingly important to achieve climate and energy goals.

On page C-171 of the Application, FEI recommends that the 2025 CGIF focus on funding innovations that will help to address seven application categories which are key to the clean energy transition, specifically: production, distribution, end-use, cost mitigation, resilience, carbon capture and storage, and generalized low-carbon.

32.1 Please discuss whether the proposed 2025 CGIF remains a suitable method of funding each of the seven application categories as noted in the preamble above. Please explain why such activities and related costs would not be better treated through inclusion in FEI's O&M expenses (formula, forecast, or both) during the proposed term of the Rate Framework given the increasing importance of innovation and technology solutions in achieving climate and energy goals.

Response:

The CGIF and rider remain the most suitable method of funding each of the seven application categories compared to embedding a funding amount in the Base O&M or through forecasting the amounts annually in O&M and flowing through the variances between forecast and actual amounts. Collecting a monthly rider and recording the amounts in the deferral account ensures a consistent and predictable level of funding is being collected, which is important when FEI is considering funding applications, and it enables FEI to manage the variability in the timing and amount of when funding is requested.

The key distinction in the nature of the funding associated with the CGIF and FEI's formula and forecast O&M is the timing of the spending. As discussed in past Annual Reviews and in the Application, the distribution of CGIF funding typically occurs over multiple years and can be lumpy. The funding is therefore more akin to capital expenditures than to O&M. This is an important consideration when determining the best approach to funding the CGIF. For example, if FEI funded the CGIF through formulaic O&M, the variances between formula and actuals each year would impact the earnings sharing calculation, which would likely result in some years where large amounts of "savings" would be experienced in O&M and other years where large amounts of "over-spending" would occur. Similarly, if FEI funded the CGIF through forecast O&M, the annual variances between forecast and actual amounts would be flowed through to customers in the following year. Either of these approaches creates unnecessary swings in the annual revenue requirement (and therefore rates).

Continuing the current approach to funding innovation through the monthly CGIF rider and deferral account benefits both customers and the parties seeking innovation funding. The $0.40

per customer monthly rider is a consistent amount on the customer bill, as opposed to creating variances between actual and formula/forecast O&M which may result in unnecessary swings in the annual delivery rates, and by capturing the funding in the deferral account it ensures that the funds can be distributed to projects when needed over multiple years. The CGIF deferral account provides a transparent and simple way to track and isolate innovation-related expenditures. Additionally, FEI has proposed that any unspent funds in the CGIF deferral account be returned in full to customers at the conclusion of the Rate Framework term.

32.2 Please explain how FEI differentiates between clean energy innovation initiatives funded by ratepayers and clean energy innovation initiatives funded by shareholders given the need for FEI's shareholders to adapt/invest in a changing operating environment (i.e. low carbon economy or gas system infrastructure resilience).

32.2.1 Please discuss whether both FEI's ratepayers and shareholders should contribute to the seven categories of the proposed 2025 CGIF, and if so, the appropriate percentage and dollar amount that would be funded by both parties.

Response:

As a regulated utility, in accordance with the regulatory compact and the Fair Return Standard, FEI has the right to a reasonable opportunity to recover its prudently incurred costs and to earn its allowed return on investment; therefore, activities that FEI undertakes on innovation should be recoverable from customers. While FEI undertakes various activities to respond to the energy transition (for example, its Clean Growth Initiatives), only innovation-related funding comes through the CGIF rider.

The purpose of the CGIF is to accelerate the pace of clean energy innovation, to achieve performance breakthroughs and cost reductions, and to provide cost effective, safe, reliable and resilient solutions for FEI's customers. These goals directly benefit FEI customers and British Columbians in general; the goals do not directly benefit FEI's shareholders. FEI's customers, who consume the Company's products and services on a daily basis, receive the direct benefits of innovation. Shareholders benefit indirectly and over the long term to the extent that FEI's assets remain in use, allowing shareholders the opportunity to earn a fair return on their investment. In this respect, like all other utility investments, the shareholder must provide the requisite equity investment for any utility assets, including those resulting from innovation.

32.3 Please discuss the similarities and differences, if any, between FEI's proposed 2025 CGIF to any innovation funds in other jurisdictions funded by either ratepayers and/or shareholders.

Response:

Although FEI did not complete a comprehensive review of innovation funds in other jurisdictions for this Application, FortisBC's evidence in the 2020-2024 MRP Application included a jurisdictional study of customer funded innovation funds[49] that can be used as a reference to respond to this question. Please refer to Attachment 32.3 for a copy of this study.

In addition to the examples provided in that study, FEI reviewed the following other more recent examples of customer funded innovation funds, summarized as follows:

- **SoCalGas Research, Development and Demonstration (RD&D) Fund:**[50] This ratepayer funded program was approved by the California Public Utilities Commission (CPUC) to support projects along the commercialization pathway with the goals of saving energy, reducing GHG emissions, improving air quality, and increasing energy safety, reliability, and affordability. The CPUC's decision[51] states that this fund "supplements other R&D projects by government agencies and other groups". Further, the CPUC's decision determined that costs for each project should be forecast based on a "zero-based methodology"[52] and that "the authorized level of funding is subject to a one-way balancing account treatment such that any unspent funds are to be returned to ratepayers at the end of each general rate case cycle".
- **Enbridge Gas' Proposed Energy Transition Technology Fund (ETTF):**[53] This proposed fund would prioritize technology innovation initiatives that reduce GHG emissions, provide safe, reliable, and affordable low-carbon options for customers, are beyond the needs already funded through demand side management, are compliant with industry codes and standards, and range from pre-commercial to commercial applications.[54] The monthly bill impact of the proposed ETTF would be $0.11 per customer. Enbridge Gas is proposing a new variance account to capture the variance

[49] Please refer to Appendix C6-1 in FortisBC's 2020-2024 MRP Application.

[50] https://www.socalgas.com/sites/default/files/2022_SoCalGas_RDD_Annual_Report.pdf; "In 2022, SoCalGas RD&D supported 339 RD&D projects and distributed $13,430,264 to projects across the entire gas value chain in California. In executing these projects, SoCalGas collaborated with many of the most forward-thinking research consortia, universities, national labs, public agencies, and entrepreneurs in the nation and the world. Collectively, these organizations provided significant leveraged funding as well as invaluable guidance, review, technical expertise, and access to resources and infrastructure".

[51] CPUC's Decision 19-09-051; dated September 26, 2019.

[52] Zero-based method is a form of budgeting in which all expenses must be justified for each new period. This method is often used when there is not historical data for the budgeted expense.

[53] EB-2021-0111 – Phase 2 Evidence Update: "Enbridge Gas proposes the ETTF to advance and accelerate research, development, demonstration, and commercialization of low carbon technologies."

[54] EB-2021-0111 – OEB Staff Interrogatories: "Enbridge Gas requests approval of an Energy Transition Technology Fund (ETTF) and provides a rationale and description of the proposed ETTF".

between the actual amounts collected by the ETTF rate rider and actual costs incurred for ETTF initiatives, and to review the balance in this account in its next rebasing application.

FEI's 2025 CGIF is similar to other utilities' innovation funds in that the funding programs focus on supporting the commercialization and deployment of new technologies for the energy sector, and there is a focus on collaboration and partnership with researchers, industry, and other stakeholders to advance these projects. Further, these funds are often designed to fill in the innovation gap in areas that are not already covered by other funding. For instance, similar to FEI, Enbridge Gas already has a Research and Innovation Fund (RIF) in its Demand-Side Management (DSM) plan that provides some funding support for energy conservation-related research and development. The newly proposed ETTF therefore focuses on other important GHG emissions-reducing elements of the energy transition like renewable gases, carbon capture utilization and storage and end-use innovations that are outside of its DSM framework.

In terms of differences, and as discussed in Concentric's report, funding levels for each innovation fund may vary across jurisdictions and between utilities although it is hard to compare the funding levels for various programs as their scope may vary as well:[55]

> Funding levels for innovation vary across the jurisdictions we have examined. The most recent data are summarized below in Table ES-2. These programs span a range from $0.72 to $14.12 per customer, or an average of $6.55. While virtually all policymakers and regulators express concern for costs, they also recognize the potential benefits … Where energy policy dictates a shift in the status quo, funding levels would be expected to be higher to facilitate the transition, and targets comparable to the CA-NY-MA range may be appropriate.

Further, FEI's proposed 2025 CGIF might be different from other innovation funds in terms of specific focus areas since these are driven in part by regional energy differences and government policy priorities.

55 FEI's CGIF funding level per customer is currently at $4.80 (40 cents per month per customer).

H. PROPOSED RATE SETTING FRAMEWORK – SERVICE QUALITY INDICATORS

33.0 Reference: PROPOSED RATE SETTING FRAMEWORK – SERVICE QUALITY INDICATORS (SQIs)

Exhibit B-1, Section C6.3.4, Table C6-6, pp. C-185 to C-186, Appendix C6-1 (FEI's SQI Report), Table 18, pp. 21–22

FEI – Energy Transition Informational Indicators

On pages C-185 to C-186 of the Application, FortisBC proposes to introduce four energy transition informational indicators for FEI as listed in Table C6-6 which is reproduced below and states they align with the pillars of the Company's Clean Growth Pathway to 2050.

Table C6-6: FEI Energy Transition Informational Indicators

Performance Measure	Description	2020 Results	2021 Results	2022 Results	2023 Results
Scope 1 Emissions	Total direct GHG emissions from FEI owned or controlled sources ($MtCO_2e$)	0.14	0.15	0.24	0.14[130]
Renewable and Low Carbon Energy Supply Volume	Acquired annual Renewable Gas and Low Carbon Energy supply (TJ)	306	790	2,295	2,778
Natural Gas for Transportation Volume	Total gas consumed by CNG and LNG customers (TJ)	2,413	2,652	3,077	3,117
Demand Side Management Energy Savings	Measure of lifetime gas savings from conservation and energy management programs (TJ)[131]	7,937	12,304	10,811	10,104

On page C-185 of the Application, FortisBC states:

> […] FEI considers it appropriate to classify the energy transition indicators as informational because of the rapidly evolving and uncertain policy and environment, trajectory of development for low-carbon technologies, and changing market circumstances which are largely outside of FEI's control but will nonetheless impact FEI's progress in the energy transition.

On pages C-177 to C-178 of the Application, FortisBC states:

> […] An SQI works well as an informational indicator when there are factors outside of the Companies' control that may influence the metric's performance. […] Another consideration when determining whether an SQI should be an informational indicator is the amount of historical performance data available, as without an adequate amount of historical data available to identify trends, it is challenging to establish an appropriate benchmark or threshold. As a result, informational indicators are generally more directional in nature, providing a high-level view into key business functions.

33.1 Given that historical data is available for FEI's energy transition indicators, please discuss whether FEI considers classifying the energy transition indicators as informational is sufficient. Please elaborate on why or why not.

Response:

FEI considers it sufficient to classify the energy transition indicators as informational only. Providing energy transition informational indicators offers a number of advantages, including:

- While the energy transition informational indicators are non-traditional and do not conform to the criteria for the design and selection of SQIs listed in Table C6-1 of the Application, they will show FEI's progress in a number of areas central to lowering emissions and assist the BCUC and interveners in better understanding how FEI is addressing the energy transition;
- Reporting on the informational indicators will provide transparency, a level of accountability, and an incentive for FEI to progress these indicators;
- Including informational indicators is consistent with how other utilities disclose and report their sustainability performance and energy transition impacts; and
- Informational indicators are easy to understand and implement, and do not require the development of an incentive framework for these metrics.

The disadvantage of this approach is that informational indicators do not have the added incentive to perform that could potentially come from having penalties attached to the indicators. However, adding benchmarks and thresholds to these indicators, as suggested in BCUC IR1 33.3, would have significant disadvantages which outweigh any benefit.

Given the constraints imposed by factors that are outside of FEI's control, it would not be just or reasonable to penalize FEI for failure to achieve levels under these indicators. While FEI expects to positively influence outcomes and create benefits for customers in these areas, it does not have control over factors such as:

- the policy and regulatory environment governing its activities, which requires periodic changes and adjustments to enable FEI's emissions-reducing activities;
- the regulatory approvals required to support expenditures in these areas;
- the pace of development and adoption of low-carbon technologies, including technologies like gas heat pumps and dual fuel heating systems identified in FEI's 2024-2027 DSM Plan; or
- changing market dynamics and consumer preferences that influence customer choices.

Because of these factors outside of the Company's control, the proposed energy transition indicators may not fully reflect the efforts undertaken by FEI and its progress towards advancing the energy transition. It would therefore be unfair to penalize FEI for not achieving a specified target for these metrics.

More generally, penalties are not appropriate for these metrics, which measure FEI's progress in achieving certain beneficial outcomes for the energy transition which will require significant investment. In the context of service quality-related indicators, a penalty-only regime is reasonable as SQIs provide the base line service levels that FEI is expected to maintain, to ensure that FEI does not compromise service quality to achieve efficiencies. Furthermore, penalties for these metrics would be duplicative of government regulations in place that seek similar emissions reduction outcomes (e.g., Carbon Tax, Zero Carbon Step Code, BC Low Carbon Fuel Standard, etc.). Instead, the energy transition indicators represent metrics that FEI should be incented to improve and which government has supported (e.g., via the *Greenhouse Gas Reduction (Clean Energy) Regulation* or DSM Regulation). In this context, an incentive-only framework is the only structure that makes sense.

As FEI has discussed in response to BCUC Panel Supplemental IRs 5, 6 and 8, if the BCUC is interested in exploring performance targets and incentives, FortisBC could file a proposed set of incentives in a standalone application or as part of a second phase to this proceeding. The primary benefit of this option is that, subject to the achievability of the targets and appropriateness of the incentives, targeted incentives could further incent progress towards decarbonization. However, FortisBC notes that the current policy uncertainty may continue to pose challenges in designing appropriate targets, as there is a risk that the target (or incentive) could become misaligned as policy changes occur, requiring periodic review and adjustment. In addition, there would be further regulatory process required to develop the targeted incentive framework.

33.2 Please elaborate on the extent to which FEI considers the energy transition indicators proposed in Table C6-6 to be largely outside of or within its control.

<u>Response:</u>

Please refer to the response to BCUC IR1 33.1.

33.3 Please discuss the advantages and disadvantages of classifying the proposed energy transition indicators as informational as opposed to having benchmarks and thresholds for the proposed term of the Rate Framework.

<u>Response:</u>

Please refer to the response to BCUC IR1 33.1.

33.4 In the event that the proposed energy transitions indicators were not treated as only informational for the Rate Framework, please state the benchmark and threshold values that FEI would propose for each energy transition indicator. As part of the response, please explain (i) how each value was calculated; (ii) how it represents a reasonable target for the proposed term of the Rate Framework; and (iii) how it will result in actionable progress towards meeting 2030 and 2050 targets.

Response:

For the reasons discussed in the response to BCUC IR1 33.1, establishing a benchmark and threshold for the proposed energy transition informational indicators would not be reasonable or appropriate. Instead, these metrics represent areas that would provide an appropriate basis for targeted incentives. As discussed in the response to BCUC Panel Supplemental IR 8, if ordered, FortisBC would propose a second phase to the regulatory review process to define targeted incentives, including the refinement of the incentive principles, definition of performance expectations, establishment of achievable targets, and establishment of appropriate incentives.

33.5 Please provide, in a similar format to Table C6-6 of the Application, historical data on the overall GHG emissions from all customers for each year from 2020 through 2023.

Response:

Please refer to the following table for the total customer GHG emissions from 2020 through 2023.

	2020	2021	2022	2023
Total Customers GHG Emissions (M tCO2e)	11.0	11.5	11.6	10.6

Note to table:

Value assumes IPCC 5th Assessment and GHG emission factor for end use residential combustion. Information specific to GHG emissions from marine vessels is not available and as such, a generic combustion emission factor has been adopted in its place.

33.5.1 Please explain whether FEI would consider an additional SQI focused on overall emissions from all customers.

33.5.1.1 Please propose a benchmark and threshold value for such an indicator. As part of the response, please explain (i) how each value was calculated; (ii) how it represents a reasonable target for the proposed term of the Rate Framework; and (iii) how it will result in actionable progress towards meeting 2030 and 2050 targets.

33.5.1.2 If FEI does not believe such an indicator would be an appropriate SQI, (i) please explain why; and (ii) please discuss whether FEI would be amenable to reporting this information outside of SQIs (e.g. as an appendix to Annual Review applications) for the proposed term of the Rate Framework.

Response:

While FEI reports overall Scope 1 and 2 GHG emissions in its annual Sustainability Report, FEI only reports Category 11, Scope 3 emissions, which are the emissions related to natural gas transmitted and delivered under certain third-party market contracts and related to supplied natural gas used by customers. These emission levels change from year to year due to many factors which are difficult to isolate, including by factors such as the weather that are outside of FEI's control. Thus, as discussed in more detail in the response to BCUC IR1 33.1, adding an SQI with a benchmark and threshold for such a metric would not be reasonable.

Further, adding an informational indicator for these emissions would divert focus away from other important topics relevant to the annual rate-setting processes and FEI's activities. While FEI considered adding an informational indicator for Category 11 Scope 3 emissions, it ultimately concluded that it would be more appropriate and useful to add informational indicators in areas where its activities positively impact Category 11 Scope 3 emissions, such as FEI's investments in renewable gas or DSM, and where FEI has greater influence.

On pages 21 to 22 of FEI's SQI Report, FortisBC states:

> FEI is displacing conventional natural gas with renewable and low-carbon gases to lower customers' GHG emissions. FEI continues to increase its supply of renewable natural gas and explore the potential of low-carbon gases (such as hydrogen). The table below provides a summary of FEI's most recent historical renewable and low carbon gas supply volumes.

Table 18: Renewable and Low Carbon Energy Supply

Description	2020	2021	2022	2023
Acquired annual Renewable and Low Carbon Energy supply (TJ)	306	790	2,295	2,778

33.6 Please provide a further breakdown of Table 18 by type of renewable and low carbon energy supply (e.g. RNG, hydrogen, etc.).

Response:

The quantities in Table 18 are all renewable natural gas (RNG); FEI did not acquire any other types of low carbon energy supply in those years.

33.7 Please provide, in a similar format to Table C6-6 of the Application, historical data on the percentage of FEI's assets that can accommodate hydrogen delivery for each year of 2020 to 2023. Please include additional columns in the table for the forecast percentage of FEI's assets that can accommodate hydrogen delivery for each year of 2025 to 2027.

33.7.1 Please explain whether FEI would consider an additional SQI that monitors the percentage of its assets that can accommodate hydrogen delivery.

33.7.1.1 Please propose a benchmark and threshold value for such an indicator. As part of the response, please explain (i) how each value was calculated; (ii) how it represents a reasonable target for the proposed term of the Rate Framework; and (iii) how it will result in actionable progress towards meeting 2030 and 2050 targets.

33.7.1.2 If FEI does not believe such an indicator would be an appropriate SQI, (i) please explain why; and (ii) please discuss whether FEI would be amenable to reporting this information outside of SQIs (e.g. as an appendix to Annual Review applications) for the proposed term of the Rate Framework.

Response:

FEI is unable to provide the requested information at this time. FEI, in collaboration with other stakeholders, is currently undertaking the British Columbia Gas System Hydrogen Blending Study and Technical Assessment project, which will allow FEI to better understand the readiness and physical limitations of the existing gas system with regard to hydrogen blending delivery. FEI expects the study to be complete in 2027 and will assess at that time whether an SQI tracking hydrogen deployment is reasonable and appropriate.

34.0 Reference: PROPOSED RATE SETTING FRAMEWORK – SQIs

Exhibit B-1, Section C6.3.1, p. C-183, Section C6.4.1, p. C-188, Appendix B2-3 – Stakeholder Communications, p. 48; FBC 2024 Annual Review of Rates, Exhibit B-2, Section 13.2, p. 124, Table 13-3; Current MRP Decision, Table 25, p. 88

FBC – All Injury Frequency Rate (AIFR)

On page C-183 of the Application, FortisBC states that during its November 2023 consultation session, it discussed the difference between leading and lagging safety indicators. FortisBC further explained that it was exploring an option to introduce a leading safety indicator to enhance its reporting on safety, as FEI and FBC currently report on the AIFR, which is a lagging indicator, and that stakeholders were generally supportive of the concept.

Further on page C-183 of the Application, FortisBC states that it will continue to examine and develop a leading safety indicator during the term of the Rate Framework and will propose a suitable leading indicator either during the Rate Framework (as part of the Annual Review process) or subsequent to the conclusion of the proposed three-year term of the Rate Framework.

In Appendix B2-3, on page 48 of the FortisBC 2025+ Rate Setting Framework Workshop Presentation, FortisBC provides key attributes of leading versus lagging indicators, including a key attribute that lagging indicators “can drive unintended behaviors.” Additionally, FortisBC states that a balanced view of the effectiveness of safety systems and programs uses both leading and lagging indicators.

34.1 Please clarify, with rationale, whether FortisBC is planning to explore the use of both leading indicators and lagging indicators for safety reporting in the future to provide a balanced view of the effectiveness of its safety systems and programs as stated in the preamble.

Response:

Confirmed. As outlined on page C-183 of the Application, FortisBC recognizes the benefit of measuring both leading and lagging indicators to provide a balanced view of overall safety performance. FortisBC is proposing to continue to report on the All Injury Frequency Rate (AIFR), which is a lagging indicator, and FortisBC is planning to explore potential leading indicators for safety reporting in the future to provide more predictive (leading) indicators of how the Companies’ safety systems and programs are performing.

34.2 Please elaborate on what FortisBC means by its statement that lagging indicators drive "unintended behaviors".

<u>Response:</u>

As discussed in Section C6.3.1 of the Application, lagging indicators measure what happened after the fact (i.e., outcomes) and can alert the Companies to a failure in the safety system, or to the existence of an uncontrolled hazard, following an event. However, lagging indicators, such as the AIFR, could drive unintended behaviors; for example, if safety systems and processes are perceived to be working well due a lack of reportable incidents even though there are in fact opportunities to improve safety. Thus, leading indicators, which attempt to measure the presence of safety and safe behaviors, can be a useful complement to lagging indicators.

Another unintended behavior associated with lagging indicators, such as the AIFR, is a tendency to focus on high frequency, low consequence incidents due to their impact on the lagging measure. However, this can divert focus away from the prevention of lower frequency, but higher consequence incidents.

As discussed on page C-183 of the Application, FortisBC is in the process of exploring adding a leading indicator to complement the existing Safety SQIs, with the intent of further strengthening the Companies' safety management systems.

On page C-188 of the Application, FBC provides Table C6-8, showing FBC AIFR historical performances from 2020 through 2024, the approved benchmark and threshold for the current MRP term, and the proposed benchmark and threshold for the Rate Framework term. Further, FBC provides the actual 2023 performance of 1.84 for the AIFR three-year rolling average.

Further on page C-188 of the Application, FortisBC states:

> […] For the term of the Rate Framework, FBC proposes to lower the benchmark based on the average of the recent three-year rolling average of the annual results from 2021 to 2023. FBC accordingly proposes to lower the benchmark from 1.64 to 1.31. Additionally, <u>FBC proposes to increase the threshold from the currently approved 2.39 to 2.56, consistent with past practice</u>. [*Emphasis added*]

On page 88 of the Current MRP Decision, the BCUC provided Table 25, showing FBC's historical SQI performance during the PBR term (2014–2019) and its proposed metrics for the Current MRP term (2020–2024). Table 25 is reproduced in part below:

Table 25: FBC Historical SQI Performance, Benchmark and Threshold Levels[323]

Indicators with Benchmarks and Thresholds		Current Benchmark	Current Threshold	Proposed Benchmark	Proposed Threshold	2014 Results	2015 Results	2016 Results	2017 Results	2018 Results
Safety	Emergency Response Time - Calls responded to within two hours	>= 93%	90.6%	>=93%	90.6%	91%	92%	97%	93%	94%
Safety	All Injury Frequency Rate	<=1.64	2.39	<=1.64	2.39	2.58	2.52	1.97	1.27	1.28

On page 124 of Exhibit B-2 to the FBC 2024 Annual Review of Rates proceeding, FBC provided Table 13-3, showing annual historical AIFR results from 2015 to 2022 inclusive and the AIFR three-year rolling average of 1.76 for year-to-date June 2023.

34.3 Please explain how FBC determines when to adjust the benchmark and threshold levels for its SQIs.

<u>Response:</u>

FortisBC considers adjustments to SQI benchmarks and threshold levels when it prepares its rate framework applications. In reviewing the appropriateness of the performance ranges, FortisBC considers several factors, including the five factors listed in the 2014-2019 PBR Decision:[56]

- The variance that has been experienced in the benchmark historically;
- The historical trend in the benchmark;
- The level of the benchmark relative to the SQI levels achieved by other utilities, including utilities in other jurisdictions;
- The sensitivity of the benchmark to external factors such as weather or economic conditions; and
- The impact of lower SQI levels on the provision of reliable, safe or adequate service.

Ultimately, whether an adjustment is reasonable will depend on the specific circumstances related to each SQI. For example, FBC selected the initial benchmark of 78 percent for the First Contact Resolution (FCR) metric for the 2014-2019 PBR Plan term in part to align with FEI's FCR benchmark of 78 percent, and because FBC considered this benchmark to be indicative of a reasonable performance level as it is based on setting a target above the industry performance average of 70 percent. FBC has not proposed to change this benchmark as it continues to be reasonable for the same reasons, and there has been no FCR results that suggest a need to change.

With respect to FBC's AIFR metric, FBC did not propose any adjustment to the AIFR benchmark and threshold in the 2020-2024 MRP Application as it believed the current benchmark and threshold remained appropriate when considering the metric's long-term performance. At the time of the 2020-2024 MRP Application, the AIFR results had recently improved after a period of volatility, and FBC's view was that, given the short-term volatility in the results, the results should

[56] FBC 2014-2019 PBR Decision and Order G-139-14, p. 150.

be monitored and reviewed on a longer term and trend basis, before the benchmark and threshold should be adjusted.

In this Application, given FBC's continued AIFR results over the Current MRP term, FBC has now proposed to update the benchmark and threshold for the AIFR. In addition to the consideration of the AIFR results, the existing AIFR benchmark and threshold were set in 2015 based on data from as far back as 2004, and therefore now need to be updated to reflect the most recent available information.

34.4 Given that FBC's threshold level for the AIFR three-year rolling average did not increase between the previously completed PBR term (2014–2019) and the Current MRP term (2020–2024), please discuss how FBC's proposal to increase the threshold from the currently approved 2.39 to 2.56 is consistent with past practice.

Response:

For clarity, FBC's reference to "consistent with past practice" was made in relation to the method used to calculate the AIFR threshold, as described in footnote 132 on page C-188 of the Application. The calculation is consistent with the method used in the 2014-2019 PBR Plan.

Please refer to the response to BCUC IR1 34.3 for a discussion of why FBC did not propose to update the AIFR for the Current MRP term but is proposing to update the threshold for AIFR for this Rate Framework term.

34.5 Given that FBC had proposed to carry forward the approved benchmark and threshold values from the completed PBR term (2014–2019) into the Current MRP term (2020–2024), please provide the rationale for adjusting the AIFR benchmark and threshold values in the proposed term of the Rate Framework.

Response:

Please refer to the response to BCUC IR1 34.3.

34.6 Given the below benchmark performance of the annual AIFR SQI in 2022 and 2023, please discuss, with rationale, whether the proposed increase in AIFR SQI threshold could unintentionally contribute to a degradation in safety performance.

Response:

The proposed increase in the AIFR SQI threshold will not contribute to a degradation in safety performance, as FortisBC's corporate safety performance targets are set to meet the benchmark, not the threshold. If performance rises above the benchmark (i.e., FortisBC performs worse than the benchmark), this is a signal to the Company to take immediate action to rectify the decline in performance and closely monitor performance to ensure FortisBC continues to provide an acceptable level of service at an acceptable cost to customers.

The threshold is necessary to recognize the inherent volatility in AIFR results in the short term, despite FortisBC's efforts to meet the benchmark. The AIFR metric can be volatile and influenced by a relatively low number of injuries in any year, which can result in sudden increases in the metric that then take an extended period to correct as FBC works to address the driver behind the increase (i.e., a failure in a safety system or uncontrolled hazard that FBC is alerted to following an event). It is therefore reasonable and appropriate to update the threshold for the AIFR SQI to reflect the most recent 10-year history of the three-year rolling averages of the annual results.

34.7 Please discuss the circumstances leading to poorer performance in the AIFR three-year rolling average SQI for 2023 (1.84) compared to year-to-date June 2023 (1.76).

Response:

As explained in the response to BCUC IR1 23.1 in the FBC Annual Review for 2024 Rates proceeding, during 2022 and early in 2023, FBC experienced a notable increase in recordable safety events (mainly slips, trips and falls due to severe winter conditions). These trends stabilized as 2023 progressed. However, FBC then experienced an unrelated increase in recordable safety events (predominately minor lacerations/cuts requiring medical attention) that resulted in another spike in the year-to-date (i.e., June 2023) AIFR. In response, FBC took additional steps towards proactive education related to the use of proper protective equipment, weather conditions, ergonomics, safe handling procedures, injury prevention, and recover at work activities. During Q3 and Q4 of 2023, FBC experienced only two reportable injuries, resulting in improved AIFR performance; however, as the AIFR is calculated based on the three-year rolling average, the previous higher results from 2022 and the first part of 2023 resulted in an overall higher 2023 AIFR for 2023 compared to the year-to-date June 2023 result.

35.0 Reference: PROPOSED RATE SETTING FRAMEWORK – SQIs

Exhibit B-1, Appendix C6-2 (FBC's SQI Report), Section 3.3.1, pp. 14–16,

Appendix B2-3 - Stakeholder Communications, p. 6

FBC – Reliability SQI – System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI)

On pages 14 to 16 of FBC's SQI Report, FBC proposes to increase the benchmark and threshold levels for both SAIDI and SAIFI SQIs based on statistical analysis (i.e. standard deviation) of the historical results from 2010 to 2019 and inclusive of 2020 to 2023.

On page 6 of Appendix B2-3, FortisBC provides the following feedback summary from participants in the FortisBC 2025+ Rate Setting Framework Workshop on reliability SQIs:

- Concern expressed that basing the benchmark and/or threshold on an increasing trend in SAIDI performance over time (i.e., higher results) may implicitly contribute to declining SAIDI performance. […]

On page 14 of FBC's SQI Report, FBC states:

> […] As SAIDI is significantly impacted by external factors, resulting in variability in SAIDI performance, FBC considers that a three-year performance average establishes a benchmark that is consistent with the level of costs required to provide this level of service and provides a consistent methodology that allows for changes in service quality to be detected, consistent with the BCUC decision from the 2014-2019 PBR Plan. […]

35.1 Please explain whether FBC considers there to be value in providing SAIDI and SAIFI SQI results for all events, including major events, in addition to normalized SAIDI and SAIFI results (excluding major events).

<u>Response:</u>

FBC does not consider there to be value in providing SAIDI and SAIFI SQI results for all events, as FBC already provides Major Event Day descriptions, causes, and impacts in the Annual Reviews, including customer outage hours lost.

FBC considers its approach to providing information on Major Event Days to be more informative than including major events in the SAIDI and SAIFI SQI results because Major Events vary significantly from year to year and abnormal events do not reflect the quality of service provided by FBC as it relates to reliability. Major Events are primarily driven by severe weather, forest fires, etc. that occur in random locations and are outside of FBC's control.

35.2 Please discuss why FBC considers it appropriate to use historical results to adjust the benchmark and threshold levels of both SAIDI and SAIFI SQIs.

35.2.1 Please discuss, with rationale, whether the proposed increases in threshold and benchmark levels for both FBC's SAIDI and SAIFI SQIs could unintentionally contribute to a degradation in service quality.

Response:

FBC considers it appropriate to use historical results to adjust the benchmark and threshold levels for both the SAIDI and SAIFI SQIs because the approach provides a consistent, statistical based methodology that is reflective of the costs required to provide this level of service. This approach is also consistent with the 2014-2019 PBR Plan Decision and Order G-139-14.

FBC does not expect that the proposed increases in threshold and benchmark levels for SAIDI and SAIFI will unintentionally contribute to a degradation in service quality. Rather, the proposed increases reflect FBC's current operating environment and the costs associated to provide an acceptable level of service at an acceptable level of cost to customers. As discussed below, the methodology used to calculate the benchmark and thresholds provides a consistent approach that allows for analysis of trends in operations, the environment and external factors impacting service reliability.

SAIDI and SAIFI results are significantly influenced by external factors that result in variability in performance that influence the proposed benchmark and threshold. Analysis of data with a consistently applied methodology allows FBC to analyze trends and make decisions to factors impacting service quality that inform future system planning to mitigate associated reliability risks. For example, in response to increasing wildfire risk, FBC has implemented policies to turn off reclosing, as well as wildfire specific trip settings for periods of high wildfire risk. These policies are an example of operational changes undertaken by FBC in response to its current operating environment that can impact service quality (and SAIDI and SAIFI performance) but also provide important wildfire risk mitigation.

I. PROPOSED RATE SETTING FRAMEWORK – INDICATIVE RATES

36.0 Reference: PROPOSED RATE SETTING FRAMEWORK – INDICATIVE RATES
Exhibit B-1, Section C7, p. C-191
FEI – Indicative Rates Assumption

On page C-191 of the Application, FortisBC states:

> FortisBC is not requesting approval of 2025 rates in this Application. FortisBC will file for interim 2025 rates before the end of 2024. As part of the 2025 interim rates filings, the Companies will […] propose an amortization period for the 2023 and 2024 Revenue Deficiency deferral account. […]

Further on page C-191 of the Application, FortisBC states that the indicative 2025 delivery rate increase for FEI is 6.2 percent, of which, approximately 2.5 percent is due to the impact of the BCUC Stage 1 Generic Cost of Capital Decision.

36.1 Please state the amortization period assumption used for the 2023 and 2024 Revenue Deficiency deferral account to determine the 6.2 percent indicative 2025 delivery rate increase.

Response:

As noted on page C-191 of the Application, FEI assumed a five-year amortization period for the 2023 and 2024 Revenue Deficiency deferral account. This is consistent with the amortization proposed by FEI in the Annual Review for 2024 Delivery Rates proceeding.

J. POLICIES AND SUPPORTING STUDIES

37.0 Reference: POLICIES AND SUPPORTING STUDIES

Exhibit B-1, Section D2.2, Table D2-1 and Table D2-2, pp. D-3 to D-4, Appendix D2-1 – FEI Depreciation Study 2022 (2022 FEI Depreciation Study), Section 1, p. 1-1

FEI – Impact of Implementing 2022 Depreciation Study Recommended Rates

In Table D2-1 on page D-3 of the Application, FortisBC provides the impact of implementing the recommended rates in the 2022 Depreciation Study for FEI, which is shown below:

Table D2-1: Impact of Implementing Depreciation Study Recommendations for FEI ($ millions)

	Existing	Recommended	Change
Depreciation	201.9	198.0	(3.9)
Net Salvage	57.1	63.0	5.9
CIAC	(7.7)	(7.7)	0.0
Total	**251.3**	**253.3**	**2.0**

In Table D2-2 on page D-4 of the Application, FortisBC provides the existing composite depreciation rate for FEI and the average rate recommendations in the 2022 FEI Depreciation Study, amounting to 2.50 percent and 2.45 percent, respectively.

On page 1-1 of the 2022 FEI Depreciation Study, Concentric Energy Advisors (Concentric) presents, among other things, the annual depreciation accrual for FEI amounting to $265,962,492.

37.1 Please explain the variance between the "Recommended" depreciation amount per Table D2-1 (i.e. $198 million) and the "Annual Accrual" amount per the summary table in the 2022 FEI Depreciation Study (i.e. $266 million).

Response:

The $265,962,492 Calculated Annual Accrual Amount on page 5-4 of the 2022 FEI Depreciation Study represents the total estimated annual accrual for the accounts studied by Concentric and is comprised of two components: (1) Depreciation related to recovery of original cost of investment - life shown on page 5-8 for the estimated amount of $202,345,433; and (2) Depreciation related to recovery of original cost of investment - cost of removal shown on page 5-12 for the estimated amount of $63,617,059.

The majority of the $4 million variance between the depreciation amount per Table D2-1 (i.e., $198 million) and the "Annual Accrual" amount per page 5-8 in the 2022 FEI Depreciation Study (i.e., $202 million) is due to two items:

1. An adjustment made in accounts 474-00 DS Meters/Regulators Installations and 478-10 DS Meters for the AMI CPCN project, that was not reflected in the 2022 FEI Depreciation Study Original Cost amounts. To clarify, while the calculated annual life depreciation rates of 4.35 percent for asset class 474-00 and 3.38 percent for asset class 478-10 in the Study are correct as proposed, the amounts shown in the "Original Cost as of Dec. 31, 2022" and "Calculated Annual Accrual Amount" for those asset classes are different than the amounts FEI used for the basis of its calculation in Table D2-1, as FEI had already removed AMI CPCN related costs in its calculation since they will be recorded in a deferral account. This difference results in FEI showing an approximately $12 million lower amount in Table D2-1 than what is calculated in the 2022 FEI Depreciation Study.
2. Asset accounts that were not studied by Concentric and therefore were not included in the 2022 Depreciation study Annual accrual calculation of $202 million. The approximate amount is $8 million, which partially offsets the variance in the AMI CPCN project adjustment described above.

37.2 Please explain how the existing composite depreciation rate of 2.50 percent and the average rate recommendation in the 2022 FEI Depreciation Study of 2.45 percent is derived. As part of the response, please include supporting calculations.

Response:

The existing and the recommended annual composite rates are calculated by dividing the total annual depreciation over the total closing cost balance, excluding land and land rights asset classes that do not depreciate. Please refer to the table below for the supporting calculations. The AMI CPCN project adjustment discussed in the response to BCUC IR1 37.1 has also been removed from the closing cost balance shown in the table below.

	Depreciation Based on 2017 Depreciation Study Rate	Depreciation Based on 2022 Depreciation Study Rate	Cost Closing Balances 2022
	(a)	(b)	(c)
Total Annual Depreciation	201,935,085	198,001,329	8,070,274,461
Annual Composite Rate	2.50%	2.45%	
	(a/c)	(b/c)	

38.0 Reference: POLICIES AND SUPPORTING STUDIES

Exhibit B-1, Section D2.3, Table D2-5 and Table D2-6, p. D-19, Appendix D2-2 – FBC Depreciation Study 2022 (2022 FBC Depreciation Study), Section 1, p. 1-1

FBC – Impact of Implementing 2022 Depreciation Study Recommended Rates

In Table D2-5 on page D-19 of the Application, FortisBC provides the impact of implementing the recommended rates in the 2022 Depreciation Study for FBC, which is shown below:

Table D2-5: Impact of Implementing Depreciation Study Recommendations for FBC ($ millions)

	Existing	Recommended	Change
Depreciation	53.8	57.0	3.2
Net Salvage	16.0	17.2	1.2
CIAC	(4.7)	(4.8)	(0.1)
Total	**65.3**	**69.6**	**4.3**

In Table D2-6 on page D-19 of the Application, FortisBC provides the existing composite depreciation rate for FBC and the average rate recommendations in the 2022 FBC Depreciation Study, amounting to 2.26 percent and 2.40 percent, respectively.

On page 1-1 of the 2022 FBC Depreciation Study, Concentric presents, among other things, the annual depreciation accrual for FBC amounting to $72,285,854.

38.1 Please explain the variance between the “Recommended” depreciation amount per Table D2-5 (i.e. $57 million) and the “Annual Accrual” amount per the summary table in the 2022 FBC Depreciation Study (i.e. $72 million).

Response:

The $72,285,854 Calculated Annual Accrual Amount on page 5-2 of the 2022 FBC Depreciation Study represents the total estimated annual accrual for the accounts studied by Concentric and is comprised of two components: (1) Depreciation related to recovery of original cost of investment - life shown on page 5-4 for the estimated amount of $55,107,743; and (2) Depreciation related to recovery of original cost of investment - cost of removal shown on page 5-6 for the estimated amount of $17,178,111.

The variance of $1.9 million between the depreciation amount per Table D2-5 (i.e. $57 million) and the “Annual Accrual” amount per page 5-4 in the 2022 FBC Depreciation Study (i.e. $55 million) is due to:

- $1.4 million related to a difference in the methodology used in FBC’s Table D2-5 compared to the 2022 FBC Depreciation Study for calculating depreciation expense for amortization-type accounts; and

- $0.5 million related to asset account 372.00 EV Stations, which has not been studied by Concentric and therefore was not included in the 2022 FBC Depreciation Study annual accrual calculation of $55 million.

38.2 Please explain how the existing composite depreciation rate of 2.26 percent and the average rate recommendation in the 2022 FBC Depreciation Study of 2.40 percent is derived. As part of the response, please include supporting calculations.

Response:

The existing and the recommended annual composite rates are calculated by dividing the total annual depreciation over the total closing cost balance, excluding land and land rights asset classes that do not depreciate. The supporting calculations are provided in the table below.

	Depreciation Based on 2017 Depreciation Study Rate	Depreciation Based on 2022 Depreciation Study Rate	Cost Closing Balances 2022
	(a)	(b)	(c)
Total Annual Depreciation	$53,834,522	$57,030,909	$2,379,958,958
Annual Composite Rate	2.26%	2.40%	
	(a/c)	(b/c)	

39.0 Reference: POLICIES AND SUPPORTING STUDIES

Exhibit B-1, Section D2.1, p. D-2, 2022 FEI Depreciation Study, Section 3.1.2,

pp. 3-1 to 3-4

FEI – Energy Transition Impact on Depreciation Study

On page D-2 of the Application, FortisBC states:

> In preparing the depreciation study for FEI, Concentric and FEI considered whether accelerated depreciation methods should be explored. […] FEI does not consider it appropriate at this time to accelerate depreciation and thereby increase costs for customers. […]

On page 3-3 of the 2022 FEI Depreciation Study, Concentric states:

> […] While future retirements that are caused by physical forces of retirement such as wear and tear and changes in technology of the assets will continue, it is reasonable to anticipate that the utilization of large groups of assets may change due to the implementation of climate change legislation. […] <u>it could be assumed that large scale retirement of assets may be required in the periods between now and 2050.</u> […] Concentric notes that future studies may require additional consideration of alternative depreciation procedures and energy transition mitigation strategies as more information becomes known. [*Emphasis added*]

39.1 Please explain when FortisBC intends to file its next depreciation study for FEI. As part of this response, please provide the pros and cons of filing a new depreciation study for FEI sooner as opposed to later (e.g. as part of the next annual review application instead of the next multi-year rate plan application, if there is one), which would consider the possible impact(s) of climate change legislation on FEI's assets, as noted by Concentric above.

<u>Response:</u>

FortisBC typically files a new depreciation study every five years, ensuring that its depreciation rates are appropriate and reflect the most recent information. Five years is sufficient in length to detect long-term trends and changes to assets' service lives.

FortisBC intends to file the next depreciation study for FEI in the 2028/2029 timeframe, or possibly a year earlier in 2027 to coincide with the end of the proposed Rate Framework term. FortisBC does not see any advantages to undertaking a new depreciation study earlier than 2027, as it is unlikely that noticeable changes to asset lives will be observed in such a short timeframe. FortisBC would only consider performing a new depreciation study earlier than 2027 if there are large, anticipated changes in retirement patterns, net salvage requirements, or technical obsolescence; however, as previously stated, such situations are unlikely to occur in the upcoming three to five years.

In terms of the advantages of filing a new depreciation study sooner than in five years (e.g., in 2027), the study would reflect the most current information available at the time. A disadvantage of preparing studies over shorter time intervals is the additional cost to customers, as the cost for Concentric (or another depreciation expert) to complete a study is approximately $125 thousand. Additionally, there would be the increased regulatory requirements and costs to review the study's results and recommendations.

Ultimately, FortisBC is not opposed to completing the next depreciation study for FEI earlier than planned, but would not recommend filing a new depreciation study any sooner than in 2027. The benefit of one or two years of new information would be far outweighed by the cost and time to undertake another study given the likely limited changes that would have occurred to asset service lives.

39.2 Please discuss the extent to which the 2022 FEI Depreciation Study has considered the possible impact(s) of legislation related to the energy transition on the future growth and retirement programs on FEI's energy system.

Response:

The following response has been provided by Concentric:

As discussed in Section 3.1.2 of the 2022 FEI Depreciation Study, the possible impacts of the energy transition were considered in relation to FEI's future capital investment and retirement expectations; however, it was concluded that no adjustments are required at this time as there is currently not enough information about the impacts of legislation related to the energy transition on FEI's assets. In reaching this conclusion, and as discussed on page 3-4 of the 2022 FEI Depreciation Study, Concentric reviewed other North American jurisdictions to determine the extent to which the energy transition developments impacted on the determination of appropriate depreciation rates to specifically address the energy transition. Based on this review, Concentric did not identify any jurisdictions that have adopted economic planning horizons (EPH) when setting depreciation rates for natural gas distribution utilities. As the energy transition evolves, Concentric will continue to monitor for any developments in FEI's and other jurisdictions on the impacts of the relevant climate change legislation that may suggest a change in the utilization of FEI's assets. Any changes required (e.g., introduction of an EPH) will be included as part of FEI's next depreciation study to allow for timely adjustment of the depreciation rates.

Additionally, as stated in the response to BCUC IR1 39.3, FEI is expecting asset retirements to follow historical retirements based primarily on physical life characteristics. However, due to the uncertainty of impacts at this time, Concentric has intentionally limited life extension estimates on long-lived asset groups until more information becomes known about the future of FEI's system. This is consistent with the industry where legislation has had little impact on the life expectations of distribution gas systems throughout Canada.

With the exception of accounts related to FEI's LNG assets, only one other life extension was proposed for FEI's assets. The estimated service life and Iowa curve for Account 477.10 – Distribution Plant Measuring and Regulating was changed from 33-R2 to 34-R2.5. This was due primarily to the 34-R2.5 producing a better visual and mathematical fit to the data. Using the 34-R2.5 Iowa curve reduces the maximum service life to 57 years from the current maximum service life of 63 years using the 33-R2 Iowa curve.

39.3 Please discuss the extent to which FEI's next depreciation study will consider the possible impact(s) of legislation related to the energy transition on the future growth and retirement programs on FEI's energy system. As part of this response, please discuss FortisBC's expectations for the retirement of FEI's assets (e.g. gas manufacturing, transmission, distribution or general plant) between now and 2050, including the possible extent of this retirement due to the energy transition.

Response:

As discussed in the response to BCUC IR1 39.1, FEI currently intends to file its next depreciation study in the 2028/2029 timeframe. As part of this next depreciation study, FEI will again ask Concentric to review the energy transition, applicable legislation and the associated impact on the future growth and retirement programs on FEI's energy system, and specifically the impact on the useful life of FEI's natural gas distribution assets. More may be known at that time about the impact of climate change legislation on the future of conventional natural gas.

As Concentric concluded in the 2022 FEI Depreciation Study that the overall impact of the energy transition on FEI's assets is unknown at this time, FEI is expecting asset retirements between now and 2050 to follow historical trends based primarily on physical life characteristics, which is consistent with the 2022 FEI Depreciation Study.

FEI considers that maintaining a role for the existing gas delivery system in BC's energy future is in the public interest and that 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. This concept is supported by the recently released provincial energy strategy, Powering Our Future, BC's Clean Energy Strategy,[57] where the BC Government concludes that:

> Not all energy needs can be met through electricity and utility-scale batteries. Liquid and gas fuels will remain essential for the foreseeable future, especially in areas like long-haul transportation, certain industrial processes, and in remote communities not connected to the electricity grid. BC's gas system will also

[57] https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/community-energy-solutions/powering_our_future_-_bcs_clean_energy_strategy_2024.pdf.

> continue to play an important role for many years to come in order to maintain system resiliency, meet peak energy demand and provide home heating in colder climates.
>
> ….
>
> Maintaining BC's existing gas infrastructure is necessary to ensure BC can deliver clean fuels as production ramps up in the years ahead, in addition to supporting the resiliency of BC's energy system. [Emphasis added.]

As such, anticipating the early retirement of assets in the foreseeable future due to the energy transition is inconsistent with BC's Clean Energy Strategy, and the development of alternative products and services using FEI's existing assets.

Consistent with the objective of climate policy to reduce GHG emissions, FEI continues to invest in decarbonization measures which support the long-term use of the gas system. For example, renewable and low carbon gases can lower emissions by replacing natural gas while investments in demand side measures can reduce gas use overall. Further, FEI expects its system will continue to provide critical peak capacity to meet BC's energy needs during cold winter periods for the foreseeable future.

FEI believes that any change to depreciation practices needs to be supported by a tangible and foreseeable change in the expected use of assets. At this time, there is not a clear case to change the useful life of FEI's assets, which if unnecessarily shortened, would amount to an unwarranted increase in customer rates, and lead to future customers not paying their fair share of the cost of assets that will be used and useful in the future.

39.4 Please explain, in the context of the above discussion in the 2022 FEI Depreciation Study regarding the potential large-scale retirement of energy-related assets due to the possible impact(s) of climate change legislation, whether and how Concentric distinguished between obsolescence due to government-enacted legislation changes (e.g. climate change legislation) and other forms of obsolescence.

39.4.1 Please explain whether FortisBC believes that some or all of the obsolescence identified in response to the preceding IR can be mitigated by other opportunities within the existing FEI energy system (e.g. hydrogen blending).

Response:

The following response has been provided by FEI in consultation with Concentric:

All forces of retirement were included in the actuarial analysis included in Section 6 of the 2022 Depreciation Study. As indicated in the response to BCUC IR1 39.2, the possible impacts of the energy transition, including obsolescence due to government-enacted legislation, change and other forms of obsolescence, were considered by Concentric as part of the study but were not incorporated in setting the proposed depreciation rates, as the impact of the energy transition on FEI's assets remains unknown at this time.

On page 3-4 of the 2022 FEI Depreciation Study, Concentric states:

> […] Concentric notes that future depreciation studies of the FortisBC Energy System <u>may require the introduction of an economic planning horizon</u> into the depreciation rate calculations. [*Emphasis added*]

On page 3-4 of the 2022 FEI Depreciation Study, Concentric also states:

> Concentric is also aware of the recent British Columbia Utilities Commission decision in Order G-19-24 regarding the Pacific Northern Gas ("PNG") revenue requirement. This order required PNG to investigate the use of an economic planning horizon and report on the findings in PNG's next rate application, to be filed in 2026. However, <u>Concentric notes that the PNG system is largely transmission, where the concept of an economic planning horizon has had more regulatory support, as compared to the FortisBC System</u>. [*Emphasis added*]

39.5 Please elaborate on the definition of an "economic planning horizon" in the context of the 2022 FEI Depreciation Study.

<u>Response:</u>

The following response has been provided by Concentric:

FEI's 2022 Depreciation Study, as in past studies, uses the actuarial analysis method to select average service life and Iowa dispersion curve estimates based primarily on the observed physical life characteristics (i.e., retirements due to age and wear and tear), a detailed peer review, and professional judgement. Unlike the actuarial analysis method, an economic planning horizon (EPH) is based on the average economic life of assets to determine the period over which it is reasonable to recover investments. Typically, a depreciation study utilizing an EPH will also include an actuarial analysis to model interim retirement activity prior to the expected terminal retirement date, however it is often the case that the EPH has a higher impact on the total depreciation rate than the actuarial analysis, particularly in circumstances with a shorter planning horizon. Factors considered in the development of an EPH include competitive factors, technological and economic obsolescence.

The potential consideration and introduction of an EPH for FEI in the future will, all else equal, lead to higher depreciation rates as the service life for its assets used will be lower.

Please refer also to Concentric's response to BCUC IR1 39.7.

39.6 Please discuss whether an economic planning horizon is expected to be introduced for any of FEI's gas manufacturing, transmission, distribution or general plant assets or asset locations in the next depreciation study due to the energy transition. If not, please explain why an economic planning horizon is not relevant for the next depreciation study.

Response:

The following response has been provided by Concentric:

The selection of depreciation parameters, including the use of an economic planning horizon is made based on the information available at the time of the depreciation study. It is unknown at this time if there will be a need for an economic planning horizon in the next depreciation study. Concentric will evaluate the economic forces at the time of the study, including information regarding any proposed or passed energy transition legislation, in deciding whether to recommend an economic planning horizon.

39.7 Please discuss, at a high level, how the introduction of an economic planning horizon could impact FEI's future depreciation studies, depreciation expense, and resulting delivery rates.

Response:

The following response has been provided by Concentric:

It is the experience of Concentric that an economic planning horizon generally increases depreciation expense. This is because the implementation of an economic planning horizon truncates the time over which the investment and cost of removal can be recovered as the economic planning horizon date is generally shorter than the maximum life implied by the Iowa curve and average service life selection for a typical planning horizon. As such, it is expected that the introduction of an economic planning horizon in a future depreciation study would increase FEI's depreciation expense in the short term and, all else equal, would also increase FEI's delivery rates.

Concentric highlights that the inclusion of an economic planning horizon in the depreciation study process can add additional cost and complexity as the selection of an appropriate economic planning horizon adds another variable to be considered. This may result in a higher level of regulatory review, including a larger number of interrogatories.

39.8 Please elaborate on the underlined statement from page 3-4 of the 2022 FEI Depreciation Study. Why would the concept of an economic planning horizon be more applicable to PNG than FEI?

Response:

The following response has been provided by Concentric:

The concept of applying an economic planning horizon to transmission related assets has received wide regulatory support throughout North America, and is one of the widely used methods for certain interprovincial transmission assets. Both the Federal Energy Regulatory Commission in the United States and the Canadian Energy Regulator allow the use of an economic planning horizon for transmission related assets as there are often firm contract dates that limit the useful life of assets. In contrast, FEI's transmission assets are integrated into its delivery system and are generally not tied to underlying economic contracts with third party shippers. Concentric is unaware of any jurisdiction that has approved the use of an economic planning horizon for distribution related assets.

While PNG was used as an example in the Depreciation Study Report, Concentric has not opined on whether an economic planning horizon would be more applicable to PNG than FEI. The purpose of the statement was to provide context to the fact that transmission related assets have been impacted by economic planning horizons and distribution related assets have not.

39.8.1 Please confirm whether, in FortisBC's view, an economic planning horizon is pertinent to FEI's assets. Please explain why or why not.

Response:

An economic planning horizon could be pertinent to FEI's assets depending on the potential future impacts of climate change legislation. However, as explained by Concentric in the 2022 FEI Depreciation Study and in the response to BCUC IR1 39.6, it is unknown and uncertain whether a large-scale retirement of assets will be required in the period between now and 2050. As such, it would not be appropriate at this time to determine that an economic planning horizon is pertinent to FEI's assets given the lack of certainty in the information available today. As discussed in the response to BCUC IR1 39.3, this is supported by the recently released provincial energy strategy, Powering Our Future, BC's Clean Energy Strategy[58] where the Province concludes that "[m]aintaining BC's existing gas infrastructure is necessary to ensure BC can deliver clean fuels as production ramps up in the years ahead, in addition to supporting the resiliency of BC's energy system."

Concentric will evaluate the economic forces at the time of the next depreciation study for FEI, including information regarding energy transition legislation, in deciding whether to recommend an economic planning horizon.

On pages 3-1 to 3-2 of the 2022 FEI Depreciation Study, Concentric states:

> […] Given the recently released Climate Change Accountability Act, Concentric reviewed the impacts of the legislation on the appropriate depreciation procedures. After such consideration, and discussion with FortisBC Energy, the continued use of the ALG [Average Life Group] Procedure is recommended at this time in the specific circumstances for FortisBC Energy. […]

On page 3-3 of the 2022 FEI Depreciation Study, Concentric states:

> […] Common depreciation practice is to deal with anticipated large-scale retirements through the introduction of an economic planning horizon within the depreciation rate calculations or shortened average service life estimates. Additionally, the use of the ELG [Equal Life Group] procedure has also been considered a "first step" in the recovery of the utilities' investment in distribution and transmission systems. […]

39.9 Please discuss the specific elements of the *Climate Change Accountability Act* that Concentric reviewed to arrive at its conclusion that the Average Life Group procedure should continue to be used for FEI's assets. As part of this response, please explain what Concentric considered to be the "impacts of the legislation on the appropriate depreciation procedures" and the "specific circumstances" of FEI that led Concentric to the conclusion of recommending continued use of the Average Life Group procedure.

<u>Response:</u>

The following response has been provided by Concentric:

---

58 https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/community-energy-solutions/powering_our_future_-_bcs_clean_energy_strategy_2024.pdf.

As part of its work in Canada, Concentric reviews any and all relevant climate change legislation affecting utilities and, as part of that review, has reviewed the entirety of the *Climate Change Accountability Act* (the Act). The targets discussed in Part 1 of the Act are of particular interest as they help inform a utility's future plans in response to the stated targets.

As part of its independent review, Concentric discussed with FEI staff the potential impacts of emissions reduction targets to FEI's assets in the short term. Based on this information, Concentric recommended that the ALG procedure continue to be used until more information becomes available. In future studies, if FEI determines that its response to the targets will have a life shortening effect, a move to another procedure (i.e., the ELG procedure or Units of Production) or the use of an economic planning horizon may be recommended to reduce FEI's risk of stranded assets in the future. Concentric views that changing the procedure or introducing an economic planning horizon at this time is premature and could cause unnecessary and unwarranted increases in depreciation expense.

39.10 Please discuss whether FortisBC or Concentric is aware of any public utility in BC that uses the Equal Life Group procedure to depreciate its assets. If so, please provide further details.

Response:

The following response has been provided by Concentric.

Concentric is unaware of any utility in British Columbia currently using the Equal Life Group Procedure.

Further, on page 3-2 of the 2022 FEI Depreciation Study, Concentric states:

> […] The introduction of hydrogen blending, for example, may have a life lengthening impact on the system if it is determined that hydrogen is a sustainable replacement fuel, and the level to which hydrogen can be blended into the transmission and distribution stream is further researched. Ultimately, if hydrogen blending proves to be a viable option to meet the legislative requirements, the overall impact [of climate change legislation] to FortisBC may be lessened. However, it may also be required that the move from carbon-based fuels necessitates a greater electrification of the grid, in which case there may be a life shortening impact on the FortisBC Energy system.

39.11 Please discuss, at a high level, the possible impact of hydrogen blending on FEI's energy system that currently relies on gas (i.e. life-shortening or life-lengthening impact to FEI's energy system assets). As part of this response, please discuss the impact on FEI's future depreciation studies, depreciation expense, and resulting delivery rates.

Response:

FEI's expectation regarding the impact of blending hydrogen is consistent with Concentric's findings in the 2022 Depreciation Study, as referenced in the preamble. FEI, like Concentric, recognizes that additional research across the entire hydro-electric and natural gas supply chain will be needed to fill current knowledge gaps and better inform decisions on future blending projects.[59]

FEI continues to advance a range of activities to study, test and verify the use of hydrogen in the existing gas system and expects that hydrogen blending will require investment and upgrades to its assets. However, FEI is currently not able to determine the extent that the existing gas system will need to be modified for hydrogen or how much dedicated hydrogen infrastructure will be needed. As a result, there is currently insufficient information available to FEI on hydrogen deployment in its delivered energy mix to inform a meaningful discussion on its impact on future depreciation studies, depreciation expense, and resulting delivery rates at this time.

[59] Refer to page 3-3 of the 2022 FEI Depreciation Study in which Concentric references a 2022 technical report released by the National Renewable Energy Laboratory (NREL) titled: "Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology" analyzing the potential for hydrogen blending in natural gas pipelines.

40.0 Reference: POLICIES AND SUPPORTING STUDIES

Exhibit B-1, Section D2.2.1, p. D-8, Section D2.3.1, p. D-21

FEI – Change in Service Life of Assets and Impact on Depreciation Rate

On page D-8 of the Application, for LNG Gas Structures – Tilbury for FEI, FortisBC states:

> […] Concentric recommends a 28-year life, an increase from the 25-year service life recommended in the 2017 Depreciation Study.
>
> […]
>
> The large new additions that this asset class has experienced in the past five years and the true-up for the depreciation rate over the remaining life of the assets result in an increase of approximately 1.5 percent in the depreciation rate […]

Further on page D-8 of the Application, for LNG Gas Equipment – Tilbury for FEI, FortisBC states:

> […] Concentric recommends a 57-year life, an increase from the 40-year service life recommended in the 2017 Depreciation Study.
>
> […]
>
> The large new additions that this asset class have experienced in the past five years and the true-up for the depreciation rate over the remaining life of the assets results in an increase of 0.48 percent in the depreciation rate […]

40.1 Please discuss the relationship (i.e. positively correlated, negatively correlated) between service life and depreciation expense for the two asset classes noted in the preamble above.

<u>Response:</u>

The following response has been provided by Concentric:

An increase in the estimated service life from a prior depreciation study to a new depreciation study does not always produce a lower depreciation rate. The depreciation rate is comprised of a life rate, a net salvage rate, and a rate for the amortization of reserve differences. If there is an increase in the estimated service life and there is no change to the mode of the Iowa curve or the net salvage rate, no true up associated with the amortization of reserve differences, and no material change in the investment in the account, the overall depreciation rate should decrease from the rate previously employed.

Specifically for the two accounts referenced in the preamble, the life rates decreased as a result of increasing the service lives; however, the true up related to the amortization of reserve differences is the main driver of the increase in the overall life rate. Please refer to the response to BCUC IR1 40.2 for a breakdown of the depreciation life rate for asset accounts 442.00 LNG Gas Structures – Tilbury and 443.00 LNG Gas Equipment – Tilbury.

40.2 Please explain, using numerical supporting information along with clarifying examples, why there is an increase in the depreciation rate for the two asset classes noted in the preamble above notwithstanding the recommended increase in service life.

Response:

The following response has been provided by Concentric:

In the table below is a breakdown of the increase in the depreciation rate from the 2017 FEI Depreciation study.

Asset Account	Previous Life Rate	Proposed Life Rate	Previous ARD Rate (Life)	Proposed ARD Rate (Life)	Previous Total Life Rate	Proposed Total Life Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)
442.00 LNG Gas Structures - Tilbury	4.00%	3.57%	-1.80%	0.13%	2.20%	3.70%
443.00 LNG Gas Equipment - Tilbury	2.50%	1.75%	-1.27%	-0.04%	1.23%	1.71%

As shown in the table above, the primary reason for the increase in the depreciation rate from the last study is the change in the true up related to the amortization of reserve differences (i.e., change in ARD (Amortization of Reserve Differences) rate). Changes of this magnitude are expected between depreciation studies. Please also refer to the response to BCUC IR1 40.1.

40.3 Please explain how the increase in the recommended service life is appropriate given the operating environment that FEI is facing with respect to the energy transition. As part of the response, please discuss how this increase in the recommended service life impacts FEI's stranded asset risk.

Response:

The following response has been provided by Concentric:

Based on Concentric's discussions of the service life expectations for these accounts with FEI management and engineering staff, and also described in the Depreciation Study Report, it was noted that the majority of the investment in these accounts were new and should have similar life characteristics to FEI's Mt. Hayes LNG facility. There was no expectation by FEI at that time that the operating environment for LNG facilities would be negatively affected by the energy transition; therefore, a life extension was considered appropriate.

Concentric also notes that this is consistent with other LNG facilities in Canada (e.g., a regulated LNG facility in Quebec) where significant expansion has resulted in similar life estimates and no consideration of economic planning horizon constraints.

FortisBC adds the following response:

FEI agrees with Concentric's findings that "[w]hile there is strong evidence that the future of natural gas may be impacted by climate change legislation, it is still unknown to what extent this change will impact FortisBC Energy's system".[60] In this instance, the change in service life is primarily attributed to additions associated with the Tilbury 1A facility, which was constructed pursuant to Direction No. 5 to the BCUC to serve the transportation market with LNG, thereby helping lower emissions. With the recent approval of the Tilbury Marine Jetty, which will allow greater access to LNG for the marine shipping market, and the approval of a grant to attract an LNG-fueled bunkering vessel, FEI expects this market to grow. Accordingly, FEI believes that the increase in service life is appropriate and does not expect that the energy transition will negatively affect the service life for its LNG facilities at this time. LNG facilities remain highly valuable and versatile, and FEI expects them to remain used and useful.

On page D-21 of the Application, for Light Duty Vehicles for FBC, FortisBC states:

> For Light Duty Vehicles (392.10), Concentric recommends a 12-year life, consistent with the 2017 Depreciation Study. […]
>
> Even though there is no change in the service life, the true-up of the depreciation rate over the remaining life of the assets results in an increase of 6.38 percent in the depreciation rate for this asset category.

40.4 Please explain, using numerical supporting information, why there is an increase in the depreciation rate for Light Duty Vehicles despite no recommended change in the service life.

[60] Appendix D2-1, p. 3-2.

Response:

The following response has been provided by Concentric:

In the table below is a breakdown of the increase in the depreciation rate from the 2017 FBC Depreciation study.

Asset Account	Previous Life Rate	Proposed Life Rate	Previous ARD Rate (Life)	Proposed ARD Rate (Life)	Previous Total Life Rate	Proposed Total Life Rate
(1)	(2)	(3)	(4)	(5)	(6)	(7)
392.10 Light Duty Vehicles	8.33%	8.33%	-3.54%	2.84%	4.79%	11.17%

As shown in the table above, the primary reason for the increase in the depreciation rate related to life from the last study is the change in the true up related to the change in the ARD (Amortization of Reserve Differences) rate.

41.0 Reference: POLICIES AND SUPPORTING STUDIES

Exhibit B-1, Section D2.2.2, p. D-17, Section D2.3.2, p. D-22, Table D2-8, p. D-23

Increase in Negative Net Salvage Percent Rate

On page D-17 of the Application, regarding change in net salvage expense for FEI, FortisBC states:

> For Services (473-00), Concentric recommends a negative 85 percent rate to represent the net salvage expectations, an increase from the negative 70 percent recommended in the 2017 Depreciation Study. <u>This account continues to experience a significant amount of net salvage activity consistent with prior years.</u> […]
>
> For Distribution Mains (475-00), Concentric recommends a negative 30 percent rate to represent the net salvage expectations, an increase from the negative 25 percent recommended in the 2017 Depreciation Study. <u>This account continues to experience a significant amount of net salvage activity consistent with prior years.</u> […] [*Emphasis added*]

41.1 Please describe the "significant amount of net salvage activity" that has occurred in each of the two asset categories noted in the preamble above for FEI in the five years preceding the effective date of the depreciation study (i.e. from 2018 to 2022).

<u>Response:</u>

The table below shows the actual cost of removal incurred for accounts 473-00 DS Services and 475-00 DS Mains in the past five years.

Table 1: Actual Cost of Removal ($000s)

Year	473-00 DS Services	475-00 DS Mains
2018	10,574	1,166
2019	9,920	1,517
2020	9,657	1,058
2021	13,120	2,024
2022	15,041	1,813

In the past five years, the cost of removal for both accounts 473-00 DS Services and 475-00 DS Mains shows a general increase due to higher inflation in the last few years, as well as an increase in third-party requests to relocate and remove existing assets to accommodate their proposed infrastructure.

Further, on page D-22 of the Application, regarding the increase in the net salvage rate for FBC, FortisBC states:

> […] The recommended net salvage rate increase by 0.06 percent is primarily driven by the increases in FBC's actual cost of removal activities as well the upward and downward changes in the net salvage percentage for various asset classes […].

On page D-23 of the Application, FortisBC provides Table D2-8, showing the Net Salvage Rates by Asset Class for FBC.

41.2 Please describe the "cost of removal activities" that have occurred for FBC's assets in the five years preceding the effective date of the depreciation study (i.e. from 2018 to 2022).

Response:

Table 1 below shows the actual total cost of removal incurred for FBC's assets in the past five years.

Table 1: Actual Cost of Removal ($000s)

Year	Total Cost of Removal	Major/CPCN Projects Cost of Removal	Base Capital Cost of Removal
2018	7,219	2,485	4,734
2019	6,593	2,717	3,876
2020	9,998	4,562	5,436
2021	11,750	5,801	5,949
2022	6,609	1,226	5,383

The higher cost of removal experienced in the past five years is primarily due to specific Major/CPCN projects, as well as inflation and higher contractors' costs in general. The specific amounts related to each of the Major/CPCN projects are provided in Table 2 below.

Table 2: Actual Cost of Removal for Major/CPCN Projects ($000s)

Year	Corra Linn	Kootenay Operations Centre	Ruckles Substation Rebuild	UBO	Grand Forks Terminal Station Reliability	KBTA (Kelowna Bulk Transformer Addition)	Total
2018	915	1,177	172	221			2,485
2019	2,358			359			2,717
2020	4,216			304	42		4,562
2021	4,260			313	900	328	5,801
2022	977					249	1,226

41.3 Please provide reasons for increase in the negative net salvage percent rate in the following asset categories for FBC:

(i) Class 368.00 – Line transformers

(ii) Class 364.00 – Poles, towers and fixtures

(iii) Class 355.00 – Poles, towers and fixtures

(iv) Class 356.00 – Conductors and devices

(v) Class 353.00 – Substation equipment

Response:

The following response has been provided by Concentric:

FBC was first approved to pre-collect net salvage costs starting in 2016. Since then, FBC has increased its net salvage collection where required in each subsequent depreciation study. As discussed below, FBC's net salvage requirements are still above what it is currently seeking in this depreciation study; however, increasing net salvage collections to the historical indications instead of moderate increases over time would cause significant rate impacts in the near term, and when considering affordability, it would not be reasonable to do so.

FBC continuously monitors its current and long-term net salvage requirements, which are analyzed by Concentric when a new study is performed. Increases to net salvage rates may be required in future studies if the current trend continues.

(i) Class 368.00 – Line transformers

There have been large cost of removal amounts in recent years leading to large net salvage percentages. This account is showing historical net salvage of -37%; however, in an effort to minimize intergenerational inequities and also give consideration to moderation and gradualism, Concentric considers it appropriate to increase the net salvage estimate to -30% from the previously approved -25%.

(ii) Class 364.00 – Poles, towers and fixtures

There have been large cost of removal amounts in recent years leading to large net salvage percentages. This account is showing historical net salvage of -126%; however, in an effort to minimize intergenerational inequities and also give consideration to moderation and gradualism, Concentric considers it appropriate to increase the net salvage estimate to -40% from the previously approved -35%.

(iii) Class 355.00 – Poles, towers and fixtures

There have been large cost of removal amounts in recent years leading to large net salvage percentages. This account is showing historical net salvage of -106%; however, in an effort to minimize intergenerational inequities and also give consideration to moderation and gradualism, Concentric considers it appropriate to increase the net salvage estimate to -40% from the previously approved -35%.

(iv) Class 356.00 – Conductors and devices

There have been large cost of removal amounts in recent years leading to large net salvage percentages. This account is showing historical net salvage of -117%; however, in an effort to minimize intergenerational inequities and also give consideration to moderation and gradualism, Concentric considers it appropriate to increase the net salvage estimate to -35% from the previously approved -30%.

(v) Class 353.00 – Substation Equipment

There have been large cost of removal amounts in recent years leading to large net salvage percentages. This account is showing historical net salvage of -69%; however, in an effort to minimize intergenerational inequities and also give consideration to moderation and gradualism, Concentric considers it appropriate to increase the net salvage estimate to -30% from the previously approved -25%.

42.0 Reference: POLICIES AND SUPPORTING STUDIES

Exhibit B-1, Appendix D4-1 (KPMG's FortisBC Corporate Services Cost Allocation Report), pp. 23–24

Corporate Services Allocation

On page 23 of KPMG's FortisBC Corporate Services Cost Allocation Report, it discusses the two ways that the divestiture of Aitken Creek Gas Storage Facility (ACGS) impacts the allocation of corporate services costs to FEI and FBC. First, it decreases the costs allocated from Fortis Inc. (FI) to FortisBC Holdings Inc. (FHI) from 21.8 percent to 20.9 percent due to FHI receiving a smaller corporate shared service allocation from FI. Second, it increases the costs allocated from FHI to both FEI and FBC under the Massachusetts Formula by 3.4 percent and 1.0 percent, respectively.

On page 24 of KPMG's FortisBC Corporate Services Cost Allocation Report, it states:

> […] Based on the 2023 budget, the ACGS divestiture is expected to result in the reallocation of approximately $466,000 in costs to FBC and FEI. Across these departments, none of the FHI costs that are reallocated by department would be greater than or equal to the average cost of an FTE within FHI (approximately $190,000). Further, based on interviews with FHI cost centre owners, the support provided to FMI (ACGS) did not take the form of dedicated staff; support was instead provided through part time effort spread across several FTEs. Therefore, the divestiture of FMI (ACGS) is not expected to result in any changes in staffing levels that would result in a reduction of cost.

42.1 Please elaborate on the types of costs that were impacted in the first step discussed on page 23 of KPMG's FortisBC Corporate Services Cost Allocation Report (i.e. what types and amounts of costs decreased in FI to result in the noted decreases to FHI).

Response:

The types of costs allocated from FI to FHI did not change with the disposition of ACGS. FI operating costs are allocated to its subsidiaries using a proportional allocator based on assets and controllable costs. The types of costs FI provides to its subsidiaries are described in Section 4.2 - Table 4 of the KPMG Corporate Service Cost Study (Appendix D4-1 to the Application), and those did not change with the disposition of ACGS.

The decrease in the amount of costs allocated from FI to FHI was due to the FHI group of companies having a smaller proportional representation amongst the broader FI group of companies.

42.2 Please discuss the benefits that will be received by FEI and FBC, respectively, from the additional costs being allocated to them from FHI as described on page 24 of KPMG's FortisBC Corporate Services Cost Allocation Report, if any.

Response:

The reference to pages 23 and 24 of the KPMG Corporate Services Cost Allocation Report provided in the preamble discuss the impact of the divestiture of ACGS on the allocation of corporate services costs to FEI and FBC. As explained in the response to BCUC IR1 42.1, the types of costs allocated from FI to its subsidiaries did not change with the disposition of ACGS, and the benefits received by FEI and FBC through the support of corporate services from FI and FHI will not change with the disposition of ACGS.

The KPMG Corporate Service Cost Study assesses whether the methodology used is a reasonable mechanism to allocate corporate service costs. As changes occur in the type or amount of corporate service costs incurred, the size and structure of the FI group of companies, or in the number of subsidiaries receiving services within the FHI group, the methodology will result in changes in the amount of corporate service costs allocated to FEI and FBC. With the disposition of ACGS, there is a change in allocation of costs under the methodology due to: (1) less FI corporate costs charged down to the FHI group of companies; and (2) more combined FI/FHI corporate service costs allocated to FEI and FBC due to the removal of ACGS from the formula. However, the benefits received by FEI and FBC through the support of corporate services from FI and FHI will not change with the disposition of ACGS.

While there is a net increase in corporate service costs allocated to FEI and FBC as a result of the ACGS disposition, it is inclusive of a reduction in FI costs allocated to FHI as result of the change in allocation percentages with ACGS no longer included. Also, for the period of time that ACGS was owned, customers benefited from less corporate service costs allocated to FEI and FBC as a result of the approved methodology allocating corporate service costs to ACGS. When compared to the period prior to ACGS ownership, the change to FEI and FBC corporate services costs is representative of annualized increases of less than 4 percent.

43.0 Reference: POLICIES AND SUPPORTING STUDIES

Exhibit B-1, Section D5.1, p. D-40, Appendix D5-1 (KPMG's FEI Overhead Capitalization Review), Table 7, pp. 23–31, 34

FEI – Overhead Capitalization

On page D-40 of the Application, FortisBC proposes a capitalized overhead rate of 14.5 percent for FEI, which compares to the 16 percent used in the Current MRP.

Table 7 on pages 23 to 31 of KPMG's FEI Overhead Capitalization Review summarizes capital-related costs by department as well as how those costs are or are not related to capital activity. Among other things, it discusses business innovation, sustainability & environment, integrated resource planning, and RNG.

On page 34 of KPMG's FEI Overhead Capitalization Review, it states that the proposed capital overhead cost allocation methodology provides flexibility to adjust individual cost centre allocations based on changes to regulatory, accounting, and/or organizational changes.

43.1 Please discuss whether FortisBC or KPMG has assessed the flexibility/adaptability of FEI's proposed capitalized overhead rate to factors such as changes in government policies and regulations related to the energy transition.

Response:

As described in Section 2.2 of the 2023 Capitalized Overhead Study for FEI in Appendix D5-1 to the Application, the methodology used in the study is flexible and adaptable to future changes. This includes the flexibility to adapt to changes in government policies and regulations related to the energy transition as part of its review in preparing rate framework applications. In short, as described in Section 4 of the study, FEI has methods to directly assign costs to capital or estimate the capitalized overhead through a process using surveys, interviews and estimation methods. If changes in government policies and regulations related to the energy transition were to impact the amount of capitalized overhead, such changes would be identified by these methods.

In the 2023 Capitalized Overhead Study for FEI, overhead costs identified as being indirectly related to capital were not assessed as having changed significantly due to government policies and regulations related to the energy transition. However, future studies will continue to assess these costs and the methodology will enable any changes due to the energy transition to be reflected in the proposed capitalized overhead rate.

43.2 Please discuss how the proposed overhead capitalization rate is or is not impacted by the energy transition. As part of the response, please discuss the types of costs as outlined in Table 7 of KPMG's FEI Overhead Capitalization Review that may be impacted by the energy transition (e.g. business innovation, sustainability & environment, integrated resource planning, and RNG, or any others).

Response:

While no direct changes have been proposed to FEI's capitalized overhead rates resulting from the energy transition (as discussed in the response to BCUC IR1 43.1), there may be changes to the composition of departments and department costs over time. As described in Section 2.2 of the 2023 Capitalized Overhead Study for FEI (Appendix D5-1 to the Application), the methodology used in the study is flexible and adaptable to future changes and therefore changes to the proposed capitalized overhead rate may be incorporated into future studies.

43.3 Please discuss whether a different capitalized overhead rate may be appropriate for assets where the expected useful life may be shorter due to the form of energy that the assets will transport (e.g. natural gas versus hydrogen blend).

Response:

The purpose of the capitalized overhead rate is to capture the costs incurred to support capital activities each year that cannot be directly charged to capital and is determined irrespective of the useful life of the capital assets constructed. Thus, FortisBC's overhead capitalization methodology, as outlined in the 2023 Capitalized Overhead Studies, does not consider specific assets or the use of different capitalized overhead rates for assets with shorter useful lives or stranded asset risks.

The determination of an associated asset's useful life is addressed in a depreciation study. Any change in the useful life of an asset or group of assets in the future would be considered in a depreciation study at that time, and the cost related to those assets would include any overhead capitalized from when it was first constructed and placed in service.

Although the methodology used by FortisBC does not use a different capitalized overhead rate, the overhead capitalized is spread across eligible capital expenditures during the year and will depreciate over the same useful life as the assets the eligible capital expenditures are allocated to. Therefore, if an asset has a shorter expected useful life, so too does the overhead cost capitalized to it.

43.4 Please explain whether either FortisBC or KPMG considered the risk of stranded assets in their respective preparation and review of FEI's overhead capitalization methodology.

Response:

Please refer to the response to BCUC IR1 43.3.

K. SUPPLEMENTAL INFORMATION

44.0 Reference: SUPPLEMENTAL INFORMATION

Exhibit B-2 (Supplemental Information), pp. 29, 30, 32, and 39, Exhibit B-1,

Section C6.3, Table C6-2, p. C-182

Targeted Incentives

On pages 29 to 30 of the Supplemental Information, FortisBC states:

> FortisBC's decision to propose a suite of energy transition informational indicators instead of reproposing targeted incentives in the Application was also informed by its review of similar incentive mechanisms in other jurisdictions. This review indicates that utility-specific PIMs [performance incentive mechanisms] have been designed to address specific aspects of performance regarding the energy transition, but that these PIMs have been designed to work along side the existing ratemaking practices (cost of service, price or revenue cap framework, hybrid MRPs, etc.), and not as a way to fundamentally change the utility remuneration paradigm.

44.1 Please discuss the pros and cons of using targeted incentives (i.e. PIMs) versus informational indicators for the purposes of tracking and incentivizing FortisBC's energy transition performance during the proposed term of the Rate Framework.

Response:

Informational indicators and targeted incentives share a common set of benefits in that they can:

- Make regulatory goals more explicit and provide specific guidance on important government and regulatory policy goals;
- Allow regulators to pay more attention to whether a desired outcome is achieved rather than focusing on the specific means to obtain that outcome; and
- Be applied incrementally.

The major difference between informational indicators and targeted incentives relates to the financial incentives associated with the targeted incentives. The financial incentives (assuming the metrics, targets and incentives are all properly designed), are intended to encourage the utility to expedite its efforts to reach the targeted outcomes.

In terms of the potential pitfalls, both informational indicators and targeted incentives can be time-consuming or a distraction from other activities for all parties involved. If this burden becomes too great, it can undermine the value of these regulatory tools.

Targeted incentives can also face the following additional challenges (if not properly designed and implemented):

- **Disproportionate Incentives:** If not designed properly, targeted incentives can sometimes provide rewards (or penalties) that are too high relative to customer benefits or to the utility costs to achieve the targeted outcome. Financial incentives can also be inappropriate if they are based on volatile or uncertain factors, especially factors that are primarily beyond a utility's control.
- **Unintended Consequences:** Providing financial incentives for selected utility performance areas may encourage utility management to shift attention away from other performance areas that do not have incentives. This creates a risk that performance in the areas without incentives will deteriorate.
- **Uncertainty:** Significant and frequent changes to the design of the targeted incentives (metrics, targets, incentives) create uncertainty for utilities, thereby inhibiting efficient utility planning and encouraging utilities to focus on short- term solutions.

The stated benefits and pitfalls of targeted incentives apply irrespective of the area of priority that is targeted (i.e., whether the focus of these incentives is on the energy transition or other priorities).

When considering the benefits and pitfalls described above, as well as the BCUC's feedback in the MRP Decision as discussed in the response to BCUC Panel Supplemental IR 5, FortisBC continues to consider its proposed suite of energy transition informational indicators for FEI to be preferrable to targeted incentives at this time.

44.2 Please discuss the pros and cons of using targeted incentives versus the CGIF for the purposes of incentivizing and funding FortisBC's energy transition performance during the proposed term of the Rate Framework.

Response:

As explained in Section C5 of the Application, the CGIF is designed to fill the funding gap in non-DSM, pre-commercial, innovative activities covering the entire value chain. In other words, the CGIF is advancing the commercialization of innovative, clean technologies through activities that are primarily undertaken by third-party institutions and not FEI. Due to the nature of these projects, the targeted incentives cannot be considered as a substitute for the CGIF; rather, the two are complementary.

44.3 Please discuss whether, in FortisBC's view, specific reporting in Annual Reviews would also be a viable option to track and incentivize FortisBC's energy transition performance during the proposed term of the Rate Framework (e.g. an appendix to each Annual Review application with specific information to be reported, similar to FEI's CMAE budget review in the Current MRP).

44.3.1 If yes, please provide FortisBC's proposal for the content of such Annual Review reporting.

Response:

A further appendix or further inclusion of reporting on FortisBC's response to the energy transition is unnecessary and would be duplicative. FortisBC will already be reporting in detail in the Annual Review applications on its Clean Growth Initiatives[61] and, for FEI, its funding activities through the CGIF as well as its progress towards emissions reductions with the proposed suite of energy transition informational indicators.

Further, as explained in the response to BCUC Panel Supplemental IR 4, many of FEI's and FBC's energy transition related activities – such as the Companies' DSM applications and long term resource plans – are already reviewed and accepted in separate, standalone regulatory proceedings.

The BCUC and interveners will have the opportunity to ask questions through IRs and at the Annual Review Workshops on topics related to energy transition activities, and given the level of reporting already being provided in the Annual Review applications described above, FortisBC considers further specific reporting to be unnecessary and potentially duplicative, while adding further regulatory burden on the Annual Review application process.

44.4 Please state, with justification, FortisBC's preferred method (e.g. targeted incentives, informational, indicators, Annual Review reporting, or a combination of these items) to track and incentivize FortisBC's energy transition performance during the proposed term of the Rate Framework.

[61] For FEI, information on Clean Growth Initiatives is found in Section 3 (NGT and LNG Demand), Section 5 (NGT Related Recoveries and Biomethane Other Revenue), Section 6 (Clean Growth Initiatives O&M), and Section 7 (Clean Growth Initiatives Capital). For FBC, information on Clean Growth Initiatives is found in Section 3 (RS 96 EV DCFC Service Forecast), Section 5 (EV Stations Carbon Credits), Section 6 (Clean Growth Initiative O&M), and Section 7 (Clean Growth Initiative Capital).

Response:

Consistent with the proposed approach in the Application, FortisBC's preferred option to address the impacts of the energy transition is a combination of the following methods:

- **Informational indicators to track FEI's progress in achieving desired outcomes in specific areas of interest**. As explained in the response to BCUC IR1 44.1, targeted incentives and informational indicators share a common set of benefits, while the informational indicators have an additional benefit of being less likely to become misaligned with changes in government policies. This is particularly important, given the continued market and policy uncertainty (as discussed in the response to BCUC Panel Supplemental IR 4) and the challenges of creating a properly designed incentive framework (as discussed in the response in BCUC IR1 44.1).
- **Annual Reviews to provide the necessary flexibility to expand the Clean Growth Initiatives and consider their rate impacts in a timely manner.** As discussed in response to BCUC Panel Supplemental IR 1, given that the level and pace of rate impacts during the energy transition for both FEI and FBC is uncertain at this time, using the Annual Reviews to address ongoing rate impacts is a flexible approach, regardless of whether the impact is due to the energy transition or other factors.
- **The CGIF to fill the funding gap for innovative, non-DSM, pre-commercialization projects.** The CGIF acts as a complementary funding source to the other components of the proposed Rate Framework and fills the funding gap in pre-commercial, innovative initiatives that can potentially deliver substantial societal benefits.
- **Separate, standalone regulatory processes to review and accept/approve energy transition related initiatives and spending**. As discussed in the Application, many of the energy transition related activities such as DSM and renewable gas supply contracts are already reviewed and accepted in separate regulatory proceedings, and FEI and FBC may file separate CPCN applications for other new Major Projects. This will allow the BCUC and interveners to thoroughly review and scrutinize FEI's and FBC's proposed projects and plans in a transparent and effective manner.

On page C-182 of the Application, FortisBC proposes energy transition informational indicators for FEI only.

44.5 In the event that further regulatory process was undertaken on targeted incentives, would FortisBC propose energy transition targeted incentives for both FEI and FBC, or only FEI? Please explain why.

Response:

In the event that a further regulatory process was directed on targeted incentives, FortisBC would explore and develop potential incentives for both FEI and FBC. Based on the results of this assessment process, FortisBC would then determine which incentives to bring forward to the BCUC through a future application. As such, FortisBC cannot say whether it would propose incentives for both FEI and FBC at this time.

FortisBC notes that its proposed targeted incentives in the 2020-2024 MRP Application included a set of targeted incentives for both FEI and FBC. Further, as discussed in the response to the BCUC Panel Supplemental IR 5, the jurisdictional study of the Performance Incentive Mechanisms in the US indicates that while the majority of the PIMs are applied to the electric utilities, they can be extended to the operations of gas utilities.

On page 32 of the Supplemental Information, FortisBC states:

> […] If the BCUC is interested in exploring performance targets and incentives under these mechanisms, FortisBC could file a proposed set of incentives in a standalone Application or as part of a second phase to this proceeding. This process could also examine and refine the four principles as well as enhance understanding of performance above and beyond what is normally expected of a utility. If FortisBC were to file a standalone application (as opposed to a second phase to this proceeding), the Companies would require a minimum of four months to develop the application.

On page 39 of the Supplemental Information, FortisBC states:

> […] The [further regulatory] process could include refinement of the incentive principles, definition of performance expectations, establishment of achievable targets, and establishment of appropriate incentives.
>
> The primary benefit of this option is that, subject to the achievability of the targets and appropriateness of the incentives, targeted incentives could further incent investment in decarbonization. However, FortisBC notes that the current policy uncertainty may continue to pose challenges in designing appropriate targets, as there is a risk that the target (or incentive) could become misaligned as policy changes occur, requiring periodic review and adjustment. The primary disadvantage (beyond potential misalignment with policy) is that further regulatory process would be required to develop the targeted incentive framework.

44.6 In the event that further process was undertaken on targeted incentives via a second stage to this proceeding, please explain how much time would be needed for FortisBC to prepare a second stage application. If it is different from the four months to prepare a standalone application, please explain why.

Response:

The minimum time required to prepare an application under both a standalone process or as a second phase to this proceeding is four months, although this may change slightly depending on the availability of the key resources at the time that such a process was initiated (for example, if the process were to overlap with the IR response timeline or rebuttal evidence preparation timeline in this Rate Framework proceeding, additional time may be required). FortisBC's statement in the response to BCUC Panel Supplemental IR 5 that "If FortisBC were to file a standalone application (as opposed to a second phase to this proceeding), the Companies would require a minimum of four months to develop the application" was meant to highlight that if the BCUC decided to initiate a standalone proceeding right away, (as opposed to a second phase to this proceeding), FortisBC would not have been able to file an application sooner than four months from the time the BCUC initiated such a process, while the second-phase proceeding would logically start after the first phase is completed.

44.7 Please elaborate on the advantages and disadvantages of FortisBC proposing a set of targeted incentives as part of a standalone application or a second stage of this proceeding.

Response:

There is no material difference between the two regulatory processes; however, in FortisBC's experience with regulatory processes where there is overlap in subject matter, attempting to proceed with a separate standalone process while the related process is ongoing can lead to regulatory inefficiencies and overlap of evidence. Initiating a staged approach to regulatory processes has been used effectively in other proceedings, such as the Generic Cost of Capital proceedings, and results in an orderly addressing of issues, an organized approach to the evidence and proceeding documents, and the retention of interveners and the BCUC Panel from the first stage of the proceeding. On the other hand, a standalone application, if initiated sooner than the conclusion of this proceeding, could lead to slightly improved timeliness (the approved targeted incentives can potentially be implemented sooner).

44.8 Please state, with justification, what FortisBC would propose as the scope of a proceeding to review targeted incentives. Please provide a separate response for a standalone application or a second stage application if the proposed scope would differ for the two processes.

Response:

FortisBC would propose that the scope of a potential proceeding to review targeted incentives, whether a standalone application or as part of the second phase to this proceeding, would encompass the following:

1. **The appropriate principles for establishing and assessing the proposed targeted incentives.**

   As discussed in response to the BCUC Panel Supplemental IR 5, the proposed scope could examine and refine the four principles the BCUC used to assess the merits of the proposed targeted incentives in the MRP Decision and Orders G-165-20 and G-166-20, as well as enhance the understanding of performance “above and beyond” what is normally expected of a utility. This will then help to identify the priority areas that align with the principles.

2. **The identification of the priority areas on which incentives should be focused and the metrics appropriate for each identified priority area, i.e. how should they be measured.**

   Developing appropriate metrics is essential to a properly designed targeted incentive framework. The appropriate metric should provide useful information about whether specific policy or regulatory goals identified in each area of priority are being attained and should be easily measured and interpreted.

3. **The approach used for setting appropriate targets for each metric.**

   Using the internal historical data and/or peer group data, the Companies should propose appropriate targets for each metric in a way that would balance the costs of achieving the target with the benefits to customers.

4. **The incentive structures options available for the targeted incentives and how the appropriate incentive structure and the appropriate level of incentive is developed for each metric.**

   As discussed in the response to BCUC Panel Supplemental IR 5, there are various incentive structures to choose from. The potential application should explain why a specific incentive structure is proposed and determine the appropriate level of incentive for the proposed metrics.

5. **How the targeted incentives should be implemented (in terms of timing and reporting).**

   The Companies should propose their preferred mechanism for reporting on the performance for each metric and associated incentives as well as the timing for when targeted incentives should take effect.

6. Any other related issues.

This could include the assessment of any other issues such as potential duplication of reporting or any other potential impact of the targeted incentives on various components of the proposed Rate Framework in this proceeding.

44.9 Please state, with justification, what FortisBC would propose as the regulatory process of a proceeding to review targeted incentives (i.e. how many rounds of IRs, etc.). Please provide a separate response for a standalone application or a second stage application if the proposed scope would differ for the two processes. Please include FortisBC's estimated timeline to complete each process.

Response:

FortisBC would propose the same regulatory process for a proceeding to review performance targets and incentives whether conducted as a standalone application or a second stage to this proceeding. However, as noted in the response to BCUC IR1 44.6, if the standalone application ran concurrently with the current review process for this Application, more time may be needed if the process overlapped with IR responses or rebuttal evidence preparation.

FortisBC would propose a regulatory process with one round of IRs followed by an argument phase and has provided an example regulatory timetable below. Based on the example timetable, FortisBC estimates the timeline to prepare the application and then complete the regulatory review process would be 8 to 9 months, excluding the time for the BCUC to issue its decision on the Targeted Incentives application.

Action	Approximate Time Duration
BCUC Direction to file a Targeted Incentives Application (either as a separate Order or as part of the Decision on this Application)	
FortisBC prepares and files Incentives Application	18 weeks (approx. 4 months)
BCUC and Intervener IR1	4 weeks
FortisBC response to IR1	4 weeks
FortisBC final argument	3 weeks
Intervener final argument	2 weeks
FortisBC reply argument	2 weeks
Proceeding Time Duration	**Approximately 8 to 9 months**

44.10 Please discuss how the timeline to prepare and review either a standalone application or a second stage application would impact the proposed term of the

Rate Framework. For example, if further process on targeted incentives were to begin halfway through the proposed Rate Framework term, should the term be longer, and if so, by how much?

Response:

As discussed in the response to BCUC IR1 44.8, the proposed timeline for implementing the targeted incentives will be examined as part of the scope for a potential application. Nevertheless, any proposed timeline for a pilot targeted incentive proposal will not impact the proposed term of the Rate Framework. The proposed targeted incentives should be in place for at least one year and can be extended in future rate plans if desired. For instance, if Targeted Incentives were introduced in the third year of the proposed three-year Rate Framework term, FortisBC could propose to extend the incentives if it proposed to extend the Rate Framework term. Or, if the Rate Framework term was not extended, the Targeted Incentives that were in place for the third year of the Rate Framework term could potentially be extended for one or more years as part of the rate setting approach in place after 2027.

Attachment 10.1a

16.1 Does FEI's methodology for estimating future residential customer additions based on the Conference Board of Canada's housing starts forecast assume that the percentage of housing starts that choose natural gas service remains steady?

Response:

No specific calculation or adjustment to FEI's residential customer additions forecast method has been made to account for the capture rate or potential future resistance to natural gas heating for the following reasons:

- The forecasting method for residential customer additions is based on the net customer additions from the most recent years with actuals recorded, which will be 2022 for this Application, plus the growth rates from CBOC's forecast of housing starts. As such, all issues and drivers, including but not limited to GHG concerns, will be intrinsic in the actual data from 2022. In other words, if all things remain equal but customer additions are declining due to increasing resistance to natural gas heating, then these preferences will be reflected and captured in the most recent actual data used to forecast future customer additions; and

- The residential customer additions forecast is refreshed each year to ensure that any new or continuing trend within the actual data, including but not limited to concerns about GHG emissions, is fully and properly captured as part of the forecast. For example, if the 2023 actual data shows a further decline in the residential customer additions from the previous year, then the trend of this decline would be captured in the forecast as it uses the 2023 actual data as the starting point.

FEI notes that the impact in FEI's overall customer count or demand forecast due to variances in the forecast of residential customer additions is small, given the majority of the customers are existing customers. For instance, FEI is forecasting over 1 million customers in 2024 (i.e., 1,089,371); therefore, even if the residential customer additions are off by 1,000 (which would be almost 100 percent off from the current forecast of 1,026), this would only represent a variance of approximately 0.09 percent to the total number of customers. Ultimately, the variances due to over- or under-forecasts of customer additions are captured in the Flow-through deferral account and are recovered from or returned to customers in subsequent years. As such, customers are generally held whole from forecasting variances due to customer additions through the deferral accounts already in place.

16.2 In forecasting residential customer additions, does FEI take into account future resistance to natural gas heating due to concerns about GHG emissions?

Response:

Please refer to the response to BCSEA IR1 16.1.

4.7 Please confirm that the Seed forecast would be lower if the COVID years of 2020 and 2021 were removed from the forecast and prior years 2016, 2017, 2018, 2019 and 2022 were used to create the Seed forecast.

Response:

Based on FEI's forecasting methods, the 2023 Seed year would be lower if 2020 and 2021 were removed from the calculation as the demand was comparatively higher in those years; however, FEI has no data to support that the primary reason for the increased demand in those years was a result of the COVID-19 pandemic. There are many factors at play in any given year that could impact, positively and negatively, the overall demand. Furthermore, there is also no indication or quantifiable evidence that suggest the trend of working from home would not be continuing post-COVID.

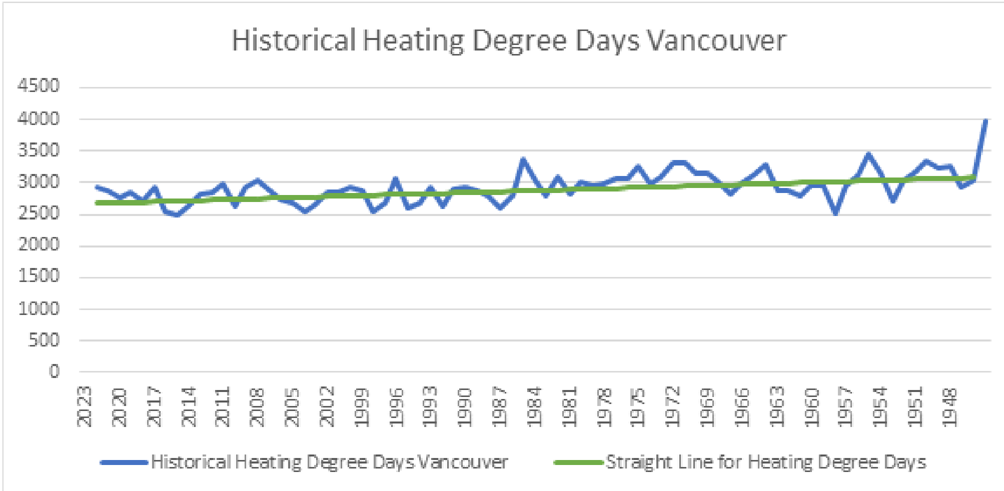
FEI does not consider it appropriate to selectively pick and choose which years should form part of the annual demand forecast. Such an approach would lead to inconsistent application of forecasting methods and require an inappropriate degree of subjectivity, with little to no benefit to customers. It is understood that there will be some variability in demand forecasting and that the actual and forecast results will differ. This is why FEI is approved to capture variances in annual demand in either the RSAM or the Flow-through deferral accounts and return/recover any variances to/from customers in subsequent years. Further, as demonstrated in Appendix A2 of the Application, the performance of FEI's forecasting method is consistently achieving small variances between actuals and forecast. For example, the average percentage variance in forecast versus actual residential demand was 2.8 percent over the past five years.

However, in order to be responsive, FEI calculated the normalized residential demand for the 2023 Seed forecast to be approximately 80 PJ with the historical data from 2020 and 2021 excluded as requested. This is approximately 2.6 PJ (or 3.1 percent) less than the 2023 Seed forecast of 82.6 PJ (which included the 2020 and 2021 data). A 2.6 PJ or (3.1 percent) variance between actual and forecast demand in any given year is normal and not unexpected. It is also in line with the average variance in the last five years. In any case, as highlighted above, the variances will be captured by deferral accounts and returned to/recovered from customers through rates in the subsequent years.

4.8 Please provide a FEI Seed forecast excluding the COVID years in a fashion FEI would use to create such a Seed forecast.

Response:

Please refer to the response to CEC IR1 4.7.

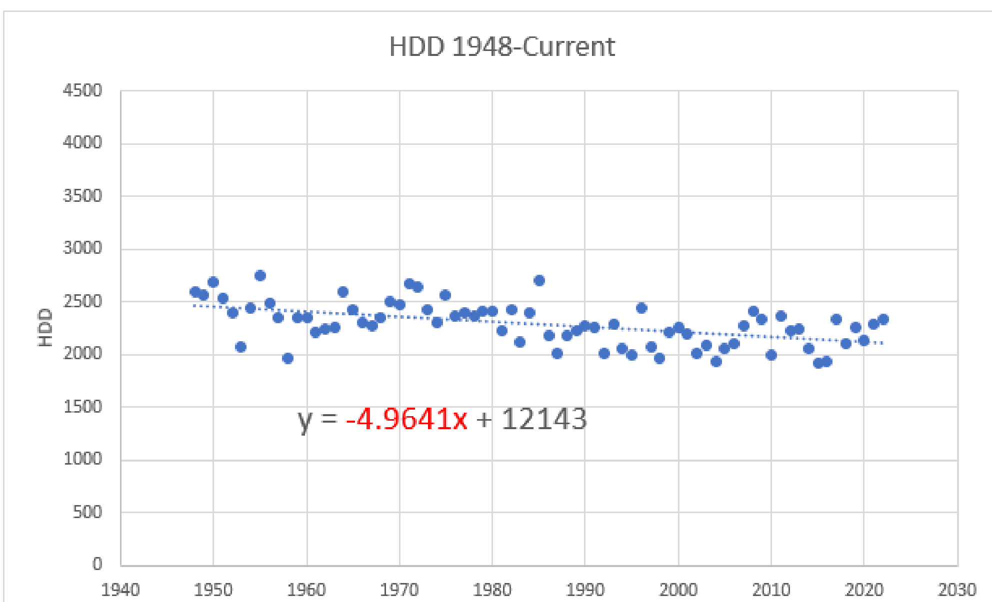


4.11 Please confirm the heating degree day information in the above graphic for Vancouver and the trendline of decreasing heating day requirements.

Response:

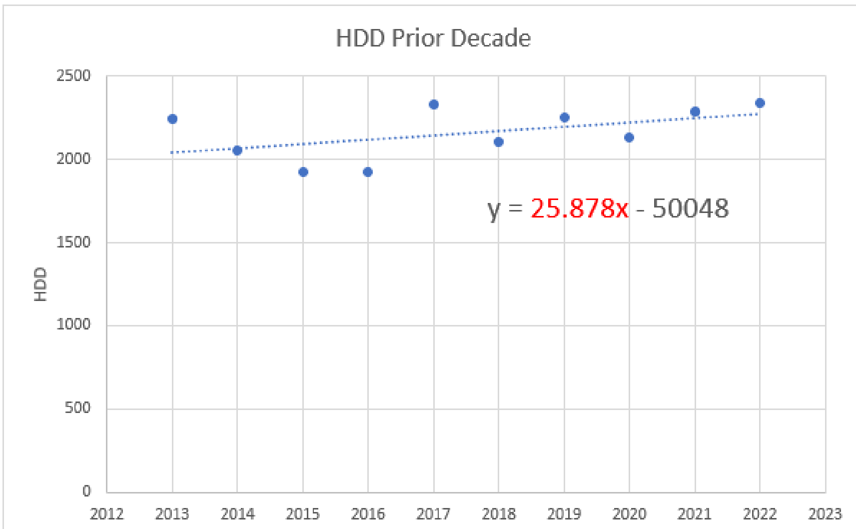
Confirmed; however, FEI notes that heating degree days (HDDs) are not an input to FEI's forecasting method.

In order to investigate the characteristics of the relation, FEI has reproduced the plot below using the HDDs from the Vancouver International Airport (YVR). FEI notes that in this plot, time increases from left to right, so the slope is opposite to the chart provided in the preamble where time decreases to the right.



FEI makes the following observations:

- When considering a trend from 1948 to present day, the annual HDD decreases by about 5 HDDs per year;
- In an average year there are approximately 2,290 HDDs, so a decline of 5 HDDs per year represents a decline of 0.2 percent per year;
- FEI does not use data back to 1948 for short-term forecasting. FEI does not consider 75-year-old data to be relevant to forecasting gas demand in 2024; and
- The HDDs trend in the last 10 years has been increasing at the rate of almost 26 HDDs (1.2 percent) per year as shown in the graph below. FEI notes that it uses 10 years of data in the ETS forecasting methods. Such an increased trend would have been reflected in the demand forecasts.



4.12 Please confirm that this graphic would be a representative proxy for the Lower Mainland and Vancouver Island, which would represent a majority of the FEI heating requirements.

Response:

Not confirmed. While this chart does depict the HDD trend since the 1940s, as explained in the response to CEC IR1 4.11, FEI does not consider 75-year-old data to be relevant to an effectively one-year forecast. Furthermore, as noted in the response to CEC IR1 4.11, the HDDs trend has been increasing at a rate of almost 26 HDDs (or 1.2 percent) per year over the last 10 years. As such, FEI does not consider the graph referenced in the preamble to this IR to be representative of current day trends for heating requirements for any of FEI's customers.

4.13 Please provide any FEI analysis of Heating Degree Days that FEI would prefer to the above heating degree day information.

Response:

FEI does not use HDDs in any part of the forecast and therefore does not have any alternative analysis. As described in Appendix A3 of the Application, FEI normalizes residential and commercial use rates for weather using a sophisticated non-linear set of equations applied to each region and rate class level. FEI uses this method because weather impacts different regions and rate classes differently.

FEI considers HDD analysis is at best, a simplistic way of accounting for weather at a high level that does not account for the different ways weather impacts different classes of customers. Using HDD analysis would mean that the same normalization factors would be applied equally between extremely weather sensitive residential customers and relatively less sensitive large commercial customers. This would lead to poor forecast performance.

3.1 Please provide, with supporting calculations, the revenue requirement and proposed rate increase for 2024 based on the following 2024 forecast load scenarios for the total load and for each customer class: (i) using the BAU load forecast for 2024; and (ii) using the 2024 Reference Case load forecast in the FBC 2021 LTERP.

Response:

FBC does not consider the two alternative approaches to forecasting load in 2024 to be reasonable for the purposes of setting 2024 rates, as the forecasts used in the 2021 LTERP are for long-term (20 year) forecasting purposes and were developed for the 2021 LTERP based on actuals up to 2019 only. As such, the LTERP forecasts do not reflect any trend in the actual demand from 2020 to 2022 or any new load that was unknown at the time of the 2021 LTERP forecast.

In contrast, the forecasts used in revenue requirements are intended for short-term forecasting purposes and include more up-to-date data. FBC's forecasts in the annual reviews have consistently produced reasonably accurate results. Variances between actual and forecast load are expected, which is why FBC is approved to record all load variances in a deferral account.

However, for the purposes of responding to this IR, please refer to Table 1 below for the calculation of the 2024 revenue requirements (i.e., Line 42) and proposed 2024 rate increase (i.e., Line 46) for FBC if the 2024 Forecast load were based on:

(i) the BAU scenario in the 2021 LTERP; and

(ii) the Reference Case scenario in the 2021 LTERP.

FBC also provides the as-filed forecast for comparative purposes. FBC notes that the load forecasts under the BAU and Reference Case scenarios provided in the 2021 LTERP were before DSM savings. For an equivalent comparison with the forecasts in the 2024 Annual Review, FBC applied the same DSM savings from the 2024 Annual Review to the load forecasts in the BAU and Reference Case scenarios from the LTERP.

Table 1: Summary of FBC 2024 Rate Increase if Load Forecast is Based on 2021 LTERP BAU and Reference Case Scenarios

Line	Particular	2021 LTERP BAU	2021 LTERP Reference	2024 Annual Review As Filed	Reference
1	**Load Before DSM Savings (MWh)**				
2	Residential	1,205,837	1,205,838	1,307,962	
3	Commercial	989,297	1,012,861	996,458	
4	Wholesale	609,027	609,027	597,438	
5	Industrial	569,987	618,701	576,954	
6	Lighting	11,039	11,039	9,262	
7	Irrigation	35,978	35,978	38,684	
8	Net	3,421,164	3,493,443	3,526,758	Sum of Line 2 to Line 7
9	Losses	294,394	300,342	303,080	
10	Gross Load (MWh)	3,715,558	3,793,785	3,829,838	Line 8 + Line 9
11					
12	**Load After DSM Savings (MWh)**				
13	Residential	1,196,766	1,196,768	1,298,891	
14	Commercial	967,007	990,570	974,168	
15	Wholesale	601,401	601,401	589,812	
16	Industrial	556,521	605,236	563,488	
17	Lighting	10,860	10,860	9,084	
18	Irrigation	35,793	35,793	38,500	
19	Net	3,368,349	3,440,628	3,473,943	Sum of Line 13 to Line 18
20	Losses	290,050	295,998	298,736	
21	Gross Load (MWh)	3,658,399	3,736,626	3,772,679	Line 19 + Line 20
22					
23	**Revenue at Existing 2023 Rate ($million)**				
24	Residential	189.809	189.810	206.007	
25	Commercial	109.993	112.674	110.808	
26	Wholesale	56.666	56.666	55.574	
27	Industrial	49.185	53.490	49.800	
28	Lighting	2.655	2.655	2.221	
29	Irrigation	3.688	3.688	3.967	
30	Total ($million)	411.997	418.983	428.377	Sum of Line 24 to Line 29
31					
32	**2024 Revenue Requirement ($million)**				
33	Cost of Energy				
34	Power Purchase	156.410	161.682	173.694	Updated Based on Gross Load on Line 21
35	Wheeling Expense & Water Fees	19.838	19.838	19.838	Section 11, Schedule 19, Line 23 + Line 28
36	O&M Expense (Net)	63.174	63.174	63.174	Section 11, Schedule 19, Line 11
37	Depreciation & Amortization	64.070	64.070	64.070	Section 11, Schedule 19, Line 12
38	Property Taxes	18.573	18.573	18.573	Section 11, Schedule 19, Line 13
39	Other Revenue	(12.092)	(12.092)	(12.092)	Section 11, Schedule 19, Line 14
40	Income Taxes	10.075	10.075	10.075	Section 11, Schedule 19, Line 17
41	Earned Return	111.719	111.719	111.719	Section 11, Schedule 19, Line 19
42	**Total ($million)**	**431.767**	**437.039**	**449.051**	**Sum of Line 34 to Line 41**
43					
44	Revenue Deficiency / (Surplus)	19.770	18.056	20.674	Line 42 - Line 30
45					
46	**2024 Rate Increase**	**4.80%**	**4.31%**	**4.83%**	Line 44 / Line 30

In both the 2021 LTERP BAU and Reference Case scenarios, the 2024 Forecast load would be lower compared to the 2024 Forecast in this Application.

However, the impact of the reduced load on the power purchase expense (PPE) is not necessarily directly proportionate to the reduction in load, which is why the revenue deficiency and rate impacts do not correlate directly to the impact on load. This is because the PPE is made up of a mix of power supply resources, including purchases under the BC Hydro PPA (which may include Tranche 2 as well as Tranche 1 energy) and market and contracted purchases.

Ultimately, the BAU scenario results in a 2024 rate increase that is almost identical to the proposed rate increase in this Application, while the Reference Case scenario results in a slightly lower rate increase for 2024. However, as explained above, FBC does not consider either forecast method from the 2021 LTERP to be an appropriate method for forecasting load in rate-setting applications. The BAU and Reference Case scenarios use less up-to-date data and are intended for long-term planning purposes.

4.1 Please explain why FBC used a regression period of six years to forecast the 2024 residential customer count, as compared to the three-year regression period used in 2022 and 2023 proceedings to forecast the residential customer counts for those years.

Response:

Each year, FBC chooses the regression period based on statistical criteria and other information available, such as the year-to-date actual customer count. As the trend in correlation between population and customers can change from year to year as the latest actual data is added, the regression period may change from forecast to forecast, just as it has this year compared to the forecast used in the Annual Review for 2023 Rates.

For the 2023 Seed year and 2024 Forecast, the statistical analysis shows that the three-year regression has a P-value of over 0.05, indicating that the data set is not statistically significant (i.e., a result of chance). As such, FBC determined that it could not use the three-year regression. In contrast, the six-year regression has a P-value of less than 0.05,[1] which indicates that the data and the underlying trend is statistically significant (i.e., not a result of chance).

4.1.1 Please explain whether FBC anticipates the trend in correlation between population and customers to change for the forecast year from previous years. If so, why. If not, why not.

[1] This is the value that is most commonly used for a statistically significant test.

Response:

FBC cannot know whether the trend in correlation between population and customers will change in the forecast year compared to previous years. Rather than attempting to guess the trend that will emerge over the forecast year, FBC bases its residential customer forecast on actual historical data using a regression that is statistically significant. This historical data will reflect the current correlation between population and customers and is therefore the most reasonable basis for the forecast. If the correlation between population and customers changes over the forecasting period, the impact of such a change would be small and any such change will be reflected in the historical data used in the forecast for the following year.

As shown in Table 12-1 of the Application, variances due to over- or under-forecasting of residential customer count and/or load are captured in the Flow-through deferral account, and are recovered from/returned to customers in the following year.

4.2 Please provide the year-to-date actual and projected residential customer count for 2023 compared to the 2023 forecast and discuss whether a longer regression period (e.g. six years as used to forecast the 2024 residential customer count) might have resulted in a more or less accurate 2023 forecast customer count.

Response:

The year-to-date actual (as of August 2023) residential customer count is 130,447 and the remaining four-month projection is 731, resulting in a total 2023 Projected residential customer count of 131,178.

If a six-year regression was used in the Annual Review for 2023 Rates, then the 2023 customer forecast would have been 129,296, which is negative 1.4 percent below the 2023 Projected number of 131,178 (with actuals up to August).

Please refer to the table below which compares the 2023 Projected number (with actuals up to August) to the 2023 Approved forecast and a new forecast using a six-year regression. The six-year regression would have resulted in an under-forecast for 2023 with a larger absolute variance.

Residential Customer Count	2023 Forecast	2023 Projected (with Actuals up to August)	Variance (%)
2023 Approved (3-year regression)	132,015	131,178	0.6%
New 2023 Forecast (6-year regression)	129,296	131,178	-1.4%

5.3 Please explain the reasonableness of using a 10-year historic trend of annual UPC values to calculate the 2024 residential UPC forecast compared to using a 6-year and 3-year historic trends.

Response:

FBC uses a 10-year historic trend of annual UPC values since it is more statistically significant compared to the 6-year and 3-year historic trends. Table 1 below presents the trend regression results for 10, 6, and 3 years. The 10-year trend has a high R^2 value of 0.8 combined with a much lower P-value of 0.00028 when compared to the 6- and 3-year trends.

Table 1: 3, 6 and 10-Year Trend Regression Results

Regression	3 Year	6 Year	10 Year
Start Year	2020	2017	2013
End Year	2022	2022	2022
R^2	0.996	0.674	0.825
Adjusted R^2	0.992	0.592	0.803
df	5	2	9
P-value	0.04124	0.04527	0.00028
Intercept	580	348	395
Slope UPC	-0.28	-0.17	-0.19
2024 Forecast (MWh)	9.75	10.01	9.89

6.1 Please provide the range of R2 values which are considered by FBC to be ‘low’ and ‘high’ values.

Response:

In this context FBC would consider any R^2 value below 0.5 to be low while any value above 0.7 would be considered high or reasonable. FBC notes there are no “textbook” definitions for high and low R^2 values and as a result these limits may be different in different forecast applications.

Furthermore, from a statistical point of view, FBC notes that when the 2022 actual weather-normalized commercial load was added to the regression, the R^2 value was less than 0.5 which suggests an alternative regression should be investigated. As a result, FBC tested the regression using actual commercial load (i.e., not normalized) which showed a high R^2 value. It is reasonable to use the regression that achieves a higher R^2 value.

6.2 Please explain and provide any reason(s) for the change in 2022 relating to the seasonal R2 values for the commercial load class (i.e. from a strong correlation in the 2014 to 2021 period to a low correlation for all seasons).

Response:

FBC cannot definitively explain the change in 2022 relating to the R^2 values, as there are various factors that could contribute to this change. However, FBC notes that it is possible that the more extreme weather observed recently did not influence the commercial load as much as the residential and wholesale loads, therefore causing a change in the correlation to weather.

Regardless of the reasons for the change, as explained in the response to BCUC IR1 6.1, FBC appropriately used a regression that showed a better correlation with actual data instead of weather-normalized data.

As discussed in the response to BCUC IR1 4.1.1, any variances due to over- or under-forecasting the 2024 commercial load will be captured in the Flow-through deferral account, and recovered from or returned to customers in the following year.

20.1 Please discuss in what ways FBC has sought to enhance the accuracy and reliability of its forecasting techniques relative to its previous rate review application?

Response:

An area where FBC has worked to improve its forecast in recent years is its engagement with Wholesale customers. In preparation for both the Annual Review for 2023 Rates and the current Application, FBC held workshops with interested municipalities to discuss forecasting for the upcoming year. Additionally, FBC's key account managers work with industrial customers to ensure that response rates for the surveys continue to be high and to understand the basis for customers' forecasts.

However, FBC does not seek to enhance the accuracy and reliability of its forecasting techniques in advance of each of its rate applications. This process requires extensive analysis of different methods and the compilation of multiple years of data to compare the accuracy of any new method to FBC's existing methods. At this time, FBC considers its forecasting methods to produce reasonably accurate results for the purposes of setting rates for the upcoming year. Over the most recent six years, as shown in Table 6.2 in Appendix A2, the average variance of the aggregate gross load forecast is low at 1.1 percent. Variability in actual and forecast results are normal and expected, which is why FBC is approved to record all load variances in the Flow-through deferral account.

Before considering any changes to any methods, the current performance needs to be carefully considered. Changes to methods should only be considered when the average aggregate load forecast variance is high, which it is not. If changes are made without considering current forecast performance, then the change may actually cause performance to decline and variances to increase.

Changing methods can be both costly and time consuming. New methods need to be precisely described and objective. They need to be tested first with historic data and then for at least five years with new data. The results need to be recorded and carefully compared to existing methods. An update should only be considered if a new method is shown to be materially superior to the current method. However, as pointed out above, the average variance in the gross load over the last six years is approximately 1.1 percent; thus, the room for improvement that could be offered by a new method is limited and would not be effective considering the time and effort.

20.2 How does FBC assess the effectiveness of its forecasting strategies and what steps are taken to identify areas for improvement?

Response:

Please refer the response to RCIA IR1 20.1.

9.1 Please provide an updated version of the response to BCOAPO 9.2 (from the Annual Review of 2023 Rates) which starts at 2013, includes 2022 actual values and extends the table to include the current forecast values for 2023 and 2024 (using 2012 as the base year for cumulative DSM savings).

Response:

Please refer to the table below for an updated version of the response to BCOAPO IR1 9.2 from the Annual Review for 2023 Rates proceeding, with 2022 Actual, 2023 Seed and 2024 Forecast included. FBC notes DSM savings per customer are first calculated on an annual basis and then added to previous years' values to show cumulative savings per customer.

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
Residential Program Savings (MWh)	16,200	8,686	5,639	12,538	10,154	6,553	7,850	7,202	7,896	5,630	4,537	4,534
Residential Customer Count	111,862	113,431	114,166	115,772	117,748	120,291	122,465	124,966	126,678	129,131	131,323	133,291
Annual Savings per Customer (kWh)	129	145	77	49	108	86	54	64	58	44	35	34
Cumulative savings per customer (kWh)	129	274	351	400	508	594	648	712	770	813	848	882

As explained in Section 1.2.1 of Appendix A3 of the Application, FBC uses the historical actual UPCs (i.e., 2013 to 2022 in this Application) to forecast future UPC (i.e., 2023 Seed and 2024 Forecast in this Application). As such, the cumulative savings per customers, including any loss to persistency, from 2013 to 2022 are already embedded in the historical actual UPCs when used to develop the "before-savings" forecast UPC slope as shown in Table A3-5 of Appendix A3 of the Application. For clarity, the term "before-savings" means the aforementioned UPC slope was developed with a regression that only included the cumulative DSM savings per customers from 2013 to 2022, but *before* the estimated DSM savings from 2023 and 2024. This before-savings slope assumes savings due to DSM measures from 2013 to 2022, including any loss to persistency, will continue in a trend that has been embedded and intrinsic in the historical actuals into the future years. Since the slope is *before* the incremental DSM savings from 2023 and 2024, they are subtracted from the before-savings forecast to arrive at the after-savings forecast, i.e., accounting for the DSM savings due to DSM measures from 2013 to 2022, *and* the estimated savings from new DSM measures in 2023 and 2024. There is no double counting of DSM savings from 2023 and 2024 as they are only subtracted from the before-savings forecast once.

9.2 Please provide a schedule that sets out for the years 2013 to 2022: i) the actual normalized UPC value; ii) the cumulative DSM savings per customer (per the previous question 9.1); and iii) the normalized UPC assuming no DSM savings after the 2012 base year (i.e., the sum of (i) and (ii)).

Response:

The requested schedule is presented in the table below.

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
i) Residential Normalized UPC (MWh)	12.48	11.51	11.41	11.27	11.31	11.03	10.43	10.89	10.57	10.32
ii) Cumulative Savings Per Customer (MWh)	0.13	0.27	0.35	0.40	0.51	0.59	0.65	0.71	0.77	0.81
iii) UPC Assuming No Cumulative DSM Savings	12.61	11.78	11.76	11.67	11.82	11.62	11.08	11.60	11.34	11.14

9.3 Please provide the results (similar to Exhibit B-2, Appendix A3, Table A3-6) based on a trend analysis of the result from previous question 9.2, part (iii).

Response:

Please refer to Table 1 below for the requested trend results using the residential UPC that exclude all cumulative DSM savings from 2013 to 2022 as shown in item iii) in the response to BCOAPO IR1 9.2. Based on this trend analysis, the 2023 and 2024 *before all DSM savings* UPC values would be 11.00 MWh and 10.89 MWh, respectively.

Table 1: Residential UPC Trend Analysis based on BCOAPO IR1 9.2

Regression	UPC
Start Year	2013
End Year	2022
R^2	0.665
Adjusted R^2	0.624
df	9
Intercept	245
Slope UPC	-0.12

As noted above, the 2023 and 2024 UPC forecasts using the residential UPC trend in Table 1 above (i.e., based on item iii) from BCOAPO IR1 9.2) do *not* include any historical DSM savings as well as any loss to persistency from all years since 2013. As such, in order to account for DSM savings and to compare against FBC's after-savings forecasts, FBC subtracted the cumulative DSM savings per residential customer from the response to BCOAPO IR1 9.1 for 2023 and 2024 as shown in Table 2 below. The difference compared to the residential after-savings UPC using FBC's forecasting method as shown in Section 4 of Appendix A2 of the Application is small, at 0.11 MWh and 0.19 MWh for 2023S and 2024F, respectively.

Table 2: Comparison of Residential After-Savings UPC between FBC's Forecasting Method and BCOAPO IR1 9.3

	2023S	2024F
UPC forecast *without all DSM Savings* from 2013 to 2022 (BCOAPO IR1 9.2, item iii)	11.00	10.89
Less: Cumulative DSM savings (BCOAPO IR1 9.1, item iv)	(0.85)	(0.88)
UPC forecast with Cumulative DSM Savings since 2013	**10.15**	**10.01**
FBC's Methods - Section 4 of Appendix A2 (As-Filed)	**10.04**	**9.82**
Difference	+0.11	+0.19

FBC's observations on this alternative forecasting approach suggested by BCOAPO are the same as discussed in the response to BCOAPO IR1 9.4 from the Annual Review for 2023 Rates proceeding:

- The regression based on the approach suggested in BCOAPO IR1 9.1 to 9.3 has a worse R^2 value at 0.665 than the regression in FBC's approach, which has an R^2 value of 0.825 as shown in Table A3-5 of Appendix A3.
- In order to accounting for DSM savings based on a regression without all cumulative DSM savings, the DSM savings will have to be added back later instead. This would require an assumption that there is no change related to those DSM savings in all years since 2013. For instance, if certain DSM measures were implemented in 2013 such as new LED light bulbs, it is entirely possible that the LED light bulbs could have been removed or replaced

with newer LED light bulbs over the years. If the regression is completed before the DSM savings, then any changes to the DSM savings would not have been captured in the regression. On the other hand, FBC's approach would be a regression on all historical load, which would capture all changes embedded in the historical load, including any changes related to the DSM savings, e.g., due to persistent losses.

Regardless, the variances between actual and forecast use rates are captured in the Flow-through deferral account.

10.7 With respect to Appendix A2, Tables 3.1 and 3.2, how was the Commercial customer count for forecast for 2023 and 2024 determined?

Response:

Please refer to the formula below for the calculation of the expected commercial customer count, which is forecast based on the provincial GDP supplied by the CBOC.

$$\textit{Commercial Customer Count}_t = b_0 + b_1 \times GDP_t$$

Coefficients' b0 and b1 are obtained from an ordinary least squares (OLS) regression analysis on the 2013 to 2022 actual customer count data. The regression results are shown in Table 1.

Table 1: Results of Commercial Customer Count Regression

Regression	Commercial
Start Year	2013
End Year	2022
R^2	0.97
Adjusted R^2	0.94
df	9
Intercept	3,457
Slope GDP	0.05

3.24 The average industrial load has been increasing at over 6% for the last several years. Please explain whether or not FBC would find Industrial SEED and FORECAST values in the 3% or 6% range as potentially reasonable.

Response:

No, such an approach would not be reasonable. FBC's approach to determining the Industrial load forecast through a combination of customer load surveys and, when not available, escalation of the most recent annual loads by the corresponding provincial GDP growth rates for individual industries continues to be the best approach.

Each individual industrial customer is uniquely impacted by many different factors, and therefore has the best understanding of what their future load requirements will be. The industrial survey provides each customer with the opportunity to concisely convey the net impact of those factors to FBC on an annual basis, providing the forecast with a level of insight that the approach suggested by the CEC would not achieve.

Attachment 10.1b

3.1 Please confirm that the demand forecast is lower by 1.6 PJ or 0.72% of total demand.

Response:

Confirmed. As shown in Figure 3-1 of the Application, the 2024 demand is forecast to be 220.2 PJ which is 1.6 PJ lower than the 2023 Approved demand of 221.8 PJ. 1.6 PJ is 0.72 percent of 221.8 PJ.

4.14 Please explain the significant drop in Industrial Demand for natural gas supply in 2022 and the anticipated continued loss of that demand.

Response:

FEI explained the drop in industrial demand in 2022 in Footnote 13 on pages 17-18 of the Application. FEI provides that footnote here for ease of reference:

> The primary driver of the 5.5 percent variance between 2022 Forecast and 2022 Actual demand is the impact of the expiry of FEI's contract with BC Hydro Island Generation (IG). The 2022 Forecast was prepared in the spring of 2021. At that time, it was not known that BC Hydro would not renew the IG contract and that the contract would instead expire in April 2022. As a result, the 2022 Forecast included a full year of demand from BC Hydro IG while the actual demand was only from January 2022 to April 2022 (i.e., up to the point of termination). Excluding the impact of BC Hydro IG, the aggregate variance drops to 1.3 percent, consistent with recent years' variance results.

4.15 Please explain whether or not there is a probability of further loss of the industrial demand from similar circumstances to those affecting 2022 demand.

Response:

The loss of industrial load in 2022 was a one-time event from the loss of an exceptionally large customer contract and not indicative of a continuing trend. Please also refer to the response to CEC IR1 4.14.

1.1 Please reconcile the forecast commercial customer additions of 426 with the average of the forecast customer additions in 2020, 2021, and 2022 (average of 384, 479, 427 = 430).

Response:

Effective January 1, 2023, FEI incorporated the Fort Nelson (FEFN) service territory into FEI's revenue requirement, in accordance with the BCUC's approval of common delivery rates for FEFN by Order G-278-22. This treatment was also explained at the FEI Workshop during the Annual Review for 2023 Delivery Rates proceeding. The dark blue bars of Figure 3-5 of the Application, which provide the historical actuals from 2013 to 2022, exclude FEFN so as to present the FEI data in a manner consistent with past annual review filings (and because FEFN was not under common rates with FEI during those years).

Please refer to Table 1 below which shows the three-year average of 426 net commercial customer additions after including FEFN. For clarity, negative customer additions mean there was a decline in the total number of customers in FEFN.

Table 1: Calculation of 3-year Average Commercial Customer Additions

Commercial Customer Additions	2020	2021	2022	3-yr Average
FEI	384	479	427	430
FEFN[1]	(5)	(7)	(1)	(4)
Total	**379**	**472**	**426**	**426**

Note to table:

[1] *Refer to Section 3.19 of Appendix A2 of the Application for historical net customer additions in FEFN.*

8.2 Please discuss and provide supporting rationale for the increase to the 2024 forecast summer system peak capacity (from 683.5 MW to 697.3 MW), given the declining gross load growth rate on the FBC system for the forecast year.

Response:

The peak forecast is based on the average of escalated historic actual peaks from the past 10 years. FBC has recently recorded some larger than average summer peaks which are included in the calculation. As a result, the peak forecast has increased compared to the 2023 Approved summer peak forecast even though the gross load forecast is decreasing.

The following table demonstrates the calculation of the 2024 Forecast summer peak as per the method described in Section 1.3 of Appendix A3.

Row	Summer, MW	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	Forecast, MW
1	Escalated to 2024	649.0	675.5	689.8	681.0	644.7	690.9	659.7	698.4	787.3	721.5	689.8
2	Adjustment for Data Centers and DSM											7.5
3	Summer Peak											697.3

The 697.3 MW result is explained as follows:

1. The average of the escalated actual peaks is 689.8 MW.
2. A net adjustment of 7.5 MW is added to account for data centre loads and DSM savings.
3. The forecast peak of 697.3 MW is the sum of 689.8 MW and 7.5 MW.

The following figure shows the escalated peaks. The impact of the “heat dome” weather event is visible in 2021.

18.1 Please explain why the Forecast 2022 Net and Gross Variance (%) values are significantly higher compared to previous years, while also acknowledging that the years affected by COVID exhibit relatively stable patterns?

Response:

The bulk of the 2022 net and gross load variance was due to a new large industrial customer having significantly higher loads than was anticipated based on the results of the industrial customer survey. If the variance from this customer is removed, the net and gross load variances would be approximately 2 percent and 2.6 percent, respectively.

FBC considers the industrial survey to be the most appropriate tool for creating the industrial forecast because each industrial customer is best able to forecast their future loads. In the case of large customers in new industrial sectors, there can be initial challenges to accurately forecasting future loads. FBC key account managers do and will continue to work with all industrial customers to help them better predict future requirements.

The remainder of the variance in 2022 net and gross load is due to residential, commercial, and wholesale loads that were higher than anticipated. As discussed in the response to RCIA IR1 3.1, FBC is not able to further identify the drivers of the demand variances for these loads since demand variations from year to year are influenced by many factors such as, but not limited to, employment trends, inflation and interest rates, GDP and other market factors which cannot be isolated and quantified from the metered load data that FBC receives.

8.1.1 Please provide an explanation of the 2022 variance (between actual weather normalized load and the 2022 forecast included in the Annual Review of 2023 Rates) for the Residential class, separating out the impact of: i) customer count; ii) forecast versus actual UPC before 2022 DSM savings; and iii) forecast versus actual 2022 DSM savings.

Response:

As explained in the response to BCOAPO IR1 8.1, the 2022 forecast included in the Annual Review for 2023 Rates application was the Seed year forecast and is thus different than the 2022 Forecast provided in the Annual Review for 2022 Rates application.

There is a 16.4 GWh increase in actual 2022 residential load when comparing the 2022 seed year forecast from the Annual Review for 2023 Rates application. The variance is due to an increased UPC forecast which is somewhat offset by a decreased customer count forecast and increased DSM forecast. The requested variance impacts are provided below.

Residential Impacts	GWh
i) Customer Count	-1.0
ii) UPC	18.6
iii) DSM	-1.2
Total	16.4

8.2 Please provide a schedule that compares the load forecast (by customer class) for 2023 as approved per FBC's Annual Review of 2023 Rates versus the forecast 2023 loads for each customer class in the current Application.

Response:

Please refer to the following table.

Table 1: Comparison of 2023 Approved Forecast and 2023 Seed Forecast

	2023F from 2023 Annual Review	2023S from 2024 Annual Review	Variance
Residential	1,301	1,308	7
Commercial	973	967	-6
Wholesale	578	591	12
Industrial	575	562	-13
Lighting	9	9	0
Irrigation	39	39	-1
Net	3,476	3,476	0
Losses & Company Use	299	299	0
Gross	3,775	3,775	0

8.2.1 Please provide an explanation of the variance for the Residential class, separating out the impact of: i) customer count; ii) the current UPC forecast prior savings from 2023 DSM programs versus the forecast UPC for 2023 (inclusive of 2022 but not 2023 DSM savings) from the Annual Review of 2023 Rates; and iii) forecast incremental 2023 DSM savings per the Annual Review of 2023 Rates versus the current Application.

Response:

There is a 7 GWh increase in 2023 when comparing the Annual Review for 2023 Rates to the Annual Review for 2024 Rates. The variance is due to an increased UPC forecast which is somewhat offset by a decreased customer count forecast. The incremental DSM is approximately the same for 2023 for both applications and therefore does not impact the variance. Please see the following breakdown.

Table 1: Residential Impacts between 2023F and 2023S (GWh)

Customer Count	-4
UPC	11
DSM	0
Total	7

8.3 With respect to Table 2.3 (Appendix A2), please provide an explanation of the change between the Residential forecast for 2023 versus 2024 separating out the impact of: i) customer count; ii) UPC prior to incremental 2024 DSM savings; and iii) incremental 2024 DSM savings.

Response:

There is a 9 GWh decrease when comparing the Residential forecast for 2023 versus 2024. The variance is due to a decreased UPC forecast and incremental 2024 DSM which is somewhat offset by an increased customer count forecast. The requested variance impacts are presented below.

Table 1: Residential Impacts between 2023S and 2024F (GWh)

i) Customer Count	21
ii) UPC	-25
iii) DSM	-5
Total	-9

10.8 What are the major factors contributing to the difference between the 2023 (after savings) forecast Commercial load used in the Annual Review of 2023 Rates and the 2023 (after savings) forecast for Commercial load in the current Application?

Response:

The following factors contributed to the difference in forecast results:

- The inclusion of the 2022 actuals in the forecast of the current Application which were not available in the Annual Review for 2023 Rates; and
- An updated CBOC GDP forecast which incorporates the latest market data that was not available in the Annual Review for 2023 Rates.

However, there is only a 5.6 GWh (0.58 percent) difference between the 2023 Commercial load forecast from the Annual Review for 2023 Rates application and the current Application.

12.3 What are the major factors contributing to the difference between the 2022 forecast (after savings) Industrial load used in the Annual Review of 2023 Rates and the actual 2022 Industrial Load?

Response:

The major contributing factor to the 20 GWh difference between the 2022 Seed year after savings Industrial forecast provided in the Annual Review for 2023 Rates application and the 2022 Actual Industrial load was lower than forecast loads from customers in the data mining, manufacturing, and forestry sectors.

12.4 What are the major factors contributing to the difference between the 2023 (after savings) forecast Industrial load used in the Annual Review of 2023 Rates and the 2023 (after savings) forecast for Industrial load in the current Application?

Response:

The major contributing factor to the 13 GWh difference between the 2023 Forecast after-savings Industrial load forecast in the Annual Review for 2023 Rates application and the 2023 Seed year forecast after-savings Industrial load in the current Application is lower than anticipated loads from customers in the data mining and manufacturing sectors.

12.5 With respect to Appendix A2, Table 2.5, please provide explanations for: the decrease in Industrial load between the 2023 (after savings forecast) and 2024 (after savings forecast).

Response:

FBC assumes that this question is referring to the variance in Industrial load; however, FBC notes that Table 2.5 of Appendix A2 of the Application provides information on the Wholesale load, not the Industrial load. Further, as shown in Table 2.6 of Appendix A2, the 2024 Forecast after savings Industrial load has increased (not decreased) compared to the 2023 Seed forecast.

FBC has explained the basis for the 2024 Forecast Industrial load forecast in the Application and notes that the difference between the 2024 Forecast and 2023 Seed forecast is only 1.4 GWh or 0.3 percent. FBC does not have any additional explanation for this increase.

3.21 Please explain what the increased Industrial Loads were in 2018, 2019, 2021 and 2022.

Response:

The following industries had the greatest increases in load resulting in increased total industrial load during the years 2018, 2019, 2021 and 2022:

- 2018: Data Centre and Forestry
- 2019: Data Centre and Forestry
- 2021: Data Centre and Forestry
- 2022: Data Centre

3.22 Please explain what the decreased loads were in 2017 and 2020.

Response:

The following industries had the greatest decreases in load in 2017 and 2020:

- 2017: Manufacturing
- 2020: Data Centre and Forestry

3.25 Please confirm that the decline in Lighting Load is a function of implementing more energy efficient lighting.

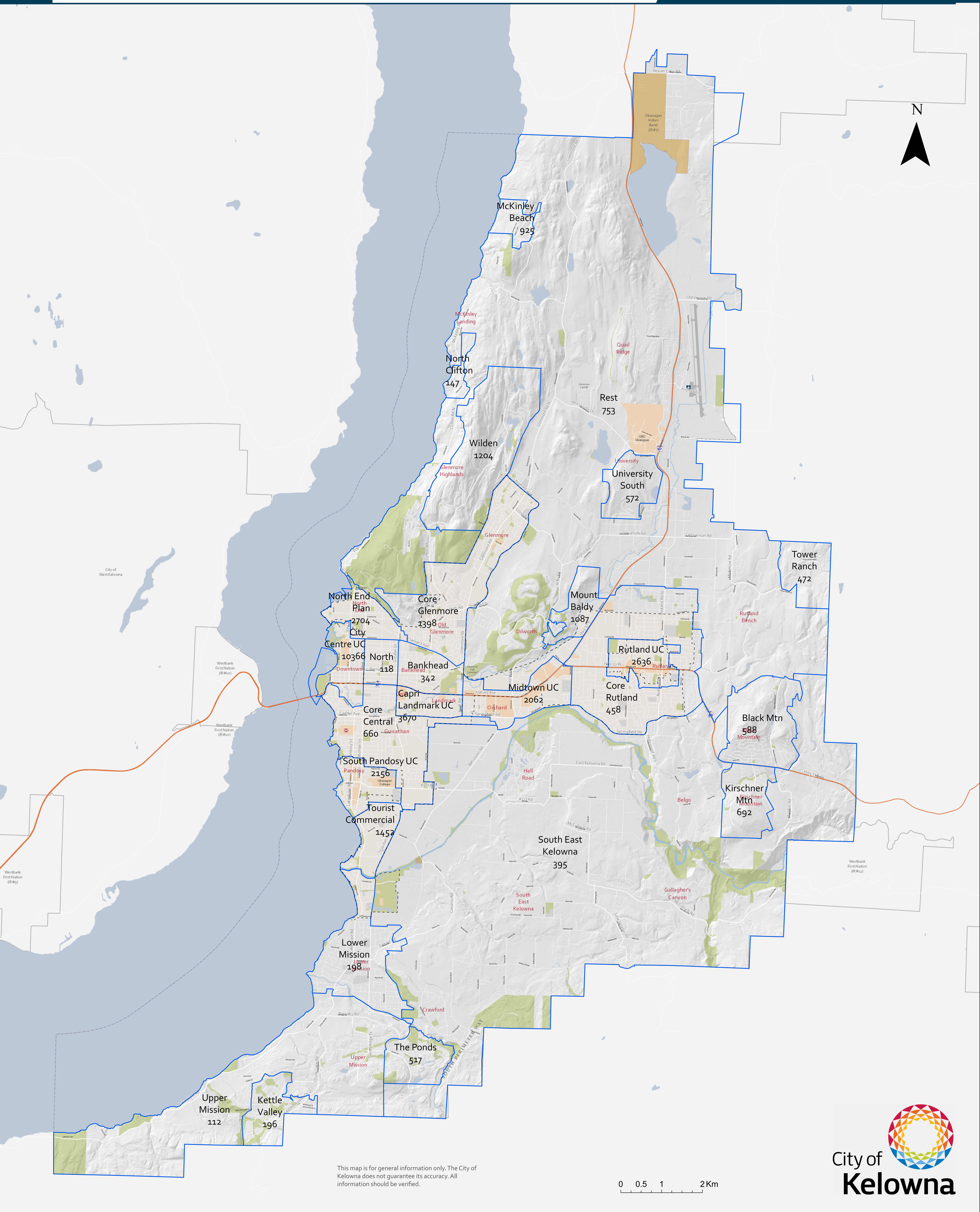
Response:

Confirmed.

Attachment 23.5

Model City Residential Unit Projection

Iteration 4
2040



This map is for general information only. The City of Kelowna does not guarantee its accuracy. All information should be verified.

City of Kelowna

Attachment 24.9

MEDIUM-VOLTAGE, METAL-CLAD SWITCHGEAR

STRATEGIC PLAN 2021

Prepared by

METSCO
MAKING IT POSSIBLE

METSCO Report no. 21-105-001-R2

December 15, 2021

Disclaimer

This 2021 report has been prepared by METSCO Energy Solutions Inc. ("METSCO") for Fortis BC ("FBC"). Neither FBC, nor METSCO, nor any other person acting on their behalf makes any warranty, expressed or implied, or assumes any legal responsibility for the accuracy of any information or for the completeness or usefulness of any process disclosed or results presented, or accepts liability for the use, or damages resulting from the use, thereof. Any reference in this report to any specific process or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement or recommendation by FBC or METSCO.

Medium-Voltage, Metal-Clad Switchgear Strategic Plan

December 2021

Prepared By: Kurtis Martin-Sturmey, P.Eng

Nirvaan Bhagwandass, EIT

Kyra Poupore , EIT

Pranav Pattabi, P.Eng., M.Eng.

Reviewed by:

Ali Naderian, P.Eng, PhD

Approved By:

Thor Hjartarson, P.Eng.

Executive Summary

Scope of the Study

METSCO Energy Solutions' ("MES") work included review and consolidation of Fortis BC's ("FBC") asset data sets for medium-voltage ("MV") metal-clad switchgear("MCS"); a site visit to supplement existing asset records with visual inspections, infrared scans, and partial discharge ("PD"); asset condition, failure probability, and risk assessment; and preparation of the recommended capital and maintenance plan. In total, METSCO assessed and calculated Health Index values for the following MCS and their associated circuit breakers ("CBs") at eight stations, all located in south-west British Columbia:

- Blueberry ("BLU")
- Castlegar ("CAS")
- Crawford Bay ("CRA")
- Creston ("CRE")
- Hollywood ("HOL")
- Pine Street ("PIN")
- Saucier ("SAU")
- O.K. Mission ("OKM")

The asset condition data used in the study is a combination of data maintained by FBC as part of its regular asset management practices and data collected by METSCO during the site visit from April 6th and 7th, 2021. The Asset Condition Assessment ("ACA") results are based on condition data recorded by FBC up to the end of May 2021. This information was provided to METSCO between February and May 2021.

Methodology

Asset Condition Assessment

For all asset classes that underwent assessment, METSCO used a consistent scale of asset health from Very Good to Very Poor. The numerical Health Index ("HI") corresponding to each condition category serves as an indicator of an asset's remaining life, expressed as a percentage. Table 0-1 presents the HI ranges corresponding to each condition score, along with their corresponding implications as to the follow-up actions recommended for FBC.

Table 0-1: Health Index Ranges and Corresponding Implications for the Asset Condition

Health Index Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of aging or minor deterioration of a limited number of components	Normal Maintenance
[70-85)	Good	Significant Deterioration of some components	Normal Maintenance
[50-70)	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
[30-50)	Poor	Widespread serious deterioration	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
[0-30)	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

Using this scale, METSCO calculated the HI for every asset in the scope of the assessment using the applicable and available “condition parameters” – individual characteristics of the state of an asset’s components. Each condition parameter has its own sub-scale of assessment and a weighting contribution that represents the percentage in the overall HI made up by the particular parameter. METSCO’s findings for each asset class were developed using this methodology, as described in more detail in Section 3.

Impact/Risk Analysis

The age and HI for each asset is used to determine its effective age. The effective age determines its failure probability based on METSCO’s industry-standard failure curves supplemented by Typical Useful Life (“TUL”) values from the original equipment manufacturer, where available (specifically for MV SF_6 circuit breakers in this analysis).

The risk cost is calculated by first finding the impact cost for all failure modes. These are then summed by category to find the total customer impact, financial impact, environmental damage impact, and collateral impact costs. Each impact cost is then multiplied by the failure probability to get risk costs which are summed to get the total risk cost. A high-risk cost can result from a high failure probability even if the asset is in otherwise good condition. This is due to failure probability being driven by both HI and asset age, either of these factors could lead to a higher risk cost associated with the asset.

METSCO's findings for MCS and MV circuit breakers were developed using this methodology, as described in more detail in Section 4.

Lifecycle Cost Analysis

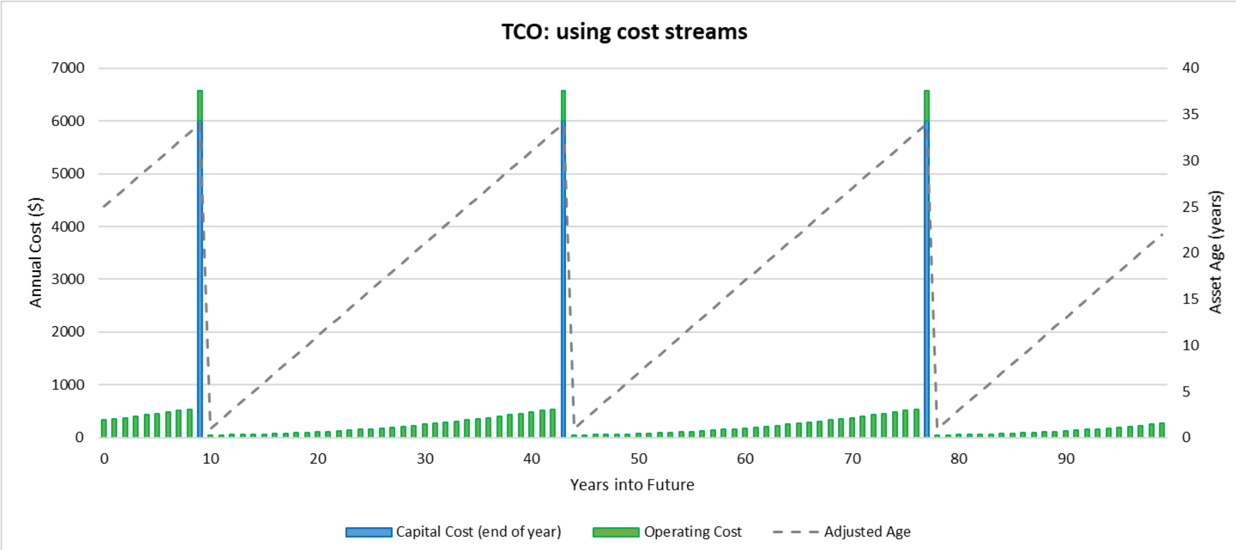
A discounted cash flow ("DCF") analysis was used to determine the value of an investment based on an analysis of the cash flows. The DCF analysis seeks to identify all cash flows (in and out) at some time or with a specified frequency and transform them into a common basis (annualized).

The total cost of ownership ("TCO") is calculated by using the concepts from the DCF analysis. The TCO represents the total cost of owning the asset over its life cycle. TCO is calculated by finding the net present value ("NPV") of the cash flows where all cash flows are outflows, therefore an end value which is "negative" is a cost. The cost streams considered during analysis were:

- Capital cost of asset replacement
- Proactive outage cost (customer outage costs associated with replacing the equipment)
- Annual Maintenance Cost: Operating cost of the equipment (based on cost and schedule of maintenance activities annualized)
- Annual Risk Cost: Calculated using the failure probability and impact of failure at a given year.
- Discount Rate: 6.5%
- Evaluation horizon: 100 years

The above cost streams were used to determine the Optimal Intervention Time ("OIT") of each asset by identifying the TCO at the economic end-of-life ("EOL") of the asset. This signifies the most optimal cost stream that can be achieved by this asset.

Figure 0-1: Economic EOL using Cost Streams



The figure above visualizes how the cash flows are used to determine the EOL of the asset by discounting all costs to the NPV.

After determining the OIT of each asset within the ten-year timeframe, investments were prioritized utilizing the TCO increase avoided by investing and the discrete replacement cost of investing which represents a benefit-to-cost ratio for each conceptualized project.

METSCO's findings for each asset class were developed using this methodology, as described in more detail in Section 5.

Results

As Table 0-2 and Table 0-3 show, most assets are in Fair or better condition. Most assets are also in the Moderate to Low-Risk categories. This can indicate FBC has taken steps in the past to manage their asset health and performance for the benefit of its customers. As with every system, however, there are areas that require FBC attention in the coming years.

Table 0-2: Summary of Circuit Breaker Results

Asset ID	Position	Station	HI Score	Total Impact	Annual Failure Probability[1]	Annual Risk Cost[1]	OIT (Year)
12392	FDR1	BLU	61%	$92,484.84	2.10%	$1,937.87	2042
12393	FDR2	BLU	61%	$105,035.27	2.10%	$2,200.84	2038
20682	FDR1	CAS	70%	$124,975.23	2.48%	$3,105.28	2037
20681	FDR2	CAS	70%	$156,020.49	2.48%	$3,876.67	2029
20680	FDR3	CAS	65%	$47,289.35	2.48%	$1,175.01	2066
14871	T5M	CRA	60%	$42,582.25	1.88%	$799.82	2064
14872	152	CRA	53%	$14,836.63	2.83%	$420.33	2086
14873	252	CRA	55%	$30,493.40	2.49%	$759.65	2067
14874	TIE	CRA	52%	$1,496.95	3.01%	$45.10	2085
14875	352	CRA	61%	$18,114.82	1.88%	$340.25	2092
14876	452	CRA	71%	$25,384.21	1.48%	$375.56	2095
14877	T4M	CRA	66%	$30,160.70	2.66%	$446.23	2095
12414	FDR1	CRE	55%	$354,328.01	9.20%	$32,602.83	2021
12413	FDR2	CRE	55%	$692,207.58	9.20%	$63,692.18	2021
21204	752	HOL	69%	$80,052.98	0.83%	$667.53	2072
21605	652	HOL	50%	$8,080.68	4.22%	$341.00	2079
21606	T1M	HOL	71%	$378,040.18	1.61%	$6,074.02	2062
21608	352	HOL	71%	$159,611.14	1.61%	$2,564.49	2044
21609	T2M	HOL	61%	$3,879.90	1.88%	$72.88	2092
21610	552	HOL	71%	$251,058.58	1.61%	$4,033.79	2056
21612	452	HOL	66%	$218,403.53	2.83%	$6,187.51	2032
21613	252	HOL	66%	$306,272.84	2.83%	$8,676.90	2038
21615	152	HOL	61%	$203,002.39	6.73%	$13,662.35	2021
21617	T3M	HOL	71%	$338,220.17	3.79%	$12,829.15	2032
12348	CAPBANK	PIN	93%	$724.91	0.23%	$1.64	2110
12347	FDR2	PIN	93%	$42,353.87	0.23%	$95.62	2065
12346	T1M	PIN	93%	$42,382.35	0.23%	$95.68	2065
22835	152	SAU 1	66%	$177,851.35	5.32%	$9,469.23	2022
22840	252	SAU 1	66%	$161,082.93	4.43%	$7,134.36	2024
22834	352	SAU 1	55%	$322,434.57	4.43%	$14,280.63	2021
22838	452	SAU 1	66%	$330,230.89	4.43%	$14,625.93	2021
22836	552	SAU 1	55%	$7,237.28	4.43%	$320.54	2080
22828	652	SAU 1	66%	$179,722.60	4.43%	$7,959.91	2021
22829	752	SAU 1	55%	$221,769.50	4.43%	$9,822.17	2021

[1] Current year

Asset ID	Position	Station	HI Score	Total Impact	Annual Failure Probability[1]	Annual Risk Cost[1]	OIT (Year)
22831	852	SAU 1	55%	$175,615.80	4.43%	$7,778.02	2021
22830	952	SAU 1	55%	$230,991.20	4.43%	$10,230.60	2021
22832	1052	SAU 1	66%	$7,237.28	4.43%	$320.54	2080
22837	MAIN1	SAU 1	66%	$674,618.45	4.43%	$29,878.85	2021
22839	MAIN2	SAU 1	49%	$8,979.93	5.64%	$506.78	2068
22833	TIE	SAU 1	66%	$8,524.11	5.32%	$453.84	2071
21150	T152	SAU 2	71%	$408,383.96	2.66%	$10,859.52	2021
21144	T252	SAU 3	61%	$7,497.76	2.66%	$199.38	2087
22105	152	OKM	67%	$260,949.42	8.54%	$22,296.06	2021
22099	252	OKM	66%	$197,595.43	4.00%	$7,910.66	2021
22106	352	OKM	63%	$280,221.90	4.00%	$11,218.58	2021
22103	452	OKM	71%	$114,489.77	4.00%	$4,583.56	2029
22104	552	OKM	71%	$405,669.80	4.00%	$16,240.84	2021
22101	T1M	OKM	67%	$948,485.34	8.54%	$81,040.55	2021
22100	T2M	OKM	71%	$490,389.72	4.00%	$19,632.57	2055
22102	MOBILE M	OKM	71%	$7,698.30	4.00%	$308.20	2080

Table 0-3: Summary of Switchgear Results

Station	HI Score	Total Impact	Annual Failure Probability[2]	Annual Risk Cost[2]	OIT (Year)
BLU	64%	$1,070,547.37	10.78%	$115,410.39	2021
CAS	13%	$1,670,022.82	41.26%	$689,101.36	2021
CRA	75%	$835,386.96	8.58%	$71,704.83	2043
CRE	63%	$1,850,965.69	14.34%	$265,429.41	2021
HOL	77%	$2,277,981.97	4.15%	$94,562.09	2046
PIN	75%	$673,940.37	5.02%	$33,801.26	2038
SAU 1	80%	$2,089,801.35	4.43%	$92,557.29	2050
SAU 2	88%	$18,238.43	3.88%	$708.27	2021
SAU 3	85%	$2,234,448.49	5.97%	$133,469.28	2087
OKM	77%	$1,823,663.04	3.88%	$70,820.14	2033

[2] Current year

Recommendations

Capital Recommendations

The recommended capital replacements for the next ten years are summarized in Table 0-4. For other assets, continued maintenance is recommended.

Table 0-4: Recommended Replacements Within 10 Years

Asset Type	Asset Number	Equip. Position	Station	CAPEX	Recommendation
MCS	CAS	N/A	CAS	$899,160	Replace Switchgear immediately. Switchgear will not outlast the breakers. CBs have already been refurbished once.
MCS	OKM	N/A	OKM	$2,397,760	Replace Switchgear in 2 years. Another option is to replace the breakers at 152 and T1MAIN at this time and then do a complete switchgear replacement after 10 years – but not recommended.
MCS	CRE	N/A	CRE	$599,440	Replace Switchgear in 4 years Replacement of entire switchgear with CBs.
MCS	BLU	N/A	BLU	$599,440	Replace Switchgear in 6 years. Switchgear will not outlast the breakers. CBs have already been refurbished once.
MVCB	SAU 1	All	SAU 1	$545,493	Replace all Circuit Breakers at SAU 1 in 8 years.
MVCB	21615, 21617, 21612	152, T3M, 452	HOL	$265,878	Replace Circuit Breakers 152, T3M, and 452 at HOL in 10 years. FBC to reassess in 10 years to determine if additional breakers may need to be replaced.

Recommendations for Data Improvements

Data availability is critical to producing prudent, accurate, and justified decision-making outputs. It represents the single most important element that can influence the degree to which the AM decision-making relies on objective factors. Companies understand that it is critical to execute continuous improvement procedures through an AM data lifecycle, such that data gaps and inaccuracies can be addressed and mitigated. In the case of this report, the quality of the results is dependent on the available data.

METSCO recommends that FBC continues to work on mitigating existing data gaps so that more accurate HI grades can be given. This includes updating the MCS age data so that assumptions do not have to be used.

Lastly, METSCO recommends that FBC continues to work on capturing more detailed loading information – specifically, load information by customer type. This will ensure the load distribution ratios, referenced in Table 4-1, are as accurate to FBC as possible.

Table of Contents

List of Figures

List of Tables

List of Abbreviations

ACA – Asset Condition Assessment

AM – Asset Management

BLU – Blueberry station

CAS – Castlegar station

CRA – Crawford Bay

CB – Circuit Breaker

CRE – Creston

DAI – Data Availability Index

DCF – Discounted Cash Flow

EOL – End-of-Life

FBC – Fortis BC

HI – Health Index

HOL – Hollywood station

IR – Infrared

MCS – Metal Clad Switchgear

METSCO – METSCO Energy Solutions Inc.

NPV – Net Present Value

OIT – Optimal Intervention Time

OKM – O.K. Mission station

PIN – Pine Street station

PD – Partial Discharge

SAMP – Strategic Asset Management Plan

SAU – Saucier station

TCO – Total Cost of Ownership

TUL – Typical Useful Life

WACC – Weighted Average Cost of Capital

1. Introduction

METSCO Energy Solutions Inc. ("METSCO") is an industry expert in Asset Condition Assessment ("ACA") and Asset Management ("AM") practices due to our extensive experience in conducting ACAs, developing AM plans, and implementing AM frameworks for transmission and distribution utilities across North America. METSCO's collective record of experience in these areas is among the most extensive in the world, with our AM frameworks gaining acceptance across multiple regulatory jurisdictions. A selection of METSCO's past projects is attached as Appendix A to this report.

Fortis BC ("FBC") is an electricity distributor operating in southern British Colombia. FBC engaged METSCO to prepare a comprehensive ACA study for ten switchgears and associated circuit breakers that are a part of FBC's electrical system. The study's primary purpose is to objectively determine the condition of FBC's assets as a key step in the capital expenditure process for renewal investments. Supplementary objectives include preparing the ACA results to be used to continuously improve FBC's AM framework.

A unique ACA methodology is applied to each asset class. The adoption of the ACA methodology requires identifying end-of-life criteria for various components associated with each asset type, followed by periodic asset inspections, and recording of asset conditions to identify the assets most at risk at reaching the end-of-life criteria over the planning horizon. Each criterion represents a factor that is influential, to a specific degree, in determining an asset's (or its component's) condition relative to its potential failure. These components and tests are weighted based on their importance in determining the assets' end-of-life.

The assets covered in the report include the major asset classes of medium-voltage ("MV") metal-clad switchgear ("MCS") and circuit breakers ("CB"). Asset condition data used in the study is a combination of FBC maintenance data as part of its regular asset management practices and data collected on-site by METSCO personnel during a site visit. The ACA results are based on condition data recorded by FBC up to the end of May 2021. This information was provided to METSCO between February 2021 and May 2021.

2. Data Collection

2.1 Data Sources

To assess the condition of FBC's system, METSCO was provided with available asset inspection and maintenance data for the asset classes in scope. Various sources hold records of FBC's inspection and maintenance activities. Most of this data came from primary sources such as equipment inspection forms completed by FBC staff, or the results of specific tests such as Infrared Scans.

Additionally, METSCO was provided with historical operating data for assets that require operating information for the HI calculation. An example of operating data used is the historical failure information.

2.2 Site Visit

METSCO conducted a site visit to the MCS in scope on April 6th and 7th, 2021. METSCO performed visual inspections, infrared ("IR") scans, and partial discharge ("PD") testing. The visual inspection included evaluating if cubicle doors, hinges, bolts, and latches were free from damage and operated properly, and if the overall installation was protected from dust, corrosion, high humidity, and high temperatures. IR thermography involved the use of a thermal imaging camera to identify the temperature rise of switchgear components with respect to the ambient temperature. PD testing provided critical information on the quality of insulation that occurs due to the localized breakdown of a certain portion of the insulation system, under voltage stress. The site visit results can be found in

Appendix A - Site Visit Report.

3. Asset Condition Assessment

The ACA is a key step in developing an asset replacement strategy. By evaluating the current set of available data related to the condition of in-service assets comprising an organization's asset portfolio, condition scores for each asset are determined. The ACA involves the collection, consolidation, and utilization of the results within an organizational AM framework for the purposes of objectively quantifying and managing the risks of its asset portfolio. The level of degradation of an asset, its configuration within the system, and its corresponding likelihood of failure feed directly into the risk evaluation process, which identifies asset candidates for intervention (i.e., replacement or refurbishment). Assets are then grouped into program and project scopes that are evaluated and prioritized.

The ACA is designed to provide insights into the current state of an organization's asset base, the risks associated with identified degradation, approaches to managing this degradation within the current AM framework, and how to best make use of these results to extract the optimal value from the asset portfolio going forward.

3.1 Inputs & Assumptions

The raw data inputs are maintenance records, age data, functional obsolescence data and historical failure information from FBC, and information gathered during the site visit.

Maintenance records included information such as:

- Visual Inspections
- Resistance Tests
- Timing Tests

The site visit inputs include:

- Visual Inspections
- IR Scans
- PD Tests

In the cases where age data for switchgears was unavailable, assumptions for age data were made based on the installation year of the corresponding transformer or assumptions made by FBC.

3.2 International Standards for AM

The following paragraphs serve as a brief introduction to the ISO standards and provide a brief overview of the applicability of AM standards within an entity.

The industry standard for AM planning is outlined in the ISO 5500X series of standards, which encompass ISO 55000, ISO 55001, and ISO 55002. Each business entity finds itself at one of the three main stages along the AM journey:

1. Exploratory stage - entities looking to establish and set up an AM system;
2. Advancement stage - entities looking to realize more value from an asset base; and
3. Continuous improvement stage - those looking to assess and progressively enhance an AM system already in place for avenues of improvement.

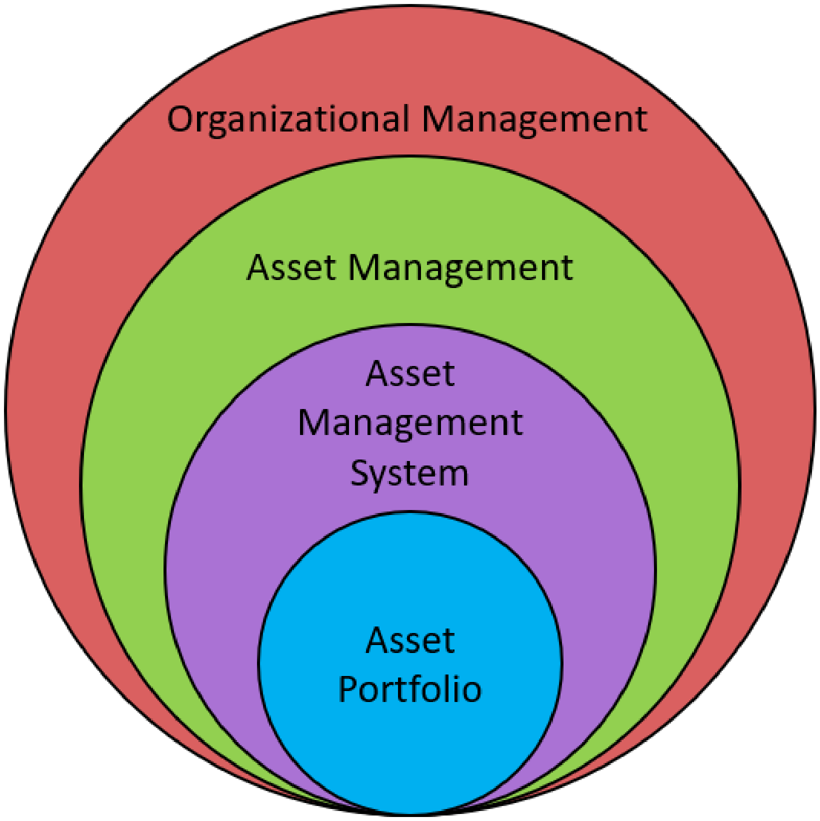
Given that AM is a continuous journey, ISO 5500X remains continuously relevant within an organization; providing an objective, evidence-based framework against which the organizations can assess the managerial decisions relating to their purpose, operating context, and financial constraints over the different stages of their existence.[3]

An asset is any item or entity that has value to the organization. This can be actual or potential value, in a monetary or otherwise intangible sense (e.g., public safety). The hierarchy of an AM framework begins with the asset portfolio, containing all known information regarding the assets, sits as the fundamental core of an organization. The ACA is the procedure to turn the known condition information into actionable insights based on the level of deterioration.

Around the asset portfolio, the AM system operates and represents a set of interacting elements that establish the policy, objectives, and processes to achieve those objectives. The AM system is encompassed by the AM practices – coordinated activities of the organization to realize maximum value from its assets. Finally, the organizational management organizes and executes the underlying hierarchy.[3]

[3] ISO 55000 – Asset management – Overview, principles and terminology

Figure 3-1: Relationship between key AM terms[3]



3.3 ACA within the AM Process

A well-executed AM strategy hinges on the ability of an organization to classify its assets via comprehensive and extensive data and data collection procedures. This includes but is not limited to: the collection and storage of technical specifications, historical asset performance, projected asset behaviour and degradation, the configuration of an asset or asset-group within the system, the operational relationship of one asset to another, etc. In this way, AM systems should be focused on the techniques and procedures in which data can be most efficiently extracted and stored from its asset base to allow for further analysis and insights to be made. With more asset data on hand, better and more informed decisions can be made to realize greater benefits and reduce the risk across the asset portfolio managed by an organization.[4]

AM is fundamentally grounded in a risk-based evaluation of continued value. The overarching goal of an AM process is to quantify all assets risk by their probability and impact (where possible)

[4] ISO 55002 – Asset management – Management systems – Guidelines for the application of ISO 55001

and then look to minimize these risks through AM operations and procedures. The ACA quantifies the condition of each asset under study and is an appropriate indicator of its failure probability. Making asset replacement decisions directly based on the ACA results constitutes a condition-based intervention strategy.

AM practices can help quantify and drive strategic decisions. A better understanding of the asset portfolio and how it is performing within an organization will allow for optimal decision-making. This is largely due to best AM practices being a fundamentally risk-based approach, which lends it to be a structured framework for creating financial plans driven by data. AM practices should also have goals in mind when framing asset investments, changes in asset configuration, or acquisition of new assets. This can include better technical compliance, increased safety, increased reliability, or increased financial performance of the asset base. ISO 55002 states explicitly that all asset portfolio improvements should be assessed via a risk-based approach prior to being implemented.[4] The criticality of the asset determines its failure impact. A risk-based asset intervention strategy should consider both the probability and impact in the decision-making process.

3.4 Continuous Improvement in the AM Process

The application of rigorous AM processes can produce multiple types of benefits for an organization including, but not limited to: realized financial profits, better classified and managed risk among assets, better-informed investment decisions, demonstrated compliance among the asset base, increased public and worker safety, and corporate sustainability.[3]

AM processes are ideally integrated throughout the entire organization. This requires a well-documented AM framework that is shared between all relevant agents. In this way, the organization stands to benefit the most from its internal resources, whether it be via technical experts, those operating and maintaining the assets or those with an understanding of the financial operations and constraints on the organization as a whole. As a future-state goal, utilities and other organizations alike should strive to document their AM guiding principles within a Strategic Asset Management Plan (“SAMP”). The SAMP should be used as a guide for the organization to apply its AM principles and practices for its specific use case. Distribution of the SAMP should be well-publicized within an organization and updated regularly, in order to best quantify the most current and comprehensive AM practices being implemented. Just as the asset base performance is subject to an in-depth review, the AM process and system should be reviewed with the same rigor.[3]

AM should be regarded as a fluid process. Adopting a framework and an idealized set of practices does not bind the organization or restrict its agency. With time, the goal of any AM system is to continually improve and realize benefits within the organization through better management of its asset portfolio. Continually improved asset data and data collection procedures, updated SAMPs, and further integration into all aspects of an organization's activities as it grows and changes over time should be the goal of any AM framework.[4]

3.5 Asset Condition Assessment Execution

METSCO's execution path in completing the ACA study can be is a four-phase procedure:

1. *Initial information gathering*: including initial interviews with FBC staff to investigate system configuration and the prominence of certain asset classes, establish the range of available condition data sources at the beginning of the engagement, and confirm the key assumptions regarding these factors with FBC subject matter experts through a series of interviews.

2. *Database construction* – activities to construct a single database of condition-related information for each FBC asset class using the provided data sources. This includes consolidation of FBC's asset inspection records, databases containing results of technical tests performed by FBC.

3. *HI and Data Availability Index ("DAI") calculation* – upon confirming the integrity of its condition dataset along with the accuracy of assumptions made in its preparation, METSCO calculated the Health Indices and DAI for all asset classes. Additional data sources were requested from FBC to improve the accuracy of the asset health calculation if applicable.

4. *Results Reporting* – the final phase of the project scope was the creation of the ACA report.

3.6 Asset Condition Assessment Methodologies

Prior to completing an ACA, a methodology needs to be selected for the current entity. The four most common methodologies that can be employed to assess the condition of the system health include:

1. Additive models – asset degradation factors and scores are used to independently calculate a score for each individual asset, with the HI representing a weighted average of all individual scores from 0 to 100;
2. Gateway models – select parameters deemed to be most impactful on the asset's overall functionality act as "gates" to drive the overall condition of an asset, by effectively "deflating" the scores of other (less impactful) components;

3. Subtractive models – consider that a relatively Poor condition for any of several major assets within a broader system of assets could act as a sufficient justification to drive investments into the entire system; and
4. Multiplicative models – a HI that dynamically shifts the calculation towards specific degradation factors, if they are a leading indicator to show that an asset is failing.

The additive and gateway models are typically used for assessing individual assets, whereas the subtractive and multiplicative models are typically used for aggregate and composite system-level assessments. The latter models are still in an early stage and require extensive refinement and validation to confirm their applicability. The gateway model assigns gates to criteria or asset subcomponents which are difficult or expensive to replace and maintain, and/or are known to be a major cause of asset malfunctioning. This methodology is commonly used in conjunction with the additive model for major assets such as wood poles, where a "gate" score will act to reduce the HI due to a low recorded score for a given criterion. For example, if the remaining strength of a wood pole is less than 60%, the final HI for that asset is halved.

In general, most distribution utilities employ an additive model with select gateway model elements. METSCO selected this approach when conducting the ACA.

3.7 Overview of Selected Methodology

3.7.1 Condition Parameters

To calculate the HI for an asset, formulations are developed based on condition parameters that can be expected to contribute to the degradation and eventual failure of that asset. A weight is assigned to each condition parameter to indicate the amount of influence the condition has on the overall health of the asset. Figure 3-2 exemplifies an HI formulation table.

Figure 3-2: HI Formulation Components

Degradation Factor:
The asset aging mechanisms, tests, or failure modes.

Condition Indicator Numerical Score:
The converted numerical score associated with the degradation factor, which corresponds directly with the indicator letter score.

Condition Max Score:
The highest obtainable Score for each degradation factor. (4 x Weight)

#	Degradation Factor	Weight	Condition Indicator Letter Score	Condition Indicator Numerical Score	Condition Max Score
1	Degradation Factor 1	4	A-E	4-0	16
2	Degradation Factor 2	6	A,C,E	4,2,0	24
3	Degradation Factor 3	6	A-E	4-0	24
				Asset Max Score	64

Condition Weight:
The impact of the condition with respect to asset failure and/or the safe operation of the asset. Higher impact results in higher weight

Condition Indicator Letter Score:
The letter grade associated with the degradation factor – this is typically captured from the raw inspection data.

Asset Max Score:
The highest numerical grade that can be assigned to the asset / asset class, given the associated degradation factors and weights.

Condition parameters of the asset are characteristic properties that are used to derive the overall HI. Condition parameters are specific and uniquely graded to each asset class. Additionally, some condition parameters can be comprised of sub-condition parameters. For example, the oil quality condition parameter for a station power transformer is based on multiple sub-condition parameters such as the acidity of the oil, its interfacial tension, dielectric strength, and water content.

The scale used to determine an asset's score for a condition parameter is called the "condition indicator". Each condition parameter is ranked from A to E and each rank corresponds to a numerical grade. In the above example, a condition score of 4 represents the best grade, whereas a condition score of 0 represents the worst grade.

A – 4 Best Condition

B – 3 Normal Wear

C – 2 Requires Remediation

D – 1 Rapidly Deteriorating

E – 0 Beyond Repair

3.7.2 Use of Age as a Condition Parameter

Some industry participants question the appropriateness of including age as a potential condition parameter for calculating asset HI values. At the core of the argument against the use of age in calculating asset condition is the notion that age implies a linear degradation path for an asset that does not always match the actual experience in the field.

While some assets lose their structural integrity faster than would be expected with the passage of time, others, such as those with limited exposure to natural environmental factors, or those that benefitted from regular predictive and corrective maintenance, may retain their original condition for a longer period of time than age-based degradation would imply.

In recognition of the argument as to the limitations of age-based condition scoring, METSCO limits the instances where it relies on only age as a parameter explicitly incorporated into the HI formulation. In some cases, however, the limited number of condition parameters available for calculation of asset health makes age a useful proxy for the important factors that the analysis would not otherwise capture. In other cases, such as when assessing the condition of complex equipment containing several internal mechanical components that degrade with continuous operation and the state of which cannot be assessed without destructive testing, age represents an important component of asset health calculation irrespective of the number of other factors that may be available for analysis.

3.7.3 Final Health Index Formulation

The final HI, which is a function of the condition scores and weightings, is calculated based on the following formula:

$$HI = \left(\frac{\sum_{i=1} Weight_i * Numerical\ Grade_i}{Total\ Score}\right) x\ 100\%$$

Where *i* corresponds to the condition parameter number, and the HI is a percentage representing the remaining life of the asset.

A gating approach is used for condition parameters that have a significant influence on the health of an asset. If the condition parameter that has been flagged as a gating parameter is below a pre-defined threshold value, the overall HI is reduced by 50%. This approach enables utilities to efficiently flag severely degraded assets through the identification of condition parameters acknowledged to be critical indicators of overall asset health.

3.7.4 Health Index Results

METSCO's assessment of asset condition uses a consistent five-point scale along the expected degradation path for every asset, ranging from Very Good to Very Poor. To assign each asset into one of the categories, METSCO constructs an HI formulation for each asset class, which captures information on individual degradation factors contributing to that asset's declining condition over time. Condition scores assigned to each degradation factor are also expressed as numerical or letter grades along with pre-defined scales. The final HI – expressed as a value between 0% and 100% - is a weighted sum of scores of individual degradation factors, with each of the five condition categories (Very Good, Good, Fair, Poor, Very Poor) corresponding to a numerical band. For example, the condition score of Very Good indicates assets with HI values between 100% and 85%, whereas assets found to be in a Very Poor condition score are those with calculated HI values between 0% and 30%. Generating an HI provides a succinct measure of the long-term health of an asset. Table 3-1 presents the HI ranges with the corresponding asset condition, its description as well as implications for maintaining, refurbishing or replacing the asset prior to failure.

Table 3-1: HI Ranges and Corresponding Asset Condition

HI Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of aging or minor deterioration of a limited number of components	Normal Maintenance
[70-85)	Good	Significant Deterioration of some components	Normal Maintenance
[50-70)	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
[30-50)	Poor	Widespread serious deterioration	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
[0-30)	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

3.8 Data Availability Index

To put the calculation of HI values into the context of available data, METSCO supplemented its HI findings with the calculation of the DAI: a measure of the availability of the condition parameter data for a specific asset weighted by each condition parameter to the HI score. The DAI is calculated by dividing the sum of the weights of the condition parameters available by the total weight of the condition parameters used in the HI formulation for the asset class. The formula is given by:

$$DAI = \left(\frac{\sum_{i=1} Weight_i * \alpha_i}{\sum_{i=1} Weight_i}\right) x\ 100\%$$

Where *i* corresponds to the condition parameter number and α is the availability of coefficient (=1 when data available =0 when data unavailable)

An asset with all condition parameter data available will have a DAI value of 100%, independent of the asset's HI score. Assets with a high DAI will correlate to HI scores that describe the asset condition with a high degree of confidence. For distribution assets – typified by relatively large asset populations – if the DAI for an asset is less than 70%, a valid HI cannot be calculated.

3.9 Health Index Formulations and Results

This section presents the developed HI formulation for each asset class, the calculated scores for HI results, and the data available to perform the study.

3.9.1 Circuit Breakers

Circuit breakers within station switchgear, are electrical devices that operate automatically during a fault. It protects other electrical assets from damage due to short-circuit current. It operates when a fault is detected and can be programmed to automatically restore the connection once the fault is cleared or can be reset manually based on the severity of the fault.

Computing the HI of a circuit breaker considers end-of-life criteria for its various components. Each criterion represents a factor critical in determining the component's condition relative to potential failure. Each type of circuit breaker has its own HI formulation.

The HI for vacuum, SF_6 and Air-Magnetic circuit breakers is calculated by considering a combination of end-of-life criteria summarized in Table 3-2, Table 3-3 and Table 3-4 respectively.

Table 3-2: Vacuum Circuit Breakers HI Formulation

#	Condition Criteria	Weight	Condition Rating	Factors	Maximum Score
1	Breaker Truck Condition	3	A,B,C,D,E	4,3,2,1,0	12
2	Control & Operating Mechanism Components	2	A,B,C,D,E	4,3,2,1,0	8
3	Overall CB Condition	4	A,B,C,D,E	4,3,2,1,0	16
4	Contact Resistance Tests	4	A,B,C,D,E	4,3,2,1,0	16
5	Breaker Timing Tests	3	A,B,C,D,E	4,3,2,1,0	12
6	Insulation Resistance Tests	5	A,B,C,D,E	4,3,2,1,0	20
7	Operating Counter	2	A,B,C,D,E	4,3,2,1,0	8
8	Vacuum Bottle Integrity	5	A,B,C,D,E	4,3,2,1,0	20
9	Functional Obsolescence	8	A,B,C,D,E	4,3,2,1,0	32
10	Equipment Failures	4	A,B,C,D,E	4,3,2,1,0	16
	MAX SCORE				**160**

Table 3-3: SF_6 Circuit Breakers HI Formulation

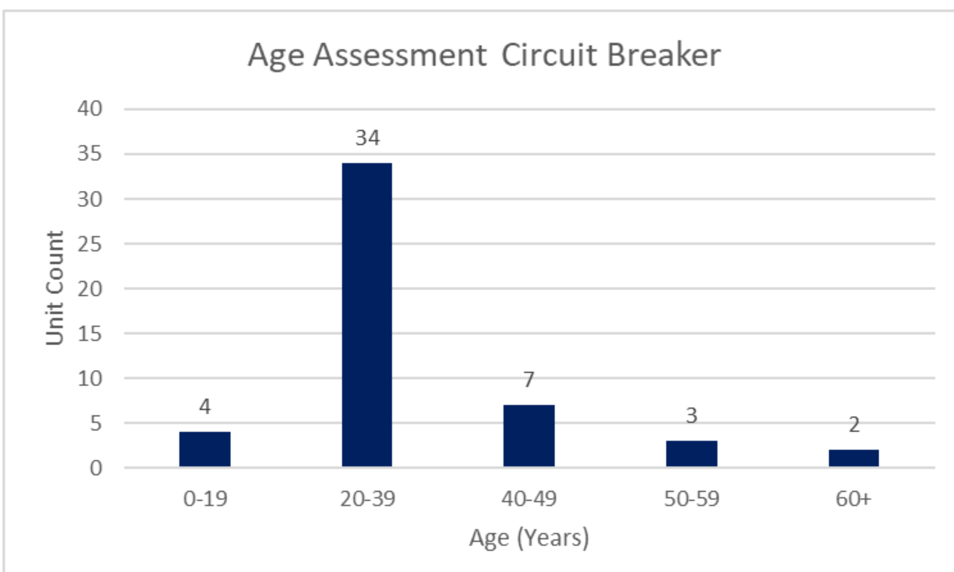
#	Condition Criteria	Weight	Condition Rating	Factors	Maximum Score
1	Breaker Truck Condition	3	A,B,C,D,E	4,3,2,1,0	12
2	Control & Operating Mechanism Components	2	A,B,C,D,E	4,3,2,1,0	8
3	Overall CB Condition	4	A,B,C,D,E	4,3,2,1,0	16
4	Contact Resistance Tests	4	A,B,C,D,E	4,3,2,1,0	16
5	Breaker Timing Tests	3	A,B,C,D,E	4,3,2,1,0	12
6	Insulation Resistance Tests	5	A,B,C,D,E	4,3,2,1,0	20
7	Operating Counter	2	A,B,C,D,E	4,3,2,1,0	8
8	SF_6 Leaks	2	A,B,C,D,E	4,3,2,1,0	8
9	Functional Obsolescence	8	A,B,C,D,E	4,3,2,1,0	32
10	Equipment Failures	4	A,B,C,D,E	4,3,2,1,0	16
	MAX SCORE				**148**

Table 3-4: Air-Magnetic Circuit Breakers HI Formulation

#	Condition Criteria	Weight	Condition Rating	Factors	Maximum Score
1	Breaker Truck Condition	3	A,B,C,D,E	4,3,2,1,0	12
2	Control & Operating Mechanism Components	2	A,B,C,D,E	4,3,2,1,0	8
3	Overall CB Condition	4	A,B,C,D,E	4,3,2,1,0	16
4	Contact Resistance Tests	4	A,B,C,D,E	4,3,2,1,0	16
5	Breaker Timing Tests	3	A,B,C,D,E	4,3,2,1,0	12
6	Insulation Resistance Tests	5	A,B,C,D,E	4,3,2,1,0	20
7	Operating Counter	2	A,B,C,D,E	4,3,2,1,0	8
8	Arc Chutes	3	A,B,C,D,E	4,3,2,1,0	12
9	Functional Obsolescence	8	A,B,C,D,E	4,3,2,1,0	32
10	Equipment Failures	4	A,B,C,D,E	4,3,2,1,0	16
	MAX SCORE				**152**

There are 50 FBC circuit breakers within the scope: 3 are vacuum, 18 are SF_6, and 29 are Air-Magnetic breakers. The age of the circuit breakers is known for the total sample. Figure 3-3 presents the age distribution for circuit breakers.

Figure 3-3: Circuit Breaker Age Demographics



FBC's maintenance records, operation data, and nameplate information were used to calculate the Health Index based on the criteria provided above.

A valid HI was calculated for 100% of the total population, as shown in Table 3-5.

Table 3-5: Circuit Breaker HI Results

Asset ID	Position	Station	HI Score
12392	FDR1	BLU	61%
12393	FDR2	BLU	61%
20682	FDR1	CAS	70%
20681	FDR2	CAS	70%
20680	FDR3	CAS	65%
14871	T5M	CRA	60%
14872	152	CRA	53%
14873	252	CRA	55%
14874	TIE	CRA	52%
14875	352	CRA	61%
14876	452	CRA	71%
14877	T4M	CRA	66%
12414	FDR1	CRE	55%
12413	FDR2	CRE	55%
21204	752	HOL	69%
21605	652	HOL	50%
21606	T1M	HOL	71%
21608	352	HOL	71%
21609	T2M	HOL	61%
21610	552	HOL	71%
21612	452	HOL	66%
21613	252	HOL	66%
21615	152	HOL	61%
21617	T3M	HOL	71%
12348	CAPBANK	PIN	93%
12347	FDR2	PIN	93%
12346	T1M	PIN	93%
22835	152	SAU 1	66%
22840	252	SAU 1	66%
22834	352	SAU 1	55%
22838	452	SAU 1	66%
22836	552	SAU 1	55%
22828	652	SAU 1	66%

Asset ID	Position	Station	HI Score
22829	752	SAU 1	55%
22831	852	SAU 1	55%
22830	952	SAU 1	55%
22832	1052	SAU 1	66%
22837	MAIN1	SAU 1	66%
22839	MAIN2	SAU 1	49%
22833	TIE	SAU 1	66%
21150	T152	SAU 2	71%
21144	T252	SAU 3	61%
22105	152	OKM	67%
22099	252	OKM	66%
22106	352	OKM	63%
22103	452	OKM	71%
22104	552	OKM	71%
22101	T1M	OKM	67%
22100	T2M	OKM	71%
22102	MOBILE M	OKM	71%

3.9.2 Switchgear

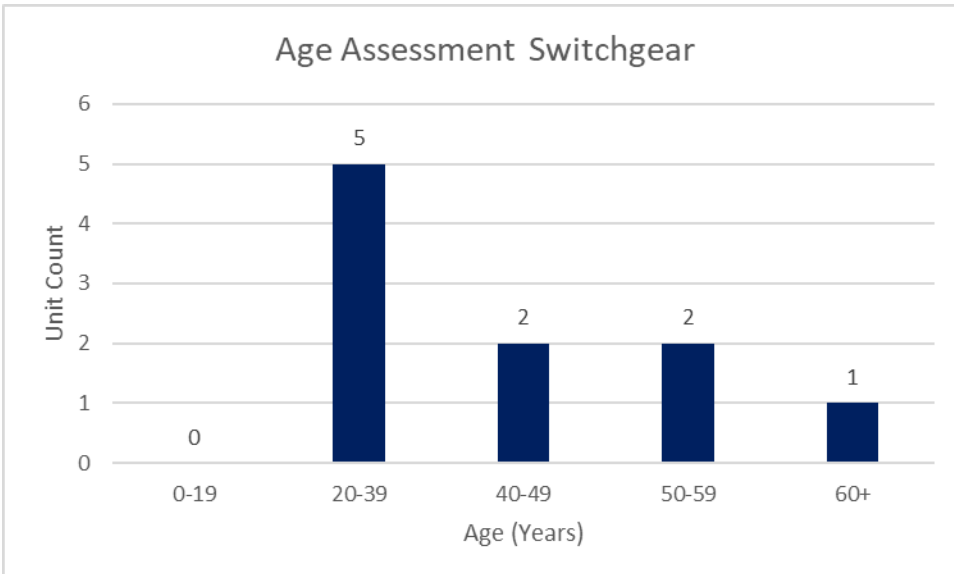
Station switchgear consists of breakers, fuses, and switches that control and regulate the current flowing through the distribution system. During a fault, the switchgear can isolate and clears the fault. It is also used to de-energize equipment during maintenance and testing. The HI for station switchgear is calculated by considering a combination of end-of-life criteria summarized in Table 3-6.

Table 3-6: Switchgear HI Formulation

#	Condition Criteria	Weight	Condition Rating	Factors	Maximum Score
1	Online PD	5	A,B,C,D,E	4,3,2,1,0	20
2	Infrared Scan Test	4	A,B,C,D,E	4,3,2,1,0	16
3	Visual Condition	3	A,B,C,D,E	4,3,2,1,0	12
4	Equipment Failures	2	A,B,C,D,E	4,3,2,1,0	8
	MAX SCORE				**56**

There are ten FBC switchgears within scope. In some cases, the age of the switchgear is assumed based on the construction year of the station. Figure 3-4 presents the age distribution for switchgears.

Figure 3-4: Switchgear Age Demographics



FBC's maintenance records, operation data, and nameplate information were used to calculate the Health Index based on the criteria provided above.

A valid HI was calculated for 100% of the total population, as shown in Table 3-7.

Table 3-7: Switchgear HI Results

Station	HI Score
BLU	64%
CAS	13%
CRA	75%
CRE	63%
HOL	77%
PIN	75%
SAU 1	80%
SAU 2	88%
SAU 3	85%
OKM	77%

4. Impact/Risk Analysis

4.1 Inputs & Assumptions

In addition to the inputs from previous steps, there were multiple costing, load and failure inputs used. These are summarized in Table 4-1.

Table 4-1: Inputs into Impact/Risk Analysis

Section	Description	Source
Collateral Damage Costs	CD Claims Cost	METSCO
	CD Claims Probability	METSCO
	CD Injury Cost	METSCO
	CD Injury Probability	METSCO
	CD Fatality Cost	METSCO
	CD Fatality Probability	METSCO
	Average CD Event Impact	METSCO
Customer Interruption Costs	Residential CIC Event Cost ($/kVA)	ICE Calculator
	Small Commercial & Industrial CIC Event Cost ($/kVA)	ICE Calculator
	Medium & Large Commercial & Industrial CIC Event Cost ($/kVA)	ICE Calculator
	Residential CIC Duration Cost ($/kVA)	ICE Calculator
	Small Commercial & Industrial CIC Duration Cost ($/kVA)	ICE Calculator
	Medium & Large Commercial & Industrial CIC Duration Cost ($/kVA)	ICE Calculator
Revenue Loss Costs	Residential ($/kWh)	METSCO
	Small Commercial & Industrial ($/kWh)	METSCO
	Medium and Large Commercial & Industrial ($/kWh)	METSCO
Environmental Impact Costs	SF_6 Fixed Cost [$]	METSCO
	SF_6 Variable Cost [$/lb]	METSCO
Power Factor Values	Residential	METSCO
	Small Commercial & Industrial (Small C&I)	METSCO
	Medium and Large Commercial & Industrial (M&L C&I)	METSCO
Typical Useful Life	SF_6 Circuit Breakers and MCS (years)	METSCO
	Air-Magnetic and Vacuum Circuit Breakers (years)	METSCO
Asset Data	SF_6 Quantity within one (1) Circuit Breaker (lbs)	METSCO

Section	Description	Source
	Load calculated as the average load across the asset over the past 5 years for both summer and winter in kVA	FBC
Customer Distribution Ratio	Residential	FBC - 2020 Sustainability Report
	Small Commercial & Industrial (Small C&I)	
	Medium and Large Commercial & Industrial (M&L C&I)	
Load Distribution Ratio	Residential	METSCO
	Small Commercial & Industrial (Small C&I)	METSCO
	Medium and Large Commercial & Industrial (M&L C&I)	METSCO
Failure Modes - Switchgear	Inspection-Based Outage Duration for Asset Failure (hours)	METSCO
	Normal Outage Duration for Asset Failure (hours) - Varies depending on the location of the asset and if distribution/station backup is available	FBC/METSCO
	Catastrophic Outage Duration for Asset Failure (hours)	FBC/METSCO
	Relative Probabilities of each failure mode were determined based on the asset's expected failure probability (Weibull curve) and its respective maintenance cycle.	METSCO
	CD Probability - Only applicable to Catastrophic Failure	METSCO
	Environmental Impact Probability - Only applicable to Switchgear containing SF_6 breakers during Catastrophic Failure	METSCO
	Backup Failure Probability	METSCO
Failure Modes - Circuit Breaker	Inspection-Based Outage Duration for Asset Failure (hours)	METSCO
	Normal Outage Duration for Asset Failure (hours) - Varies depending on the location of the asset and if distribution/station backup is available	FBC/METSCO
	Catastrophic Outage Duration for Asset Failure (hours)	FBC/METSCO
	Relative Probabilities of each failure mode were determined based on the asset's expected failure probability (Weibull curve) and its respective maintenance cycle.	METSCO
	CD Probability - Only applicable to Catastrophic Failure	METSCO
	Environmental Impact Probability - Only applicable to SF_6 breakers during Catastrophic Failure	METSCO

Section	Description	Source
	Backup Failure Probability - Determined by identifying the backup and double backup (if available) and using the asset's FP as calculated using the Weibull parameters.	METSCO

4.2 Methodology

4.2.1 TUL & Weibull Curves

METSCO uses its industry-wide definition for asset-specific typical useful life ("TUL") values that have been created a basis for planning and depreciation assumptions. For this project, these industry values were supplemented by manufacturer-specific values for FBC's SF_6 circuit breakers. The TUL of circuit breakers is 40 years for SF_6 breakers and 45 years for Air-Magnetic and Vacuum breakers. The TUL of metal-clad switchgear is 40 years. These TUL values were then used to calculate the shape and scale of the Weibull Curves.

Figure 4-1: Weibull Curve for MCS & SF_6 CB

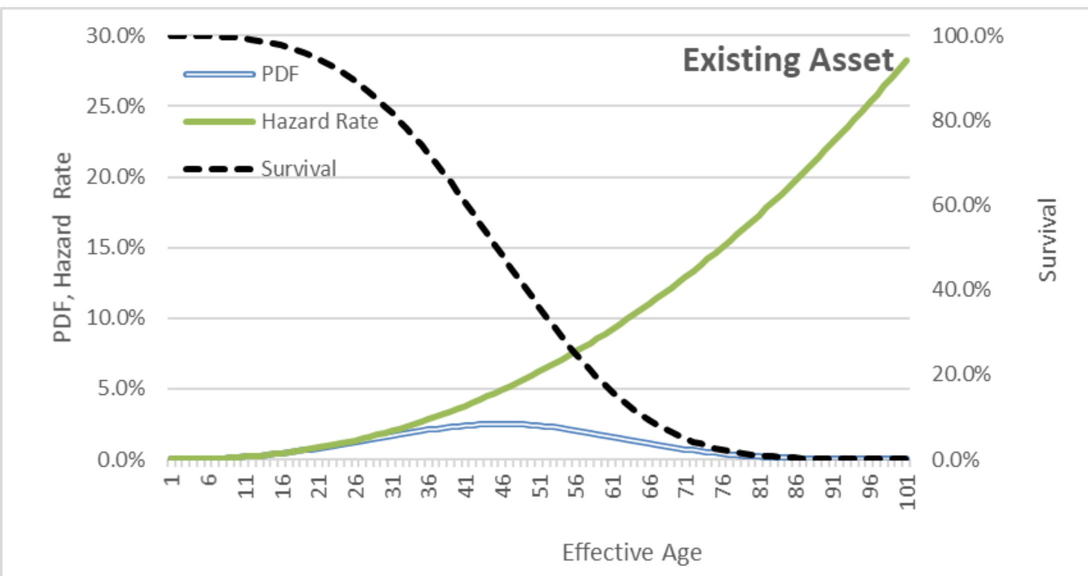
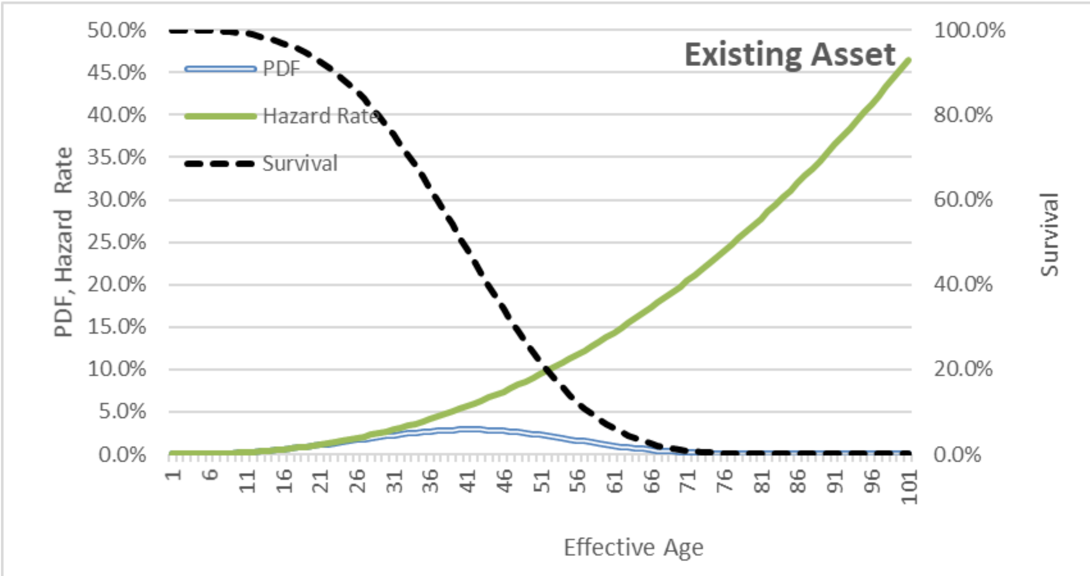


Figure 4-2: Weibull Curve for Air-Magnetic & Vacuum CB



4.2.2 Effective Age

The HI for each asset is used to calculate failure probability, based on a METSCO standard chart. The failure probability is then compared to the hazard rates on the Weibull Curves above to find condition-suggested age. From this, the asset age is adjusted to get the effective age.

4.2.3 Circuit Breaker Relative Failure Probabilities

Inspection-Based Failure Probability

The inspection-based failure probability is calculated by first summing the hazard rates over the FBC's maintenance cycle frequency in years starting at the effective age of the asset. The percentage is then subtracted from 100% to get the inspection-based failure probability.

Failure to Open Probability

Failure to Open probability is calculated by first subtraction Inspection based failure from 100%. METSCO standard is that Failure to Open probability is then 20% of the result.

Failure to Close Probability

Failure to Close probability is calculated by first subtraction Inspection based failure from 100%. METSCO standard is that Failure to Close probability is then 70% of the result.

Catastrophic Failure Probability

Catastrophic failure probability is calculated by first subtraction Inspection based failure from 100%. METSCO standard is that Catastrophic failure probability is then 10% of the result.

4.2.4 Switchgear Relative Failure Probabilities

Inspection-Based Failure Probability

The inspection-based failure probability is calculated by first summing the hazard rates over the FBC's maintenance cycle frequency in years starting at the effective age of the asset. The percentage is then subtracted from 100% to get the inspection-based failure probability.

Normal Failure Probability

Normal failure probability is calculated by first subtraction Inspection based failure from 100%. METSCO standard is that normal failure probability is then 90% of the result.

Catastrophic Failure Probability

Catastrophic failure probability is calculated by first subtraction Inspection based failure from 100%. METSCO standard is that Catastrophic failure probability is then 10% of the result.

4.2.5 Risk

The risk cost is calculated by first finding the impact cost for all failure modes. These are then summed by category to find the total customer impact, financial impact, environmental damage impact and collateral impact costs. Each impact cost is then multiplied by the failure probability to get risk costs which are summed to get the total risk cost. A high-risk cost can result from a high failure probability even if the asset is in otherwise good condition. This is due to failure probability being driven by both HI and asset age, either of these factors could lead to a higher risk cost associated with the asset.

4.3 Risk Assessment

4.3.1 Circuit Breakers

The risk cost for circuit breakers falls between $1.64 and $81,040.55. The breakdown of risk cost can be found in Figure 4-3.

Figure 4-3: Circuit Breaker Total Risk Cost Demographics

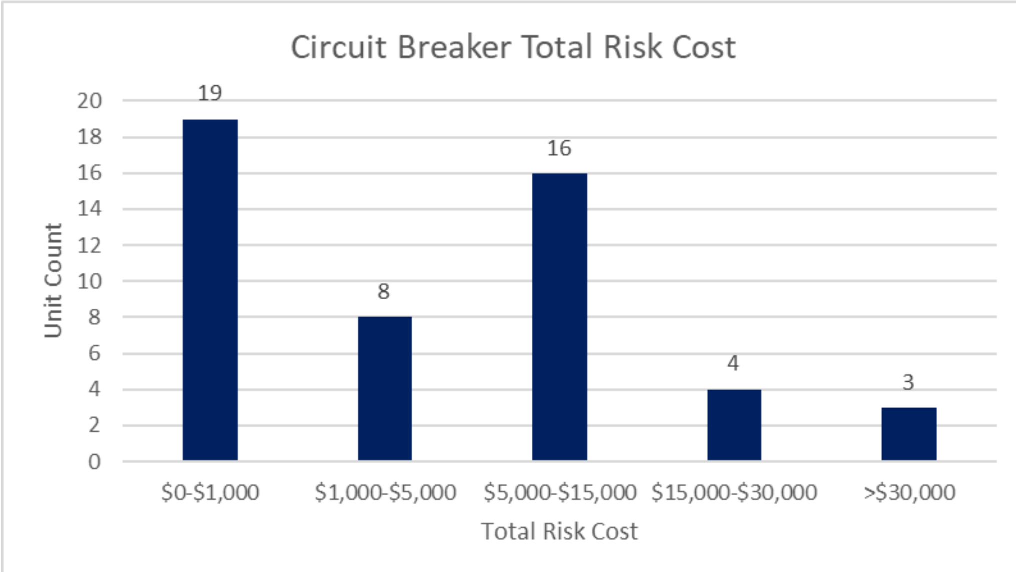


Table 4-2: Circuit Breaker Impact and Risk

Asset ID	Position	Station	Total Impact	Annual Failure Probability[5]	Annual Risk Cost[5]
12392	FDR1	BLU	$92,484.84	2.10%	$1,937.87
12393	FDR2	BLU	$105,035.27	2.10%	$2,200.84
20682	FDR1	CAS	$124,975.23	2.48%	$3,105.28
20681	FDR2	CAS	$156,020.49	2.48%	$3,876.67
20680	FDR3	CAS	$47,289.35	2.48%	$1,175.01
14871	T5M	CRA	$42,582.25	1.48%	$799.82
14872	152	CRA	$14,836.63	1.88%	$420.33
14873	252	CRA	$30,493.40	2.83%	$759.65
14874	TIE	CRA	$1,496.95	2.49%	$45.10
14875	352	CRA	$18,114.82	3.01%	$340.25
14876	452	CRA	$25,384.21	1.88%	$375.56
14877	T4M	CRA	$30,160.70	1.48%	$446.23
12414	FDR1	CRE	$354,328.01	9.20%	$32,602.83
12413	FDR2	CRE	$692,207.58	9.20%	$63,692.18
21204	752	HOL	$80,052.98	0.83%	$667.53
21605	652	HOL	$8,080.68	4.22%	$341.00
21606	T1M	HOL	$378,040.18	1.61%	$6,074.02
21608	352	HOL	$159,611.14	1.61%	$2,564.49

[5] Current year

Asset ID	Position	Station	Total Impact	Annual Failure Probability[5]	Annual Risk Cost[5]
21609	T2M	HOL	$3,879.90	1.88%	$72.88
21610	552	HOL	$251,058.58	1.61%	$4,033.79
21612	452	HOL	$218,403.53	2.83%	$6,187.51
21613	252	HOL	$306,272.84	2.83%	$8,676.90
21615	152	HOL	$203,002.39	6.73%	$13,662.35
21617	T3M	HOL	$338,220.17	3.79%	$12,829.15
12348	CAPBANK	PIN	$724.91	0.23%	$1.64
12347	FDR2	PIN	$42,353.87	0.23%	$95.62
12346	T1M	PIN	$42,382.35	0.23%	$95.68
22835	152	SAU 1	$177,851.35	5.32%	$9,469.23
22840	252	SAU 1	$161,082.93	4.43%	$7,134.36
22834	352	SAU 1	$322,434.57	4.43%	$14,280.63
22838	452	SAU 1	$330,230.89	4.43%	$14,625.93
22836	552	SAU 1	$7,237.28	4.43%	$320.54
22828	652	SAU 1	$179,722.60	4.43%	$7,959.91
22829	752	SAU 1	$221,769.50	4.43%	$9,822.17
22831	852	SAU 1	$175,615.80	4.43%	$7,778.02
22830	952	SAU 1	$230,991.20	4.43%	$10,230.60
22832	1052	SAU 1	$7,237.28	4.43%	$320.54
22837	MAIN1	SAU 1	$674,618.45	4.43%	$29,878.85
22839	MAIN2	SAU 1	$8,979.93	5.64%	$506.78
22833	TIE	SAU 1	$8,524.11	5.32%	$453.84
21150	T152	SAU 2	$408,383.96	2.66%	$10,859.52
21144	T252	SAU 3	$7,497.76	2.66%	$199.38
22105	152	OKM	$260,949.42	8.54%	$22,296.06
22099	252	OKM	$197,595.43	4.00%	$7,910.66
22106	352	OKM	$280,221.90	4.00%	$11,218.58
22103	452	OKM	$114,489.77	4.00%	$4,583.56
22104	552	OKM	$405,669.80	4.00%	$16,240.84
22101	T1M	OKM	$948,485.34	8.54%	$81,040.55
22100	T2M	OKM	$490,389.72	4.00%	$19,632.57
22102	MOBILE M	OKM	$7,698.30	4.00%	$308.20

4.3.2 Switchgear

The risk cost for switchgears falls between $708.27and $689,101.36. The breakdown of risk cost can be found in Figure 4-4.

Figure 4-4: Switchgear Total Risk Cost Demographics

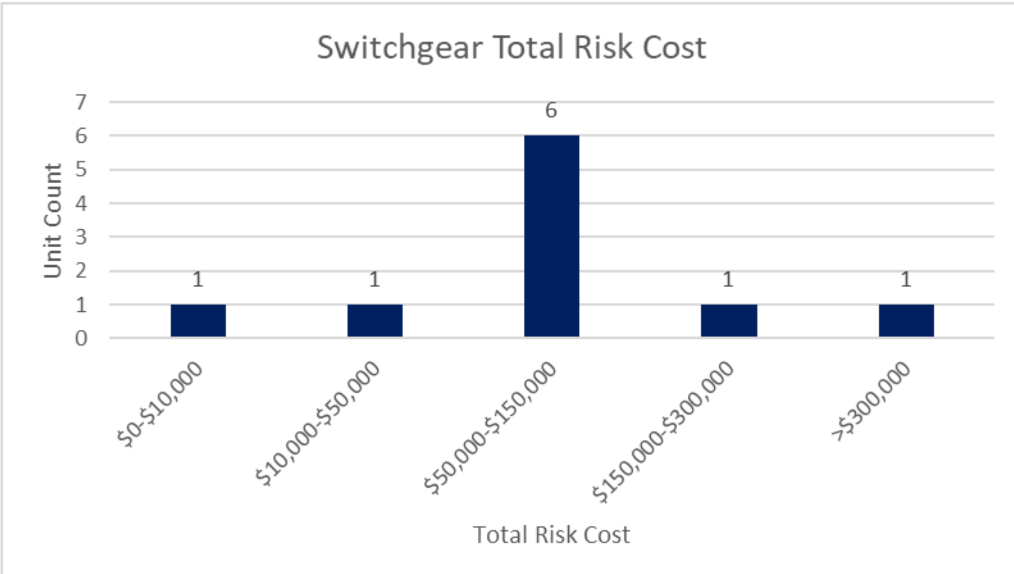


Table 4-3: Switchgear Impact and Risk

Station	Total Impact	Annual Failure Probability[6]	Annual Risk Cost[6]
BLU	$1,070,547.37	10.78%	$115,410.39
CAS	$1,670,022.82	41.26%	$689,101.36
CRA	$835,386.96	8.58%	$71,704.83
CRE	$1,850,965.69	14.34%	$265,429.41
HOL	$2,277,981.97	4.15%	$94,562.09
PIN	$673,940.37	5.02%	$33,801.26
SAU 1	$2,089,801.35	4.43%	$92,557.29
SAU 2	$18,238.43	3.88%	$708.27
SAU 3	$2,234,448.49	5.97%	$133,469.28
OKM	$1,823,663.04	3.88%	$70,820.14

[6] Current year

5. Lifecycle Cost Analysis

5.1 Inputs & Assumptions

In addition to the inputs from previous steps, there were multiple input summaries in Table 5-1. The assumptions made are summarized in Table 5-2.

Table 5-1: Inputs for Lifecycle Cost Analysis

Section	Description	Source
Replacement/ Refurbishment Costs	Each cell of MCS - Determined from the latest actual costing of 2 projects by FBC and scaled up 27% to account for building cost. Cost includes Material, Building, Labour and Installation per cell. Total replacement cost of switchgear calculated by scaling up this value by the number of circuit breaker cells within proposed switchgear.	FBC – 2020 actuals for extension projects
	Emergency Premium - Switchgear	METSCO
	Emergency Premium - Circuit Breaker	METSCO
	Circuit Breaker Replacement -1200A. Received material costs from FBC and scaled up to include labour, transportation, and installation.	METSCO/FBC
	Circuit Breaker Replacement -2000A. Received material costs from FBC and scaled up to include labour, transportation, and installation.	METSCO/FBC
	Refurbishment of Circuit Breaker - 1200A. Received data of $91,000.00 for refurbishment of a single breaker. METSCO understands that with an increased number of assets being sent to refurbish simultaneously will bring this cost down and has scaled down this value to accommodate.	METSCO/FBC
Maintenance Cost	Annual Maintenance Cost calculated at a rate of $175/hr per worker with a crew of 2 persons working 8-hour days for 4 days per switchgear divided by the number of years per maintenance cycle (per hour).	FBC
	Annual Maintenance Cost calculated at a rate of $175/hr per worker with a crew of 2 persons working 8 hours for 1 day per circuit breaker divided by the number of years per maintenance cycle (per hour).	FBC

Table 5-2: Assumptions for Lifecycle Cost Analysis

Section	Description	Value (if applicable)	Source
Analysis	When determining the OIT of the asset, the Effective age was used in place of the Actual age to account for the asset's condition during the analysis.	N/A	METSCO
	The asset's lifecycle was looked at over a 100-year period.	N/A	METSCO
	Refurbishment option not analyzed since an initial review of Refurbishment option does not make it a viable option; i.e., cost-to-benefit ratio (extends the life of the asset by one-third of its TUL) does not outweigh the replacement option.	N/A	METSCO
	Discount Rate.	6.5%	METSCO

5.2 Methodology

A discounted cash flow ("DCF") analysis was used to determine the value of an investment based on an analysis of the cash flows. The DCF analysis seeks to identify all cash flows (in and out) at some time or with a specified frequency and transform them into a common basis (annualized).

Understanding that money today is worth more than money in the future, the time value of money and present value are considered for each year of cash flow considered in the analysis. This is done by calculating the future/present value of a cash flow using the formula:

$$FV = PV * (1 + i)^n$$

Where:

- *Future Value (FV),*
- *Present Value (PV),*
- *interest per period (i),*
- *number of periods/years (n)*

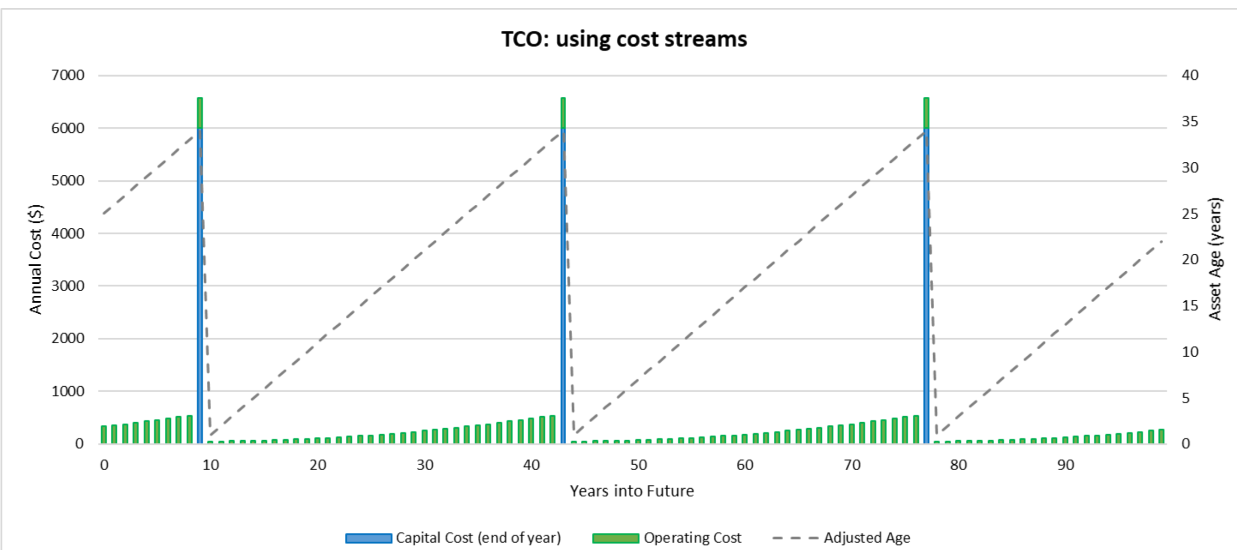
The "interest per period" above is referred to as the Discount Rate when performing a DCF analysis which is used to compute and compare present values of cash flows. The discount rate applied to FBC analysis was 6.5% based on the average weighted average cost of capital ("WACC") within the regulated utility sector.

The total cost of ownership ("TCO") is calculated by using the concepts from the DCF analysis. The TCO represents the total cost of owning the asset over its life cycle. TCO is calculated by finding the net present value ("NPV") of the cash flows where all cash flows are outflows, therefore an end value which is "negative" is a cost. The cost streams considered during analysis were:

- Capital cost of asset replacement
- Proactive outage cost (customer outage associated with replacing the equipment)
- Annual Maintenance Cost: Operating cost of the equipment (based on the schedule of maintenance activities and cost associated annualized)
- Annual Risk Cost: Calculated using the Failure probability and Impact of Failure at a given year.
- Discount Rate: 6.5%
- Evaluation horizon: 100 years (length of time the asset's lifecycle was looked at)

The above cost streams were used to determine the Economic end-of-life ("EOL") of each asset from cost stream analysis, considering risk and intervention costs to identify the minimum TCO cost stream. This signifies the most optimal cost stream that can be achieved by this asset. The EOL is Optimal Intervention Time ("OIT").

Figure 5-1: Economic EOL using Cost Streams



The figure above visualizes how the cash flows are used to determine the economic end of life of the asset by discounting all costs to the NPV. The operating cost stream (green) represents the summation of the annualized maintenance cost and annual risk cost streams. The capital cost (blue) represents the cost of replacing the asset and the adjusted age stream (grey) represents the age of the asset which is reset after each replacement.

The OIT indicates the number of years before the asset reaches its Economic EOL, it signifies the year at which the asset's annual risk cost will exceed its annual lifecycle cost under the current conditions described by the input data. Beyond this OIT, the asset experiences a greater operating cost than if some corrective action had been taken and is used as an indicator of high-risk costs when considering investment opportunities.

Given an Evaluation Horizon of 100 years, any asset with an OIT that is the maximum value of 100 is analogous to "run-to-failure" strategy and does not in any way imply the asset is expected to last 100 years. Instead, it implies that the asset will fail at some time within the 100-year Evaluation Horizon and that it would be unreasonable to evaluate assets for a longer time period.

After determining the OIT of each asset within the 10-year timeframe, investments were prioritized utilizing the TCO increase avoided by investing and the discrete replacement cost of investing which represents a benefit-to-cost ratio for each project.

5.3 Optimal Intervention Time Results

5.3.1 Circuit Breaker

The breakdown of OIT for circuit breakers can be found in Table 5-3.

Table 5-3: Circuit Breaker Optimal Intervention Time Results

Asset ID	Position	Station	OIT (Year)
12392	FDR1	BLU	2042
12393	FDR2	BLU	2038
20682	FDR1	CAS	2037
20681	FDR2	CAS	2029
20680	FDR3	CAS	2066
14871	T5M	CRA	2064
14872	152	CRA	2086
14873	252	CRA	2067
14874	TIE	CRA	2085
14875	352	CRA	2092
14876	452	CRA	2095
14877	T4M	CRA	2095
12414	FDR1	CRE	2021
12413	FDR2	CRE	2021
21204	752	HOL	2072
21605	652	HOL	2079

Asset ID	Position	Station	OIT (Year)
21606	T1M	HOL	2062
21608	352	HOL	2044
21609	T2M	HOL	2092
21610	552	HOL	2056
21612	452	HOL	2032
21613	252	HOL	2038
21615	152	HOL	2021
21617	T3M	HOL	2032
12348	CAPBANK	PIN	2110
12347	FDR2	PIN	2065
12346	T1M	PIN	2065
22835	152	SAU 1	2022
22840	252	SAU 1	2024
22834	352	SAU 1	2021
22838	452	SAU 1	2021
22836	552	SAU 1	2080
22828	652	SAU 1	2021
22829	752	SAU 1	2021
22831	852	SAU 1	2021
22830	952	SAU 1	2021
22832	1052	SAU 1	2080
22837	MAIN1	SAU 1	2021
22839	MAIN2	SAU 1	2068
22833	TIE	SAU 1	2071
21150	T152	SAU 2	2021
21144	T252	SAU 3	2087
22105	152	OKM	2021
22099	252	OKM	2021
22106	352	OKM	2021
22103	452	OKM	2029
22104	552	OKM	2021
22101	T1M	OKM	2021
22100	T2M	OKM	2055
22102	MOBILE M	OKM	2080

5.3.2 Switchgear

The breakdown of OIT for switchgear can be found in Table 5-4.

Table 5-4: Switchgear Optimal Intervention Time Results

Station	OIT (Year)
BLU	2021
CAS	2021
CRA	2043
CRE	2021
HOL	2046
PIN	2038
SAU 1	2050
SAU 2	2021
SAU 3	2087
OKM	2033

6. Recommended Capital & Operational Plans

The recommended capital and operational plan are as follows.

6.1 Priorities for the next 10 Years

The capital plan recommendations for the next ten years are summarized in Table 6-1. Continued maintenance is recommended for all MCS up to replacement and includes assets not scheduled for replacement in the next ten years.

Table 6-1: Recommended Replacements Within 10-Years

Asset Type	Asset Number	Equip. Position	Station	CAPEX	Recommendation
MCS	CAS	N/A	CAS	$899,160.00	Replace Switchgear immediately. Switchgear will not outlast the breakers. CBs have already been refurbished once.
MCS	OKM	N/A	OKM	$2,397,760.00	Replace Switchgear in 2 years. Another option is to replace the breakers at 152 and T1M at this time and then do a complete switchgear replacement after 10 years – but not recommended.
MCS	CRE	N/A	CRE	$599,440.00	Replace Switchgear in 4 years Replacement of entire switchgear with CBs.

MCS	BLU	N/A	BLU	$599,440.00	Replace Switchgear in 6 years. Switchgear will not outlast the breakers. CBs have already been refurbished once.
MVCB	SAU 1	All	SAU 1	$545,493.00	Replace all Circuit Breakers at SAU 1 in 8 years.
MVCB	21615, 21617,21612	152, T3M, 452	HOL	$265,878.00	Replace Circuit Breakers 152, T3M and 452 at HOL in 10 years. FBC to reassess in 10 years to determine if additional breakers may need to be replaced.

6.2 Low Priority Assets

Crawford Bay

Replace switchgear within 20 years. No replacement within 10-year timeframe.

Pine

No replacement within 10-year timeframe.

Saucier 2

Replacement of switchgear is not recommended within this 10-year timeframe due to the good condition of the asset.

Saucier 3

No replacement within 10-year timeframe.

6.3 Summary Hazard Analysis

Appendix B contains the summary hazard analysis for projects replacing breakers and switchgear.

7. Conclusions & Recommendations

7.1 Conclusions

Summary of Results

As Table 7-1 and

Table 7-2 show the majority of assets are in Fair or better condition. Most assets are also in the Moderate to Low-Risk categories. This can indicate FBC has taken steps in the past to manage their asset health and performance for the benefit of its customers. As with every system, however, there are areas that require FBC's attention in the coming years.

Table 7-1: Summary of Circuit Breaker Results

Asset ID	Position	Station	HI Score	Total Impact	Annual Failure Probability[7]	Annual Risk Cost[7]	OIT (Year)
12392	FDR1	BLU	61%	$92,484.84	2.10%	$1,937.87	2042
12393	FDR2	BLU	61%	$105,035.27	2.10%	$2,200.84	2038
20682	FDR1	CAS	70%	$124,975.23	2.48%	$3,105.28	2037
20681	FDR2	CAS	70%	$156,020.49	2.48%	$3,876.67	2029
20680	FDR3	CAS	65%	$47,289.35	2.48%	$1,175.01	2066
14871	T5M	CRA	60%	$42,582.25	1.88%	$799.82	2064
14872	152	CRA	53%	$14,836.63	2.83%	$420.33	2086
14873	252	CRA	55%	$30,493.40	2.49%	$759.65	2067
14874	TIE	CRA	52%	$1,496.95	3.01%	$45.10	2085
14875	352	CRA	61%	$18,114.82	1.88%	$340.25	2092
14876	452	CRA	71%	$25,384.21	1.48%	$375.56	2095
14877	T4M	CRA	66%	$30,160.70	1.88%	$446.23	2095
12414	FDR1	CRE	55%	$354,328.01	9.20%	$32,602.83	2021
12413	FDR2	CRE	55%	$692,207.58	9.20%	$63,692.18	2021
21204	752	HOL	69%	$80,052.98	0.83%	$667.53	2072
21605	652	HOL	50%	$8,080.68	4.22%	$341.00	2079
21606	T1M	HOL	71%	$378,040.18	1.61%	$6,074.02	2062
21608	352	HOL	71%	$159,611.14	1.61%	$2,564.49	2044
21609	T2M	HOL	61%	$3,879.90	1.88%	$72.88	2092
21610	552	HOL	71%	$251,058.58	1.61%	$4,033.79	2056
21612	452	HOL	66%	$218,403.53	2.83%	$6,187.51	2032
21613	252	HOL	66%	$306,272.84	2.83%	$8,676.90	2038
21615	152	HOL	61%	$203,002.39	6.73%	$13,662.35	2021
21617	T3M	HOL	71%	$338,220.17	3.79%	$12,829.15	2032
12348	CAPBANK	PIN	93%	$724.91	0.23%	$1.64	2110
12347	FDR2	PIN	93%	$42,353.87	0.23%	$95.62	2065
12346	T1M	PIN	93%	$42,382.35	0.23%	$95.68	2065
22835	152	SAU 1	66%	$177,851.35	5.32%	$9,469.23	2022

[7] Current year

Asset ID	Position	Station	HI Score	Total Impact	Annual Failure Probability[7]	Annual Risk Cost[7]	OIT (Year)
22840	252	SAU 1	66%	$161,082.93	4.43%	$7,134.36	2024
22834	352	SAU 1	55%	$322,434.57	4.43%	$14,280.63	2021
22838	452	SAU 1	66%	$330,230.89	4.43%	$14,625.93	2021
22836	552	SAU 1	55%	$7,237.28	4.43%	$320.54	2080
22828	652	SAU 1	66%	$179,722.60	4.43%	$7,959.91	2021
22829	752	SAU 1	55%	$221,769.50	4.43%	$9,822.17	2021
22831	852	SAU 1	55%	$175,615.80	4.43%	$7,778.02	2021
22830	952	SAU 1	55%	$230,991.20	4.43%	$10,230.60	2021
22832	1052	SAU 1	66%	$7,237.28	4.43%	$320.54	2080
22837	MAIN1	SAU 1	66%	$674,618.45	4.43%	$29,878.85	2021
22839	MAIN2	SAU 1	49%	$8,979.93	5.64%	$506.78	2068
22833	TIE	SAU 1	66%	$8,524.11	5.32%	$453.84	2071
21150	T152	SAU 2	71%	$408,383.96	2.66%	$10,859.52	2021
21144	T252	SAU 3	61%	$7,497.76	2.66%	$199.38	2087
22105	152	OKM	67%	$260,949.42	8.54%	$22,296.06	2021
22099	252	OKM	66%	$197,595.43	4.00%	$7,910.66	2021
22106	352	OKM	63%	$280,221.90	4.00%	$11,218.58	2021
22103	452	OKM	71%	$114,489.77	4.00%	$4,583.56	2029
22104	552	OKM	71%	$405,669.80	4.00%	$16,240.84	2021
22101	T1M	OKM	67%	$948,485.34	8.54%	$81,040.55	2021
22100	T2M	OKM	71%	$490,389.72	4.00%	$19,632.57	2055
22102	MOBILE M	OKM	71%	$7,698.30	4.00%	$308.20	2080

Table 7-2: Summary of Switchgear Results

Station	HI Score	Total Impact	Annual Failure Probability[8]	Annual Risk Cost[8]	OIT (Year)
BLU	64%	$1,070,547.37	10.78%	$115,410.39	2021
CAS	13%	$1,670,022.82	41.26%	$689,101.36	2021
CRA	75%	$835,386.96	8.58%	$71,704.83	2043
CRE	63%	$1,850,965.69	14.34%	$265,429.41	2021
HOL	77%	$2,277,981.97	4.15%	$94,562.09	2046
PIN	75%	$673,940.37	5.02%	$33,801.26	2038
SAU 1	80%	$2,089,801.35	4.43%	$92,557.29	2050
SAU 2	88%	$18,238.43	3.88%	$708.27	2021
SAU 3	85%	$2,234,448.49	5.97%	$133,469.28	2087
OKM	77%	$1,823,663.04	3.88%	$70,820.14	2033

Use of Online PD Testing and IR Scans

The PD testing and IR scans added value to the condition assessment as they added more detailed analysis than the scheduled maintenance inspections. These tests identify possible defects, such as insulation deterioration and hot spots, that cannot be identified during visual inspections.

7.2 Next Steps

The next steps for FBC are to carry out the proposed capital and operational plan in Section 6. METSCO also recommends that FBC use the approach outlined in this document to assess other assets in their system.

7.3 Data Gaps

Data availability is critical to producing prudent, accurate, and justified decision-making outputs. It represents the single most important element that can influence the degree to which the AM decision-making relies on objective factors. Companies understand that it is critical to execute continuous improvement procedures through an AM data lifecycle, such that data gaps and inaccuracies can be addressed and mitigated. In the case of this report, the quality of the results is dependent on the available data.

[8] Current year

METSCO recommends that FBC continues to work on mitigating existing data gaps so that more accurate HI grades can be given. This includes updating the switchgear age data so that assumptions do not have to be used.

Lastly, METSCO recommends FBC continues to work on capturing more detailed loading information. Specifically, load information by customer type. This will ensure the load distribution ratios, referenced in Table 4-1, are as accurate to FBC as possible.

Appendix A - Site Visit Report

Fortis BC Switchgear Inspection

Field Inspection Report

Report P-21-105-002-R0

Prepared by:
METSCO Energy Solutions Inc.

Prepared for:
Fortis BC

Date: April 19, 2021

Table of Contents

1. Introduction

Two METSCO personnel were involved in inspecting switchgear units at eight stations identified by Fortis BC. The field inspection was performed on April 6th and April 7th, 2021. The scope of work included:

1. Visual Inspection
2. Online Partial Discharge (PD) testing
3. Infrared (IR) Thermography

This report summarizes the field inspection results, by evaluating the switchgear lineups at each station based on the aforementioned factors.

2. Assessment Methodology

2.1. Visual Inspection

A comprehensive visual inspection was performed to assess the physical condition of the switchgear units. In evaluating the switchgear at each station: cubicle doors, hinges, bolts, and latches were checked to be free from damage and operated properly. A visual check was also performed to determine if overall installation was protected from dust, corrosion, high humidity, and high temperatures.

2.2. Online PD Testing

A PD is a high energy and short current pulse that occurs due to the localized breakdown of a certain portion of the insulation system, under voltage stress. In the field, it is common to indirectly measure PD activity through the form of one of its energy by-products: sound, electrical transients, electromagnetic emissions, heat, etc. In this background, the use of acoustic emissions (AE) is a preferred methodology to capture any surface discharges through the air gaps in metal-clad switchgear. For this site visit, a handheld PD measuring instrument with an ultrasonic sensor was utilized to detect the presence of any discharge events.

Figure 1: Online PD testing performed using a handheld PD measuring instrument

A discharge event was captured by listening to the characteristic crackling sound of PD through a microphone and observing the corresponding phase resolved partial discharge (PRPD) pattern obtained. PRPD is a plot between the PD magnitude and phase angle of the test or operating voltage of an asset being considered. For this inspection, the handheld PD instrument was synced to the natural power frequency of 60 Hz.

In analyzing the PRPD pattern, any signature that indicates discharges spaced 180° apart is indicative of a PD event. Background noise is characterized by discharges that are spaced out evenly and occur across the complete voltage signal (from 0° to 360°).

2.3. IR Thermography

IR thermography involves the use of a thermal imaging camera to identify the temperature rise of switchgear components with respect to the ambient temperature. Table 1 shows the criteria used for interpreting the IR test results, in accordance with the NETA MTS – 2019.

Table 1: Criteria for the interpretation of IR test results based on NETA MTS - 2019

Temperature difference (ΔT) based upon comparison between the switchgear component and ambient (°C)	Interpretation
1 – 10	Possible deficiency, monitor periodically
11 – 20	Probable deficiency, investigate further if a repair is required
21 – 40	Monitor regularly until corrective actions can be accomplished
> 40	Major deficiency, repair soon

3. Results and Recommendations

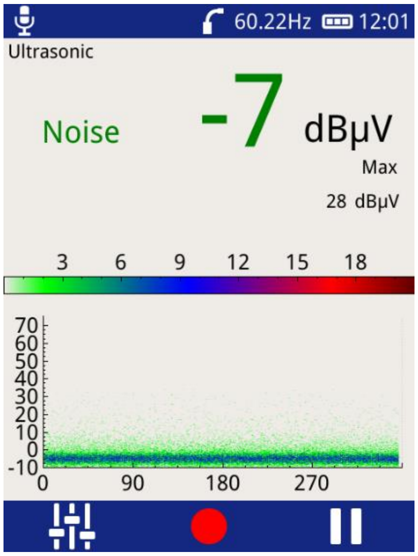
This section highlights the detailed results from the field captured at each station, across the three parameters considered: visual inspection, online PD testing and IR thermography.

3.1. HOL

3.1.1. Visual Inspection

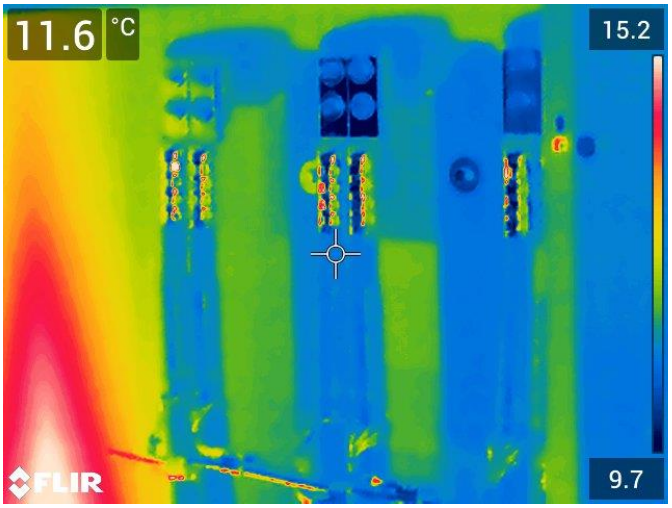
Some bolts were found to be missing at the panel doors of SS2 and T2 - MAIN. The switchgear was found to operate in a non-temperature-controlled environment with significant dust accumulation.

3.1.2. Online PD Testing



Interpretation: Only background noise was observed, based on the absence of a characteristic PD sound in the ultrasonic microphone, confirmed by the PRPD pattern spread uniformly across one complete 60 Hz cycle.

3.1.3. IR Thermography



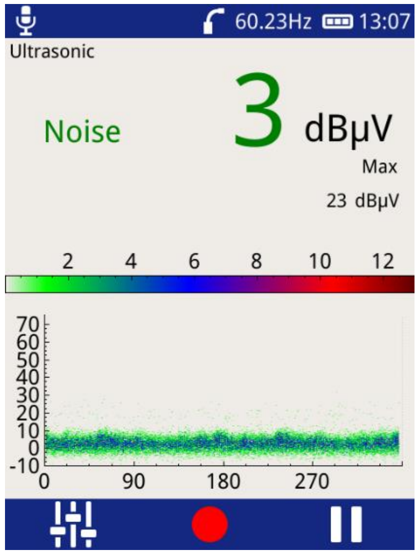
Interpretation: A temperature difference of 4.9°C was observed between the maximum temperature of the switchgear unit and ambient, indicating a slight overheating.

3.2. OKM

3.2.1. Visual Inspection

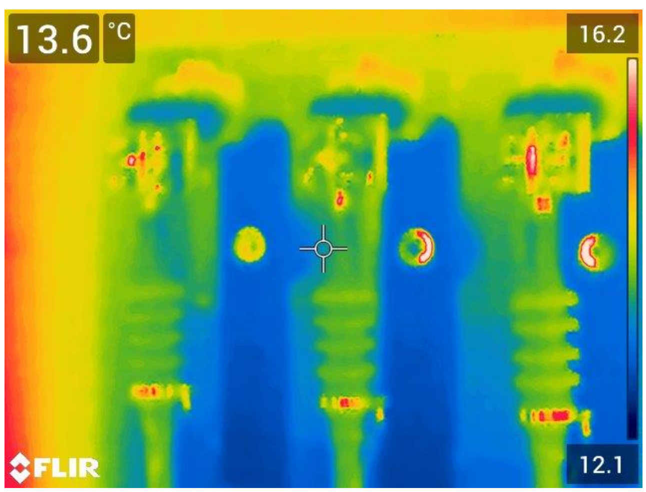
Some bolts were found to be missing at the panel door of T2 – MAIN. The switchgear was found to operate in a non-temperature-controlled environment with significant dust accumulation.

3.2.2. Online PD Testing



Interpretation: Only background noise was observed, based on the absence of a characteristic PD sound in the ultrasonic microphone, confirmed by the PRPD pattern spread uniformly across one complete 60 Hz cycle.

3.2.3. IR Thermography



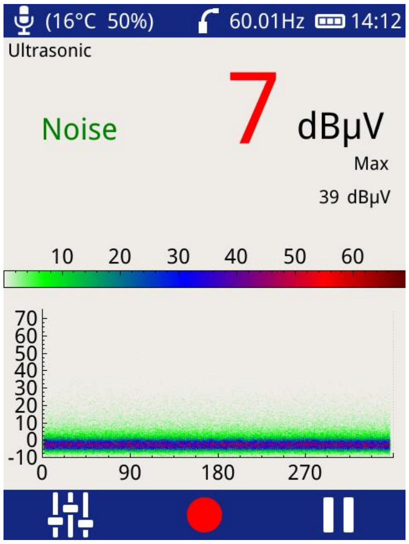
Interpretation: A temperature difference of 4.4°C was observed between the maximum temperature of the switchgear unit and ambient, indicating a slight overheating.

3.3. SAU 1

3.3.1. Visual Inspection

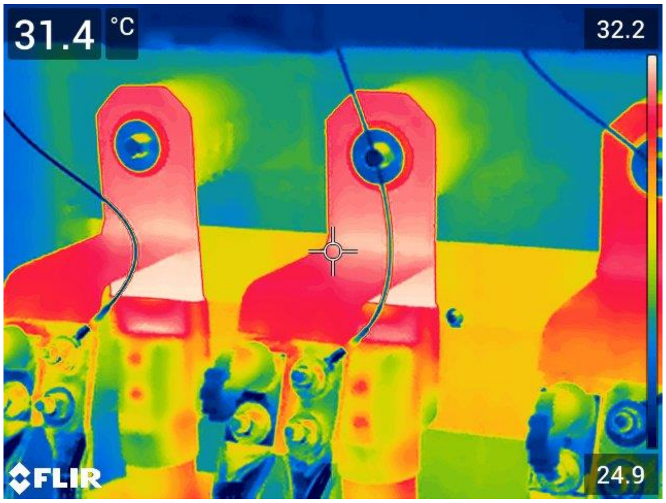
Normal wear, no major visual deficiencies found.

3.3.2. Online PD Testing



Interpretation: Only background noise was observed, based on the absence of a characteristic PD sound in the ultrasonic microphone, confirmed by the PRPD pattern spread uniformly across one complete 60 Hz cycle.

3.3.3. IR Thermography



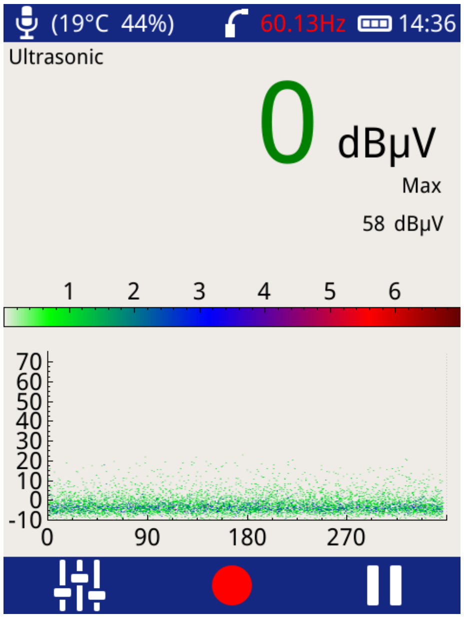
Interpretation: A temperature difference of 11.5°C was observed between the cable terminations and ambient. Based on the even temperature distribution between components (no hotspots) this indicates temperature rise due to loading.

3.4. SAU 2

3.4.1. Visual Inspection

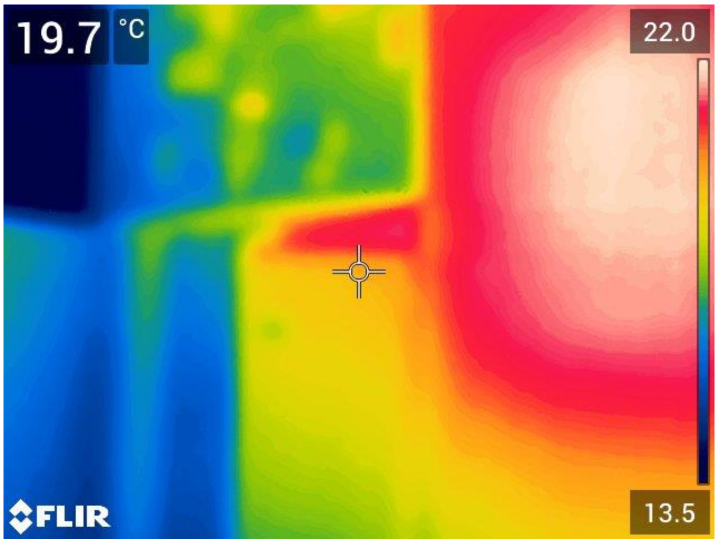
Normal wear, no major visual deficiencies found.

3.4.2. Online PD Testing



Interpretation: Only background noise was observed, based on the absence of a characteristic PD sound in the ultrasonic microphone, confirmed by the PRPD pattern spread uniformly across one complete 60 Hz cycle. The overall background noise level was also found to be high.

3.4.3. IR Thermography



Interpretation: A temperature difference of 9°C was observed between the maximum temperature of the switchgear unit and ambient, indicating overheating.

3.5. SAU 3

3.5.1. Visual Inspection

Normal wear, no major visual deficiencies found.

3.5.2. Online PD Testing

No online PD testing was performed due to the switchgear being offline at the time of inspection.

3.5.3. IR Thermography

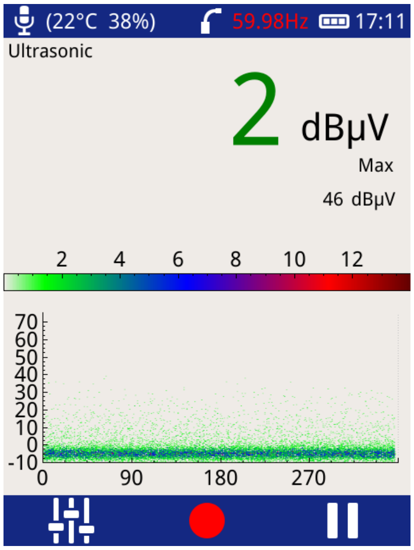
No IR thermography was performed due to the switchgear being offline at the time of inspection.

3.6. PIN

3.6.1. Visual Inspection

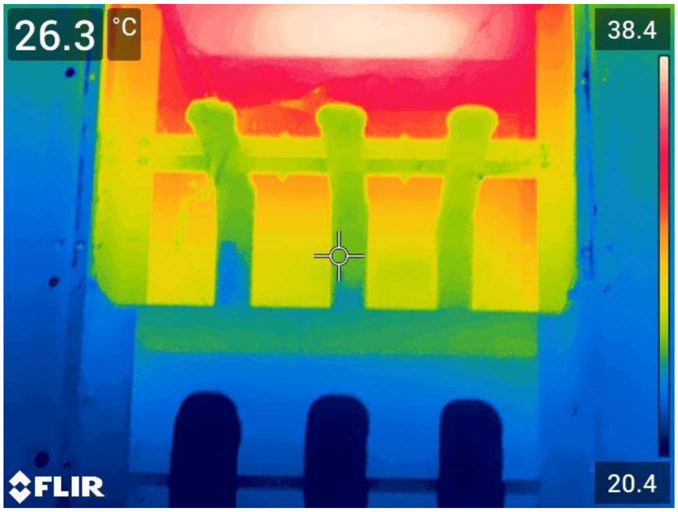
Some bolts were missing on the rear switchgear panels as well as significant dust accumulation was observed within the switchgear.

3.6.2. Online PD Testing



Interpretation: Only background noise was observed, based on the absence of a characteristic PD sound in the ultrasonic microphone, confirmed by the PRPD pattern spread uniformly across one complete 60 Hz cycle. The overall background noise level was also found to be high.

3.6.3. IR Thermography



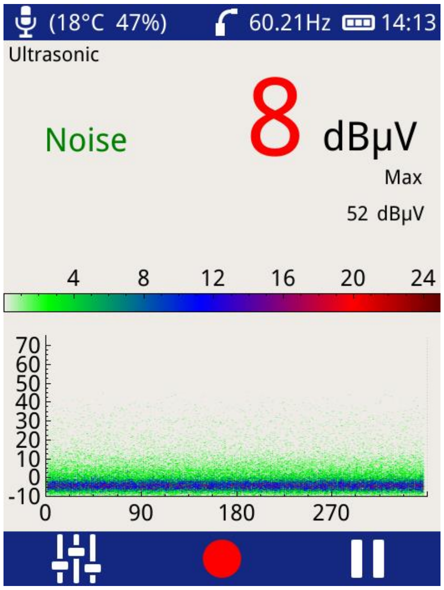
Interpretation: A temperature difference of 17.1°C was observed between the switchgear unit and ambient, indicating a probable deficiency.

3.7. CRE

3.7.1. Visual Inspection

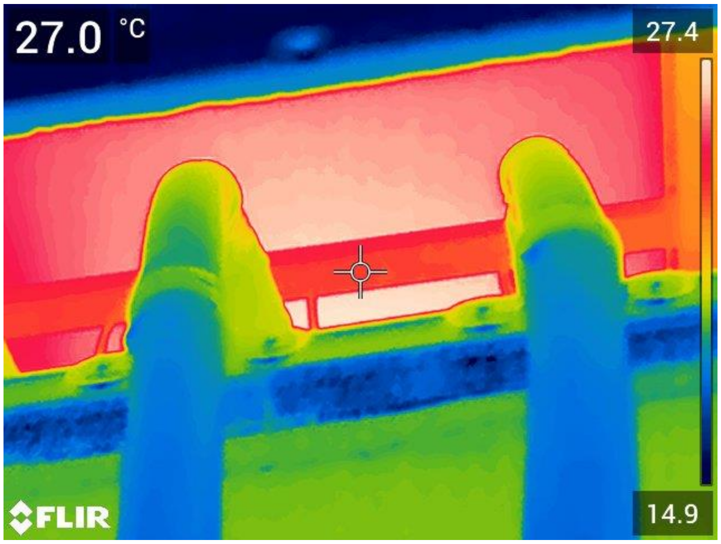
Insufficient insulation within the enclosure as well as corrosion present on the exterior of the switchgear.

3.7.2. Online PD Testing



Interpretation: Only background noise was observed, based on the absence of a characteristic PD sound in the ultrasonic microphone, confirmed by the PRPD pattern spread uniformly across one complete 60 Hz cycle. The overall background noise level was also found to be high.

3.7.3. IR Thermography



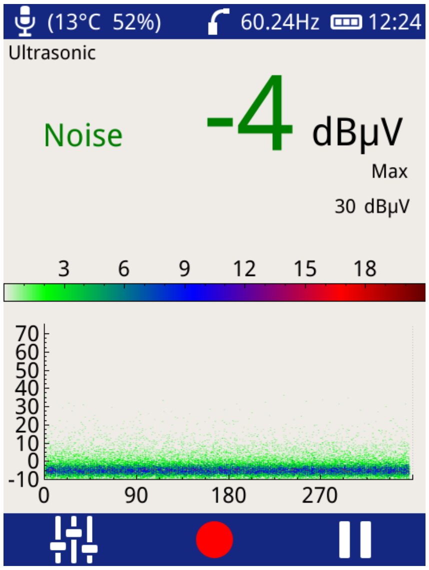
Interpretation: A temperature difference of 7.4°C was observed between the maximum temperature of the switchgear unit and ambient, indicating overheating.

3.8. CRA

3.8.1. Visual Inspection

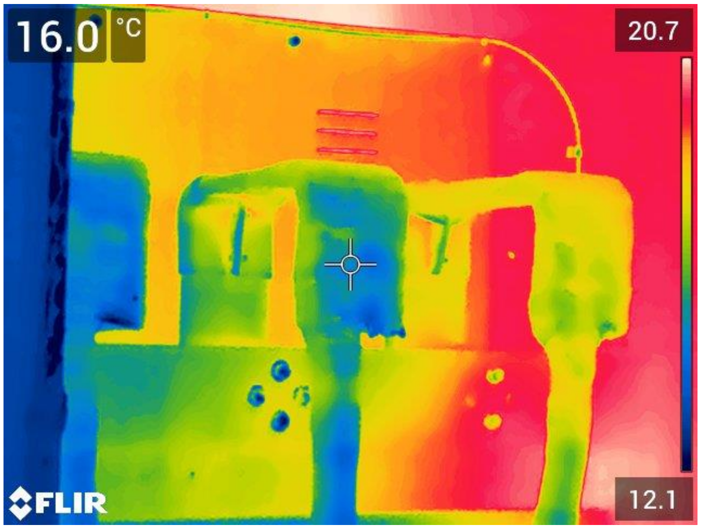
Excessive corrosion was found on the switchgear cubicle doors and the overall enclosure.

3.8.2. Online PD Testing



Interpretation: Only background noise was observed, based on the absence of a characteristic PD sound in the ultrasonic microphone, confirmed by the PRPD pattern spread uniformly across one complete 60 Hz cycle.

3.8.3. IR Thermography



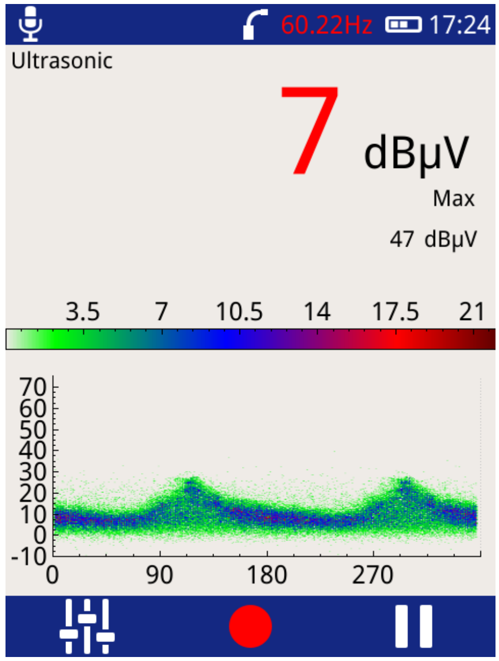
Interpretation: A temperature difference of 12.7°C was observed between the maximum temperature of the switchgear unit and ambient. Different temperature readings are observed between phases and on the cabinet itself indicating a probable deficiency.

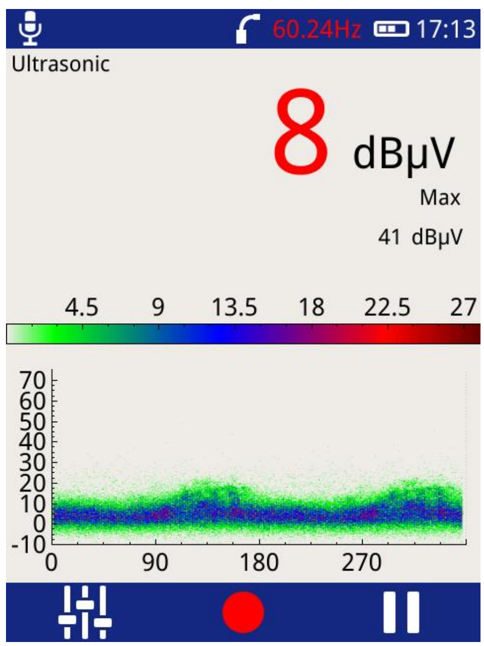
3.9. CAS

3.9.1. Visual Inspection

Excessive corrosion was found within the switchgear enclosure as well as the rear panels of the FDR 2 and FDR 3 cells were missing a few bolts. Visible signs of a previous flashover event.

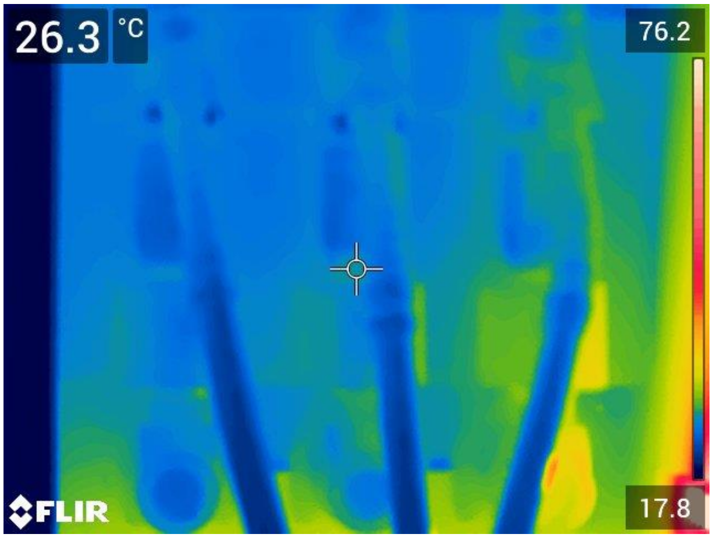
3.9.2. Online PD Testing





Interpretation: Discharges were observed on two separate occasions, based on the characteristic crackling sound of a PD that could be heard through the ultrasonic microphone, confirmed by the PRPD pattern with two peaks, separated by 180°. It is recommended to investigate further and locate the source of the discharges.

3.9.3. IR Thermography



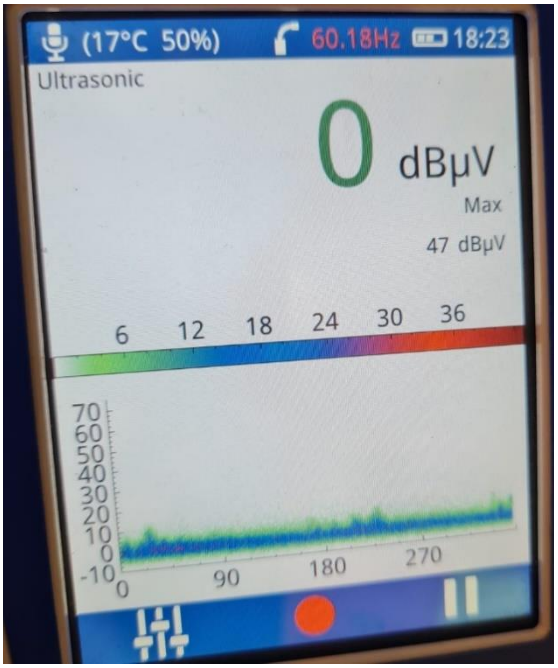
Interpretation: A major temperature difference in excess of 40°C was observed between the maximum temperature of the switchgear unit and ambient, around the same location that the discharges were picked up through the air gaps. Immediate attention advised and a possible repair.

3.10. BLU

3.10.1. Visual Inspection

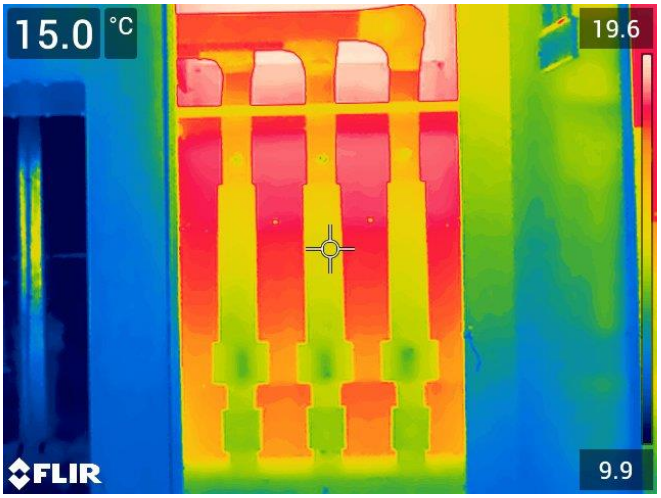
Excessive corrosion was found within the switchgear as well as missing a few bolts on both rear panels of the switchgear enclosure.

3.10.2. Online PD Testing



Interpretation: Slight discharges were observed, based on the light characteristic crackling sound of a PD in the ultrasonic microphone, with the PRPD pattern indicating small spikes, separated by 180°. It is recommended to investigate further and check if there is actually any source of PD.

3.10.3. IR Thermography



Interpretation: A temperature difference of 2.2°C was observed between the maximum temperature of the switchgear unit and ambient, indicating a slight overheating.

Appendix B - Summary Hazard Analysis

HAZARD ANALYSIS WORKSHEET

Job/Task: Performing Switchgear Upgrade/Breaker Retrofit

Prepared For: Fortis BC

Completed By: METSCO Energy Solutions Inc.

Hazard Category	Possible Plan of Action for hazard control or elimination
Equipment Incompatibility and Malfunction	- Check the connection of the busbar systems and ensure that the rating of both the existing and new equipment is not compromised - Verify the load rating and the short-circuit rating of old equipment retained in a retrofit scenario - Verify the condition of secondary wiring, protection and control system - Validate the interlocking and earthing arrangement in accordance with current safety standards - Ensure mechanical compatibility between any fixed and new moving assemblies - Ensure that the new switchgear components adhere to electrical standards such as ANSI and CSA - Follow the safety instruction manual for switchgear equipment handling and commissioning - Ensure proper earthing procedures in commissioning/ operating new switchgear equipment - Label and provide proper demarcation of new switchgear compartments - Use fire resisting barriers or compartments and ensure proper venting arrangements (where applicable)
Arc Flash	- Perform an overall arc flash assessment on the system - Ensure proper labeling related to shock and arc flash hazard highlighting the arc flash boundary and the calculated incident energy - Ensure safe work practices and the use of relevant personal protective equipment (PPE) by operating personnel - Verify the arc resistant capability of new switchgear in accordance with industry standards such as the IEEE Std. C37.20.2
Poor Workmanship	- Restrict access to trained/authorized personnel - Prepare a safety and protection plan with a clear listing of roles and responsibilities - Provide adequate training for working safely along with emergency response capability - Ensure good work practices during commissioning/retrofit to avoid leaving behind tools or metallic particles within the switchgear
Protection and Control Malfunction	- Provide adequate means to access and check the interlock systems

Hazard Category	Possible Plan of Action for hazard control or elimination
	- Use remote control and ensure the interlock system functioning as intended - Coordinate protection system with the associated properties (e.g., not reclosing on internal faults) - Ensure control system capability to withstand operating stresses and external influences
Insulation Breakdown	- Plan a thorough factory acceptance testing (FAT) and site acceptance testing (SAT) - Involve a third-party expert for the verification of new switchgear specifications, FAT witness and performing SAT
Personnel Mobility and Environment	- Mark emergency exits and keep passages clear of obstructions - Provide appropriate information related to the design of the surrounding region, ventilation / exhaust and gas detection

Attachment 32.3

REGULATOR RATIONALE FOR RATEPAYER-FUNDED ELECTRICITY AND NATURAL GAS INNOVATION

PREPARED FOR:

CANADIAN GAS ASSOCIATION and CANADIAN ELECTRICITY ASSOCIATION

April 2018

CONCENTRIC ENERGY ADVISORS

WWW.CEADVISORS.COM

Table of Contents

This report was prepared by Robert Yardley, Jr. (ryardley@ceadvisors.com), James Coyne (jcoyne@ceadvisors.com) and Jessalyn Pryciak (jpryciak@ceadvisors.com) of Concentric Energy Advisors ("Concentric") in collaboration with the Canadian Gas Association and the Canadian Electricity Association.

Concentric would like to thank Bryan Berry, Ceiran Bishop, Paula Conboy, Neil Copeland, Jennifer Davison, Jonathan Morris, Rolf Nordstrom, and Paul Wieringa for their contributions and insights.

EXECUTIVE SUMMARY

The case for utility-led, ratepayer-funded innovation has strengthened over the past decade and is being driven by a series of interconnected energy realities. These include the need to employ technology to integrate significant quantities of customer-sited distributed energy resources, the emergence of new natural gas end-use technologies, and a recognition by governments that utilities can play a central role in the achievement of energy and environmental public policy goals that require innovative solutions. Regulators in Canada should take note that these factors have taken hold among global economic regulators and this report concludes that the trend is spreading beyond some of the early movers: The United Kingdom, California, New York and British Columbia. The responsibility for ensuring that innovation prepares the energy industry to realize the potential for reliable, affordable, and clean energy with greater customer choices among products and services is shared by the utilities, regulators and other policy makers.

It is becoming increasingly accepted that new business models need to be developed, enabled by energy and data system technologies that require development and testing before they can be deployed at scale. Network infrastructure (pipeline and wire) modernization is an explicit goal for utilities and regulators, for both gas and electric utilities. Future investments in the networks are being designed to support an unfolding market characterized by engagement of both customers and third parties in the utility business model and the implementation of new consumer products and services. Utilities can support this evolving market via rate-funded demonstration projects that test new technologies and business models. Generally, while innovation in energy technologies and less expensive ways of performing traditional utility activities continue to grow, there has been more focus in the past few years on integration of demand energy resources, new business models, and the security of "big data" that enables this transformation. These programs de-risk investments for both customers and shareholders and help establish the business case for full-scale technology development and market adoption. Utility-led technology deployment and demonstration activities will have important direct benefits for customers by improving the way their customers use energy, control their energy use and derive benefit from it. Further, we are seeing many national and subnational governments developing large technology and funding programs. Utility ratepayer funding offers an opportunity to leverage these funds.

Regulators have another important objective with innovation: to spur a transformation of utility cultures to become learning and innovative organizations. Electricity and natural gas "utilities of the future" will be required to leverage advancements in energy technology, big data, and the desire of consumers to be evermore involved in their energy use patterns. Regulators also cite a desire to increase the reliability and resiliency of utility service and improve environmental performance.

The United Kingdom regulator concluded that its earliest efforts at innovation, the Low Carbon Network Fund (LCNF), which aimed to achieve aggressively low carbon goals, demonstrated that regulation has a critical role in promoting utility innovation and removing existing barriers for utilities. California has long been a supporter of customer-funded demonstration projects and continues this effort. New York's policy makers have implemented longer-term research and development programs, and requested that the regulator adopt a longer-term perspective when evaluating ten-year business plans that can be reprioritized during the plan as experience is gained. Minnesota has engaged a stakeholder process to contribute to the design of demonstration projects before they are submitted for review by the regulatory commission, thereby improving the opportunities for learning by all parties. AVANGRID, for example, is developing a demonstration "Energy Smart Community" that will test new customer engagement and business models after it installs Advanced Metering capabilities for over 10,000 customers in Ithaca, New York. Australia has supported customer-funded innovation that aims to reduce peak demand as growth is threatening reliability and will require expensive infrastructure investments. Ontario currently funds innovation through a combination of customer, utility shareholder, and vendor funding. The Ministry of Energy recently published a 2017 Long Term Energy Plan that focuses more intently on the role of innovation, and the potential barriers presented by existing regulation. The Massachusetts Commission has recently signaled its willingness to fund demonstration projects, indicating a willingness to follow through with a policy that was established in 2014 by a prior Commission. In British Columbia, an ambitious provincial clean energy policy has provided flexibility for utilities to propose - and the regulator to approve - customer-funded innovation projects in areas such as renewable natural gas and natural gas for transportation. These projects are seen as precursors to kick-starting new technologies and new applications of those technologies that may ultimately lead to scaled-up competitive markets.

Table ES-1 identifies programs in each of these jurisdictions where regulators have made an explicit determination that they meet specific innovation or demonstration project requirements to merit customer funding.

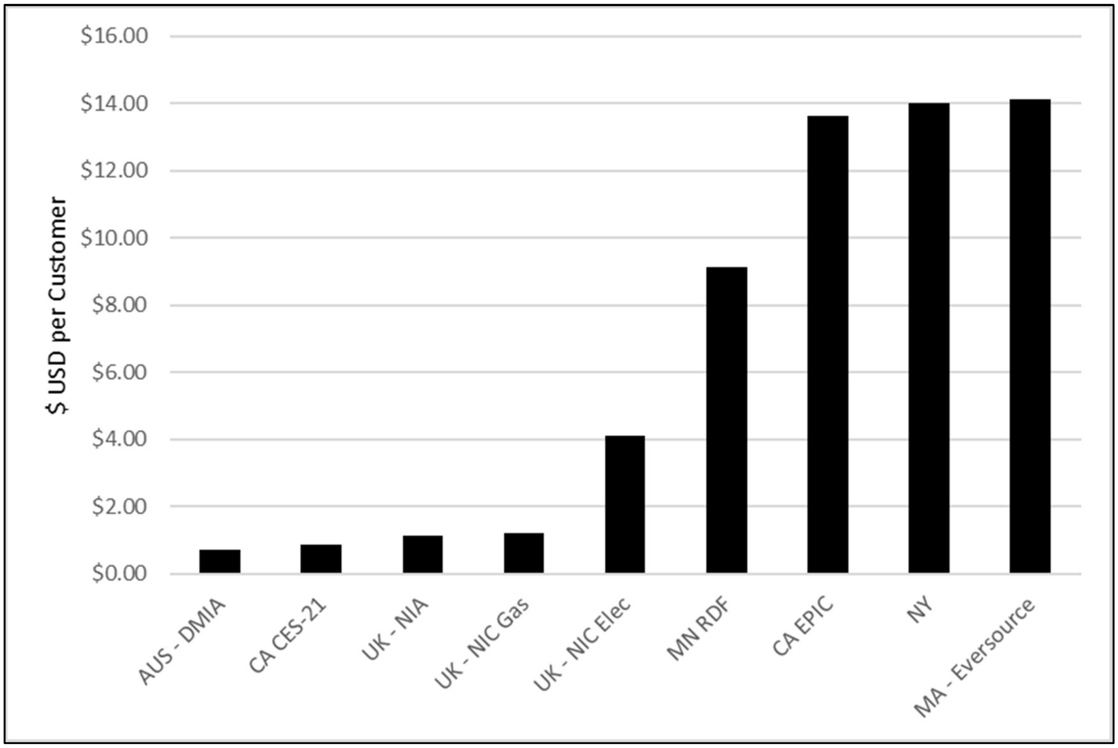
Table ES-1: Summary of Innovation Programs

Regulator/ Government	Program/ Directive	Link to Program	Start Date	Funding Level (annually per customer, $USD)
Ofgem	RIIO framework: Network Innovation Allowance (NIA) & Network Innovation Competition (NIC)	https://www.ofgem.gov.uk/network-regulation-riio-model https://www.ofgem.gov.uk/network-regulation-riio-model/current-network-price-controls-riio-1/network-innovation	2013-2015*	NIA: $1.13 NIC: $4.11 Electricity, $1.23 Gas
California PUC	California Energy Systems for the 21st Century (CES-21)	https://www.llnl.gov/sites/default/files/field/file/CES21.pdf	December 2012	$0.87
California PUC	Electric Program Investment Charge (EPIC)	http://www.energy.ca.gov/research/epic/	May 2012	$13.61
New York PSC and NYSERDA	Reforming the Energy Vision (REV)	https://rev.ny.gov/ http://www.dps.ny.gov/REV/	April 2014	NYSERDA funding: $4.69 ConEd REV project: $9.33
Minnesota PUC	Renewable Development Fund	https://www.xcelenergy.com/energy_portfolio/renewable_energy/renewable_development_fund	1994	$9.12
Australian Energy Regulator	Demand management incentive scheme and innovation allowance mechanism	https://www.aer.gov.au/networks-pipelines/guidelines-schemes-models-reviews/demand-management-incentive-scheme-and-innovation-allowance-mechanism	December 2017	DMIA: $0.72 *(hypothetical)*
Massachusetts DPU	Order requiring Grid Modernization Plan	http://www.raabassociates.org/Articles/MA%20DPU%2012-76-B.pdf	June 2014	Eversource demo projects: $14.12
IESO (Ontario)	Conservation Fund	http://www.ieso.ca/get-involved/funding-programs/conservation-fund/cf-overview	2005	*Insufficient data*

*Start dates vary by gas vs. electricity, and transmission vs. distribution.

Funding levels for innovation vary across the jurisdictions we have examined. The most recent data are summarized below in Table ES-2. These programs span a range from $0.72 to $14.12 per customer, or an average of $6.55. While virtually all policymakers and regulators express concern for costs, they also recognize the potential benefits. Ratepayer advocates have expressed concern that demonstration projects should be sufficiently defined with quantifiable benefits to support such investments.[1] The potential gains from adaptation of new technologies and business approaches to a "mature" industry are large, and studies indicate the potential consumer benefits from RD&D outweigh the costs by up to 5:1 multiples.[2]

Diagram ES-2: Examples of Utility Funding Levels, in Annual USD Per Customer[3]



Notes:
AUS – DMIA: Australia Demand Management Innovation Allowance
CA CES-21: California Energy Systems for the 21st Century
UK – NIA: Ofgem Network Innovation Allowance
UK – NIC Gas/Electric: Ofgem Gas/Electric Network Innovation Competition
MN RDF: Minnesota Renewable Development Fund
CA EPIC: California Electric Program Investment Charge
NY: New York State Energy Research & Development Authority and Con Edison
MA – Eversource: Eversource Grid Modernization Plan projects

In considering these funding levels, policymakers and regulators might ask: what is the optimal level of funding, which programs are most successful, and what factors determine whether funding should be increased or decreased? These are important questions without easy answers, but our research sheds light on them. Where energy policy dictates a shift in the status quo, funding levels would be expected to be higher to facilitate the transition, and targets comparable to the CA-NY-MA range may be appropriate. Given the relatively new nature of utility funded innovation, it is difficult to measure success, but Ofgem programs appear at the forefront, with benefits for certain programs estimated in the 4.5-6.5 times funding level range. Capital investment theory stipulates that any investment with a positive return should be undertaken with risk and capital costs factored in. This suggests that program funding up to a return ratio of 1:1 is warranted. Even with current budgets, California has estimated its RD&D funding gap is as much as $670 million per year. As long as estimated benefits continue to exceed funding levels, policymakers and regulators are serving the public interest.

Overall, this report documents the trend toward increased customer funding of innovation projects in both the natural gas and electricity industries and cites the rationale relied upon by policy makers and regulators. In some jurisdictions, the changes are implemented through a combination of legislation and regulation. The potential returns from innovation are significant. Whether avoiding costly investments in infrastructure, or helping customers save money on their bills by utilizing technology to manage their energy use, regulators are concluding that the short- and long-term benefits clearly justify the costs of demonstration projects.

INTRODUCTION

Concentric's 2014 report, "Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Consumers" described the significant benefits that energy innovation provides to customers and society with benefit-to-cost ratios in the 2 to 5:1 range across several programs. As noted in the Executive Summary:

> *An increased emphasis on innovation by utilities could yield a range of new technologies, applications, processes, and business models—e.g., more efficient end-use equipment, smart-grid technologies and services, advanced low-carbon energy sources, energy storage technology solutions, and community energy systems. Such innovations can provide cleaner, less expensive energy services to Canadian households and businesses while creating jobs, bolstering Canadian competitiveness, and promoting Canada's position among global energy leaders.*[4]

The 2014 report provided a framework for evaluation of alternative funding mechanisms, focusing primarily on government (taxpayer) and utility (customer) funding options. Government funding is most appropriate in the high-risk early research & development phase or where there are significant spillover benefits that discourage risk-taking. Utility customer funding is most appropriate where the benefits largely accrue to utility customers and where they are in a unique position to test new technologies and business models. The report identified potential obstacles to utility innovation and recommended a utility customer-funding model that maintains active regulatory oversight.

Two subsequent updates (2015 and 2016) provided updates on trends in utility-sponsored innovation along with examples of recent projects. This 2018 update focuses on customer-funded innovation programs with a deeper dive into the reasons why regulators in eight jurisdictions support customer-funded innovation. These include four leading United States jurisdictions (California, New York, Minnesota, and Massachusetts), two Canadian provinces (Ontario and British Columbia), and two international jurisdictions (Great Britain and Australia). We supplemented regulatory research with regulatory and policy interviews in these jurisdictions to obtain perspective on whether the programs were working, and indications of results achieved to date. The following sections describe the approaches taken in each jurisdiction and insights gained from evaluation of these programs.

CUSTOMER-FUNDED INNOVATION FROM AROUND THE GLOBE

1. UNITED KINGDOM

'The United Kingdom's energy regulator, the Office of Gas and Electricity Markets ("Ofgem"), has been an international leader in regulatory reform since its predecessor agencies were established when natural gas and electricity markets were privatized in the 1980s. Notably, it was an earlier adopter of performance-based regulation ("PBR"). The most recent version of this multi-year utility revenue model is "RIIO", representing the equation, "Revenue = Incentives + Innovation + Outputs", which was applied to natural gas and electricity distributors in 2013 and 2015, respectively. This new model was the result of a "RPI-X@20" review of PBR as applied in the UK. During this same era, Ofgem and the U.K. utilities gained experience with the Low Carbon Network Fund (LCNF).

The LCNF provided approximately £250m of funding for Distribution Network Operators ("DNOs") during the 2010-2015 period, a dramatic increase in innovation funding that was occurring under the PBR framework. LCNF was part of the electricity distribution price control. In the electricity distribution network, there are 14 DNOs which are owned by 6 groups. Focusing on achieving a low-carbon future while maintaining reliability and efficient services to customers, the LCNF was designed to integrate innovation as part of normal business operations and to share learning across the six DNOs. The estimated net benefit from this investment was £1.1 to £1.7 billion[5] or 4.5 to 6.5 times the funding level.[6]

The concept of compensating utilities for how well they perform as innovators grew from the recognition that the energy sector was about to experience significant change and that utilities needed to be able to innovate in order to respond to evolving customer demands and policy drivers.[7] Ofgem recognized that even within the new incentive-based ratemaking framework, "research, development, trials and demonstration projects - the earlier stages of the innovation cycle - are speculative in nature and yield uncertain commercial returns."[8] Ofgem recognized that even "failures" in terms of innovation attempts could provide useful information.[9]

Regulatory Rationale

Ofgem noted that the innovation stimulus is intended to "kick start" a cultural change at utilities.[10] Innovation funding is provided by customers since they will benefit from innovations.[11]

The initial decision noted that there was widespread support throughout the consultation for an incentive for innovation:

> *Given the scale of the challenge that network companies face and the uncertainty about how best to deliver, innovation is needed to ensure network companies deliver a sustainable energy sector and long-term*

> *value for money. The need for innovation has been widely recognized throughout RPI-X@20, including in responses to our consultations.*[12]

Ofgem concluded that networks will need to become a lot "smarter" to meet several challenges including:

- connecting more home-based microgeneration, i.e., solar panels and small scale renewable generation;
- connecting more small-scale renewables and CHP to the low voltage distribution network;
- balancing the electricity network to manage large amounts of renewable generation which by its nature is intermittent; and
- gas networks will face further growth in the use of Liquefied Natural Gas, as well as carbon capture and storage facilities at power stations.[13]

This rationale was restated in a March 2017 network innovation review:

> *As a consequence, network-related costs could increase significantly from connecting large volumes of generation, as well as managing the impacts of new sources of gas. We think it is in consumers' interests that the network companies respond creatively to the challenges posed by these changes. New approaches could deliver more efficient and timely services needed by network customers and lessen the cost impact on consumers. This might be achieved, for example, by developing and adopting new technology, different operational practices and novel commercial arrangements.*[14]

Ofgem noted the enormity of the investment that will be required to achieve its objectives, estimating that approximately £32 billion (approximately $53 billion Canadian dollars) of network investment will be required.[15] Ofgem recognized that in order to have an impact, the incentives for innovation must be significant:

> *The innovation stimulus package will include substantial prize funds to reward network companies and third parties that successfully implement new commercial and charging arrangements to help deliver a sustainable energy sector.*[16]

Ofgem established two distinct innovation funding programs to implement the innovation component of RIIO: the Network Innovation Allowance (NIA) and the Network Innovation Competition (NIC). These two programs fund research by the Distribution Network Operators (DNOs) that will facilitate the transition to a low carbon economy, while providing cost savings to customers. Customers will pay for these activities through their energy bills. The NIA is for funding smaller innovation projects and is a set annual allowance available to each network operator. For electricity distribution, Ofgem required utilities to define innovation strategies based on NIA funding of between 0.5 and 1 percent of their base revenues. NIA projects do not require individual project approvals. While funding caps are company-specific, they have generally been between 0.5 and 0.7% for both electric and natural gas DNOs. £61 million is available for the NIA annually.[17]

The NIC is an annual competition to fund selected innovation projects, and is focused on larger, more complex projects that require approval.[18] In 2016, Ofgem provided £44.6 million in funding to six projects through the NIC. This funding is combined with the companies' contributions and external funding, creating a total of £53.9 million (approximately $75 and $90 billion Canadian dollars, respectively). These recently approved projects are shown in Table 1. The projects must meet certain criteria, such as generating new and shareable knowledge, being cost effective, and accelerating to move to a low carbon energy sector.[19] The total annual funding available for the electricity NIC was recently reduced to £70 million, down from £90 million, but the amount available annually for gas networks remained at £20 million.[20]

Table 1: NIC Projects Approved in 2016

	Project	DNO	Funding Sources	Length	Description
ELECTRIC	OpenLV	Western Power Distribution	4.9m – NIC, 0.5m – WPD, 0.5m – partners	3 years	Develop software platform to enhance visibility of residential substations
	TDI 2.0	National Grid Electric Transmission	8m – NIC, 1.5m – NGET + UKPN	3 years	Test technical & commercial solutions to resolve constraints on the transmission network
	PowerFul-CB	UK Power Networks	4.6m – NIC, 0.6m – UKPN, 0.9 – partners	4.5 years	Develop 2 types of circuit breakers on GB network
	Phoenix	SP Transmission	15.6m – NIC, 1.8m – SPT, 2.3m – partners	4 years	Test new way of providing services (traditionally fossil-fueled power stations) to balance electricity network
GAS	HyDeploy	National Grid Gas Distribution	6.8m – NIC, 0.4m – NGGD, 0.4m – NGN	3 years	1st practical deployment of hydrogen onto live GB gas distribution network since the 1970s
	Future Billing Methodology	National Grid Gas Distribution	4.8m – NIC, 0.5m – NGGD	3 years	Explore options for fair & equitable billing methodology, fit-for-purpose in lower carbon future

DNOs submit annual reports that provide a summary of all NIA projects. Customer-facing NIA projects are the subject of more detailed technical reports. DNOs have been providing individual reports on each NIC project that present spending updates along with learning to date and key challenges and risks that have been encountered. This is being transitioned to a single report for each company in 2018.

NIC projects were eligible for rewards based on successful delivery, but this has been subsequently eliminated now that the programs are up and running and the DNOs have been deemed to be managing the programs well.

Interview Insights[21]

The UK's focus on innovation is intended to produce a low-carbon future, while also driving down costs for network customers. Ofgem has significant authority and has not required legislation to implement its innovation agenda. The LCNF experience, supported by a survey from an independent evaluation report prepared by the consultancy Pöyry in October 2016, demonstrated that regulation has a critical role to serve in promoting utility innovation and removing existing barriers for DNOs.[22] The NIA and NIC programs continued the goal to foster a more innovative culture within network companies. Policy makers are hopeful that the innovative culture will be applied to resolving industry challenges as they arise and provide value to customers. Ofgem has made tweaks to governance over the past few years, providing more flexibility to DNOs based on satisfactory performance to date.

Funding Levels

In 2016, funding for the NIC was approximately £3.05 per electric customer and £0.91 per gas customer ($4.11 and $1.23 USD, respectively). With the reduction of £90 million to £70 million in electric NIC funding, future funding will be approximately £2.37 per electric customer ($3.20 USD).[23]

Insights: The UK government, through Ofgem, has made utility innovation a key objective of its regulatory framework. The regulator wants to drive cultural change at utilities in order to create a smarter, distributed, renewable, sustainable, efficient, and diversified electric and gas grid for the benefit of customers. Utility customer funding is utilized along with co-funding from third party vendors. The goals and scope of the UK program are among the most ambitious examined.

2. CALIFORNIA

California has two large programs that fund RD&D in the energy sector. The CES-21 program is a collaborative effort among the three large investor-owned utilities and Lawrence Livermore National Laboratories (LLNL) that funds investments in several specified areas, focusing most recently on cybersecurity and grid integration projects. The Electric Program Investment Charge (EPIC) Program funds investments that promote the adoption of clean technologies. Both programs are reviewed and approved by the California Public Utilities Commission (CPUC) and rely on customer funding.

In 2011, California's three large investor-owned utilities requested approval from the CPUC to enter into a five-year, $150 million research and development agreement with LLNL that was projected to produce over $550 million in savings. This program is referred to as the "21st Century Energy Systems Research Project" or "CES-21". The PUC approved this initial funding level in 2012 after determining that the proposal was consistent with a provision in the California Public Utility statute that authorized the CPUC to approve utility research, development and demonstration (RD&D) programs that considered the following guidelines:

1. Projects should offer a reasonable probability of providing benefits to ratepayers.
2. Expenditures on projects which have a low probability of success should be minimized.
3. Projects should be consistent with the corporation's resource plan.
4. Projects should not unnecessarily duplicate research currently, previously, or imminently undertaken by other electrical or gas corporations or research organizations.
5. Each project should also support one or more of the following objectives:
    a. Environmental improvement;
    b. Public and employee safety;
    c. Conservation by efficient resource use or by reducing or shifting system load;
    d. Development of new resources and processes, particularly renewable resources and processes which further supply technologies;
    e. Improve operating efficiency and reliability or otherwise reduce operating costs.

Regulatory Rationale

The statute provides the CPUC with the clear authority to approve RD&D funding by utilities and establishes a set of guidelines to consider. In the absence of clearly expressed legislative intent, the CPUC could have relied on more general "public interest" statutory provisions that are common in utility statutes. The Commission cited a Staff position suggesting that the California RD&D funding gap was as much as $670 million per year.[24]

Noting that the petition was consistent with the statutory guidance, the CPUC cited six benefits to utility customers:

1. The research findings are very likely to improve the safety of gas operations by reducing the gas pressure in transmission pipes needed to maintain distribution flows, by improving leak detection, and by predicting pipe breaks;
2. The project is very likely to provide benefits to ratepayers that exceed costs across both electric and gas operations by avoiding unnecessary purchases of power support services and by identifying with precision places where more grid investment is needed;
3. Research pertaining to the operations of electric and gas utilities is currently underfunded;
4. The research pertaining to cybersecurity will better protect both electric and gas operations and customer privacy;
5. Only the use of supercomputers, a core strength of LLNL, will enable utilities to process the three terabytes of data a day produced by smart meters and thereby improve grid operations and stability; and
6. The proposed research uses the special research strengths of LLNL in supercomputing, modeling, and cybersecurity.

It is evident from the fifth and sixth reasons that the CPUC was particularly focused on cybersecurity and potential threats to customer privacy and network security. In approving the initial funding levels of $30 million per year, the CPUC exercised care not to be overly prescriptive and require detailed project definitions, recognizing that the projects would be developed over time through collaboration among the utilities and LLNL. These decisions were delegated to CES-21's Board of Directors subject to the requirement that projects must fall within one of four areas: Gas Operations, Electric Operations, Electric Resource Planning, and Cybersecurity. The CPUC approved the agreement over the objections of two California ratepayer advocate organizations (TURN and DRA) whose objections focused on governance concerns, citing the reliance on estimates of benefits and the delegation of decision-making authority to CES-21's Board of Directors.

Subsequent legislation enacted in 2014 (Senate Bill 96) reduced the level of spending from approximately $150 million to $35 million over the five-year period. The Bill limited the areas of research to cyber security and grid integration and streamlined the governance process while adding more rigorous monitoring and reporting requirements that documented expenditures and described the beneficial outcomes from the research, as well as limiting administrative charges to 10% of program budgets. The limit was in response to concerns regarding administrative costs that were charged to the program and recovered from customers. The CPUC decision reaffirmed its support for RD&D by utilities.[25]

The program has been operating for a few years, and annual reports which detail progress to date have been released. Most recently, the 2016 Annual Report discussed updates to the cybersecurity and grid integration projects. The Simulation Engine has modeled security threats and malware attacks, and outreach sessions have focused on identifying synergies and checking for duplication. The project has also expanded simulations of the Western Interconnect, modeling every generation unit and load zone across the region. This allows the researchers to examine power flows between regions to study the impact on the grid's need for operational flexibility.[26] The cybersecurity project will continue addressing next steps over the coming years, while the grid integration half of the program is set to produce the final deliverables by 2018.

The EPIC program was established by the CPUC in 2012, and consists of the three utilities administering an RD&D program that funds innovative technologies and approaches that promote reliability, lower costs, and increase safety. The investment decisions reflect the following principles:

1. Providing societal benefits;
2. Reducing greenhouse gas emissions in the electricity sector at the lowest possible cost;
3. Supporting California's loading order to meet energy needs first with energy efficiency and demand response, second with renewable energy (distributed generation and utility scale), and third with clean conventional electricity supply;
4. Supporting low-emission vehicles and transportation;
5. Providing economic development; and
6. Using ratepayer funds efficiently.

A broad range of programs has been implemented including research on net zero emissions buildings, testing of new demand response strategies, microgrid commercialization, adaption of the electric system to climate risk, and energy storage.

The initial 2012-2014 EPIC budget was $368.7 million, including a 10% cap on administrative costs. This increased modestly to $405.8 million for the 2015-2017 period. The California Energy Commission, as one of the administrators of EPIC, produces an annual report that documents investments.

Funding Levels

CES-21 funding in 2016 was $10.3 million, divided among the approximately 11.9 million customers of the three IOUs, results in a funding level of $0.87 per customer. EPIC's annual budget of $162 million translates to funding of approximately $13.61 per customer.

Insights: California is a leader in customer-funded innovation. The California CES-21 program demonstrates that enabling legislation can achieve two objectives: 1) clarifying the authority of a regulatory agency to approve RD&D expenditures by utilities and 2) establishing guidelines that a regulatory agency can apply in approving specific proposals. However, it also demonstrates that legislatures can subsequently modify their perspectives with respect to the amount and focus of RD&D. In this instance, the decision to reduce funding of the CES-21 program appears to have been caused by concerns about the proportion of the funding that was being used to fund administrative costs.

3. NEW YORK

New York supports customer-funded RD&D projects in both the natural gas and electric industries. There are several categories of funding. The seminal order establishing competition in New York's electric and natural gas industries (Order 96-12) established a non-bypassable systems benefits charge (SBC) from customers to fund research and development as well as energy efficiency investments, low-income programs, and environmental monitoring. The New York State Energy and Research Development Authority (NYSERDA) was designated in 1998 to administer the SBC funds. Prior to that time, utilities performed research and development activities that were approved by the New York Public Service Commission (NYPSC) and funded through customers' utility bills. New York's utilities continue to request and receive authorization to perform R&D activities that are approved in their rate cases.

In 2000, the NYPSC approved a surcharge intended to fund medium-to-long-term R&D by New York's investor-owned natural gas local distribution companies (LDCs) in response to a decision by the Federal Energy Regulatory Commission to phase out support for the Gas Research Institute through a surcharge on interstate pipeline deliveries.[27] New York's LDCs pledged to work collaboratively to address common needs and avoid duplication of research activities. The NYPSC relied on a Staff recommendation to have funds directed to distribution activities, and not to upstream activities (i.e., supply and storage) or to improving end-use appliances that were considered competitive activities. An appendix to the recommendation provides a list of qualifying distribution activities that includes pipe installation, pipe repair and maintenance, modeling of pipe flows, and improvements that would address environmental impacts related to the distribution function. This effort came to be known as the Millennium Fund. An industry trade group estimated that the benefit-to-cost ratio of gas R&D projects was approximately 3:1. The Millennium Fund remains in place today.

Millennium Fund programs are supplemented by utility-specific natural gas R&D programs that are approved in individual LDC rate cases. For example, Consolidated Edison proposed the deployment of trenchless technologies that allow the companies to repair gas distribution lines without digging a trench. Central Hudson has proposed to test a "non-pipes alternatives" concept as a way to meet growing peak demand on constrained parts of their system.

New York's support for innovation experienced a renaissance with its "Reforming the Energy Vision" (REV) proceeding that began in 2014. Customer-funded RD&D occurs through two mechanisms: (1) REV demonstration projects proposed pursuant to the Track 1 Order in the REV proceeding, and (2) RD&D efforts organized and managed by NYSERDA and funded by the SBC.

REV demonstration projects were filed pursuant to guidelines established in the REV Track 1 Order issued on February 26, 2015. The REV proceeding is New York's broad-based initiative to leverage technology and business model innovation in order to integrate substantial amounts of "Distributed Energy Resources" and thereby enhance reliability and resiliency while lowering carbon emissions.

Regulatory Rationale

The NYPSC expressed its support for innovation with its opening paragraph of the Track 1 Order:

The electric industry is in a period of momentous change. The innovative potential of the digital economy has not yet been accommodated within the electric distribution system. Information technology, electronic controls, distributed generation, and energy storage are advancing faster than the ability of utilities and regulators to adopt them, or to adapt to them. At the same time, electricity demands of the digital economy are increasingly expressed in terms of reliability, choice, value, and security.[28]

The Track 1 demonstration projects represent the NYPSC's commitment to supporting the realization of REV's ambitious objectives by inviting and subsequently approving customer-funded demonstration projects. Customer-funded demonstration projects were broadly supported by stakeholders, but the largest industrial customers expressed reservation about "significant" commitment of customer funds while REV concepts were still under development.[29] The NYPSC cited the following rationale for approving demonstration projects:

> *Demonstration projects will inform decisions with respect to developing DSP functionalities, measuring customer response to programs and prices associated with REV markets, and determining the most effective implementation of DER. Demonstration projects will test new technology approaches to assess value before going to scale. Data collected from these projects will inform regulatory changes, rate design, and the most effective means to integrate DER on a larger scale. Demonstration projects will also help to identify the kinds of price signal, tariff, data and consumer protection regulations necessary to bring products to scale.*[30]

As documented in our 2015 Update, the NYPSC established the following eight criteria for reviewing utility demonstration project proposals:

1. Demonstrating Innovation – Diversity of projects in the demonstration portfolio;
2. Value Distribution – Allocation of project benefits among customers, utilities and third parties;
3. Partnerships – Between utilities and third parties;
4. Customer Engagement – Response to DERs across the spectrum of customers;
5. Market Solutions – Enabling participants to propose solutions through competitive solicitations;
6. Developing Competitive Markets – Testing rules that will further the development of new markets;
7. Cyber Security – Developing data security standards and protocols; and
8. Scalability – The ability to accelerate development at scale.[31]

The five New York utilities submitted eleven demonstration projects in July 2015. These were approved on a staggered basis during the following 9-month period. Cost recovery is approved in utility rate cases, with a cap on demonstration project cost recovery at 0.5% of total revenue requirements or $10 million. The following table lists five of these projects.[32]

Table 2: Highlighted REV Demo Projects

Demo Project	IOU	Partners	Project Goals
Building Efficiency Marketplace	ConEd	Ecova Inc. and Honest Buildings	Build an online C&I marketplace to enable targeted building owners to leverage energy data and connect with qualified products/service vendors
CenHub Marketplace	Central Hudson	Simple Energy	Build an online mass market marketplace that connects customers and 3rd party DER providers with detailed home energy profiles and enhanced data analytics
Clean Virtual Power Plant	ConEd	SunPower and Sunverge	Bundle residential solar with storage offerings to aggregate and dispatch as a virtual power plant for local distribution system needs
Community Energy Coordination	NYSEG	Taitem Engineering	Aggregate and coordinate local demand for clean energy technologies through an online marketplace
Flexible Interconnect Capacity Solution	NYSEG	Smarter Grid Solutions	Provide cheaper/faster large scale DER interconnections with infrastructure-as-a-service model

These projects are supplemented by electric RD&D projects in rate cases. National Grid has requested approval for a number of demonstration projects that examined the value of data analytics, changes in workflow and business processes, and the use of mobile device applications by employees. They also proposed electric heat and electric transportation demonstration projects.

In a recent National Grid rate case, the Commission explained: "Although, to date, we have not adopted REV programs expressly targeted to our natural gas utilities, we support economically viable projects to the extent that they advance REV goals and benefit the gas system."[33] In this spirit, National Grid and Con Edison have both proposed natural gas demonstration projects in their rate case filings to align with the goals of REV. The Commission approved National Grid's three demonstration projects that aim to create a smarter and more resilient gas network while also encouraging customer engagement and helping to achieve the goals set out in REV. These projects consist of technology packages to test behaviors and response to energy efficiency options, assessing the effectiveness of generating units in load reduction, and a commercial demand response program to test market incentives. In Con Edison's most recent rate case (case 16-G-0061), the company emphasized how AMI deployment will help build the smart grid of the future as envisioned in REV. Con Edison has also recently proposed the Smart Solutions for Natural Gas Customers Program, which aims to decrease gas usage, procure alternative resources, and contribute to State environmental goals. The proposal also includes a Gas Innovation Program, aimed at testing new business models for clean heating technologies in order to determine if the technology could be scaled for a greater impact.[34]

A third category of RD&D projects in New York is either funded by NYSERDA or hosted on a recently launched REVConnect web-based platform. NYSERDA is interested in demonstration projects that test REV concepts, particularly those involving new business models that will provide revenue and earnings opportunities for utilities and third parties. These projects will test the willingness of customers to engage with – and pay for – new products and services that are delivered in an innovative manner. Ideally, proposed projects are scalable if they prove to be promising.

The REVConnect platform (https://nyrevconnect.com) brings utilities, third parties, investors, and regulators together to develop innovative solutions, and the REVConnect team serves as a facilitator to promote collaboration.

Interview Insights[35]

Policy makers were particularly interested in demonstrating that the industry could transition to a new business model without having an adverse impact on reliability. NYSERDA recognizes that utility participation in RD&D is critical to the ultimate goal of new technologies and business models being deployed for the benefit of customers who are funding the research through the SBC. There is a tension between the uncertainty and risk associated with RD&D and the cost-benefit analysis that regulators typically apply to more traditional utility investments. The longer timeframe associated with returns to RD&D also present a challenge as regulators are generally looking for some measurable customer or environmental benefit (e.g., a specified carbon reduction quantity) within the first five years. Although NYSERDA is a state agency, its budget and activities are subject to review and approval by the NYPSC. As part of the Clean Energy Fund review, NYSERDA has received approval to apply a ten-year business planning horizon to its portfolio of programs. NYSERDA will file annual, rolling updates to its portfolio, adjusting priorities in response to technology and market developments, and defunding programs that no longer appear promising. This longer horizon is more aligned with the risk associated with RD&D, and also provides greater certainty and continuity as the NYSPC grows more comfortable with NYSERDA's portfolio approach.

The New York approach to innovation requires that the NYPSC apply a different perspective to its review and oversight of RD&D than it takes to its more traditional approval actions. The Commission is being asked to adopt a higher risk tolerance on behalf of customers based on the belief that customers will benefit in the long run from innovation and that, absent customer-funding, a suboptimal level of RD&D will occur in the regulated utility segment.

Funding Levels

Cap on REV demonstration project cost recovery of 0.5% of total revenue requirements, or $10 million per year.

Insights: New York has promoted utility innovation through multiple programs targeting both the gas and electric industries. While New York policy makers are pressuring the utilities to be innovative, they are also keeping utilities firmly within a cost-of-service regulatory environment. The introduction of potentially disruptive market and regulatory models is a concern among utilities as DERs continue to be integrated throughout the state. The issue may be brought to a head with NYSERDA taking a more active policy role in an effort to sustain the momentum toward increasing innovation.

4. MINNESOTA

Minnesota has two initiatives that provide customer-funded RD&D projects: a Renewable Development Fund established in 1994, and a more recent effort to develop demonstration projects through extensive stakeholder participation as part of Minnesota's e21 initiative. This initiative is addressing the future of energy market more comprehensively by examining changes to business models and regulatory frameworks necessary to leverage new technologies to promote a sustainable future with greater reliance on customer-sited and other renewable energy supplies.

a. Renewable Development Fund

The Minnesota Legislature established the Renewable Development Fund in 1994 as part of a condition that allowed Xcel Energy, Minnesota's largest electric utility, to store spent nuclear fuel in dry casks at the Prairie Island nuclear generating plant site. The legislation required the utility that operates the Prairie Island nuclear generating plant (Xcel Energy) to transfer $500,000 per year for each cask being used to store spent nuclear fuel into a fund that could only be used to develop renewable energy sources. This same legislation required Xcel Energy to spend 2 percent of its annual revenue requirements on energy conservation improvements. Funding requirements have been amended by legislation as on-site storage needs continued to grow, increasing to $25.6 million by 2016. Xcel Energy must file an annual report to the legislature listing each project and its projected financial benefit for customers. RDF is funded by a surcharge to Xcel Energy's Minnesota and Wisconsin customers. A typical Minnesota customer pays 0.1034 cents per kWh or $0.76 per month for the program.[36]

Regulatory Rationale

The RDF's objective is to remove barriers to entry for renewable energy technologies, including economic barriers from competing against conventional energy sources.[37]

Specifically, the RDF is allowed to fund:

- Increasing market penetration of renewables;
- Promoting start-up, expansion, and attraction of renewable projects in Minnesota;
- Stimulating in-state R&D into renewable electric energy technologies; and
- Developing near-commercial and demonstration scale renewable or infrastructure products.

The funds are allocated either as designated by the legislature or to energy production projects (biomass, hydro, solar, and wind) or research programs that are recommended by a stakeholder group to Xcel Energy and the Minnesota Public Utilities Commission (MPUC). Up to $10.9 million annually must be allocated to support renewable energy production incentives through Jan 2021 with over 85% of this targeted for wind energy facilities.

As reported in Xcel Energy's 2017 annual report to the legislature, the RDF program has funded over $276 million in renewable energy projects since its inception. The majority of this spending provides direct support to projects that produce renewable energy or to customers that are securing solar power. However, the RDF has also supported $52.5 million to 181 R&D projects that have produced research papers, funded workshops, and supported patent applications. Examples of ongoing or recent R&D projects are provided in Table 3.

Table 3: Highlighted RDF-Funded Projects

	Project Name	Funding	Resource	Description
1	University of Minnesota (Dairy)	$982,408	Solar/Wind	Model a "net zero" energy dairy parlor at the West Central Research and Outreach Center by integrating 20 kW wind and 54 kW solar with storage.
2	University of Minnesota (Biomass)	$819,159	Biomass	Evaluated economic and technical issues related to biomass fuel and integrated gasification combined cycle technology.
3	University of Minnesota (Torrefaction)	$1,899,449	Biomass	Demonstrate a prototypic torrefaction bioconversion process and distributed electric generation.
4	West Central Telephone Association	$137,000	Wind/Solar	Designed and tested configurations and specifications of a hybrid wind/solar power system for distributed generation in remote locations.
5	University of Florida	$999,995	Biomass	Demonstrated two-stage anaerobic digester at American Crystal Sugar in Moorhead, MN to generate methane for conversion to electricity.
6	Xcel Energy	$1,000,000	Wind	Installed a 1.0 MW sodium sulfur battery adjacent a wind farm to validate the value of energy storage for greater wind energy penetration.
7	University of Minnesota (Noise)	$625,102	Wind	Research the sources and quality of wind turbine sound and the thresholds of potential health impacts on humans.
8	University of St. Thomas	$2,157,215	Solar/Wind	Install a 0.25 MW peak, multi-purpose microgrid in Chicago City to establish an Engineering Senior Design Clinic for microgrid research and testing.
9	SarTee Corporation	$350,000	Biofuel	Researched the growth of algae fed on CO2 from flue gas and extracted the algae oils for conversion into a marketable biodiesel product.
10	Windlogics	$997,000	Wind	Defined, designed, built and demonstrated a complete wind power forecasting system.

The largest of these projects is the microgrid project at the University of St. Thomas, including 50kW each of solar capacity, wind, biodiesel generators and energy storage.

b. e21 Stakeholder Initiative

The e21 initiative is funded by the Minnesota-based McKnight Foundation that brings together energy industry stakeholders in an effort to develop a future business model and regulatory framework that better align utility financial objectives with public policy goals. The e21 initiative has produced Phase I (2015) and II (2016) reports and is currently engaged in a third and final phase that focuses on demonstration projects. As part of the third and final e21 phase, Xcel Energy has consulted with stakeholders to develop a pilot program for time-of-use rates. The initial filing for this pilot was completed in November of this year, and estimates the total pilot cost to be $8 million in capital and $2.9 million in O&M. If the project is approved, Xcel will seek to recover the majority of these costs through the annual Transmission Cost Recovery (TCR) Rider. The pilot provides participants with increased information and support, and seeks to shift load away from peak times in order to reduce or avoid the need for system investments in fossil fuel plants. The filing cites the Minnesota Legislature's Grid Modernization Statute, which directs utilities to identify investments that modernize the grid and authorizes the Commission to certify these projects. The utility may then seek cost recovery for these projects under the TCR rider.[38]

A second project, developed as a partnership between Seventhwave and Lawrence Berkeley National Laboratory (LBNL), would evaluate alternative performance-based regulatory frameworks. Finally, the MPUC has directed Xcel to develop a 400 MW demand response pilot program.[39]

Interview Insights[40]

The e21 approach to innovation tests the value of including stakeholders in the design and development of demonstration projects, particularly when the objective is to test a new business model or a new way for utilities to work with third-parties, or when the demonstration project is testing the engagement and responsiveness of customers to new products and services. Although specific demonstration projects still need to be reviewed and approved by the MPUC, the stakeholder experience improves the design of the projects and increases their eventual likelihood of success. Stakeholders engage directly with the utility throughout this facilitated process and are in a position to support regulatory approval, including ratepayer support. The benefits of improved stakeholder relationships can carry over to more controversial utility regulatory matters that employ stakeholder engagement, including integrated resource planning efforts. This type of engagement has the potential to reduce regulatory risk and regulatory lag that is exacerbated by lengthy litigation.

One byproduct of the e21 Initiative is legislation that codifies the authority of MPUC to approve multi-year rate plans, extending the maximum from 3 to 5 years, and requires any such plan to include a distribution system plan.[41] This legislation, the 2015 Jobs and Energy Bill, also provides the MPUC with the authority to develop performance metrics for utilities.[42] The identification of measures, specific metric definitions, and targets all benefit from stakeholder engagement outside of a more rigid litigation process. Thus, the e21 Initiative has effectively created a role for itself that complements rather than competes with the more traditional relationship among the regulator, utilities, and stakeholder intervenors. The issues faced by utilities and their regulators are expected to become increasingly complex as energy business models continue to evolve in response to technology and market developments.

Funding Levels

For the RDF, there is a $25.6 million annual contribution to the fund. In 2017 the RDF charge for a typical customer was $0.76 per month, equaling $9.12 per year.

Insights: Minnesota, with the e21 initiative, is increasing the likelihood that regulators will be willing to approve customer-funded innovation by increasing the degree of collaboration between the utilities and stakeholders, and by beginning the collaboration while the demonstration projects are still in the design phase.

5. AUSTRALIA

The Australian Energy Regulator (AER) is beginning to respond to changes in the energy industry and the role of behind-the-meter resources as it faces rising peak demands. The AER proposed a demand management incentive scheme (DMIS) and demand management innovation allowance (DMIA) to encourage utilities to manage demand more proactively. The AER released a draft decision on the DMIS and DMIA in August of 2017 and finalized the decision that December.[43]

The DMIS is ongoing and will give electric companies a stronger incentive to undertake expenditures on demand management options. It benefits the grid and gives consumers more opportunities to earn money from managing their demand by making it more financially attractive for network businesses to use demand management. For example, customers may rely on their solar panels and batteries to trade electricity on a local energy exchange.

The DMIA supplements Australia's existing incentive based regulatory framework. The program is dedicated to specific projects and will provide funding for R&D on demand management projects that have potential to reduce long-term costs. The innovation allowance continues to reduce the risk that utilities currently face when investing in R&D activities. Customers contribute to the fund through an increment in each distributor's revenue requirement according to the formula: $200,000 plus 0.075% of the applicable maximum allowed revenue requirement.[44] Projects must satisfy at least one of three criteria to be funded:

1. Based on new or original concepts,
2. Involves technology or a technique not previously implemented in the National Electricity Market (NEM), or
3. Focused on customers in a market segment that has not been exposed to the technology.

Distributors must file an annual report that identifies the funding for all projects. Subsequent project-specific reports will describe the methodology and outcomes.

In describing the background for the mechanism, the AER cites a July 2017 report prepared by Energy Networks Australia (ENA),[45] an industry association, with support from the Energy Consumers Association.[46] The AER highlights the unique role that distributors play in addressing the challenges to distribution operations from integration of intermittent generation and distributed energy resources. The DMIA rationale addresses regulatory barriers directly, noting that regulated utilities have a lower incentive to conduct R&D than competitive businesses because they:

- Face lower 'up-side risk.' Competitive businesses may be more likely to profit from R&D than monopolies as R&D can provide them with a 'competitive advantage.' Moreover, to the extent that R&D results in future cost reductions, distributors will pass a material portion of these gains onto electricity consumers under [the] regulatory regime.
- Still face 'down-side risk.' If R&D costs occur significantly before the benefits, distributors risk being financially penalized from making these decisions under the regulatory regime.[47]

The ENA report, "Network Innovation: Discussion Paper" describes the barriers to innovation at great length. It observes that the proposed DMIA applies only to the electricity industry and not to the natural gas distributors. It cites two industry reports that address the immediate challenges and future role of technology in both the electricity and natural gas industries.[48] The report identifies several regulatory barriers including the fact that RD&D projects cannot satisfy traditional pre-approval investment tests and the mismatch between the relatively high risk of innovation and low regulated returns. The report notes that the benefits of innovation typically accrue over a longer-term than traditional investments, reinforcing these risks and financial barriers.[49]

The ENA report also points to the potential role for innovation in the gas sector. "Similarly, innovation will play a key role in realizing opportunities for further decarbonizing Australia's gas sector. There is a strong potential to use three transformational technologies - biogas, hydrogen and carbon capture and storage – to create clean, dispatchable energy resulting in zero emissions that can use existing gas networks' infrastructure."[50] Pointing to the gap it sees in the scale of investment required to achieve this potential, the ENA cites industry-led initiatives, including Energy Networks Australia's Gas Committee innovation fund established in 2016 for targeted R&D and technical activities in industry-identified priority areas.[51]

The AER has also addressed the issue of which services should be provided by regulated distributors (DNSPs), and which should be open to competition through a "ring-fencing" set of guidelines. The objectives of these guidelines, as illustrated by those established for electric distributors, are designed to prevent:

- Cross-subsidizing an affiliate's services in contestable markets with revenue derived from its regulated services
- Discrimination in favor of a DNSP's related electricity service provider operating in a contestable market
- Providing related electricity service providers with access to commercially sensitive information acquired through provision of regulated services
- Restricting access of other participants in contestable markets to infrastructure services provided by the DNSP, or providing access on less favorable terms than to its related electricity service providers.

According to the AER: "The Guideline sets out the obligations a DNSP must meet to separate its regulated monopoly services from any services it may seek to offer to contestable markets. We expect the Guideline will aid development of competitive markets where competition is feasible and support efficient, incentive-based regulation of monopoly networks where competition is not feasible."[52]

Interview Results[53]

The driving forces impacting utility regulatory policy in Australia are consumer concerns regarding energy prices, reliability concerns, pending retirements of coal-fired plants and the growing penetration of renewables. The existing regulatory model is a multi-year incentive program. Companies come in every five years with forecasts for the next five years. The regulator, with technical advisors, determines if the forecast reflects "efficient costs," and then sets revenue for five years. The underlying rationale is if the utility can improve on costs, they retain the difference, and if there is a non-network alternative that's more cost-effective, the utility has the incentive to look at that alternative.

Regulatory Rationale

Despite these incentives, the AER has found it challenging to move utilities beyond a perceived focus on capital investments, and prior incentives have not been sufficient to overcome that hurdle. There is a cultural resistance. The AER is attempting to promote innovation through the DMIA and also wants to distinguish between services that should remain under regulation, and those that should be competitive, as described in its ring-fencing guidelines.

The AER is seeing more partnering between the networks and different innovators, and the networks are becoming more open to innovation. The AER sees its role as setting up a framework, and the industry is responding. The AER is also emphasizing a movement away from an adversarial relationship to a more collaborative model. Pilot projects are beginning to illustrate scalability. Tesla, for example, is building a 129-MWh battery with French energy company Neoen in South Australia, characterized as the world's largest battery.

Australia also funds RD&D projects as a result of the ARENA Act 2011, which targeted $2 billion (Australian dollars, equal to approximately $1.97 billion Canadian dollars) to invest in renewable energy and the Australian renewable technology sector. Funding has been modified by the Clean Energy Legislation (Carbon Tax Repeal) Bill 2013 and Budget Savings (Omnibus) Bill 2016.

Funding Levels

DMIA funding is AU$200,000 plus 0.75% of annual revenue requirements (ARR). DMIS funding is up to 1% of ARR.

Insights: Australia is poised to implement customer-funded innovation mechanism at a meaningful level. This proposal is broadly supported by stakeholders who recognize that utility innovation is part of the solution to adapt to a changing environment. This includes targeting a combination of energy costs, reliability, and the integration of renewable energy resources. A combination of government-funded, customer-funded and industry-led mechanisms are being utilized.

6. ONTARIO

Ontario currently funds innovation through a combination of ratepayer, utility investor, and third-party vendor resources. Ratepayer-funded projects are financed through the IESO's Conservation Fund and are included as a component of the Global Adjustment charge that appears as a separate line item on electric bills for all customers.

More recently, the provincial government of Ontario and its energy regulator have increased their attention on the role that innovation needs to serve in the energy sector. The Ministry of Energy's 2017 Long Term Energy Plan (2017 LTEP), released in October 2017, devotes an entire chapter to innovation.

Regulatory Rationale

Ontario is focused on maintaining affordable energy for residential and business customers. Innovation in the delivery of electricity and natural gas, greater customer choice, and expanded access to natural gas, are viewed as major contributors to realizing this goal. The emphasis on innovation responds to stakeholder input that "electricity costs are too high," the Ministry should "consider new technologies and methods to manage energy use," and there is a need to "expand access to natural gas."[54] The Ontario Energy Board's (OEB) 2017-2020 Business Plan identifies "technological innovation that presents new choices for consumers and challenges traditional business and regulatory models" as one of four key trends that define the current environment.[55]

The 2017 LTEP projects that innovation in the natural gas sector will increase Ontario's reliance on renewable natural gas, leveraging the Waste-Free Ontario Act 2016 and the Organic Waste Action Plan that promote the use of organic waste to produce natural gas. The Government of Ontario intends to work with the Independent Electricity System Operator (IESO) on a pilot program to transform electricity into hydrogen gas that can be used for traditional and new transportation end-uses.

Technology innovation in the electricity sector will focus on three areas:

1. Employing technologies to modernize the electricity network, increasing automation, addressing cybersecurity issues, and enabling transactive energy markets;
2. Integrating distributed energy resources (DER) including energy storage to help customers manage their energy end-use (frequently referred to as "Smart Home" initiatives); and
3. Electrification of the transportation sector.

The 2017 LTEP calls for pricing innovation that would test alternative time-varying pricing approaches, leveraging smart technologies and communications as well as consideration of net energy metering policies.

There are innovative uses for natural gas as well in Ontario, as discussed in the 2017 LTEP. Renewable natural gas (RNG) is seen as innovative in that it is a low-carbon fuel that can use the existing distribution system to replace conventional natural gas. Along this same vein and in connection with Ontario's Climate Change Action Plan, the government is developing a pilot program that will allow agricultural sectors to produce RNG and will support businesses in using RNG for vehicles. Power-to-gas, transforming electricity to hydrogen gas, is seen as another potential innovative link between Ontario's electricity and natural gas systems. Recognizing the versatility of this fuel, and the fact that it is a way to decarbonize the natural gas supply, Ontario is undertaking a feasibility study of fueling passenger trains with hydrogen. The government will also work with the IESO to explore the energy system benefits and GHG emission reductions that could result from using electricity to create hydrogen.[56]

The LTEP acknowledges that there are currently several barriers to innovation, and stakeholders are indicating a need for government funding support for R&D, including enhanced funding of the existing Smart Grid Fund. Ontario's $50 million Smart Grid Fund was launched in 2011 to assist local distribution and smart grid companies test and build the technologies needed for grid modernization. Nonetheless, the report notes that there has been uneven investment in grid modernization, citing an Electricity Distributors Association finding that "half of Ontario LDCs still approach innovation in a gradual or incremental way," before concluding:

> *It is clear that barriers to innovation remain. With the rapid development of new technology and the increase in customer expectations, the time to address these barriers is now. To encourage change in the energy sector, the government will work with utilities and other partners to build a culture of innovation, and will look to the OEB to explore, where cost-appropriate.*

The report identifies specific barriers, including three regulatory framework barriers:

1. The regulatory treatment of LDC capital and operational expenditures, which can inhibit the uptake of these non-wires solutions;
2. A cost-benefit framework that provides clarity on the treatment of investments, such as those with localized costs that provide benefits to other electricity system participants (also known as the diffuse benefits issue); and
3. The ability of utilities to make non-traditional distribution system investments and participate in market opportunities that would ultimately reduce ratepayers' costs associated with capital or other investments.

As noted by the Ministry, the OEB will play a key role in addressing these and other barriers to utility innovation. The OEB's business plan cites many of the same industry drivers, trends, and objectives as the 2017 LTEP. These include the need for utilities to integrate increasing numbers of DER, including electric vehicles and microgrids. The OEB is working on a 2018 roadmap for regulatory reforms needed to take advantage of technology innovation and new rate designs that will support efficient use of distribution networks.

Interview Results[57]

Ontario funds innovation through a combination of ratepayer, utility investor, and third-party vendor resources. Ratepayer-funded projects are financed through the IESO's Conservation Fund and are included as a component of the Global Adjustment charge that appears as a separate line item on electric bills for all customers. Recent demonstration projects that have been funded through this mechanism include several pilot programs that test TOU and other pricing mechanisms (often combined with energy management system technologies). They also include testing new energy technologies such as energy storage and the potential for solar power to defer infrastructure investments.

Stakeholders involved generally understand the goals: be cost effective, make the customer's voice heard, and meet environmental policy goals. An outcomes approach to regulation is compatible with these objectives. The OEB perceives a hangover of existing habits and approaches to distribution planning, and some prior regulatory features that do not provide adequate incentives for least cost systems. Incentives that align customer and utility objectives will drive down system costs. The OEB has also relied on moving more distribution charges to the fixed customer charge to remove barriers to innovation.

Governance for pilot projects includes the OEB establishing guidelines, followed by interim reports showing results based on the sample (e.g., how effective is it at demand response and consumer elasticity), followed by a mandatory final report. Monthly monitoring reports are sometimes utilized in the first period, followed by bimonthly reports.

Insights: Ontario is supporting customer-funded innovation through a broad-based customer-funded mechanism collected through the ISO. The strong positioning of the role of innovation in addressing energy costs in Ontario by the Ministry is important in reaching alignment with the OEB to provide support for innovation. The 2017 LTEP and OEB business plan recognize that regulatory barriers need to be addressed. The regulator is seeking to better align utility and customer interests and the regulatory model through demonstration projects and incentives that will ultimately deliver lower energy costs.

7. MASSACHUSETTS

In 2014, the Massachusetts Department of Public Utilities (DPU) issued an order on electric grid modernization, requiring each utility to file a Grid Modernization Plan (GMP). The order supports utility innovation and directs each of the Commonwealth's three investor-owned utilities (National Grid, Eversource, and Fitchburg Gas & Electric) to propose a list of projects that focus on testing, piloting, and deploying RD&D projects that modernize the grid and employ new technologies. The DPU invited the utilities to propose funding mechanisms as part of their GMP filings, clearly inviting customer-funded proposals. However, the DPU also directs utilities to leverage outside funding and pursue collaboration to the extent possible.[58]

Regulatory Rationale

Notably, the DPU indicated that it would not deny cost recovery "merely because of lack of success," responding directly to one of the major barriers to utility innovation, noting further that the DPU had not been supportive of RD&D projects in the past, and signaling an intent to reverse existing precedent. Grid modernization would result in lower energy costs by contributing to a less expensive electric system (investments, operations and maintenance expenses), reducing peak demands, and by providing customers with tools that they could employ to reduce their electricity usage, particularly during price spikes.

The DPU cited increasing reliability, lower energy bills, and clean energy as grid modernization goals. Increases in reliability and resiliency would be supported by "a range of grid modernization technologies and policies." [59] The DPU's order expressed a clear preference for advanced metering functionality (AMF) which would enable time-varying pricing mechanisms.[60] Clean energy is another factor cited by the Department in support of its grid modernization initiative:

> *The modern electric system that we envision will be cleaner, more efficient and reliable, and will empower customers to manage and reduce their energy costs. The modern electric system will build on the Patrick Administration's progress towards our clean energy goals by maximizing the integration of solar, wind, and other local and renewable sources of power.*[61]

The utilities filed their GMPs in August 2015, in compliance with the DPU policy directives. For example, National Grid proposed to fund its grid modernization RD&D efforts through an RD&D provision in a new tariff, identifying $29.3 million that it proposes to pursue through the grid modernization RD&D program over the next decade. National Grid pledges to continue to leverage RD&D investments by joining with other utilities (through industry organizations or other means) to seek to fund work that, by itself, would be too expensive for a single utility and to seek outside funding.

The DPU review of the grid modernization filings was put on hold after the election of a new Governor in November 2015, and subsequent appointment of a new Chair. This is not uncommon when there is a change in administration, particularly when there is also a change in party, as in this case. The entire Commission has now turned over. Hearings were held this past summer, and the parties have filed initial and reply briefs.

Eversource filed a five-year performance-based regulation proposal earlier in the year, proposing to roll-in its grid modernization investments as part of its rate plan. In an order dated November 30, 2017, the Department declined to address grid modernization and indicated that it preferred to consider the three plans together in the grid modernization dockets to allow time for a more thorough examination and enable the DPU to establish consistent policy across the utilities with respect to cost recovery and other issues. The DPU noted the level of uncertainty associated with both costs and anticipated benefits, and its intention to ensure that grid modernization investments will produce an optimized level of net benefits.[62] The DPU did signal its intent to apply the standards established by the prior Commission in the grid modernization policy proceeding.

The DPU, however, made two exceptions that it deemed to be consistent with existing precedent. First, it approved funding of $55 million for Eversource's two energy storage demonstration projects, finding that they will facilitate the market for energy storage in Massachusetts and provide data that will be critical in evaluating future energy storage deployments as part of Massachusetts' clean energy future. The Department found that the proposed energy storage demonstration program is consistent with the grid modernization objectives of integrating distributed resources and improving asset management.

Second, the DPU approved $45 million to fund EV charging stations and customer education and outreach, noting that these investments will help accelerate electric vehicle charging infrastructure development in Massachusetts, encourage electric vehicle purchases, and contribute to greenhouse gas emissions reductions in the Commonwealth.

Funding Levels

As an example, the recent approval of Eversource's storage and EV projects includes approved capital investments of $100 million. The annual revenue requirements associated with these investments will be recovered from Eversource's 1.4 million electric customers in Massachusetts. The Department considered bill impacts, net of customer benefits, when approving these spending levels.

Insights: Although the DPU has not yet issued orders in the grid modernization cases filed over two years ago, the Eversource order signals its intention to apply the policies from the prior Commission and its willingness to fund demonstration projects that advance the public interest. Most importantly, this qualifies as customer-funded innovation. It will be a few years before these recently approved projects will produce results that can be evaluated. The funding for Eversource's storage and EV projects coincided with approval of its PBR plan, indicating innovation and PBR can be pursued simultaneously.

8. BRITISH COLUMBA

Legislative Rationale

British Columbia, through a series of legislative actions, has established aggressive goals for its energy sector that depend on investments in clean energy production and infrastructure as well as technologies that support energy management activities. Many of these programs are funded through surcharges on energy usage.

The 2007 Greenhouse Gas Reduction Targets Act set initial targets for reductions in greenhouse gas ("GHG") emissions at a 33% reduction by 2020 and 80% by 2050, and established a carbon tax. The 2010 Clean Energy Act (CEA) set goals with respect to electricity self-sufficiency, including reducing the expected increase in electricity demand by at least 66% by 2020, generating at least 93% of electricity from clean or renewable resources, supporting the development of innovative technologies that support the conservation and clean energy goals, and reducing GHG emissions dramatically by 2050.

The CEA directs the British Columbia Utilities Commission to set rates as necessary to allow utilities, including British Columbia's largest electric utility, provincial-owned BC Hydro, to recover the costs they incur to achieve these goals. The Greenhouse Gas Reduction Regulation ("GGRR"), authorized under the CEA, allows for utilities' prescribed undertakings that work towards GHG reductions, while still allowing them to recover their costs through utility rates. The GGRR allows utilities to implement prescribed undertakings without seeking the prior approval of the BC Utilities Commission, although the Commission still has the ability to rule on the prudency of expenditures. British Columbia's utilities have provided incentive funding to customers to support development of CNG and LNG fueling stations, vehicle and marine vessel conversions, and the use of renewable natural gas.

One fund that is instrumental in achieving British Columbia's goals is the Innovative Clean Energy (ICE) Fund administered by the Province's Ministry of Energy, Mines and Petroleum Resources. The ICE Fund is a legislated Special Account designed to support the Province's energy, economic, environmental and greenhouse gas reduction priorities, and to advance B.C.'s clean energy sector. The ICE Fund was initially funded by a 0.4% levy on the final sales of electricity, natural gas, fuel oil and grid-delivered propane. The electricity levy has since been removed with the reinstatement of the Provincial Sales Tax on April 1, 2013.

British Columbia is interested in demonstrating the commercial viability of new technologies as an economic development program, with successful capabilities potentially being exported to other markets. In March 2017, the Province announced a $40 million partnership with Sustainable Development Technology Canada to support the development of pre-commercial clean energy projects and technologies. The parties will conduct a joint call over a three-year continuous intake period to seek out clean energy projects and technologies that will mitigate or avoid provincial greenhouse gas emissions, including prototype deployment, field testing and commercial-scale demonstration projects. Projects must take place in British Columbia and must demonstrate how the proposed project will result in GHG reductions, commercialization, and economic growth in British Columbia and Canada.

FortisBC has a Smart Learning Thermostat Pilot Program for both natural gas and electricity customers that is designed to test customer engagement and energy savings. FortisBC offers a renewable natural gas service that has attracted 9,000 customers. BC Hydro has invested in a $12.5 million project to test the ability of grid storage to support reliability in remote areas of its distribution network. British Columbia's clean electric vehicle (CEV) program provides additional funding to meet growing demand for rebates on vehicles and specialty-use vehicles, and supports the expansion of charging stations, hydrogen fueling stations, and the development of new research and training programs. Both BC Hydro and FortisBC are building EV charging infrastructure to support growing demand in this sector.

Interview Insights[63]

A series of legislative and policy initiatives led to the establishment of the Clean Energy Act in 2010, and the subsequent GGRR in 2012. Under this legislation, utilities have the option to implement prescribed undertakings without seeking the prior approval of the BC Utilities Commission, although the Commission still has the ability to rule on the prudency of expenditures. The Province does not contribute any funding. The programs are fully funded by natural gas utilities and paid for by natural gas customers.

The GGRR has been amended over time to allow utilities to implement specific undertakings. In November 2013, amendments were made to allow utilities to expand their incentives to include trains and mine-haul trucks, and to provide tanker-truck delivery services to trucking, mining and marine-transportation customers. In May 2015, the Government further amended the GGRR to allow for shifts in the allocation of incentives and investments within the previously-approved total spending cap in order to better respond to changes in the marine market place. Amendments made in early 2017 enabled utilities to increase natural gas distribution to the marine transportation sector. Amendments also increased incentives for using RNG in transportation and established a Renewable Portfolio Allowance to increase the supply of RNG.

Concerns in BC have been expressed that these services might be offered by unregulated industry in a competitive market (e.g., LNG and CNG), and should not be supported by innovation funding because this would provide the utility with an "unfair advantage." Amendments to the legislation have been justified on the basis that utilities are serving a market that would likely not be served by competitive service providers. Utilities may also ask for incentives to execute innovative programs, particularly where a competitive procurement process is employed and overseen by an independent third-party "fairness advisor."

Utilities provide comprehensive reports on these initiatives to the provincial government and the commission.

Insights: In British Columbia, an ambitious clean energy policy has provided flexibility for utilities to propose - and the regulator to allow - cost recovery for customer-funded innovation investments. These projects are seen as precursors to kick-starting new technologies and new applications of those technologies that may ultimately lead to scaled-up competitive markets.

CONCLUSIONS

REGULATORY RATIONALE

Several policymakers, including utility regulators, have recognized the need for utilities to actively contribute to innovation in the electricity and natural gas sectors of the economy and the value this provides to customers. This report focuses on jurisdictions that provide customer funding for innovation and the reasons that regulators have cited in approving this funding. They have approved funding for demonstration projects that explore new business models, pilot technologies that result in delivery efficiencies, test new products and services, and support scalable investments. All of these investments help accelerate the pace of change in the sector.

Goals for these programs vary by jurisdiction, but common themes include: greenhouse gas reductions, lower energy prices, demand reduction or load shifting, accelerated deployment of renewable and distributed resources, improved system reliability, and the introduction of new utility technologies. Rationales also vary according to specific circumstances and preferences of regulators and policymakers. Ofgem sees innovation funding as a vehicle for driving cultural change at utilities, and necessary to achieve these objectives. California and BC see innovation as a mechanism for economic development. BC and Australia see innovation as a path for stimulating competitive service offerings. Ontario and Massachusetts emphasize new choices for consumers.

There is a growing recognition that customers are long-term beneficiaries from innovation in the utility business model, so investments on their behalf are justified and in the public interest. Customer funding for innovation-related projects is often applied in conjunction with funds that are contributed by government and third-party vendors.

MEASURING THE BENEFITS

The history of utility customer-funded innovation funding is relatively recent, so data on the benefits of these programs can be difficult to quantify. Successful deployment requires regulatory flexibility and appropriate governance to ensure the trade-offs between costs and impacts on rates are justified. Given the global nature of these policy objectives, the opportunity exists for lessons learned to be shared among regulators and industry stakeholders.

While not all demonstration projects successfully prove out a new technology or business model, these investments frequently prove to be gateways to new utility models, short-term accelerators to competitive service offerings, or some combination of quantitative and qualitative benefits. The potential gains from adaptation of new technologies and business approaches to a "mature" industry are large, and studies indicate the potential consumer benefits from RD&D outweigh the costs by up to 5:1 multiples. Whether avoiding costly investments in infrastructure, or helping customers save money on their bills by utilizing technology to manage their energy use, regulators are concluding that the short- and long-term benefits of customer-funded innovation justify the costs.

APPENDIX: Interview Subjects and Outline of Questions

INTERVIEWEES

UK | Jonathan Morris and Neil Copeland, both of Ofgem

New York | Bryan Berry, of NYSERDA

Minnesota | Rolf Nordstrom, of Great Plains Institute

Australia | Paula Conboy, of the Australian Energy Regulator

Ontario | Ceiran Bishop, of the Ontario Energy Board

British Columbia | Paul Wieringa and Jennifer Davison, both of British Columbia Government

QUESTION OUTLINE

A Q&A with Key Regulators & Policymakers on the process from conception to reality on their innovation levy, discussing:

1. The history and how it came to be
    - Was this led by the utility industry, political class or the economic regulator or some combination thereof?
    - What was the gap that needed to be filled?
2. What challenges the regulators faced;
    - Challenges from interveners
    - Information challenges
    - Political challenges
3. What was the rationale/justification (e.g., legal, market, financial or economic) for approving the program? Or, was there a gap in the market that was viewed to be filled effectively by the regulated utility?
4. How the regulator is kept informed/engaged in how the money is spent and the overall governance structure established;
    - What are the KPIs?
    - Is there an annual or semi-annual review?
    - How are the approved funds set aside (deferral account or other?)
5. How they think the program is working;
    - What, if anything, would be considered an improvement to the current design?
6. Results achieved – have they been measured?
    - Who measures them – third party, the utility or other?
    - What if there is an underperformance?

END NOTES

[1] Office of Ratepayer Advocate, Policy Position on CES-21: See http://www.ora.ca.gov/general.aspx?id=2422
[2] Concentric Energy Advisors, *Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Customers*, August 21, 2014, at 2.
[3] Massachusetts - Eversource spending represents costs of recently approved electric vehicle and energy storage projects. The UK NIC Electric is decreasing funding from £90 million to £70 million – this decrease is not reflected in the chart. UK NIA funding uses SGN Scotland and SGN Southern NIA expenditure as an example. New York data represents NYSERDA funding for the most recent year (significantly lower than the previous year as a result of a funding mechanism logistical change), plus ConEd funding for REV Demo projects. Australia DMIA funding is based on an average of hypothetical allowance of selected companies. Sources: AER Determinations Attachments 1 – annual revenue requirements; CES-21 Annual Report 2016; Ofgem, RIIO-GD1 Annual Report 2015-16; Ofgem, The Network Innovation Review: Our Policy Decision, March 2017; Xcel Energy, RDF Annual Report 2017; CA IOU websites; NYSERDA Financial Statements March 2017; New York DPS Order in Case 16-E-0060; Massachusetts DPU 17-05 Order.
[4] Concentric Energy Advisors, *Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Customers*, August 21, 2014, at 1.
[5] Pöyry, *An Independent Evaluation of the LCNF*, October 2016, at 78. See https://www.ofgem.gov.uk/system/files/docs/2016/11/evaluation_of_the_lcnf_0.pdf
[6] Pöyry, *An Independent Evaluation of the LCNF*, October 2016, at 2.
[7] Ofgem, *RIIO: A New Way to Regulate Energy Networks: Final Decision*, October 2010. See https://www.ofgem.gov.uk/ofgem-publications/51870/decision-docpdf
[8] Ofgem, *Decision and Further Consultation on the Design of the Network Innovation Competition*, September 2, 2011, at 4. See https://www.ofgem.gov.uk/sites/default/files/docs/2011/09/nic-consultation.pdf
[9] Ofgem, "Innovation in Energy Networks: Is More Needed and How Can This Be Stimulated?" Working Paper, 2009, at 11. See: https://www.ofgem.gov.uk/sites/default/files/docs/2009/07/rpi-x20-innovation-working-paper_final-draft_0.pdf
[10] Ofgem, *Electricity Network Innovation Competition Governance Document*, February 1, 2013, at 5. See https://www.ofgem.gov.uk/ofgem-publications/53526/spnic-pdf
[11] Ofgem, *Decision and Further Consultation on the Design of the Network Innovation Competition*, September 2, 2011, at 2.
[12] Ofgem, *The network innovation review: our policy decision*, 31 March 2017, at 43. See https://www.ofgem.gov.uk/system/files/docs/2017/03/the_network_innovation_review_our_policy_decision.pdf
[13] Ofgem, *Factsheet 93: RIIO – A New Way to Regulate Energy Networks*, October 4, 2010. See https://www.ofgem.gov.uk/ofgem-publications/64031/re-wiringbritainfs.pdf
[14] Ofgem, *The network innovation review: our policy decision*, 31 March 2017, at 2.
[15] Ofgem, *Factsheet 93: RIIO – A New Way to Regulate Energy Networks*, October 4, 2010.
[16] Ofgem, *RIIO: A New Way to Regulate Energy Networks: Final Decision*, October 2010, at 42. See
[17] Ofgem, *The network innovation review: our policy decision*, 31 March 2017, at 9.
[18] Concentric Energy Advisors, *Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Customers*, August 21, 2014, at 37.
[19] Ofgem, *Making Britain's Energy Networks Better*, 2016, at 2. See https://www.ofgem.gov.uk/system/files/docs/2016/11/innovation_competitions_brochure_to_upload.pdf
[20] Ofgem, *The network innovation review: our policy decision*, 31 March 2017, at 9.
[21] Based on a discussion with Jonathan Morris and Neil Copeland of Ofgem.
[22] Pöyry, *An Independent Evaluation of the LCNF*, October 2016.
[23] Ofgem, *Infographic: The energy network*, 28 September 2017. See https://www.ofgem.gov.uk/publications-and-updates/infographic-energy-network
[24] *Electric Program Investment Charge, Staff Proposal*, February 10, 2012, Rulemaking 11-10-003, at 9- 10, 17; D.12-05-037, *Phase 2 Decision Establishing Purposes and Governance for Electric Program Investment Charge and Establishing Funding Collections for 2013-2020,* May 24, 2012, at 6. See http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/167664.pdf

[25] J. Randwyk, A. Boutelle, C. McClelland, C. Weed, *California Energy Systems for the 21st Century 2016 Annual Report*, March 29, 2017, at 22-23. See https://e-reports-ext.llnl.gov/pdf/878504.pdf
[26] J. Randwyk, A. Boutelle, C. McClelland, C. Weed, *California Energy Systems for the 21st Century 2016 Annual Report*, March 29, 2017, at 2-3.
[27] New York Public Service Commission Staff Recommendation in Case 99-G-1369, January 31, 2000.
[28] New York Public Service Commission, Case 14-M-0101, Track 1 Order, February 26, 2015 at 1. See http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=14-m-0101
[29] New York Public Service Commission, Case 14-M-0101, Track 1 Order, February 26, 2015 at 113-114.
[30] New York Public Service Commission, Case 14-M-0101, Track 1 Order, February 26, 2015 at 115.
[31] Case 14-M-0101, Memorandum and Resolution on Demonstration Projects, issued December 12, 2014.
[32] The complete list is available at the following web address: http://www3.dps.ny.gov/W/PSCWeb.nsf/All/B2D9D834B0D307C685257F3F006FF1D9?OpenDocument
[33] New York Public Service Commission, Case 16-G-0058 et al., Order, December 16, 2016 at 134. Case filings available at: http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=16-g-0059&submit=Search
[34] See New York Public Service Commission Case 17-G-0606, available at: http://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterSeq=54621
[35] Based on a discussion with Bryan Berry, Assistant Director at NYSERDA.
[36] Xcel Energy, *Annual Report to the Minnesota State Legislature*, February 15, 2017, at 3. See https://www.xcelenergy.com/staticfiles/xe-responsive/Energy%20Portfolio/Renewable%20Energy/Renewable%20Development%20Fund/2017%20RDF%20Annual%20Report.pdf
[37] Xcel Energy, *Biennium Report to the Minnesota State Legislature and the Minnesota Public Utilities Commission*, January 2010, at 3. See https://www.xcelenergy.com/staticfiles/xe/Corporate/Corporate%20PDFs/RDF_Biennium_Report--January2007-December2008.pdf
[38] Xcel Energy, Docket E002/M-17-775 Petition Before the Minnesota Public Utilities Commission, 1 November 2017, at 3-7. See https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId=%7B40D77C5F-0000-C614-A997-18C8C3D839F9%7D&documentTitle=201711-137092-01
[39] Order issued January 11, 2017 in Docket No. E-002/RP-15-21. See https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showPoup&documentId={978E98E8-C6BD-4851-80E2-14ED10400D48}&documentTitle=20171-128000-01
[40] Based on a discussion with Rolf Nordstrom, President and Chief Executive Officer of the Great Plains Institute.
[41] 2015 Jobs and Energy Bill, H.F. 1437, 89th Minn. House of Rep. (2015), at 66. See https://www.revisor.mn.gov/bills/text.php?number=HF1437&version=4&session=ls89&session_year=2015&session_number=0
[42] 2015 Jobs and Energy Bill, H.F. 1437, 89th Minn. House of Rep. (2015), at 67.
[43] AER Presentation to the Disruption & Energy Industry Conference, September 7, 2017. See https://www.aer.gov.au/news/regulation-that-supports-innovation-demand-and-consumers-presentation-to-disruption-the-energy-industry-conference-sydney-7-september-2017
[44] AER, Explanatory Statement – Draft Demand Management Innovation Allowance Mechanism, August 2017, at 7. See https://www.aer.gov.au/system/files/AER%20-%20Explanatory%20statement%20-%20Draft%20demand%20management%20innovation%20allowance%20mechanism%20-%20%2028%20August%202017.pdf
[45] Energy Networks Australia (ENA), *Network Innovations Discussion Paper*, July 2017, p. 1; ENA and CSIRO, *Electricity Network Transformation Roadmap: Final Report*, April 2017. See http://www.energynetworks.com.au/sites/default/files/network_innovations_26072017.pdf and http://www.energynetworks.com.au/sites/default/files/entr_final_report_web.pdf
[46] Energy Consumers Australia, *Short Submission following Demand Management Options Day*, June 2017.
[47] AER, Explanatory Statement – Draft Demand Management Innovation Allowance Mechanism, August 2017, at 10.

[48] CSIRO, *Electricity Network Transformation Roadmap, Final Report*, April 2017; and Gas Vision 2050, Energy Networks Australia. See
http://www.energynetworks.com.au/sites/default/files/gasvision2050_march2017_0.pdf
[49] Energy Networks Australia (ENA), *Network Innovations Discussion Paper*, July 2017 at 10-11.
[50] *Ibid*, at 2.
[51] *Ibid*, at 22.
[52] Ring-fencing Guideline, Electricity Distribution Version 2, Explanatory Statement, AER, October 2017, pp. 8-9
https://www.aer.gov.au/system/files/AER%20-%20Ring-fencing%20Guideline%20Version%202%20-%20Explanatory%20Statement%20-%20October%202017.pdf
[53] Based on a discussion with Paula Conboy, Chair of the Australian Energy Regulator.
[54] Ontario's Long-Term Energy Plan, Delivering Fairness and Choice, at 18. See
https://www.ontario.ca/document/2017-long-term-energy-plan
[55] Ontario Energy Board 2017-2020 Business Plan, at 3. See
https://www.oeb.ca/oeb/_Documents/Corporate/OEB_Business_Plan_2017-2020.pdf
[56] Ontario's Long-Term Energy Plan, Delivering Fairness and Choice, at 74-75.
[57] Based on a discussion with Ceiran Bishop of the Ontario Energy Board.
[58] Concentric Energy Advisors, *Stimulating Innovation on Behalf of Canada's Electricity and Natural Gas Customers*, August 21, 2014, at 32.
[59] Massachusetts Department of Public Utilities, Investigation 12-76, October 2, 2012, at 1.
[60] Trabish, Herman. "Massachusetts Utilities Take Divergent Approaches to Grid Modernization." UtilityDive, September 6, 2017. See https://www.utilitydive.com/news/massachusetts-utilities-take-divergent-approaches-to-grid-modernization/504119/
[61] Massachusetts Department of Public Utilities, Order 12-76-B, June 12, 2014, at 1. See
http://www.raabassociates.org/Articles/MA%20DPU%2012-76-B.pdf
[62] Massachusetts Department of Public Utilities, Order 17-05, November 30, 2017, at 438-439. See
http://170.63.40.34/DPU/FileRoomAPI/api/Attachments/Get/?path=17-05%2f1705_Final_Order_Revenue_Requi.pdf
[63] Based on a discussion with Paul Wieringa, Executive Director, and Jennifer Davison, Senior Policy Analyst, both of British Columbia Government.