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July 29, 2022

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC
V6Z 2N3

Attention: Ms. Sara Hardgrave, Acting Commission Secretary

Dear Ms. Hardgrave:

Re: FortisBC Energy Inc. (FEI)

Multi-Year Rate Plan for 2020 through 2024 approved by British Columbia Utilities Commission (BCUC) Order G-165-20 (MRP Plan)

Annual Review for 2023 Delivery Rates

In accordance with the MRP Plan and BCUC Order G-194-22 setting out the Regulatory Timetable for FEI's Annual Review, FEI hereby attaches its Annual Review for 2023 Delivery Rates Application materials.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Interveners to the FEI Annual Review for 2022 Delivery Rates

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FORTISBC ENERGY INC.

Multi-Year Rate Plan for 2020 through 2024

Annual Review for 2023 Delivery Rates

July 29, 2022

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1. APPROVALS SOUGHT, OVERVIEW OF THE APPLICATION AND PROPOSED PROCESS

1.1 *INTRODUCTION*

FortisBC Energy Inc. (FEI or the Company) files this Application in compliance with British Columbia Utilities Commission (BCUC) Order G-165-20, which approved a Multi-Year Rate Plan (MRP or the Plan) for FEI for the years 2020 to 2024. In accordance with the MRP, an annual review process is required to set rates for each year of the MRP.

The MRP provides stable levels of O&M funding, the flexibility to innovate and adapt, and incentive to invest in the future, while maintaining service quality. The approved Earnings Sharing Mechanism (ESM), set out in Section 10, aligns the incentive properties of the Plan between customers and the Company.

As explained in Section 10.2 of the Application, FEI proposes to distribute $0.377 million[1] in earnings sharing to customers in 2023.

The proposed delivery rates for 2023 flowing from the approved formulas and forecasts set out in the Application, including returning the actual 2021 earnings sharing to customers, result in a 7.42 percent delivery rate increase from 2022 delivery rates. After consideration of the delivery rate riders, the annual bill impact is an increase of approximately $34.83 or 2.67 percent for a residential customer[2]. The increase is primarily due to rate base growth and increased depreciation expense driven by approved major capital project expenditures entering rate base, including the Inland Gas Upgrade (IGU) project, Pattullo Gasline Replacement (PGR) project, and the Coastal Transmission System Transmission Integrity Management Capabilities (CTS-TIMC) project, as well as a decrease in demand primarily due to FEI's contract with BC Hydro Island Generation (IG) expiring in April 2022.

In the subsections below, FEI sets out the approvals it is seeking and provides an overview of the requirements for the annual review process. This is followed by a discussion of FEI's 2021 formula O&M savings and the productivity initiatives that FEI is developing. Finally, FEI provides a summary of its proposed revenue requirements and rate changes for 2023 and a summary of the SQI results. These matters are addressed in more detail in subsequent sections of the Application.

[1] This amount is pre-tax and includes financing accrued on the MRP Earnings Sharing deferral account.

[2] Average residential customer with consumption of 90 GJ per year. Annual bill impact before BVA rate rider and RSAM rate rider is $48.15 or 3.69 percent.

1.2 *APPROVALS SOUGHT*

With this Application, FEI requests BCUC approval for the following pursuant to sections 59 to 61 and 89 of the *Utilities Commission Act* (UCA):

1. Approval to recover the 2023 revenue requirement and resultant delivery rate change on an interim basis, effective January 1, 2023, as filed in the Application and subject to any adjustments identified by FEI during the regulatory process and from any directives or determinations made by the BCUC in its decision on the Application. Delivery rates will remain interim pending the outcomes of the current generic cost of capital (GCOC) proceeding and FEI's 2023 Demand Side Management (DSM) Plan application.
2. The level of forecast sustainment and other capital to be incorporated in rates for the years 2023 and 2024, as set out in Section 7.2.1.
3. The following deferral account approvals as described in Section 7.5:
   - Creation of a rate base deferral account titled the Gibsons Capacity Upgrade (GCU) Preliminary Stage Development Costs deferral account to be amortized over three years, commencing January 1, 2023.
   - Approval of a three-year amortization period for the existing COVID-19 Customer Recovery Fund Deferral Account, commencing January 1, 2023.
   - Approval to change the amortization period of the existing Emissions Regulations deferral account from five years to one year, commencing January 1, 2023.
4. Approval to cease reporting on the COVID-19 Customer Recovery Fund Deferral Account, as described in Section 7.5.2.1.
5. A Biomethane Variance Account (BVA) Rate Rider for 2023 in the amount of $0.132 per gigajoule (GJ) as calculated in Section 10.3.1.
6. Revenue Stabilization Adjustment Mechanism (RSAM) riders for 2023 in the credit amount of $0.209 per GJ as set out in Table 10-5 in Section 10.3.2.
7. The 2023 Core Market Administration Expense (CMAE) budget of $5.795 million, as set out in Appendix B, and the allocation of the CMAE between FEI's Commodity Cost Reconciliation Account (CCRA) and Midstream Cost Reconciliation Account (MCRA) based on the allocation percentages of 30 percent and 70 percent, respectively.

FEI also seeks acceptance, pursuant to section 44.2(3) of the UCA, of a capital expenditure schedule consisting of the capital expenditures for the GCU Project, as described in Section 7.2.3.2.2 and in Appendix C3.

Additionally, FEI seeks approval pursuant to section 99 of the UCA to vary the following Orders:

1. Directive 10 of Order G-319-20 in order to facilitate the return of the net incremental COVID-19 related cost reductions to customers through inclusion of the cost reductions in the Flow-through deferral account, as described in Section 12.2.1.

2. Directive 2 of Order G-83-14 to ensure that FEI continues to have approval from the BCUC to use US GAAP for regulatory accounting purposes, as described in Section 12.3.1.

A draft order is included in Appendix E.

1.3 *REQUIREMENTS FOR THE ANNUAL REVIEW*

On page 167 of the MRP Decision, the BCUC set out its expectations for the Annual Review component of the MRP. For reference, the table below sets out each requirement and FEI's response or where it is addressed in the Application.

Table 1-1: Annual Review Requirements

Item	Description	Response or Reference
1	Review of the current year projections and the upcoming year's forecast. For further clarity, these items are listed below:	See items 1(a) to 1(f) below
1(a)	Customer growth, volumes and revenues;	Section 3
1(b)	Year-end and average customers, and other cost driver information including inflation;	Section 2
1(c)	Expenses, determined by the indexing formula plus items forecast annually;	Section 6
1(d)	Capital expenditures (as provided for by the capital forecast with FEI's Growth capital determined by the indexing formula), plus other items forecast annually;	Section 7
1(e)	Plant balances, deferral account balances and other rate base information and depreciation and amortization to be included in rates; and	Sections 7 and 12
1(f)	Projected earnings sharing for the current year and true-up to actual earnings sharing for the prior year.	Section 10.2
2	Identification of any efficiency initiatives that the Utilities have undertaken, or intend to undertake, that require a payback period extending beyond the MRP period with recommendations to the BCUC with respect to the treatment of such initiatives.	FEI has not identified any efficiency initiatives with a payback beyond the end of the MRP period
3	Review of any exogenous events that the Company or stakeholders have identified that should be put forward to the BCUC for review.	Section 12.2
4	Review of the Utilities' performance with respect to SQIs. Bring forward recommendations to the BCUC where there have been a "sustained serious degradation" of service.	Section 13

Item	Description	Response or Reference
5	Assess and make recommendations with respect to any SQIs that should be reviewed in future Annual Reviews.	FEI does not have any recommendations at this time
6	Reporting on the Innovation Fund status.	Section 10.3.3
7	Assess and make recommendations to the BCUC on potential issues or topics for future Annual Reviews.	FEI does not have any recommendations at this time

1.4 *FORMULA O&M SAVINGS AND PRODUCTIVITY INITIATIVES*

1.4.1 Overview of 2021 Formula O&M Savings

For 2021, FEI achieved formula O&M savings in addition to meeting the embedded productivity improvement factor in the O&M formula. Total formula O&M savings before earnings sharing were approximately $4.2 million.

Approximately $2.2 million in formula O&M savings were realized due to the net incremental impact of the COVID-19 pandemic, which will be returned to customers via the Flow-through deferral account. Please refer to Section 12.2.1 for further details. This was partially offset by higher costs of approximately $1.3 million incurred to perform repairs to the distribution system in response to flooding conditions experienced in BC late in 2021. Additionally, approximately $3.3 million of O&M savings were due to the timing of expenditures, such as vacancies and consulting expenditures, and lower general and miscellaneous expenditures. While some of the savings are one-time in nature (e.g., delay in filling vacancies), some of the savings are expected to continue into the future, recognizing that cost pressures in the future may offset the savings.

FEI will continue to pursue productivity improvements to achieve savings beyond the productivity improvement factor as it seeks to manage its business needs and cost pressures resulting from its evolving and challenging operating environment.

1.4.2 Productivity Initiatives

As mentioned in FEI's Annual Review for 2022 Delivery Rates (2022 Annual Review), in 2021, FEI and FortisBC Inc. (together FortisBC) initiated a working group consisting of senior managers and directors from different parts of the organization that is responsible for reviewing and identifying areas for productivity initiatives. An area of focus for potential productivity opportunities is initiatives that offer financial and customer service benefits and leverage technology and innovation to achieve these benefits.

Following is a summary of productivity initiatives from different parts of the organization FortisBC reviewed this past year and/or is investigating.

1. **Operational Field Excellence:** This initiative targets improvements to overall field operations efficiency by better prioritization of emergency repairs, improved work planning and reducing low value activities such as wait times and pulled work orders. In 2021, FEI implemented leak categorization processes that align with industry practice and enable a more planned response to leak repairs where appropriate. By providing a more planned response to work, FEI is able to reduce unnecessary disruption to scheduled work and reduce wait times for materials and services. This change will enable improved decision making, provide improved field resource utilization, and serve customers better. This change, along with other improvements such as field management skills development planned for 2022, is expected to result in annual O&M savings of approximately $0.5 million starting in 2022. The savings are expected to materialize in lower contracting and overtime costs. The incremental O&M cost to implement the change is approximately $1.1 million.

2. **Methane Leak Detection:** FEI is investigating the use of satellite-based infrared remote sensing technology. FEI's current leak survey approach is a traditional walking survey. Challenges of a traditional walking survey include: limited access for some assets, requiring secondary visits; overall timeframe duration to complete; resourcing availability; and surveying assets within the current year survey cycle. A satellite-based leak survey approach allows FEI to survey every asset within the provided boundary, may offer a more cost-effective approach for completing this work, and may allow for more timely identification and resolution of leaks. In 2021, FEI began a pilot to evaluate capabilities of the technology, including accuracy and sensitivity, as well as to understand the cost effectiveness of this technology as compared to the traditional walking survey. Additional objectives of the pilot included understanding the false positive rates and related causes, and understanding the ideal weather and landscape conditions for using this solution for conducting leak surveys. Based on the initial pilot results, FEI is currently executing a more robust pilot throughout 2022, with the goal of partial or full implementation of a satellite-based leak survey program in the future.

3. **Technology Investments to Support Enhanced Communications:** FEI introduced enhancements during the COVID-19 pandemic to enable employees to productively work remotely. The implementation of the Microsoft Teams platform was expedited in 2021, allowing for use of video meetings for employee communications. In 2021, FEI also introduced the Microsoft Teams mobile app that provided seamless integration and access to Teams meetings, Teams sites, calendar, chat functionality and a seamless transition from phone to computer or vice versa during meetings. It was and continues to be a platform to reduce travel requirements for staff, providing options to meet in person less often, which enables continued savings on fuel costs, hotels, meals, and wear and tear on vehicles. Hybrid meetings support large audience attendance using Teams meetings, with the added benefit of not requiring time away from the home office and the resulting lost productivity. Additional functionality will continue to be added to the Teams platform (i.e., whiteboard, enhancements to breakout rooms, Presenter modes and group control of

presentation, etc.) as Microsoft continues to develop and release upgrades. The mobile application will also see improvements.

The Company's rapid implementation of communications software during the pandemic has contributed to creating a productive work environment for employees to complete their work with the benefit of not requiring time away from the home office and lost productivity. In total, the Company invested approximately $1.5 million over the two years 2020 and 2021. This investment has contributed to achieving employee related expense savings (i.e., travel) during the pandemic and will also help to permanently sustain some of the related savings post pandemic.

4. **Data Analytics:** This is an initiative to centralize the Company's data sources coupled with a suite of analytic tools to analyze and use the data to inform decision-making. Data analytics is the process of extracting and analyzing data sets to identify or uncover patterns, correlations, trends, customer preferences and other information for the purpose of allowing an organization to make more informed business decisions. Better decisions will lead to improved business operations and customer service and increased productivity. The ability to easily access and analyze data can be inhibited by internal processes, decentralization of information and a lack of understanding of the data. With Data Analytics, departments will be provided a common cleansed data source and the tools to create advanced analytics quickly and easily. Resources will be provided to business areas to help identify reporting and analytic needs that will lead to efficiencies. Through a centralized approach, this will provide the skills along with the data and the tools to drive business capability to support analytic needs and also provide better visibility to cost or benefits of data analytics initiatives.

   The requirements and business case for the necessary information systems infrastructure were completed in 2021. FEI plans to implement systems that will allow centralized data access in 2022 and add new data sources in priority sequence over time. Data usage cases for this initiative are being prioritized first for those that enable cost savings.

5. **Streamlining and Automating Reporting Process:** This initiative is one of the earlier usage cases that FEI is considering for the Data Analytics initiative. The focus is on streamlining the reporting processes for financial and management reporting information (i.e., internal cost reporting, key performance indicators, etc.). Currently, the reporting processes work well with clearly defined requirements and processes but rely on manual effort. Source system (i.e., SAP) reports are not formatted for users and SAP reports are data extracts and are not set-up for data integration and manipulation. Instead, Excel is used to integrate, transform and format reports. FEI is presently assessing the feasibility of implementing an automated solution that will reduce the effort required to generate reports, with expected productivity gains. This automation is expected to be achieved through the use of a data model to aggregate data sources and a reporting tool to allow for self-service.

FEI will be in a better position at next year's Annual Review to provide details of this initiative should it be undertaken, and to provide details of other specific data analytics initiatives undertaken and the benefits achieved.

6. **Robotics Process Automation (RPA):** This is an efficiency initiative using automation software to alleviate repetitive and simple manual tasks. With the rising volume of manual tasks performed for operational work, such as financial transactions or project closeout activities, departments within FortisBC are challenged. Both the Finance and Engineering departments have experienced an increase in manual activities over several years. Between steps performed multiple times daily, to weekly, monthly or annually, the common theme is a manual and repetitive task with limited decision points.

   In the first phase of RPA implementation, the Company is evaluating opportunities within the Finance and Engineering areas to apply RPA. There are a number of processes being evaluated for RPA with the focus on processes requiring supporting manual activities. The processes vary from creating journal entries, generating third party billing, populating reports, filing documents, and collecting information for budgeting purposes.

   FEI will be in a better position at next year's Annual Review to provide details of this initiative, including the results and benefits achieved.

7. **Willingdon Park Redesign:** This is an initiative to optimize the existing space for housing of contact centre staff to service FortisBC customers. In 2021, the Willingdon Park contact centre 10-year lease was set to expire. Historically, workspace requirements at this site necessitated the lease of two of the four floors at the location. Following a review of the workspace requirements and a consideration of new ways to approach the use of space, the Customer Service and Facilities Departments made the determination that with redesigned workstations, meeting rooms and collaborative spaces, the contact centre could be accommodated on a single floor at this site. With renovation work occurring throughout 2021 at an approximate cost of $1.1 million for tenant improvements, Customer Service moved into the new space in the fall of 2021. The annual operating savings associated with this project are approximately $1.0 million per year, effective 2022.

8. **Paperless Billing Customer Campaigns:** This initiative focuses on working with customers to encourage the switch to paperless billing. In addition to the convenience for customers of receiving their bill electronically and the environmental considerations of less paper and physical transport of the bills, an increased percentage of customers making the switch to paperless billing results in ongoing printing and postage cost savings. At the start of 2021, FEI had approximately 463,000 customers choosing paperless billing as their preferred bill delivery method. Following the success of several internal programs that encouraged employees to highlight this option with customers and including an external social media campaign that resulted in donations to food banks in need, FEI achieved an increase of approximately 47,000 customers choosing this option in 2021.

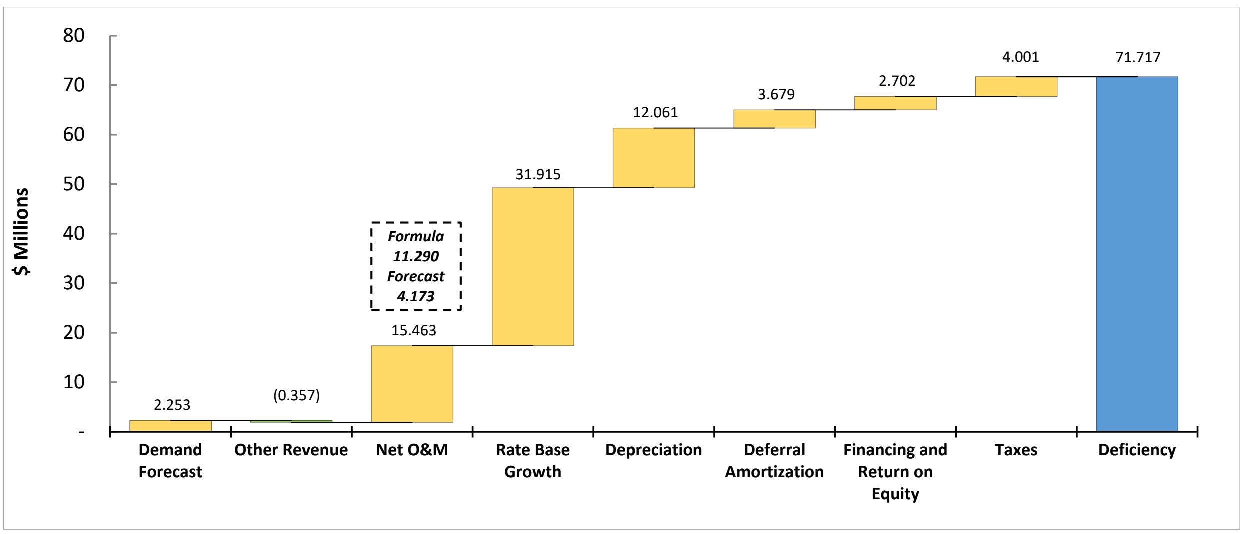
This increase equates to approximately $0.3 million in printing and postage cost savings in 2021 as compared to 2020.[3]

1.5 REVENUE REQUIREMENT AND RATE CHANGES FOR 2022

The revenue requirement components set out in the Application result in an effective delivery rate increase of 7.42 percent for 2023 compared to 2022. The effective delivery rate increase results from a revenue deficiency of $71.717 million.

The following chart summarizes the items that contribute to the 2023 revenue deficiency. The chart shows each item that increases the deficiency in yellow and each item that decreases the deficiency in green. The 2023 deficiency of $71.717 million is then the sum of all of the previous bars and is shown at the end of the chart in blue.

Figure 1-1: 2023 Delivery Revenue Deficiency ($ millions)



Each of the categories is discussed briefly below.

1.5.1 Demand Forecast (Section 3)

In 2023, demand is forecast to decrease by approximately 12.8 PJ compared to 2022 Approved primarily due to FEI's contract with BC Hydro IG expiring in April 2022 which had a contract demand of approximately 16.4 PJ. The impact of the overall decrease of 12.8 PJ is an increase to the 2023 deficiency of $2.253 million. FEI's 2023 Forecast revenue at 2022 approved rates is $2,168.836 million and the 2023 Forecast gross delivery margin is $1,001.008 million.

[3] Calculation is a high level estimate based the incremental monthly paperless billing growth at an average savings of approximately $1.09 per bill.

1.5.2 Other Revenue (Section 5)

Other Revenue is forecast to decrease the 2023 deficiency by approximately $0.357 million, mainly due to increases in Late Payment Charges and NGT-related recoveries.

1.5.3 Operations and Maintenance (O&M) Expense (Section 6)

FEI establishes the majority of its O&M costs by formula during the MRP term. For 2023, the formula incorporates a net inflation factor of 4.080 percent, which is inclusive of a productivity improvement factor (X-Factor) of 0.5 percent, and uses a forecast of the change in average customers,[4] for a total increase in formula O&M of $12.959 million[5] (4.5 percent) from 2022 formula O&M. O&M forecast outside of the formula is also increasing by $7.208 million[6] (15.0 percent) compared to 2022 Approved, primarily due to increases in integrity-related O&M, insurance, and Biomethane O&M (which will be transferred to the BVA as described in Section 10.3.1). The 2023 increase in total O&M expense net of capitalized overhead and Biomethane O&M transferred to the BVA is $15.463 million.

1.5.4 Rate Base Growth and Depreciation (Section 7)

The 2023 rate base is forecast to increase by approximately $520.740 million when compared to the 2022 Approved rate base. The increase in rate base is primarily the result of multiple CPCN additions to plant, including the IGU project, the PGR project and the CTS-TIMC project, as described in Section 7.

The increase in rate base, primarily due to the additions of the aforementioned CPCN projects, also results in an increase in 2023 depreciation expense by approximately $12.159 million compared to 2022 Approved, which is offset by approximately $0.098 million of CIAC from net additions, resulting in a net increase of $12.061 million in depreciation expense.

1.5.5 Amortization of Deferral Accounts (Section 7 and Section 12)

Amortization of deferral accounts in 2023 increased by $3.679 million. This is primarily due to the increased amortization of the Demand-Side Management (DSM) deferral account by approximately $9.643 million, the amortization of $2.521 million of the TIMC deferral account starting in 2023, and a debit amortization of $19.512 million for the 2020-2024 Flow-through non-rate base deferral account. These increases in amortization expense are mostly offset by a credit amortization of $28.848 million for the Emissions Regulations deferral account. As discussed in Section 7.5.2.2, FEI has accumulated approximately 80,149 of validated carbon credits by the British Columbia Low Carbon Fuel Standard (BC-LCFS) since 2019 to the end of the first quarter of 2022, which has a market value of approximately $37.5 million (pre-tax). FEI is proposing to

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4 Modified by 75 percent.
5 Increase of formula O&M by $11.290 million net of capitalized overhead.
6 Increase of forecast O&M by $4.173 million net of capitalized overhead and biomethane O&M transferred to BVA.

change the amortization period of the Emissions Regulations deferral account from five years to one year, thus returning all available carbon credits to customers in 2023.

1.5.6 Financing and Return on Equity (Section 8)

Financing and Return on Equity (ROE) increased the 2023 deficiency by $2.702 million through changes in financing rates, as well as changes in the ratio of long-term debt vs. short-term debt.

For 2023, FEI has forecast a mid-year long-term debt issue of $300 million and is forecasting a short-term debt rate of 3.95 percent, which is an increase from the 2.31 percent short-term debt rate embedded in the 2022 Approved revenue requirement. Overall, the 2023 deficiency is increased by $5.841 million due to financing rate changes and decreased by $3.139 million as a result of the ratio change between long-term and short-term debt.

In calculating its 2023 revenue deficiency, FEI has utilized its currently approved capital structure and ROE of 38.5 percent and 8.75 percent, respectively. As explained in Sections 1.2 and 8.1, FEI is currently participating in the BCUC-initiated GCOC proceeding and has filed evidence on its recommended capital structure and ROE as part of Stage 1 of the proceeding. In Order G-156-21 and accompanying Reasons for Decision, the BCUC found that the effective date to implement a new cost of capital will depend on the timing and progress of the GCOC proceeding. FEI is seeking approval of interim 2023 delivery rates pending the outcome of Stage 1 of the GCOC proceeding as well as a decision on FEI's 2023 DSM Expenditure Plan. When a decision is reached on these proceedings, FEI will update its rate calculations and apply for permanent 2023 delivery rates.

1.5.7 Taxes (Section 9)

FEI's 2023 property taxes are forecast to increase by 7.6 percent or $5.588 million from 2022 Approved. Over half of the increase is driven by higher in-lieu taxes calculated based on a fixed percentage of FEI's revenues, which has increased due to the higher cost of gas. The remaining increase is driven by construction activities and market value increases, partly offset by decreases in tax rates of local taxing authorities.

There has been no change in the income tax rate of 27 percent from 2022. Taxes are forecast to decrease in 2023 by 3.0 percent or $1.587 million from 2022 Approved primarily due to higher deductible temporary differences associated with property, plant and equipment and lower taxable temporary differences associated with pension and OPEB, partially offset by higher rate base and amortization of deferred charges.

1.6 *SERVICE QUALITY INDICATORS (SECTION 13)*

FEI reports on its 2021 and June 2022 year-to-date SQI results in Section 13. In 2021, for the nine SQIs with benchmarks, eight performed at or better than the approved benchmarks, with one, Meter Reading Accuracy, lower than the threshold due to the impact of the COVID-19 pandemic. For the four SQIs that are informational only, in 2021, performance generally remains at a level consistent with prior years. In 2022 to date, performance for the metrics with benchmarks is trending towards meeting the benchmark or the threshold.

2. FORMULA DRIVERS

2.1 INTRODUCTION AND OVERVIEW

This section provides the calculation of the Inflation Factor (or I-Factor) and Growth Factors used for calculating the 2023 O&M and growth capital amounts according to the MRP formula.

In the MRP Decision and Order G-165-20, the BCUC approved an I-Factor using the actual CPI-BC and BC-AWE indices from the previous year and a labour weighting based on the most recent completed year of actuals.[7]

The MRP Decision approved the use of a forecast of growth[8] to determine formula O&M and formula growth capital as well as a growth factor multiplier of 75 percent for formula O&M.

The Inflation Factor and Growth Factor calculations utilize the above-described inputs and determinations. For 2023, FEI has used July 2020 through June 2022 inflation data for the 2023 revenue requirement calculations, using the Statistics Canada tables included in Appendix A1 of the Application.

Section 2.2 below explains how FEI determined the 2023 Inflation Factor based on prior years' BC-CPI and BC-AWE that is used to calculate the formula O&M discussed in Section 6 and formula growth capital discussed in Section 7. Section 2.3 below explains how FEI determined the average customer count that is used to calculate the formula O&M discussed in Section 6 and provides the gross customer additions forecast that is used to calculate the formula growth capital discussed in Section 7.

2.2 INFLATION FACTOR CALCULATION SUMMARY

In the MRP Decision, the BCUC approved an I-Factor using the actual CPI-BC and BC-AWE indices from the previous year and the actual labour weighting based on the most recent completed year of actuals. FEI uses inflation data from July through June and Statistics Canada Table 18-10-0004-01 for CPI-BC and Table 14-10-0223-01 to determine AWE-BC. The supporting Statistics Canada tables are provided in Appendix A1. The latest available month of April 2022 for AWE-BC has been used as a placeholder, as results to June 2022 have not been released by Statistics Canada. Once results for these periods are available, this placeholder will be replaced with actuals and included in an Evidentiary Update or Compliance Filing.

As shown in Table 2-1 below, the I-Factor has been calculated utilizing actual CPI-BC and AWE-BC data. Applying the actual 2021 labour weighting of 51 percent, the calculation of the 2023 I-Factor is (4.940 percent x 49 percent) + (4.235 percent x 51 percent) = 4.580 percent.

[7] FEI's most recent year of completed actuals is 2021 so that ratio has been used for the 2023 I-Factor calculation.

[8] Forecast of average customers for Formula O&M and a forecast of gross customer additions for Formula Growth Capital, both including a true-up to actual customers in the following years.

Table 2-1: I-Factor Calculation

		Table: 18-10-0004-01	*Table: 14-10-0223-01*	12 Mth Average				Last Completed Year			
Line No.	Date	BC CPI index	BC AWE $	CPI index	AWE $	CPI %	AWE %	Non Labour %	Labour %	I-Factor %	MRP Year
1	Jul-2020	132.6	1,093.72								
2	Aug-2020	132.4	1,089.35								
3	Sep-2020	132.5	1,093.75								
4	Oct-2020	132.9	1,095.32								
5	Nov-2020	133.3	1,102.95								
6	Dec-2020	132.8	1,110.36								
7	Jan-2021	133.6	1,113.22								
8	Feb-2021	134.1	1,114.21								
9	Mar-2021	134.9	1,107.66								
10	Apr-2021	135.2	1,112.04								
11	May-2021	135.1	1,118.59								
12	Jun-2021	135.8	1,115.40	133.8	1,105.55						
13	Jul-2021	136.7	1,140.52								
14	Aug-2021	137.0	1,142.40								
15	Sep-2021	137.2	1,139.64								
16	Oct-2021	137.9	1,136.85								
17	Nov-2021	138.1	1,132.25								
18	Dec-2021	138.0	1,134.84								
19	Jan-2022	139.4	1,157.19								
20	Feb-2022	140.4	1,153.88								
21	Mar-2022	143.0	1,161.22								
22	Apr-2022	144.2	1,176.54								
23	May-2022	146.1	1,176.54								
24	Jun-2022	146.5	1,176.54	140.4	1,152.37	4.940%	4.235%	49%	51%	4.580%	2023

2.3 *GROWTH FACTOR CALCULATION SUMMARY*

As noted above, the BCUC approved the use of a forecast of average customers with a 75 percent modifier to determine formula O&M, and a forecast of gross customer additions to determine formula growth capital.

The calculation of the average customers used to determine 2023 Formula O&M is summarized in the table below. The growth factor is applied to the unit cost O&M (UCOM), which was calculated based on 2019 average customers of 1,031,862 (shown on line 21 under year 2020 or line 28 in Table 2-2 below). Starting with this 2019 average customer count, the calculation adds 75 percent of the cumulative average of actual/forecast customer growth during the MRP term from 2020 to 2023 (shown on line 26 in Table 2-2 below) to determine the average customers for rate setting (shown on line 29 of Table 2-2 below).

Table 2-2: Calculation of 2023 Average Customer (AC) Growth Factor

Line No.	Date	Actual 2020	Actual 2021	Projected 2022	Forecast 2023	Total for 2023 Rate Setting	Reference
1	Prior Year Ending Customer Count	1,038,354	1,051,752	1,062,480	1,071,333		Appendix A2 Table A2-1 FEI Customers
2							
3	Additions:						
4	January	1,544	2,043	1,376	1,262		
5	February	1,028	1,162	627	562		
6	March	403	1,178	626	572		
7	April	722	395	174	140		
8	May	726	(37)	18	(12)		
9	June	921	(167)	64	41		
10	July	824	(507)	(10)	(24)		
11	August	848	256	678	290		
12	September	338	862	582	526		
13	October	2,006	1,797	1,568	1,425		
14	November	2,010	2,035	1,619	1,489		
15	December	2,028	1,711	1,531	1,406		
16	Total Additions	13,398	10,728	8,853	7,677		Appendix A2 Table A2-1 FEI Customer Additions
17	12-month Weighted Average Additions	6,268	5,334	3,913	3,381		
18							
19	Current Year Ending Customer Count	1,051,752	1,062,480	1,071,333	1,079,010		Line 1 + Line 16; Appendix A2 Table A2-1 FEI Customers
20							
21	Actual/Projected Prior Year Average Customers	1,031,862	1,044,622	1,057,086	1,066,393		2020: G-319-20; Sch 3, Line 13; 2021 onward: Prior Year Ending, Line 22
22	Average Customers for the Year	1,044,622	1,057,086	1,066,393	1,074,714		Line 1 + Line 17
23	Change in Average Customers	12,760	12,464	9,307	8,320	**42,851**	Sum of Annual Change in Average Customers on Line 23
24							
25	Growth Factor Multiplier					**75%**	G-165-20
26	Change in Average Customers for Rate Setting Purposes					**32,138**	Line 25 x Line 23
27							
28	Average Customers Used to Determine the Starting UCOM					**1,031,862**	Line 21, Yr 2020
29	**Average Customer Forecast for Rate Setting**					**1,064,000**	Line 28 + Line 26
30							
31	2021 Approved Average Customers for Rate Setting		1,047,935				2021: G-319-20; Sch 3, Line 22
32	2021 Actual Average Customers for Rate Setting		1,050,780				Line 21(2020) + Sum of Line 23 (2020 & 2021) x 0.75
33	**2021 True Up**		**2,845**				Line 32 - Line 31

The forecast for FEI's Gross Customer Additions for determination of the formula growth capital is provided in the table below.

Table 2-3: Forecast Gross Customer Additions (GCA)

Line No.	Gross Customer Additions		Reference
1	2021 Approved	16,000	
2	2021 Actual	20,294	
3	2021 True-up	4,294	Section 7, Table 7-9, line 14
4			
5	2022 Approved	20,000	
6			
7	2023 Forecast	16,000	Schedule 4, line 5

FEI is forecasting gross customer additions of 16,000 for 2023, which is lower than the 2022 Approved amount of 20,000 but is reflective of FEI's expectation of its 2022 customer growth, which is projected at 16,000. As explained in Section 7.2.2, the calculation of formula growth capital includes the true-up of gross customer additions from two years prior (i.e., 2021). While the 2022 Projected additions are lower than 2022 Approved, and have informed FEI's forecast for

2023, they do not impact the calculation of formula growth capital in this annual review; instead, 2022 additions will be trued up when setting 2024 delivery rates.

Gross customer additions is a forecast of new customers attaching to the gas distribution system. It comprises both new construction activity and conversions from other fuels to natural gas. In developing the forecast, FEI has assumed that the market capture rate for new construction is likely to retreat somewhat versus previous years due to the continued impacts of building policies, building codes, and strong financial incentives provided for home electrification. FEI has also assumed that conversion activity is likely to be reduced versus previous years due to both strong financial incentives for home electrification and rapidly rising financing costs. The forecast for 2023 has been undertaken by reviewing information contained in FEI's customer relationship management system (leads, connection requests, timing of connection requests, etc.) along with interactions with builders, developers, and contractors. FEI uses market information such as building permits, forecast housing starts and completions as well as any knowledge of policy or building code changes that may affect specific municipalities. The impact of a rapid increase in inflation and financing costs is creating greater uncertainty in the forecast of gross customer additions, which will be corrected in subsequent years with the BCUC approved true-up mechanism.

2.4 *INFLATION AND GROWTH CALCULATION SUMMARY*

A summary of the factors used to determine formula O&M and formula growth capital for 2023 is provided in Table 2-4, including the I-Factor calculated in Section 2.2, the approved X-Factor of 0.5 percent, and the forecasts of average customers and gross customer additions determined in Section 2.3.

Table 2-4: Summary of Formula Drivers

Line No.	Particulars	2023	Reference
1	CPI	4.940%	Table 2-1, Line 24
2	AWE	4.235%	Table 2-1, Line 24
3			
4	Non Labour	49%	Table 2-1, Line 24
5	Labour	51%	Table 2-1, Line 24
6			
7	CPI/AWE Inflation	4.580%	(Line 1 x Line 4) + (Line 2 x Line 5)
8			
9	Productivity Factor	-0.500%	Order G-165-20
10			
11	Net Inflation Factor	4.080%	Line 7 + Line 9
12			
13	Average Customers for 2023 Formula O&M purposes	1,064,000	Table 2-2, Line 29
14			
15	Gross Customer Additions for 2023 Formula Growth Capital purposes	16,000	Table 2-3

In summary, the Net Inflation Factor for 2023 is 4.080 percent. Formula O&M for 2023 is determined using average customers of 1,064,000. Formula growth capital for 2023 is determined using gross customer additions of 16,000.

3. DEMAND FORECAST AND REVENUE AT EXISTING RATES

3.1 INTRODUCTION AND OVERVIEW

This section describes FEI's forecast of gas sales and transportation volumes. FEI's forecasting method remains consistent with prior years and the methods adopted in FEI's Forecasting Method Study completed in response to the forecasting directives in Order G-86-15. The total demand is a combination of energy demand from residential, commercial, industrial, and natural gas for transportation (NGT) customers.

FEI is forecasting a decrease in consumption in the 2023 Forecast (2023F) compared to the 2022 Approved. The 2023F normalized load is forecast to be approximately 221.3 PJ, which is a decrease of 12.8 PJ compared to the 2022 Approved forecast. The decrease in 2023F is due to decreased load in the industrial sector, which is primarily due to FEI's contract with BC Hydro Island Generation (IG) expiring in April 2022.

Based on the 2022 Approved rates for each customer class, FEI's 2023 revenue forecast is $2,169 million and FEI's 2023 gross margin forecast is $1,001 million.

FEI has provided further information supporting its demand forecast in Appendix A of the Application.

3.2 OVERVIEW OF FORECAST METHODS

FEI's demand forecast methods are consistent with prior years and the recommendations in the FEI Forecasting Method Study filed as Appendix B2 in FortisBC's 2020-2024 MRP Application. The Forecasting Method Study represented the culmination of a number of years of research and testing of alternative forecasting methods in response to the forecasting directives in Order G-86-15 and accompanying decision related to the FEI Annual Review for 2015 Rates Application. As a result of this study, FEI adopted the Exponential Smoothing method (ETS) for the purpose of forecasting residential and commercial use rates, as ETS proved to be the most accurate method for this purpose. See Appendix A3 for a detailed description of FEI's demand forecast methods.

The demand forecast relies on three components:

- the residential and commercial net customer additions forecast;[9]
- the residential and commercial use per customer (UPC) forecast; and
- the industrial forecast.

The demand forecast for residential and commercial customers is based on forecasts for the number of customers and UPC rates. Specifically, the monthly UPC is estimated for customers

[9] The net customer additions are the year-over-year change in the total number of customers.

under Rate Schedules 1, 2, 3 and 23 and then multiplied by the corresponding monthly forecast of the number of customers in these rate schedules. Monthly values are then aggregated for each year to derive the annual energy consumption.

The forecast of industrial energy demand is based upon customer-specific forecasts obtained through an Industrial Survey, as discussed in Section 3.3.3.

The forecast NGT demand is for Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG) volumes. The NGT demand and the LNG demand forecast is discussed is Section 3.3.4 below.

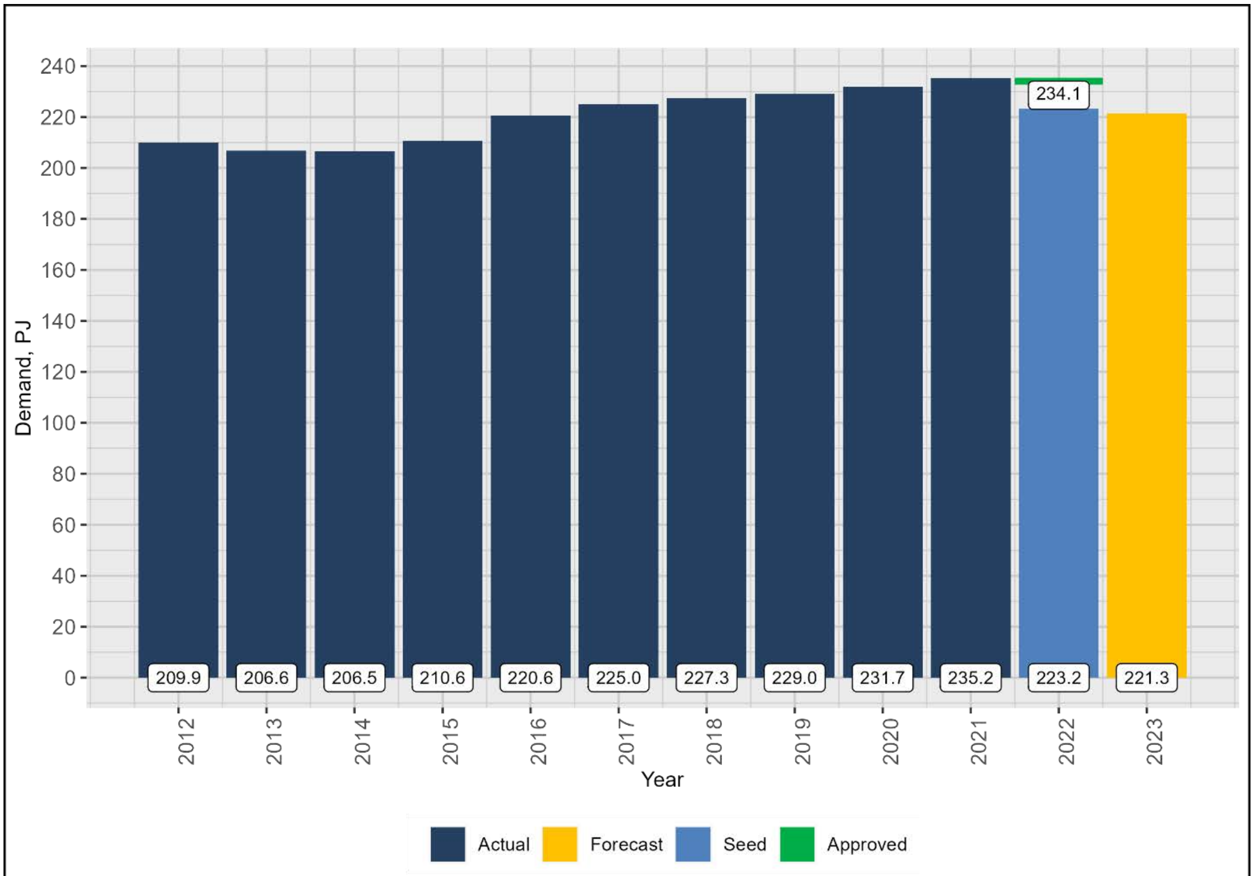
The following sections set out the results of the demand forecast. In the figures provided in the demand forecast sections, the following three time periods are shown:

- Actual Years: Actual years are those for which actual data exists for the full calendar year. For this Annual Review the latest calendar year for which full actual data exists is the 2021 calendar year.
- Seed Year: The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available, and will be different than the original forecast for that year in the previous filing. For example, for this Application the Seed Year is 2022 (2022S) and the Seed Year forecast is based on the latest actual years, including 2021. As such, the 2022 Seed Year forecast in this Application will differ from the 2022 Forecast presented in the Annual Review for 2022 Delivery Rates, for which 2021 actual data was not available.
- Forecast Year: This is the year or years for which the forecast is being developed. This can be one year (in the case of the Annual Review) or a range of two or more years depending on the filing. In this Application, the forecast year is 2023 (2023F).
- Also included in the figures in this section is the prior year's forecast (shown as the green Approved line in the figures below), as presented in the Annual Review for 2022 Delivery Rates.

3.3 *DEMAND FORECAST*

FEI's total energy demand consists of the weather normalized residential and commercial demand, and the customer-specific industrial, NGT, and non-NGT (LNG) demand. In aggregate, the absolute demand forecast variance in 2021 was 0.7 percent. As shown in Figure 3-1 below, the total load is forecast to be 221.3 PJ in 2023F, down by 1.9 PJ from 2022S.

Figure 3-1: Total Energy Demand in PJ



The residential, commercial, industrial, and NGT and non-NGT (LNG) demand forecasts are provided separately in the following subsections.

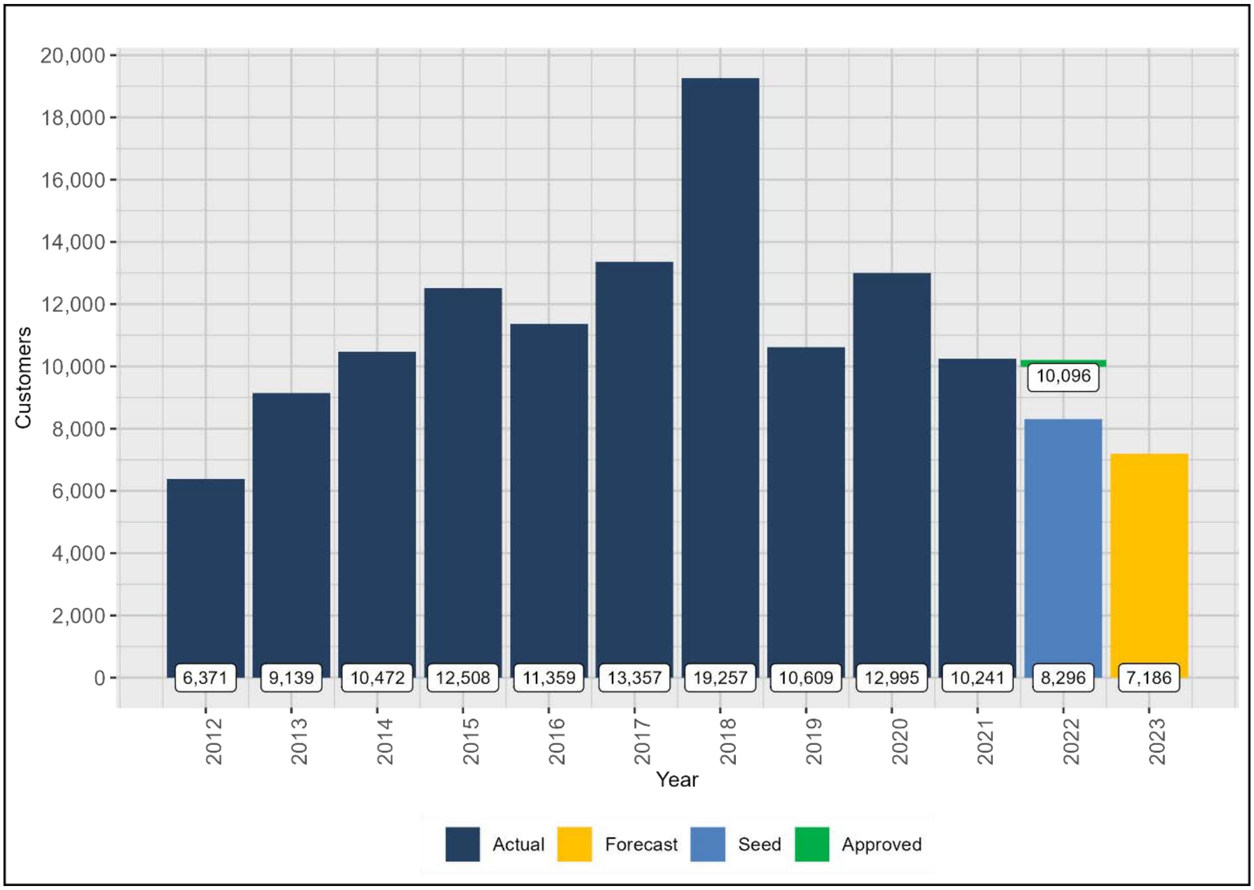
3.3.1 Residential

3.3.1.1 Residential Customer Additions

Consistent with past practice, FEI uses the Conference Board of Canada (CBOC) housing starts forecast as a proxy for residential net customer additions. The CBOC data used for the forecast, provided in Appendix A1, was issued in January 2022. The 2023 forecast of 7,186 additions reflects the actual residential additions recorded in 2021 and the single family and multi-family growth rate forecasts from the CBOC forecast.

As shown in Figure 3-2, residential customer additions are forecast to be 1,110 less in 2023F compared to 2022S. Figure 3-2 provides the residential net customer additions for 2012 through 2023.

Figure 3-2: Residential Net Customer Additions

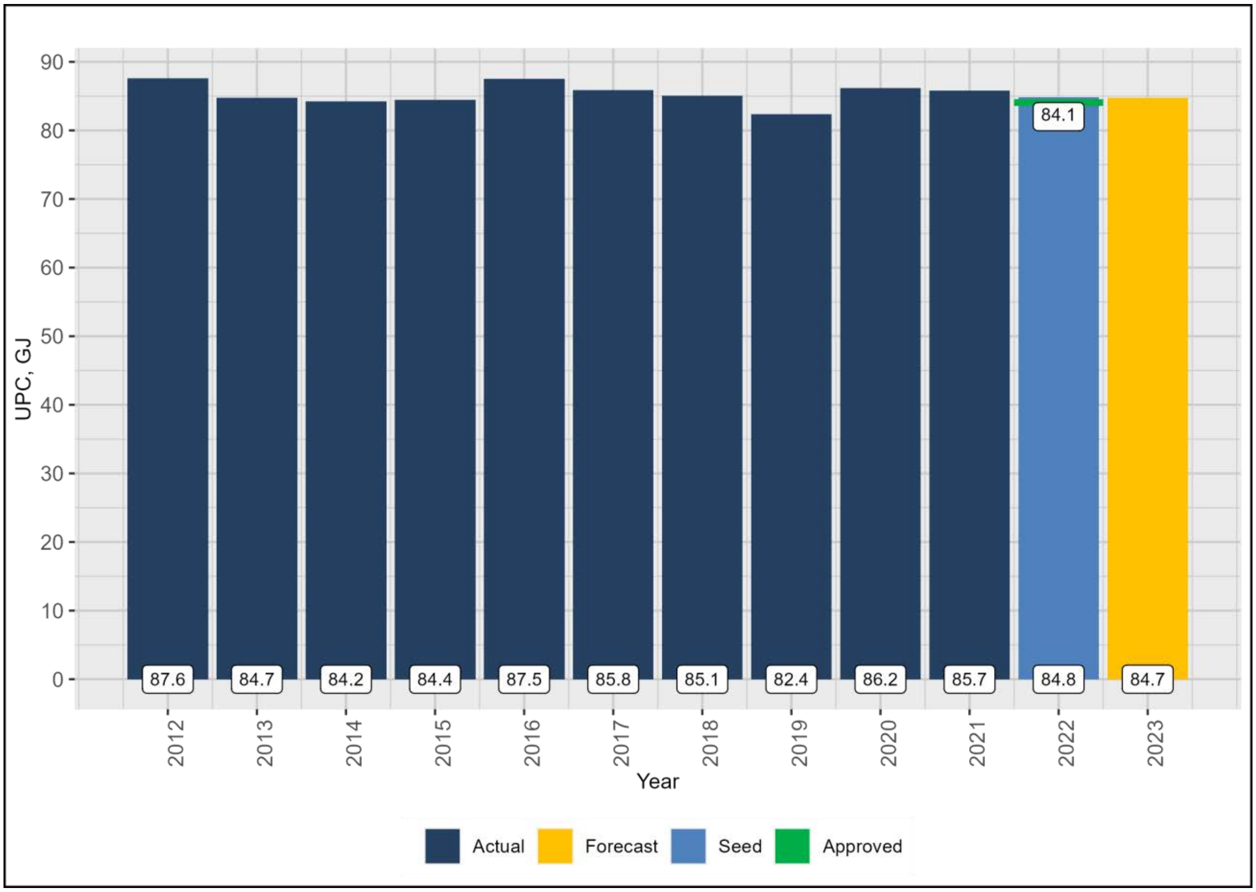


3.3.1.2 Residential UPC

The residential UPC forecast was developed using the ETS method with the most recent 10 years of historical weather-normalized UPC, described in Appendix A3.

As shown in Figure 3-3, the residential UPC is forecast to decrease by approximately 0.1 GJ in 2023F compared to 2022S.

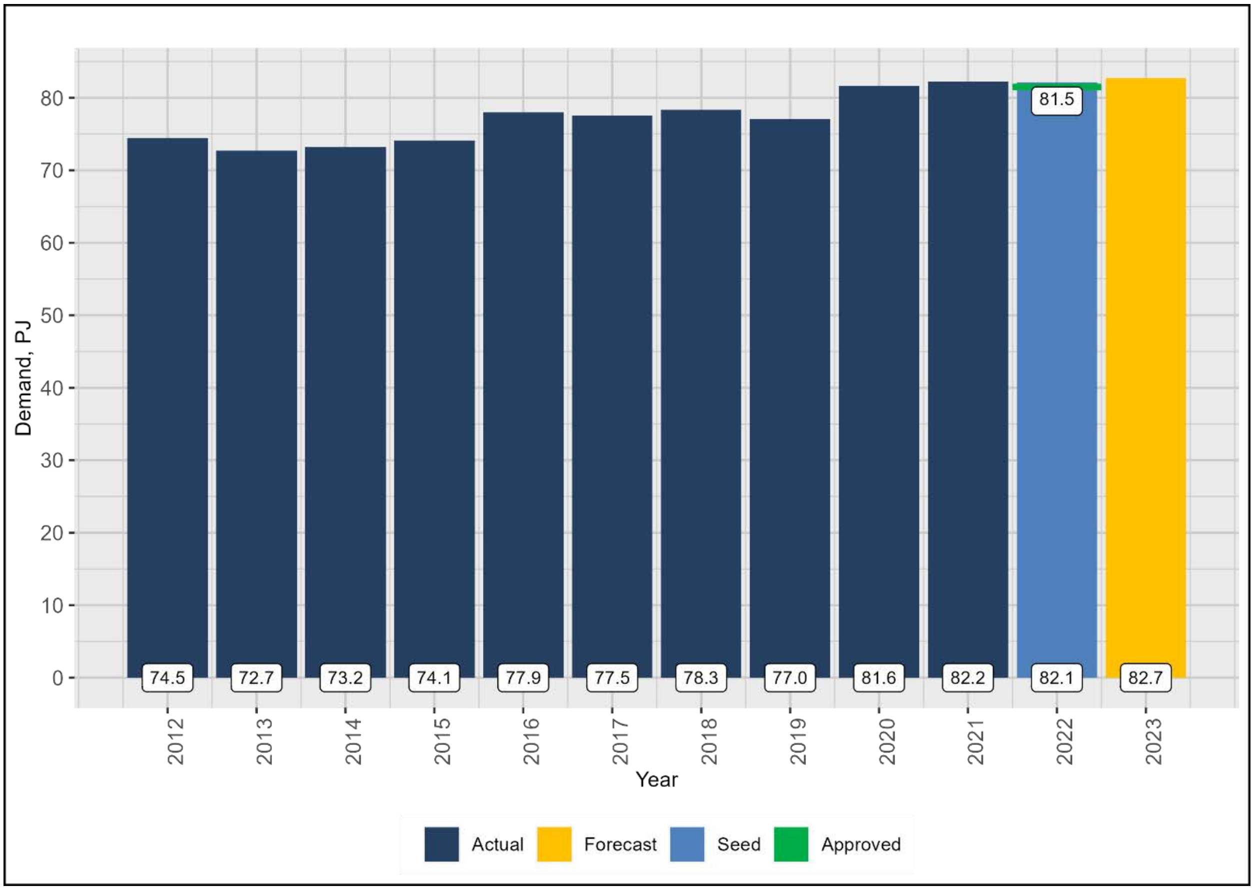
Figure 3-3: Rate Schedule 1 UPC



3.3.1.3 Residential Demand

Taking into account the customer additions and UPC forecasts described above, and as shown in Figure 3-4 below, residential demand is forecast to increase by 0.6 PJ in 2023F compared to 2022S.

Figure 3-4: Normalized Residential Demand



3.3.2 Commercial

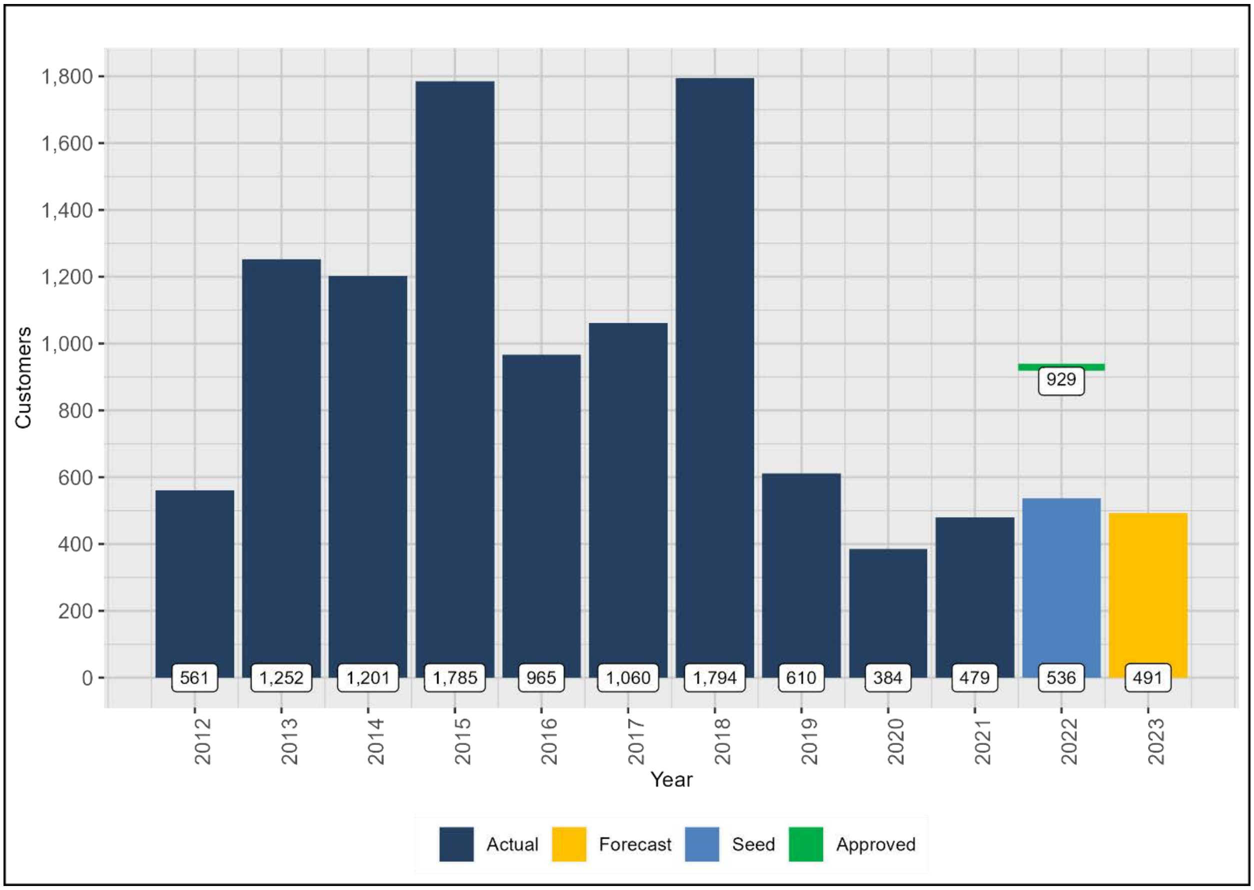
3.3.2.1 Commercial Customers

The commercial net customer additions forecast is based on the average of the actual net customer additions over the last three years for which a full year of actual data is available (i.e., 2019 to 2021).

With respect to the variance between the 2022 Approved and 2022S commercial customer additions, the COVID-19 pandemic likely had impacts on many commercial segments that resulted in lower customer additions. For example, restrictions imposed by the pandemic adversely impacted the operation and viability of customers in the tourism, hotel and restaurant sectors. FEI notes, however, that the commercial customer segment is very diverse and, as a result, it is difficult to pinpoint specific trends.

As shown in Figure 3-5 below, commercial customer additions are forecast to decrease by 45 in 2023F compared to 2022S.

Figure 3-5: Commercial Net Customers Additions

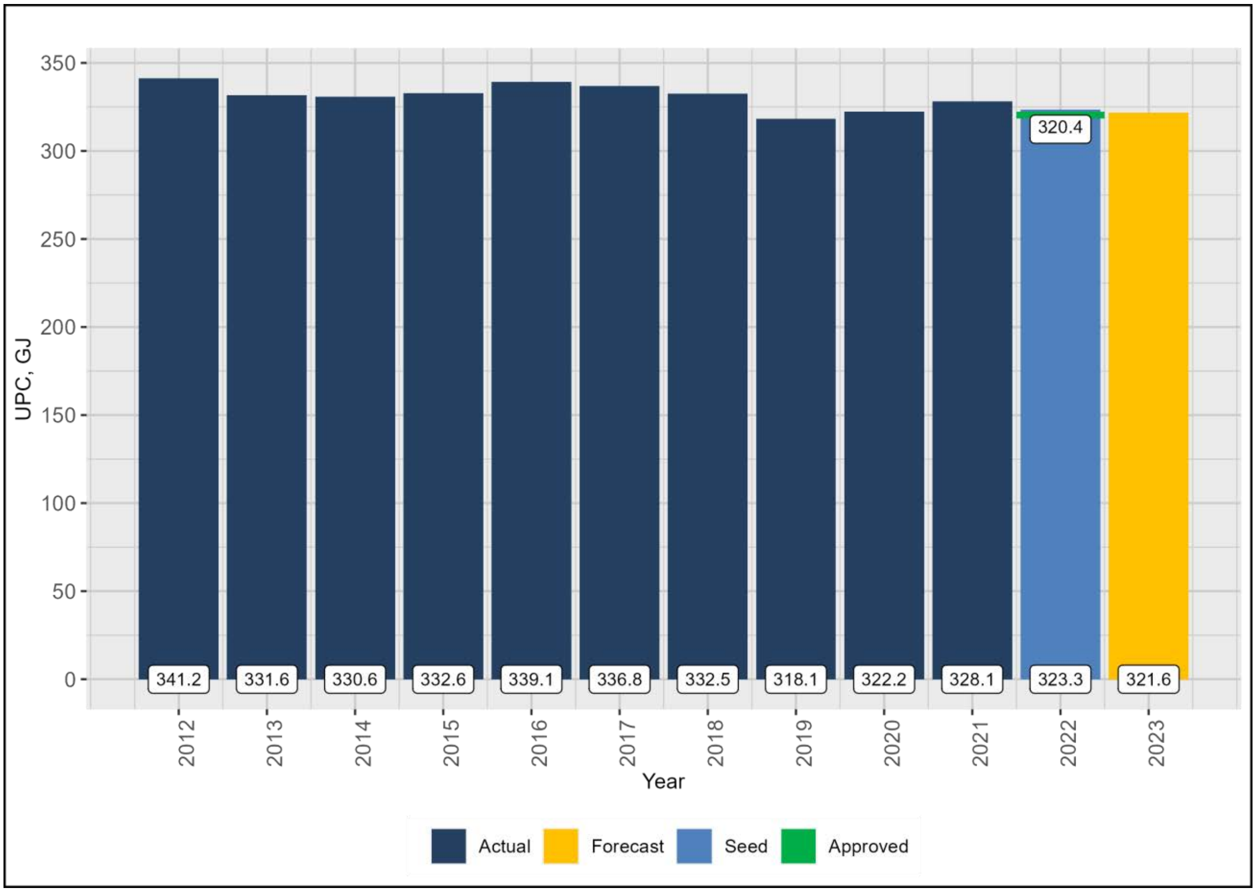


3.3.2.2 Commercial UPC

The commercial UPC forecast was developed using the ETS method, considering the most recent 10 years of historical weather-normalized UPC.

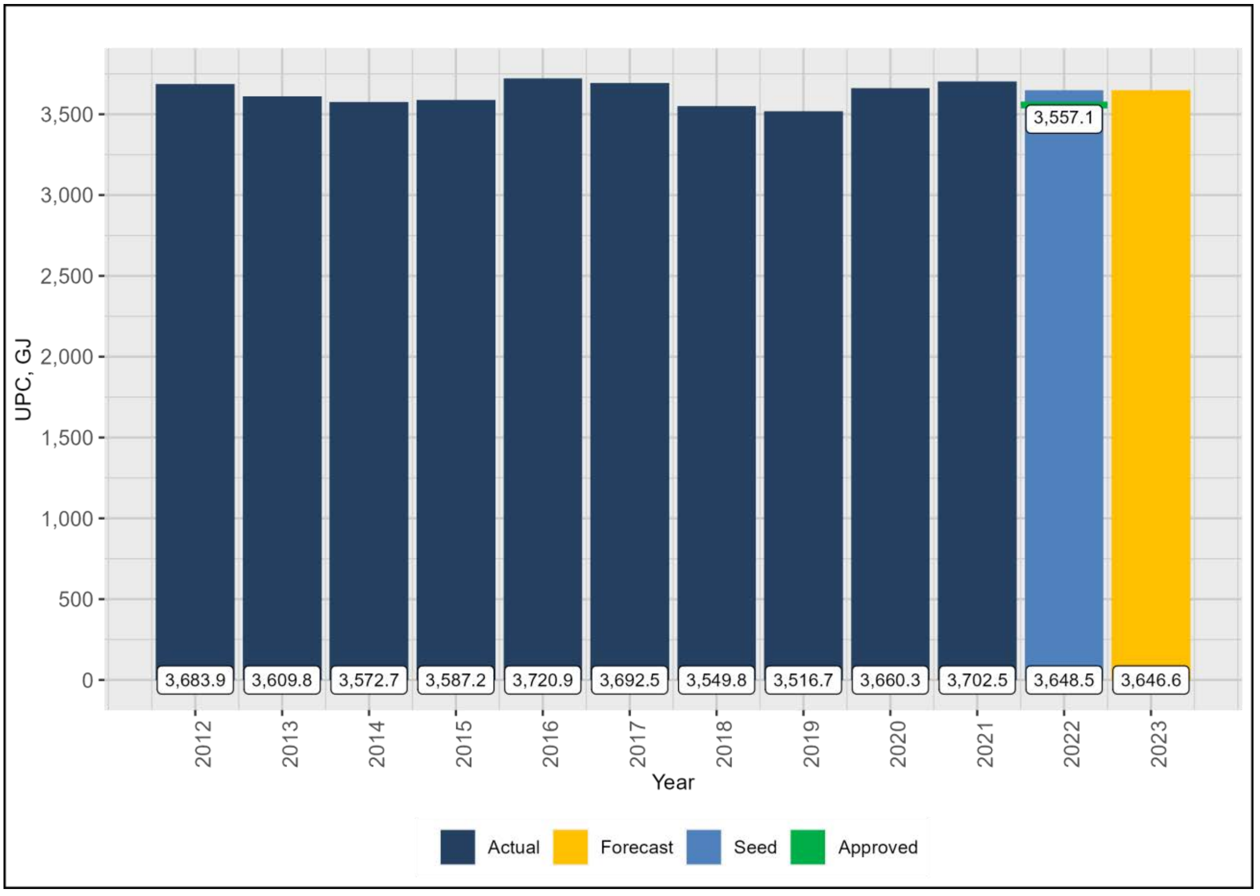
As shown in Figure 3-6, the Rate Schedule 2 UPC is forecast to decrease by 1.7 GJ in 2023F compared to 2022S.

Figure 3-6: Rate Schedule 2 UPC



As shown in Figure 3-7, the Rate Schedule 3 UPC is forecast to decrease by approximately 1.9 GJ in 2023F compared to 2022S.

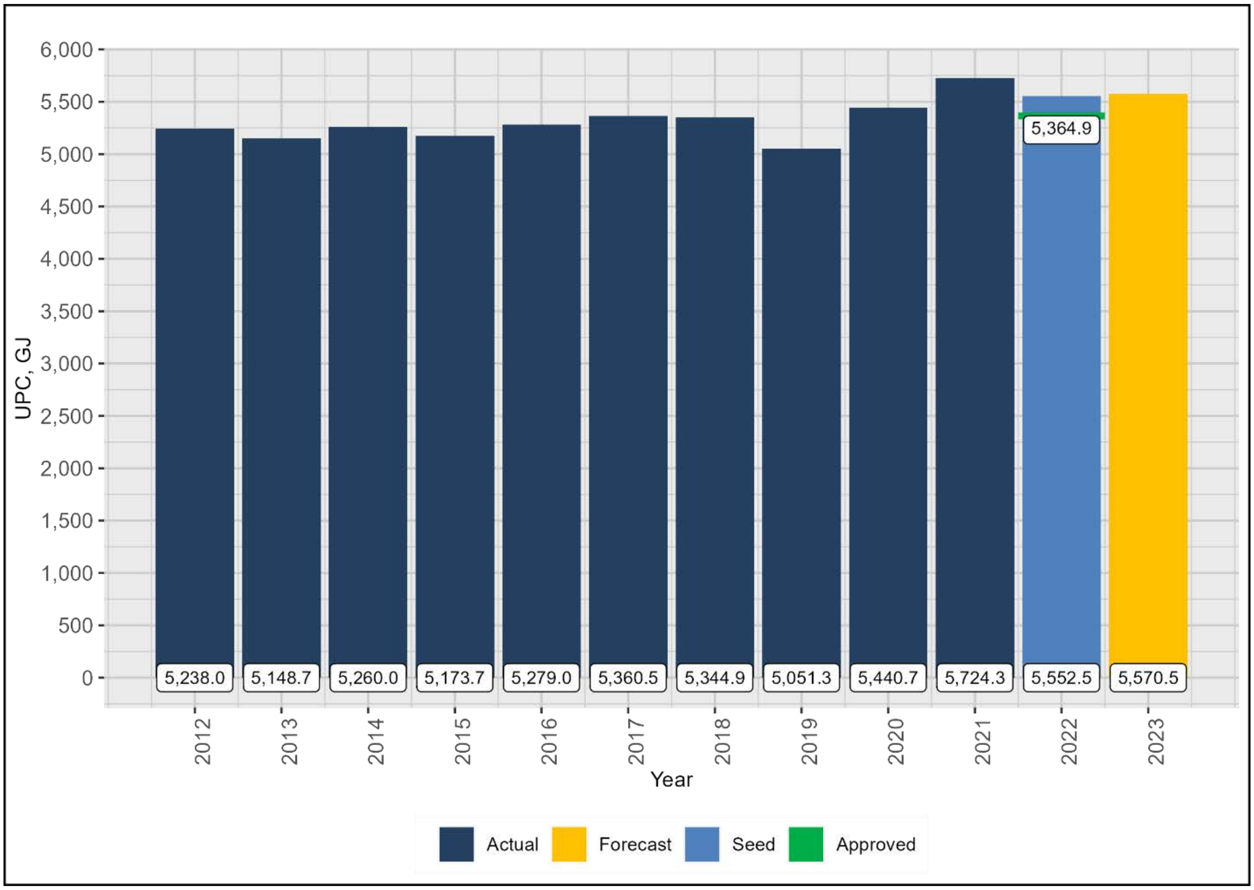
Figure 3-7: Rate Schedule 3 UPC[10]



As shown in Figure 3-8, the Rate Schedule 23 UPC is forecast to increase by 18.0 GJ in 2023F compared to 2022S.

[10] Excludes NGT customers under Rate Schedule 3.

Figure 3-8: Rate Schedule 23 UPC[11]

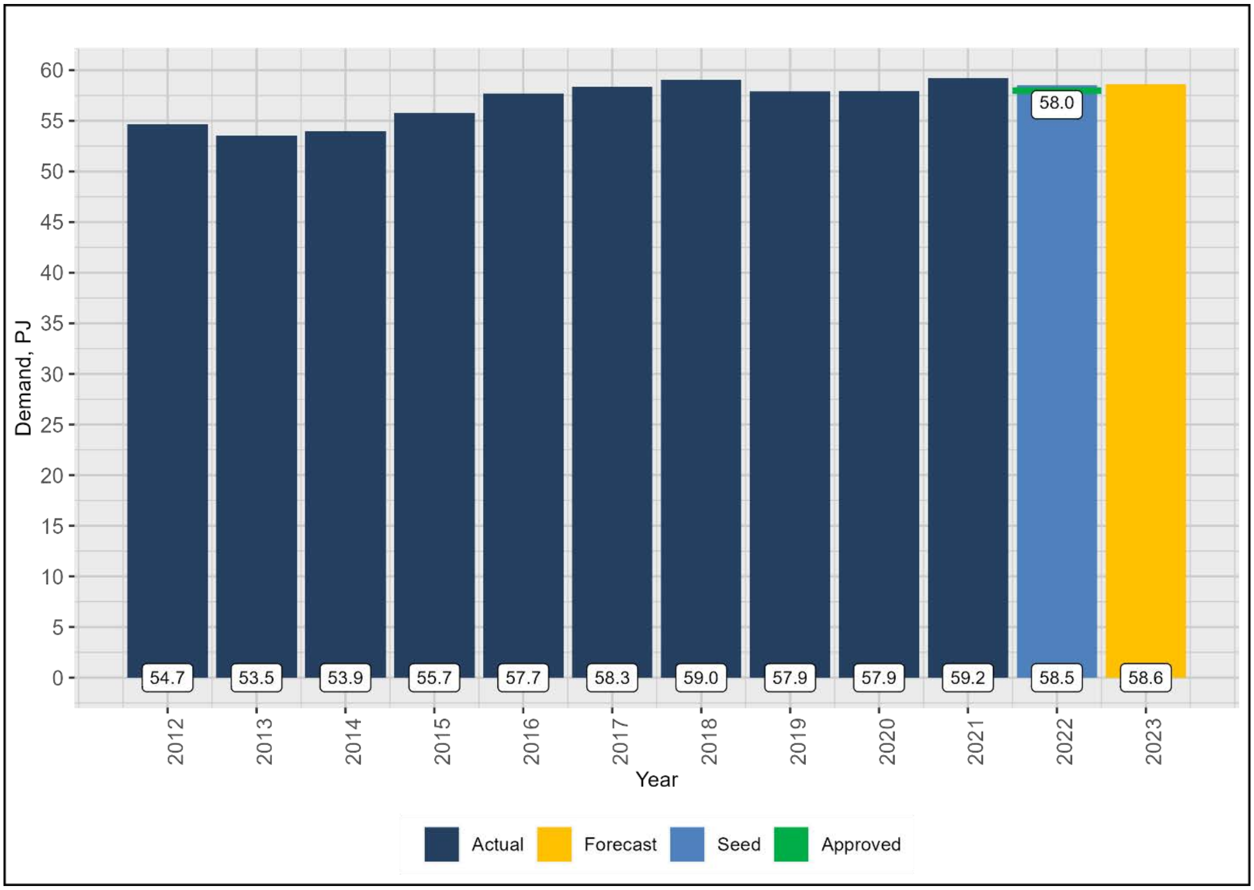


3.3.2.3 Commercial Demand

Taking into account the commercial customer additions and UPC forecasts described above, and as seen in Figure 3-9 below, commercial demand is forecast to increase by 0.1 GJ in 2023F compared to 2022S.

[11] Excludes NGT customers under Rate Schedule 23.

Figure 3-9: Commercial Demand[12]



3.3.3 Industrial Demand

The 2023F demand for industrial customers was forecast using the Industrial Survey.

For the 2023 Forecast, customers responded to the survey in May and June of 2022. The survey was launched as close as possible to the filing date to mitigate potential variances in the forecast. The survey needed to be completed by June 21, 2022 to allow sufficient time for internal review of the results, loading of data in FEI's Forecasting Information System (FIS), preparing the forecast and drafting the Application. Since the survey requires approximately five weeks to complete, it was launched on May 16, 2022.

As shown in Table 3-1 below, the response rate achieved in 2022 was 50.2 percent of industrial customers, representing approximately 90.4 percent of industrial volumes. There was no reply from 48.0 percent of industrial customers who received the survey after three reminder notifications; this group represents only 9.3 percent of the industrial demand. Surveys could not be delivered to 1.8 percent of the industrial customers due to issues such as incorrect email addresses; this group represents 0.3 percent of the total industrial demand.

[12] Excludes NGT customers under Rate Schedules 3 and 23.

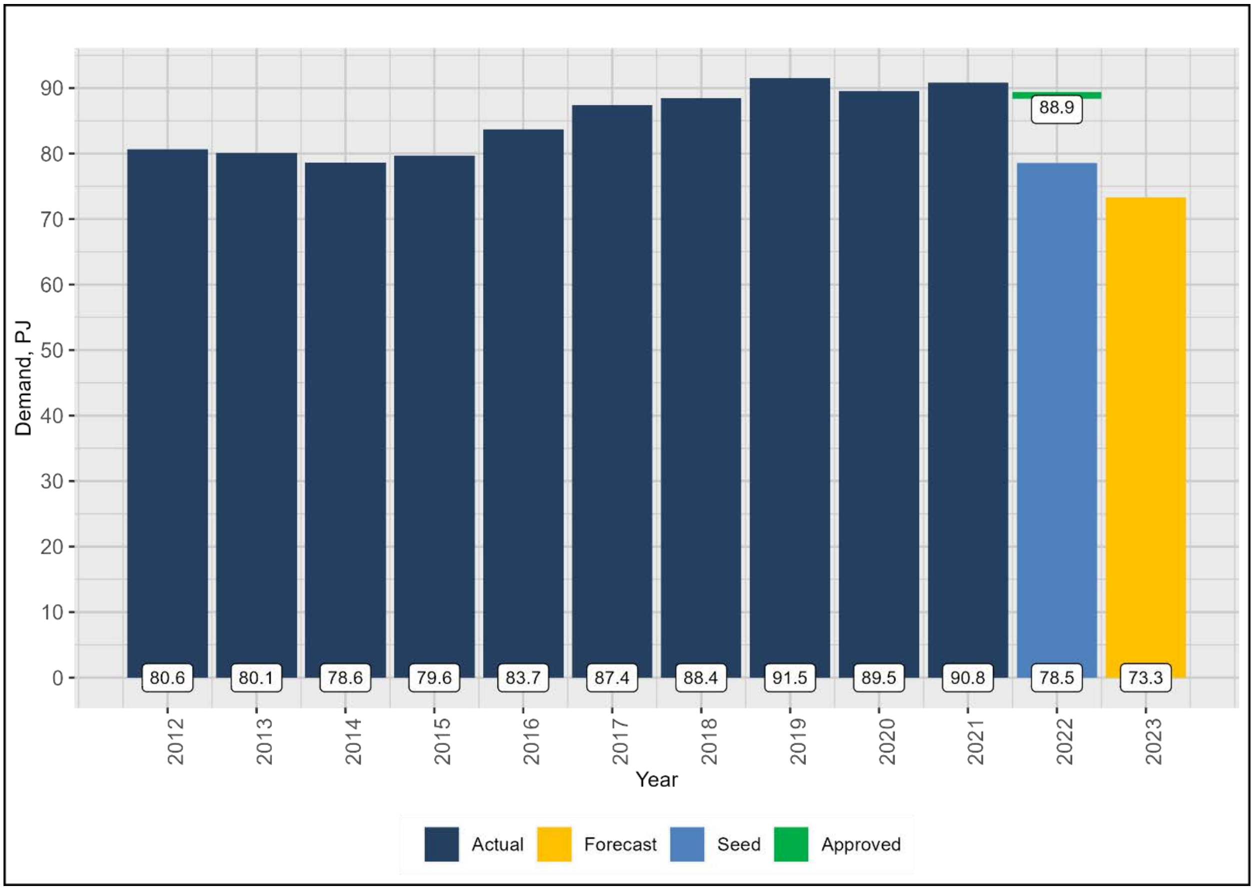
Table 3-1: Industrial Survey Response Rates

2022 Industrial Survey	Description	Customers	Demand
Survey Completed	The survey was delivered and completed.	50.2%	90.4%
Survey delivered but not completed	The survey was delivered, but after three follow-up emails was not completed.	48.0%	9.3%
Survey undeliverable	The survey was not deliverable. This can be a result of invalid email addresses, faulty email servers etc.	1.8%	0.3%
Total		100.0%	100.0%

The forecast of demand for customers that either chose not to reply to the survey or could not be contacted (representing 9.6 percent of the total industrial demand) was set to equal 2021 Actual consumption.

As shown in Figure 3-10 below, the demand from the industrial rate schedules is forecast to decrease by approximately 12.3 PJ in 2022S compared to 2021 Actual and to decrease by a further 5.2 PJ in 2023F when compared to 2022S. This decrease in demand is primarily due to FEI's contract with BC Hydro Island Generation (IG) expiring in April 2022, which had a contract demand of approximately 16.4 PJ. BC Hydro IG is now included in the 2023F as a fully interruptible RS 22 customer with a forecast minimum contract demand of 12 TJ per month (or 1.2 PJ per year).

Figure 3-10: Industrial Demand[13]



3.3.4 Natural Gas for Transportation and LNG Demand

This section summarizes the CNG and LNG demand forecasts related to demand from NGT customers for CNG and LNG, as well as non-NGT related demand for LNG supplied under Rate Schedule 46. Table 3-2 below provides the 2022 Approved, 2022 Projected and 2023 Forecast total NGT and non-NGT LNG demand. As directed by Order G-86-15, FEI has included the forecast of demand provided to customers under spot purchase agreements (i.e., not under firm take-or-pay commitments) in the total NGT and non-NGT LNG demand.

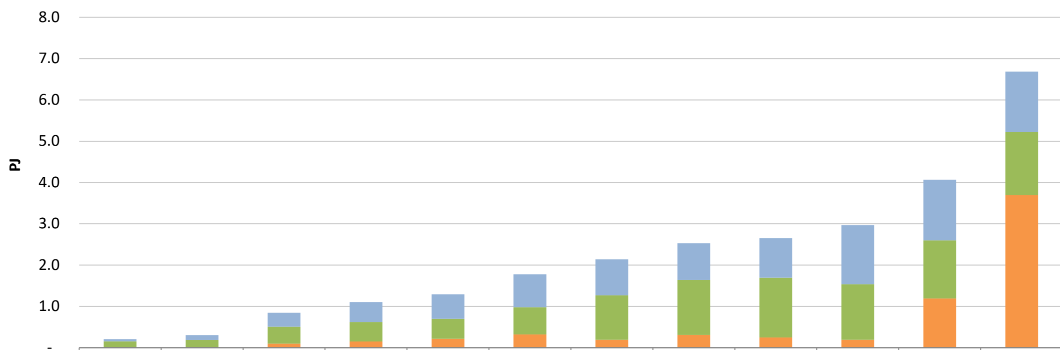
Table 3-2: FEI Total Natural Gas Demand for NGT and non-NGT LNG (GJ per year)

GJ	2022 Approved	2022 Projected	2023 Forecast
CNG	1,024,550	1,471,479	1,468,479
LNG	1,566,989	1,407,696	1,527,696
Total NGT Demand	**2,591,539**	**2,879,175**	**2,996,175**
Non-NGT Demand (export)	3,083,297	1,188,389	3,690,789
Total NGT and Non-NGT Demand	**5,674,836**	**4,067,564**	**6,686,964**

[13] Excludes NGT and non-NGT LNG customers under Rate Schedules 5, 25, and 46.

The following figure shows the 2012 Actual to 2021 Actual, 2022 Projected and 2023 Forecast annual demand for CNG (RS 3/5/23/25/6P) and LNG (RS 46), including a breakdown of LNG demand between NGT and non-NGT.

Figure 3-11: Actual (A), Projected (P) and Forecast (F) Demand for CNG & LNG[14]



	2012A	2013A	2014A	2015A	2016A	2017A	2018A	2019A	2020A	2021A	2022P	2023F
RS 3/5/23/25/6P - CNG (NGT)	0.1	0.1	0.3	0.5	0.6	0.8	0.9	0.9	1.0	1.4	1.5	1.5
RS 46 - LNG (NGT)	0.2	0.2	0.4	0.5	0.5	0.7	1.1	1.3	1.4	1.3	1.4	1.5
RS 46 - LNG (Non-NGT)	-	-	0.1	0.1	0.2	0.3	0.2	0.3	0.2	0.2	1.2	3.7
Total CNG & LNG	0.2	0.3	0.8	1.1	1.3	1.8	2.1	2.5	2.7	3.0	4.1	6.7

The 2022 Projected demand of 4.1 PJ is 1.1 PJ higher than the 2021 Actual demand of 3.0 PJ, as shown in Figure 3-11 above. This increase is primarily related to the projected increase in LNG (Non-NGT) export deliveries by ISO containers in 2022.

For 2023, CNG demand for NGT customers has remained consistent with the 2022 Projected level. The 2023F LNG demand for NGT customers is forecast to increase by 0.1 PJ from the 2022 Projected level, primarily due to an increase in LNG consumption from marine customers for 2023 as the one new BC Ferries vessel and two new Seaspan Ferries Corp vessels reach a full service schedule.

For non-NGT LNG demand, the 2023 Forecast represents an approximate 2.5 PJ increase from the 2022 Projected volume. FEI continues to have ongoing discussions with multiple potential customers, as global demand for North American LNG remains high as a result of continued easing of COVID-19 pandemic restrictions, geo-political concerns with energy supply from Russia, and rising LNG costs in Asia. While discussions with these potential customers are ongoing, no firm commitments for non-NGT LNG have been made. The main barriers for this demand to materialize continue to be congestion in shipping, and at ports and terminals. However, potential customers remain optimistic that these barriers can be overcome and remain confident in their ability to take supply in 2022 and beyond. FEI expects to secure firm contracts in 2022 as the winter energy demand in Asia increases.

[14] Forecast includes all NGT related CNG and LNG demand, and Other LNG demand, inclusive of contract and excess demand flowing through stations as well as spot volumes and third party station CNG/LNG volumes.

3.4 REVENUE AND MARGIN FORECAST

The forecast of revenues and margins has been developed by considering the total 2023 Forecast energy in GJ applied at 2022 Approved delivery rates and applicable 2022 Approved commodity and storage and transport rates (most recently approved commodity and storage and transport rates).

3.4.1 Revenue

Revenues are a function of both energy consumption and the rate applicable at the time the energy is consumed. FEI has developed its forecast of revenues by multiplying the energy forecast by the approved rates for each customer class.

Table 3-3 below summarizes the 2022 Approved, 2022 Projected and 2023 Forecast revenue, by customer segment, at currently approved 2022 rates.

Table 3-3: Forecast Sales Revenue at 2022 Approved Rates (Commodity, Midstream, and Delivery)

Revenue ($ millions)	Approved 2022	Projected 2022	Forecast 2023
Residential[1]	935.165	1,136.730	1,209.050
Commercial[2]	494.394	630.234	673.617
Industrial[3]	221.672	244.454	286.169
Total	**1,651.231**	**2,011.418**	**2,168.836**

Notes to table:

[1] Rate Schedule 1.

[2] Rate Schedules 2, 3, 23.

[3] Rate Schedules 4, 5, 6, 6P, 46, 7, 22, 25, 27, Joint Venture.

3.4.2 Margin

Margins are calculated by subtracting the cost of gas (discussed in Section 4) from the total revenues set out in Table 3-3 above.

Table 3-4 below summarizes the 2022 Approved, 2022 Projected and 2022 Forecast margin, by customer segment, at currently approved 2022 delivery rates.

Table 3-4: Forecast Gross Margin at 2022 Approved Delivery Rates

Margin ($ millions)	Approved 2022	Projected 2022	Forecast 2023
Residential[1]	589.064	592.272	596.381
Commercial[2]	269.840	271.488	271.822
Industrial[3]	144.357	125.270	132.805
Total	**1,003.261**	**989.030**	**1,001.008**

Notes to table:

[1] Rate Schedule 1.

[2] Rate Schedules 2, 3, 23.

[3] Rate Schedules 4, 5, 6, 6P, 46, 7, 22, 25, 27, Joint Venture.

Variances between the delivery margin forecast in this section and actual delivery margin are captured in either the RSAM deferral account if they relate to use rate variances for residential and commercial customers, or the Flow-through deferral account for all other variances.

3.5 SUMMARY

FEI's forecast of demand for natural gas is based upon methods that are consistent with those used in prior years and FEI's adoption of the ETS method which has been demonstrated to be superior to past practice as reported previously to the BCUC. FEI's forecast provides a reasonable estimate of future natural gas demand for 2023. Based on these methods, FEI is forecasting a decrease in consumption in 2023F of 12.8 PJ compared to the 2022 Approved level. Based on the 2022 Approved rates for each customer class, FEI's 2023 Forecast revenue is $2,169 million, which is an increase of approximately $518 million from the 2022 Approved amount.

4. COST OF GAS

The cost of gas includes the cost of the gas commodity, the cost of midstream resources (storage and transportation), and the Core Market Administration Expense (CMAE) costs associated with providing the gas supply function. With the exception of the CMAE costs, as further explained below and in Appendix B, the Company is not requesting approval of forecast gas costs within this Application. Instead, any rate changes related to the flow through of gas costs are dealt with in separate applications to the BCUC. Any variations between forecast and actual gas costs will continue to be returned to, or recovered from, customers through the existing deferral account mechanisms.

In compliance with the BCUC's determination in decision and Order G-79-14, FEI will be filing annually for approval of the CMAE budget as part of the Annual Review filings. Further, pursuant to the BCUC's direction in the FEI Annual Review for 2020 and 2021 Delivery Rates Decision and Order G-319-20, FEI will include a comprehensive review of the CMAE costs in its next revenue requirements or MRP application following the MRP term. Please see Appendix B for a detailed discussion of the CMAE budget. In summary, and as included in the Approvals Sought (Section 1.2) of the Application, FEI is requesting BCUC approval of the following related to CMAE, effective January 1, 2023:

- Approval of the 2023 CMAE Budget of $5.795 million, as set out in Schedule 1 of Appendix B; and
- Approval of the allocation of the 2023 CMAE between the Commodity Cost Reconciliation Account (CCRA) and the Midstream Cost Reconciliation Account (MCRA) based on the allocation percentages of 30 percent and 70 percent, respectively.

While the Company is not requesting approval of forecast gas costs (other than CMAE) with this Application, the forecast cost of gas is required in the determination of a number of revenue requirement line items that form part of the forecasts included in this Application. The total cost of gas for the purposes of this Application has been determined by multiplying forecast sales volumes using the demand forecast described in Section 3, by the current unit gas cost recovery charges for each rate schedule.

The natural gas commodity cost recovery rate for the Mainland and Vancouver Island service area became effective July 1, 2022 pursuant to Order G-154-22, dated June 9, 2022. The natural gas storage and transport rates and riders, also known as the midstream cost recovery rates and MCRA rate riders, for the Mainland and Vancouver Island service area became effective January 1, 2022 pursuant to Order G-354-21, dated December 2, 2021.

The table below sets out the forecast cost of gas at existing rates, by rate schedule group.

Table 4-1: Forecast Cost of Gas at Existing Rates [15,16]

Cost of Gas ($ millions)	Approved 2022	Projected 2022	Forecast 2023
Residential[1]	346.101	544.458	612.669
Commercial[2]	224.554	358.746	401.795
Industrial[3]	77.315	119.184	153.364
Total	**647.970**	**1,022.388**	**1,167.828**

Notes to table:

1 Includes Rate Schedules 1 volumes
2 Includes Rate Schedules 2, 3, 23 volumes
3 Includes Rate Schedules 4, 5, 6, 6P, 46, 7, 22, 25, 27 volumes

The 2022 Approved cost of gas was based on the commodity cost recovery rate effective July 1, 2021, which was $2.844 per GJ as approved by Order G-231-20. In comparison, the 2022 Projected cost of gas is based on the approved commodity cost recovery rate in effect for 2022, which is $4.503 per GJ as approved by Order G-354-21 for January to June 2022, and $5.907 per GJ as approved by Order G-154-22 for July to December 2022. The same rates have been applied in calculating the 2022 Approved and 2022 Projected revenues in Table 3-3 of Section 3.4.1, such that this variance does not impact the 2022 gross margin shown in Table 3-4 of Section 3.4.2. FEI also notes that the 2023 Forecast cost of gas is based on the current approved commodity cost recovery rate, which is $5.907 per GJ as approved by Order G-154-22 effective July 1, 2022.

The natural gas storage and transport, or midstream, component of the cost of gas includes the costs for the contracted third-party pipeline and storage resources, seasonal and peaking supply, and also includes costs for unaccounted for gas (UAF).

UAF refers to gas that is not specifically accounted for in gas energy balance of receipts, deliveries, and operations use. UAF includes measurement variances and line loss of gas that is flowing in the transmission and distribution systems. Sources of UAF comprise, but are not limited to, system leakage, lost gas (i.e., gas lost as a result of utility and third-party activities, including gas theft), and measurement inaccuracies. The cost of UAF related to the Sales rate classes is included in the cost of gas and recovered from core customers[17] via the gas cost rates. The cost of UAF related to the Transportation Service rate classes is included in the determination of the delivery rates to facilitate recovery of UAF costs from Transportation Service customers, as they do not pay midstream charges.

15 Biomethane commodity costs are excluded from the table because they are allocated directly to the Biomethane Variance Account (BVA).
16 Cost of gas from transportation customers (i.e., RS 22, 23, 25 and 27) is resulting from UAF.
17 Core customers are those for whom FEI is obligated to ensure the purchase, transportation, and uninterrupted delivery of natural gas to their premises.

5. OTHER REVENUE

5.1 INTRODUCTION AND OVERVIEW

This section discusses FEI's forecasts of Other Revenue. In the MRP Decision (page 74), the BCUC approved that forecast variances in certain components of Other Revenue were to be subject to earnings sharing. These components include Late Payment Charges, Application Charges, NSF Returned Cheque Charges, Other Recoveries, and NGT Overhead and Marketing Recoveries. The remaining components of Other Revenue continue to receive flow-through treatment of variances between forecast and actual results, consistent with the treatment during the 2014-2019 PBR Plan term.

As shown in the table below, FEI is forecasting Other Revenue to increase from the amount approved for 2022, primarily due to an increase in Late Payment Charges and NGT Related Recoveries. These increases are partially offset by decreases in Biomethane Other Revenue and SCP Third Party Revenue.

Table 5-1: Other Revenue Components ($ millions)

	Approved 2022	Projected 2022	Forecast 2023
Late Payment Charge	$ 2.704	$ 4.108	$ 3.364
Application Charge	2.013	2.001	2.016
NSF Returned Cheque Charges	0.028	0.028	0.028
Other Recoveries	0.288	0.288	0.288
NGT Related Recoveries	4.168	4.411	4.460
Biomethane Other Revenue	0.986	0.812	0.512
SCP Third Party Revenue	13.410	13.410	13.286
LNG Capacity Assignment	18.039	18.039	18.039
Total Other Operating Revenue	**$ 41.636**	**$ 43.097**	**$ 41.993**

In the following sections, FEI summarizes the methods used to forecast the line items included in the table above, and also addresses the largest components of Other Revenue, the SCP Third Party Revenue and the LNG Capacity Assignment.

5.2 OTHER REVENUE COMPONENTS

5.2.1 Late Payment Charge

Late Payment Charges have historically been forecast based on the average of the most recent three years of actual Late Payment Charges earned. However, due to a number of factors in the most recent years, including the COVID-19 pandemic and FEI's implementation of customer relief measures which included the suspension of Late Payment Charges until March 2021, the actual amounts collected have fluctuated significantly from year to year.

In addition to the impact of the COVID-19 pandemic, the amount of Late Payment Charges being collected for 2022 has been influenced by the impacts of the higher cost of gas and carbon tax on customers' bills. As Table 5-1 above shows, 2022 Projected is $1.404 million higher than 2022 Approved.

In consideration of the above-described factors, the 2023 Forecast has been calculated based on the average of 2021 Actual Late Payment Charges of $2.622 million and 2022 Projected of $4.108 million. This results in a forecast increase in Late Payment Charges of $0.660 million compared to 2022 Approved.

5.2.2 Application Charge

Application Charges are calculated based on the application fees specified in FEI's rate schedules applied to new customer connections or current customer reconnections. The 2023 Forecast amounts are expected to be in line with 2022 levels.

5.2.3 NSF Returned Cheque Charges and Other Recoveries

The 2023 Forecast amounts for NSF Returned Cheque Charges and other miscellaneous income items are based on 2022 levels.

5.2.4 NGT Related Recoveries

FEI has forecast recoveries associated with the NGT program related to the overhead and marketing charge that is applied to FEI fuelling station customers, tanker rentals from LNG customers, and CNG and LNG fuelling stations (CNG & LNG Service Revenues) as shown in Table 5-2 below. Variances between forecast and actual NGT Overhead and Marketing Recoveries are subject to earnings sharing. Variances in the NGT Tanker Rental Revenue and CNG & LNG Service Revenues are treated as Flow-through with the variances being captured in the Flow-through deferral account and the CNG & LNG Service Revenues deferral account, respectively.

Table 5-2: 2022 and 2023 NGT Related Recoveries ($ millions)

	Approved 2022	Projected 2022	Forecast 2023
NGT Overhead and Marketing Recovery	$ 0.283	$ 0.291	$ 0.273
NGT Tanker Rental Revenue	0.928	0.850	0.926
CNG & LNG Service Revenues	2.958	3.270	3.261
Total NGT Related Recoveries	**$ 4.168**	**$ 4.411**	**$ 4.460**

The following subsections discuss each of the NGT related recoveries.

5.2.4.1 NGT Overhead and Marketing Recovery

Pursuant to Order G-78-13, FEI has included a forecast of overhead and marketing (OH&M) recovery from FEI's NGT fuelling station customers. As shown in Table 5-3 below, the forecast NGT OH&M revenue for 2023 is $0.273 million. This revenue is calculated by multiplying the approved OH&M rate of $0.52 per GJ by the applicable[18] 2023 Forecast CNG and LNG sales volumes.

Table 5-3: NGT Overhead and Marketing Revenue Forecast ($ millions)

	2022 Approved	2022 Projected	2023 Forecast
Applicable Volume (GJ)	543,622	559,773	525,898
Rate ($/GJ)	$ 0.52	$ 0.52	$ 0.52
Total NGT OH&M Revenue ($ millions)	**$ 0.283**	**$ 0.291**	**$ 0.273**

5.2.4.2 NGT Tanker Rental Revenue

Table 5-4 below shows the tanker rental revenue for each type of FEI-owned tanker based on the currently approved RS 46 tanker rental rates.

Table 5-4: LNG Tanker Rental Revenue ($ millions)

	2022 Approved	2022 Projected	2023 Forecast
Standard Tanker Rental Deliveries	240	132	96
Rate ($/Delivery)	$ 301	$ 302	$ 308
Sub Total ($ millions)	$ 0.072	$ 0.040	$ 0.030
Tridem Tanker Rental Deliveries	-	-	-
Rate ($/Delivery)	$ 360	$ 361	$ 368
Sub Total ($ millions)	$ -	$ -	$ -
Marine Equipped Tridem Tanker Rental Deliveries	1,688	1,592	1,728
Rate ($/Delivery)	$ 507	$ 509	$ 519
Sub Total ($ millions)	$ 0.856	$ 0.810	$ 0.897
Total Tanker Rental Revenue ($ millions)	**$ 0.928**	**$ 0.850**	**$ 0.926**

For the Standard tankers, the 2022 Projected rental revenue is forecast to be lower than the 2022 Approved mainly due to the reduction of rental deliveries projected in 2022. For 2023, FEI is forecasting the Standard tanker rental revenue to decrease from the 2022 level, primarily due to a reduction in LNG vehicles on the road, as the existing heavy duty LNG engines have been discontinued, and there is not expected to be a replacement until 2024-2025 at the earliest.

For Tridem tankers, the 2022 Approved rental revenue is zero since these tankers are primarily used for long haul deliveries in Canada, such as to the Yukon, and these tankers are not permitted in the US (due to weight restrictions in the US). FEI does not expect Canadian deliveries to occur

[18] For host customers with CNG or LNG delivered through an FEI-owned CNG or LNG fueling station, the applicable volume for OH&M is limited to the contract minimum volume. For third-party fueling customers, all volume is applicable for OH&M.

outside of British Columbia and is therefore expecting the 2022 Projected and 2023 Forecast Tridem tanker rental revenue to be zero.

For the Marine tankers, the 2022 Projected rental revenue is forecast to be slightly lower than the 2022 Approved, as the number of rental deliveries decreased by 96. FEI expects that vessels which were previously delayed in their delivery will be commissioned in 2022 and 2023, resulting in an increase in 2023 Forecast deliveries. For 2023, FEI forecasts 136 additional marine tanker deliveries due to increased vessel consumption and additional vessels put into service.

5.2.4.3 CNG and LNG Service Revenue Forecast

The CNG and LNG Service Other Revenue forecast includes the FEI-owned CNG and LNG fuelling station recoveries (i.e., capital, O&M, and short-term fuelling rates) at the contracted minimum take-or-pay volumes of each station. Table 5-5 below provides a breakdown of the CNG and LNG fuelling station recoveries. The forecast of station recoveries as Other Revenue does not include recoveries from spot volume and excess volume (i.e., fuelling customer uses more than their contracted minimum take-or-pay volume).[19]

Table 5-5: CNG and LNG Fuelling Service Station Revenue Forecast ($ millions)

	2022 Approved	2022 Projected	2023 Forecast
CNG Station	$ 2.133	$ 2.561	$ 2.570
LNG Station	0.687	0.543	0.525
Subtotal - NGT Stations	**$ 2.820**	**$ 3.104**	**$ 3.095**
Surrey Ops CNG Pump	0.137	0.166	0.166
Total	**$ 2.958**	**$ 3.270**	**$ 3.261**

The 2022 Projected recoveries for CNG and LNG Stations are higher than the 2022 Approved levels by $0.284 million. This increase is primarily due to the projected increase in CNG Station revenue of $0.428 million related to the addition of two CNG stations for Annacis Island and GFL Abbotsford. However, this was offset by the closing of the Cool Creek LNG Fuelling station in early 2022. CNG Station recoveries are forecast to slightly increase in 2023 compared to 2022 Projected due to anticipated new CNG stations being put into service near the end of 2023. LNG Station revenues are forecast to decrease by $0.018 million in 2023 compared to 2022 Projected due to a reduction in LNG vehicles on the road as discussed in Section 5.2.4.2.

5.2.5 Biomethane Other Revenue

The Other Revenue amount of $0.512 million in 2023 shown in Table 5-1 above is the transfer from delivery margin to the Biomethane Variance Account (BVA) for the earned return and income tax components of the cost of service of the Biomethane capital assets.

[19] Station revenue recoveries from spot and excess volume are recorded in the CNG and LNG Recoveries deferral account. CNG and LNG Station recoveries under minimum take-or-pay contracts are recorded in Other Revenue.

In accordance with Order G-210-13, which approved the Biomethane Program on a permanent basis, the following delivery margin related costs must be included in the BVA:[20]

- Upgrading plant cost of service;
- Interconnection cost of service; and
- Program overhead costs.[21]

The 2023 Forecast amount is made up of $2.866 million for the earned return on biomethane assets currently and expected to be in-service in 2023, offset by an income tax credit amount of $2.354 million related to those biomethane assets. Biomethane upgrading assets have a high capital cost allowance of 50 percent which causes an income tax expense credit when the assets are first capitalized and depreciated for tax purposes. FEI has forecast the City of Vancouver upgrading assets, worth approximately $40.8 million (including AFUDC), to enter rate base in 2023 causing most of the income tax expense credit noted above.

5.3 *Southern Crossing Pipeline (SCP) Third Party Revenue*

The SCP Third Party Revenue includes the items shown in the table below.

Table 5-6: 2022 and 2023 SCP Revenue Components ($ millions)

	Approved 2022	Projected 2022	Forecast 2023
MCRA	$ 13.284	$ 13.284	$ 13.284
Net Other Mitigation - West to East Capacity	0.126	0.126	0.002
Total SCP Revenue	**$ 13.410**	**$ 13.410**	**$ 13.286**

The components of the SCP Third Party Revenues shown in Table 5-6 are discussed separately below. Any variance from the forecast SCP Third Party Revenues will continue to be recorded in the SCP Mitigation Revenues Variance Account and returned to or recovered from customers over a two-year period.

5.3.1 Midstream Cost Reconciliation Account (MCRA)

The Other Revenue of $13.284 million is related to the inclusion of the 105 MMcfd of SCP east to west capacity in the MCRA portfolio. As part of the FEI Annual Review for 2020 and 2021 Delivery Rates Decision and Order G-319-20, the BCUC approved, effective November 1, 2020, the

[20] The cost of procuring Biomethane supply does not need to be transferred because it is accounted for directly in the BVA.

[21] Program costs as defined in Order G-210-13 include education, marketing, direct administration, cost of enrollment and the cost of IT upgrades.

debiting of the MCRA and crediting of Other Revenue in the amount of $346.617 per MMcfd. This treatment is approved to remain in effect for the remainder of the MRP term.

5.3.2 Net Other Mitigation Revenue

The Company has been seeking, and will continue to seek, opportunities to contract the west to east capacity on the SCP.

The forecast mitigation revenue for the SCP west to east capacity for 2023 is based on the current forward market price differentials for summer 2023. FEI forecasts generating net mitigation revenue in the amount of $0.002 million in 2023.

The mitigation revenue generated from the SCP west to east capacity ties to market price differentials during the summer months and reflects the existing pipeline capacity within the region. The mitigation revenue forecast is net of the cost of using FEI gas supply resources, such as the Westcoast Energy Inc. Kingsvale South transportation capacity held in the midstream portfolio, to connect with the SCP system. The mitigation revenue net of the gas supply resource costs is allocated to Other Revenue.

5.4 *LNG CAPACITY ASSIGNMENT*

The $18.039 million in LNG capacity assignment Other Revenue shown in Table 5-1 above represents a transfer of costs from the delivery margin to gas costs reflecting the allocation of a portion of the Mt. Hayes LNG facility costs to gas costs.

The Mt. Hayes cost allocations were reviewed during the FEI 2016 Rate Design Application proceeding. The BCUC approved FEI's proposal to continue to allocate costs based on the Mt. Hayes LNG facility having a dual purpose serving as a gas supply storage facility and as a transmission facility providing additional transmission system capacity.[22]

5.5 *SUMMARY*

FEI has forecast the Other Revenue components for 2023 reflecting all applicable contracts and fixed revenues, and based on the Company's best knowledge of the factors that drive the variable components. Variances in Other Revenue are recorded in the SCP Mitigation Revenues Variance Account (for variances in the items discussed in Section 5.3), the Biomethane Variance Account (for variances in the items discussed in Section 5.2.5), the CNG/LNG Recoveries deferral account (for excess revenue from the CNG & LNG Service Recoveries forecast discussed in Section 5.2.4.3), and the Flow-through deferral account (for any remaining variances from forecast in Section 5.2.4.3 and all variances from forecast in Sections 5.2.4.2 and 5.4), with variances in the remaining items being shared with customers through the ESM.

[22] The cost allocation for the Mt. Hayes LNG facility was approved pursuant to Order G-4-18 and the Reasons for Decision attached as Appendix A, both dated January 9, 2018.

6. O&M EXPENSE

6.1 INTRODUCTION AND OVERVIEW

Under the MRP, FEI's O&M expense is primarily determined by formula, with the addition of a number of items that are forecast outside the formula on an annual basis.

In 2023, the Formula O&M is $297.920 million, representing a 4.5 percent increase from the 2022 Formula O&M, primarily due to the formula drivers. O&M expenses forecast outside the formula for 2023 are $55.292 million, representing a 15.0 percent increase from the amount approved for 2022. Overall, the increase in gross O&M expense from 2022 Approved to 2023 Forecast is 6.2 percent.

The components of 2023 O&M expense are shown in Table 6-1 below.

Table 6-1: 2023 O&M Expense ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Formula O&M	$ 284.961	$ 284.961	$ 297.920	Section 11, Schedule 20, Line 8
2	Forecast O&M	48.084	48.493	55.292	Section 11, Schedule 20, Lines 15 to 22
3	Prior year O&M True-up	0.258	0.258	0.740	Section 11, Schedule 20, Line 10
4	Total Gross O&M	333.303	333.712	353.952	Line 1 + Line 2 + Line 3
5	Capitalized Overhead (16%)	(53.328)	(53.328)	(56.632)	Section 11, Schedule 20, Line 27
6	Biomethane O&M transferred to BVA	(3.355)	(3.249)	(5.237)	Section 11, Schedule 20, Line 26
7	Net O&M	$ 276.620	$ 277.135	$ 292.083	Line 4 through 6

In the sections below, FEI provides further details on its formula and forecast O&M expenses for 2023. Additionally, in compliance with the BCUC's directive in the MRP Decision[23], FEI provides information related to its System Operations, Integrity and Security expenditures in Subsection 6.2.1.

6.2 FORMULA O&M EXPENSE

The formula-driven portion of O&M starts from the prior year's Approved Base O&M per Customer (UCOM), escalated by the prior year's inflation less a productivity improvement factor of 0.5 percent, and then multiplied by 75 percent of the forecast growth in average customers, resulting in the current year inflation-indexed O&M before true-up. A true-up of formula O&M based on actual average customers from two years prior is then added to the current year inflation-indexed O&M.

As calculated in Section 2, the 2023 inflation based on prior year's BC-CPI and BC-AWE, less the productivity improvement factor, is 4.080 percent.

[23] MRP Decision, p. 115.

For 2023, the annual operating and maintenance expense under the formula is calculated as:

> 2022 Approved formula UCOM x [1 + (I Factor – X Factor)] x [Prior Year Average Customers + (0.75 x growth in average customers)] + 2021 Formula O&M True-up

Table 6-2 below shows the calculation of the 2023 Formula O&M, including the calculation of the 2021 Formula O&M true-up. FEI notes the true-up of formula O&M is a two-year lag based on actual average customer counts from 2021.

Table 6-2: Calculation of 2023 Formula O&M ($ millions)

Line No.	Description	Forecast 2023	Reference
1	Prior Year Base Unit Cost O&M ($/customer)	$ 269	G-366-21 2022 FEI Annual Review Decision
2	I-Factor	4.080%	Section 2, Table 2-4
3	Current Year Unit Cost O&M ($/customer)	$ 280	
4	Average Customer Forecast	1,064,000	Section 2, Table 2-2
5	2023 Inflation-Indexed O&M before 2021 True-up	$ 297.920	Line 3 x Line 4
6	2021 True-up O&M	$ 0.740	Line 16
7	Inflation-Indexed O&M	$ 298.660	Line 5 + Line 6
8			
9	2021 O&M True-up		
10	2021 Actual 12 month Average Customers	1,057,086	FEI 2021 Annual Report
11	2021 Forecast 12 month Average Customers	1,053,292	G-319-20 2021 FEI Annual Review Decision
12	Difference	3,794	Line 10 - Line 11
13	Growth Factor	75%	G-165-20 MRP Decision
14	Change in Customers - True-up	2,845	Line 12 x Line 13
15	2021 Unit Cost ($/customer)	$ 260	G-319-20 2021 FEI Annual Review Decision
16	O&M True-up for 2023	$ 0.740	Line 14 x Line 15 / 1,000,000

6.2.1 New/Incremental System Operations, Integrity and Security Funding

In the MRP Decision (page 115), the BCUC directed FEI to provide in each Annual Review a breakdown and explanation of both annual and cumulative variances between forecast/actual and formula O&M related to the approved new/incremental System Operations, Integrity and Security funding, and quantify the variances attributable to the following areas: integrity management; maintaining system infrastructure; operations, compliance and safety; cyber security; data analytics; gas control; Canadian Energy Pipeline Association (CEPA) participation; and any other significant factors or miscellaneous items.

The table below shows the requested information, including the new/incremental funding in each category for 2021 Formula O&M, 2021 Actual O&M, and the resulting variances, as well as the Cumulative Forecast/Actual Variance for the first two years of the MRP.

Table 6-3: System Operations, Integrity and Security New/Incremental Spending ($ millions)

Line No.	Description	2021 Formula O&M[1]	Actual 2021 O&M	2021 Forecast/Actual Variance	Cumulative Forecast/Actual Variance[2]
1	Integrity Management	$ 1.426	$ 2.331	$ 0.905	$ 0.671
2	Maintaining System Infrastructure	$ 0.739	$ 0.790	$ 0.051	$ 0.064
3	Operations, Compliance and Safety	$ 0.634	$ 0.925	$ 0.291	$ 0.381
4	Cyber Security	$ 0.537	$ 0.537	$ -	$ 0.610
5	Data Analytics	$ 0.317	$ -	$ (0.317)	$ (0.624)
6	Gas Control	$ 0.687	$ 0.134	$ (0.553)	$ (1.217)
7	CEPA Participation	$ 0.739	$ 0.235	$ (0.505)	$ (0.745)
8	Other	$ -		$ -	$ -
9	Total	$ 5.078	$ 4.951	$ (0.127)	$ (0.861)

Notes to table:

[1] 2021 Formula O&M is the approved 2020 formula for incremental funding with Net Inflation factor applied (3.253%).

[2] Cumulative Forecast/Actual variance is the 2020 Actual variance plus the 2021 Actual variance.

Overall, total actual spending in 2021 was $4.951 million, which is $0.127 million lower than the 2021 Formula O&M amount. Areas with notable variances include integrity management, data analytics, gas control and CEPA participation.

For integrity management, FEI spent $0.905 million more than the formula amount for pipeline right-of-way activities, crossing assessments, and increased engineering technical studies (i.e., general studies, geohazard and seismic inspections and assessments) for maintaining the integrity of the pipeline delivery system.

Offsetting the higher costs in integrity management was the lower spending in data analytics, gas control and CEPA participation.

With regard to data analytics, FEI spent $0.317 million less than the formula amount in 2021 primarily due to labour savings from a delay in hiring. In 2021, FEI focused on finalizing the requirements for the necessary information infrastructure, with the implementation of the systems that will allow centralized data access occurring in 2022 and the addition of new data sources in priority sequence over the remaining term of the MRP.

For gas control and CEPA participation, FEI spent $1.058 million less than the formula amount in 2021 due to the timing of hiring gas controllers and the timing of control room management improvements. One gas controller was hired in 2021 and the plan is to hire one net new gas controller per year and to coordinate the timing of the new hires with retirements of existing employees. Also in 2021, FEI proceeded with implementing CEPA required control room management improvements and performed activities including CEPA assessments and other improvements due to non-CEPA drivers (e.g., regulatory requests, industry practice).

For the first two years of the MRP, FEI spent $0.861 million less than the formula amount. Over the term of the MRP, FEI anticipates that the total new/incremental spending required in the combined categories of System Operations, Integrity and Security will be relatively close to the cumulative formula-based amounts, although there will continue to be variations from year to year.

6.3 O&M EXPENSE FORECAST OUTSIDE THE FORMULA

In addition to FEI's formula O&M, FEI forecasts a number of O&M items outside of the formula annually, including pension and OPEB expense, insurance, integrity, BCUC levies, and O&M supporting Clean Growth initiatives, as well as any exogenous factors. These amounts are shown in Table 6-4 below along with a comparison to 2022.

Table 6-4: 2023 Forecast O&M ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Pension/OPEB (O&M Portion)	$ 9.537	$ 9.537	$ 9.544
2	Insurance	11.474	11.552	12.242
3	Integrity O&M	5.700	6.000	8.000
4	BCUC Levies	7.408	7.408	8.473
5	**Clean Growth Initiatives:**			
6	Biomethane O&M	3.355	3.249	5.237
7	Renewable Gas Development	1.000	1.750	2.000
8	NGT O&M	2.057	1.944	1.937
9	Variable LNG Production Costs	7.553	7.053	7.859
10	Forecast O&M	$ 48.084	$ 48.493	$ 55.292

Each of the items that is forecast outside of the formula is discussed below. Variances in pension and OPEB expenses are captured in the Pension and OPEB Variance deferral account and amortized into rates over a three-year period, as approved by the BCUC in Order G-138-14. Variances in BCUC fees are captured in the BCUC Levies Variance deferral account and amortized into rates in the subsequent year. Variances in insurance, integrity, Clean Growth initiatives and exogenous factors are captured in the Flow-through deferral account.

6.3.1 Pension and OPEB Expense

Pension and OPEB expense for 2023 is based upon actuarial estimates using a range of assumptions as of December 31, 2021 with an update of discount rate estimates as of April 30, 2022 provided by the Company's external third-party actuary, Willis Towers Watson. The discount rate determined reflects the market yields of high quality Canadian corporate bonds which have increased since 2021. In addition to O&M, pension and OPEB expense is embedded in Capital Expenditures, Asset Removal Costs, and Core Market Administration Expense (CMAE) categories, as shown in Table 6-5.

Table 6-5: Pension and OPEB Expense ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	O&M	$ 9.537	$ 9.537	$ 9.544
2	Capital - Growth	1.693	1.693	1.034
3	Capital - Other (Approved)	3.275	3.275	3.045
4	Capital - Other (to Pension & OPEB Variance Deferral)[1]	1.712	1.712	-
5	Deferral - Asset Removal Costs	1.967	1.967	1.201
6	Deferral - CMAE	0.595	0.595	0.363
7	Total	$ 18.779	$ 18.779	$ 15.187

Notes to table:

[1] This line item represents the pension and OPEB expense difference between the estimates embedded in the Regular Sustainment and Other Capital expenditure forecasts on Line 3 in this table, which were based on the pension and OPEB actuarial estimates provided in 2019 as part of the 2020 to 2024 MRP Application, and the actuarial estimates updated for 2023 rate-setting purposes. There is no difference for 2023 since FEI has filed updated forecasts of the 2023 and 2024 Regular Sustainment and Other Capital Expenditures in this Application, as directed in the MRP Decision and Order G-165-20.

The variance between the 2022 Approved and actual pension and OPEB expense, including the known capital variance on Line 4 of Table 6-5 above, and any variance between the 2023 Forecast and actual amounts, is included in the Pension and OPEB Variance deferral account and amortized into rates over a three-year period, as approved by Order G-138-14.

The 2023 Forecast pension and OPEB expense has decreased by $3.592 million compared to the 2022 Approved expense primarily due to the following factors, which are all components of pension and OPEB expense:

- An approximate $9 million decrease due to an increase in amortization of actuarial gains and a decrease in current service costs, which are primarily due to an increase in the discount rate. The discount rate, which is determined with reference to the market rate of interest on high quality debt instruments at a point in time, increased from 3.5 percent, which was used to determine the 2022 Approved expense, to 4.5 percent, which is used to determine the 2023 Forecast expense; and
- An approximate $2 million decrease due to an increase in investment returns as a result of a higher balance of pension plan assets;

offset in part by:

- An approximate $8 million increase in interest costs due to an increase in the discount rate.

6.3.2 Insurance Expense

Insurance expense relates to the insurance premium expense allocated to FEI by Fortis Inc. as set out in Table 6-6 below.

Table 6-6: Insurance Expense ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Insurance Premiums	$ 11.474	$ 11.552	$ 12.242	Section 11, Schedule 20, Line 16
2	Total	$ 11.474	$ 11.552	$ 12.242	

The 2022 Projected insurance premium expense of $11.552 million is $0.078 million higher than 2022 Approved, as it incorporates the first six months of FEI's actual July 2022 to June 2023 insurance renewals of $11.943 million. The higher premiums experienced in 2022 are expected to continue into 2023, though at a lower rate of increase. The 2023 Forecast is $12.242 million, which is an increase of $0.690 million from 2022 Projected. The 2023 Forecast is calculated as the amount of the first six months of actual annual insurance premiums for January to June 2023 of $5.972 million and applying a 5 percent increase for the remaining six months.[24]

6.3.3 Integrity O&M

In the MRP Decision and Order G-165-20,[25] the BCUC approved the treatment of integrity digs as a flow-through item with variances between forecast and actual amounts captured in the Flow-through deferral account. Further, since the MRP Decision the BCUC has approved CPCNs for two integrity-driven projects: the IGU Project and the CTS TIMC Project. In these two CPCN applications FEI identified the need for changes to O&M associated with these projects and has included these incremental expenditures in the 2023 Forecast. As approved in the MRP Decision,[26] these expenditures also fall outside of the formula O&M.

The 2023 Forecast for integrity digs is $7.0 million, which is an increase of $1.3 million from 2022 Approved and $1.0 million from 2022 Projected. Additionally, FEI is forecasting $1.0 million in 2023 for incremental integrity activities related to the IGU and CTS-TIMC projects. Each of these areas is discussed below.

6.3.3.1 Integrity Dig Expenditures

FEI provides the following update and forecast of its integrity dig expenditures.

Table 6-7 below provides the forecast number of integrity digs with Reason for Dig categories as well as the total cost and cost per dig. The table identifies integrity digs associated with inline inspection (ILI) activities (lines 1 to 3), and digs resulting from other reasons (lines 4 and 5).

[24] $11.943 million/2 = $5.972 million x 1.05 = $6.270 million. $5.972 million + $6.270 million = $12.242 million.
[25] MRP Decision, p. 74.
[26] MRP Decision and Order G-165-20, pp. 132-133.

Each of the drivers for integrity digs have significant uncertainty with respect to the number and cost of integrity digs that continues to support the Flow-through treatment of these costs. A discussion of each Reason for Dig follows the table.

Table 6-7: Integrity Digs – Activities and Expenditures

Line No.	Reason for Digs	Number of Digs per Year				
		2020 Actuals	2021 Actuals	2022 Approved	2022 Projected	2023 Forecast
1	**ILI Digs – New Tool(s):** ILI digs attributed or projected due to an inspection with an ILI technology or ILI tool that has not been previously run in a given pipeline segment[1]	27	13	40	22	50
2	**ILI Digs – New Practice(s):** ILI digs attributed or projected due to changes to industry practices or standards (e.g., strain-based criteria for dent digs) requiring a corresponding change from FEI's past integrity dig practices[2]	47	25	20	15	30
3	**ILI Digs – Established Tools and Practices:** ILI digs identified through previously established technologies, tools, and practices[3]	45	87	80	65	40
4	**Non-ILI Digs:** Digs identified through above-ground cathodic protection and coating surveys	27	17	15	17	20
5	**Facilities Digs:** Digs identified on piping within facilities (e.g., control stations, regulator stations, compressor stations) through assessment of available design, construction, operations, and maintenance information.	0	0	0	1	5
6	**Total Integrity Digs**	**146**	**142**	**155**	**120**	**145**
7	Total Integrity Dig Expenditures ($ millions)	5.9	7.2	5.7	6.0	7.0
8	Cost per dig ($000s)	40	51	37	50	48

FEI's forecast related to **ILI Digs – New Tools** is primarily an estimate of the integrity digs resulting from first-time in-line inspections associated with the IGU Project.[27] FEI has reduced its 2022 Projection for number of digs in this area due to the timing of in-line inspections as well as FEI's expectations of pipeline conditions. FEI's 2022 Projection also includes five integrity digs associated with FEI's ongoing analysis of first-time EMAT[28] (crack-detection) in-line inspection data collected as part of the CTS-TIMC EMAT pilot project (see Sections 3.3.3 and 5.3.3 of the CTS-TIMC CPCN Application for details of the pilot project). The 2023 Forecast number of digs

[27] FEI Application for a CPCN for the IGU Project Decision and Order G-12-20.

[28] EMAT refers to electro-magnetic acoustic transducer in-line inspection technology which is typically employed to detect cracks in pipeline walls and seam welds.

in this category is higher than prior years due to the additional length of pipeline that is becoming capable of ILI inspection as the IGU Project progresses, and hence will result in additional integrity digs to verify the new ILI data and conduct any needed repairs.

FEI's forecast related to **ILI Digs – New Practices** continues to be influenced by the required adoption of the strain-based criteria for dents in current industry practice and standards. FEI is assessing the need for, feasibility, and implications of modified dent repair methods which may impact the schedule and cost of digs reported in this category. Further, FEI has recently been observing an increasing number of necessary repairs to address pipeline dents which is leading to a higher forecast for 2023 in this category compared to 2021 and 2022.

FEI's forecast related to **ILI Digs – Established Tools and Practices** results from FEI's analysis of its existing technology (i.e., non-EMAT) tool runs, which are currently scheduled on a maximum seven-year interval but may vary from year to year. As other tool technologies (e.g., EMAT) become established and included in a similar re-run schedule, FEI's estimates of ongoing ILI digs will also include integrity digs identified through those tools. The 2023 Forecast for the number of digs in this category shows a decrease, attributed to fluctuating factors such as the number of inspections and ILI assessment results.

FEI's forecast related to **Non-ILI Digs** reflects assessments of transmission pipelines for which in-line inspection tools are not currently proven, commercialized, and adopted and hence are identified through other methods (such as cathodic protection surveys). The number of these digs is expected to vary depending on the survey results from the previous year(s).

FEI's forecast related to **Facilities Digs** reflects FEI's prior indication in the MRP Application[29] that it needs to expand its current Integrity Management Program (IMP) for pipeline assets to include facilities (e.g., compressor stations and control stations). This includes performing asset condition assessments of buried facilities piping. FEI's assessments have identified the need for integrity digs in facilities beginning in 2022, which resulted in this new Reason for Dig category. Consistent with its practices for assessing linear pipeline assets, this category of digs includes underground piping within facilities that is capable of failure by rupture, but is not capable of ILI inspection. FEI's forecast for the number of digs in this category for 2023 will inspect facilities piping that has been prioritized on the basis of factors including construction (e.g., age, expected external coating) and operating characteristics (e.g., station criticality, operating stress).

As noted, FEI continues to experience a range of scope and costs associated with its 2022 year-to-date integrity digs. Factors that impact dig costs include site access, site management during the dig, site restoration, and pipeline repairs (if necessary). The increase in the 2022 Projected average cost per dig is attributed to factors including more challenging locations and steep-slope engineering costs experienced in 2022. For 2023, the average cost per dig is close to that experienced in 2021 and projected for 2022, and incorporates experience from prior years, while

[29] MRP Application, Section 2.4.2.3.4, page C-38, ll. 5-9.

also reflecting fluctuations due to year-to-year variability in dig categories and the geographic locations of the digs.

6.3.3.2 CPCN-related Integrity Expenditures

FEI is forecasting a total of $1.0 million in incremental integrity management costs due to increased integrity-related activities such as ILI data collection and analysis (as a result of the ongoing IGU project), and development of a sustainable quantitative risk assessment process (QRA) for FEI's transmission pipelines (as identified in the CTS-TIMC project CPCN application).

6.3.3.2.1 INLAND GAS UPGRADES PROJECT

In 2020, the BCUC approved a CPCN for the IGU project (Order G-12-20). This project includes system modifications to allow for ongoing ILI of 11 laterals, pipeline replacement for 4 laterals, and installation of a pressure regulating station for 14 laterals.[30] As FEI explained in the CPCN proceeding, incremental operating costs are associated with both the ongoing ILI activities and pressure regulating station aspects of the project.[31]

As the IGU project nears completion, laterals have been becoming available for ILI, beginning in 2022 (see Section 7.2.3.2 of this Application for further details). In 2022, FEI inspected two laterals using ILI, and although there remains some schedule uncertainty, FEI is projecting that approximately half of the 11 laterals where ILI capability will be provided will have their tool runs completed by 2023. Ongoing data assessments and analysis of the information collected from these newly ILI-capable pipelines is the most significant driver of the incremental O&M, as detailed in Appendix E of the IGU project CPCN application. Engineering resources are involved in the various steps, with the most significant effort occurring during the data analysis phase (Section 1.6 of Appendix E).

For 2023, FEI is forecasting $0.300 million in incremental O&M resources associated with the IGU project. These costs are associated with performing engineering analysis of ILI data as well as planning and implementing operational responses (such as identifying future integrity digs, or other monitoring activities).

6.3.3.2.2 COASTAL TRANSMISSION SYSTEM TRANSMISSION INTEGRITY MANAGEMENT CAPABILITIES PROJECT

In 2022, the BCUC approved a CPCN for the CTS-TIMC project (Order C-3-22). This project will provide the ongoing ability to run crack-detection EMAT ILI tools in 11 CTS pipelines, as well as the installation of a pressure regulating station on a single segment of one of the pipelines where crack-detection ILI is not possible.

As discussed in the CTS-TIMC CPCN application, FEI is also establishing a sustainable and ongoing process to allow FEI to periodically conduct a QRA on its transmission pipelines.[32] The

[30] Decision and Order G-12-20, Section 5.1, Table 3, p. 25.
[31] Exhibit B-5, FEI Response to CEC IR1 31.2.
[32] Exhibit B-11, FEI Response to BCUC IR2 38.1.

QRA submitted as part of the CTS-TIMC application was the first iteration of FEI's QRA. As explained during the CTS-TIMC proceeding, FEI is transitioning to performing future iterations of the QRA using internal resources.[33] FEI is implementing a software tool for performing QRAs during 2022 (these costs are included in the approved Information Systems capital budget), and plans to perform its second iteration of a QRA by the end of 2023.[34] FEI's implementation of a QRA of its transmission pipelines has been, and will continue to be, iterative in that FEI is allowing for the data and learnings from previous steps to inform the next steps in its integrity planning.[35] Over time, FEI intends to complete ongoing QRAs for each of its three transmission systems (the Coastal, Interior and Island transmission systems).

Next steps currently include: defining and establishing capabilities for ensuring that suitable and validated data inputs are fed into the risk model; defining and establishing capabilities for assessing risk for all in-scope assets; and driving risk-informed and risk-based decisions. These capabilities exceed FEI's existing integrity management resources and will require FEI to recruit and retain additional specialist technical and engineering personnel. Given the highly specialized nature of these roles, long lead times are necessary to secure or develop employees with the required engineering competencies.

For 2023, FEI is forecasting $0.700 million in incremental O&M primarily associated with securing additional engineering resources to develop and implement the next QRA iteration. FEI will identify any incremental costs for further developing and implementing the QRA process in future rate applications, as well as incremental resources associated with the increased ILI program scope.

6.3.4 BCUC Levies

FEI's 2023 Forecast for BCUC levies is $8.473 million. The 2023 Forecast is based on Order G-188-22 for the BCUC's Fiscal 2022/23 year, which represents the best information available at this time, as the BCUC levy calculation for Fiscal 2023/24 will not be available until early or mid 2023.

BCUC levies receive flow-through treatment, with annual variances between actual and forecast amounts in O&M expense being recorded in the BCUC Levies Forecast Variance deferral account and amortized over one year.

6.3.5 Clean Growth Initiative - Biomethane O&M

A summary of the Biomethane O&M, by project, is provided in Table 6-8 below:

[33] Exhibit B-5, FEI Response to BCUC IR1 1.5.
[34] Exhibit B-11, FEI Response to BCUC IR2 38.2 and 38.2.2.
[35] Exhibit B-11, FEI Response to BCUC IR2 38.2.

Table 6-8: Biomethane O&M by Project ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Program Overhead	2.617	2.502	2.648	
2	City of Surrey	0.010	0.010	0.010	
3	Kelowna	0.502	0.521	0.512	
4	Salmon Arm	0.196	0.179	0.200	
5	Fraser Valley Biogas	0.010	0.012	0.012	
6	Seabreeze Farms	0.010	0.012	0.012	
7	Lulu Island WWTP	0.010	0.012	0.012	
8	Dickland Farms	-	0.001	0.012	
9	City of Vancouver	-	-	0.340	
10	Capital Regional District	-	-	0.004	
11	Net Zero Waste	-	-	0.009	
12	Delta RNG (MAS Energy)	-	-	1.467	
13	Total Biomethane O&M	3.355	3.249	5.237	Section 11, Schedule 20, Line 17

The 2022 Projected Biomethane O&M is expected to be close to 2022 Approved. The 2023 Forecast Biomethane O&M is $5.237 million. This increase is primarily a result of an expected increase of $1.467 million for the Delta RNG (MAS Energy) project and an expected increase of $0.340 million for the City of Vancouver biomethane production project. These projects are anticipated to commence production in early and late 2023, respectively.

As approved by Order G-133-16, Biomethane O&M is transferred to the Biomethane Variance Account (BVA). The net-of-tax year-end BVA balance, after adjustment for the value of unsold biomethane quantities, is amortized/transferred to the BVA Rate Rider Account for recovery from, or refund to, all non-bypass customers via the BVA Rate Rider in the subsequent year, as described further in Section 10.3.1.

6.3.6 Clean Growth Initiative – Renewable Gas Development

Table 6-9: Renewable Gas Development O&M ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Renewable Gas Development	1.000	1.750	2.000	Section 11, Schedule 20, Line 21
2	Total	1.000	1.750	2.000	

In order to support the continued growth of the renewable gas portfolio, including the incorporation of other renewable gases such as hydrogen, synthesis gas (syngas) and lignin, FEI requires resources within its Renewable Gas team to work on safety, codes and standards, and for feasibility work more generally.

In May 2021, the Provincial government issued an amendment to the GGRR that forms the basis for FEI's acquisition of renewable gas. The amendment expanded the amount of renewable gas that can be acquired from 5 to 15 percent and enabled FEI to acquire hydrogen, syngas and lignin, in addition to biomethane. The policy initiatives expand the resources that are required to support renewable gas development.

For 2022, FEI projects to spend approximately $1.750 million, which is an increase of $0.750 million compared to the 2022 Approved amount. These costs are for activities and feasibility work related to developing the supply of renewable gases, including hydrogen, into the program. Such activities include investigating the feasibility of pursuing the development of facilities to produce renewable and low-carbon hydrogen, feasibility and system readiness assessments to distribute hydrogen, end-use impacts, and customer and stakeholder education that will enable the safe distribution and customer end-use of hydrogen. The 2022 Projected O&M costs include the addition of two incremental labour resources and the increased use of external consultants to successfully execute on planned activities to meet business goals and objectives. Actual expenditures in 2022 may vary from that projected depending on the timing of the completion of work required and renewable gas development opportunities.

The 2023 Forecast O&M is approximately $2.0 million, which is an increase from the 2022 Projected amount, and is related to requirements to continue work on project feasibility, safety, codes and standards, and business development. In addition to the work identified above, FEI is seeing the need to support Indigenous groups that are exploring the production of renewable gases in their communities. FEI requires funding to hire internal resources to work with Indigenous groups on the evaluation of opportunities. FEI expects the Renewable Gas Clean Growth Initiative to be an area that will continue to grow as FEI's supply of renewable gas increases to meet provincial targets.

6.3.7 Clean Growth Initiative - NGT O&M

NGT O&M is comprised of O&M expenses related to the operation of the FEI-owned CNG and LNG fuelling stations and FEI-owned LNG tankers available for rental to LNG customers. Table 6-10 below summarizes the NGT O&M.

Table 6-10: NGT O&M ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	CNG Stations	1.090	0.990	0.980	
2	LNG Stations	0.282	0.269	0.272	
3	LNG Tankers	0.615	0.615	0.615	
4	Emergency Response and Preparedness (ERAP)	0.070	0.070	0.070	
5	Total NGT O&M	2.057	1.944	1.937	Section 11, Schedule 20, Line 18

The 2022 Projected O&M expense is approximately $0.113 million lower than 2022 Approved. This is primarily due to one customer, Waste Management, exercising their option to purchase their CNG station from FEI in 2022.

The 2023 Forecast NGT O&M expense is consistent with the 2022 Projected amount. NGT O&M has remained relatively consistent since March 31, 2022[36], representing the end of the time period under the GGRR for customer incentives for CNG and LNG vehicles and infrastructure.

[36] Greenhouse Gas Reduction (Clean Energy) Regulation, Section (2)(a).

6.3.8 Clean Growth Initiative - Variable LNG Production Costs

For the MRP, LNG O&M costs are allocated between formula and forecast (flow-through) O&M based on whether they are fixed or variable costs. Fixed costs represent the fixed costs to operate the LNG plant, regardless of its use (for peak shaving storage, or LNG production for sales). The remaining portion of total LNG O&M costs is treated as flow-through outside of formula O&M. These costs represent the variable costs for the production of LNG (liquefaction of natural gas, the dispensing of LNG, the handling and loading of tankers with LNG, etc.) where the costs fluctuate and are dependent on sales volumes.

A table breaking out the various components of the Variable LNG Production Costs is provided below.

Table 6-11: Variable LNG Production O&M ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Tilbury Plant:			
2	Labour	1.706	1.506	1.775
3	Materials	0.765	0.715	0.794
4	Contractor	0.612	0.612	0.637
5	Power	3.492	3.242	3.634
6	Fees and Employee Expenses	0.319	0.319	0.332
7	Sub-total	6.893	6.393	7.172
8	Mt. Hayes Plant			
9	Labour	0.325	0.325	0.339
10	Materials	0.027	0.027	0.028
11	Contractor	0.057	0.057	0.060
12	Power	0.251	0.251	0.261
13	Fees and Employee Expenses	0.000	0.000	0.000
14	Sub-total	0.660	0.660	0.687
15	Total O&M	7.553	7.053	7.859

The Variable LNG Production O&M expense required for operation of the expanded Tilbury LNG facility[37] and the Mt. Hayes LNG facility consists of variable labour, materials, certain contractor costs, power to run the plants, and employee expenses for the employees included in variable labour, as set out in the MRP Application (page C-25). The definition of variable costs was also outlined in the response to BCUC IR2 173.4 as part of the MRP proceeding.

Included in the variable labour is the following: LNG operators for truck loading and shunting of LNG; millwrights and electrical and instrumentation technicians to support production-related maintenance activities; and operations management personnel to oversee activities. In 2022, timing of new hires to support LNG loading is expected to contribute to lower labour costs

[37] The expanded LNG facility includes the Phase 1A facilities defined in Direction No. 5 to the BCUC, B.C. Reg. 245/2013, as amended by B.C. Reg. 265/2014.

compared to 2022 Approved. In 2023, labour costs are expected to increase to reflect the full cost of staffing and labour required.

The materials costs are for materials related to the production of LNG. In 2022, expenditures are projected to be slightly lower compared to the 2022 Approved. In 2023, compared to 2022 Projected, materials costs are expected to increase for inflation and the higher forecast LNG sales.

Contractor costs are for variable contractor services used for truck loading and support of production related activities. In 2022, it is expected that contractor costs will be similar to the 2022 Approved based on the anticipated work for the year. In 2023, higher contractor services are forecast due to inflation and may vary as the Company starts to reach full time operations.

Other variable costs include power (i.e., electricity) costs and consumables. Electricity costs vary with production. In 2022, electricity costs are expected to be lower compared to the 2022 Approved due to the lower than anticipated sales volumes. For 2023, FEI has forecast higher electricity costs due to the expected increase in LNG production. Actual electricity costs vary from the forecast depending on the demand for LNG exports. Refer to Section 3.3.4 Natural Gas for Transportation and LNG Demand for further discussion.

The overall 2023 Forecast Variable LNG Production O&M costs are estimated to increase compared to the 2022 Approved and Projected amounts. Drivers for the increase are the increase in labour to address full staffing requirements, higher materials costs and an increase in power costs for higher LNG production.

6.4 *NET O&M EXPENSE*

Net O&M expense is Gross O&M less capitalized overhead and Biomethane O&M transferred to the BVA. As approved by the BCUC in Order G-165-20, the capitalized overhead rate is set at 16 percent for FEI. After capitalized overhead and the transfer of $5.237 million of Biomethane O&M to the BVA, the net O&M expense for 2023 is $292.083 million.

6.5 *SUMMARY*

Overall, the increase in gross O&M expense from 2022 Approved to 2023 Forecast is 6.2 percent. The formula-driven O&M is increasing at a rate of 4.5 percent and the O&M forecast outside of the formula is increasing by 15.0 percent. The capitalized overhead rate of 16 percent remains unchanged from 2022, as approved by the BCUC in Order G-165-20.

7. RATE BASE

7.1 INTRODUCTION AND OVERVIEW

Rate Base for FEI is forecast to be $5.930 billion for 2023. Rate Base is comprised of mid-year net gas plant in service, construction advances, work-in-progress not attracting AFUDC, unamortized deferred charges, working capital, deferred income tax, and LILO benefit.

FEI's 2023 Rate Base includes the full-year impacts of the 2022 closing projected plant balances as well as the impact of the following amounts:

- Mid-year impact of regular capital additions, net of CIAC additions of $412.072 million;
- Mid-year impact of plant depreciation, net of CIAC amortization of $214.824 million; and
- Capital additions of CPCN and Special Projects of $246.888 million[38] as discussed in Section 7.2.3.2 below, which include:
    - Mid-year impact of $2.177 million for the final start-up and commissioning components of the Tilbury 1A Expansion Project;
    - Full-year impact of $73.889 million of capital expenditures and related AFUDC for the IGU Project;
    - Full-year impact of $157.545 million of capital expenditures and related AFUDC for the PGR Project; and
    - Full-year impact of $13.271 million of capitalized development costs and related AFUDC for the CTS TIMC Project that were approved by Order C-2-33 to transfer from the TIMC deferral account to rate base on January 1, 2023.

In addition, various changes in deferred charges, working capital and other items increase Rate Base by a net amount of $130.322 million in 2023.

Details of the 2023 Forecast plant balances can be found in Section 11, Schedules 5 through 9.

7.2 REGULAR CAPITAL EXPENDITURES

As part of the MRP Decision and Order G-165-20, FEI received the following approvals for capital expenditures:

- Approval of FEI's forecasts submitted for regular sustainment and other capital expenditures for the years 2020 through 2022;

[38] The 2023 capital additions of $246.888 million also include $0.006 million for final expenditures and related AFUDC for the Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) Project.

- Approval of growth capital to be set annually on a formula basis; and
- Approval of several items to be forecast outside the formula on an annual basis.

Further, in the MRP Decision the BCUC directed FEI to file an updated forecast of the 2023 and 2024 regular sustainment and other capital expenditures in the 2023 Annual Review.[39]

The components of FEI's 2023 regular capital expenditures are shown in Table 7-1 below.

Table 7-1: Regular Capital Expenditures ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Formula Growth Capex	87.583	100.302	87.631	Table 7-9, Line 9
2	Forecast Sustainment & Other Capex	163.580	172.343	183.542	Section 11, Schedule 4, Lines 16 + 17
3	Flow through Capex	50.619	36.558	66.172	Section 11, Schedule 4, Sum of Lines 13 through 15
4	Total Gross Regular Capex	301.782	309.204	337.345	
5	Less: Formula CIAC	(1.950)	(1.950)	(2.457)	Section 11, Schedule 9, Line 2
6	Less: Forecast CIAC	(3.902)	(5.047)	(4.342)	Section 11, Schedule 9, Line 3
7	Net Regular Capex	295.930	302.206	330.546	

In Section 7.2.1, FEI provides its updated 2023 and 2024 regular sustainment and other capital forecasts. In the remaining sections, FEI provides details on its formula growth capital and forecast flow-through expenditures for 2023, consistent with the format provided in previous annual reviews during this MRP term.

7.2.1 Sustainment and Other Capital Expenditures

As stated above, in the MRP Decision and Order G-165-20[40], the BCUC directed FEI to file updated 2023 and 2024 regular sustainment and other capital forecasts as part of the 2023 Annual Review. The BCUC in its decision highlighted FEI's evolving operating environment and inherent uncertainties in the capital forecasts, and thus considered it appropriate for FEI to have the opportunity to true-up its capital spending and re-forecast its capital for the final two years of the MRP term. Specifically, the BCUC stated the following:

> …FEI and FBC face evolving operating environments and there are inherent uncertainties in the five-year forecast. Reviewing the capital forecast in 2022 allows for a review of any significant variances between forecast and actual to date and provides an opportunity to true-up the rate-base for actual spending and to re-forecast the remaining years in the MRP term.[41]

As further explained in the subsections below, FEI has experienced pressures due to a variety of factors which are outside of the Company's control and could not have been anticipated at the time of the MRP proceeding, including the COVID-19 pandemic, supply chain issues, significant

[39] MRP Decision and Order G-165-20, p. 131.
[40] Directive 1.c. of Order G-165-20.
[41] MRP Decision and Order G-165-20, p. 131.

inflationary increases, and the war in Ukraine, among others. These factors have impacted FEI's ability to execute on all of its planned capital projects and programs within the approved capital spending envelope during the first three years of the MRP. While FEI has pursued various mitigation measures to manage through the spending pressures, FEI requires an increase in its capital spending for 2023 and 2024 compared to its original forecasts to execute on its planned activities.

The following tables summarize the sustainment and other capital expenditures[42]. The first table presents the 2020 through 2022 Approved forecasts (i.e., the forecasts approved in the MRP Decision) and the 2023 and 2024 forecasts which were reviewed during the MRP proceeding (Original Forecasts). The second table provides the Actual/Projected results for 2020 through 2022 and FEI's updated forecasts for 2023 and 2024 (Updated Forecasts).

Table 7-2: Sustainment and Other Capital Expenditures, 2020-2022 Approved, 2023-2024 Original Forecasts ($ millions)

Line No.	Description	Approved 2020	Approved 2021	Approved 2022	Original Forecast 2023	Original Forecast 2024
1	Sustainment Capital (excl. CIAC)	111.530	112.944	117.106	119.663	124.533
2	Other Capital	49.770	49.916	46.474	46.403	45.351
3	Total	161.300	162.860	163.580	166.066	169.884

Table 7-3: Sustainment and Other Capital Expenditures, 2020-2021 Actual, 2022 Projected, 2023-2024 Updated Forecasts ($ millions)

Line No.	Description	Actual 2020	Actual 2021	Projected 2022	Updated Forecast 2023	Updated Forecast 2024
1	Sustainment Capital (excl. CIAC)	112.405	115.763	124.160	129.086	130.378
2	Other Capital	50.745	50.246	48.183	54.456	51.194
3	Total Capital	163.151	166.009	172.343	183.542	181.572

In Section 7.2.1.1, FEI describes its updated forecasts for sustainment capital, and in Section 7.2.1.2, FEI describes its updated forecasts for other capital.

7.2.1.1 Sustainment Capital

Sustainment capital includes gas system improvements to the transmission and distribution system in order to meet forecast load and to ensure the safety, reliability and integrity of the system. It also includes expenditures for meter exchange programs, replacements and upgrades

[42] Excluding sustainment CIAC.

to the distribution and transmission systems, and expenditures for mains and service renewals and alterations.

The four main sustainment capital portfolios are: (i) Customer Measurement; (ii) Transmission System Reliability & Integrity; (iii) Distribution System Reliability; and (iv) Distribution System Integrity. In the MRP Application, FEI provided forecasts of these four categories of sustainment capital expenditures based on a bottom-up approach which included a two percent inflationary increase per year.

The following table provides the 2020 to 2022 Approved vs Actual/Projected expenditures and the Original and Updated 2023 and 2024 Forecasts.

Table 7-4: Sustainment Capital Expenditures 2020-2022 ($ millions)

Line No.	Description	2020 Approved	2020 Actual	2021 Approved	2021 Actual	2022 Approved	2022 Projected
1	Customer Measurement	30.559	30.398	31.328	32.182	31.781	29.386
2	Transmission System Reliability & Integrity	42.213	34.963	37.599	38.251	41.021	42.942
3	Distribution System Reliability	14.539	14.022	12.402	13.464	19.224	17.154
4	Distribution System Integrity	24.219	33.023	31.615	31.866	25.080	34.678
5	Total Sustainment Capital (excl. CIAC)	111.530	112.405	112.944	115.763	117.106	124.160

Table 7-5: Sustainment Capital Expenditures 2023 and 2024 ($ millions)

Line No.	Description	2023 Original Forecast	2023 Updated Forecast	2024 Original Forecast	2024 Updated Forecast
1	Customer Measurement	32.461	30.015	32.979	30.494
2	Transmission System Reliability & Integrity	45.792	47.937	47.355	49.573
3	Distribution System Reliability	12.486	15.141	22.031	17.659
4	Distribution System Integrity	28.924	35.993	22.168	32.651
5	Total Sustainment Capital (excl. CIAC)	119.663	129.086	124.533	130.378

As shown in Table 7-5 above, FEI's Updated Forecasts for sustainment capital have increased by $9.423 million in 2023 and $5.845 million in 2024 compared to the Original Forecasts. The required increases are primarily in the Transmission System Reliability & Integrity portfolio and the Distribution System Integrity portfolio, with FEI proposing to reduce the expenditures for the Customer Measurement portfolio in both 2023 and 2024, and the expenditures for the Distribution System Reliability portfolio in 2024 to offset some of the required increases in the other portfolios.

The drivers of the increases in the Transmission System Reliability & Integrity and the Distribution System Integrity portfolios are described in detail below but can be summarized as follows:

- Significant inflationary increases brought on by unanticipated events such as the COVID-19 pandemic and the war in Ukraine, which have resulted in large cost escalations in materials, labour and fuel;

- Alteration activities driven by various large third-party infrastructure upgrade projects that have received funding from various levels of government as part of the COVID-19 pandemic economic recovery efforts; and
- Additional reliability and integrity projects being required that were not anticipated at the time of the MRP proceeding.

These cost drivers, as well as the mitigation efforts FEI has undertaken during the first three years of the MRP term, are described in the following subsections.

7.2.1.1.1 SIGNIFICANT INFLATIONARY PRESSURES

FEI's Original Forecasts were developed using an assumption of two percent for annual inflation. While FEI has generally managed its overall sustainment capital spending within the approved levels over the first two years of the MRP term, FEI has begun to experience pressures throughout its sustainment capital portfolios. These pressures coincide with the significant global market events experienced during this time period, including the COVID-19 pandemic, supply chain disruptions, and the war in Ukraine. These unforeseen events have had significant impacts on market conditions for many commodities and services that make up FEI's supply chain, and the impacts are still being felt and continue to contribute to volatility in the supply chain and the overall commodity and services market in 2022.

In order to better understand the extent of the inflationary impacts that have affected North American utilities since 2020 and to compare the impacts on the industry with FEI's experience, FEI engaged Wood Mackenzie Supply Chain Consulting (Wood Mackenzie) to provide a market report on electric and gas utility transmission and distribution (T&D) markets from 2020 to 2022 and the anticipated impact until the end of 2024 (Wood Mackenzie Report). Wood Mackenzie identified an average escalation of 31.2 percent in capital costs for gas utilities between the period of the first quarter of 2020 and the first quarter of 2022. The Wood Mackenzie Report is based on the aggregated spend from utilities across North America, and incorporated over 150 indices which roll up to form the model for each category. Indices specific to BC have also been incorporated where appropriate, particularly around trades and other labour in the Province. This report has been included as Appendix C1.

These inflationary pressures are seen, for example, in FEI's new Mains and Services (M&S) construction contract for construction work typically used for projects within the Distribution System Integrity portfolio[43]. FEI's M&S contract expired at the end of 2021 and, during the competitive bidding process for the new contract, market cost escalations similar in magnitude to those identified in the Wood Mackenzie Report became evident from all contractors. Major contributing factors to the increased rates in the new M&S construction contract include:

[43] FEI's growth capital mains and services work is also affected by this contract.

- A new surcharge / rebate structure to mitigate fuel cost increases related to current fuel price increases and volatility. This was structured to allow for price reductions if fuel costs return to pre-early 2022 levels. These adjustments will be made on an annual basis;
- CPI adjustments occurring on March 31 of each calendar year, with the M&S contract rates otherwise being held for the duration of the contract term. CPI adjustments will be based on the federal CPI rates published by the Bank of Canada. Based on current Bank of Canada projections, FEI expects these increases to be between 2 to 8 percent annually for the duration of the contract term; and
- Increased labour costs associated with union-affiliated contractors. Labour rates across North America have increased by almost 12 percent from the first quarter of 2020 to the second quarter of 2022 as indicated by the Wood Mackenzie Report. As union agreements come up for renewal across British Columbia, some unions are proposing large labour rate increases. For example, negotiations with the BC General Employees' Union (BCGEU) are currently underway, with the BCGEU requesting 5 percent annual increases as well as cost of living protection. As such, increased labour rates are reflected in the new M&S contract where new union agreements have occurred.

Although the M&S contract will primarily impact costs for the Distribution System Integrity portfolio, similar pressures are being experienced in other portfolios, particularly when competitively bidding work to contractors.

While FEI currently completes approximately 50 percent of its construction work using internal labour under long-term collective agreements, these collective agreements are set to expire in 2023 and 2024. Any changes from the current rates are unknown at this time.

Another area where cost escalation is impacting FEI is related to steel commodity prices in North America, which have increased approximately 117 percent from the first quarter of 2020.

FEI has experienced significant inflationary pressures during the first three years of the MRP term and expects these pressures will continue into 2023 and to some extent into 2024. As shown in the Wood Mackenzie Report, it is expected that the average capital costs for gas utilities will remain close to the higher level of 2022 until the fourth quarter of 2024 and will not come back down to the 2020 level. This expectation also aligns with the Bank of Canada's July 2022 Monetary Policy Report[44] which projects that CPI is expected to hover around 8 percent in the third quarter of 2022 before decreasing to approximately 3 percent by the fourth quarter of 2023 and 2 percent in 2024.

7.2.1.1.2 ALTERATION ACTIVITIES DRIVEN BY THIRD-PARTY PROJECTS IMPACTING DISTRIBUTION SYSTEM INTEGRITY

As Tables 7-4 and 7-5 above show, FEI has experienced the greatest cost pressure in the Distribution System Integrity portfolio. In addition to the impact of the renewal of FEI's M&S

[44] https://www.bankofcanada.ca/wp-content/uploads/2022/07/mpr-2022-07-13.pdf.

construction contract described above, this portfolio has seen a significant increase in costs primarily due to the COVID-19 pandemic economic recovery efforts from various levels of government.

For example, beginning in 2021 and continuing into 2022, FEI has seen a significant increase in M&S alterations activity primarily due to various large third-party infrastructure upgrade projects that have received funding from various levels of government as part of the COVID-19 pandemic economic recovery efforts. These third-party driven projects are sometimes paid by the customer as a CIAC, depending on the proponent undertaking the work, and can include gas M&S relocations to accommodate highway widening projects, interchange upgrades, other municipal infrastructure projects (e.g., water or sanitary infrastructure), as well as expansions to the transit network. Further, for a number of large third-party relocation projects taking place in the Fraser Valley, the cost allocation between FEI and the proponent, and in some cases the timeframes in which FEI assets must be relocated by, are governed by operating agreements and permits in place with various municipalities, landowners, or the provincial government (e.g., the Ministry of Transportation and Infrastructure). FEI works closely with proponents to ensure FEI's relocation activities are completed in an appropriate timeframe; however, the timing of these relocations is typically governed by the schedule of the third-party relocation proponent and hence FEI may not be able to defer this work to future years. FEI expects this trend to continue into 2023.

7.2.1.1.3 UPDATED FORECASTS REFLECT NEW RELIABILITY AND INTEGRITY PROJECTS

As noted by the BCUC in the MRP Decision, there are inherent uncertainties in capital forecasting, particularly when forecasting projects over a five-year period. In the MRP Application, FEI identified projects over $2 million that it anticipated undertaking over the five-year MRP term in the categories of Transmission System Reliability & Integrity, Distribution System Reliability, and Distribution System Integrity. Due to a variety of reasons, such as land and permitting issues, re-prioritization of capital spending, and changes in capacity requirements, some projects have been delayed or cancelled while other new projects have been identified and prioritized.

As detailed in the MRP Application[45], FEI manages its capital investment plan to maintain a safe and reliable system, optimize resources and spending, and achieve efficiencies and cost savings. The capital plan contains a mix of projects across the four main portfolio categories, some of which are time sensitive and others that have some schedule flexibility. The plan is developed with the understanding that conditions change and the plan must be capable of adapting. This provides FEI flexibility to manage and execute normal levels of unforeseen urgent work that are expected to occur throughout the year within the resource and budget constraints of the capital plan. While this flexibility means that individual projects may move around, at a portfolio level, FEI has consistently executed a similar portfolio of work to the Original Forecasts.

In Appendix C2, FEI provides a list of the projects over $2 million which are included in the Updated Forecasts for 2023 and 2024.

[45] Section 3.2, page C-52.

7.2.1.1.4 FEI HAS EMPLOYED MITIGATION STRATEGIES TO LIMIT COST PRESSURES

FEI has successfully implemented a number of mitigation strategies to limit the impact of cost pressures since 2020, thus allowing FEI to manage the overall cost increases. These mitigation strategies include:

- Reprioritizing projects, or components of a project (e.g., final paving) that could be safely re-scheduled to 2023 to accommodate other project cost increases that could not be deferred. While FEI has delayed some work with flexible timing to accommodate the increased capital demands in the first three years of the MRP term, this has only mitigated part of the capital pressures due to the magnitude of market and other pressures;
- Entering into long-term supply contracts for many commonly used materials and service providers (e.g., engineering consultants, construction contractors, etc.);
- Competitively tendering large materials and services contracts to ensure competitive pricing. FEI routinely competitively bids work that does not fall within the scope of the M&S contract, and recently competitively bid the M&S construction contract to market;
- Communicating with critical suppliers and contractors to discuss issues and mitigation strategies;
- Negotiating collective agreements with unionized FEI employees that provide longer-term stability for internal labour rates); and
- Optimally allocating construction work to internal or external construction crews as appropriate.

Despite the mitigation strategies listed above, due to the magnitude of the overall inflationary pressure seen by the North American gas utility markets, as shown by the Wood Mackenzie Report, FEI has not been able to fully mitigate the cost increases.

7.2.1.2 Other Capital

In this section, FEI provides its Updated Forecasts for other capital. Other capital includes Equipment, Facilities, and Information System (IS) expenditures.

Table 7-6 below shows the Approved and Actual/Projected other capital from 2020 to 2022 while Table 7-7 below shows the Original and Updated Forecasts of other capital for 2023 and 2024. FEI notes that the majority of the increase shown in the Updated Forecasts is related to Facilities, primarily as a result of the Kelowna Space Project.

Table 7-6: Approved and Actual/Projected Other Capital Expenditures from 2020-2022 ($ millions)

Line No.	Description	2020 Approved	2020 Actual	2021 Approved	2021 Actual	2022 Approved	2022 Projected
1	Equipment	15.106	16.025	13.378	14.025	12.288	11.723
2	Facilities	6.356	6.675	7.977	8.447	5.760	8.260
3	Information Systems	28.308	28.046	28.561	27.774	28.426	28.200
4	Total Other Capital	49.770	50.745	49.916	50.246	46.474	48.183

Table 7-7: Original and Updated Forecasts of Other Capital Expenditures for 2023 and 2024 ($ millions)

Line No.	Description	2023 Original Forecast	2023 Updated Forecast	2024 Original Forecast	2024 Updated Forecast
1	Equipment	12.100	12.270	12.110	12.240
2	Facilities	6.803	14.686	5.636	11.349
3	Information Systems	27.500	27.500	27.605	27.605
4	Total Other Capital	46.403	54.456	45.351	51.194

The following sections provide further details on the Updated Forecasts for other capital.

7.2.1.2.1 EQUIPMENT

Equipment capital expenditures include the acquisition of vehicles and equipment, telecommunication infrastructure, specialized tools and equipment, and radio system upgrades. Expenditures for the equipment category are driven by obsolescence, excessive wear, and regulatory compliance.

FEI's 2023 and 2024 capital forecasts for Equipment have increased by $170 thousand and $130 thousand, respectively, compared to the Original Forecasts. The forecast capital increases are primarily in the category of vehicles, as FEI is experiencing a significant increase in the average unit cost per vehicle due to market pressures. In particular, FEI is experiencing the following increases in the average cost of vehicles:

- Substantial reduction of $10.5 to $2.5 thousand per unit in volume-based concessions from manufacturers to all commercial fleets;
- Increased costs on steel, aluminum, glass and paint; and
- Inflationary surcharges on services and labour by manufacturers.

7.2.1.2.2 FACILITIES

Facilities capital expenditures include the acquisition or leasing of land, buildings, and facilities furniture and equipment. Facilities capital expenditures focus primarily on capacity planning, upgrading, and replacement of end of life assets. The Facilities department ensures approved facilities projects are built to meet internal standards, building codes and regulations, and provide long-term and efficient solutions that meet business requirements.

As shown in Table 7-7 above, FEI's 2023 and 2024 Facilities capital forecasts have increased by $7.883 million and $5.713 million in 2023 and 2024, respectively, compared to the Original Forecasts. As further explained below, the majority of the increase is for the Kelowna Space Project. The remainder of the increase is related to: (i) energy management and GHG emissions reductions activities that FEI is planning to undertake to improve the adaptability and resiliency of FEI's facilities; and (ii) the installation of EV infrastructure at FEI's facilities.

Kelowna Space Project

FEI continues to experience capacity challenges at numerous locations for office, material storage and parking spaces and has been working to address these complex challenges. These capacity issues are impacting FEI's facilities across the Province and require different solutions depending on the location, as the challenges vary depending on the unique circumstances of each region. At the time of filing the MRP Application, FEI was in the process of developing a strategy for a cost-effective solution to the capacity issues in the Kelowna area, and therefore did not include this project in its Original Forecasts.

Both FEI and FBC have been experiencing space capacity challenges in the Kelowna region. Identifying solutions to address the space constraints has been very challenging, particularly due to the significant escalation in real estate costs to acquire new industrial land in the Kelowna area. However, the companies have now finalized a solution which leverages the use of FEI's and FBC's existing sites and results in the leasing of a new site for FEI's and FBC's Shared Services Departments. As further explained below, the Kelowna Space Project is a combined project for FEI and FBC, and the cost of the project has therefore been allocated between the two utilities accordingly. The total cost of the Kelowna Space Project is $13.996 million. Of this total, approximately $10.996 million is allocated to FEI based on employee count, with $6.083 million and $3.913 million reflected in FEI's Updated Forecasts for 2023 and 2024, respectively[46].

As part of the Kelowna Space Project, both FEI and FBC Shared Services Departments (Support Services) located in Kelowna will relocate to a new office lease facility approximately 25,000 ft^2 in size. Tenant improvements will be completed in 2023 and the Shared Services Departments will be relocated to this new leased facility. The allocation of leasing costs for this site will be determined using a cost driver approach based on the number of employees for FEI and FBC. In addition, FBC's Electrical Operations will move to the existing FEI-owned Springfield facility, as that location has a larger footprint and thus better aligns with the required Electrical Operations Space Program. FEI's Gas Operations will move to the existing FBC-owned Benvoulin property, as Gas Operations has a smaller footprint requirement. Broadly speaking, the Electrical and Gas Operations will "swap" locations.

Each building will require modifications to accommodate the Space Program requirements. Work will commence in late 2023 to complete the swap in 2025. Changes in building occupancy will be captured through new lease agreements where FEI will lease the entire Benvoulin building from

[46] There was also approximately $1.000 million of actual costs related to the Kelowna Space Project allocated to FEI in 2021, with the total allocation to FEI equaling approximately $10.996 million, including the forecast expenditures in 2023 and 2024.

FBC and FBC will lease the entire Springfield building from FEI. The buildings will remain operational while these changes are made.

The Kelowna Space Project results in a number of benefits for both FEI and FBC, including:

- Provision of sufficient space for both Operations and Support Services:
  - Support Services space requirement of 25,000 ft^2 of office at a new leased facility;
  - Gas Operations space requirement of 15,000 ft^2 of office and 12,000 ft^2 of industrial storage and shop space align with the sizing of the Benvoulin buildings and site; and
  - Electric Operations space requirement of 33,000 ft^2 of office and 13,000 ft^2 of industrial storage and shop space align with the sizing of the Springfield buildings and site;
- Retaining and updating the existing properties and adding a leased office facility results in a reasonable implementation timeline; changes are made at a measured pace to minimize business and employee disruption and do not require temporary relocation to another facility;
- The solution is cost effective in contrast to other options such as purchasing new property or constructing a new Operation Hub, and utilizes FEI's and FBC's existing properties to the best extent possible; and
- Each Operations group is located in its own facility, increasing planning, operations, and management efficiencies.

Capital Expenditures to Support Energy Efficiency and GHG Reductions

The Updated 2023 and 2024 Forecasts include $1.8 million in each year for expenditures that are specifically in support of energy efficiency and GHG reductions. These expenditures consist of projects that will result in reduced electrical and natural gas usage in FEI's facilities and/or will result in GHG emissions reductions. Where applicable, the planned projects are aligned with the ISO 50,001 Energy Management Standard, and enable FEI to prepare for the impacts of climate change and the transition to net-zero emissions. These planned projects will improve FEI's buildings' energy efficiency, support the adoption of electric vehicles, and contribute to efforts towards climate change and the Province's CleanBC Plan targets.

FEI is pursuing energy management and GHG emissions reduction opportunities for its buildings as part of the Company's climate action initiatives, including energy management activities related to climate adaptation, mitigation, and resiliency for buildings. FEI also plans to install EV charging infrastructure at FEI's facilities for fleet use.

Historically, the Facilities department has prioritized capital spending for capacity planning, end-of-life replacements, and meeting building codes and regulations. However, in light of the importance of addressing climate change, Facilities is now focusing on advancing climate action initiatives and strategies. Examples of advancements are installation of EV charging infrastructure, upgrading lighting to LED, completing energy audits to identify opportunities to inform capital planning, and incorporating energy efficiency components in long-term lease agreements.

7.2.1.2.3 INFORMATION SYSTEMS CAPITAL

FEI's Information Systems (IS) expenditures focus on enhancing, replacing, upgrading, and sustaining existing applications and infrastructure or, as needed, introducing new technology capabilities in order to improve safety, customer service, reliability and efficiency.

As shown in Table 7-6 above, the actual/projected expenditures for 2020 through 2022 are generally consistent with the forecasts in the MRP Application. As such, FEI has not made any changes to the 2023 and 2024 IS capital forecasts compared to what was presented in the MRP Application as there have been no changes in circumstances or anticipated spending that warrant revision at this time.

7.2.1.3 Summary of FEI's Updated Sustainment and Other Capital for 2023 and 2024

FEI provided an updated forecast for the sustainment and other capital in 2023 and 2024. These Updated Forecasts are summarized in Table 7-8 below.

Table 7-8: Summary of 2023-2024 Updated Forecasts of Sustainment and Other Capital

Line No.	Description	2023 Updated Forecast	2024 Updated Forecast
1	Customer Measurement	30.015	30.494
2	Transmission System Reliability	47.937	49.573
3	Distribution System Reliability	15.141	17.659
4	Distribution System Integrity	35.993	32.651
5	Subtotal (excl. CIAC)	129.086	130.378
6	Sustainment CIAC	(4.342)	(4.342)
7	Total Sustainment Capital	124.744	126.036
8			
9	Equipment	12.270	12.240
10	Facilities	14.686	11.349
11	Information Systems	27.500	27.605
12	Total Other Capital	54.456	51.194

For FEI's sustainment capital, the Updated Forecasts reflect the significant and unanticipated cost pressures experienced over recent years. These pressures, generally experienced by North American utilities, are being driven by factors outside of FEI's control, and include, among others, the COVID-19 pandemic, supply chain pressures and the war in Ukraine. The Updated Forecasts will ensure FEI's ability to execute its planned integrity and reliability programs which are critical to ensuring the ongoing safe and reliable operation of FEI's system.

For FEI's other capital, the Updated Forecasts are primarily related to the Kelowna Space Project, as well as expenditures for activities at FEI's facilities related to energy efficiency and GHG emissions reductions.

7.2.2 Formula Growth Capital Expenditures

The formula-driven growth capital expenditures start from a base of the prior year's approved unit cost for growth capital (UCGC), escalated by the prior year's inflation, and multiplied by the forecast gross customer additions, resulting in the forecast inflation-indexed growth capital before the true-up of formula growth capital, the formulaic CIAC, and the forecast for the system extension fund (SEF). The true-up of formula growth capital is based on actual gross customer additions from two years prior (i.e., 2021).

As calculated in Section 2, the 2023 net inflation factor based on prior year's BC-CPI and BC-AWE is 4.080 percent. Forecast gross customer additions in 2023 of 16,000 are then multiplied by the unit cost for growth capital.

For 2023, the annual growth capital expenditures under the formula are calculated as:

> 2022 Approved formula UCGC x [1 + (I Factor – X Factor)] x Gross Customer Additions + 2021 Formula Growth Capital True-up + 2023 Formula CIAC + 2023 Forecast SEF

Table 7-9 below shows the calculation of the resulting 2023 Formula growth capital expenditures.

Table 7-9: Calculation of 2023 Formula Growth Capital ($ millions)

Line No.	Description	Forecast 2023	Reference
1	Prior Year Base Unit Cost Growth Capital ($/customer)	4,046	G-366-21 and Section 11, Schedule 4, Line 2
2	Net Inflation Factor	4.080%	Section 11, Schedule 3, Line 9
3	Current Year Unit Cost Growth Capital ($/customer)	4,211	Line 1 x (1 + Line 2)
4	Gross Customer Addition Forecast	16,000	Section 11, Schedule 4, Line 5
5	Inflation Indexed Growth Capital	67.376	Line 3 x Line 4 / 1,000,000
6	2021 Growth Capital True-up	16.798	Line 16
7	Formulaic CIAC	2.457	Section 11, Schedule 9, Line 2
8	System Extension Fund	1.000	G-338-20 SEF Decision
9	Gross Formula Growth Capex	87.631	Sum of Line 5 to Line 8
10			
11	2021 Growth Capital True-up		
12	2021 Actual Gross Customer Addition	20,294	Section 2, Table 2-3
13	2021 Forecast Gross Customer Addition	16,000	G-319-20 2021 FEI Annual Review Decision
14	Difference	4,294	Line 12 - Line 13
15	2021 Unit Cost Growth Capital ($/customer)	3,912	G-319-20 2021 FEI Annual Review Decision
16	Growth Capital True-up in 2023	16.798	Line 14 x Line 15 / 1,000,000

The 2023 Gross Formula growth capital amount is $87.631 million. This amount includes the 2021 growth capital true-up of $16.798 million, the formulaic CIAC amount of $2.457 million, and the forecast SEF amount for 2023 of $1 million[47].

7.2.3 Flow-Through Capital Expenditures

7.2.3.1 Regular Capital Expenditures

FEI is afforded flow-through treatment for certain capital items due to a variety of factors, including their uncontrollable nature, because they drive incremental revenues, because they are related to clean growth initiatives, or because of the uncertainty in scope, costs and timing.

The amounts for 2023 are shown in Table 7-10 below along with a comparison to 2022.

Table 7-10: Flow-Through Regular Capital Expenditures ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023	Reference
1	Pension/OPEB (Growth Capital Portion)	1.693	1.693	1.034	Section 11, Schedule 4, Line 13
2	Biomethane Assets	40.255	28.183	58.571	Section 11, Schedule 4, Line 14
3	NGT Assets	8.671	5.844	6.567	Section 11, Schedule 4, Line 15
4	Forecast Regular Capex	50.619	35.720	66.172	Sum of Lines 1 through 3

Each of these items is described further below.

Pension/OPEB (Growth Capital Portion)

The 2023 Forecast Pension and OPEB capital expenditures of $1.034 million represent the forecast growth capital portion of the total Pension and OPEB costs for 2023. Pension and OPEB costs are described in Section 6.3.1.

Biomethane Capital

The following table provides the 2022 Approved, 2022 Projected and 2023 Forecast for Biomethane capital expenditures, including the Order approving each project.

[47] The SEF, up to $1 million per year, was approved on a permanent basis pursuant to Order G-338-20.

Table 7-11: Biomethane Capital Expenditures ($ millions)

Line No.	Description	Order	Approved 2022	Projected 2022	Forecast 2023
1	Kelowna	E-19-12	0.005	0.187	-
2	Salmon Arm Landfill	G-194-10		0.004	
3	City of Surrey	E-3-16		0.014	
4	REN Energy	G-60-20	0.150	0.476	-
5	Foothill LF (RDFFG)	E-2-22	-	1.171	10.000
6	Dickland Farms	E-13-20	0.100	0.554	-
7	Capital Regional District	E-15-21	7.000	4.451	3.000
8	City of Vancouver	G-235-19	24.000	13.371	21.771
9	Net Zero Waste	E-21-21	4.000	2.917	1.000
10	Delta RNG	E-3-22	5.000	4.776	6.000
11	Comox Valley LF	To be filed	-	0.117	10.800
12	Andion - Semiahmoo	To be filed	-	0.146	2.000
13	Vernon LF	To be filed	-	-	4.000
14	Total Biomethane CAPEX		40.255	28.183	58.571

The 2022 Projected and 2023 Forecast Biomethane capital expenditures are $28.183 million and $58.571 million, respectively.

FEI's applications for each biomethane project are filed and accepted individually by the BCUC; therefore, the capital estimates provided here are not being requested for approval as part of the annual review process, but are provided to include the current estimates for biomethane capital expenditures in customer rates.

The 2022 Projected capital expenditures are less than 2022 Approved by $12.072 million. The variance between 2022 Projected and Approved is primarily due to a delay in spending on the City of Vancouver (COV) and Capital Regional District (CRD) projects. The lower 2022 Projected expenditures on both the COV and CRD projects are partially offset by work beginning on the RDFFG project which was not yet filed with the BCUC at the time of the 2022 Annual Review. With regard to the COV project, FEI is now forecasting a higher total capital cost than was forecast in the 2022 Annual Review. These higher costs are primarily a result of delays resulting from a change in the project execution strategy in 2021.

With regard to the 2023 Forecast capital expenditures of $58.571 million, over a third of this amount is related to the COV project, with the remainder of the forecast expenditures related to existing projects such as RDFFG and Delta RNG, and new projects that are expected to be filed for acceptance late in 2022. Also, while FEI has provided a forecast of capital expenditures for the Delta RNG project, the agreement which was accepted by the BCUC on January 21, 2022 by Order E-3-22, requires Delta to provide a CIAC to FEI for the cost of the FEI facilities when they are completed. Therefore, when Delta RNG is completed and placed into rate base, there will be a corresponding CIAC equal to the value of FEI's capitalized plant related to this project.

Natural Gas for Transportation (NGT) Assets

The following table provides additional detail by project for the 2022 and 2023 NGT Assets capital expenditures.

Table 7-12: NGT Assets Capital Expenditures ($ millions)

Line No.	Description	BCUC Order	Approved 2022	Projected 2022	Forecast 2023
1	Waste Connections Abbotsford (CNG)	G-25-21	-	0.087	-
2	GFL Abbotsford (CNG)	G-116-21	-	0.451	-
3	Annacis Island (CNG)	G-313-21	-	0.823	-
4	McRae's Richmond (CNG)	Filed	-	0.220	1.180
5	Waste Management Expansion (CNG)	N/A	0.751	-	-
6	Surrey (CNG)	N/A	1.500	-	-
7	LNG Tanker (LNG)	GGRR	2.000	-	-
8	T1A Truck Load-out	GGRR	4.420	4.262	5.387
9	Total NGT Capital Expenditures		8.671	5.844	6.567

The 2022 Projected and 2023 Forecast NGT Assets capital expenditures are $5.844 million and $6.567 million, respectively. The capital expenditures for NGT Assets listed in Table 7-12 above are Prescribed Undertakings under the GGRR, with station recovery rates (i.e., capital and O&M rates) approved individually by the BCUC for each CNG or LNG station. Therefore, the capital estimates provided here are not being requested for approval as part of the annual review process, but are provided to include the current estimates for NGT Assets capital expenditures in customer rates.

The differences between the 2022 Projected and 2022 Approved capital expenditures are due to the following:

- Waste Connections Abbotsford (Order G-25-21) was to be completed in 2021 but has been delayed to 2022 which resulted in 2022 capital expenditures of $0.087 million;
- Construction of two new CNG stations at GFL Abbotsford and Annacis Island have experienced delays which have pushed the completion date and associated capital expenditures to 2022;
- Prior to the expiry of the GGRR provisions, FEI entered into a binding commitment to construct and own a new station, McRae's Richmond CNG station, which is forecast to start construction in 2022 and be complete in 2023;
- In the 2022 Annual Review, FEI had expected to complete an expansion at the existing Waste Management CNG station; however, Waste Management has since elected to exercise their option to purchase the station from FEI, thus no capital expenditure was incurred;

- In the 2022 Annual Review, FEI had forecast a new CNG station at Surrey; however, FEI and the City of Surrey were not able to finalize the project; thus, no capital expenditure was incurred; and
- The one new LNG marine tank trailer, which is a prescribed undertaking under section (3)(a)(i) of the GGRR,[48] was originally forecast for 2021 ($2.000 million); however, a binding committed was not made prior to the expiry of the GGRR provisions, and therefore this expenditure will not occur.

The 2023 Forecast capital expenditures are related to the following:

- Completion of the McRae's Richmond CNG station; and
- Completion of the Tilbury 1A truck load-out project. The Tilbury 1A truck load-out project, which involves two new LNG tanker truck load-outs at FEI's Tilbury facility for transferring LNG from the T1A storage tank to LNG tank trailers, is a prescribed undertaking under section (3)(a)(ii) of the GGRR.[49] FEI is forecasting that the total capital expenditures for the Tilbury 1A truck load-out project will be $19.4 million, exclusive of AFUDC, and that the project will be complete in 2023.

7.2.3.2 Major Projects Capital Expenditures

Major Projects are capital expenditures that do not form part of regular capital spending as they are approved through a separate CPCN or other application, or are projects that are proceeding as a result of an Order in Council (OIC). As part of the MRP Decision, the BCUC approved the continuation of the current process of reviewing Major Projects outside of the proposed MRP and approved the continuation of the existing financial threshold for CPCNs of $15 million for FEI for the MRP term.[50]

7.2.3.2.1 APPROVED MAJOR PROJECTS

In 2023, FEI is forecasting capital expenditures related to approved projects - the Tilbury 1A Expansion project, the LMIPSU project, the IGU project, the PGR project and the CTS-TIMC project. Each project is discussed below.

Tilbury 1A Expansion Project

The cost recovery of expenditures associated with the Tilbury 1A Expansion Project is authorized by Direction No. 5 to the BCUC as amended by OIC Nos. 557 (2013), 749 (2014), and 162 (2017). Under Direction No. 5, FEI can spend up to $425 million, plus AFUDC and feasibility and development costs, to construct storage and liquefaction facilities. FEI is forecasting the cost of

[48] Section (3)(a)(i) – One or more liquefied natural gas tank trailers or LNG fueling stations for the purposes of providing within British Columbia LNG fuel and fueling services to owners of vehicles that operate on LNG.

[49] Section (3)(a)(ii) – One or more tanker truck load-outs for the purposes of providing within British Columbia LNG fuel and fueling services to owners of vehicles that operate on LNG or to owners or operators of marine vehicles that operate on LNG.

[50] MRP Decision and Order G-165-20, pp. 132-133.

the Tilbury 1A Expansion Project to be within the authorized amount, at a total of approximately $495.000 million ($425.000 million excluding AFUDC and feasibility and development costs). A total of $488.474 million was added to rate base by the end of 2021[51]. FEI forecasts 2022 expenditures of $4.243 million that will be added to rate base in 2022 and final 2023 expenditures of $2.177 million (including AFUDC) that will be added to rate base in 2023. These expenditures are the final close out costs for the process scrubber as well as for operational readiness and on-site noise mitigation work.

LMIPSU Project CPCN

The LMIPSU project CPCN application was filed with the BCUC in December 2014 and approved by Order C-11-15. The LMIPSU project includes work on the Coquitlam Gate IP project, which addresses an increasing number of gas leaks on the Coquitlam Gate IP line and restores operational flexibility and resiliency to the Metro Vancouver IP system, and the Fraser Gate IP project, which will provide required seismic upgrades to the Fraser Gate IP line. The Burnaby and Coquitlam IP sections of the Coquitlam Gate IP project and the Coquitlam gate station were placed in service in 2019 at a cost of $304.414 million and were added to rate base January 1, 2020. The Coquitlam gate section of the LMIPSU project was placed in service in 2020 at a cost of $18.389 million and was added to rate base January 1, 2021. The Fraser Gate portion of the LMIPSU project was placed in service in 2021 at a cost of $23.560 million and was added to rate base on January 1, 2022. FEI forecasts further expenditures of $5.288 million and $0.006 million (excluding AFUDC) in 2022 and 2023, respectively, for contribution payments and environmental monitoring. These amounts will enter rate base in each of the respective years. The total estimated capital cost for the LMIPSU project, including AFUDC and abandonment/demolition costs, is $429.717 million.

IGU Project CPCN

The IGU project CPCN application was filed with the BCUC in December 2018 and approved by Order G-12-20. The IGU project includes upgrades to 29 pipeline laterals in the Interior of British Columbia that currently do not accommodate in-line inspection. This project addresses pipeline integrity risk associated with pipelines that operate at a hoop stress that has the potential for pipeline rupture due to corrosion on these lines that cannot be detected using current pipeline integrity methods.

FEI upgraded the Mackenzie, Cranbrook and Fording Laterals in 2020 at a cost of $54.572 million. These expenditures were added to rate base on January 1, 2021. FEI upgraded the Fording 2, Prince George 1, Kimberly and Skookumchuck Laterals in 2021 at a cost of $63.782 million. These expenditures were added to rate base on January 1, 2022. FEI is forecasting expenditures of $77.108 million and $56.518 million (excluding AFUDC) in 2022 and 2023, respectively, with a total of $73.889 million (including AFUDC) being added to rate base on January 1, 2023. As

[51] The amounts that entered rate base in 2019, 2020, and 2021 were $481.992 million, $3.966 million, and $2.516 million, respectively.

provided in the IGU project CPCN application, the total estimated capital cost for the project, including AFUDC and abandonment/demolition costs, is approximately $360 million.

PGR Project CPCN

The PGR project CPCN application was filed with the BCUC in August 2020 and approved by Order C-2-21. The PGR project includes construction of a new NPS 20 (508 mm) gas line and associated facilities in the City of Burnaby to replace the distribution system capacity currently provided by FEI's distribution pressure gas line affixed on the Pattullo Bridge (Pattullo Gas Line), which must be decommissioned in 2023 prior to the demolition of the Pattullo Bridge by the Province. The project scope also includes the modification, decommissioning and/or abandonment of existing infrastructure no longer required due to the removal of the Pattullo Gas Line crossing of the Fraser River. FEI forecasts expenditures of $103.039 million and $3.481 million (excluding AFUDC) in 2022 and 2023, respectively, with a total of $157.545 million (including AFUDC) being added to rate base on January 1, 2023. The capital cost estimate for the PGR project is $186.646 million in as-spent dollars, including AFUDC and decommissioning/abandonment costs.

CTS-TIMC Project CPCN

The CTS-TIMC project CPCN application was filed with the BCUC in February 2021 and approved by Order C-2-33. The CTS-TIMC project consists of alterations to FEI's Coastal Transmission System to allow FEI to run electro-magnetic acoustic transducer (EMAT) in-line inspection (ILI) tools on 11 pipelines that were deemed susceptible to cracking threats. These alterations are expected to be constructed in 2023 and 2024, with the project being completed by the end of 2025. FEI forecasts expenditures of $3.873 million and $29.551 million (excluding AFUDC) in 2022 and 2023, respectively. Additionally, as approved by Order C-2-33, FEI transfers $13.271 million (including AFUDC) of capitalized development costs, which were originally captured by the TIMC deferral account, to rate base on January 1, 2023. As described in the CTS-TIMC project CPCN application, the total estimated capital cost for the project, including AFUDC, is approximately $137.8 million.

7.2.3.2.2 GIBSONS CAPACITY UPGRADE PROJECT

In addition to the approved projects described above, FEI is requesting acceptance under section 44.2(3) of the UCA of a capital expenditure schedule consisting of the capital expenditures for one new Major Project, the Gibsons Capacity Upgrade (GCU) project. This project is further described below and in Appendix C3.

In the MRP Application (Section 3.3.3, page C-77), FEI identified the GCU project as a Major Project (the GCU project was referred to as the FEI Sunshine Coast Capacity Upgrade project in the MRP Application). At the time of filing the MRP Application, FEI had anticipated that the GCU project would exceed the $15 million materiality threshold and would therefore be filed as a CPCN application at some point during the MRP term. However, through further refinement of the preliminary project scope and associated cost estimate, FEI was able to arrive at a lower cost solution which has resulted in the forecast project cost being lower than originally contemplated in the MRP Application and below FEI's CPCN materiality threshold of $15 million. FEI is therefore filing for approval of the GCU project pursuant to section 44.2 of the UCA as part of this Application. FEI has included a detailed business case to support the project in Appendix C3 to this Application, which is summarized briefly below.

The community of Gibsons is supplied with natural gas by a 19-kilometre IP pipeline from the Sechelt Gate Station which is in turn served by the Vancouver Island Transmission System (VITS). The capacity of the IP pipeline is insufficient to meet current peak demand such that FEI is currently unable to supply sufficient capacity to the community during design conditions without the support of a temporary contracted CNG trailer on site during winter months. FEI considered several alternatives for this project, including IP pipe installation, and determined that a local CNG peak shaving facility is the preferred and lowest cost alternative. FEI has completed the project scope and cost estimate development for a local peak shaving CNG unit in the Gibsons distribution system area to offset the peak demand support required of the IP pipeline supplying the distribution system.

The GCU project would become FEI's first operational non-pipe solution installed within a distribution system and will provide valuable information on using non-pipe solutions as alternatives to address system capacity issues within the distribution system.

The total forecast capital cost for the GCU project is $12.194 million. Table 7-13 below shows the annual spending for the GCU project. FEI is also requesting a rate base deferral account to record the preliminary stage development costs incurred for the GCU project (see Section 7.5.1) as shown in Table 7-13 below.

Table 7-13: Forecast of Expenditures for the GCU Project ($ millions)

Line No.	Description	Prior Years Actual	2022 Projected	2023 Forecast	2024 Forecast	Total
1	Preliminary Development (Deferred Costs)	0.978	-	-	-	0.978
2	Project Capital Costs	0.794	2.380	6.950	0.190	10.314
3	Subtotal	1.772	2.380	6.950	0.190	11.292
4	AFUDC	0.018	0.129	0.457	0.298	0.902
5	Total Project Costs	1.790	2.509	7.407	0.488	12.194

7.3 *2023 PLANT ADDITIONS*

The 2023 Plant Additions are comprised of: (i) FEI's 2023 regular capital expenditures from Section 7.2 above, plus the Tilbury 1A Expansion project, LMIPSU project, IGU project, PGR project and CTS-TIMC project; (ii) the change in work in progress which adjusts for capital expenditures for projects such as those listed in Section 7.2 that are in progress at year end; (iii) AFUDC; and (iv) overhead capitalized for the year. A reconciliation of capital expenditures to plant additions is shown below and is also provided in Section 11, Schedule 5.

Table 7-14: Reconciliation of 2023 Capital Expenditures to Plant Additions ($ millions)

Line No.	Description	2023 Forecast	Reference
1	Formula Growth Capex	87.631	Section 11, Schedule 4, Line 10
2	Forecast Sustainment & Other Capex	183.542	Section 11, Schedule 4, Lines 16 + 17
3	Flow through Capex	66.172	Section 11, Schedule 4, Sum of Lines 13 through 15
4	Total Gross Regular Capex	337.345	Sum of Lines 1 through 3
5	Capitalized Overheads	56.632	Section 11, Schedule 5, Line 21
6	AFUDC	5.225	Section 11, Schedule 5, Line 22
7	Change in Work in Progress	19.669	Section 11, Schedule 5, Line 24
8	Total Regular Additions to Plant	**418.871**	Sum of Lines 4 through 7
9			
10	Special Projects and CPCN Capex		
11	Tilbury 1A Expansion	2.177	Section 11, Schedule 5, Line 7
12	LMIPSU	0.006	Section 11, Schedule 5, Line 8
13	Inland Gas Upgrade (IGU)	56.518	Section 11, Schedule 5, Line 9
14	CTS Transmission Integrity Program (CTS-TIMC)	29.551	Section 11, Schedule 5, Line 10
15	Pattullo Gasline Replacement (PGR)	3.481	Section 11, Schedule 5, Line 11
16	Gibsons Capacity Upgrade	6.950	Section 11, Schedule 5, Line 12
17	AFUDC	4.899	Section 11, Schedule 5, Line 28
18	Change in Special Projects and CPCN Work in Progress	143.306	Section 11, Schedule 5, Line 30
19	Total Special Projects and CPCN Additions to Plant	**246.888**	
20			
21	Total Plant Additions	**665.759**	

7.4 *ACCUMULATED DEPRECIATION*

FEI's rate base includes both the accumulated depreciation on plant in service and accumulated amortization of CIAC. Both are increased through depreciation expense and decreased through retirements.

The depreciation rates used for 2023 were approved by Order G-165-20 and are based on FEI's most recent depreciation study. Depreciation is calculated beginning January 1 of the year after the assets are placed in service, which is the treatment approved by Order G-138-14.

Based on calculating depreciation expense at these approved depreciation rates on the opening plant-in-service balance net of CIAC, the 2023 depreciation expense is calculated as $211.491 million.[52]

7.5 *DEFERRED CHARGES*

On May 3, 2017, the BCUC issued its Regulatory Account Filing Checklist.[53] The stated purpose of the checklist is to assist regulated entities when filing regulatory account requests and to facilitate an efficient review by the BCUC.

[52] $220.189 million depreciation expense as calculated in Section 11, Schedule 21, Line 5 less $8.698 million amortization of CIAC as calculated in Section 11, Schedule 21, Lines 11 and 12.

[53] Log No. 53608, Appendix B.

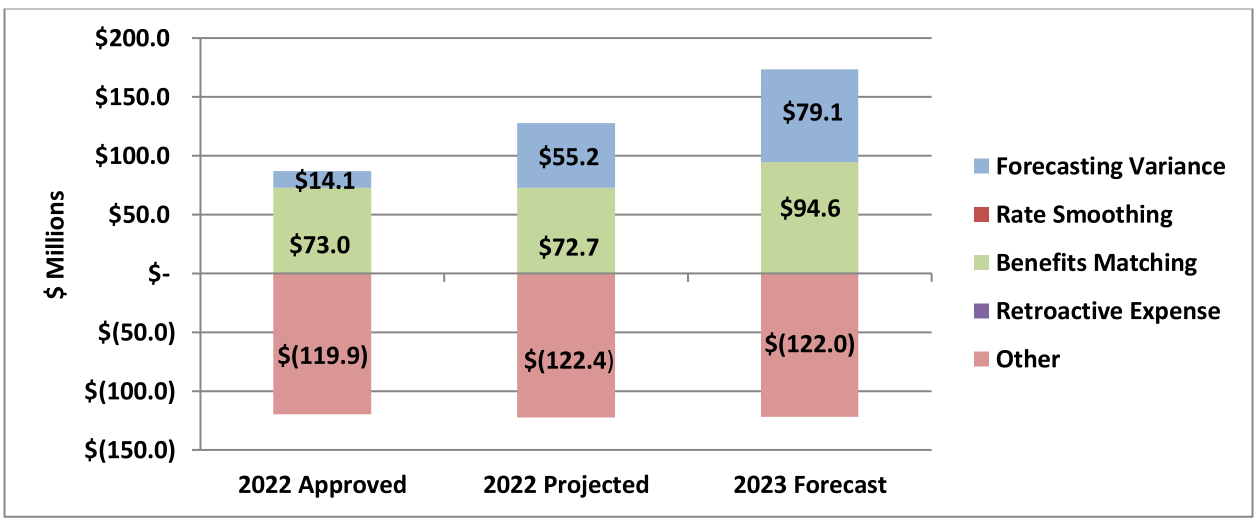
The checklist classifies deferral accounts as one of: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching (capital-like) account; (d) retroactive expense account; or (e) other. In Section 11, Schedules 11 and 11.1, FEI has classified its existing rate base deferral accounts in accordance with this classification.

The 2023 Forecast mid-year balance of unamortized deferred charges in rate base for FEI is a debit of $51.711 million.

The 2023 debit balance is driven largely by the balances in several deferral accounts, including Demand-Side Management, CCRA, Greenhouse Gas Reductions Regulation Incentives, Pension and OPEB Variance, Transmission Integrity Management Capabilities, BVA Balance Transfer, Whistler Pipeline Conversion, Gains and Losses on Asset Disposition, 2021 Renewable Gas Program Comprehensive Review, and the COVID-19 Customer Recovery Fund. The debit balance is partially offset by the Net Salvage Provision, the net variance between the Pension and OPEB Funding accounts, Emissions Regulations, MCRA, and the RSAM.

Figure 7-1 provides the mid-year deferral account balances summarized by deferral account category.

Figure 7-1: FEI Forecast Mid-Year Balances of Rate Base Deferral Accounts by Category



Based on amortizing the opening deferral account balances using the approved amortization periods, the 2023 amortization expense is calculated as $112.426 million.[54] The subsections below include a discussion on new rate base deferral accounts and changes or updates to existing rate base deferral accounts. For a discussion on non-rate base deferral accounts, please refer to Section 12.

[54] Section 11, Schedule 21, Column 3, Sum of Lines 8 to 10.

7.5.1 New Deferral Accounts

FEI is seeking approval of one new rate base deferral account in this Application.

7.5.1.1 Gibsons Capacity Upgrade Preliminary Stage Development Costs Deferral Account

As discussed in the MRP Application (Section C3.3.7) and further described in Section 7.2.3.2.2 as well as Appendix C3 of this Application, FEI has identified a capacity constraint and requirement to upgrade the Gibsons distribution system. To develop the solution to the capacity constraint (the GCU project), FEI incurred preliminary stage development costs, including expenditures for project management, engineering, and consultants for assessment of the potential alternatives, scope, feasibility, and design of the project that totalled $0.978 million pre-tax (Table 7-13, Line 1).

FEI's accepted regulatory practice for these types of preliminary stage development costs, related to CPCNs and other Major Projects, is to record these costs in a deferral as they are incurred and then to request approval for the deferral account and its amortization period within the related filing that requests approval of the project. Consequently, the preliminary stage development cost amounts related to the GCU project have been recorded in a deferral account as they were incurred.

Therefore, FEI is now seeking approval within this Annual Review, the proceeding where approval of the project is being requested, for the rate base GCU Preliminary Stage Development Costs deferral account with a three-year amortization period. FEI believes a three-year amortization period is appropriate as it is consistent with the recovery period of other similar preliminary stage development cost deferrals and serves to mitigate the rate impact to customers.

7.5.1.1.1 THE BCUC'S DEFERRAL ACCOUNT CHECKLIST

Table 7-15 below addresses the considerations identified in the Regulatory Account Filing Checklist, as they pertain to this deferral account request.

Table 7-15: Deferral Account Filing Considerations

Item	Consideration	GCU Preliminary Stage Development Costs
I.	Indicate if the request is: (a) for a modification or a change in scope to an existing Commission approved regulatory account; or (b) to establish a new regulatory account.	FEI requests the establishment of one new deferral account to capture the preliminary stage development costs related to the upgrade of the Gibsons Distribution System. Please refer to Section 7.2.3.2.2 for additional information.

Item	Consideration	GCU Preliminary Stage Development Costs
a)	If the request is for a modification or change in scope to an existing regulatory account, explain why the existing regulatory account is an appropriate account to use (specifically addressing the existing account's intended and approved purpose, mechanism for recovery, timeline for recovery and carrying costs).	N/A
b)	If the request is for approval of a new regulatory account, state the purpose of the regulatory account and explain its intended use.	The requested account will capture preliminary stage development costs related to the upgrade of the Gibsons Distribution System, including expenditures for project management, engineering, and consultants for assessment of the potential alternatives, scope, feasibility, and design.
II.	Propose a term (i.e. length of time) that the regulatory account should be approved for and explain why that term is appropriate.	This account will capture costs related to the development phase of the project. The term of the account encompasses the preliminary stage and subsequent amortization period, equivalent to the term of the benefit.
III.	Identify any alternate treatments that were considered, including an overview of what the accounting treatment would be in the absence of approval of the request to establish a regulatory account, and explain why these alternate treatments may not be appropriate.	In the absence of this deferral account, costs would have been forecast as a combination of O&M and capital expenses outside of the formula.
IV a)	Address: whether, or to what extent, the item is outside of management's control;	The preliminary stage development costs are generally within FEI's control; however, it is accepted regulatory practice to defer development costs and recover them in a future period. This allows the costs of the complete project to be matched against when the benefits are realized, as well as to smooth the rate impact to customers from the recovery of the deferred costs.
b)	the degree of forecast uncertainty associated with the item;	Given the actual costs are known, the forecast of costs is certain.
c)	the materiality of the costs	The preliminary stage development costs totalled $0.978 million pre-tax.
d)	any impact on intergenerational equity	See the response to item IX.
V.	Classify the regulatory account as either: (a) forecast variance account; (b) rate smoothing account; (c) benefit matching account; (d) retroactive expense account; or (e) other.	FEI classifies development cost accounts as benefit matching accounts since the costs are recovered over the period of time the benefits are generally realized.

Item	Consideration	GCU Preliminary Stage Development Costs
VI.	Identify if the regulatory account is a cash or non-cash account.	Preliminary stage development cost accounts are cash accounts.
VII.	Specify what additions to the regulatory account are being requested (i.e. type and amount of additions), including whether the account is intended to capture additions for a specific period of time or on an ongoing basis.	Eligible preliminary stage development costs related to the upgrade of the Gibsons distribution system include expenditures for project management, engineering, and consultants for assessment of the potential alternatives, scope, feasibility, and design that totalled $0.978 million pre-tax.
VIII.	Propose a mechanism for recovery (e.g. how the balance in the regulatory account will be recovered or refunded to ratepayers) and explain why it is appropriate.	Costs are recovered in revenue requirements by way of amortization expense.
IX.	Propose a timeline for recovery (e.g. the period over which the regulatory account balance is either collected or refunded; also referred to as the amortization period) and explain why it is appropriate.	FEI proposes a recovery period of three years with amortization beginning January 1, 2023. This period is appropriate as it is consistent with the recovery period for similar preliminary stage development costs deferrals.
X.	Propose a carrying cost for the balance in the regulatory account and explain why it is appropriate.	Rate base deferral accounts are included in rate base and therefore, implicitly financed using the weighted average cost of capital (WACC).
XI.	Outline a recommended regulatory process for the Commission's review of the application.	The proposed deferral account can be reviewed as part of the present proceeding. Deferral account approvals and disposition are generally determined in revenue requirements proceedings. Where requested within CPCNs and other applications, the regulatory process will be included within the draft timetable for each specific application.

7.5.2 Existing Deferral Accounts

In the discussion below, FEI provides information on two existing deferral accounts and requests an amortization period for one of them and a revised amortization period for the other deferral account.

7.5.2.1 COVID-19 Customer Recovery Fund Deferral Account

7.5.2.1.1 DESCRIPTION AND FINANCIAL ESTIMATES

In June 2020, FEI received approval through Order G-132-20 to establish the COVID-19 Customer Recovery Fund Deferral Account in rate base to record three items:

1. any bill payment deferrals provided to customers due to the COVID-19 pandemic and subsequent payments of those deferred amounts;

2. any bill credits provided to customers due to the COVID-19 pandemic; and

3. any unrecovered revenue resulting from customers being unable to pay their bills due to the COVID-19 pandemic, which will be tracked separately by rate schedule.

The following section provides 2022 and 2023 financial estimates and descriptions for each of the three items approved for inclusion in the COVID-19 Customer Recovery Fund Deferral Account. FEI also proposes to commence amortization of the deferral account balance in 2023 and to discontinue quarterly reporting.

Bill payment deferrals provided to residential and small commercial customers

The bill payment deferral program was offered to residential and small commercial customers affected by the COVID-19 pandemic. FEI experienced high collection rates in regard to this program, recovering approximately 95 percent of the outstanding balances through the regular monthly instalments. The remaining customer balances that were ultimately deemed unrecoverable have been designated as unrecoverable revenue and as such, a total of $0.144 million has been transferred to the COVID-19 Customer Recovery Fund Deferral Account. These additions to the deferral account are shown in section (c), Table 7-18 *Unrecoverable Revenue Amounts*.

FEI ceased accepting new applications effective June 1, 2021 and is therefore not forecasting further additions related to this relief measure.

Table 7-16: Bill Payment Deferral Amounts ($ millions)

	2020 Actual[55]	2021 Actual	2022 Projected	2023 Forecast
Opening Balance	-	1.952	0.020	-
Additions	2.803	0.034	-	-
Repayments	(0.851)	(1.835)	(0.007)	-
Transfers	-	(0.131)	(0.013)	-
Ending Balance	1.952	0.020	-	-

Bill credits provided to small commercial customers

The bill credit program offered to small commercial customers has been calculated using the existing balance of $0.709 million as of April 2022. Given the duration and period these credits were available for, as well as the June 1, 2021 closure of the program for new applications, FEI does not expect additional credits to be offered to customers throughout the remainder of 2022

[55] In response to CEC IR1 36.2 in the 2022 Annual Review, FEI revised the 2020 Actual Additions from $2.837 million to $2.803 million and revised the 2020 Actual Repayments from $(0.885) million to $(0.836) million due to errors being noted while filing the IR response. While preparing the current Application, FEI noted a further error in the 2020 Actual Repayments and has revised the amount to $(0.851) million to reflect the correct amount.

or in 2023. As such, FEI is proposing to amortize the $0.709 million over three years, with the 2023 amortization amount shown in Table 7-17 below.

Table 7-17: Bill Credit Amounts ($ millions)

	2020 Actual	2021 Actual	2022 Projected	2023 Forecast
Opening Balance	-	0.708	0.709	0.709
Additions	0.970	0.001	-	-
Tax	(0.262)	-	-	-
Amortization[56]	-	-	-	(0.236)
Ending Balance	0.708	0.709	0.709	0.473

Unrecovered revenue resulting from customers being unable to pay their bills due to the COVID-19 pandemic

This portion of the deferral account forecast represents the amount of customer balances owing (i.e., account receivables) that are recognized as unrecoverable due to the COVID-19 pandemic. As such, these amounts are in excess of the normal course forecast bad debt expense that is recognized in indexed-based O&M.

Table 7-18: Unrecoverable Revenue Amounts ($ millions)

	2020 Actual	2021 Actual	2022 Projected	2023 Forecast
Opening Balance	-	0.064	0.303	1.024
Additions[57]	0.088	0.196	0.975	-
Transfers[58]	-	0.131	0.013	-
Tax	(0.024)	(0.088)	(0.267)	-
Amortization[56]	-	-	-	(0.341)
Ending Balance	0.064	0.303	1.024	0.683

The unrecovered revenue recorded in the deferral account includes:

- any remaining balances associated with the bill payment deferral program, described in section (a), that resulted from customers' inability to pay (shown as the Transfers line in Table 7-18 above); and
- any unrecovered revenue from all customer classes due to the COVID-19 pandemic, including industrial and large commercial customers and those residential and small

[56] Based on a requested three-year amortization period commencing on January 1, 2023, as discussed in Section 7.5.2.1.2.

[57] The actual 2020 unrecoverable revenue additions of $0.088 million consist of $0.004 million of small commercial customer balances and $0.084 million of residential customer balances. The actual 2021 unrecoverable revenue additions of $0.196 million consist of $0.009 million of small commercial customer balances and $0.187 million of residential customer balances.

[58] The actual 2021 unrecoverable revenue transfers of $0.131 million consist of $0.007 million of small commercial customer balances and $0.124 million of residential customer balances.

commercial customers that did not participate in the bill payment deferral or bill credit relief offerings (shown as the Additions line in Table 7-18 above).

The 2022 Projected transfers of $0.013 million represent the actual 2022 transfers for the months available and any remaining bill payment deferral loan balances that were not yet repaid. The 2022 Projected additions of $0.975 million have been calculated using actual additions for the months available with the remainder of the year forecast using an approach consistent with the prior year. That is, a factor of 15 percent has been applied to the total outstanding balance of customer accounts that are past due as at March 1, 2022. This approach was based on a pilot outreach program in 2021 where 15 percent of customers with an average balance of $550 confirmed that they were financially impacted by the COVID-19 pandemic and required support to bring their account into good standing.

While the forecasts of the unrecovered revenue additions above rely on estimates and broader macroeconomic factors, the actual amounts that will be recorded in the deferral account will reflect actual balances that are attributable to specific customers that cannot make payment due to the COVID-19 pandemic.

In this regard, to support the development of a consistent and appropriate approach for identifying amounts deemed unrecoverable due to COVID-19, FEI has created an internal set of guidelines to be used by members of the customer service team with an objective to identify and support customers that have been financially impacted by the COVID-19 pandemic. The underlying goal and intent of this approach is for customers to be able to maintain their gas services while maximizing recoveries associated with any balances due. These internal guidelines include questions that help identify the extent to which the customer has been impacted by COVID-19 as well as payment arrangement guidelines that include partial or full recognition of receivable balances as unrecoverable due to the COVID-19 pandemic.

7.5.2.1.2 DISPOSITION OF DEFERRAL ACCOUNT

As indicated in the 2022 Annual Review, additions to the COVID-19 Customer Recovery Fund Deferral Account for unrecovered revenues resulting from customers being unable to pay their bills due to the COVID-19 pandemic were expected to continue into 2022. As such, FEI has continued to capture unrecovered revenues in this deferral account during 2022.

Since the 2022 Annual Review, conditions have improved such that most COVID-19 pandemic restrictions in BC have been lifted.[59] The Federal government support programs such as the Canada Emergency Response Benefit (CERB) and the Canada Emergency Wage Subsidy (CEWS) for businesses have ended as the impact of the COVID-19 pandemic lessens. This along with the improved economic conditions[60], although somewhat tempered recently with

[59] Refer to Section 12.2.1.4 for further discussion and details.
[60] As at time of filing and compared generally to the economic conditions experienced during the pandemic.

inflationary and recessionary considerations, suggests that ongoing pandemic support is not needed anymore.

Additionally, FEI has resumed most of its collection practices in 2022 with no significant uptick in unrecoverable revenues from customers experienced so far, and FEI anticipates full resumption of normal collection practices by mid-2022.

As a result, based on the positive current outlook for the COVID-19 pandemic and the lessened impact, FEI does not anticipate any further additions to the deferral account after 2022 and proposes to commence amortization of the balance in the deferral account on January 1, 2023 using a three-year amortization period. FEI considers a three-year amortization period to be appropriate because it matches the number of years during which the COVID-19 Customer Recovery Fund Deferral Account was active (i.e., 2020 through 2022).

Should public health and economic conditions deteriorate significantly due to the resurgence of the COVID-19 pandemic later this year or in the future (i.e., another wave of the pandemic which causes shutdowns and job losses impacting individuals and businesses), FEI may seek BCUC approval again for deferral account treatment for the same purpose and reasons set out in the 2020 application.

7.5.2.1.3 REQUEST TO DISCONTINUE REPORTING

FEI seeks approval to discontinue the existing quarterly reporting requirements for the COVID-19 Customer Recovery Fund Deferral Account filed with the BCUC. If approved, the final quarterly report would be for Q4 2022 and would be submitted in Q1 2023.

With more than two full years of reporting complete, the closure of the deferral and credit program to new applicants as of June 1, 2021, and the planned discontinuation of additions to the deferral account as of December 31, 2022, FEI does not see further value in providing separate detailed reporting for this account.

7.5.2.2 Emissions Regulations

As part of its 2012-2013 Revenue Requirement and Rates Application, FEI requested and received approval through Order G-44-12 to establish the Emissions Regulations deferral account due to a growing number of regulations around emissions trading that could lead to incremental compliance costs and recoveries. Given the uncertainty around the final form and applicability of emissions trading regulations, FEI requested approval for a rate base Emissions Regulations deferral account to capture potential compliance costs and revenues collected from credits.

From 2016 through 2018, FEI collected pre-tax revenues of approximately $9.8 million ($7.2 million after-tax) from the sale of credits earned under the Renewable Low Carbon Fuel Requirements Regulation (RLCFRR). The RLCFRR was introduced in order to reduce the carbon intensity of transportation fuels. The carbon intensity of both CNG and LNG fall below the maximum carbon intensity limit set by the RLCFRR; therefore, FEI earns credits from the sale of

CNG and LNG for use in transportation applications. FEI issues a request for proposal to potential buyers to ensure it maximizes the value of these credits for the benefit of ratepayers.

These revenues, and any other credits received under the RLCFRR, are recorded directly in the deferral account. Any costs related to the administration of these sales, not already embedded in formula O&M, are tracked by charging the costs to an internal order within the deferral account.

In the FEI Annual Review for 2017 Delivery Rates Application, FEI requested and received approval through Order G-182-16 to amortize any additions to the account over a period of five years. In that Application, FEI stated "This amortization period is appropriate given that FEI expects to continue to receive revenues which will vary depending on the number of credits FEI earns under the RLCFRR and the price at which FEI is able to sell those credits. The longer recovery period of five years will help smooth the rate impact on customers as these revenues are received from time to time."

In this Application, FEI is requesting approval to change the amortization period of this deferral account from five years to one year. As of the end of the first quarter of 2022, the British Columbia Low Carbon Fuel Standard (BC-LCFS) has validated approximately 80,149 in carbon credits for FEI that have accumulated since 2019, with an approximate market value of $37.5 million[61]. FEI anticipates monetizing those amounts through the sale of credits prior to the end of 2022. Given the significant dollar amount expected to be received and the time period that has already elapsed between when the credits were earned and validated, accelerating the return of these credits to customers is the appropriate measure to take and may serve to mitigate other rate pressures in the short-term, which will be beneficial to customers in the current market environment.

7.6 *WORKING CAPITAL*

The working capital component of rate base is comprised of cash working capital and other working capital.

Cash working capital is defined as the average amount of capital provided by investors in the Company to bridge the gap between the time expenditures are required to provide service (expense lag) and the time collections are received for that service (revenue lag). The cash working capital requirements that have been included reflect the most recent Lead Lag Study results, as approved through Order G-165-20.

Other working capital includes gas in storage, transmission line pack gas, inventory of materials and supplies, employee loans and withholdings and refundable contributions.

The main components of other working capital are gas in storage and transmission line pack, which are forecast on a 13-month average basis using the approved costs embedded in the Q2

[61] 80,149 credits x $467.32 average Q1-2022 sales price (source: https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/rlcf-017.pdf).

2022 gas cost report and historical volumes. All other 2023 amounts are forecast based on 2021 Actual levels.

7.7 SUMMARY

FEI's rate base includes the impact of formula-driven growth capital expenditures, regular capital expenditures that are forecast outside of the formula, and CPCNs and major projects, adjusted for work-in-progress, AFUDC and overheads capitalized. FEI has provided forecasts for all of its rate base deferral accounts in the financial schedules included in Section 11. In Section 7.2.1, FEI requested approval of its updated 2023 and 2024 regular sustainment and other capital forecasts. In Section 7.2.3.2.2, FEI requested approval of the capital expenditures for the GCU project, and in Section 7.5, FEI requested one new deferral account and discussed two existing accounts, including requesting to commence amortization of one of these existing accounts and to change the amortization period of the other existing account. Finally, the rate base includes other working capital, composed of gas in storage and other smaller components that have been forecast consistent with prior years.

8. FINANCING AND RETURN ON EQUITY

8.1 INTRODUCTION AND OVERVIEW

FEI has prepared this Application using the benchmark capital structure of 61.5 percent debt and 38.5 percent equity and Return on Equity (ROE) of 8.75 percent approved by Order G-129-16. FEI is currently participating in the BCUC-initiated Generic Cost of Capital (GCOC) proceeding and has filed evidence on its recommended capital structure and ROE as part of Stage 1 of the proceeding. In Order G-156-21 and accompanying Reasons for Decision, the BCUC found that the effective date to implement a new cost of capital will depend on the timing and progress of the GCOC proceeding. As explained in Section 1.2, FEI is seeking approval of interim 2023 delivery rates pending the outcome of Stage 1 of the GCOC proceeding as well as a decision on FEI's 2023 DSM Expenditure Plan. When a decision is reached on these proceedings, FEI will update its rate calculations and apply for permanent 2023 delivery rates.

The 2023 Forecast for financing costs, including the interest expense on issued long- and short-term debt and on new issuances that are forecast, has been updated as described in Section 8.3 below. Based on the updated financing costs, FEI's AFUDC rate for 2023 (which is equal to its after-tax weighted average cost of capital) is 5.46 percent. Any variances from interest rates used to set delivery rates, and any variances in interest resulting from items subject to flow-through in the Flow-through deferral account, will be flowed through to customers. All other differences in interest expense will affect the achieved ROE and be subject to earnings sharing.

8.2 CAPITAL STRUCTURE AND RETURN ON EQUITY

The Company finances its investment in rate base assets with a mix of debt and equity, as approved by the BCUC from time to time. Pursuant to Order G-129-16, the BCUC has approved a benchmark capital structure of 61.5 percent debt and 38.5 percent equity with an allowed ROE of 8.75 percent, effective January 1, 2016, which have been used to calculate rates in this Application.

8.3 FINANCING COSTS

Debt financing costs include the borrowing costs on issued debt as well as on new issuances that are forecast. Debt consists of both long- and short-term debt.

8.3.1 Long-Term Debt

FEI is a public issuer of long-term debt. FEI plans to issue long-term debt of approximately $200 million in 2022 and $300 million in 2023. FEI will use the funds to repay existing indebtedness and finance the Company's capital expenditure program. The 2022 and 2023 debt issuances are reflected in the financial schedules in October 2022 and October 2023 at a rate of 4.80 percent[62] and 4.70 percent[63], respectively. The exact timing, amount and rate of the issuances will depend on future market conditions and capital expenditure requirements. Variances in interest expense related to the timing and amount of the issuances of the debt or the rates at which they are issued will be captured in the Flow-through deferral account.

8.3.2 Short-Term Debt

FEI obtains short-term funding primarily through the issuance of commercial paper to Canadian institutional investors. FEI backstops the commercial paper issuances by maintaining a $700 million committed credit facility that matures in July 2026.[64] The credit facility provides FEI with short-term liquidity to fund its capital program and working capital requirements. FEI also maintains a $55 million letter of credit facility that matures in March 2023 to support its letters of credit.

8.3.3 Forecast of Interest Rates

FEI uses interest rate forecasts to estimate future interest expense. Forecasts of Treasury Bills and benchmark Government of Canada Bond interest rates are used in determining the overall interest rates for short-term debt and for rates on new issues of long-term debt, respectively. The forecasts are based on available projections made by Canadian Chartered banks.

Credit spreads on new long-term debt are based on current indicative rates, on the assumption that the current credit ratings of FEI are maintained.

FEI's short-term borrowing rate is based on the rate at which it issues commercial paper. Since commercial paper issuance rates are not forecast by economists, a forecast needs to be derived by FEI. The forecast is based on the historical differential between the Canadian Deposit Overnight Rate (CDOR) and the rate obtained by FEI under its commercial paper program. CDOR is used because FEI's short-term borrowings under its credit facility are priced based on CDOR and therefore CDOR is tracked relative to FEI's commercial paper borrowings. As CDOR is not forecast by economists, FEI must first obtain the 3-Month T-Bill rate forecast and then convert it to a CDOR forecast. FEI does this by taking the 3-year historical spread between CDOR and the 3-month T-Bill rate. Then, to derive the short-term borrowing rate forecast, FEI adjusts the CDOR forecast with the 3-year historical spread between CDOR and rates of issuances under its commercial paper program.

The 3-month T-Bill forecast for 2023 is 3.14 percent, which is a significant increase from the 0.47 percent approved in 2022. FEI is in a rising interest rate environment due to high inflation, Russia's invasion in Ukraine, and the removal of monetary policy actions that were prevalent during the initial years of the COVID-19 pandemic (i.e., 2020 and 2021). In addition, on July 13, 2022 the Bank of Canada completed its fourth rate hike of the year, raising the benchmark interest

[62] Section 11, Schedule 27, Line 18 (effective rate 4.864 percent).
[63] Section 11, Schedule 27, Line 19 (effective rate 4.763 percent).
[64] On July 14, 2021, the credit facility was extended to July 14, 2026.

rate to 2.5 percent from 0.25 percent at the beginning of 2022 and signalling that more rate hikes will be announced in 2022. The market volatility is expected to persist given many ongoing elevated risk variables.

For 2023, FEI forecasts a similar level of other financing fees to the 2022 Approved amount. Other financing fees include the fees that FEI incurs for its letters of credit under the $700 million credit facility and the $55 million letter of credit facility discussed in Section 8.3.2, as well as interest paid on customer deposits. The short-term borrowing rate forecast is shown in Table 8-1 below.

Table 8-1: Short Term Interest Rate Forecast

FEI Short Term Interest Rate	Approved 2022	Projected 2022	Forecast 2023
3-Month T-Bill Rate [1]	0.47%	3.08%	3.14%
Spread to CDOR	0.39%	0.36%	0.36%
CDOR Rate	0.86%	3.44%	3.50%
Spread to CP	-0.32%	-0.34%	-0.34%
CP Dealer Commission	0.10%	0.10%	0.10%
ST Interest Rate on Credit Facilities	**0.64%**	**3.20%**	**3.26%**
Fixed Financing Fees [2]			
Standby fee on Undrawn Credit [3]	1.12%	0.54%	0.44%
Renewal Fee on Undrawn Credit	0.40%	0.19%	0.16%
Other Financing Fees [4]	0.15%	0.11%	0.10%
ST Interest Rate on Fixed Financing Fee	**1.67%**	**0.85%**	**0.69%**
FEI Short Term Rate	**2.31%**	**4.05%**	**3.95%**

Notes to table:

1 3-Month T-Bill Rate for 2023 is a weighted average rate based on forecasts provided by Canadian Chartered banks in July 2022.

2 Fixed financing fees represent the costs of maintaining the $700 million credit facility and letter of credit facility, which are fixed fees incurred regardless of whether FEI draws from the credit facility. The fees have been converted into a short-term rate for forecast purposes.

3 A standby fee of 16 bps is charged on undrawn credit facility amounts, which would change if credit facility amounts are drawn through banker acceptances or prime loans. However, the forecast assumes FEI will borrow through commercial paper and will not change the undrawn credit facility fee percentage.

4. Other financing fees include commercial paper issuance fees, letter of credit fees, customer deposit interest expense and miscellaneous bank administration costs. The letter of credit fees, customer deposit interest and miscellaneous bank administration costs are incurred regardless of whether FEI draws from the credit facility.

As noted above, FEI's interest rate forecasts are based on CDOR. An indirect result of the cessation of the publication of the London Interbank Offered Rate (LIBOR) is that Canada is reassessing its use of CDOR as a risk-free rate benchmark for financial instruments in multiple asset classes. This will impact FEI's credit facility agreement as Refinitiv Benchmark Services

(UK) Limited (RBSL), CDOR's regulated administrator, announced that CDOR will cease to be published after June 28, 2024.[65] The Canadian Alternative Reference Rate Working Group (CARR) was established to coordinate the transition to a new risk-free rate benchmark. It is anticipated that CDOR will transition to the Canadian Overnight Repo Rate Average (CORRA), a transaction-based overnight risk-free interest rate benchmark in existence since 1997.[66] FEI will work with its banking syndicate members to transition its credit facility agreements to CORRA and will revisit the methodology for short-term interest rate forecasting when such a transition is complete.

8.3.4 Interest Expense Forecast

The interest expense forecast reflects FEI's existing and forecast borrowing costs on long- and short-term debt.

Short-term interest expense is determined by applying the forecast short-term debt rate to the estimated short-term debt balance. Long-term debt interest expense is determined using the effective interest method. For each long-term debt issue, the effective rate (forecast effective rate if it is a new issue) is multiplied by the average balance of that long-term debt for the year. The 2023 long-term debt schedule for FEI can be found in Section 11, Schedule 27.

8.3.5 Allowance for Funds Used During Construction (AFUDC)

FEI applies AFUDC to projects that are greater than three months in duration and greater than $100 thousand. Based on the above information, FEI's AFUDC rate for 2023 (which is equal to its after-tax weighted average cost of capital) is 5.46 percent. The calculation of the rate is shown in the following table.

Table 8-2: Calculation of AFUDC Rate for 2023

	Weight	Pre Tax Rate	After Tax Rate	Earned Return
Short Term Debt	4.26%	3.95%	2.88%	3.95%
Long Term Debt	57.24%	4.70%	3.43%	4.70%
Common Equity	38.50%	11.99%	8.75%	8.75%
Weighted Average	100.00%	7.47%	5.46%	6.23%

8.4 *SUMMARY*

FEI's equity financing and ROE have been forecast for 2023 at the same percentages as approved by Order G-129-16. FEI's debt financing costs on rate base are primarily determined

[65] https://www.bankofcanada.ca/markets/canadian-alternative-reference-rate-working-group/.
[66] https://www.bankofcanada.ca/wp-content/uploads/2021/12/CARR-Review-CDOR-Analysis-Recommendations.pdf.

by embedded rates on long-term debt, and to a lesser degree by short-term debt rates; the embedded rate on long-term debt is forecast to increase in 2023 as compared to 2022 Approved.

9. TAXES

9.1 *INTRODUCTION AND OVERVIEW*

This section discusses FEI's forecasts of property taxes and income tax which have been forecast on a basis consistent with prior years. In 2023, property taxes are forecast to increase by 7.6 percent from 2022 Approved, while income tax is forecast to decrease by 3.0 percent compared to 2022 Approved.

9.2 *PROPERTY TAXES*

Property taxes for 2023 of $78.985 million incorporate Company forecasts of assessed values of taxable assets, mill rates and taxes from revenues earned from gas consumed within municipalities. A breakdown of property taxes by asset type is provided in Table 9-1 below.

Table 9-1: Property Tax Forecasts ($ millions)

Line No.	Description	Approved 2022	Projected 2022	Forecast 2023
1	Distribution Assets	$ 28.360	$ 26.772	$ 27.855
2	Transmission Assets	19.209	19.649	20.138
3	Gas Storage Assets	7.118	7.514	7.818
4	Manufactured Gas Assets	0.036	0.046	0.051
5	General Assets	5.128	5.902	6.642
6	In-Lieu	13.368	13.507	16.289
7	OGC Fees	0.285	0.285	0.285
8	Total Property Taxes	$ 73.504	$ 73.675	$ 79.077
9	Less: Property Tax Transferred to BVA	(0.107)	(0.075)	(0.092)
10	Net Property Tax	$ 73.397	$ 73.600	$ 78.985
11				
12	Forecast Change from 2022 Approved			7.6%
13	Forecast Change from 2022 Projected			7.3%

As shown in the above table, in 2023 property taxes are forecast to increase by 7.6 percent from 2022 Approved and increase by 7.3 percent compared to 2022 Projected. Over half of the increase in the 2023 Forecast compared to 2022 Projected is due to higher in-lieu taxes as discussed below. The remainder is driven by construction activities and market value assessment increases, partly offset by decreases in tax rates. FEI's property asset base is heavily weighted to the Lower Mainland, and despite a general drop in taxation rates in the region, as outlined below, land values have increased by up to 20 percent in some classifications, such as LNG. The most significant drivers of the forecast changes are as follows:

1. ***Changes in Tax Rates***. Tax Rates are expected to change for 2023 as follows:
   a) Effective municipal tax rates are expected to decrease on average by 1.25 percent across FEI's operating municipalities;
   b) School rates are expected to decrease by 1.0 percent;
   c) Rural rates are expected to decrease by 1.6 percent;
   d) Tax rates on First Nations are expected to decrease by 0.40 percent; and
   e) Other rates are expected to range from increases of 1.3 percent for some Interior areas to decreases of 4.5 percent in the Lower Mainland.
2. ***Changes in Revenues to Calculate Grants In-lieu of Taxes.*** Revenues reported to municipalities are expected to increase by 20.6 percent based on actual revenues applicable to the taxation year. Increases in the cost of gas and higher industrial volumes than forecast led to higher revenues used to derive the 2023 grants in-lieu. Grants in-lieu of taxes are based on a fixed percentage of revenues; the overall increase in revenues reported to municipalities increases the grants in-lieu of taxes due.
3. ***Changes in Assessed Values***. Forecast changes in the assessed values of FEI's property are based on expected inflationary changes to BC Assessment legislated improvement rates, pipeline additions and land values. Changes include:
   a) A 2.0 percent increase in assessed values of distribution lines and services plus additional new construction. Land associated with distribution lines and services is expected to increase by 13.0 percent;
   b) A 3.0 percent increase in assessed values of transmission lines. Changes to linear rates from BC Assessment's systematic review that concluded in 2019 are expected to be delayed until 2024. Land associated with transmission lines is expected to increase by 13.3 percent;
   c) A 1.0 percent decrease in assessed values for LNG improvements. Land associated with LNG facilities is expected to increase by 19.5 percent; and
   d) A 0.3 percent decrease in office improvements. Land associated with offices is expected to increase by 19.0 percent.

Any variances from the forecast of property taxes included in rates will be recorded in the Flow-through deferral account and will be returned to or collected from customers in the following year.

9.3 *INCOME TAX*

FEI is subject to corporate income taxes imposed by the Federal and BC governments. Current income taxes have been calculated using the flow-through (taxes payable) method, consistent with BCUC-approved past practice, at the corporate tax rate of 27 percent for 2023, which is unchanged from 2022. The corporate tax rates used in this Application are based on the Canada Income Tax Act and the BC Income Tax Act enacted legislation and are updated each year as part of the annual rate setting process.

Income tax for 2023 is forecast to decrease by $1.587 million or 3.0 percent compared to 2022 Approved. The 2023 decrease is primarily due to higher deductible temporary differences associated with property, plant and equipment and lower taxable temporary differences associated with pension and OPEB, partially offset by higher rate base and amortization of deferred charges.

Any tax rate variances and variances in income taxes on items that are flowed through in rates are subject to flow-through treatment.

All other differences in income tax expense are subject to earnings sharing.

9.4 *SUMMARY*

FEI has forecast its property and income taxes on a basis consistent with prior years, utilizing enacted legislation for income taxes and forecast changes in property tax rates and assessments.

10. EARNING SHARING AND RATE RIDERS

10.1 *INTRODUCTION AND OVERVIEW*

In this section, FEI discusses earnings sharing and the calculation of its delivery rate riders. FEI proposes to distribute a $0.377 million pre-tax credit ($0.275 million after-tax) earnings sharing amount to customers as part of 2023 delivery rates. FEI has also set out the BVA, RSAM and Clean Growth Innovation Fund (CGIF) rate riders for 2023 and provides details on the CGIF, which is funded through the collection of the CGIF rate rider.

10.2 *EARNINGS SHARING*

In the MRP Decision (at page 82), the BCUC approved an earnings sharing mechanism from 2020 to 2024 whereby 50 percent of the achieved ROE above or below the allowed ROE will be shared with customers. Since FEI is unable to determine final earnings sharing until all items required for the ROE calculation are known, including the final rate base, there is a lag in when FEI distributes earnings sharing amounts. This is consistent with the calculations of formula O&M and growth capital, where the true-up of the formula inputs happens only once actuals are known. Thus, for 2023 delivery rates, it is the 2021 formula O&M, 2021 growth capital, and 2021 earnings sharing amounts that are calculated and impact rates in 2023.

For 2023, FEI proposes to distribute a $0.377 million pre-tax credit ($0.275 million after-tax) to customers, comprised of:

- The $0.122 million credit difference between the projected 2021 deferral account after-tax credit addition of zero embedded in 2022 delivery rates, and the actual 2021 deferral account after-tax credit addition of $0.122 million as provided in FEI's 2021 Annual Report to the BCUC;
- The $0.132 million credit difference between the projected 2021 financing addition of $0.068 million credit[67] and the actual 2021 financing addition of $0.200 million credit, as provided in FEI's 2021 Annual Report to the BCUC;
- The $0.014 million credit difference between the forecast 2022 financing addition of $0.035 million credit[68] embedded in 2022 delivery rates, and the projected 2022 financing addition of $0.049 million credit embedded in this Application; and
- 2023 forecast financing of a $0.007 million credit.[69]

[67] Annual Review for 2022 Delivery Rates, Section 10.2.
[68] Annual Review for 2022 Delivery Rates Compliance Filing, Schedule 12, Line 21, Column 4.
[69] Section 11, Schedule 12, Line 21, Column 4.

FEI proposes to distribute $0.377 million to customers in 2023 as a reduction in 2023 revenue requirements through amortization of the projected 2023 opening after-tax balance and 2023 financing of $0.275 million in the MRP Earnings Sharing deferral account.

As part of future rate filings, the actual earnings sharing for 2022 will be distributed to or collected from customers in a similar manner as described above, which will account for the actual 2022 ROE variance from approved.

10.3 *RATE RIDERS*

There are two delivery rate riders that are set each year through the annual review process. These are the BVA Rate Rider and the RSAM Rate Riders. Additionally, pursuant to the MRP Decision, FEI was approved to collect a basic charge fixed rate rider of $0.40 per month from all non-bypass customers for the term of the MRP to support FEI’s Clean Growth Innovation Fund (CGIF) activities.

10.3.1 BVA Rate Rider

The 2022 BVA rate rider was approved on a permanent basis by Order G-366-21. The following supports the BVA rate rider for 2023.

On August 12, 2016, the BCUC issued Order G-133-16 and the accompanying Decision in the matter of the Biomethane Energy Recovery Charge (BERC) Rate Methodology Application (2016 Biomethane Decision). The 2016 Biomethane Decision approved the Short Term BERC rate based on a premium of $7 per GJ above the Conventional Gas Cost (defined as the sum of the Commodity Cost Recovery Charge, the carbon tax and any other taxes applicable to conventional natural gas sales). The Long Term BERC rate is to be set at a $1 per GJ discount to the Short Term BERC rate.

FEI also received approval to amortize/transfer the net of tax year-end balance in the BVA, after adjustment for the value of unsold biomethane quantities, to a BVA Rate Rider Account for recovery from, or refund to, all non-bypass customers via a delivery rate rider effective January 1 of the subsequent year.

In the 2016 Biomethane Decision, FEI was directed to provide the following information:

- A continuity schedule showing the breakdown of the forecast December 31st balance in the BVA to be recovered by the BVA Rate Rider by year including sufficient supporting details.
- The calculation of the BVA Rate Rider by rate class.
- A continuity schedule showing the forecast, actual and variance (actual – forecast) biomethane revenues and volumes sold (GJ) by rate class, type of contract (short term/long term) and year.

- Number of customers in each rate class.

FEI provides the requested information below for the projected closing 2022 balance of the BVA rate rider account, and the calculation of the BVA Rate Riders for 2023.

10.3.1.1 BVA Rate Rider Account

The BVA balance at the end of December 31, 2022 is projected to be a debit of $34.596 million before-tax.[70] This balance consists of the 2021 ending inventory balance of $2.881 million plus a projected $52.484 million in costs to acquire biomethane less $20.769 million of recoveries by way of the Biomethane Energy Recovery Charge (BERC). FEI projects 661.5 TJ of biomethane to remain in inventory at the end of 2022.

The amount transferred from the BVA to the BVA rate rider account is determined on an after-tax basis. The after-tax balance in the BVA before transfer to the BVA rate rider account is projected to be $25.255 million.[71]

The following table summarizes the BVA rate rider account and shows both the projected after-tax ending 2022 balance of $6.668 million[72] and the $18.587 million[73] transfer to the BVA rate rider account.

[70] Table 10-1, Line 17.
[71] Table 10-1, Line 26.
[72] Table 10-1, Line 30.
[73] Table 10-1, Line 28.

Table 10-1: BVA Rate Rider Account

Line No	BVA Continuity	Note	2022 Projected (a) ($000s)	Reference
1	**BVA Opening Balance**	(b)		
2	Pre-Tax Balance (Before Adjustment for Unsold Biomethane)		$ 2,881.1	
3	Pre-Tax Adjustment for Unsold Biomethane		(2,881.1)	
4	Pre-Tax Adjustment for Unsold Biomethane		$ -	Line 2 + Line 3
5				
6	Tax Recovery		-	- Line 4 x Line 19
7	Net of Tax Balance (After Adjustment for Unsold Biomethane)		$ -	Line 4 + Line 6
8				
9	**BVA Activities:**			
10	Biomethane Costs Incurred		$ 52,483.5	
11	Biomethane Costs Recovered		(20,768.9)	
12	Total Activities - Pre-Tax		**$ 31,714.6**	Line 10 + Line 11
13				
14	Pre-Tax Opening Balance of Unsold Biomethane	(c)	2,881.1	- Line 3
15	Pre-Tax Balance of Unsold Biomethane	(c)	$ 6,253.3	
16	Pre-Tax Balance After Adjustment for Unsold Biomethane		25,461.3	Line 12 - Line 15
17	**BVA Ending Balance**		**$ 34,595.7**	Line 14 + Line 15 + Line 16
18				
19	Tax Recovery Rate		27%	
20				
21	Tax Recovery on Balance of Unsold Biomethane		$ (2,466.3)	-(Line 14 + Line 15) x Line 19
22	Tax Recovery on Balance after adjustment		(6,874.6)	- Line 16 x Line 19
23				
24	After-Tax Balance of Unsold Biomethane		6,668.1	Line 14 + Line 15 + Line 21
25	After-Tax Balance After adjustment for Unsold Biomethane		18,586.8	Line 16 + Line 22
26	**Net of Tax BVA Balance before Transfer to BVA Rider Account**		**$ 25,254.8**	Line 24 + Line 25
27				
28	**Transfer to BVA Rate Rider Account**	(d)	**$ (18,586.8)**	- Line 25
29				
30	**Net of Tax Balance (After transfer to BVA Rider Account)**		**$ 6,668.1**	Line 26 + Line 28

Notes

(a) The annual forecast is an updated 2022 forecast

(b) Recorded opening balance reconciles to the December 31, 2021 balance in the FortisBC Energy Inc. 2021 BVA Status Report.

(c)

Calculation of Adjustment for Unsold Biomethane	2021 Recorded	2022 Projected
Beginning Quantity Unsold Biomethane (in TJ)	-	208.7
Biomethane Purchased (in TJ)	790.0	2,186.6
Biomethane Sold (in TJ)	(581.4)	(1,733.7)
Ending Total Biomethane Unsold (in TJ)	208.7	661.5
BERC rate in effect at forecast (in $/GJ)		
January 1st effective BERC rate (in $/GJ)	$ 13.808	$ 13.808
Value of Unsold Biomethane at December 31st	$ 2,881.1	$ 9,134.4

(d) Pursuant to Order G-133-16, and the Decision issued concurrently, the net of tax balance at December 31, 2022, after adjustment for the value of unsold biomethane quantities, will be transferred to the BVA Rate Rider Account for recovery from / refund to all non-bypass customers.

10.3.1.2 BVA Rate Rider Calculation

The cumulative BVA rate rider for recovery in 2023 is forecast at $26.146 million and is recovered from non-bypass customers through a rate rider based on 2023 Forecast volumes. The $26.146 million to be collected consists of the 2021 Projected recovery variance of $0.685 million[74] plus the $18.587 million after-tax debit transferred from the BVA grossed up to a before-tax debit value of $25.461 million.[75]

To calculate the BVA rate rider, the projected BVA rate rider account balance of $26.146 million is divided by the 2023 Forecast non-bypass customer volume of 198,408 TJ, which results in a BVA rate rider of $0.132 per GJ. Any difference between the actual and forecast BVA rate rider amount collected will be trued up in the subsequent year. Details of the BVA rate rider calculation are provided in Table 10-2 below.

Table 10-2: 2022 BVA Rate Rider Calculation

Line No	Particulars	BVA Rider Projected 2022 ($000s) Net of Tax	($000s) Grossed Up	Non-Bypass Forecast 2023 Vol (TJ)
1	BVA Rider Account Balance			
2	**BVA Balance Transfer Deferral Account Balance Dec 31, 2021 - Actual**	9,037.0	$ 12,379.5	
3	Less Projected 2022 BVA Rider recoveries for 2021 using 2022 Projected Non-bypass volumes	(8,536.9)	(11,694.4)	
4	**2022 projected true up adjustment - 2021 projected recovery variance**	500.1	685.0	
5	BVA Balance transferred to BVA Balance Transfer Deferral Account Dec 31, 2022 - Projected	18,586.8	$ 25,461.3	
6	**BVA Balance Transfer Deferral Account Balance Dec 31, 2022 - Projected**	**19,086.8**	**26,146.4**	**198,408.0**
7				
8	**Residential**			
9	Rate Schedule 1		$ 10,892.8	82,658.7
10	**Commercial**			
11	Rate Schedule 2		$ 3,828.2	29,050.1
12	Rate Schedule 3		$ 3,381.8	25,662.4
13	Rate Schedule 23		$ 514.4	3,903.8
14	**Industrial**			
15	Rate Schedule 4		$ 21.9	166.1
16	Rate Schedule 5		$ 1,426.8	10,826.9
17	Rate Schedule 6		$ 2.8	20.9
18	Rate Schedule 7		$ 791.2	6,004.2
19	Rate Schedule 22- Firm Service		$ 1,367.7	10,378.3
20	Rate Schedule 22- Interruptible Service		$ 2,259.3	17,144.2
21	Rate Schedule 25		$ 1,094.2	8,303.3
22	Rate Schedule 27		$ 565.2	4,289.1
23				
24	**Total BVA Rider (Non-Bypass)**		**$ 26,146.4**	**198,408.0**
25				
26	**Calculation BVA Rider Per ($/GJ) Flat Rate**		**$ 0.132**	
27	(Line 6 (Grossed Up $000) divided by Line 6 (TJ)			

In the 2016 Biomethane Decision, FEI was directed to provide a continuity of forecast, actual and variance (actual - forecast) biomethane (BERC) revenues and volumes sold by rate schedule, and type of contract.

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[74] The $0.685 million represents a combined adjustment for the 2021 Actual and Projected BVA balance transfer variance and the 2022 recovery variance because of the 2022 volume projection variance.

[75] Table 10-2, Line 5.

The following table breaks down the BERC revenues and volumes by rate schedule and by short-term and long-term contracts. In 2022, the projected recoveries are $20.769 million attributable to sales volumes of 1,734 TJ from 9,913 RNG customers. The expected sales volume from existing and projected long-term contracts is included in the 2022 Projected volume and revenue in Table 10-3 below.

Table 10-3: BERC Revenue and Volume

Line No.	Volume and Revenue	2021 Actual	2021 Projected	2021 Variance	2022 Projected
1	**Volume (TJ)**				
2	**Short-term**				
3	Rate Schedule 1B	103.7	101.9	1.9	112.1
4	Rate Schedule 2B	23.9	21.2	2.7	88.8
5	Rate Schedule 3B	20.2	18.2	2.0	56.1
6	Rate Schedule 5B	157.6	116.3	41.3	1,077.8
7	Rate Schedule 11B	14.7	133.6	(119.0)	57.0
8	Rate Schedule 46B	3.0	-	3.0	-
9	Rate Schedule 30	-	-	-	-
10	Sub-total	323.1	391.2	(68.1)	1,391.7
11					
12	**Long Term**				
13	Rate Schedule 11B	258.3	277.6	(19.3)	342.0
14	Sub-total	258.3	277.6	(19.3)	342.0
15					
16	**Total Sales Volume (TJ)**	581.4	668.8	(87.4)	1,733.7
17					
18	**Recoveries ($000s)**				
19	**Short-term**				
20	Rate Schedule 1B	$ 1,227.4	$ 1,205.2	$ 22.2	$ 1,448.7
21	Rate Schedule 2B	282.8	250.5	32.3	1,097.9
22	Rate Schedule 3B	237.6	215.1	22.5	692.9
23	Rate Schedule 5B	1,864.6	1,376.2	488.4	12,866.7
24	Rate Schedule 11B	179.53	1,581.0	(1,401.4)	695.5
25	Rate Schedule 46B	35.49	-	35.5	-
26	Rate Schedule 30	-	-	-	-
27	Sub-total	3,827.3	4,627.9	(800.6)	16,801.7
28					
29	**Long Term**				
30	Rate Schedule 11B	2,675.7	2,833.1	(157.4)	3,967.2
31	Sub-total	2,675.7	2,833.1	(157.4)	3,967.2
32				-	
33	**Total Sales**	$ 6,503.0	$ 7,461.0	$ (958.0)	$20,768.9

In the 2016 Biomethane Decision, FEI was also directed to provide the number of customers by rate schedule. The following table sets out the 2022 Projected number of renewable natural gas customers by rate schedule.

Table 10-4: RNG Customers by Rate Schedule

2022 RNG Projected Participation (Rate Schedule)	Customer Enrollment
Short Term	
Rate Schedule 1B	9,647
Rate Schedule 2B	221
Rate Schedule 3B	25
Rate Schedule 11B	2
Rate Schedule 5B	15
Rate Schedule 30 Off System	-
Long Term	
Rate Schedule 11B	3
Total	**9,913**

In summary, the 2023 BVA rate rider attributable to the cumulative December 31, 2022 transfers from the BVA is $0.132 per GJ recoverable from all non-bypass customers.

10.3.2 RSAM Rate Riders

The RSAM Rate Riders collect or refund the previous year's Projected RSAM balance from Rate Schedule 1, 2, 3 and 23 customers over two years. The Projected balance in the RSAM account at the end of 2022 is a credit of $43.112 million. The calculation of the 2023 RSAM riders is shown in Table 10-5.

Table 10-5: 2023 RSAM Riders

2022 RSAM + Interest Closing Balance ($000)	(43,112)
Amortization Period (Years)	2
2023 Amortization Post-Tax ($000)	(21,556)
Tax Rate	27%
2023 Amortization Pre-Tax ($000)	(29,529)

RSAM (Rider 5) Calculation

Rate Class	RSAM Amortization (S000)	2023 Volume (TJ)	Rider ($/GJ)
Rate 1/1BU/1U/1X		82,658.7	(0.209)
Rate 2/2BU/2U/2X		29,050.1	(0.209)
Rate 3/3BU/3U/3X		25,662.4	(0.209)
Rate 23		3,903.8	(0.209)
	(29,529)	141,275.0	(0.209)

The differences that result from the actual 2022 ending RSAM balance varying from the projection, and the actual 2023 volumes varying from the forecast set out in this filing, will be included in the calculation of the 2024 RSAM Riders and, in this way, refunded to or collected from customers.

10.3.3 Clean Growth Innovation Fund (CGIF)

The collection of the $0.40 per month innovation rider commenced on August 1, 2020 and is forecast to collect $5.2 million in 2023.

Table 10-6 below shows the amounts collected and the amounts expended for clean growth projects since the inception of the Fund to the end of 2023. In total, $2.5 million in actual expenditures have been invested up to June 2022, with a further $1.1 million projected to the end of 2022, and $2.5 million for 2023.

Table 10-6: Clean Growth Innovation Fund 2020-2023 Deferral Account Continuity ($millions)

	Actual 2020	Actual 2021	Actual Jan-June 2022	Projected July-Dec 2022	Forecast 2023
Opening Balance	**$ -**	**$ (0.791)**	**$ (3.816)**	**$ (5.545)**	**$ (6.739)**
Gross Additions	1.022	1.127	0.372	1.128	2.500
Rider recoveries	(2.099)	(5.093)	(2.567)	(2.552)	(5.158)
Tax	0.291	1.071	0.593	0.384	0.718
AFUDC	(0.005)	(0.130)	(0.127)	(0.154)	(0.422)
Closing Balance	**$ (0.791)**	**$ (3.816)**	**$ (5.545)**	**$ (6.739)**	**$ (9.101)**

To date, FEI has completed four portfolio reviews with approved spending of $4.3 million, with a further two portfolio reviews anticipated by year-end 2022. The fund approvals are generally focused on the production and delivery of renewable gases (renewable natural gas, syngas, hydrogen), carbon capture, as well as funding FEI's participation in broad low-carbon research activities such as the Low-Carbon Resource Initiative, which is a joint initiative between the Electric Power Research Institute and GTI Energy to accelerate the development and demonstration of low- and zero-carbon energy technologies.

10.3.3.1 Governance

FEI committed to and has established two employee groups with oversight of the CGIF. First, the Innovation Working Group (IWG) is responsible for the identification, evaluation, selection, and execution of projects. The IWG is comprised of FEI staff that provide subject matter expertise from a variety of departments key to assessing the technical and business proposals which are part of the portfolios.

Second, the Executive Steering Committee (ESC) has been established to provide strategic direction to the CGIF and to approve the funding for the portfolios recommended by the IWG and reviewed by the External Advisory Council (EAC).

The EAC is made up of a variety of FEI stakeholders to provide insight and feedback on the Company's innovative initiatives on a periodic basis. The EAC includes the following stakeholders:

- BCOAPO;
- MoveUP;
- BCSEA;
- BC Ministry of Energy, Mines and Low-Carbon Innovation;
- Foresight Cleantech Accelerator Centre;
- BC Bioenergy Network;
- University of Victoria; and
- City of Kamloops.

10.3.3.2 Spending Commitments

Since the 2022 Annual Review, $2.3 million has been approved for spending in Portfolios 3 and 4, as shown in the table below. The table also provides information on Portfolios 1 and 2, which were reported on in the 2022 Annual Review.

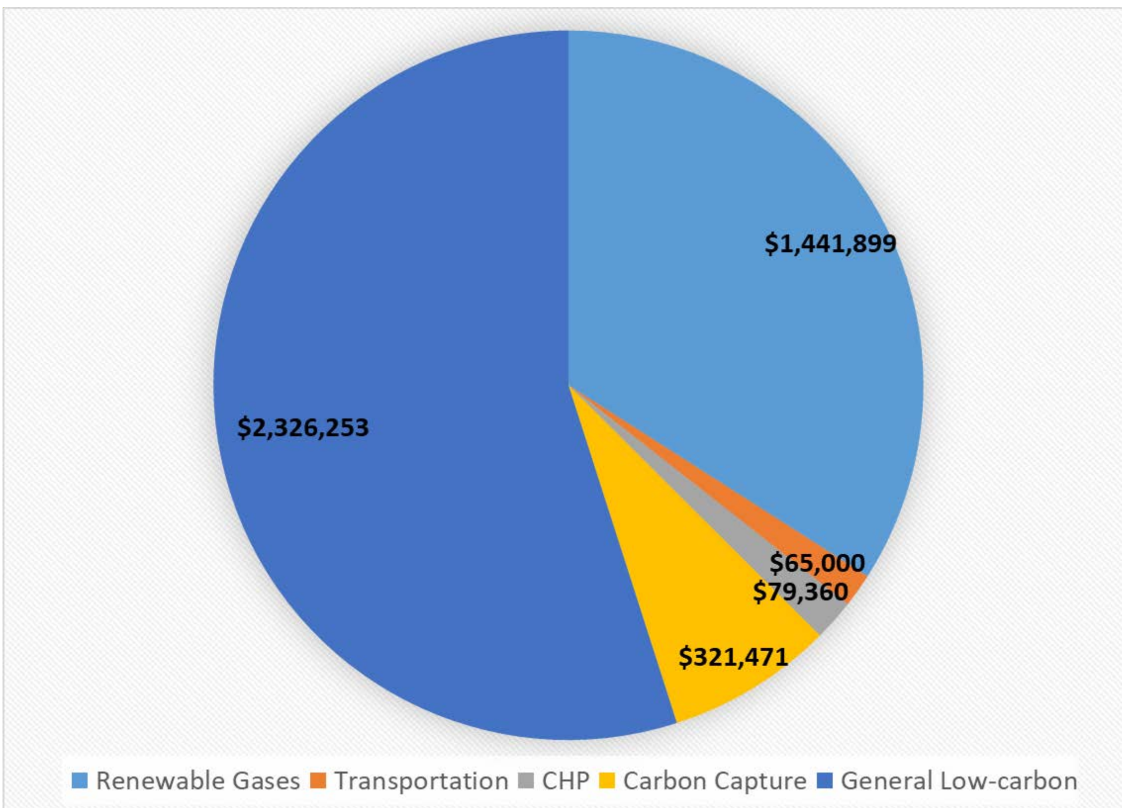
Table 10-7: Approved and Rejected Spending for Portfolios One through Four ($ millions)

	Portfolio 1	Portfolio 2	Portfolio 3	Portfolio 4	Total
Approved	$1.5	$0.5	$1.7	$0.6	$4.3
Rejected, Cancelled or Deferred	$0.2	$3.2	$1.8	$0.2	$5.4

"Rejected, Cancelled or Deferred" are proposals that did not meet the CGIF criteria from the outset, proposals that were approved and subsequently cancelled by one or more parties, and proposals that have merit but require further changes to meet the CGIF criteria. In some cases, Conservation and Energy Management (C&EM) Innovative Technologies has funded projects that were better aligned with its criteria as compared to the CGIF criteria.

The categories for the $4.3 million in approved spending across all four portfolios are shown in the figure below.

Figure 10-1: All CGIF Approved Spending by Category



The categories in the figure above encompass the following types of projects:

- **Renewable Gases.** There are 16 projects approved in this category. The majority of the projects are testing innovative processes for creating low-carbon gaseous fuels, particularly hydrogen and biomethane (renewable natural gas or RNG). Seven of the projects are creating low-carbon hydrogen, five are for improved processes for creating renewable natural gas and one is for syngas.

- **Transportation.** This category includes a single research project focused on reducing GHG emissions from natural gas engines using a combination of lab-based engine experiments, as well as field measurements of GHG emissions from in-use engines.
- **Combined Heat and Power (CHP).** A CHP can produce both heat and electricity from gaseous fuels, including natural gas and hydrogen. FEI funded one demonstration project, which is complete. A second CHP project which could be compatible with hydrogen has been approved for funding since the 2022 Annual Review.
- **Carbon Capture.** This category includes four projects that capture carbon dioxide in some manner. In some cases, the carbon dioxide is converted into other marketable products and in others the carbon dioxide is being selectively captured from exhaust gases. The carbon capture processes being tested are generally suited for capturing smaller, customer-driven carbon emissions rather than large-scale industrial emissions.
- **General Low-Carbon.** These expenditures are related to low-carbon initiatives that broadly advance decarbonization of the gaseous fuel distribution system. Included in this category is FEI's share of the operating expenses of the Canadian Gas Association's NGIF, of which FEI is a member with a number of other Canadian utilities and oil and gas producers. In total, 19 of the 24 proposals funded by the CGIF are NGIF projects that are co-funded by other Canadian utilities and oil and gas producers. This category also includes FEI membership fees related to its participation in the Low Carbon Resource Initiative, discussed below.

Details on each project included in Portfolios 3 and 4 and approved since the 2022 Annual Review are set out in the following table.

Table 10-8: CGIF Approved Project Funding

Primary Partner	Category	CGIF Funding Approved (millions)	Project Description
NGIF	Combined Heat & Power	$0.064	Development of a 3 - 5 kW solid oxide fuel cell (SOFC) CHP for use with natural gas, hydrogen or blends of both. Apogee's CHP will have reduced GHG emissions (when operating with natural gas) through the use of proprietary SOFC that operates at a lower temperature, allowing for lower cost materials.
	Combined Heat & Power Total	**$0.064**	
NGIF	Low-Carbon Gases	$0.094	Development of a combination space and water heater capable of running on 100% hydrogen.

Primary Partner	Category	CGIF Funding Approved (millions)	Project Description
NGIF	Low-Carbon Gases	$0.054	Development of a new stable and efficient process for methane pyrolysis with low emissions. The process is scalable and can be applied in a modular fashion. The process uses a stable alloy as a catalyst for methane decomposition to selectively produce low-carbon hydrogen and solid carbon, at the temperatures below 1,000°C and at atmospheric pressure.
NGIF	Low-Carbon Gases	$0.064	Development of a microwave catalytic methane reformation process which addresses the most polluting aspect of conventional steam methane reforming (gas fired heating) through electrification in a microwave reactor that is also up to 30 times smaller for the same production capacity.
	Low-Carbon Gases Total	**$0.213**	
Low Carbon Resources Initiative	General Low-Carbon	$1.380	The Electric Power Research Institute (EPRI) and Gas Technology Institute (GTI) created the Low Carbon Resources Initiative (LCRI) to accelerate development and demonstration of low- and zero-carbon energy technologies. LCRI will focus on fundamental advances in a variety of low-carbon chemical energy carriers - such as clean hydrogen, bioenergy, and renewable natural gas – that are needed to enable affordable pathways to economy-wide decarbonization. LCRI is a $100 million, five-year effort funded by energy companies and other related businesses or interests.
NGIF	General Low-Carbon	$0.601	NGIF operations and administration expenses for 2021 and 2022 per the NGIF/FortisBC Master Funding Agreement. NGIF-sponsored projects account for $1.2 million of the total CGIF approvals.
	General Low-Carbon	**$1.981**	
	Grand Total	**$2.258**	

The CGIF funding commitment of $1.4 million for the Low Carbon Resources Initiative (LCRI) shown in the table above will be spread equally over the years 2021 to 2024 and is allocated to four subtopics of interest:

1. **Renewable Fuels.** The Renewable Fuels subtopic undertakes and facilitates research on potential renewable fuel options for economy-wide deep decarbonization. Renewable

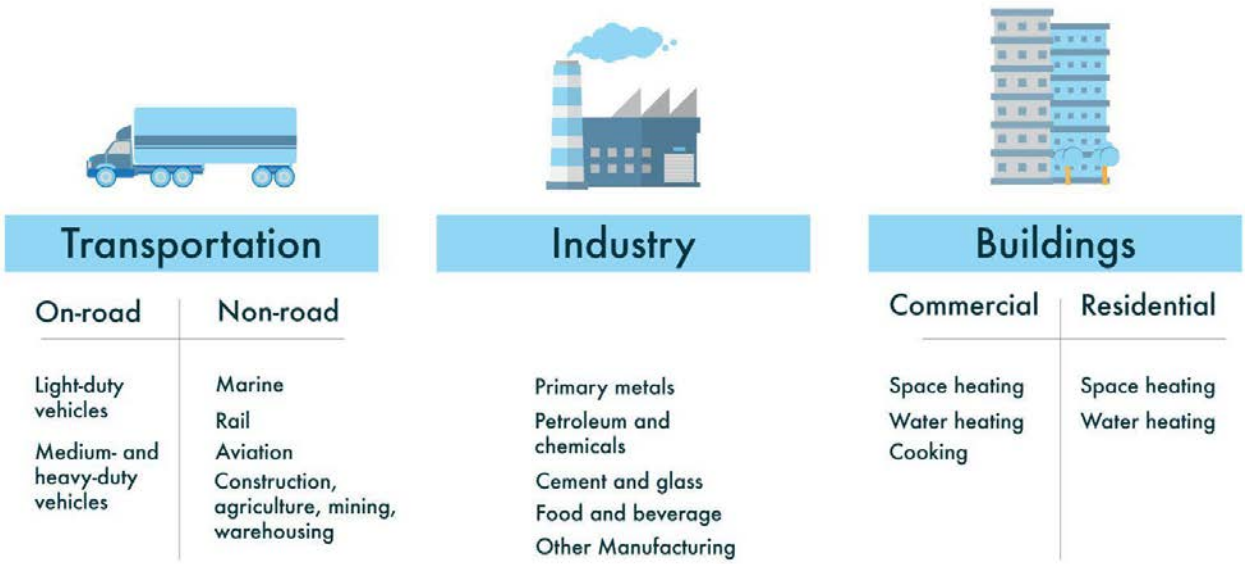
fuels as a concept encompasses many possible energy sources, conversion technologies, and end uses. This Technical Subcommittee is focused on solid and waste renewable biogenic feedstocks and pursues research related to the potential production of Alternative Energy Carriers (AECs). This includes research related to feedstock production and conversion, RNG production from feedstocks such as biomass, biogas, and bio-CO_2. Multiple pathways and conversion technologies will be evaluated that include, but are not limited to, biological, biochemical, and thermochemical routes to produce renewable fuels.

2. **Hydrocarbon-Based Processes.** The Hydrocarbon-Based Processes subtopic is focused on evaluating and advancing technologies in the following areas:
    a. Production of low-carbon energy carriers from hydrocarbons;
    b. Processes for converting hydrogen to other hydrogen-based fuels such as ammonia;
    c. Conversion of CO_2 to fuels; and
    d. Carbon capture and storage from industrial sources as well as from the atmosphere (Direct Air Capture).

3. **Delivery and Storage.** As multiple sectors of the energy economy transition towards a decarbonized future, a more tightly integrated energy system will become even more critical in leveraging electricity, gases, liquids, and existing energy infrastructure. Greater deployment of AECs and fuels will impact transportation and delivery of energy which must be accomplished in an affordable, reliable, and resilient manner. For example, low carbon intensity ammonia may be a useful fuel for powering marine vessels, but a safe and reliable distribution and storage mechanism needs to be designed and deployed. Existing and proven infrastructure will play a key role in enabling AECs, but must be evaluated to ensure adequacy and durability of service. Development of new infrastructure will ensure that energy is delivered where and when it is needed across the economy in the future. The objective of the Delivery and Storage subtopic is to identify and explore the technoeconomic feasibility of various technologies which could enable the delivery, transport, and storage of AECs.

4. **End-Use of Low Carbon Resources.** The LCRI End-Use subtopic is analyzing the landscape of AEC-based decarbonization pathways and technologies from a customer segmentation and final energy application perspective. Work is divided into three major end-use sectors: Buildings, Transportation, and Industry. Detailed assessments of the low-carbon resource landscape for each of these market segments and sub-segments have been developed and used to inform this roadmap.

Figure 10-2: Major End-Uses Addressed by the LCRI



10.3.3.3 Results-to-Date

Three projects were completed since the 2022 Annual Review, all in the Low-Carbon Gases category, and all through FEI's membership in the NGIF. The results of these projects are described below.

10.3.3.3.1 EKONA POWER INC.

Ekona Power Inc. (Ekona) is a company based in Vancouver that was approved for $43 thousand in CGIF funding for the development and field testing of a Tri-Generation Pyrolysis (TGP) system for low-cost, clean hydrogen production from natural gas. The Ekona technologies include the pyrolysis reactor and a fuel cell for creating electricity from the solid carbon by-product of pyrolysis.

Ekona achieved the milestones expected from the funding, specifically:

- Field trial program plan with lead customers completed.
- Completed proof-of-concept (PoC) pyrolyzer reactor design and test fixture design.
- PoC pyrolyzer and test fixture assembly complete, includes completing of manufacturing drawings, purchasing and assembly of BOM. Test facilities established and building and assembling the pyrolyzer reactor and associated test fixture subsystems complete.
- Testing completed to verify hydrogen and carbon production efficiencies, measure production gases to validate modelling, and confirm by-product carbon morphology for integration with fuel cell technology. Testing completed to validate Ekona's techno-economic model and inform prototype reactor design.

- PoC fuel cell design and test fixture complete. PoC fuel cell built and delivered to lab for testing.
- Analysis and reporting demonstrates the validity of the PoC fuel cell design for scaling to industrial applications and informs the design of next stage unit cell and stack development.

In February 2022, after these milestones were successfully completed, Ekona announced the close of a CAD $79 million equity investment from eight companies. The investment will support the commercialization of Ekona's novel methane pyrolysis technology platform.

Pyrolysis-based hydrogen is an important technology as it is likely to be competitive in price and carbon intensity with both "green" (electrolysis-based) and "blue" (steam methane reforming with carbon capture) hydrogen. Pyrolysis-based technologies can also operate efficiently at a relatively small scale, enabling the deployment of "hydrogen hubs" that can directly supply large individual customers with 100 percent hydrogen while providing the existing gas distribution network with hydrogen for blending. Ekona's progress toward making this technology commercially feasible will help maximize potential deliveries of low carbon-intensity hydrogen to customers with the minimum amount of infrastructure that must be adapted to hydrogen.

10.3.3.4 G4 Insights Inc.

G4 Insights Inc. is a Vancouver-based company developing and commercializing a proprietary PyroCatalytic Hydrogenation Process (PCH) to produce renewable natural gas. PCH is a low temperature thermochemical process that enables large-scale, economic production of renewable natural gas from biomass. The CGIF invested $77 thousand through the NGIF in this innovative technology.

Key milestones included:

- Continuous successful run-time of the technology for 24 hours with at least 97 percent methane purity and total produced methane volume of 12 cubic metres.
- Continuous operation for 36 hours with at least 97 percent methane purity and total produced methane volume of 18 cubic metres (0.5 cubic metre/hour RNG output).
- Continuous operation for 12 hours with at least 97 percent methane purity and total produced methane volume of 9 cubic metres (0.75 cubic metre/hour RNG output).

Due to an ancillary equipment failure, the last milestone was missed by five hours. However, this milestone and the other two were considered complete by all NGIF participants, including FEI.

Pyrolysis-generated hydrogen is an important technology for the reasons described in the Ekona project, above.

10.3.3.5 CHAR Technologies

This project involves scaling-up CHAR's pilot production system to demonstrate that it can efficiently and safely scrub hydrogen sulfide from a biogas stream to an amount less than 4 parts per million.

The CGIF invested $0.077 million in this project through its participation in the NGIF. Key milestones included:

- Complete design, engineering, fabrication and pre-commissioning of production unit.
- Installation, commissioning and operation of production unit.
- Full-scale demonstration of removing H_2S at a biogas facility and testing the spent byproduct as a soil conditioner/fertilizer.

The system was installed, commissioned and operated, producing five tonnes of biocarbon.

Multiple batches of biocarbon were produced and used in multiple trials in a real-world application, at an operational biogas plant, showing its ability to remove H_2S from biogas at a lower cost than current technologies.

Ultimately, this technology could reduce the operating costs for the removal of hydrogen sulfide from renewable natural gas, allowing biogas producers to be more competitive with overall pricing, and leading to more renewable natural gas into the grid.

10.4 SUMMARY

As discussed in Section 10.2 above, FEI proposes to distribute a $0.377 million pre-tax credit ($0.275 million after-tax) earnings sharing amount to customers as part of 2023 delivery rates. In Section 10.3, FEI updated all of the 2023 delivery rate riders for 2022 Projected ending balances and 2023 Forecast volumes. Based on these updates, FEI has calculated a BVA rate rider of $0.132 per GJ and a RSAM credit rate rider of $0.209 per GJ for 2023 for a net delivery rate rider credit of $0.077 per GJ. FEI has also provided details on the CGIF in Section 10.3, which is funded through the collection of the basic charge CGIF rider.

11. FINANCIAL SCHEDULES

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Summary Of Rate Change	1
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Formula Inflation Factors	3
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Capital Expenditures To Plant Reconciliation	5
Plant In Service Continuity Schedule	6
Accumulated Depreciation Continuity Schedule	7
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Contributions In Aid Of Construction Continuity Schedule	9
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Embedded Cost Of Long Term Debt	27

SUMMARY OF RATE CHANGE
FOR THE YEAR ENDING DECEMBER 31, 2023
($millions)

Line No.	Particulars	2023 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	$ 2.253		
3	Change in Other Revenue	(0.357)	1.896	
4				
5	**O&M CHANGES**			
6	Gross O&M Change	18.767		
7	Capitalized Overhead Change	(3.304)	15.463	
8				
9	**DEPRECIATION EXPENSE**			
10	Depreciation from Net Additions		12.159	
11				
12	**AMORTIZATION EXPENSE**			
13	CIAC from Net Additions	(0.098)		
14	Deferrals	3.679	3.581	
15				
16	**FINANCING AND RETURN ON EQUITY**			
17	Financing Rate Changes	5.841		
18	Financing Ratio Changes	(3.139)		
19	Rate Base Growth	31.915	34.617	
20				
21	**TAX EXPENSE**			
22	Property and Other Taxes	5.588		
23	Other Income Taxes Changes	(1.587)	4.001	
24				
25				
26	**REVENUE DEFICIENCY (SURPLUS)**		**$ 71.717**	Schedule 16, Line 11, Column 4
27				
28	Non-Bypass Margin at 2022 Approved Rates		966.767	Schedule 19, Line 17, Column 3
29	Rate Change		7.42%	

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 7,867,224	$ 8,210,710	$ 343,486	Schedule 6.2, Line 35, Column 3
2	Opening Balance Adjustment	-	-	-	Schedule 6.2, Line 35, Column 4
3	Net Additions	355,808	598,203	242,395	Schedule 6.2, Line 35, Columns 5+6+7
4	Plant in Service, Ending	8,223,032	8,808,913	585,881	
5					
6	Accumulated Depreciation Beginning	$ (2,423,184)	$ (2,571,244)	$ (148,060)	Schedule 7.2, Line 35, Column 5
7	Opening Balance Adjustment	-	-	-	Schedule 7.2, Line 35, Column 6
8	Net Additions	(152,345)	(155,994)	(3,649)	Schedule 7.2, Line 35, Columns 7+8
9	Accumulated Depreciation Ending	(2,575,529)	(2,727,238)	(151,709)	
10					
11	CIAC, Beginning	$ (451,881)	$ (457,733)	$ (5,852)	Schedule 9, Line 6, Column 2
12	Opening Balance Adjustment	-	-	-	
13	Net Additions	(5,852)	(6,799)	(947)	Schedule 9, Line 6, Columns 5+6
14	CIAC, Ending	(457,733)	(464,532)	(6,799)	
15					
16	Accumulated Amortization Beginning - CIAC	$ 187,384	$ 196,013	$ 8,629	Schedule 9, Line 13, Column 2
17	Opening Balance Adjustment	-	-	-	
18	Net Additions	8,628	8,726	98	Schedule 9, Line 13, Columns 5+6
19	Accumulated Amortization Ending - CIAC	196,012	204,739	8,727	
20					
21	Net Plant in Service, Mid-Year	$ 5,282,663	$ 5,599,814	$ 317,151	
22					
23	Adjustment for timing of Capital additions	$ 49,088	$ 122,355	$ 73,267	
24	Capital Work in Progress, No AFUDC	42,035	42,695	660	
25	Unamortized Deferred Charges	(32,829)	51,711	84,540	Schedule 11.1, Line 26, Column 10
26	Working Capital	68,253	113,372	45,119	Schedule 13, Line 14, Column 3
27	Deferred Income Taxes Regulatory Asset	689,807	747,445	57,638	Schedule 15, Line 6, Column 3
28	Deferred Income Taxes Regulatory Liability	(689,807)	(747,445)	(57,638)	Schedule 15, Line 6, Column 3
29	LILO Benefit	(3)	-	3	
30					
31	Mid-Year Utility Rate Base	$ 5,409,207	$ 5,929,947	$ 520,740	

FORMULA INFLATION FACTORS
FOR THE YEARS ENDING DECEMBER 31, 2020 to 2023
($000s)

Line No.	Particulars	Reference	2020	2021	2022	2023	Total for 2023 Rate Setting	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**Formula Cost Drivers**							
2	CPI		2.692%	1.596%	1.281%	4.940%		
3	AWE		2.881%	5.745%	6.455%	4.235%		
4	Labour Split							
5	Non Labour		48.000%	48.000%	49.000%	49.000%		
6	Labour		52.000%	52.000%	51.000%	51.000%		
7	CPI/AWE	(Line 2 x Line 5) + (Line 3 x Line 6)	2.790%	3.753%	3.920%	4.580%		
8	Productivity Factor	G-165-20	-0.500%	-0.500%	-0.500%	-0.500%		
9	Net Inflation Factor	Line 7 + Line 8	2.290%	3.253%	3.420%	4.080%		
10								
11								
12	**Growth in Average Customer Calculation**							
13	Actual/Projected Prior Year Average Customers		1,031,862	1,044,622	1,057,086	1,066,393		
14	Average Customers for the Year	Schedule 19, Line 30, Column 9	1,044,622	1,057,086	1,066,393	1,074,714		
15	Change in Average Customers	Line 14 - Line 13	12,760	12,464	9,307	8,320	42,851	
16	Customer Growth Factor Multiplier	G-165-20					75%	
17	Change in Customers - Rate Setting Purposes	Line 15 x Line 16					32,138	
18								
19	**Average Customer Continuity for Rate Setting Purposes**							
20	Average Customers Used to Determine Starting UCOM	Line 13, Column 3					1,031,862	
21								
22	Average Customer Forecast - Rate Setting Purposes	Line 17 + Line 20					1,064,000	

Schedule 4

CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	Growth CapEx	Other CapEx	Forecast CapEx	Total CapEx	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Inflation Indexed Capital Growth**					
2	2022 Unit Cost Growth Capital	$ 4,046				
3	2023 Net Inflation Factor	4.080%				Schedule 3, Line 9, Column 6
4	2023 Unit Cost Growth Capital	$ 4,211				
5	2023 Gross Customer Additions	16,000				
6	2023 Inflation Indexed Growth Capital	$ 67,376			$ 67,376	
7	2021 Growth Capital Customer True-Up				16,798	
8	2023 System Extension Fund				1,000	
9	2023 Growth CIAC				2,457	
10	2023 Inflation Indexed Gross Growth Capital				$ 87,631	
11						
12	**Capital Tracked Outside of Formula**					
13	Pension & OPEB (Growth Capital Portion)			$ 1,034		
14	Biomethane Assets			58,571		
15	NGT Assets			6,567		
16	Sustainment Capital			129,086		
17	Other Capital			54,456		
18	Sub-total			$ 249,714	249,714	
19						
20	**Total Capital Expenditures Before CIAC**				$ 337,345	

CAPITAL EXPENDITURES TO PLANT RECONCILIATION
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 5

Line No.	Particulars		2023 Formula	Cross Reference
	(1)		(2)	(3)
1	**CAPEX**			
2	Growth Capital Expenditures	$	87,631	Schedule 4, Line 10, Column 5
3	Forecast Capital Expenditures		249,714	Schedule 4, Line 18, Column 5
4	Total Capital Expenditures	$	337,345	
5				
6	**Special Projects and CPCN's**			
7	Tilbury 1A Expansion	$	2,177	
8	LMIPSU CPCN		6	
9	Inland Gas Upgrade		56,518	
10	Transmission Integrity Program (CTS TIMC)		29,551	
11	Pattullo Gasline Replacement		3,481	
12	Gibsons Capacity Upgrade		6,950	
13	Total Capital Expenditures	$	98,683	
14				
15	**Total Capital Expenditures**	$	436,028	
16				
17				
18	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**			
19				
20	Regular Capital Expenditures	$	337,345	Line 4
21	Add - Capitalized Overheads		56,632	Schedule 20, Line 27, Column 4
22	Add - AFUDC		5,225	
23	Gross Capital Expenditures		399,202	
24	Change in Work in Progress		19,669	
25	**Total Regular Additions to Plant**	$	418,871	
26				
27	Special Projects and CPCN's Capital Expenditures	$	98,683	Line 13
28	Add - AFUDC		4,899	
29	Gross Capital Expenditures		103,582	
30	Change in Work in Progress		143,306	
31	**Total Special Projects and CPCN Additions to Plant**	$	246,888	
32				
33	**Grand Total Additions to Plant**	$	665,759	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 6

Line No.	Account	Particulars	12/31/2022	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**INTANGIBLE PLANT**							
2	175-10	Unamortized Conversion Expense	$ 109	$ -	$ -	$ -	$ -	$ 109	
3	175-00	Unamortized Conversion Expense - Squamish	-	-	-	-	-	-	
4	178-00	Organization Expense	728	-	-	-	-	728	
5	401-01	Franchise and Consents	197	-	-	-	-	197	
6	402-11	Utility Plant Acquisition Adjustment	-	-	-	-	-	-	
7	402-03	Other Intangible Plant	1,907	-	-	-	-	1,907	
8	440-02	Water/Land Rights Tilbury	4,299	-	-	-	-	4,299	
9	461-01	Transmission Land Rights	52,986	-	-	-	-	52,986	
10	461-02	Transmission Land Rights - Mt. Hayes	609	-	-	-	-	609	
11	461-12	Transmission Land Rights - Byron Creek	16	-	-	-	-	16	
12	461-13	IP Land Rights Whistler	24	-	-	-	-	24	
13	471-01	Distribution Land Rights	3,482	-	-	-	-	3,482	
14	471-11	Distribution Land Rights - Byron Creek	1	-	-	-	-	1	
15	402-01	Application Software - 12.5%	66,584	-	-	11,854	(5,984)	72,454	
16	402-02	Application Software - 20%	37,380	-	-	11,573	(3,946)	45,007	
17			$ 168,322	$ -	$ -	$ 23,427	$ (9,930)	$ 181,819	
18									
19		**MANUFACTURED GAS / LOCAL STORAGE**							
20	430-00	Manufact'd Gas - Land	$ 31	$ -	$ -	$ -	$ -	$ 31	
21	432-00	Manufact'd Gas - Struct. & Improvements	1,199	-	-	-	-	1,199	
22	433-00	Manufact'd Gas - Equipment	610	-	-	-	-	610	
23	434-00	Manufact'd Gas - Gas Holders	2,955	-	-	-	-	2,955	
24	436-00	Manufact'd Gas - Compressor Equipment	367	-	-	-	-	367	
25	437-00	Manufact'd Gas - Measuring & Regulating Equipment	1,714	-	-	-	-	1,714	
26	440-00	Land in Fee Simple and Land Rights (Tilbury)	15,164	-	-	-	-	15,164	
27	442-00	Structures & Improvements (Tilbury)	100,809	-	-	-	-	100,809	
28	443-00	Gas Holders - Storage (Tilbury)	180,974	-	-	-	-	180,974	
29	448-11	Piping (Tilbury)	48,635	-	-	-	-	48,635	
30	448-21	Pre-treatment (Tilbury)	38,682	-	70	-	-	38,752	
31	448-31	Liquefaction Equipment (Tilbury)	92,672	-	2,107	-	-	94,779	
32	449-00	Local Storage Equipment (Tilbury)	27,862	-	-	-	-	27,862	
33	440-01	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	-	-	-	-	1,083	
34	442-01	Structures & Improvements (Mount Hayes)	19,045	-	-	-	-	19,045	
35	443-05	Gas Holders - Storage (Mount Hayes)	61,774	-	-	-	-	61,774	
36	448-41	Send out Equipment(Tilbury)	7,746	-	-	20,426	-	28,172	
37	448-51	Sub-station and Electric (Tilbury)	36,846	-	-	-	-	36,846	
38	448-61	Control Room (Tilbury)	3,805	-	-	-	-	3,805	
39	448-10	Piping (Mount Hayes)	12,455	-	-	-	-	12,455	
40	448-20	Pre-treatment (Mount Hayes)	29,238	-	-	-	-	29,238	
41	448-30	Liquefaction Equipment (Mount Hayes)	28,880	-	-	-	-	28,880	
42	448-40	Send out Equipment (Mount Hayes)	23,552	-	-	-	-	23,552	
43	448-50	Sub-station and Electric (Mount Hayes)	21,788	-	-	-	-	21,788	
44	448-60	Control Room (Mount Hayes)	6,425	-	-	-	-	6,425	
45	448-65	MH Inspection (Mount Hayes)	-	-	-	-	-	-	
46	449-01	Local Storage Equipment (Mount Hayes)	5,727	-	-	-	-	5,727	
47			$ 770,038	$ -	$ 2,177	$ 20,426	$ -	$ 792,641	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Account	Particulars	12/31/2022	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**TRANSMISSION PLANT**							
2	460-00	Land in Fee Simple	$ 10,805	$ -	$ -	$ 349	$ -	$ 11,154	
3	461-00	Transmission Land Rights	-	-	-	-	-	-	
4	462-00	Compressor Structures	38,679	-	-	1,623	(254)	40,048	
5	463-00	Measuring Structures	20,210	-	-	4,242	(143)	24,309	
6	464-00	Other Structures & Improvements	12,622	-	-	-	-	12,622	
7	465-00	Mains	1,606,551	-	84,096	12,941	(1,120)	1,702,468	
8	465-20	Mains - INSPECTION	52,083	-	1,817	13,516	(5,759)	61,657	
9	465-11	IP Transmission Pipeline - Whistler	58,689	-	-	207	-	58,896	
10	465-30	Mt Hayes - Mains	6,307	-	-	-	-	6,307	
11	465-10	Mains - Byron Creek	1,371	-	-	-	-	1,371	
12	466-00	Compressor Equipment	203,229	-	-	1,914	(478)	204,665	
13	466-10	Compressor Equipment - OVERHAUL	8,199	-	-	633	(2,323)	6,509	
14	467-00	Mt. Hayes - Measuring and Regulating Equipment	8,276	-	-	-	-	8,276	
15	467-10	Measuring & Regulating Equipment	103,325	-	1,247	3,161	(120)	107,613	
16	467-20	Telemetering	18,289	-	-	501	(11)	18,779	
17	467-31	IP Intermediate Pressure Whistler	404	-	-	-	-	404	
18	467-30	Measuring & Regulating Equipment - Byron Creek	291	-	-	-	-	291	
19	468-00	Communication Structures & Equipment	13,428	-	-	-	-	13,428	
20			$ 2,162,758	$ -	$ 87,160	$ 39,087	$ (10,208)	$ 2,278,797	
21									
22		**DISTRIBUTION PLANT**							
23	470-00	Land in Fee Simple	$ 5,457	$ -	$ -	$ 90	$ -	$ 5,547	
24	472-00	Structures & Improvements	62,891	-	-	505	(17)	63,379	
25	472-10	Structures & Improvements - Byron Creek	124	-	-	-	-	124	
26	473-00	Services	1,501,521	-	-	88,574	(3,656)	1,586,439	
27	474-00	House Regulators & Meter Installations	158,179	-	-	24,929	(6,183)	176,925	
28	474-02	Meters/Regulators Installations	237,640	-	-	-	-	237,640	
29	475-00	Mains	2,067,303	-	157,551	81,006	(4,852)	2,301,008	
30	476-00	Compressor Equipment	614	-	-	-	-	614	
31	477-10	Measuring & Regulating Equipment	228,840	-	-	12,272	(706)	240,406	
32	477-20	Telemetering	23,515	-	-	1,429	(83)	24,861	
33	477-30	Measuring & Regulating Equipment - Byron Creek	153	-	-	-	-	153	
34	478-10	Meters	317,076	-	-	21,577	(5,873)	332,780	
35	478-20	Instruments	16,172	-	-	525	-	16,697	
36	479-00	Other Distribution Equipment	-	-	-	-	-	-	
37			$ 4,619,485	$ -	$ 157,551	$ 230,907	$ (21,370)	$ 4,986,573	
38									
39		**BIO GAS**							
40	472-20	Bio Gas Struct. & Improvements	$ 777	$ -	$ -	$ 6,021	$ -	$ 6,798	
41	475-10	Bio Gas Mains – Municipal Land	3,098	-	-	23,748	-	26,846	
42	475-20	Bio Gas Mains – Private Land	398	-	-	-	-	398	
43	418-10	Bio Gas Purification Overhaul	24	-	-	-	-	24	
44	418-20	Bio Gas Purification Upgrader	11,563	-	-	28,334	-	39,897	
45	477-40	Bio Gas Reg & Meter Equipment	3,819	-	-	4,666	-	8,485	
46	478-30	Bio Gas Meters	41	-	-	248	-	289	
47	474-10	Bio Gas Reg & Meter Installations	770	-	-	1,680	-	2,450	
48	483-25	RNG Comp S/W	-	-	-	-	-	-	
49			$ 20,490	$ -	$ -	$ 64,697	$ -	$ 85,187	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 6.2

Line No.	Account	Particulars	12/31/2022	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Natural Gas for Transportation**							
2	476-10	NG Transportation CNG Dispensing Equipment	$ 18,597	$ -	$ -	$ 1,202	$ -	$ 19,799	
3	476-20	NG Transportation LNG Dispensing Equipment	13,714	-	-	-	-	13,714	
4	476-30	NG Transportation CNG Foundations	3,141	-	-	-	-	3,141	
5	476-40	NG Transportation LNG Foundations	1,049	-	-	-	-	1,049	
6	476-50	NG Transportation LNG Pumps (Pumps only apply to LNG)	77	-	-	-	-	77	
7	476-60	NG Transportation CNG Dehydrator	809	-	-	-	-	809	
8	476-70	NG Transportation LNG Dehydrator	-	-	-	-	-	-	
9			$ 37,387	$ -	$ -	$ 1,202	$ -	$ 38,589	
10									
11		**GENERAL PLANT & EQUIPMENT**							
12	480-00	Land in Fee Simple	$ 31,306	$ -	$ -	$ -	$ -	$ 31,306	
13	482-10	Frame Buildings	24,658	-	-	707	-	25,365	
14	482-20	Masonry Buildings	128,253	-	-	4,842	(124)	132,971	
15	482-30	Leasehold Improvement	3,224	-	-	90	(54)	3,260	
16	483-30	GP Office Equipment	3,408	-	-	133	(42)	3,499	
17	483-40	GP Furniture	22,238	-	-	2,293	(412)	24,119	
18	483-10	GP Computer Hardware	48,417	-	-	11,611	(19,628)	40,400	
19	483-20	GP Computer Software	4,143	-	-	-	(635)	3,508	
20	484-00	Vehicles	61,391	-	-	9,150	-	70,541	
21	484-10	Vehicles - Leased	13,963	-	-	-	(1,458)	12,505	
22	485-10	Heavy Work Equipment	750	-	-	4	-	754	
23	485-20	Heavy Mobile Equipment	9,277	-	-	1,721	-	10,998	
24	486-00	Small Tools & Equipment	60,614	-	-	7,127	(3,556)	64,185	
25	487-20	Equipment on Customer's Premises	-	-	-	-	-	-	
26	488-10	Telephone	1,223	-	-	-	(139)	1,084	
27	488-20	Radio	19,365	-	-	1,447	-	20,812	
28	489-00	Other General Equipment	-	-	-	-	-	-	
29			$ 432,230	$ -	$ -	$ 39,125	$ (26,048)	$ 445,307	
30									
31		**UNCLASSIFIED PLANT**							
32	499-00	Plant Suspense	-	-	-	-	-	-	
33			$ -	$ -	$ -	$ -	$ -	$ -	
34									
35		**Total Plant in Service**	$ 8,210,710	$ -	$ 246,888	$ 418,871	$ (67,556)	$ 8,808,913	
36									
37		Cross Reference			Schedule 5, Line 31, Column 2	Schedule 5, Line 25, Column 2			

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 7

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2022	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2023	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**INTANGIBLE PLANT**										
2	175-10	Unamortized Conversion Expense	$ 109	1.00%	$ 66	$ -	$ 1	$ -	$ -	$ -	$ 67	
3	175-00	Unamortized Conversion Expense - Squamish	-	10.00%	-	-	-	-	-	-	-	
4	178-00	Organization Expense	728	1.00%	464	-	7	-	-	-	471	
5	401-01	Franchise and Consents	197	1.08%	149	-	2	-	-	-	151	
6	402-11	Utility Plant Acquisition Adjustment	-	0.00%	-	-	-	-	-	-	-	
7	402-03	Other Intangible Plant	1,907	2.50%	1,294	-	48	-	-	-	1,342	
8	440-02	Water/Land Rights Tilbury	4,299	0.00%	-	-	-	-	-	-	-	
9	461-01	Transmission Land Rights	52,986	0.00%	1,766	-	-	-	-	-	1,766	
10	461-02	Transmission Land Rights - Mt. Hayes	609	0.00%	-	-	-	-	-	-	-	
11	461-12	Transmission Land Rights - Byron Creek	16	0.00%	19	-	-	-	-	-	19	
12	461-13	IP Land Rights Whistler	24	0.00%	-	-	-	-	-	-	-	
13	471-01	Distribution Land Rights	3,482	0.00%	248	-	-	-	-	-	248	
14	471-11	Distribution Land Rights - Byron Creek	1	0.00%	1	-	-	-	-	-	1	
15	402-01	Application Software - 12.5%	66,584	12.50%	27,620	-	8,323	(5,984)	-	-	29,959	
16	402-02	Application Software - 20%	37,380	20.00%	8,712	-	7,475	(3,946)	-	-	12,241	
17			$ 168,322		$ 40,339	$ -	$ 15,856	$ (9,930)	$ -	$ -	$ 46,265	
18												
19		**MANUFACTURED GAS / LOCAL STORAGE**										
20	430-00	Manufact'd Gas - Land	$ 31	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
21	432-00	Manufact'd Gas - Struct. & Improvements	1,199	2.50%	455	-	30	-	-	-	485	
22	433-00	Manufact'd Gas - Equipment	610	5.00%	375	-	30	-	-	-	405	
23	434-00	Manufact'd Gas - Gas Holders	2,955	2.50%	951	-	74	-	-	-	1,025	
24	436-00	Manufact'd Gas - Compressor Equipment	367	4.00%	198	-	15	-	-	-	213	
25	437-00	Manufact'd Gas - Measuring & Regulating Equipment	1,714	5.00%	1,330	-	86	-	-	-	1,416	
26	440-00	Land in Fee Simple and Land Rights (Tilbury)	15,164	0.00%	1	-	-	-	-	-	1	
27	442-00	Structures & Improvements (Tilbury)	100,809	2.20%	13,301	-	2,218	-	-	-	15,519	
28	443-00	Gas Holders - Storage (Tilbury)	180,974	1.23%	22,823	-	2,225	-	-	-	25,048	
29	448-11	Piping (Tilbury)	48,635	2.45%	4,283	-	1,192	-	-	-	5,475	
30	448-21	Pre-treatment (Tilbury)	38,752	3.84%	5,217	-	1,488	-	-	-	6,705	
31	448-31	Liquefaction Equipment (Tilbury)	94,779	2.45%	8,555	-	2,322	-	-	-	10,877	
32	449-00	Local Storage Equipment (Tilbury)	27,862	2.77%	20,494	-	772	-	-	-	21,266	
33	440-01	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	0.00%	-	-	-	-	-	-	-	
34	442-01	Structures & Improvements (Mount Hayes)	19,045	3.85%	8,295	-	733	-	-	-	9,028	
35	443-05	Gas Holders - Storage (Mount Hayes)	61,774	1.65%	11,656	-	1,019	-	-	-	12,675	
36	448-41	Send out Equipment(Tilbury)	7,746	2.41%	695	-	187	-	-	-	882	
37	448-51	Sub-station and Electric (Tilbury)	36,846	2.41%	3,530	-	888	-	-	-	4,418	
38	448-61	Control Room (Tilbury)	3,805	6.09%	910	-	232	-	-	-	1,142	
39	448-10	Piping (Mount Hayes)	12,455	2.45%	3,415	-	305	-	-	-	3,720	
40	448-20	Pre-treatment (Mount Hayes)	29,238	3.84%	13,192	-	1,123	-	-	-	14,315	
41	448-30	Liquefaction Equipment (Mount Hayes)	28,880	2.45%	8,262	-	708	-	-	-	8,970	
42	448-40	Send out Equipment (Mount Hayes)	23,552	2.41%	6,634	-	568	-	-	-	7,202	
43	448-50	Sub-station and Electric (Mount Hayes)	21,788	2.41%	6,191	-	525	-	-	-	6,716	
44	448-60	Control Room (Mount Hayes)	6,425	6.09%	4,587	-	391	-	-	-	4,978	
45	448-65	MH Inspection (Mount Hayes)	-	20.00%	-	-	-	-	-	-	-	
46	449-01	Local Storage Equipment (Mount Hayes)	5,727	3.08%	1,172	-	176	-	-	-	1,348	
47			$ 772,215		$ 146,522	$ -	$ 17,307	$ -	$ -	$ -	$ 163,829	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 7.1

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2022	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2023	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**TRANSMISSION PLANT**										
2	460-00	Land in Fee Simple	$ 10,805	0.00%	$ 503	$ -	$ -	$ -	$ -	$ -	$ 503	
3	461-00	Transmission Land Rights	-	0.00%	-	-	-	-	-	-	-	
4	462-00	Compressor Structures	38,679	3.32%	21,341	-	1,284	(254)	-	-	22,371	
5	463-00	Measuring Structures	20,210	2.13%	9,094	-	430	(143)	-	-	9,381	
6	464-00	Other Structures & Improvements	12,622	3.62%	4,335	-	457	-	-	-	4,792	
7	465-00	Mains	1,690,647	1.46%	493,767	-	24,683	(1,120)	-	-	517,330	
8	465-20	Mains - INSPECTION	53,900	15.20%	17,732	-	8,194	(5,759)	-	-	20,167	
9	465-11	IP Transmission Pipeline - Whistler	58,689	1.54%	9,142	-	904	-	-	-	10,046	
10	465-30	Mt Hayes - Mains	6,307	1.54%	1,175	-	97	-	-	-	1,272	
11	465-10	Mains - Byron Creek	1,371	5.03%	1,635	-	69	-	-	-	1,704	
12	466-00	Compressor Equipment	203,229	2.42%	110,291	-	4,918	(478)	-	-	114,731	
13	466-10	Compressor Equipment - OVERHAUL	8,199	10.19%	5,881	-	836	(2,323)	-	-	4,394	
14	467-00	Mt. Hayes - Measuring and Regulating Equipment	8,276	2.34%	2,031	-	194	-	-	-	2,225	
15	467-10	Measuring & Regulating Equipment	104,572	2.12%	32,462	-	2,217	(120)	-	-	34,559	
16	467-20	Telemetering	18,289	8.97%	16,510	-	1,640	(11)	-	-	18,139	
17	467-31	IP Intermediate Pressure Whistler	404	2.26%	135	-	9	-	-	-	144	
18	467-30	Measuring & Regulating Equipment - Byron Creek	291	2.41%	52	-	7	-	-	-	59	
19	468-00	Communication Structures & Equipment	13,428	0.00%	4,393	-	-	-	-	-	4,393	
20			$ 2,249,918		$ 730,479	$ -	$ 45,939	$ (10,208)	$ -	$ -	$ 766,210	
21												
22		**DISTRIBUTION PLANT**										
23	470-00	Land in Fee Simple	$ 5,457	0.00%	$ (13)	$ -	$ -	$ -	$ -	$ -	$ (13)	
24	472-00	Structures & Improvements	62,891	2.15%	13,525	-	1,352	(17)	-	-	14,860	
25	472-10	Structures & Improvements - Byron Creek	124	4.67%	89	-	6	-	-	-	95	
26	473-00	Services	1,501,521	2.18%	418,279	-	32,733	(3,656)	-	-	447,356	
27	474-00	House Regulators & Meter Installations	158,179	7.45%	112,591	-	11,784	(6,183)	-	-	118,192	
28	474-02	Meters/Regulators Installations	237,640	4.55%	55,198	-	10,813	-	-	-	66,011	
29	475-00	Mains	2,224,854	1.35%	586,567	-	30,036	(4,852)	-	-	611,751	
30	476-00	Compressor Equipment	614	0.00%	1,444	-	-	-	-	-	1,444	
31	477-10	Measuring & Regulating Equipment	228,840	2.51%	70,582	-	5,744	(706)	-	-	75,620	
32	477-20	Telemetering	23,515	3.59%	8,424	-	844	(83)	-	-	9,185	
33	477-30	Measuring & Regulating Equipment - Byron Creek	153	0.00%	210	-	-	-	-	-	210	
34	478-10	Meters	317,076	6.06%	195,702	-	19,214	(5,873)	-	-	209,043	
35	478-20	Instruments	16,172	2.92%	8,122	-	472	-	-	-	8,594	
36	479-00	Other Distribution Equipment	-	0.00%	-	-	-	-	-	-	-	
37			$ 4,777,036		$ 1,470,720	$ -	$ 112,998	$ (21,370)	$ -	$ -	$ 1,562,348	
38												
39		**BIO GAS**										
40	472-20	Bio Gas Struct. & Improvements	$ 777	2.69%	$ 166	$ -	$ 21	$ -	$ -	$ -	$ 187	
41	475-10	Bio Gas Mains – Municipal Land	3,098	1.56%	193	-	49	-	-	-	242	
42	475-20	Bio Gas Mains – Private Land	398	1.56%	19	-	6	-	-	-	25	
43	418-10	Bio Gas Purification Overhaul	24	5.00%	9	-	1	-	-	-	10	
44	418-20	Bio Gas Purification Upgrader	11,563	5.00%	3,847	-	578	-	-	-	4,425	
45	477-40	Bio Gas Reg & Meter Equipment	3,819	3.22%	714	-	123	-	-	-	837	
46	478-30	Bio Gas Meters	41	4.89%	18	-	2	-	-	-	20	
47	474-10	Bio Gas Reg & Meter Installations	770	5.32%	116	-	41	-	-	-	157	
48	483-25	RNG Comp S/W	-	20.00%	-	-	-	-	-	-	-	
49			$ 20,490		$ 5,082	$ -	$ 821	$ -	$ -	$ -	$ 5,903	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 7.2

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2022	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2023	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**Natural Gas for Transportation**										
2	476-10	NG Transportation CNG Dispensing Equipment	18,597	5.00%	$ 5,225	-	930	-	-	-	$ 6,155	
3	476-20	NG Transportation LNG Dispensing Equipment	13,714	5.00%	4,905	-	686	-	-	-	5,591	
4	476-30	NG Transportation CNG Foundations	3,141	5.00%	943	-	157	-	-	-	1,100	
5	476-40	NG Transportation LNG Foundations	1,049	5.00%	446	-	52	-	-	-	498	
6	476-50	NG Transportation LNG Pumps (Pumps only apply to LNG)	77	10.00%	50	-	1	-	-	-	51	
7	476-60	NG Transportation CNG Dehydrator	809	5.00%	229	-	40	-	-	-	269	
8	476-70	NG Transportation LNG Dehydrator	-	5.00%	-	-	-	-	-	-	-	
9			$ 37,387		$ 11,798	$ -	$ 1,866	$ -	$ -	$ -	$ 13,664	
10												
11		**GENERAL PLANT & EQUIPMENT**										
12	480-00	Land in Fee Simple	$ 31,306	0.00%	$ 17	$ -	$ -	$ -	$ -	$ -	$ 17	
13	482-10	Frame Buildings	24,658	3.17%	14,107	-	782	-	-	-	14,889	
14	482-20	Masonry Buildings	128,253	1.52%	36,789	-	1,949	(124)	-	-	38,614	
15	482-30	Leasehold Improvement	3,224	9.49%	1,602	-	198	(54)	-	-	1,746	
16	483-30	GP Office Equipment	3,408	6.67%	1,389	-	227	(42)	-	-	1,574	
17	483-40	GP Furniture	22,238	5.00%	6,158	-	1,112	(412)	-	-	6,858	
18	483-10	GP Computer Hardware	48,417	25.00%	24,395	-	12,104	(19,628)	-	-	16,871	
19	483-20	GP Computer Software	4,143	12.50%	2,903	-	518	(635)	-	-	2,786	
20	484-00	Vehicles	61,391	11.07%	26,098	-	6,796	-	-	-	32,894	
21	484-10	Vehicles - Leased	13,963	9.44%	13,785	-	68	(1,458)	-	-	12,395	
22	485-10	Heavy Work Equipment	750	5.14%	526	-	39	-	-	-	565	
23	485-20	Heavy Mobile Equipment	9,277	6.09%	5,283	-	565	-	-	-	5,848	
24	486-00	Small Tools & Equipment	60,614	5.00%	25,486	-	3,031	(3,556)	-	-	24,961	
25	487-20	Equipment on Customer's Premises	-	6.67%	-	-	-	-	-	-	-	
26	488-10	Telephone	1,223	6.67%	1,081	-	82	(139)	-	-	1,024	
27	488-20	Radio	19,365	6.67%	6,685	-	1,292	-	-	-	7,977	
28	489-00	Other General Equipment	-	0.00%	-	-	-	-	-	-	-	
29			$ 432,230		$ 166,304	$ -	$ 28,763	$ (26,048)	$ -	$ -	$ 169,019	
30												
31		**UNCLASSIFIED PLANT**										
32	499-00	Plant Suspense	-	0.00%	-	-	-	-	-	-	-	
33			$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	
34												
35		**Total**	$ 8,457,598		$ 2,571,244	$ -	$ 223,550	$ (67,556)	$ -	$ -	$ 2,727,238	
36		Less: Depreciation & Amortization Transferred to Biomethane BVA					(821)					
37		Less: Vehicle Depreciation Allocated To Capital Projects					(2,540)					
38		**Net Depreciation Expense**					$ 220,189					
39												
40		Cross Reference	Schedule 6.2, Line 35, Columns 3+4+5									

NON-REG PLANT CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars			12/31/2022	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
1	**Non-Regulated Plant**									
2	NRB Depreciation @ 0%			$ 1,054	$ -	$ -	$ -	$ -	$ 1,054	
3	NRB Depreciation @ 2.4%			176,594	-	-	-	-	176,594	
4									-	
5	**Total**			$ 177,648	$ -	$ -	$ -	$ -	$ 177,648	
6										
7										
8										

9 **NON-REG PLANT ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE**
10 **FOR THE YEAR ENDING DECEMBER 31, 2023**
11 **($000s)**

Line No.	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2022	Opening Bal Adjustment	Depreciation Expense	Depreciation Retirements	Cost of Removal	12/31/2023	Cross Reference
12										
13										
16	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
17										
18	**Non-Regulated Plant Depreciation**									
19	NRB Depreciation @ 0%	$ 1,054	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	
20	NRB Depreciation @ 2.4%	176,594	2.40%	142,652	-	4,238	-	-	146,890	
21									-	
22	**Total**	$ 177,648		$ 142,652	$ -	$ 4,238	$ -	$ -	$ 146,890	

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	CPCN / Open Bal Adjt	Adjustment	Additions	Retirements	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CIAC**							
2	Distribution Contributions	$ 298,152	$ -	$ -	$ 2,457	$ -	$ 300,609	
3	Transmission Contributions	156,616	-	-	4,342	-	160,958	
4	Others	2,399	-	-	-	-	2,399	
5	Biomethane	566	-	-	-	-	566	
6	**Total**	$ 457,733	$ -	$ -	$ 6,799	$ -	$ 464,532	
7								
8	**Amortization**							
9	Distribution Contributions	$ (133,635)	$ -	$ -	$ (6,291)	$ -	$ (139,926)	
10	Transmission Contributions	(60,967)	-	-	(2,287)	-	(63,254)	
11	Others	(1,110)	-	-	(120)	-	(1,230)	
12	Biomethane	(301)	-	-	(28)	-	(329)	
13	**Total**	$ (196,013)	$ -	$ -	$ (8,726)	$ -	$ (204,739)	
14								
15	**Net CIAC**	$ 261,720	$ -	$ -	$ (1,927)	$ -	$ 259,793	
16								
17								
18	Total CIAC Amortization Expense per Line 13				$ (8,726)			
19	Less: CIAC Amortization Transferred to Biomethane BVA				28			
20	**Net CIAC Amortization Expense**				$ (8,698)			

NET SALVAGE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2022	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**INTANGIBLE PLANT**							
2	471-01	Distribution Land Rights	3,482	0.00%	146	-	-	146	
3			$ 3,482		$ 146	$ -	$ -	$ 146	
4									
5		**MANUFACTURED GAS / LOCAL STORAGE**							
6	437-00	Manufact'd Gas - Measuring & Regulating Equipment	$ 1,714	0.00%	$ (22)	$ -	$ -	$ (22)	
7	442-00	Structures & Improvements (Tilbury)	100,809	0.68%	2,858	686	-	3,544	
8	443-00	Gas Holders - Storage (Tilbury)	180,974	1.12%	7,593	2,027	-	9,620	
9	448-11	Piping (Tilbury)	48,635	0.28%	707	136	-	843	
10	448-21	Pre-treatment (Tilbury)	38,752	0.50%	945	194	-	1,139	
11	448-31	Liquefaction Equipment (Tilbury)	94,779	0.57%	2,853	540	-	3,393	
12	449-00	Local Storage Equipment (Tilbury)	27,862	0.82%	1,580	228	-	1,808	
13	442-01	Structures & Improvements (Mount Hayes)	19,045	0.49%	513	93	-	606	
14	443-05	Gas Holders - Storage (Mount Hayes)	61,774	0.36%	1,298	222	-	1,520	
15	448-41	Send out Equipment(Tilbury)	7,746	0.28%	85	22	-	107	
16	448-51	Sub-station and Electric (Tilbury)	36,846	0.56%	1,066	206	-	1,272	
17	448-10	Piping (Mount Hayes)	12,455	0.28%	198	35	-	233	
18	448-20	Pre-treatment (Mount Hayes)	29,238	0.50%	835	146	-	981	
19	448-30	Liquefaction Equipment (Mount Hayes)	28,880	0.57%	959	165	-	1,124	
20	448-40	Send out Equipment (Mount Hayes)	23,552	0.28%	384	66	-	450	
21	448-50	Sub-station and Electric (Mount Hayes)	21,788	0.56%	717	122	-	839	
22	449-01	Local Storage Equipment (Mount Hayes)	5,727	0.32%	108	18	-	126	
23			$ 740,576		$ 22,677	$ 4,906	$ -	$ 27,583	

NET SALVAGE CONTINUITY SCHEDULE Schedule 10.1
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2022	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**TRANSMISSION PLANT**							
2	462-00	Compressor Structures	$ 38,679	0.11%	$ 561	$ 43	$ -	$ 604	
3	463-00	Measuring Structures	20,210	0.62%	756	125	-	881	
4	464-00	Other Structures & Improvements	12,622	0.29%	148	37	-	185	
5	465-00	Mains	1,690,647	0.42%	38,717	7,101	-	45,818	
6	465-11	IP Transmission Pipeline - Whistler	58,689	0.34%	1,030	200	-	1,230	
7	465-30	Mt Hayes - Mains	6,307	0.30%	117	19	-	136	
8	466-00	Compressor Equipment	203,229	0.07%	2,577	142	-	2,719	
9	467-00	Mt. Hayes - Measuring and Regulating Equipment	8,276	0.21%	73	17	-	90	
10	467-10	Measuring & Regulating Equipment	104,572	0.16%	1,163	167	-	1,330	
11	467-20	Telemetering	18,289	0.00%	(28)	-	-	(28)	
12	467-31	IP Intermediate Pressure Whistler	404	0.35%	5	1	-	6	
13	468-00	Communication Structures & Equipment	13,428	0.00%	401	-	-	401	
14			$ 2,175,352		$ 45,520	$ 7,852	$ -	$ 53,372	
15									
16		**DISTRIBUTION PLANT**							
17	470-00	Land in Fee Simple	$ 5,457	0.00%	$ (1,989)	$ -	$ -	$ (1,989)	
18	472-00	Structures & Improvements	62,891	0.52%	806	327	-	1,133	
19	473-00	Services	1,501,521	2.09%	86,651	31,381	(15,145)	102,887	
20	474-00	House Regulators & Meter Installations	158,179	3.37%	1,878	5,331	-	7,209	
21	474-02	Meters/Regulators Installations	237,640	0.00%	748	-	-	748	
22	475-00	Mains	2,224,854	0.50%	59,232	11,124	(2,029)	68,327	
23	476-00	Compressor Equipment	614	0.00%	706	-	-	706	
24	477-10	Measuring & Regulating Equipment	228,840	0.45%	5,332	1,030	-	6,362	
25	477-20	Telemetering	23,515	0.48%	321	113	-	434	
26	478-10	Meters	317,076	0.00%	2,789	-	-	2,789	
27			$ 4,760,587		$ 156,474	$ 49,306	$ (17,174)	$ 188,606	
28									
29		**BIO GAS**							
30	472-20	Bio Gas Struct. & Improvements	$ 777	0.29%	$ 12	$ 2	$ -	$ 14	
31	475-10	Bio Gas Mains – Municipal Land	3,098	0.39%	50	12	-	62	
32	475-20	Bio Gas Mains – Private Land	398	0.39%	3	2	-	5	
33	418-20	Bio Gas Purification Upgrader	11,563	0.24%	148	28	-	176	
34	477-40	Bio Gas Reg & Meter Equipment	3,819	0.00%	(6)	-	-	(6)	
35	474-10	Bio Gas Reg & Meter Installations	770	1.44%	27	11	-	38	
36			$ 20,425		$ 234	$ 55	$ -	$ 289	

NET SALVAGE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 10.2

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2022	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2023	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Natural Gas for Transportation**							
2	476-10	NG Transportation CNG Dispensing Equipment	$ 18,597	0.00%	$ (1)	$ -	$ -	$ (1)	
3	476-20	NG Transportation LNG Dispensing Equipment	13,714	0.00%	11	-	-	11	
4	476-40	NG Transportation LNG Foundations	1,049	0.00%	10	-	-	10	
5	476-50	NG Transportation LNG Pumps (Pumps only apply to LNG)	77	0.00%	23	-	-	23	
6			$ 33,437		$ 43	$ -	$ -	$ 43	
7									
8		**GENERAL PLANT & EQUIPMENT**							
9	482-10	Frame Buildings	$ 24,658	0.37%	$ (111)	$ 91	$ -	$ (20)	
10	482-20	Masonry Buildings	128,253	0.08%	1,202	103	-	1,305	
11	482-30	Leasehold Improvement	3,224	0.00%	(73)	-	-	(73)	
12	483-30	GP Office Equipment	3,408	0.00%	1	-	-	1	
13	483-40	GP Furniture	22,238	0.00%	(94)	-	-	(94)	
14	484-00	Vehicles	61,391	-3.70%	(2,712)	(2,271)	-	(4,983)	
15	485-10	Heavy Work Equipment	750	-0.67%	(26)	(5)	-	(31)	
16	485-20	Heavy Mobile Equipment	9,277	-1.80%	(1,009)	(167)	-	(1,176)	
17	486-00	Small Tools & Equipment	60,614	0.00%	51	-	-	51	
18	487-20	Equipment on Customer's Premises	-	0.00%	(2)	-	-	(2)	
19	488-20	Radio	19,365	0.00%	(7)	-	-	(7)	
20			$ 333,178		$ (2,780)	$ (2,249)	$ -	$ (5,029)	
21									
22		**Total**	$ 8,067,037		$ 222,314	$ 59,870	$ (17,174)	$ 265,010	
23		Less: Depreciation & Amortization Transferred to Biomethane BVA				(55)			
24		**Net Salvage Depreciation Expense**				$ 59,815			
25		Cross Reference	Schedule 6.2, Columns 3+4+5				Schedule 11.1, Line 5, Column 4		

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE Schedule 11
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2023	Mid-Year Average	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**1. Forecasting Variance Accounts**										
2	Midstream Cost Reconciliation Account (MCRA)	$ (49,582)	$ -	$ -	$ -	$ -	$ 33,960	$ (9,169)	$ (24,791)	$ (37,187)	
3	Commodity Cost Reconciliation Account (CCRA)	175,424	-	(110,478)	29,829	-	-	-	94,775	135,100	
4	Revenue Stabilization Adjustment Mechanism (RSAM)	(42,252)	-	-	-	-	28,940	(7,814)	(21,126)	(31,689)	
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(82)	-	1,459	(394)	(483)	1,781	(481)	1,800	859	
6	SCP Mitigation Revenues Variance Account	325	-	-	-	(112)	-	-	213	269	
7	Pension & OPEB Variance	14,018	-	-	-	(5,154)	-	-	8,864	11,441	
8	BCUC Levies Variance	685	-	-	-	(685)	-	-	-	343	
9		$ 98,536	$ -	$ (109,019)	$ 29,435	$ (6,434)	$ 64,681	$ (17,464)	$ 59,735	$ 79,136	
10											
11	**2. Rate Smoothing Accounts**										
12											
13	**3. Benefits Matching Accounts**										
14	Demand-Side Management (DSM)	$ 243,343	$ 60,954	$ 59,870	$ (16,165)	$ (41,553)	$ -	$ -	$ 306,449	$ 305,373	
15	NGV Conversion Grants	8	-	-	-	(3)	-	-	5	7	
16	Emissions Regulations	(28,848)	-	-	-	28,848	-	-	-	(14,424)	
17	On-Bill Financing Pilot Program	1	-	(1)	-	-	-	-	-	1	
18	Greenhouse Gas Reduction Regulation Incentives	24,308	-	4,700	(1,269)	(5,387)	-	-	22,352	23,330	
19	CNG and LNG Recoveries	(548)	-	(873)	236	548	-	-	(637)	(593)	
20	BCUC Initiated Inquiry Costs	121	-	100	(27)	(121)	-	-	73	97	
21	2017 Rate Design Application	263	-	-	-	(263)	-	-	-	132	
22	PGR Application and Preliminary Stage Development Costs	261	-	-	-	(151)	-	-	110	186	
23	Transportation Service Report	176	-	59	(16)	-	-	-	219	198	
24	2021 Generic Cost of Capital Proceeding	731	-	450	(122)	-	-	-	1,059	895	
25	City of Coquitlam Application Proceeding	129	-	-	-	(129)	-	-	-	65	
26		$ 239,945	$ 60,954	$ 64,305	$ (17,363)	$ (18,211)	$ -	$ -	$ 329,630	$ 315,267	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE Schedule 11.1
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2023	Mid-Year Average	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**3. Benefits Matching Accounts (cont'd)**										
2	Whistler Pipeline Conversion	$ 4,974	$ -	$ -	$ -	$ (737)	$ -	$ -	$ 4,237	$ 4,606	
3	Gas Asset Records Project	544	-	-	-	(266)	-	-	278	411	
4	Gains and Losses on Asset Disposition	4,498	-	-	-	(3,986)	-	-	512	2,505	
5	Net Salvage Provision/Cost	(222,314)	-	17,174	-	(59,870)	-	-	(265,010)	(243,662)	
6	PCEC Start Up Costs	568	-	-	-	(44)	-	-	524	546	
7	2022 Long Term Gas Resource Plan Application	822	-	350	(95)	-	-	-	1,077	950	
8	2020–2024 MRP Application	271	-	-	-	(135)	-	-	136	204	
9	2021 Renewable Gas Program Comprehensive Review	1,061	-	1,551	(419)	-	-	-	2,193	1,627	
10	GCU Preliminary Stage Development Costs	776	-	-	-	(259)	-	-	517	647	
11	Transmission Integrity Management Capabilities	-	12,604	-	-	(2,521)	-	-	10,083	11,344	
12	Annual Review of 2020-2024 Rates	98	-	160	(43)	(98)	-	-	117	108	
13		$ (208,702)	$ 12,604	$ 19,235	$ (557)	$ (67,916)	$ -	$ -	$ (245,336)	$ (220,714)	
14											
15	**4. Retroactive Expense Accounts**										
16											
17	**5.Other Accounts**										
18	Pension & OPEB Funding	$ (240,902)	$ -	$ 2,345	$ -	$ -	$ -	$ -	$ (238,557)	$ (239,730)	
19	US GAAP Pension & OPEB Funded Status	106,710	-	-	-	-	-	-	106,710	106,710	
20	BVA Balance Transfer	500	18,587	-	-	-	(26,146)	7,059	-	9,544	
21	COVID-19 Customer Recovery Fund	1,733	-	-	-	(577)	-	-	1,156	1,445	
22	Stargas Assets Acquisition Deferral Account	-	106	-	-	(106)	-	-	-	53	
23	Residual Delivery Rate Riders	-	-	-	-	-	-	-	-	-	
24		$ (131,959)	$ 18,693	$ 2,345	$ -	$ (683)	$ (26,146)	$ 7,059	$ (130,691)	$ (121,978)	
25											
26	**Total**	$ (2,180)	$ 92,251	$ (23,134)	$ 11,515	$ (93,244)	$ 38,535	$ (10,405)	$ 13,338	$ 51,711	
27	Less: Net Salvage Amortization Transferred to Biomethane BVA					55					
28	**Net Rate Base Deferred Amortization Expense**					$ (93,189)					

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE Schedule 12
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	12/31/2022	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2023	Mid-Year Average	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**1. Forecasting Variance Accounts**										
2	Biomethane Variance Account	$ 25,255	$ (18,587)	$ -	$ -	$ -	$ -	$ -	$ 6,668	$ 6,668	
3	Flowthrough (2020-2024)	19,006	-	506	-	(19,512)	-	-	-	9,503	
4	Marketer Cost Variance	(48)	-	66	(18)	-	-	-	-	(24)	
5		$ 44,213	$ (18,587)	$ 572	$ (18)	$ (19,512)	$ -	$ -	$ 6,668	$ 16,147	
6	**2. Rate Smoothing Accounts**										
7	City of Vancouver Biomethane Purchase Agreement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
8											
9	**3. Benefits Matching Accounts**										
10	Demand-Side Management (DSM) - Non Rate Base	$ 60,954	$ (60,954)	$ 82,441	$ (21,823)	$ -	$ -	$ -	$ 60,618	$ 30,309	
11	PEC Pipeline Development Costs and Commitment Fees	(2,398)	-	-	-	-	-	-	(2,398)	(2,398)	
12	Transmission Integrity Management Capabilities	12,029	(12,604)	142	(46)	-	-	-	(479)	(527)	
13	Clean Growth Innovation Fund	(6,739)	-	2,078	(675)	-	(5,158)	1,393	(9,101)	(7,920)	
14		$ 63,846	$ (73,558)	$ 84,661	$ (22,544)	$ -	$ (5,158)	$ 1,393	$ 48,640	$ 19,464	
15											
16	**4. Retroactive Expense Accounts**										
17											
18	**5.Other Accounts**										
19	Mark to Market - Hedging Transactions	$ 76	$ -	$ -	$ -	$ -	$ -	$ -	$ 76	$ 76	
20	MRP Earnings Sharing Account	(268)	-	(7)	-	275	-	-	-	(134)	
21	Stargas Assets Acquisition Deferral Account	106	(106)	-	-	-	-	-	-	-	
22	US GAAP Uncertain Tax Positions	-	-	-	-	-	-	-	-	-	
23		$ (86)	$ (106)	$ (7)	$ -	$ 275	$ -	$ -	$ 76	$ (58)	
24											
25											
26	**Total Non Rate Base Deferral Accounts**	$ 107,973	$ (92,251)	$ 85,226	$ (22,562)	$ (19,237)	$ (5,158)	$ 1,393	$ 55,384	$ 35,553	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 19,040	$ 19,690	$ 650	Schedule 14, Line 30, Column 5
3					
4	Add/Less: Funds Unavailable/(Funds Available)				
5	Employee Loans	1,559	1,890	331	
6	Employee Withholdings	(6,367)	(6,873)	(506)	
7					
8	**Other Working Capital Items**				
9	Transmission Line Pack Gas	1,725	5,869	4,144	
10	Gas In Storage	50,364	90,540	40,176	
11	Inventories - Materials and Supplies	2,250	2,568	318	
12	Refundable Contributions	(318)	(312)	6	
13					
14	Total	$ 68,253	$ 113,372	$ 45,119	

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 14

Line No.	Particulars	2023 at Revised Rates	Lag (Lead) Days	Extended	Weighted Average Lag (Lead) Days	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**REVENUE**					
2	**Sales Revenue**					
3	Residential Tariff Revenue	$ 1,253,290	40.3	$ 50,507,587		
4	Commercial Tariff Revenue	693,782	37.8	26,224,959		
5	Industrial Tariff Revenue	223,169	47.7	10,645,142		
6	Bypass and Special Rates	70,312	37.6	2,643,730		
7						
8	**Other Revenue**					
9	Late Payment Charges	3,364	53.8	180,983		
10	Application Charges	2,016	39.0	78,624		
11	Other Utility Income	36,613	39.0	1,427,907		
12						
13	Total	$ 2,282,546		$ 91,708,932	40.2	
14						
15	**EXPENSES**					
16	Energy Purchases	$ 1,167,828	(40.0)	$ (46,713,120)		
17	Operating and Maintenance	292,083	(31.8)	(9,288,239)		
18	Property Taxes	78,985	(1.3)	(102,681)		
19	Operating Fees	14,095	(352.9)	(4,974,247)		
20	Carbon Tax	500,291	(30.7)	(15,358,934)		
21	GST	38,691	(39.7)	(1,536,019)		
22	PST	35,261	(45.8)	(1,614,958)		
23	Income Tax	50,625	(15.2)	(769,500)		
24						
25	Total	$ 2,177,859		$ (80,357,698)	(36.9)	
26						
27	Net Lag (Lead) Days				3.3	
28	Total Expenses				$ 2,177,859	
29						
30	Cash Working Capital				$ 19,690	

DEFERRED INCOME TAX LIABILITY / ASSET
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 15

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Total DIT Liability- After Tax	$ (520,816)	$ (567,344)	$ (46,528)	
2	Tax Gross Up	(192,631)	(209,840)	(17,209)	
3	DIT Liability/Asset - End of Year	$ (713,447)	$ (777,184)	$ (63,737)	
4	DIT Liability/Asset - Opening Balance	(666,166)	(717,706)	(51,540)	
5					
6	DIT Liability/Asset - Mid Year	$ (689,807)	$ (747,445)	$ (57,638)	

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 16

Line No.	Particulars	2022 Approved	2023 Forecast at 2022 Approved Rates	Revised Revenue	at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (TJ)	156,232	159,608		159,608	3,375	
3	Transportation Volume (TJ)	77,825	61,672		61,672	(16,152)	
4		234,057	221,280	-	221,280	(12,777)	Schedule 17, Line 24, Column 3
5							
6	**REVENUE AT EXISTING RATES**						
7	Sales	$ 1,552,577	$ 2,087,672	$ -	$ 2,087,672	$ 535,095	
8	Deficiency (Surplus)	-	-	66,283	66,283	66,283	
9	Transportation	98,654	81,164	-	81,164	(17,490)	
10	Deficiency (Surplus)	-		5,434	5,434	5,434	
11	Total	1,651,231	2,168,836	71,717	2,240,553	589,322	Schedule 19, Line 30, Column 8
12				-			
13	**COST OF ENERGY**	647,970	1,167,828	-	1,167,828	519,858	Schedule 18, Line 24, Column 3
14							
15	**MARGIN**	1,003,261	1,001,008	71,717	1,072,725	69,464	
16							
17	**EXPENSES**						
18	O&M Expense (net)	276,620	292,083	-	292,083	15,463	Schedule 20, Line 28, Column 4
19	Depreciation & Amortization	308,177	323,917	-	323,917	15,740	Schedule 21, Line 15, Column 3
20	Property Taxes	73,397	78,985	-	78,985	5,588	Schedule 22, Line 8, Column 3
21	Other Revenue	(41,636)	(41,993)	-	(41,993)	(357)	Schedule 23, Line 12, Column 3
22	Utility Income Before Income Taxes	386,703	348,016	71,717	419,733	33,030	
23							
24	Income Taxes	52,212	31,267	19,358	50,625	(1,587)	Schedule 24, Line 13, Column 3
25							
26	**EARNED RETURN**	$ 334,491	$ 316,749	$ 52,359	$ 369,108	$ 34,617	Schedule 26, Line 5, Column 7
27							
28	**UTILITY RATE BASE**	$ 5,409,207	$ 5,929,177		$ 5,929,947	$ 520,740	Schedule 2, Line 31, Column 3
29	**RATE OF RETURN ON UTILITY RATE BASE**	6.18%	5.34%		6.22%	0.04%	Schedule 26, Line 5, Column 6

VOLUME AND REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 17

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (TJ)**				
2	Residential				
3	Rate Schedule 1	81,494.4	82,658.7	1,164.3	
4	Commercial				
5	Rate Schedule 2	29,000.0	29,050.1	50.1	
6	Rate Schedule 3	24,886.2	25,662.4	776.2	
7	Rate Schedule 23	4,125.4	3,903.8	(221.6)	
8	Industrial				
9	Rate Schedule 4	159.5	166.1	6.6	
10	Rate Schedule 5	9,420.4	10,826.9	1,406.5	
11	Rate Schedule 6	20.8	20.9	0.1	
12	Rate Schedule 7	6,601.1	6,004.2	(596.9)	
13	Rate Schedule 22 - Firm Service	10,379.2	10,378.3	(0.9)	
14	Rate Schedule 22 - Interruptible Service	16,533.0	17,144.2	611.2	
15	Rate Schedule 25	9,163.8	8,303.3	(860.5)	
16	Rate Schedule 27	4,510.5	4,289.1	(221.4)	
17	Bypass and Special Rates				
18	Rate Schedule 22 - Firm Service	10,916.5	11,945.6	1,029.1	
19	Rate Schedule 25	1,017.5	951.3	(66.2)	
20	Rate Schedule 46	4,650.0	5,218.5	568.5	
21	Byron Creek	8.7	11.6	2.9	
22	BC Hydro IG	16,425.0	-	(16,425.0)	
23	VIGJV	4,745.0	4,745.0	-	
24	Total	234,057.0	221,280.0	(12,777.0)	
25					
26	**REVENUE AT EXISTING RATES**				
27	Residential				
28	Rate Schedule 1	$ 935,165	$ 1,209,050	$ 273,885	
29	Commercial				
30	Rate Schedule 2	275,898	368,612	92,714	
31	Rate Schedule 3	202,044	289,467	87,423	
32	Rate Schedule 23	16,452	15,538	(914)	
33	Industrial				
34	Rate Schedule 4	985	1,525	540	
35	Rate Schedule 5	61,335	103,635	42,300	
36	Rate Schedule 6	131	203	72	
37	Rate Schedule 7	35,373	51,121	15,748	
38	Rate Schedule 22 - Firm Service	7,897	8,431	534	
39	Rate Schedule 22 - Interruptible Service	20,111	21,201	1,090	
40	Rate Schedule 25	24,222	22,038	(2,184)	
41	Rate Schedule 27	8,088	7,703	(385)	
42	Bypass and Special Rates				
43	Rate Schedule 22 - Firm Service	794	799	5	
44	Rate Schedule 25	426	424	(2)	
45	Rate Schedule 46	41,646	64,059	22,413	
46	Byron Creek	119	134	15	
47	BC Hydro IG	15,735	-	(15,735)	
48	VIGJV	4,810	4,896	86	
49	Total	$ 1,651,231	$ 2,168,836	$ 517,605	

COST OF ENERGY
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 18

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**COST OF GAS**				
2	Residential				
3	Rate Schedule 1	$ 346,101	$ 612,669	$ 266,568	
4	Commercial				
5	Rate Schedule 2	123,827	216,392	92,565	
6	Rate Schedule 3	100,657	185,256	84,599	
7	Rate Schedule 23	70	147	77	
8	Industrial				
9	Rate Schedule 4	586	1,133	547	
10	Rate Schedule 5	34,441	73,578	39,137	
11	Rate Schedule 6	59	127	68	
12	Rate Schedule 7	24,251	40,943	16,692	
13	Rate Schedule 22 - Firm Service	258	571	313	
14	Rate Schedule 22 - Interruptible Service	200	466	266	
15	Rate Schedule 25	156	313	157	
16	Rate Schedule 27	77	162	85	
17	Bypass and Special Rates				
18	Rate Schedule 22 - Firm Service	185	450	265	
19	Rate Schedule 25	17	36	19	
20	Rate Schedule 46	17,085	35,585	18,500	
21	Byron Creek	-	-	-	
22	BC Hydro IG	-	-	-	
23	VIGJV	-	-	-	
24	Total	$ 647,970	$ 1,167,828	$ 519,858	

MARGIN AND REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 19

Line No.	Particulars	2022 Approved Margin	2023 Forecast Margin at 2022 Approved Rates	2023 Forecast Effective Increase	2023 Forecast Margin at Revised Rates	2023 Forecast Revenue at 2022 Approved Rates	2023 Forecast Effective Increase	2023 Forecast Revenue at Revised Rates	Average Number of Customers	Terajoules	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**NON - BYPASS**										
2	Residential										
3	Rate Schedule 1	$ 589,064	$ 596,381	$ 44,240	$ 640,621	$ 1,209,050	$ 44,240	$ 1,253,290	975,665	82,658.7	
4	Commercial										
5	Rate Schedule 2	152,071	152,220	11,292	163,512	368,612	11,292	379,904	90,198	29,050.1	
6	Rate Schedule 3	101,387	104,211	7,731	111,942	289,467	7,731	297,198	7,030	25,662.4	
7	Rate Schedule 23	16,382	15,391	1,142	16,533	15,538	1,142	16,680	701	3,903.8	
8	Industrial										
9	Rate Schedule 4	399	392	29	421	1,525	29	1,554	18	166.1	
10	Rate Schedule 5	26,894	30,057	2,230	32,287	103,635	2,230	105,865	632	10,826.9	
11	Rate Schedule 6	72	76	6	82	203	6	209	13	20.9	
12	Rate Schedule 7	11,122	10,178	755	10,933	51,121	755	51,876	45	6,004.2	
13	Rate Schedule 22 - Firm Service	7,639	7,860	583	8,443	8,431	583	9,014	9	10,378.3	
14	Rate Schedule 22 - Interruptible Service	19,911	20,735	1,538	22,273	21,201	1,538	22,739	29	17,144.2	
15	Rate Schedule 25	24,066	21,725	1,612	23,337	22,038	1,612	23,650	272	8,303.3	
16	Rate Schedule 27	8,011	7,541	559	8,100	7,703	559	8,262	70	4,289.1	
17	Total Non-Bypass	$ 957,018	$ 966,767	$ 71,717	$ 1,038,484	$ 2,098,524	$ 71,717	$ 2,170,241	1,074,682	198,408.0	
18											
19											
20	**Bypass and Special Rates**										
21	Rate Schedule 22 - Firm Service	$ 609	$ 349		$ 349	$ 799		$ 799	6	11,945.6	
22	Rate Schedule 25	409	388		388	424		424	3	951.3	
23	Rate Schedule 46	24,561	28,474		28,474	64,059		64,059	21	5,218.5	
24	Byron Creek	119	134		134	134		134	1	11.6	
25	BC Hydro IG	15,735	-		-	-		-	-	-	
26	VIGJV	4,810	4,896		4,896	4,896		4,896	1	4,745.0	
27	Total Bypass & Special	$ 46,243	$ 34,241	$ -	$ 34,241	$ 70,312	$ -	$ 70,312	32	22,872.0	
28											
29											
30	Total	$ 1,003,261	$ 1,001,008	$ 71,717	$ 1,072,725	$ 2,168,836	$ 71,717	$ 2,240,553	1,074,714	221,280.0	
31											
32	**Effective Increase**			7.42%			3.42%				

OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	Inflation Indexed O&M	Forecast O&M	Total O&M	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Inflation Indexed O&M**				
2	2022 Base Unit Cost O&M	$ 269			
3	2023 Net Inflation Factor	4.080%			Schedule 3, Line 9, Column 6
4	2023 Base Unit Cost O&M	$ 280			Line 2 x (1 + Line 3)
5					
6	2023 Average Customer Forecast - Rate Setting Purpose	1,064,000			Schedule 3, Line 22, Column 7
7					
8	2023 Inflation Indexed O&M before prior year True-up	$ 297,920			Line 4 x Line 6 / 1000
9					
10	2021 Average Customer True-up	740			
11					
12	2023 Inflation Indexed O&M	$ 298,660		$ 298,660	Sum of Lines 8 and 10
13					
14	**O&M Tracked Outside of Formula**				
15	Pension & OPEB (O&M Portion)		$ 9,544		
16	Insurance		12,242		
17	Biomethane O&M		5,237		
18	NGT O&M		1,937		
19	Variable LNG Production		7,859		
20	Integrity O&M		8,000		
21	Renewable Gas Development		2,000		
22	BCUC fees		8,473		
23	Sub-total		$ 55,292	55,292	Sum of Lines 15 through 22
24					
25	**Total Gross O&M**			$ 353,952	Line 12 + Line 23
26	O&M Transferred to Biomethane BVA			(5,237)	
27	Capitalized Overhead			(56,632)	-16 % x Line 25
28	**Net O&M Expense**			$ 292,083	Sum of Lines 25 through 27

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 210,971	$ 223,550	$ 12,579	Schedule 7.2, Line 35, Column 7
3	Depreciation & Amortization Transferred to Biomethane BVA	(765)	(821)	(56)	Schedule 7.2, Line 36, Column 7
4	Vehicle Depreciation Allocated To Capital Projects	(2,176)	(2,540)	(364)	Schedule 7.2, Line 37, Column 7
5		208,030	220,189	12,159	
6					
7	**Amortization**				
8	Rate Base Deferrals	$ 98,731	$ 93,244	$ (5,487)	Schedule 11.1, Line 26, Column 6
9	Rate Base Deferrals - Net Salvage Amortization Transferred to Biomethane BVA	(48)	(55)	(7)	Schedule 11.1, Line 27, Column 6
10	Non-Rate Base Deferrals	10,064	19,237	9,173	Schedule 12, Line 26, Column 6
11	CIAC	(8,628)	(8,726)	(98)	Schedule 9, Line 13, Column 5
12	CIAC Amortization Transferred to Biomethane BVA	28	28	-	Schedule 9, Line 19, Column 5
13		100,147	103,728	3,581	
14					
15	Total	$ 308,177	$ 323,917	$ 15,740	

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 22

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	General School and Other	$ 60,136	$ 62,788	$ 2,652	
2	1% In-Lieu of Municipal Taxes	13,368	16,289	2,921	
3					
4	Total	$ 73,504	$ 79,077	$ 5,573	
5					
6	Total Property Tax Expense per Line 4	$ 73,504	$ 79,077		
7	Less: Property Tax Transferred to Biomethane BVA	(107)	(92)		
8	**Net Property Tax Expense**	$ 73,397	$ 78,985		

OTHER REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 23

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Late Payment Charge	$ 2,704	$ 3,364	$ 660	
2	Application Charge	2,013	2,016	3	
3	NSF Returned Cheque Charges	28	28	-	
4	Other Recoveries	288	288	-	
5	SCP Third Party Revenue	13,410	13,286	(124)	
6	NGT Tanker Rental Revenue	928	926	(2)	
7	NGT Overhead and Marketing Recovery	283	273	(10)	
8	Biomethane Other Revenue	986	512	(474)	
9	LNG Capacity Assignment	18,039	18,039	-	
10	CNG & LNG Service Revenues	2,957	3,261	304	
11					
12	Total	$ 41,636	$ 41,993	$ 357	

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 24

Line No.	Particulars	2022 Approved	2023 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 334,491	$ 369,108	$ 34,617	Schedule 16, Line 26, Column 5
2	Deduct: Interest on Debt	(152,268)	(169,343)	(17,075)	Schedule 26, Lines 1+2, Column 7
3	Adjustments to Taxable Income	(41,057)	(62,889)	(21,832)	Line 36
4	Accounting Income After Tax	$ 141,166	$ 136,876	$ (4,290)	
5					
6	1 - Current Income Tax Rate	73.00%	73.00%	0.00%	
7	Taxable Income	$ 193,378	$ 187,501	$ (5,877)	
8					
9	Current Income Tax Rate	27.00%	27.00%	0.00%	
10	Income Tax - Current	$ 52,212	$ 50,625	$ (1,587)	
11					
12	Previous Year Adjustment	-	-	-	
13	**Total Income Tax**	$ 52,212	$ 50,625	$ (1,587)	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Non-tax Deductible Expenses	$ 1,200	$ 1,200	$ -	
19	Depreciation	208,030	220,189	12,159	Schedule 21, Line 5, Column 3
20	Amortization of Deferred Charges	108,747	112,426	3,679	Schedule 21, Lines 8+9+10, Column 3
21	Amortization of Debt Issue Expenses	1,259	981	(278)	
22	Vehicles: Interest & Capitalized Depreciation	2,181	2,545	364	
23	Pension Expense	11,137	10,167	(970)	
24	OPEB Expense	7,642	5,020	(2,622)	
25					
26	Deductions:				
27	Capital Cost Allowance	(298,674)	(330,010)	(31,336)	Schedule 25, Line 23, Column 6
28	CIAC Amortization	(8,600)	(8,698)	(98)	Schedule 21, Lines 11+12, Column 3
29	Debt Issue Costs	(1,816)	(1,984)	(168)	
30	Vehicle Lease Payment	(142)	(73)	69	
31	Pension Contributions	(13,739)	(14,361)	(622)	
32	OPEB Contributions	(3,206)	(3,171)	35	
33	Overheads Capitalized Expensed for Tax Purposes	(26,664)	(28,316)	(1,652)	
34	Removal Costs	(24,653)	(17,174)	7,479	Schedule 11.1, Line 5, Column 4
35	Major Inspection Costs	(3,759)	(11,630)	(7,871)	
36	Total	$ (41,057)	$ (62,889)	$ (21,832)	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Schedule 25

Line No.	Class	CCA Rate	12/31/2022 UCC Balance	2023 Additions	UCC Adjustment for AIIP *	2023 CCA	Forecast 12/31/2023 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 1,014,241	$ 1,298	$ 650	$ (40,647)	$ 974,892
2	1(b)	6%	6,957	17,757	8,878	(2,016)	22,698
3	2	6%	76,761	-	-	(4,605)	72,156
4	3	5%	1,525	-	-	(76)	1,449
5	6	10%	214	-	-	(21)	193
6	7	15%	20,104	1,528	764	(3,359)	18,273
7	8	20%	30,582	10,967	5,483	(9,406)	32,143
8	10	30%	15,237	9,149	4,574	(8,688)	15,698
9	10.1	30%	90	-	-	(27)	63
10	12	100%	-	23,004	-	(23,004)	-
11	13	manual	2,778	89	44	(478)	2,389
12	14.1 (pre 2017)	7%	14,183	-	-	(993)	13,190
13	14.1 (post 2016)	5%	5,062	-	-	(254)	4,808
14	17	8%	885	-	-	(71)	814
15	38	30%	1,050	1,721	861	(1,089)	1,682
16	43.2	50%	98	31,182	-	(31,231)	49
17	47	8%	140,734	-	-	(11,259)	129,475
18	47 (LNG Equip - post Feb 2015)	8%	148,233	21,350	10,675	(14,421)	155,162
19	49	8%	491,121	36,682	18,341	(43,692)	484,111
20	50	55%	3,466	11,502	5,751	(11,395)	3,573
21	51	6%	1,712,844	227,857	113,928	(123,278)	1,817,423
22							
23	Total		$ 3,686,165	$ 394,086	$ 169,949	$ (330,010)	$ 3,750,241
24							
25	* Note - Accelerated Investment Incentive Property						

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	2022 Approved Earned Return	2023 Amount	2023 Ratio	2023 Average Embedded Cost	Cost Component	Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 149,765	$ 3,394,248	57.24%	4.70%	2.69%	$ 159,363	$ 9,598	Schedule 27, Lines 29&31, Columns 5&6&7
2	Short Term Debt	2,503	252,669	4.26%	3.95%	0.17%	9,980	7,477	
3	Common Equity	182,223	2,283,030	38.50%	8.75%	3.37%	199,765	17,542	
4									
5	Total	$ 334,491	$ 5,929,947	100.00%		6.22%	$ 369,108	$ 34,617	
6									
7	Cross Reference		Schedule 2, Line 31, Column 3						

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2023
($000s)

Line No.	Particulars	Issue Date	Maturity Date	Net Proceeds of Issue	Average Principal Outstanding	Interest * Rate	Interest Expense	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	Medium Term Note - Series 11	September 21, 1999	September 21, 2029	$ 147,710	$ 150,000	7.073%	$ 10,610	
2	2004 Long Term Debt Issue - Series 18	April 29, 2004	May 1, 2034	148,085	150,000	6.598%	9,897	
3	2005 Long Term Debt Issue - Series 19	February 25, 2005	February 25, 2035	148,337	150,000	5.980%	8,970	
4	2006 Long Term Debt Issue - Series 21	September 25, 2006	September 25, 2036	119,216	120,000	5.595%	6,714	
5	2007 Medium Term Debt Issue - Series 22	October 2, 2007	October 2, 2037	247,697	250,000	6.067%	15,168	
6	2008 Medium Term Debt Issue - Series 23	May 13, 2008	May 13, 2038	247,588	250,000	5.869%	14,673	
7	2009 Med.Term Debt Issue- Series 24	February 24, 2009	February 24, 2039	98,766	100,000	6.645%	6,645	
8	2011 Medium Term Debt Issue - Series 25	December 9, 2011	December 9, 2041	98,590	100,000	4.334%	4,334	
9	2015 Medium Term Debt Issue - Series 26 (Series A Renewal)	April 13, 2015	April 13, 2045	148,938	150,000	3.413%	5,120	
10	2016 Medium Term Debt Issue - Series 27 (Series B Renewal)	April 8, 2016	April 8, 2026	130,944	131,785	2.644%	3,484	
11	2016 Medium Term Debt Issue - Series 28	April 8, 2016	April 9, 2046	148,746	150,000	3.716%	5,574	
12	2016 Medium Term Debt Issue - Series 29	December 13, 2016	March 6, 2047	148,865	150,000	3.822%	5,733	
13	2017 Medium Term Debt Issue - Series 30	October 30, 2017	October 30, 2047	173,584	175,000	3.735%	6,536	
14	2018 Medium Term Debt Issue - Series 31	December 7, 2018	December 7, 2048	198,351	200,000	3.897%	7,794	
15	2019 Medium Term Debt Issue - Series 32	August 9, 2019	August 9, 2049	198,500	200,000	2.857%	5,714	
16	2020 Medium Term Debt Issue - Series 33	July 13, 2020	July 13, 2050	198,392	200,000	2.579%	5,158	
17	2021 Medium Term Debt Issue - Series 34	April 14, 2021	July 18, 2031	148,984	150,000	2.495%	3,743	
18	2022 Medium Term Debt Issue	October 1, 2022	October 1, 2052	198,000	200,000	4.864%	9,728	
19	2023 Medium Term Debt Issue	October 1, 2023	October 1, 2053	297,000	75,616	4.763%	3,602	
20								
21	FEVI L/T Debt Issue - 2008	February 16, 2008	February 15, 2038	247,999	250,000	6.109%	15,273	
22	FEVI L/T Debt Issue - 2010	December 6, 2010	December 6, 2040	98,836	100,000	5.278%	5,278	
23								
24								
25	Vehicle Lease Obligation				144	3.472%	5	
26								
27	Sub-Total				$ 3,402,545		$ 159,753	
28	Less: Fort Nelson Division Portion of Long Term Debt				(8,297)		(390)	
29	Total				$ 3,394,248		$ 159,363	
30								
31	Average Embedded Cost					4.70%		
32								
33	* Interest Rate is Effective Interest Rate as it includes amortization of debt issue costs							

12. ACCOUNTING MATTERS AND EXOGENOUS FACTORS

12.1 INTRODUCTION AND OVERVIEW

In this section, FEI discusses "Exogenous Factors" under its MRP, identifying one new potential exogenous factor for the impacts of flooding in 2021 and an update on the exogenous factor treatment for the impacts of the COVID-19 pandemic. FEI also discusses emerging accounting guidance, and the status of its non-rate base deferral accounts. With respect to its non-rate base deferral accounts, FEI provides information on the Flow-through deferral account.

12.2 EXOGENOUS (Z) FACTORS

FEI is permitted to adjust the cost of service for "Exogenous Factors" under the MRP. The BCUC established the following criteria for evaluating whether the impact of an event qualifies for exogenous factor treatment:

1. The costs/savings must be attributable entirely to events outside the control of a prudently operated utility;
2. The costs/savings must be directly related to the exogenous event and clearly outside the base upon which the rates were originally derived;
3. The impact of the event was unforeseen;
4. The costs must be prudently incurred; and
5. The costs/savings related to each exogenous event must exceed the BCUC-defined materiality threshold.

The materiality threshold (item 5) for FEI has been established at $0.500 million, as approved in the MRP Decision.

In the Annual Review for 2020 and 2021 Delivery Rates, FEI identified the COVID-19 pandemic as a potential exogenous factor affecting 2020 and future years, and the BCUC approved FEI's request to record COVID-19 pandemic incremental costs and cost reductions from 2020 and 2021 into the previously approved COVID-19 Customer Recovery Fund Deferral Account[76]. FEI also stated in the Annual Review for 2020 and 2021 Delivery Rates application that it would review the amounts in 2021 when actual 2020 amounts and forecasts for future years could be ascertained, and an appropriate recovery method could be determined. In the Annual Review for 2022 Delivery Rates application, FEI provided a status update on the COVID-19 pandemic net incremental costs (costs less cost reductions), including reduced late payment revenues. In the following section,

[76] FEI Annual Review for 2020 and 2021 Delivery Rates Decision and Order G-319-20.

FEI reports on the net incremental cost reductions and proposes to return these cost reductions to customers.

FEI has also identified one new potential exogenous factor related to the flooding damages in 2021. This is discussed in Section 12.2.2.

12.2.1 COVID-19 Pandemic

During the COVID-19 pandemic, FEI has taken the necessary steps as a critical infrastructure service provider to ensure the health, safety and well-being of its customers, employees and their communities, and to continue to operate its delivery system safely and reliably. This has resulted in net incremental O&M impacts and a reduction in late payment charge revenues.

12.2.1.1 FEI Has Reasonably Tracked the Impact of the COVID-19 Pandemic on Net Operating Costs

Consistent with the MRP, FEI's general approach to managing its formula O&M funding is at an overall Company level. O&M funding is prioritized and allocated as required to meet the business environment, conditions and requirements the Company faces. Funding utilized for a specific purpose in one year may be used differently in the following year. This makes the determination of COVID-19 pandemic net incremental O&M costs from year to year challenging and fluid, particularly for cost reductions, as the Company reprioritizes its funding regularly to meet its needs to provide safe and reliable operations.

Further, the COVID-19 pandemic has a broad impact throughout the organization, making the determination of the incremental costs more challenging. The impact of the COVID-19 pandemic varies in different parts of the business. For example, there may be additional overtime costs in departments that are indirectly influenced by the pandemic (e.g., less internal resources available due to reassignment to assist with other priorities), which are difficult to specifically identify. Also, there may be delays in work scheduled as a result of the pandemic that may increase the total cost of the work required, which are not specifically identified as COVID-19 pandemic related.

Recognizing the above circumstances, FEI has undertaken its best efforts to track and report on the net incremental O&M costs that are directly related to the COVID-19 pandemic. FEI has included below all costs that are specifically identifiable as attributable to activities required to respond to the COVID-19 pandemic as part of the overall net incremental costs (costs less cost reductions). While acknowledging there are uncertainties, the following summary of net incremental cost reductions provides a reasonable representation of the overall COVID-19 pandemic impact on the Company.

12.2.1.2 Summary of Net Incremental Cost Reductions

The combined impact in 2020 and 2021 as a result of the COVID-19 pandemic is a decrease of approximately $3.86 million in FEI's net incremental O&M expense (costs less cost reductions). The net O&M expense decrease was offset by a shortfall in Late Payment Charge revenues of approximately $1.19 million, resulting from the discontinuation of customer collection activities during the pandemic. When combined, the total impact of the COVID-19 pandemic in 2020 and 2021, including reduced late payment revenues, was an incremental decrease in net costs of approximately $2.68 million.

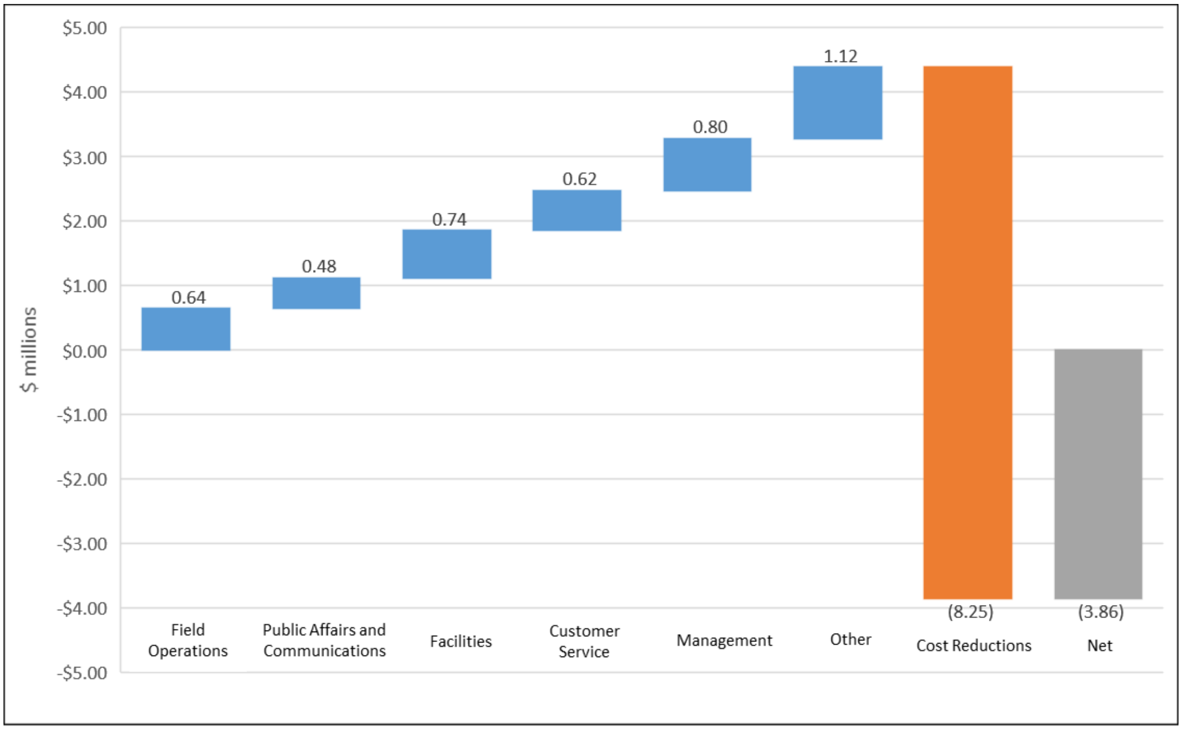
Table 12-1: Net Incremental Cost Reductions ($ millions)

	2020	2021	2020/2021
Direct Costs			
Field Operations	$ 0.50	$ 0.14	$ 0.64
Public Affairs and Communications	$ 0.46	$ 0.02	$ 0.48
Facilities	$ 0.38	$ 0.36	$ 0.74
Customer Service	$ 0.32	$ 0.30	$ 0.62
Management	$ 0.40	$ 0.40	$ 0.80
Other	$ 0.78	$ 0.33	$ 1.12
Total Direct Costs	$ 2.84	$ 1.55	$ 4.39
Cost Reductions	$ (4.51)	$ (3.74)	$ (8.25)
Total	$ (1.68)	$ (2.18)	$ (3.86)
Late payment charges	$ 0.85	$ 0.33	$ 1.19
Net difference	$ (0.82)	$ (1.85)	$ (2.68)

12.2.1.3 2020 and 2021 COVID-19 Pandemic Impact

While the COVID-19 pandemic increased many areas of O&M costs in 2020 and 2021, these were more than offset by lower employee related expenses. In 2020 and 2021, FEI incurred approximately $4.39 million in O&M costs related to the COVID-19 pandemic. These costs were primarily to ensure the health, safety and well-being of FEI's customers, employees, and their communities, and to continue to operate the delivery system safely and reliably. The incremental costs were offset by approximately $8.25 million in employee expense related reductions. The figure below shows the categories of costs incurred and the offsetting savings. Each of the categories is described further below.

Figure 12-1: FEI COVID-19 Pandemic 2020 and 2021 Net O&M Cost Reductions



12.2.1.3.1 INCREASED O&M EXPENDITURES DUE TO THE COVID-19 PANDEMIC

In the Field Operations area, FEI incurred approximately $0.64 million related to the COVID-19 pandemic. These costs were mostly for personal protective equipment (i.e., masks, gloves and sanitizers).

In the Public Affairs and Communications area, FEI incurred approximately $0.48 million for activities to keep customers and key stakeholders informed of the Company's assistance available during the COVID-19 pandemic, including the support required to develop the materials and to monitor and maintain messaging as needed. The costs were for advertising, various communication materials such as bill inserts, and labour and consultant services required to develop the materials and to monitor and maintain messaging as needed.

FEI incurred approximately $0.74 million for Facilities-related resources and activities including safety supplies, furniture storage, additional cleaning, first aid coverage, and signage.

For the Customer Service area, FEI incurred approximately $0.62 million, primarily for expanded hours to operate the Willingdon Park facility to accommodate the after-hours group and support appropriate social distancing in the work environment.

Under the category of Management, approximately $0.80 million in management resource costs were added to support the following areas: the operation of the Emergency Operating Centre (EOC); the Human Resources and Environmental, Health and Safety groups' response to COVID-19 pandemic incidents and issues for employees and contractors; and the increased needs of supporting departments such as Information Systems, Supply Chain, Communications and Business Continuity. The resources were necessary to respond to the COVID-19 pandemic and to address the various needs of the health authorities, regulators and organizations like Emergency Management BC.

The Other category of approximately $1.12 million includes miscellaneous items such as different support group costs (e.g., Information Systems and Telus Babylon health service).

12.2.1.3.2 O&M COST REDUCTIONS OFFSET INCREASED COSTS

The cost reductions that FEI achieved consist primarily of lower employee expenses, in part as a response to the travel restrictions, including in and out of Province travel, and the effect that the COVID-19 pandemic has had on social interactions. Employee expenses that were not incurred due to the COVID-19 pandemic include course fees, travel, meals and accommodation, Company function expenses, and employee hiring and relocation expenses.

For the years 2020 and 2021, the reduced employee expenses were estimated at approximately $8.25 million.

12.2.1.3.3 REDUCED REVENUE FROM LATE PAYMENT CHARGES

In the Annual Review for 2020 and 2021 Delivery Rates application (pages 30-31), FEI explained that the calculation of 2020 Projected Late Payment Charges included six months of actual results, with the remaining six months projected based on the prorated average of the actual 2017 to 2019 Late Payment Charges. FEI was expecting to resume its collection activities during the latter part of 2020 when the impact of the COVID-19 pandemic subsided. However, the COVID-19 pandemic continued, leading FEI to not resume its customer collection activities until March 2021 with the resumption of Late Payment Charges. Select disconnections commenced in late March and automated notices of disconnections for accounts with a threshold balance of $400 outstanding started in August 2021. As a result of the COVID-19 pandemic, 2020 Actual Late Payment Charges were lower than 2020 Approved by approximately $0.9 million. In 2021, there was a shortfall of approximately $0.3 million in Actual Late Payment Charges compared to the 2021 Approved. The shortfall in Late Payment Charges is directly linked to the discontinuation of customer collection activities during the COVID-19 pandemic.

12.2.1.3.4 CUMULATIVE NET IMPACT

When the 2020 and 2021 variances for the net incremental O&M (costs less cost reductions) and the Late Payment Charges are aggregated, the net variance of the two factors is approximately $2.68 million, consisting of a $3.86 million decrease in net incremental O&M costs and a shortfall of approximately $1.19 million in Late Payment Charges.

Accordingly, FEI requests approval to return the exogenous factor savings of $2.68 million to customers in 2023, as further described below.

12.2.1.4 2022 COVID-19 Pandemic Impact

With the Company's transition to normal operations, FEI does not anticipate further impacts on its costs in 2022 requiring exogenous factor treatment. As mentioned in FEI's 2022 Annual Review, FEI started the transition to normal operations in September 2021 with the Province achieving Step 4 of the Province of BC Four Step Restart Plan. Step 4 included the lifting of restrictions with normal social contact allowed and workplaces fully reopened. For FEI, this meant having its employees return to offices and worksites starting September 7, 2021 with 100 percent of employees on site at least 50 percent of the time while maintaining building capacity at 50 percent.

The transition to normal operations continued into early 2022 with the provincial government lifting the workplace safety order on April 8, 2022, enabling businesses to transition back to communicable disease plans to reduce risk of all communicable disease, instead of maintaining a COVID-19 safety plan. At the same time, the provincial government also removed restrictions on gatherings and events, including at restaurants, bars, pubs and nightclubs. With the lifting of the workplace safety order, FEI accordingly adjusted its existing COVID-19 safety protocols at its worksites to balance safety with the return to normal operations. The adjustments included suspension of COVID-19 daily health check confirmation and the removal of mandatory mask wearing, although the practice of wearing a mask is still recommended. As of July 4, 2022, employees have returned to a primarily office-based work model. Employee-related activities and expenses for business purposes (i.e., travel, accommodation, etc.) have also returned to normal.

12.2.1.5 Mechanism to Return Cost Reductions to Customers

As part of the Annual Review for 2020 and 2021 Delivery Rates, FEI proposed (and was approved by Order G-319-20) to include the amounts related to incremental COVID-19 costs and cost reductions in the previously approved COVID-19 Customer Recovery Fund Deferral Account.

However, upon further review of FEI's original proposal, FEI has concluded that a better approach is to record these amounts in the Flow-through deferral account. This approach is preferable for three reasons:

1. It is consistent with the treatment of other exogenous items;
2. It will allow the O&M and Late Payment Charge Revenue reported in the Annual Reports to be more reflective of the actual amounts incurred, as using the Flow-through deferral account does not result in direct adjustments to O&M or Late Payment Charge Revenue, but rather one catch-all account for all flow-through adjustments. Alternatively, transferring the actual O&M savings or Late Payment Charge shortfall directly to the COVID-19 Customer Recovery Fund Deferral Account would result in those respective O&M and Other Revenue actual amounts being effectively booked back to the forecast amounts; and

3. The COVID-19 incremental savings will be returned to customers immediately in 2023, as opposed to over three years, which is the amortization period being proposed for the COVID-19 Customer Recovery Fund Deferral Account in Section 7.5.2.1.

From a customer perspective, there is no negative impact from the proposed change in treatment as customers will still have the full net savings returned to them. The benefit of the proposed treatment, as described above, is that the net savings will be returned to customers over one year as opposed to three years.

As such, FEI has included the O&M and Late Payment Charge amounts shown above in the 2022 Flow-through projection provided in Table 12-5 below, on Lines 15 and 27 respectively, so that the net amounts will be returned to customers in 2023 via the amortization of the Flow-through deferral account forecast in this Application.

Accordingly, FEI seeks a variance to Directive 10 of Order G-319-20. FEI requests that Directive 10 be varied as followed: "FEI is approved to record COVID-19 incremental costs and related savings from 2020 and 2021 into the Flow-through deferral account."

12.2.1.6 Conclusion

FEI proposes to refund to customers for years 2020 and 2021, via the Flow-through deferral account, the cumulative net variance of the net incremental O&M (costs less reductions) and the Late Payment Charges, resulting in a net amount returned to customers of $2.68 million in 2023.

12.2.2 Flooding Damage

In November 2021, a series of atmospheric rivers brought heavy rain to parts of southern British Columbia and the northwestern United States, causing extensive flooding in the Province and affecting some of FEI's assets and customers in its service territory. FEI estimates the total costs associated with repairing damage to its facilities and restoring service to affected customers are approximately $3.3 million. At the time of this Application, the Company is working with its insurance company to determine the expenditures eligible for recovery. Any insurance recoveries would be used to offset the costs incurred. Given that the outcome of FEI's insurance claim is unknown at this time, FEI has identified the costs related to the 2021 flooding event as a potential exogenous factor but is not requesting recovery of the costs in this proceeding.

In the following sections, FEI provides details of the flooding damage, remediation activities undertaken, and the associated costs incurred.

12.2.2.1 Flooding Damage and Remediation Activities

There were a number of areas or communities that sustained significant impacts from the severe weather event and were most impacted by outages on FEI's distribution system. These areas included Princeton, Merritt and the Fraser Valley, particularly parts of Langley, Abbotsford and Chilliwack and the Sumas Prairie. Details of the work undertaken and remediation activities completed are included below.

Overall, FEI found 63 sites where gas mains and pipelines became exposed as a result of washouts and flooding during the severe weather event. These exposures have been inspected, stabilized if necessary, and backfilled. In total, six kilometres of FEI's distribution pipeline, a 4-inch diameter transmission line, and two 10-inch diameter transmission pressure pipelines were exposed and required remediation. Additionally, some control stations were submerged in water as the result of the flooding. The Huntingdon station experienced some flooding, but the equipment was not submerged and it remained fully operational. The Fraser Valley Biogas and McDermott stations were also affected by flooding, with restoration required to remove wall panels and insulation, clean surfaces, and replace some telemetry/electrical equipment.

Service to FEI's natural gas customers was disrupted in the flooded areas. For the Princeton area, the outage originally impacted approximately 1,282 customers. Outages began on November 15, 2021 and service was mostly restored on November 25, 2021 with the exception of 126 customers that were locked off due to flood damage and 71 where residents were not home that were left tagged for relight later. In Merritt, door to door assessments of 564 homes were completed in the affected flood area. During the assessment, 429 homes were shutoff at the meter as it was unclear of the damage done to appliances inside the homes. Customers were advised to work with a gas contractor to restore service to the homes after an assessment was done to downstream piping and appliances. 20 services were abandoned due to gas mains that were broken during the flooding. Most of these services remain off as they were in areas hardest hit by the flooding. In the Fraser Valley area, approximately 3,485 meters were investigated and serviced where required as the water receded. The majority of service to customers was restored by mid-December 2021. Additionally, there were 36 mains and 13 services investigated and evaluated. Work performed included inspecting the integrity of the pipe and conducting leak surveys during and after the backfilling of the exposed mains and services. Crews inspected and serviced the underground valves in the flooded area and bridge crossing inspections were completed in the affected area with the majority of work completed by mid-December 2021.

12.2.2.2 Remediation Costs (O&M and Capital)

The following tables summarize the total O&M and capital costs related to the exogenous factor event, including 2021 actuals, 2022 May year-to-date actuals and the forecast for the remainder of 2022 shown for the various municipalities affected by the floods, along with a brief description of the remediation activities completed. The same information has been provided to FEI's insurers to support FEI's insurance claim.

1 **Table 12-2: O&M Costs ($000s)**

Municipality	Actual 2021	Actual 2022 May YTD	Projected Additional Costs in 2022	Total	Description of Work
n/a	$ 51	$ 3	$ -	$ 54	Engineering assessment costs including for Huntingdon station seismic and flood assessment.
Various areas in service territory	$ 160	$ 18	$ -	$ 178	Repair and restoration work for Transmission assets affected including for: Merritt 4 inch TP; distribution system near Merritt; Vancouver Island NPS 10 inch Trout Lake washout; Vancouver Island Trans Canada Trail in Duncan; reinforcement and preparedness work at Huntingdon station in Abbotsford.
Various areas in Fraser Valley - Lower Mainland	$ 529	$ 202	$ 20	$ 752	Fraser Valley region flood repair activities including for emergency hits, odour, exposed mains and services, corrective work, unscheduled meter exchanges, relights and investigates.
Merritt	$ 110	$ 9	$ -	$ 120	Activities for flood repairs in Merritt including for repairing gas lines, leak surveys for worst affected areas in Merritt, and remove and re-install station fence to allow access to CNG station.
Princeton	$ 330	$ 25	$ -	$ 354	Activities for flood repairs in Princeton including for isolation and temporary service restoration of damaged four inch gas line crossing the Tulameen River. Also, including isolation of gas services, clearing water from lines, restoring gas service and relights for 900+ outages.
Gibsons/Sechelt - Sunshine Coast, Sanich	$ 73	$ 9	$ -	$ 82	For remediation response at Lower Road and Red Roofs locations. Also for repair of exposed pipe in local situations.
Total	$ 1,253	$ 266	$ 20	$ 1,540	

2

Table 12-3: Capital Costs ($000s)

Municipality	Actual 2021	Actual 2022 May YTD	Projected Additional Costs in 2022	Total	Description of Work
Abbotsford	$ -	$ -	$ 375	$ 375	Replacement of the NPS2 DPST main secured to the bridge crossing structure on Lakemont/McDermott destroyed as the result of the flood. The City of Abbotsford erected a temporary bridge structure in late 2021/early 2022; however, the City is unsure when a permanent crossing structure will be erected. The estimated timeline to replace the pipeline crossing is likely in the next 2-5 year period.
Merritt	$ 126	$ 486	$ 14	$ 626	Flood caused the Coldwater River near Merritt to jump the normal river channel, exposing and damaging a section of the TP pipe. Emergency replacement and lowering of approximately 150 metres of the exposed pipe with the Coldwater River relocated back to the original channel.
Princeton	$ 185	$ 84	$ 16	$ 285	Washout of the existing NPS 4" DP main line crossing the Tulameen River. A temporary DP line was installed. Permanent replacement for the damaged section of pipe by completing a HDD across the Tulameen River, and tying into the existing infrastructure on the north and south side of river.
Roberts Creek	$ 320	$ 36	$ 119	$ 475	Washout near lower road in Roberts Creek, Sunshine Coast resulted replacement of 60 feet of IP and DP pipe due to exposure and damage.
Total	$ 631	$ 606	$ 524	$ 1,761	

Figure 12-2 below shows the repairs and preventative measures completed at some of the sites impacted by the floods.

- Left photo – FEI Distribution crew at Princeton tying in temporary bypass that was used to restore service to the community until a permanent line could be drilled across the river.
- Middle photo – 4-inch transmission line near Merritt was exposed as the result of the Coldwater River overflowing. A diversion was put in place allowing water to recede.
- Top right photo – This shows the impact of Coldwater River changing course with debris shown floating down river. A car floating down the river was secured by emergency personnel to prevent it from striking the 4-inch transmission line.
- Bottom right photo – Due to the suspension of the 4-inch transmission line, it was necessary to bring in CNG to Merritt. The CNG equipment was located at the main gate station in Merritt for approximately 10 days, as a backup, if required, and also then was used during the replacement of the section of transmission line impacted by the new river channel. The CNG was able to meet the needs of IP and DP pressure served from the station. Five CNG trucks were bought in to ensure enough supply if needed considering impacts of road closures potentially impacting delivery.

Figure 12-2: Repairs and Preventative Measures

12.2.2.3 Summary Potential Exogenous Factor for Flooding

As outlined above, the total incremental capital and O&M costs related to the flooding event are currently expected to be $3.3 million, which includes actual costs for 2021 and 2022 as well as forecast costs for the remainder of 2022 (i.e., $1.761 million of capital and $1.540 million of O&M). FEI has submitted an insurance claim to recover the total O&M and capital costs. As part of the same insurance claim, FEI has also submitted a claim to recover the approximately $0.9 million in evacuation relief bill credits provided to customers related to the flooding incident. If FEI's insurance claim is successful, FEI's net incremental costs would be limited to the $1 million insurance deductible. However, until the insurance claim has been settled, FEI will not know the total cost related to the flooding, as FEI may receive all, partial or no reimbursement.

At this time, FEI is unable to predict when the insurance claim is likely to be settled. However, once the insurance claim has been settled, FEI will determine if exogenous factor treatment is warranted and will file for approval of exogenous factor treatment, if applicable, in a future rate filing.

12.3 *ACCOUNTING MATTERS*

In the following section, FEI provides information on emerging accounting guidance.

12.3.1 Emerging Accounting Guidance

In the PBR Plan decision, the BCUC directed FEI to "communicate any accounting policy changes and updates to the Commission and other stakeholders as part of the Annual Review process during the PBR period." While this directive was not included as part of the MRP Decision, FEI will continue to provide accounting policy changes and updates as part of the Annual Review materials.

There are no new accounting policy changes that FEI is proposing, or that are required to be implemented under US GAAP, that result in a change in accounting for 2023; however, FEI provides an update on its exemptive relief to report under US GAAP.

12.3.1.1 Ontario Securities Commission Exemption to use US GAAP

FEI follows US GAAP for both financial and regulatory accounting purposes. Since 2011, FEI has made use of an exemption from the Ontario Securities Commission (OSC) permitting FEI to prepare and file its financial statements in accordance with US GAAP. Like other reporting issuers, FEI also has the option to obtain an exemption permitting the use of US GAAP by qualifying as a US Securities and Exchange Commission Issuer (SEC Issuer) pursuant to Canadian securities law. During 2022, FEI sought and received approval from its primary securities regulator, the BC Securities Commission (BCSC), for the same exemptive relief as the 2011 OSC exemption. FEI's original exemption from 2011 was filed jointly with FEI's parent company Fortis Inc., whose primary securities regulator is the OSC; however, Fortis Inc. is now an SEC Issuer and no longer makes use of the OSC exemption. As a result, FEI obtained an exemption on a stand-alone basis from the BCSC.

The BCUC has approved FEI's use of US GAAP for regulatory accounting purposes since 2011.[77] As part of the most recent BCUC approval to use US GAAP, the BCUC directed the following[78]:

> Approval is granted until such time as the FortisBC Utilities no longer has an Ontario Securities Commission exemption to use US GAAP or is no longer reporting under US GAAP for financial reporting purposes.

FEI considers that the intention of the above direction was to ensure that FEI has an exemption from its securities regulator to use US GAAP, and not that an exemption specifically from the OSC was required, as opposed to a different securities regulator that had jurisdiction. It was not contemplated at the time of the above direction that FEI would make use of a BCSC exemption rather than an OSC exemption.

To ensure that FEI has approval from the BCUC to use US GAAP for regulatory accounting purposes, FEI is seeking a variance of Directive 2 to Order G-83-14 to remove the reference to the OSC, so that it removes the reference to the Ontario Securities Commission, and states:

> Approval is granted until such time as FEI no longer has an exemption to prepare and file its financial statements in accordance with US GAAP or is no longer reporting under US GAAP for financial reporting purposes.

[77] Order G-117-11 dated July 7, 2011 and Order G-83-14 dated July 3, 2014.
[78] Order G-83-14, Directive 2.

FEI notes that there have been no other changes in circumstances beyond the change in the regulatory body granting exemptive relief. However, similar to the original 2011 OSC exemptive relief, the 2022 BCSC exemptive relief is not permanent and would expire January 1, 2027 unless extended further. Should FEI plan to no longer report under US GAAP (e.g., convert from US GAAP to IFRS), it would file an application for approval from the BCUC at that time.

12.4 *NON-RATE BASE DEFERRAL ACCOUNTS*

FEI maintains both rate base and non-rate base deferral accounts. Rate base deferral accounts are included in rate base and earn a rate base return. In contrast, non-rate base deferral accounts are outside of rate base and, subject to BCUC approval, attract a weighted average cost of capital (WACC) return (which is equal to a rate base return).

On May 3, 2017, the BCUC issued its Regulatory Account Filing Checklist.[79] The purpose of this checklist is to facilitate an efficient review of applications for deferral accounts. The checklist classifies deferral accounts as either: (a) forecast variance accounts; (b) rate smoothing accounts; (c) benefit matching accounts; (d) retroactive expense accounts; or (e) other.

In the following section, FEI provides information on the Flow-through deferral account. Information on FEI's non-rate base earnings sharing, BVA and CGIF deferral accounts is included in Section 10.

12.4.1 New Deferral Accounts

FEI is not seeking approval of any new non-rate base deferral accounts in this Application.

12.4.2 Existing Deferral Accounts

In the section below, FEI discusses the Flow-through deferral account.

12.4.2.1 Flow-Through Deferral Account (2020-2024)

As approved through Order G-165-20, the Flow-through deferral account is used to capture the annual variances between the approved and actual amounts for all costs and revenues which are forecast annually, are not subject to earnings sharing, and which do not have a previously approved deferral account. The specific items included in the Flow-through deferral account were set out in Table C4-1 of the MRP Application, reproduced below.

[79] Letter Log No. 53608, Appendix B.

Table 12-4: Variances Captured in the Flow-through Deferral Account

	FEI	FBC
Delivery Revenues (FEI):		
Residential and commercial use rate variances	RSAM	N/A
Customer variances	Flow-through deferral	N/A
Industrial and all other revenue variances	Flow-through deferral	N/A
Revenues and Power Supply (FBC):		
Revenue variances	N/A	Flow-through deferral
Power Supply variances net of PSI	N/A	Flow-through deferral
Gross O&M:		
Index-based O&M variances	Subject to earnings sharing	Subject to earnings sharing
BCUC fees variances	BCUC variances deferral	BCUC variances deferral
Pension & OPEB variances	Pension/OPEB variances deferral	Pension/OPEB variances deferral
All other O&M variances [1,3]	Flow-through deferral	Flow-through deferral
Capitalized Overhead:		
Capitalized overhead variances	No variance	No variance
Depreciation and Amortization:		
Depreciation rate variances	No variance	No variance
Depreciation on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other depreciation variances	Subject to earnings sharing	Subject to earnings sharing
Amortization of deferrals	No variance	No variance
Property Tax:		
Property tax variances	Flow-through deferral	Flow-through deferral
Other Revenues :		
SCP Mitigation revenues variances	SCP Revenues deferral	N/A
CNG/LNG Recoveries variances	CNG/LNG Recoveries deferral	N/A
Revenues from Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
All other other revenue/income variances	Subject to earnings sharing	Subject to earnings sharing
Interest Expense/Cost of Debt:		
Interest on RSAM/CCRA/MCRA/Gas storage	Interest on RSAM/CCRA/MCRA/Gas Storage	N/A
Interest rate variances	Flow-through deferral	Flow-through deferral
Interest on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other interest variances	Subject to earnings sharing	Subject to earnings sharing
Income Tax:		
Income tax rate variances	Flow-through deferral	Flow-through deferral
Income tax on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Other income tax variances	Subject to earnings sharing	Subject to earnings sharing

1: Including items forecast outside of the formula such as insurance premiums, NGT stations, biomethane, variable LNG production, integrity digs and EV charging stations.

2: Cost of service for NGT fueling stations and tankers, variable LNG production, and EV stations will be captured in the Flow-through deferral account.

3: Biomethane other revenues will continue to capture the actual cost of service of the biomethane capital assets and transfer it to the BVA

In accordance with the method set out in the table above, the calculation of the 2022 Projected Flow-through amount of $7.730 million debit is shown in Table 12-5 below. To calculate the amount to be collected from customers, FEI has also included the following adjustments:

- The $10.491 million debit difference between the projected ending 2021 deferral account debit balance of $11.121 million,[80] embedded in 2022 delivery rates, and the actual ending 2021 deferral account debit balance of $21.612 million. A more detailed breakout of the 2021 variance is provided in Table 12-6 below;
- The $0.785 million debit difference between the forecast 2022 financing addition of $0.296 million debit[81] embedded in 2022 delivery rates, and the projected 2022 financing addition of $1.081 million debit embedded in this Application; and
- 2023 forecast financing of a $0.506 million debit.[82]

80 Annual Review for 2022 Delivery Rates Compliance Filing financial schedules, Schedule 12, Line 3, Column 2.
81 Annual Review for 2022 Delivery Rates Compliance Filing financial schedules, Schedule 12, Line 3, Column 4.
82 Section 11, Schedule 12, Line 3, Column 4.

Table 12-5: 2022 Projected Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	2022 Approved	2022 Projected	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Delivery Margin**			
2	Residential (Rate 1)	$ (589.064)	$ (588.539)	$ 0.525
3	Commercial (Rate 2, 3, 23)	(269.840)	(269.214)	0.626
4	Industrial (All Others)	(144.357)	(135.619)	8.738
5				
6	**Net O&M Expense**			
7	Pension & OPEB	9.537	9.537	-
8	Insurance	11.474	11.552	0.078
9	Biomethane	3.355	3.249	(0.106)
10	NGT	2.057	1.944	(0.113)
11	Variable LNG Production Costs	7.553	7.053	(0.500)
12	Integrity O&M	5.700	6.000	0.300
13	Renewable Gas Development	1.000	1.750	0.750
14	BCUC Levies	7.408	7.408	-
15	COVID-19 Pandemic	-	(3.860)	(3.860)
16	Biomethane O&M transferred to BVA	(3.355)	(3.249)	0.106
17	Capitalized Overhead	(53.328)	(53.328)	-
18				
19	**Depreciation and Amortization**			
20	Amortization of Deferrals	108.747	108.747	-
21	Depreciation variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
22	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
23				
24	**Total Property Taxes**	73.397	73.600	0.203
25				
26	**Other Revenues**			
27	Late Payment Charges (2020/2021 exogenous portion)	-	1.185	1.185
28	SCP Third Party Revenue	(13.410)	(13.410)	-
29	NGT Tanker Rental Revenue	(0.928)	(0.850)	0.078
30	Biomethane Other Revenue	(0.986)	(0.812)	0.174
31	LNG Capacity Assignment	(18.039)	(18.039)	-
32	CNG & LNG Service Revenues	(2.957)	(3.270)	(0.313)
33				
34	**Interest Expense**			
35	Long-term debt interest expense variance	149.765	148.555	(1.210)
36	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
37	Short-term debt rate variance	-	1.886	1.886
38	Short-term debt volume variance from long-term debt issue variance	-	-	-
39	Short-term debt timing variance from long-term debt issue timing	-	2.042	2.042
40				
41	**Income Tax Expense**			
42	Income tax variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
43	Income tax/CCA rate changes	-	-	-
44	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	-	(2.859)	(2.859)
45				
46	**2022 After-Tax Flow-Through Addition to Deferral Account (excluding Financing)**			**7.730**
47				
48	2021 Ending Deferral Account Balance True-up			10.491
49	2022 Financing True-up			0.785
50	2023 Financing Addition to Deferral Account			0.506
51				
52	**2023 After-Tax Amortization**			**19.512**

12.4.2.1.1 2022 PROJECTED FLOW-THROUGH VARIANCES

As shown in Table 12-5 above, the 2022 Projected flow-through variance is $7.730 million. The variances in each flow-through category are described below.

The projected variances in delivery margin are due to the following:

- unfavourable industrial margin as a result of lower LNG and BC Hydro Island Cogeneration plant demand, partially offset by favourable interruptible volumes for the Vancouver Island Joint Venture as described in Section 3; and

- unfavourable commercial and residential margin mainly as a result of lower customers than forecast.

The Flow-through O&M amount shown on Line 15 in Table 12-5, which is a credit of $3.86 million, is discussed in Section 12.2. The remaining flow-through O&M amounts are discussed in Section 6.

Amortization expense is equal to the approved value. Variances in property taxes are provided in Section 9. Variances in Other Revenue are provided in Section 5 or in Section 12.2 for the exogenous item shown on Line 27 in Table 12-5, for a recovery of $1.185 million. The projected interest expense variances are derived from FEI expecting to issue long-term debt later in 2022 than forecast, but at a higher rate than forecast, and FEI projecting a higher short-term interest rate than the approved short-term interest rate, as discussed in Section 8. The income tax variance is derived as 27 percent of the variances described above.

An adjustment to include the difference between the projected and final actual amounts for 2022 subject to flow-through will be recorded in the deferral account in 2022 and amortized in 2024 rates.

12.4.2.1.2 2021 FLOW-THROUGH DEFERRAL ACCOUNT TRUE-UP

As mentioned above, FEI provides a breakout of the 2021 true-up amount of $10.491 million debit in Table 12-6 below, along with an explanation of the variances.

Table 12-6: 2021 Actual vs. Projected Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	2021 Projected	2021 Actual	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Delivery Margin**			
2	Residential (Rate 1)	$ (533.413)	$ (534.649)	$ (1.236)
3	Commercial (Rate 2, 3, 23)	(252.746)	(247.772)	4.974
4	Industrial (All Others)	(133.392)	(122.773)	10.619
5				
6	**Net O&M Expense**			
7	Pension & OPEB	22.354	22.354	-
8	Insurance	10.430	10.308	(0.122)
9	Biomethane	2.668	2.810	0.142
10	NGT	1.919	1.974	0.055
11	Variable LNG Production Costs	7.281	7.040	(0.241)
12	Integrity Digs	5.900	7.186	1.286
13	Renewable Gas Development	1.000	1.112	0.112
14	BCUC Levies	7.290	7.290	-
15	Biomethane O&M transferred to BVA	(2.668)	(2.810)	(0.142)
16	Capitalized Overhead	(52.689)	(52.689)	-
17				
18	**Depreciation and Amortization**			
19	Amortization of Deferrals	89.710	89.710	-
20	Depreciation variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.288)	(0.288)
21	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
22				
23	**Total Property Taxes**	70.867	70.611	(0.256)
24				
25	**Other Revenues**			
26	SCP Third Party Revenue	(14.053)	(14.053)	-
27	NGT Tanker Rental Revenue	(0.810)	(0.606)	0.204
28	Biomethane Other Revenue	(0.926)	(0.926)	-
29	LNG Capacity Assignment	(18.039)	(18.039)	-
30	CNG & LNG Service Revenues	(2.771)	(3.032)	(0.261)
31				
32	**Interest Expense**			
33	Long-term debt interest expense variance	146.605	146.564	(0.041)
34	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.069)	(0.069)
35	Short-term debt rate variance	(0.676)	(1.137)	(0.461)
36	Short-term debt volume variance from long-term debt issue variance	0.603	0.315	(0.288)
37	Short-term debt timing variance from long-term debt issue timing	(0.796)	(0.411)	0.385
38				
39	**Income Tax Expense**			
40	Income tax variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.046)	(0.046)
41	Income tax/CCA rate changes	-	-	-
42	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	(2.302)	(6.279)	(3.977)
43				
44	**2021 After-Tax Flow-Through Addition to Deferral Account (excluding Financing)**			**10.349**
45				
46	2021 Financing True-up			0.142
47				
48	**2021 Ending Deferral Account Balance True-up**			**10.491**

The variances in delivery margin are due to the following:

- unfavourable industrial margin as a result of lower LNG demand, partially offset by favourable interruptible volumes for the Vancouver Island Joint Venture; and
- unfavourable commercial margin mainly as a result of lower customers than forecast, partially offset by favourable residential margin mainly as a result of higher customers than forecast.

The flow-through components of O&M expense were $1.090 million higher than projected, with the main variance related to integrity digs, which was $1.286 million higher than projected. The variance in integrity digs was due to a higher cost per dig as a result of the various dig locations. FEI's actual dig locations involved a greater proportion of digs in residential areas (requiring increased restoration), on roadways (requiring road detours and road re-construction), and on steep slopes (requiring advanced engineering and more complex field execution).

Actual property tax expenses were relatively consistent with the projected amount.

The flow-through components of Other Revenue were $0.057 million higher than projected, with the main variance related to CNG & LNG Service Revenues, which were $0.261 million higher than projected. The variance in CNG & LNG Service Revenues was mainly due to higher CNG Station demand than forecast.

The variance between the actual (1.26 percent) and projected (1.64 percent) short-term debt interest rates results in an amount to be returned to customers of $0.461 million,[83] shown on Line 35 of Table 12-6 above. The long-term debt interest expense variance of $0.041 million to be returned to customers is due to lower issue costs than projected on the 2021 long-term debt issuance. The net variance of $0.097 million recoverable from customers on Lines 36 and 37 of Table 12-6 above is due the impact of a lower actual short-term interest rate than projected.

The favourable income tax variance of $3.977 million is calculated as 27 percent of the aforementioned variances.

The combined favourable variance of $0.404 million related to depreciation/CIAC amortization, interest and tax variances on Clean Growth/CPCN/exogenous capital amounts, shown on Lines 20, 21, 34 and 40, respectively, in the table above, were derived for 2021 by comparing the actual 2021 cost of service impacts of the NGT Assets and the Inland Gas Upgrade, Tilbury 1A Expansion, Lower Mainland Intermediate Pressure System Upgrade and CTS projects to the amounts forecast for those same projects.

12.5 *SUMMARY*

FEI has discussed one new potential exogenous factor and has requested approval to return the incremental net cost reductions related to the COVID-19 pandemic to customers in 2023 through inclusion in the Flow-through deferral account. FEI has also provided an update on certain accounting related matters, and included information on the Flow-through deferral account.

[83] (1.2649% - 1.64%) x $122.859 million forecast 2021 short-term debt in Schedule 26 of Annual Review for 2020 and 2021 Delivery Rates Compliance Filing financial schedules.

13. SERVICE QUALITY INDICATORS

13.1 *INTRODUCTION AND OVERVIEW*

Under the MRP, SQIs are used to monitor the Utility's performance to ensure that any efficiencies and cost reductions do not result in a degradation of the quality of service to customers.

In the MRP Decision and Order G-165-20, the BCUC approved a balanced set of SQIs for FEI, covering safety, responsiveness to customer needs, and reliability. Nine of the SQIs have benchmarks and performance ranges set by a threshold level. Four of the SQIs are for information only and as such do not have benchmarks or performance ranges.

In the subsections below, FEI reports on its 2021 and June 2022 year-to-date performance as measured against the SQI benchmarks and thresholds. In 2021, for the nine SQIs with benchmarks, eight performed at or better than the approved benchmarks, with one, Meter Reading Accuracy, lower than the threshold due to the impact of the COVID-19 pandemic[84] as well as the multiple extreme weather events that occurred during the year. For the four SQIs that are informational only, performance in 2021 generally remains at a level consistent with prior years. In 2022 to date, performance for the metrics with benchmarks is trending towards meeting the benchmark or the threshold.

Consistent with how SQIs were reviewed during the 2014-2019 PBR Plan term,[85] FEI has provided 2021 and year-to-date 2022 SQI results in this annual review. In accordance with Order G-44-16, the BCUC will evaluate FEI's actual 2022 SQI performance in the Annual Review for 2024 Delivery Rates when actual SQI results are known. FEI also notes that it will provide information on the 2023 year-to-date SQI results in the Annual Review for 2024 Delivery Rates.

13.2 *REVIEW OF THE PERFORMANCE OF SERVICE QUALITY INDICATORS*

For each SQI, Table 13-1 provides a comparison of FEI's 2021 and June year-to-date performance for 2022 to the proposed benchmarks and thresholds approved as part of the MRP. Actual 2021 and June year-to-date results for 2022 are also provided for the four informational SQIs.

[84] In Letter L-20-20, dated March 31, 2020, the BCUC granted public utilities relief from meter reading, when necessary, for the duration of the State of Emergency in the Province of British Columbia and while social distancing practices remain in place.

[85] MRP Decision page 99: "the Panel determines that the existing approved process for interpreting metric performance is to remain in effect over the term of the MRPs".

Table 13-1: Approved SQIs, Benchmarks and Actual Performance

Performance Measure	Description	Benchmark	Threshold	2021 Results	2022 June YTD Results
Safety SQIs					
Emergency Response Time	Percent of calls responded to within one hour	>= 97.7%	96.2%	97.7%	98.1%
Telephone Service Factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	>= 95%	92.8%	96.9%	97.4%
All Injury frequency rate (AIFR)	3 year average of lost time injuries plus medical treatment injuries per 200,000 hours worked	<= 2.08	2.95	1.75	1.64
Public Contacts with Gas Lines	Current year average of number of line damages per 1,000 BC One calls received	<= 8	12	6	5
Responsiveness to the Customer Needs SQIs					
First Contact Resolution	Percent of customers who achieved call resolution in one call	>= 78%	74%	79%	78%
Billing Index	Measure of customer bills produced meeting performance criteria	<= 3.0	5.0	0.9	0.99
Meter Reading Accuracy	Number of scheduled meters that were read	>= 95%	92%	88%	86%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	>= 70%	68%	70%	61%
Meter Exchange Appointment	Percent of appointments met for meter exchanges	>= 95%	93.8%	98.3%	98.1%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.7	8.6
Average Speed of Answer	Informational indicator – amount of time it takes to answer a call (seconds)	-	-	65	104
Reliability SQIs					
Transmission Reportable Incidents	Informational indicator – number of reportable incidents to outside agencies	-	-	0	0
Leaks per KM of Distribution System Mains	Informational indicator - measures the number of leaks on the distribution system per KM of distribution system mains	-	-	0.0055	0.0032

In the following sections, FEI reviews each SQI's year-to-date individual performance in 2021 and 2022. Discussion is also provided for the informational SQIs.

13.2.1 Safety Service Quality Indicators

13.2.1.1 Emergency Response Time

This SQI measures the utility's responsiveness to on average 24,000 annual emergency events that include gas odour calls, carbon monoxide calls, house fires and hit lines. It is calculated as:

$$\frac{\text{Number of emergency calls responded to within one hour}}{\text{Total number of emergency calls in the year}}$$

There are many variables affecting the response time, including time of day (i.e., during business hours or after business hours), number and type of events, available resources, location (i.e., travel times and traffic congestion) and weather conditions.

The 2021 result was 97.7 percent which met the benchmark. The 2021 performance was consistent with 2020 and slightly lower than the previous three years (2017-2019); however, the performance was higher than the three years previous to that (2014-2016). The June 2022 year-to-date performance is 98.1 percent, which is better than the benchmark.

For comparison, the Company's annual results under the 2014-2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date emergency response time results are provided below.

Table 13-2: Historical Emergency Response Time

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Results	96.7%	97.3%	97.4%	97.8%	97.8%	97.9%	97.7%	97.7%	98.1%
Benchmark	97.7%								
Threshold	96.2%								

13.2.1.2 Telephone Service Factor (Emergency)

This indicator measures the percentage of emergency calls answered within 30 seconds and is calculated as:

$$\frac{\text{Number of emergency calls answered within 30 seconds}}{\text{Number of emergency calls received}}$$

The telephone service factor (TSF) is a measure of how well the Company can balance costs and service levels, with the overall objective to maintain a consistent TSF level. This ensures the Company is staying within appropriate cost levels and maintaining adequate service for its customers. The principal factors influencing the TSF results include the volume of inbound calls received and the resources available to answer those calls. Staffing is matched to the calls forecast based on historical data in order to reach the service level benchmark desired.

The 2021 result was 96.9 percent which was better than the benchmark of 95 percent. The June 2022 year-to-date performance is 97.4 percent which is also better than the benchmark.

For comparison, the Company's annual results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date for TSF (Emergency) are provided below:

Table 13-3: Historical TSF (Emergency) Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Results	95.8%	97.6%	98.5%	97.6%	97.9%	97.2%	96.9%	96.9%	97.4%
Benchmark	95.0%								
Threshold	92.8%								

13.2.1.3 All Injury Frequency Rate

The All Injury Frequency Rate (AIFR) is an employee safety performance indicator based on injuries per 200,000 hours worked, with injuries defined as lost time injuries (i.e., one or more days missed from work) and medical treatments (i.e., medical treatment was given or prescribed). The annual performance for this metric is calculated as:

$$\frac{\text{Number of Employee Injuries x 200,000 hours}}{\text{Total Exposure Hours Worked}}$$

For the purpose of this SQI, the measurement of performance is based on the three-year rolling average of the annual results.

The 2021 (three-year rolling average) result was 1.75 which was better than the benchmark of 2.08. The 2021 annual AIFR was 1.99 which reflected 11 Medical Treatments and 24 Lost Time Injuries.

The June 2022 year-to-date performance (three-year rolling average) result is 1.64 which is better than the benchmark. The June 2022 year-to-date performance (annual) is 1.20 and reflects 4 Medical Treatments and 7 Lost Time Injuries.

Strengthening the safety culture continues to be a key driver for FEI, building on the commitment to learn from safety events, identify safety hazards, assess risk and continually improve through the implementation and sustainment of robust safety barriers and controls.

While the AIFR result is better than the benchmark, the 2021 injury rate was slightly higher than recent years. The majority of the injuries experienced in 2021 were low severity in nature (strains and sprains), resulting from slips and trips and improper equipment use that mainly involved workers conducting manual labour tasks. FEI has adopted mitigation measures, including enhanced safe work planning, task specific training and education, additional ergonomic assessments and a range of technology solutions.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date AIFR results are provided below.

Table 13-4: Historical All Injury Frequency Rate Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	1.73	2.52	2.13	1.36	1.74	1.82	1.43	1.99	1.20
Three year rolling average	2.22	2.42	2.13	2.00	1.74	1.64	1.66	1.75	1.64
Benchmark	2.08								
Threshold	2.95								

13.2.1.4 Public Contact with Gas Lines

This metric measures the overall effectiveness of the Company's efforts to minimize damage to the gas system through public awareness, which is designed to reduce interruptions and the associated public safety and service issues to customers.

This indicator is calculated as:

Number of Line Damages per 1,000 BC One Calls received

For the purpose of this service quality indicator, the measurement of performance is based on the annual results. The new benchmark and threshold approved in the MRP are 8 and 12, respectively.

In its Decision on FEI's Annual Review of 2015 Delivery Rates, the BCUC directed FEI to provide the number of line damages and the number of calls to BC One Call in future annual reviews. Therefore, the number of line damages and number of calls to BC One Call are provided in Table 13-5 below.

The 2021 result was 6, which is better than the benchmark. The June 2022 year-to-date performance is 5, which is also better than the benchmark.

Principal factors influencing results for this metric include economic growth (i.e., construction activity), damage prevention awareness programs, and heightened public awareness created by the BC One Call program. The current year result reflects an ongoing positive trend for this metric. Increased awareness through targeted workshops with municipalities and excavating contractors, together with the ongoing execution of the Damage Investigation Program have contributed to the improved performance.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results, and June 2022 year-to-date results are provided below. The annual result has been trending downward.

The Company continues to take steps to address line damage. FEI continues to have Damage Prevention Investigators focus on repeat damagers and is working with Technical Safety BC to reduce line hits. In addition, in 2021, FEI implemented the installation of marker tape above new underground gas assets. 2021 BC One Call ticket volume was higher than previous years as a result of improved awareness and a high level of construction activity. While 2022 year-to-date volume (82,699) is lower than 2021 (86,673), it is higher than 2020 (72,034), and fairly consistent with 2018 (80,970) and 2019 (79,694) levels. The hits per 1,000 ticket metric continues to trend in the right direction, indicating the effectiveness of the additional steps the Company is taking to address line damages.

Table 13-5: Historical Public Contact with Gas Lines Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	9	8	8	9	8	7	7	6	5
Benchmark	16						8		
Threshold	16						12		
BC One Call Ticket Volume	107,509	122,627	129,645	146,868	157,708	144,413	141,262	163,584	82,699
Line Damages	954	1,035	1,086	1,247	1,201	1,069	973	1,034	416

13.2.2 Responsiveness to Customer Needs Service Quality Indicators

13.2.2.1 First Contact Resolution

First Contact Resolution (FCR) measures the percentage of customers who receive resolution to their issue in one contact with FEI. The Company determines the FCR results using a customer survey, tracking the number of customers who responded that their issue was resolved in the first contact with the Company. The FCR rate is impacted by factors such as the quality and effectiveness of the Company's coaching and training programs and the composition of the different call drivers.

The 2021 result was 79 percent which was better than the benchmark of 78 percent. The minor reduction in FCR as compared to previous years as shown in Table 13-6 below is largely attributable to the changing circumstances of the COVID-19 pandemic. More specifically, disconnection notices resumed in Q3 2020, with the effects of these notices and resumption of collections related activities carrying over into 2021. Depending on the circumstances of the payment challenges faced by the customer, follow up investigation and option analysis may be required such that the interaction is not resolved in one contact. The June 2022 year-to-date performance is 78 percent, which meets the benchmark.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-6: Historical First Contact Resolution Levels

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	80%	81%	81%	80%	83%	81%	81%	79%	78%
Benchmark	78%								
Threshold	74%								

13.2.2.2 Billing Index

The Billing Index indicator tracks the effectiveness of the Company's billing system by measuring the percentage of customer bills produced meeting performance criteria. The Billing Index is a composite index with three components:

- Billing completion (percent of accounts billed within two days of the billing due date);
- Billing timeliness (percent of invoices delivered to Canada Post within two days of file creation); and
- Billing accuracy (percent of bills without a production issue based on input data).

The objective is to achieve a score of five or less.

The Billing Index is impacted by factors such as the performance of the Company's billing system, weather variability, which can cause a high volume of billing checks and estimation issues, and mail delivery by Canada Post.

The 2021 result was 0.94 which was better than the benchmark of 3.0. No significant billing issues occurred in 2021. The June 2022 year-to-date result is 0.99 which is also better than the benchmark.

The 2021 Billing Index sub-measures calculation is as follows.

Table 13-7: Calculation of 2021 Billing Index

Billing sub-measure	Percent Achieved (PA)	Formula		Result
Billing Accuracy (Percent of bills without a Production Issue, based on input data); Target - 99.9%	99.9988%	If (PA≥99.9%,5000*(1 - PA),100*(1.05-PA))	=5000*(1-0.999988)	0.06
Billing Timeliness (Percent of invoices delivered to Canada Post within 2 days of file creation); Target - 95%	100.00%	(100%-PA)*100	=(100%-100%)*100	0.00
Billing Completion (Percent of accounts billed within 2 days of the billing due date); Target - 95%	97.23%	(100%-PA)*100	= (100%-97.23%)*100	2.77
Billing Service Quality Indicator; Target < 3		(Accuracy PA+Timeliness PA+Completion PA)/3	=(0.06 +0+2.77) / 3	0.94

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-8: Historical Billing Index Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	0.89	1.06	0.57	0.75	2.63	0.44	0.62	0.94	0.99
Benchmark	5.0						3.0		
Threshold	5.0								

13.2.2.3 Meter Reading Accuracy

This SQI compares the number of meters that are read to those scheduled to be read. Providing accurate and timely meter reads for customers is a key driver for the Company and its customers. The results are calculated as:

$$\frac{\text{Number of scheduled meters read}}{\text{Number of scheduled meters for reading}}$$

Factors typically influencing this SQI's performance include the resources available, system issues impacting the Company's billing or reading collections systems, weather conditions including road and highway conditions, and traffic related issues.

The 2021 result was 88.0 percent, which is lower than the benchmark and threshold and represents the second consecutive year that FEI has had below threshold performance in this metric. Overall SQI performance for 2020 was evaluated in FEI's Annual Review for 2022 Delivery Rates and the BCUC determined that service quality requirements were met and that the lower than threshold Meter Reading Accuracy results were primarily attributable to safety protocols introduced in response to the COVID-19 pandemic. Consistent with the experience in 2020, the results for 2021 reflect continued challenges as a result of the impact of the COVID-19 pandemic and the need for physical distancing and enhanced hygiene practices by meter readers.[86] While the restrictions associated with the pandemic were gradually lifted and the State of Emergency expired on June 30, 2021, Olameter continued to experience staffing challenges throughout the remainder of the year, including periods where subsequent variants of the virus affected their employees. In addition, meter reading efforts in 2021 were significantly impacted by the multiple extreme weather events that occurred, including the active wildfire season, the extreme heat event, and the flooding that led to evacuations of several communities. All of these weather events contributed to larger percentages of estimated reads due to the inability to safely access meters. For these reasons, FEI's meter accuracy results for 2021 being below threshold are attributable to the COVID-19 pandemic and extreme weather conditions in 2021, rather than any action or inaction of FEI.

FEI has remained consistent in its approach and measures to mitigate the potential service quality impact on customers as a result of the higher number of estimated reads. That is, measures used in 2021 and continuing in 2022 are consistent with those used in 2020 and evaluated by the BCUC in the 2022 Annual Review. These measures include: working closely with FEI's meter reading service provider, Olameter, to achieve as many actual meter reads as safely possible; using the best available historical billing information to estimate reads for billing purposes; working with customers to acquire additional information to support minimizing the variance between estimated and actual reads; and continuing to mitigate bill payment challenges that may result from estimations through flexible and supportive payment arrangements.[87]

The June 2022 year-to-date performance is 86.3 percent which is below the threshold. Staffing challenges attributable to the impacts of the Omicron variant experienced in the early part of the year, as well as overall labour shortages, have contributed to this below threshold result. FEI has continued to apply the mitigation measures described above throughout 2022. While year-to-date performance remains below threshold, significant improvement and consistent monthly

[86] The BCUC anticipated this impact in Letter L-20-20, which granted public utilities relief from meter reading, when necessary, for the duration of the State of Emergency in the Province of BC and while social distancing practices remain in place. In BCUC Letter L-20-20, dated March 31, 2020, the BCUC stated:

"The BCUC recognizes that this Pandemic greatly impacts utilities and utility customers across British Columbia as many businesses and individuals adjust to working from home, social distancing, and self-isolation. Given these difficult circumstances, the BCUC understands that utilities may not be able to conduct in-person meter reading for all customers at this time due to safety and operational concerns. As such, any public utilities regulated by the British Columbia Utilities Commission (BCUC) that are unable to estimate billings within their endorsed tariff Terms and Conditions are granted relief from meter reading, when necessary, for the duration of the State of Emergency in the Province of British Columbia and while social distancing practices remain in place.

In place of meter readings, when necessary, energy consumption may be estimated from best available sources and evidence for billing purposes. When the next actual meter reading is completed, customers' bills must then be adjusted for the difference between estimated and actual use over the interval between meter readings."

[87] For example, where capacity is available, FEI is proactively contacting customers with multiple estimates in a row to determine if a customer provided read is possible to support the estimation.

performance of this metric has been experienced starting in April of 2022 (91 percent for the month of April, 89 percent for the month of May, and 91 percent for the month of June), with the year-to-date performance trending upwards over the three months. FEI continues to work closely with Olameter on their improved performance and as such, barring the impact of any extreme weather or other unforeseen events, FEI expects Olameter to continue to meet the threshold and achieve the benchmark on a monthly basis for the remainder of the year.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-9: Historical Meter Reading Accuracy Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	97.0%	97.5%	96.9%	96.2%	95.4%	95.2%	89.2%	88.0%	86.3%
Benchmark	95.0%								
Threshold	92.0%								

13.2.2.4 Telephone Service Factor (Non-Emergency)

The Telephone Service Factor (Non-Emergency) measures the percentage of non-emergency calls that are answered in 30 seconds. It is calculated as:

$$\frac{\text{Number of non-emergency calls answered within 30 seconds}}{\text{Number of non-emergency calls received}}$$

Similar to the TSF (Emergency), this is a measure of how well the Company can balance costs and service levels with the overall objective to maintain a consistent TSF level. This ensures the Company is staying within appropriate cost levels and maintaining adequate service for its customers. The principal factors influencing the TSF results include volume and type of inbound calls received and the resources available to answer those calls. Staffing is matched to the expected call volume based on historical data in order to reach the service level benchmark desired. Other factors that can influence the non-emergency TSF are billing system related issues and weather patterns that may generate high numbers of billing related queries and the complexity of the calls.

The 2021 result was 70 percent which meets the benchmark. The June 2022 year-to-date performance is 61 percent which is lower than the threshold.

Several challenging circumstances were faced in the first quarter of 2022 that have contributed to a year-to-date performance in the non-emergency TSF below threshold. These challenges include higher than normal attrition levels being experienced in the contact centre coupled with rate increases, colder weather and meter reading estimates that resulted in approximately 160 percent more high bill inquiries in the first quarter than the average of the preceding four years.[88] Each of these is described further below.

Customer Service is experiencing higher than expected levels of attrition, having lost 65 Customer Service employees in 2021.[89] More than half of the employee exits were in the last half of 2021, resulting in fewer and less experienced employees prepared to support call volumes in the first quarter of 2022. To mitigate the impact of this, FEI accelerated the timing of planned new hire classes as well as the size of new hire classes in both 2021 and 2022. While some success has been achieved, FEI has continued to face challenges recruiting and retaining newly hired contact centre employees in 2022. In addition, it takes on average approximately 12 months for new employees to be proficient and fully trained in order to support all customer inquiries and calls, and as such, average call handle times remain higher than normal while a greater portion of employees gain this experience.

High bill inquiries are expected in the first quarter of the year and planned for with staffing levels and schedules adjusted, new hire classes timed accordingly, and refresher training offered to those employees that may need it. However, several circumstances converged that resulted in a volume of high bill inquiries that was significantly greater than anticipated and lasted longer than typical, carrying into April instead of early March. The contributing factors to the higher volume of this call type included heavy snowfall in several parts of the Province, resulting in a larger volume of bills based on estimated reads in the early part of 2022, a rate increase, carbon tax increase, and colder than normal temperatures. This particular call type is often longer in duration and may also result in follow-up work and investigation. As noted above, there were fewer and less experienced employees prepared to support these types of calls. Thus, the contact centre experienced the compounding impact of fewer employees along with the significantly higher volume of this call type, resulting in overall longer average wait times and a lower percentage of calls answered within thirty seconds or less.

Although the start of 2022 has been challenging, strong performance in first contact resolution, in addition to the promotion of self-service and the call back feature, continues to mitigate the impacts of lower TSF on customer experience and service quality. Further, recovery of the non-emergency TSF to above benchmark began in May and positive progress continues (83 percent for the month of May and 79 percent for the month of June), with FEI expecting to recover to threshold levels on a year-to-date basis within the fourth quarter. Finally, the customer service index has remained high throughout 2021 and 2022 to date, indicating that the mitigation measures and focus on first contact resolution continue to result in an overall high quality of service being experienced by customers.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

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[88] FEI experienced approximately 20,000 high bill inquiries in Q1 2022 which compares to an average of approximately 7,800 in the first quarter for the four-year period 2018-2021.

[89] This is approximately 50 percent more employees than typical. In a typical year, customer service experiences employee attrition in the range of 40-50 employees.

Table 13-10: Historical TSF (Non-Emergency) Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	75%	71%	71%	71%	71%	71%	70%	70%	61%
Benchmark[90]	75%	70%							
Threshold	68%								

13.2.2.5 Meter Exchange Appointments

The Meter Exchange Appointments SQI measures FEI's performance in meeting appointments for meter exchanges (excluding industrial meters). The calculation for percentage meter exchange appointments met is calculated as:

$$\frac{\text{Number of meter exchange appointments met}}{\text{Number of meter exchange appointments made}}$$

Factors influencing results include processes, number of emergencies, weather, and traffic conditions. The processes require the contact centre and operations departments to work closely together in order to better meet the needs of customers and match resources to appointments while maintaining emergency response capabilities.

The 2021 result was 98.3 percent which was better than the benchmark of 95 percent. The June 2022 year-to-date performance is 98.1 percent, which is also better than the benchmark.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-11: Historical Meter Exchange Appointment Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	95.5%	96.6%	96.9%	97.0%	96.3%	96.0%	98.1%	98.3%	98.1%
Benchmark	95.0%								
Threshold	93.8%								

13.2.2.6 Customer Satisfaction Index

The Customer Satisfaction Index (CSI) is an informational indicator that measures overall customer satisfaction with the Company. The index reflects customer feedback about important

[90] The 2014 result was achieved with the Company targeting 75 percent as the benchmark. The BCUC approved the revised target of 70 percent in mid-September 2014. In 2015 and subsequent years, actual results were reflective of the revised target of 70 percent.

service touch points including the contact centre, perceived accuracy of meter reading, energy conservation information and field services. The index includes feedback from both residential and mass market commercial customers. The survey is conducted quarterly and results are presented as a score out of ten.

The annual CSI score for 2021 was 8.7, the same as that obtained in 2020. There were no statistically significant shifts from 2020 to 2021 in the five measures that make up the overall customer satisfaction score. The scores for overall satisfaction and satisfaction with the contact centre metrics were both static at 8.7. The score for satisfaction with the accuracy of meter reading decreased from 8.5 in 2020 to 8.4 in 2021, and the score for satisfaction with energy conservation information decreased from 7.9 in 2020 to 7.7 in 2021. The score for the satisfaction with field services metric increased from 9.2 in 2020 to 9.3 in 2021. None of these changes are statistically significant.

The score for 2022 year-to-date is 8.6. Of the five measures that make up the overall customer satisfaction score, the results for June 2022 year-to-date were higher in one area and lower in four when compared to the annual 2021 scores. The score for satisfaction with field services increased from 9.3 in 2021 to 9.6 in 2022. The scores for overall satisfaction, satisfaction with the accuracy of meter reading, satisfaction with energy conservation information and contact centre decreased from 8.7 to 8.5, 8.4 to 8.2, 7.7 to 7.5, and 8.7 to 8.5, respectively.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-12: Historical Customer Satisfaction Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	8.5	8.6	8.8	8.4	8.7	8.7	8.7	8.7	8.6
Benchmark	n/a								
Threshold	n/a								

13.2.2.7 Average Speed of Answer

The Average Speed of Answer (ASA) is an informational indicator that measures the amount of time it takes for a customer service representative to answer a customer's call (seconds).

The 2021 result was 65 seconds. The June 2022 year-to-date performance is 104 seconds. As described above, challenges experienced in the contact centre resulted in monthly non-emergency TSF performance levels below the threshold. Comparatively, the ASA also experienced challenges, and so far in 2022, calls are being answered on average under two minutes. Aligned with the recovery to threshold levels of the TSF, the monthly ASA also returned to typical levels of less than one minute in May and FEI expects this metric to continue to decrease on a year-to-date basis throughout the remainder of the year.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below.

Table 13-13: Average Speed of Answer

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results	34	37	40	34	35	39	72	65	104
Benchmark	n/a								
Threshold	n/a								

13.2.3 Reliability Service Quality Indicators

13.2.3.1 Transmission Reportable Incidents

The Transmission Reportable Incidents metric is an informational indicator that measures the number of reportable incidents to outside agencies for transmission assets as defined by the Oil and Gas Commission (OGC). The metric is intended to be an indicator of the integrity of the transmission system.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020 and 2021 results and the June 2022 year-to-date results are provided below. There were no recorded incidents in 2021 and none so far to June 2022 year-to-date.

Table 13-14: Historical Transmission Reportable Incidents

Description	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Annual Results – Level 1	1	3	3	4	2	0	1	0	0
Annual Results – Level 2	1	0	0	0	0	0	0	0	0
Annual Results – Level 3	0	0	0	0	0	0	0	0	0
Benchmark	n/a								
Threshold	n/a								

13.2.3.2 Leaks per KM of Distribution System Mains

The Leaks per KM of Distribution System Mains metric is an informational indicator that measures the number of leaks on the distribution system per KM of distribution system mains. The metric is intended to be an indicator of the integrity of the distribution system. Each year, approximately one fifth of the distribution system is surveyed for leaks, with the number of leaks varying from year to year, depending on the condition of the pipe surveyed.

Variability in the number of leaks detected is influenced by the timing of the leak survey program as well as the condition of the distribution system, as some sections of the pipeline system are more prone to leaks depending on soil conditions, age of the pipelines, pipeline material and the location of the pipeline. As the distribution system ages, the expected number of leaks may increase depending on the Company's pipeline renewal/replacement activities. Increases in leak survey activity levels will generally also result in a higher number of leaks detected.

In its Decision on FEI's Annual Review of 2015 Delivery Rates, the BCUC directed FEI to provide a five-year rolling average as follows:

> The Panel agrees with BCSEA that a five-year rolling average of Leaks per KM of Distribution System Mains would be helpful information and directs FEI to provide this information in future annual reviews.

Table 13-15 below provides the historical data for the calculation of the June 2022 year-to-date five-year rolling average result of 0.0059 calculated using data from July 2017 to June 2022.

Table 13-15: June 2022 Year-to-Date Five-Year Rolling Average[91]

Period	Metric
July – December 2017	0.0024
January – December 2018	0.0061
January – December 2019	0.0060
January – December 2020	0.0065
January – December 2021	0.0055
January – June 2022	0.0032
Five Year Rolling Average	0.0059

The Company's 2014 to 2021 annual results are provided below. The five-year average for each year shown is calculated by taking the average of the results of the stated year and the four years prior (e.g., the 2021 five-year average is calculated using 2017 to 2021 annual data). The June 2022 year-to-date result is 0.0032 based on 75 leaks detected year-to-date, which is slightly higher than the 2021 and 2020 results for the similar time period. The number of leaks on DP mains will vary from year to year.

[91] FEI notes that the June 2021 year-to-date five-year rolling average table provided in the 2022 Annual Review showed incorrect figures for the years 2018 to 2020. After stating these results correctly, the June 2021 YTD five-year rolling average is restated to 0.0057 from 0.0053.

Table 13-16: Historical Leaks per KM of Distribution System Mains

Leaks per KM of Distribution System Mains	2014	2015	2016	2017	2018	2019	2020	2021	June 2022 YTD
Leaks	114	102	107	108	140	139	152	131	75
Total km	19,172	22,602	22,813	22,951	23,060	23,268	23,460	23,707	23,734
Leaks per km	0.0059	0.0045	0.0047	0.0047	0.0061	0.0060	0.0065	0.0055	0.0032
5 year average	0.0077	0.0071	0.0063	0.0055	0.0052	0.0051	0.0056	0.0058	0.0059

13.3 *SUMMARY*

In summary, FEI's 2021 results and June 2022 year-to-date SQI results indicate that the Company's overall performance is representative of a high level of service quality. In 2021, for those SQIs with benchmarks, eight performed at or better than the approved benchmarks with the Meter Reading Accuracy metric performance lower than the threshold due to the impact of the COVID-19 pandemic and weather-related events. For the four SQIs that are informational only, performance in 2021 generally remains at a level consistent with prior years.

Appendix A

DEMAND FORECAST SUPPLEMENTARY INFORMATION

Table A1-1: Consumer Price Index (CPI)

Products and product groups[3, 4]	All-items
Reference period	
	2002=100
July 2020	132.6
August 2020	132.4
September 2020	132.5
October 2020	132.9
November 2020	133.3
December 2020	132.8
January 2021	133.6
February 2021	134.1
March 2021	134.9
April 2021	135.2
May 2021	135.1
June 2021	135.8
July 2021	136.7
August 2021	137.0
September 2021	137.2
October 2021	137.9
November 2021	138.1
December 2021	138.0
January 2022	139.4
February 2022	140.4
March 2022	143.0
April 2022	144.2
May 2022	146.1
June 2022	146.5

Table A1-2: Average Weekly Earnings (AWE)

North American Industry Classification System (NAICS)[5]		Industrial aggregate excluding unclassified businesses[6, 7]
Geography	Reference period	
		Dollars
British Columbia (map)	July 2020	1,093.72[B]
	August 2020	1,089.35[B]
	September 2020	1,093.75[B]
	October 2020	1,095.32[B]
	November 2020	1,102.95[B]
	December 2020	1,110.36[B]
	January 2021	1,113.22[B]
	February 2021	1,114.21[B]
	March 2021	1,107.66[B]
	April 2021	1,112.04[B]
	May 2021	1,118.59[B]
	June 2021	1,115.40[B]
	July 2021	1,140.52[B]
	August 2021	1,142.40[B]
	September 2021	1,139.64[B]
	October 2021	1,136.85[B]
	November 2021	1,132.25[B]
	December 2021	1,134.84[B]
	January 2022	1,157.19[B]
	February 2022	1,153.88[B]
	March 2022	1,161.22[B]
	April 2022	1,176.54[B]

Table A1-3: Provincial Outlook Long-Term Economic Forecast 2022

BRITISH COLUMBIA	**2020**	**2021**	**2022**	**2023**
Housing Starts, Singles, British Columbia (Thousands ('000s))	8,519	10,710	8,275	7,273
Forecast Percent Change		**25.7%**	**-22.7%**	**-12.1%**
Housing Starts, Multiples, British Columbia (Thousands ('000s))	29,215	36,706	29,340	27,776
Forecast Percent Change		**25.6%**	**-20.1%**	**-5.3%**
Total	37,734	47,416	37,615	35,049

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Appendix A-2

Historical Forecast and Consolidated Tables

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List of Appendices

1. INTRODUCTION

This appendix presents two data sets as follows:

1. Historical and Forecast Data
    a. 2012 – 2021 Actual data
    b. 2022 Seed data
    c. 2023 Forecast data
2. Percent Error
    a. 2012 - 2021 Forecast, Actual and percent error

2. HISTORICAL AND FORECAST DATA TABLES

Table A2-1: FEI Customer Counts, Customer Additions, Use per Customer, and Energy[1]

FEI Customer Counts

Rate	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022-S	2023-F
RS 1	854,050	863,189	873,661	886,169	897,528	910,885	930,142	940,751	953,746	963,987	972,283	979,469
RS 2	81,123	82,452	83,625	85,076	86,074	86,973	88,244	88,686	89,363	89,683	90,202	90,682
RS 3	5,220	5,134	5,169	5,301	5,189	5,441	6,028	6,973	6,805	7,013	7,027	7,035
RS 23	1,520	1,529	1,522	1,724	1,803	1,712	1,648	871	746	697	700	703
Industrial	954	981	977	976	955	976	989	1,020	1,023	1,026	1,026	1,026
NGT	5	10	18	31	42	56	41	53	69	74	95	95
Total	942,872	953,295	964,971	979,277	991,591	1,006,043	1,027,092	1,038,354	1,051,752	1,062,480	1,071,333	1,079,010

FEI Customer Additions

Rate	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022-S	2023-F
RS 1	6,371	9,139	10,472	12,508	11,359	13,357	19,257	10,609	12,995	10,241	8,296	7,186
RS 2	577	1,329	1,173	1,450	998	899	1,271	442	677	320	519	480
RS 3	-104	-86	35	132	-112	252	587	945	-168	208	14	8
RS 23	88	9	-7	202	79	-91	-64	-777	-125	-49	3	3
Industrial	8	27	-4	-1	-21	21	13	31	3	3	0	0
NGT	3	5	8	13	11	14	-15	12	16	5	21	0
Total	6,943	10,423	11,676	14,305	12,314	14,452	21,049	11,262	13,398	10,728	8,853	7,677

FEI Normalized Use Per Customer (GJ)

Rate	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022-S	2023-F
RS 1	87.6	84.7	84.2	84.4	87.5	85.8	85.1	82.4	86.2	85.7	84.8	84.7
RS 2	341.2	331.6	330.6	332.6	339.1	336.8	332.5	318.1	322.2	328.1	323.3	321.6
RS 3	3,683.9	3,609.8	3,572.7	3,587.2	3,720.9	3,692.5	3,549.8	3,516.7	3,660.3	3,702.5	3,648.5	3,646.6
RS 23	5,238.0	5,148.7	5,260.0	5,173.7	5,279.0	5,360.5	5,344.9	5,051.3	5,440.7	5,724.3	5,552.5	5,570.5

FEI Energy (PJ)(1)

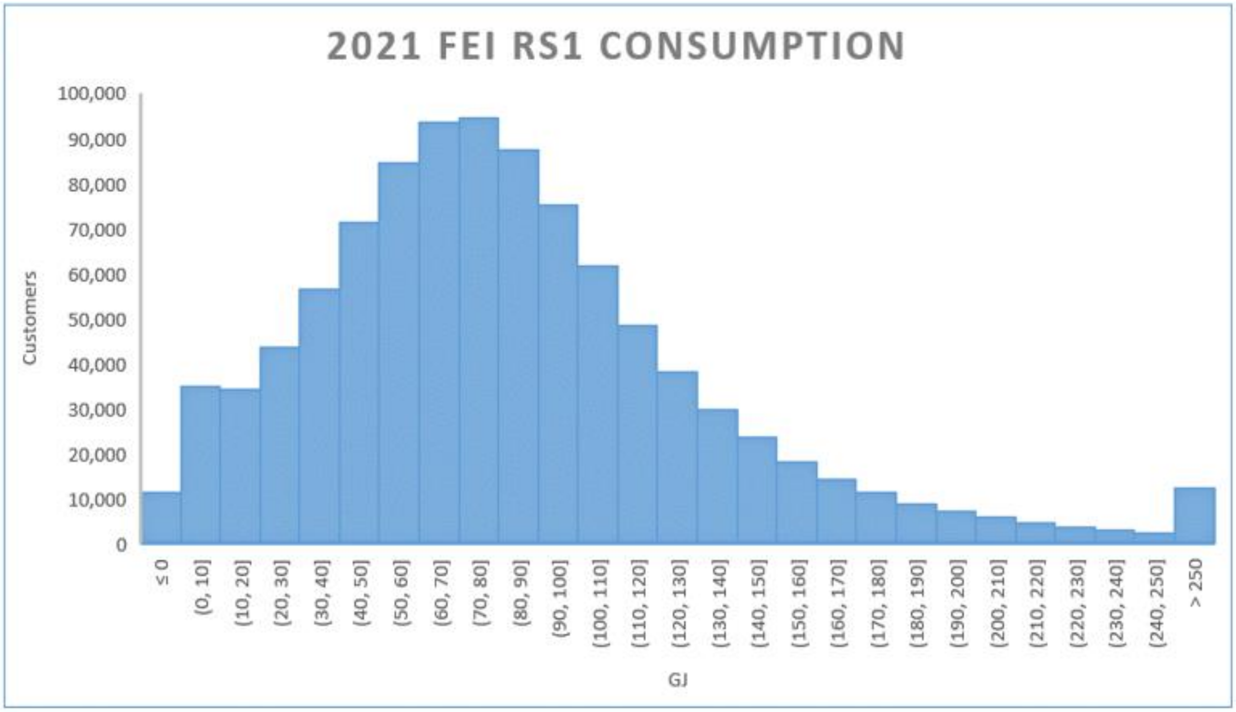
Rate	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022-S	2023-F
RS 1	74.5	72.7	73.2	74.1	77.9	77.5	78.3	77.0	81.6	82.2	82.1	82.7
RS 2	27.6	27.0	27.5	28.0	29.0	29.1	29.1	28.1	28.7	29.3	29.0	29.1
RS 3	19.3	18.7	18.5	19.2	19.4	19.7	20.9	22.5	24.6	25.7	25.6	25.6
RS 23	7.8	7.9	8.0	8.6	9.3	9.5	9.0	7.3	4.6	4.2	3.9	3.9
Industrial	80.6	80.1	78.6	79.6	83.7	87.4	88.4	91.5	89.5	90.8	78.5	73.3
Sub-Total	209.7	206.3	205.7	209.5	219.3	223.3	225.8	226.4	229.0	232.2	219.1	214.6
NGT	0.2	0.3	0.8	1.1	1.3	1.8	1.6	2.6	2.6	3.0	4.1	6.7
Total	209.9	206.6	206.5	210.6	220.6	225.0	227.3	229.0	231.7	235.2	223.2	221.3

Table A2-2: FEI 2023F Industrial Forecast Demand by Region[2]

Industrial	**2023 Forecast Demand By Region (PJ)**
Mainland	66.9
Vancouver Island	6.3
Whistler	0.1
Total	**73.3**

1 Historical industrial tables do not include Burrard Thermal demand.
2 Does not include NGT forecast demand.

Figure A2-1: FEI Residential Customers Normalized UPC in 2021



3. PERCENT ERROR DATA TABLES

In the data tables presented below, FEI provides 10 years of historical actual demand, forecast demand and percent error for each customer class and service area and on a consolidated (or amalgamated) basis, for total demand, total net customers, net customer additions and use per customer. The data tables are also provided as a fully-functional Excel file in Appendix A2-1.

Percent error is the difference between the actual demand and the forecast demand, divided by the actual demand in a given year, or stated as a formula:

$$PE_t = \left(\frac{Y_t - F_t}{Y_t}\right) \times 100$$

Where F_t is the forecast at time t and Y_t is the actual value at time t.

The tables provided below present the historical data in amalgamated form, unless specifically identified for a particular region. In order to provide historical amalgamated data, FEI mapped the Vancouver Island and Whistler customers to FEI rate schedules for periods prior to 2015. This mapping was completed using the mapping approved for the purposes of amalgamation presented in FEI's Common Rates Methodology Application, Section 4.2, as approved by BCUC Order G-131-14.

3.1 *AMALGAMATED NET CUSTOMERS*

FEI Customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 1										
Forecast	870,980	880,331	866,852	883,371	892,830	909,727	916,365	934,804	950,330	958,899
Actual	854,050	863,189	873,661	886,169	897,528	910,885	930,142	940,751	953,746	963,987
Error = (ACT-FCST)	(16,930)	(17,142)	6,809	2,798	4,698	1,158	13,777	5,947	3,416	5,088
Percent Error = (Error/ACT)	-2.0%	-2.0%	0.8%	0.3%	0.5%	0.1%	1.5%	0.6%	0.4%	0.5%

FEI Customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 2										
Forecast	85,482	85,627	81,923	84,651	85,667	87,712	88,494	89,203	89,558	90,430
Actual	81,123	82,452	83,625	85,076	86,074	86,973	88,244	88,686	89,363	89,683
Error = (ACT-FCST)	(4,359)	(3,175)	1,702	425	407	(739)	(250)	(517)	(195)	(747)
Percent Error = (Error/ACT)	-5.4%	-3.9%	2.0%	0.5%	0.5%	-0.8%	-0.3%	-0.6%	-0.2%	-0.8%

FEI Customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 3										
Forecast	5,553	5,597	5,147	5,117	5,035	5,354	5,223	5,623	7,221	7,469
Actual	5,220	5,134	5,169	5,301	5,189	5,441	6,028	6,973	6,805	7,013
Error = (ACT-FCST)	(333)	(463)	22	184	154	87	805	1,350	(416)	(456)
Percent Error = (Error/ACT)	-6.4%	-9.0%	0.4%	3.5%	3.0%	1.6%	13.4%	19.4%	-6.1%	-6.5%

FEI Customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 23										
Forecast	1,526	1,586	1,634	1,552	1,670	1,760	1,934	1,744	906	941
Actual	1,520	1,529	1,522	1,724	1,803	1,712	1,648	871	746	697
Error = (ACT-FCST)	(6)	(57)	(112)	172	133	(48)	(286)	(873)	(160)	(244)
Percent Error = (Error/ACT)	-0.4%	-3.7%	-7.4%	10.0%	7.4%	-2.8%	-17.4%	-100.2%	-21.4%	-35.0%

3.2 AMALGAMATED NET CUSTOMER ADDITIONS

FEI Customer Additions	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 1										
Forecast	8,984	9,352	6,647	9,710	9,461	11,522	9,141	10,724	9,579	8,569
Actual	6,371	9,139	10,472	12,508	11,359	13,357	19,257	10,609	12,995	10,241
Error = (ACT-FCST)	(2,613)	(213)	3,825	2,798	1,898	1,835	10,116	(115)	3,416	1,672
Percent Error = (Error/ACT)	-41.0%	-2.3%	36.5%	22.4%	16.7%	13.7%	52.5%	-1.1%	26.3%	16.3%

FEI Customer Additions	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 2										
Forecast	145	145	411	1,026	1,026	1,318	1,210	1,115	872	872
Actual	577	1,329	1,173	1,450	998	899	1,271	442	677	320
Error = (ACT-FCST)	432	1,184	762	424	(28)	(419)	61	(673)	(195)	(552)
Percent Error = (Error/ACT)	74.9%	89.1%	65.0%	29.2%	-2.8%	-46.6%	4.8%	-152.3%	-28.8%	-172.5%

FEI Customer Additions	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 3										
Forecast	44	44	4	(52)	(51)	26	19	91	248	248
Actual	(104)	(86)	35	132	(112)	252	587	945	(168)	208
Error = (ACT-FCST)	(148)	(130)	31	184	(61)	226	568	854	(416)	(40)
Percent Error = (Error/ACT)	142.3%	151.2%	88.6%	139.4%	54.5%	89.7%	96.8%	90.4%	247.6%	-19.2%

FEI Customer Additions	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 23										
Forecast	60	60	57	30	30	18	66	16	35	35
Actual	88	9	(7)	202	79	(91)	(64)	(777)	(125)	(49)
Error = (ACT-FCST)	28	(51)	(64)	172	49	(109)	(130)	(793)	(160)	(84)
Percent Error = (Error/ACT)	31.8%	-566.7%	914.3%	85.1%	62.0%	119.8%	203.1%	102.1%	128.0%	171.4%

3.3 AMALGAMATED NORMALIZED USE PER CUSTOMER

FEI UPC, GJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 1										
Forecast	86.3	85.2	86.0	83.1	81.6	82.2	89.1	87.0	85.7	83.1
Actual	87.6	84.7	84.2	84.4	87.5	85.8	85.1	82.4	86.2	85.7
Error = (ACT-FCST)	1.3	(0.5)	(1.8)	1.3	5.9	3.7	(4.0)	(4.6)	0.4	2.6
Percent Error = (Error/ACT)	1.5%	-0.6%	-2.1%	1.5%	6.7%	4.3%	-4.7%	-5.6%	0.5%	3.1%

FEI UPC, GJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 2										
Forecast	315.0	314.5	340.0	333.7	329.5	328.4	345.2	341.3	324.9	321.8
Actual	341.2	331.6	330.6	332.6	339.1	336.8	332.5	318.1	322.2	328.1
Error = (ACT-FCST)	26.2	17.1	(9.4)	(1.1)	9.6	8.3	(12.7)	(23.2)	(2.7)	6.3
Percent Error = (Error/ACT)	7.7%	5.2%	-2.8%	-0.3%	2.8%	2.5%	-3.8%	-7.3%	-0.8%	1.9%

FEI UPC, GJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 3										
Forecast	3,450.0	3,435.0	3,872.0	3,754.0	3,593.0	3,487.9	3,841.9	3,831.0	3,648.0	3,551.3
Actual	3,684.0	3,610.0	3,573.0	3,587.0	3,721.0	3,692.5	3,549.8	3,516.7	3,660.3	3,702.5
Error = (ACT-FCST)	234.0	175.0	(299.0)	(167.0)	128.0	204.6	(292.2)	(314.3)	12.2	151.2
Percent Error = (Error/ACT)	6.4%	4.8%	-8.4%	-4.7%	3.4%	5.5%	-8.2%	-8.9%	0.3%	4.1%

FEI UPC, GJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 23										
Forecast	4,901.0	4,927.0	5,546.0	5,309.0	5,382.0	5,227.5	5,399.3	5,491.6	5,479.5	5,277.8
Actual	5,238.0	5,149.0	5,260.0	5,174.0	5,279.0	5,360.5	5,344.9	5,051.3	5,440.7	5,724.3
Error = (ACT-FCST)	337.0	222.0	(286.0)	(135.0)	(103.0)	133.1	(54.4)	(440.3)	(38.8)	446.5
Percent Error = (Error/ACT)	6.4%	4.3%	-5.4%	-2.6%	-2.0%	2.5%	-1.0%	-8.7%	-0.7%	7.8%

3.4 *AMALGAMATED DEMAND*

FEI Demand,PJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 1										
Forecast	74.7	74.6	74.2	73.1	72.5	74.3	81.2	80.8	81.1	79.3
Actual	74.5	72.7	73.2	74.1	77.9	77.5	78.3	77.0	81.6	82.2
Error = (ACT-FCST)	(0.2)	(1.9)	(1.0)	1.0	5.4	3.3	(2.9)	(3.7)	0.5	2.9
Percent Error = (Error/ACT)	-0.3%	-2.6%	-1.4%	1.3%	6.9%	4.2%	-3.7%	-4.9%	0.6%	3.5%
Abs. Percent Error	0.3%	2.6%	1.4%	1.3%	6.9%	4.2%	3.7%	4.9%	0.6%	3.5%

FEI Demand,PJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 2										
Forecast	26.9	26.9	27.7	28.1	28.0	28.5	30.3	30.2	28.9	28.9
Actual	27.6	27.0	27.5	28.0	29.0	29.1	29.1	28.1	28.7	29.3
Error = (ACT-FCST)	0.7	0.1	(0.2)	(0.1)	1.0	0.6	(1.2)	(2.1)	(0.2)	0.4
Percent Error = (Error/ACT)	2.5%	0.4%	-0.7%	-0.4%	3.4%	2.0%	-4.3%	-7.4%	-0.8%	1.2%

FEI Demand,PJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 3										
Forecast	19.1	19.1	19.9	19.2	18.1	18.7	20.1	21.5	25.2	26.2
Actual	19.3	18.7	18.5	19.2	19.4	19.7	20.9	22.5	24.6	25.7
Error = (ACT-FCST)	0.2	(0.4)	(1.4)	(0.0)	1.3	1.0	0.9	1.0	(0.6)	(0.5)
Percent Error = (Error/ACT)	1.0%	-2.1%	-7.6%	-0.2%	6.7%	5.2%	4.1%	4.3%	-2.4%	-1.8%

FEI Demand,PJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 23										
Forecast	7.2	7.5	8.7	8.3	9.0	9.2	10.3	9.6	4.8	4.9
Actual	7.8	7.9	8.0	8.6	9.3	9.5	9.0	7.3	4.6	4.2
Error = (ACT-FCST)	0.6	0.4	(0.7)	0.3	0.3	0.4	(1.3)	(2.3)	(0.2)	(0.7)
Percent Error = (Error/ACT)	7.7%	5.1%	-8.7%	3.5%	3.2%	3.9%	-13.9%	-31.3%	-5.2%	-16.1%

FEI Demand,PJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Commercial										
Forecast	53.2	53.5	56.3	55.6	55.1	56.4	60.7	61.3	59.0	60.0
Actual	54.7	53.6	54.0	55.8	57.7	58.3	59.0	57.9	57.9	59.2
Error = (ACT-FCST)	1.5	0.1	(2.3)	0.2	2.6	2.0	(1.6)	(3.4)	(1.1)	(0.8)
Percent Error = (Error/ACT)	2.7%	0.2%	-4.3%	0.3%	4.5%	3.4%	-2.8%	-5.9%	-1.9%	-1.3%
Abs. Percent Error	2.7%	0.2%	4.3%	0.3%	4.5%	3.4%	2.8%	5.9%	1.9%	1.3%

FEI Demand,PJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate 5										
Forecast	4.0	4.0	3.9	3.5	2.2	2.2	2.5	2.9	7.6	7.6
Actual	4.0	3.8	3.4	2.3	2.4	2.8	3.8	4.8	8.1	9.1
Error = (ACT-FCST)	0.0	(0.2)	(0.5)	(1.2)	0.3	0.7	1.3	1.9	0.5	1.6
Percent Error = (Error/ACT)	0%	-5%	-15%	-52%	11%	23%	34%	40%	6%	17%

FEI Demand,PJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate 25										
Forecast	13.4	13.5	13.3	13.9	13.8	13.8	14.4	14.8	10.3	10.8
Actual	12.9	13.1	13.4	13.7	13.9	14.5	13.9	13.2	9.9	9.3
Error = (ACT-FCST)	(0.5)	(0.4)	0.1	(0.2)	0.1	0.7	(0.5)	(1.7)	(0.4)	(1.5)
Percent Error = (Error/ACT)	-4%	-3%	1%	-1%	1%	5%	-3%	-13%	-4%	-16%

FEI Demand,PJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate 22										
Forecast	29.7	29.6	43.2	33.2	36.3	38.2	38.5	43.3	41.0	37.4
Actual	38.0	36.4	36.0	37.0	40.5	40.9	42.0	43.3	39.0	40.1
Error = (ACT-FCST)	8.3	6.8	(7.2)	3.8	4.2	2.6	3.5	0.1	(2.0)	2.7
Percent Error = (Error/ACT)	22%	19%	-20%	10%	10%	6%	8%	0%	-5%	7%

FEI Demand,PJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate 27										
Forecast	5.8	5.8	6.5	6.6	6.5	6.4	7.3	7.9	4.7	4.8
Actual	6.4	7.5	6.6	7.2	6.8	7.5	6.2	5.9	4.6	4.4
Error = (ACT-FCST)	0.6	1.7	0.1	0.5	0.3	1.1	(1.1)	(2.0)	(0.1)	(0.4)
Percent Error = (Error/ACT)	9%	23%	2%	7%	4%	14%	-17%	-34%	-1%	-8%

FEI Demand,PJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Industrial*										
Forecast	72.1	72.1	86.2	76.4	78.1	82.1	84.3	90.6	91.9	87.8
Actual	80.6	80.1	78.6	79.6	83.7	87.4	88.4	91.5	89.5	90.8
Error = (ACT-FCST)	8.5	8.0	(7.6)	3.2	5.6	5.3	4.2	0.9	(2.4)	2.9
Percent Error = (Error/ACT)	10.5%	10.0%	-9.7%	4.0%	6.7%	6.0%	4.7%	1.0%	-2.7%	3.2%
Abs. Percent Error	10.5%	10.0%	9.7%	4.0%	6.7%	6.0%	4.7%	1.0%	2.7%	3.2%

FEI Demand,PJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
FEI*										
Forecast	200.0	200.2	216.7	205.2	205.7	212.8	226.2	232.6	232.0	227.1
Actual	209.8	206.4	205.8	209.5	219.3	223.3	225.8	226.4	229.0	232.3
Error = (ACT-FCST)	9.8	6.2	(10.9)	4.3	13.6	10.5	(0.4)	(6.2)	(2.9)	5.1
Percent Error = (Error/ACT)	4.7%	3.0%	-5.3%	2.1%	6.2%	4.7%	-0.2%	-2.7%	-1.3%	2.2%
Abs. Percent Error	4.7%	3.0%	5.3%	2.1%	6.2%	4.7%	0.2%	2.7%	1.3%	2.2%

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3.5 MAINLAND NET CUSTOMERS

Mainland Customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 1										
Forecast	773,231	780,005	768,622	780,972	787,836	799,732	803,319	813,959	823,255	828,146
Actual	759,712	766,668	774,083	782,914	790,562	798,917	811,696	817,817	826,142	831,178
Error = (ACT-FCST)	(13,519)	(13,337)	5,461	1,942	2,726	(815)	8,377	3,858	2,887	3,032
Percent Error = (Error/ACT)	-1.8%	-1.7%	0.7%	0.2%	0.3%	-0.1%	1.0%	0.5%	0.3%	0.4%

Mainland Customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 2										
Forecast	76,126	76,175	72,922	75,315	76,166	77,597	78,228	78,767	79,027	79,703
Actual	72,235	73,480	74,464	75,451	76,326	77,047	78,044	78,351	78,941	79,108
Error = (ACT-FCST)	(3,891)	(2,695)	1,542	136	160	(550)	(184)	(416)	(86)	(595)
Percent Error = (Error/ACT)	-5.4%	-3.7%	2.1%	0.2%	0.2%	-0.7%	-0.2%	-0.5%	-0.1%	-0.8%

Mainland Customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 3										
Forecast	4,962	5,002	4,577	4,560	4,497	4,667	4,608	5,029	6,545	6,799
Actual	4,675	4,598	4,625	4,671	4,605	4,867	5,478	6,291	6,046	6,243
Error = (ACT-FCST)	(287)	(404)	48	111	108	200	870	1,262	(499)	(556)
Percent Error = (Error/ACT)	-6.1%	-8.8%	1.0%	2.4%	2.3%	4.1%	15.9%	20.1%	-8.3%	-8.9%

Mainland Customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 23										
Forecast	1,526	1,586	1,634	1,552	1,582	1,609	1,669	1,562	836	872
Actual	1,520	1,529	1,522	1,573	1,614	1,546	1,458	800	708	661
Error = (ACT-FCST)	(6)	(57)	(112)	21	32	(63)	(211)	(762)	(128)	(211)
Percent Error = (Error/ACT)	-0.4%	-3.7%	-7.4%	1.3%	2.0%	-4.1%	-14.5%	-95.3%	-18.1%	-31.9%

3.6 *MAINLAND NET CUSTOMER ADDITIONS*

Mainland Customer Additions	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 1										
Forecast	6,507	6,774	4,594	6,889	6,863	8,250	6,203	6,756	5,438	4,891
Actual	4,475	6,956	7,415	8,831	7,648	8,355	12,779	6,121	8,325	5,036
Error = (ACT-FCST)	(2,032)	182	2,821	1,942	785	105	6,576	(635)	2,887	145
Percent Error = (Error/ACT)	-45.4%	2.6%	38.0%	22.0%	10.3%	1.3%	51.5%	-10.4%	34.7%	2.9%

Mainland Customer Additions	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 2										
Forecast	49	49	331	851	851	1,072	951	860	676	676
Actual	325	1,245	984	987	875	721	997	307	590	167
Error = (ACT-FCST)	276	1,196	653	136	24	(351)	46	(553)	(86)	(509)
Percent Error = (Error/ACT)	84.9%	96.1%	66.4%	13.7%	2.7%	-48.7%	4.6%	-180.1%	-14.6%	-304.8%

Mainland Customer Additions	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 3										
Forecast	40	40	-	(65)	(64)	(1)	2	81	254	254
Actual	(144)	(77)	27	46	(66)	262	611	813	(245)	197
Error = (ACT-FCST)	(184)	(117)	27	111	(2)	263	609	732	(499)	(57)
Percent Error = (Error/ACT)	127.8%	151.9%	100.0%	241.3%	3.0%	100.4%	99.7%	90.0%	203.7%	-28.9%

Mainland Customer Additions	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 23										
Forecast	60	60	57	30	30	18	28	8	36	36
Actual	88	9	(7)	51	41	(68)	(88)	(658)	(92)	(47)
Error = (ACT-FCST)	28	(51)	(64)	21	11	(86)	(116)	(666)	(128)	(83)
Percent Error = (Error/ACT)	31.8%	-566.7%	914.3%	41.2%	26.8%	126.5%	131.8%	101.2%	139.1%	176.6%

3.7 *MAINLAND NORMALIZED USE PER CUSTOMER*

Mainland UPC GJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 1										
Forecast	90.8	89.9	90.7	88.1	86.3	86.2	93.5	91.5	90.8	88.2
Actual	92.2	89.3	88.8	88.7	92.0	90.4	89.7	87.1	91.1	90.8
Error = (ACT-FCST)	1.4	(0.6)	(1.9)	0.6	5.7	4.2	(3.8)	(4.5)	0.3	2.6
Percent Error = (Error/ACT)	1.5%	-0.7%	-2.1%	0.7%	6.2%	4.6%	-4.2%	-5.1%	0.4%	2.8%

Mainland UPC GJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 2										
Forecast	308.0	306.4	333.6	328.9	328.5	327.3	344.5	338.6	323.6	320.1
Actual	337.6	329.6	330.4	329.6	338.0	335.2	329.4	315.6	321.8	327.3
Error = (ACT-FCST)	29.6	23.2	(3.2)	0.7	9.5	7.9	(15.2)	(23.0)	(1.8)	7.2
Percent Error = (Error/ACT)	8.8%	7.0%	-1.0%	0.2%	2.8%	2.4%	-4.6%	-7.3%	-0.6%	2.2%

Mainland UPC GJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 3										
Forecast	3,334.0	3,316.0	3,769.0	3,599.0	3,537.0	3,517.0	3,770.0	3,745.5	3,640.4	3,501.2
Actual	3,566.0	3,517.0	3,529.0	3,524.0	3,658.0	3,625.1	3,477.5	3,467.8	3,682.1	3,703.6
Error = (ACT-FCST)	232.0	201.0	(240.0)	(75.0)	121.0	108.1	(292.5)	(277.7)	41.7	202.4
Percent Error = (Error/ACT)	6.5%	5.7%	-6.8%	-2.1%	3.3%	3.0%	-8.4%	-8.0%	1.1%	5.5%

Mainland UPC GJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 23										
Forecast	4,901.0	4,927.0	5,546.0	5,309.0	5,348.0	5,197.2	5,416.2	5,521.4	5,537.4	5,362.3
Actual	5,238.0	5,149.0	5,260.0	5,157.0	5,304.0	5,388.0	5,357.1	5,127.5	5,496.9	5,698.8
Error = (ACT-FCST)	337.0	222.0	(286.0)	(152.0)	(44.0)	190.9	(59.2)	(393.9)	(40.6)	336.5
Percent Error = (Error/ACT)	6.4%	4.3%	-5.4%	-2.9%	-0.8%	3.5%	-1.1%	-7.7%	-0.7%	5.9%

3.8 *MAINLAND NORMALIZED DEMAND*

Mainland Demand, PJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 1										
Forecast	69.9	69.8	69.5	68.5	67.7	68.6	74.8	74.2	74.5	72.8
Actual	69.8	68.1	68.5	68.9	72.3	71.8	72.2	70.9	74.9	75.2
Error = (ACT-FCST)	(0.1)	(1.7)	(1.0)	0.4	4.6	3.2	(2.6)	(3.2)	0.4	2.4
Percent Error = (Error/ACT)	-0.2%	-2.5%	-1.5%	0.5%	6.4%	4.5%	-3.6%	-4.6%	0.5%	3.2%
Abs. Percent Error	0.2%	2.5%	1.5%	0.5%	6.4%	4.5%	3.6%	4.6%	0.5%	3.2%

Mainland Demand, PJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 2										
Forecast	23.4	23.3	24.2	24.7	24.9	25.2	26.7	26.5	25.5	25.4
Actual	24.3	23.9	24.5	24.6	25.6	25.7	25.5	24.7	25.3	25.8
Error = (ACT-FCST)	0.9	0.6	0.2	(0.0)	0.7	0.5	(1.3)	(1.8)	(0.1)	0.5
Percent Error = (Error/ACT)	3.6%	2.5%	0.9%	-0.2%	2.7%	2.0%	-5.0%	-7.3%	-0.5%	1.7%

Mainland Demand, PJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 3										
Forecast	16.5	16.5	17.3	16.4	16.0	16.4	17.4	18.8	22.6	23.5
Actual	16.7	16.3	16.3	16.5	16.8	17.3	18.5	20.1	22.1	22.9
Error = (ACT-FCST)	0.2	(0.2)	(1.0)	0.0	0.8	0.9	1.2	1.3	(0.5)	(0.5)
Percent Error = (Error/ACT)	1.2%	-1.2%	-6.1%	0.3%	5.0%	5.4%	6.3%	6.4%	-2.4%	-2.3%

Mainland Demand, PJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 23										
Forecast	7.2	7.5	8.7	8.3	8.4	8.3	9.0	8.6	4.5	4.6
Actual	7.8	7.9	8.0	8.0	8.4	8.6	8.1	6.6	4.3	4.0
Error = (ACT-FCST)	0.6	0.4	(0.7)	(0.3)	-	0.3	(0.8)	(2.0)	(0.2)	(0.6)
Percent Error = (Error/ACT)	7.7%	5.1%	-8.7%	-3.3%	0.0%	3.1%	-10.4%	-30.8%	-4.8%	-15.9%

Mainland Demand, PJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Commercial										
Forecast	47.1	47.3	50.2	49.3	49.3	49.9	53.1	53.9	52.6	53.4
Actual	48.8	48.1	48.8	49.1	50.8	51.6	52.2	51.3	51.7	52.7
Error = (ACT-FCST)	1.7	0.8	(1.5)	(0.3)	1.5	1.7	(0.9)	(2.5)	(0.9)	(0.7)
Percent Error = (Error/ACT)	3.4%	1.6%	-3.0%	-0.5%	3.0%	3.3%	-1.8%	-5.0%	-1.6%	-1.4%
Abs. Percent Error	3.4%	1.6%	3.0%	0.5%	3.0%	3.3%	1.8%	5.0%	1.6%	1.4%

3.9 *VANCOUVER ISLAND AND WHISTLER AMALGAMATED DATA*

In order to provide historical amalgamated data, FEI mapped the Vancouver Island and Whistler customers to FEI rate schedules for periods prior to 2015. This mapping was completed using the mapping approved for the purposes of amalgamation presented in FEI's Common Rates Methodology Application, Section 4.2 as approved by Order G-131-14. Tables in Sections 3.10 through 3.17 use this mapped data for historical calculations.

3.10 *VANCOUVER ISLAND NET CUSTOMERS*

VI Customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 1										
Forecast	95,460	98,023	95,858	99,921	102,458	107,314	110,270	117,957	124,041	127,631
Actual	92,067	94,173	97,162	100,747	104,358	109,259	115,618	119,998	124,627	129,764
Error = (ACT-FCST)	(3,393)	(3,850)	1,304	826	1,900	1,945	5,348	2,041	586	2,133
Percent Error = (Error/ACT)	-3.7%	-4.1%	1.3%	0.8%	1.8%	1.8%	4.6%	1.7%	0.5%	1.6%

VI Customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 2										
Forecast	9,081	9,172	8,710	9,047	9,209	9,808	9,971	10,131	10,218	10,408
Actual	8,613	8,691	8,875	9,330	9,459	9,629	9,891	10,028	10,117	10,270
Error = (ACT-FCST)	(468)	(481)	165	283	250	(179)	(80)	(103)	(101)	(138)
Percent Error = (Error/ACT)	-5.4%	-5.5%	1.9%	3.0%	2.6%	-1.9%	-0.8%	-1.0%	-1.0%	-1.3%

VI Customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 3										
Forecast	532	536	509	497	479	647	567	539	605	597
Actual	484	476	484	582	531	517	492	613	686	697
Error = (ACT-FCST)	(48)	(60)	(25)	85	52	(130)	(75)	74	81	100
Percent Error = (Error/ACT)	-9.9%	-12.6%	-5.2%	14.6%	9.8%	-25.1%	-15.2%	12.1%	11.8%	14.3%

VI Customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 23										
Forecast					83	141	243	164	66	65
Actual				141	175	152	179	67	37	35
Error = (ACT-FCST)				141	92	11	(64)	(97)	(29)	(30)
Percent Error = (Error/ACT)					52.6%	7.2%	-35.8%	-144.8%	-78.4%	-85.7%

3.11 VANCOUVER ISLAND NET CUSTOMER ADDITIONS

VI Customer Additions	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 1										
Forecast	2,463	2,564	2,001	2,759	2,537	3,188	2,857	3,888	4,043	3,590
Actual	1,845	2,106	2,989	3,583	3,611	4,901	6,359	4,380	4,629	5,137
Error = (ACT-FCST)	(618)	(458)	988	824	1074	1713	3502	492	586	1547
Percent Error = (Error/ACT)	-33.5%	-21.7%	33.1%	23.0%	29.8%	35.0%	55.1%	11.2%	12.7%	30.1%

VI Customer Additions	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 2										
Forecast	91	91	71	171	171	239	256	251	190	190
Actual	251	78	184	453	129	170	262	137	89	153
Error = (ACT-FCST)	160	(13)	113	282	(42)	(69)	6	(114)	(101)	(37)
Percent Error = (Error/ACT)	63.8%	-16.4%	61.1%	62.2%	-32.6%	-40.6%	2.3%	-83.2%	-113.5%	-24.2%

VI Customer Additions	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 3										
Forecast	4	4	4	13	13	32	19	11	(8)	(8)
Actual	39	(8)	8	98	(51)	(14)	(25)	121	73	11
Error = (ACT-FCST)	35	(12)	4	85	(64)	(46)	(44)	110	81	19
Percent Error = (Error/ACT)	89.7%	150.0%	50.0%	86.6%	125.5%	328.6%	176.0%	90.9%	111.0%	172.7%

VI Customer Additions	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 23										
Forecast					-	-	34	6	(1)	(1)
Actual				141	34	(23)	27	(112)	(30)	(2)
Error = (ACT-FCST)				141	34	(23)	(7)	(118)	(29)	(1)
Percent Error = (Error/ACT)					100.0%	100.0%	-25.9%	105.4%	96.7%	50.0%

3.12 *VANCOUVER ISLAND NORMALIZED USE PER CUSTOMER*

VI UPC, GJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 1										
Forecast	48.6	46.9	45.0	44.0	45.1	51.3	56.3	54.7	51.2	49.6
Actual	49.5	47.3	47.1	50.5	52.6	51.5	51.6	49.7	52.3	52.7
Error = (ACT-FCST)	0.9	0.4	2.1	6.5	7.5	0.3	(4.7)	(5.0)	1.1	3.1
Percent Error = (Error/ACT)	1.8%	0.8%	4.5%	12.9%	14.3%	0.5%	-9.1%	-10.1%	2.1%	5.8%

VI UPC, GJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 2										
Forecast	365.0	372.0	390.0	372.0	334.0	322.8	342.5	357.0	331.9	333.4
Actual	369.0	344.0	328.0	346.0	343.0	344.8	351.2	332.7	322.2	331.2
Error = (ACT-FCST)	4.0	(28.0)	(62.0)	(26.0)	9.0	22.0	8.7	(24.3)	(9.7)	(2.2)
Percent Error = (Error/ACT)	1.1%	-8.1%	-18.9%	-7.5%	2.6%	6.4%	2.5%	-7.3%	-3.0%	-0.7%

VI UPC, GJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 3										
Forecast	6,351.0	6,398.0	5,896.0	5,187.0	4,030.8	3,068.6	4,171.0	4,411.0	3,628.7	3,882.2
Actual	4,820.0	4,431.0	3,901.0	3,894.0	4,060.0	4,180.7	4,074.2	3,826.5	3,403.8	3,603.9
Error = (ACT-FCST)	(1531)	(1967)	(1995)	(1293)	29	1112	(97)	(584)	(225)	(278)
Percent Error = (Error/ACT)	-31.8%	-44.4%	-51.1%	-33.2%	0.7%	26.6%	-2.4%	-15.3%	-6.6%	-7.7%

VI UPC, GJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 23										
Forecast					5,996.2	5,635.7	5,343.6	5,281.6	4,799.8	4,169.3
Actual				5,636.0	5,052.0	5,157.5	5,260.4	4,368.5	4,726.7	6,022.6
Error = (ACT-FCST)					(944.2)	(478.2)	(83.3)	(913.1)	(73.1)	1853.3
Percent Error = (Error/ACT)					-18.7%	-9.3%	-1.6%	-20.9%	-1.5%	30.8%

1 ## 3.13 VANCOUVER ISLAND NORMALIZED DEMAND

VI Demand, PJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 1										
Forecast	4.6	4.5	4.3	4.3	4.6	5.4	6.1	6.3	6.2	6.2
Actual	4.5	4.4	4.5	5.0	5.4	5.5	5.8	5.9	6.4	6.7
Error = (ACT-FCST)	(0.1)	(0.1)	0.2	0.6	0.8	0.1	(0.3)	(0.5)	0.1	0.5
Percent Error = (Error/ACT)	-2.2%	-2.3%	4.4%	12.9%	15.6%	1.5%	-5.6%	-8.3%	2.3%	6.9%
Abs. Percent Error	2.2%	2.3%	4.4%	12.9%	15.6%	1.5%	5.6%	8.3%	2.3%	6.9%

VI Demand, PJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 2										
Forecast	3.3	3.4	3.3	3.3	3.0	3.1	3.4	3.6	3.4	3.4
Actual	3.1	3.0	2.9	3.2	3.2	3.3	3.4	3.3	3.2	3.4
Error = (ACT-FCST)	(0.2)	(0.4)	(0.5)	(0.2)	0.2	0.2	0.0	(0.3)	(0.1)	(0.1)
Percent Error = (Error/ACT)	-5.1%	-14.9%	-16.0%	-4.7%	6.3%	5.4%	1.4%	-8.0%	-3.4%	-1.8%

VI Demand, PJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 3										
Forecast	2.4	2.4	2.4	2.5	1.9	2.0	2.4	2.4	2.3	2.3
Actual	2.3	2.1	1.9	2.4	2.2	2.1	2.1	2.0	2.2	2.5
Error = (ACT-FCST)	(0.1)	(0.3)	(0.5)	(0.1)	0.3	0.1	(0.3)	(0.3)	(0.0)	0.2
Percent Error = (Error/ACT)	-2.6%	-13.7%	-28.3%	-5.0%	13.6%	6.5%	-14.6%	-16.8%	-1.9%	6.9%

VI Demand, PJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 23										
Forecast					0.5	0.8	1.2	0.8	0.3	0.3
Actual				0.5	0.8	0.9	0.8	0.6	0.3	0.2
Error = (ACT-FCST)				(0.5)	(0.3)	(0.1)	0.4	0.2	0.0	0.1
Percent Error = (Error/ACT)					-37.5%	-9.2%	44.9%	32.2%	11.0%	24.6%

VI Demand, PJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Commercial										
Forecast	5.7	5.8	5.7	5.9	5.4	5.9	7.0	6.8	5.9	6.0
Actual	5.5	5.1	4.8	6.2	6.2	6.3	6.3	6.0	5.8	6.1
Error = (ACT-FCST)	(0.2)	(0.7)	(1.0)	0.3	0.8	0.4	(0.6)	(0.8)	(0.2)	0.1
Percent Error = (Error/ACT)	-4.0%	-14.4%	-20.8%	4.4%	12.9%	6.3%	-10.0%	-13.6%	-3.2%	1.0%
Abs. Percent Error	4.0%	14.4%	20.8%	4.4%	12.9%	6.3%	10.0%	13.6%	3.2%	1.0%

2

3.14 WHISTLER NET CUSTOMERS

WH Customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 1										
Forecast	2,289	2,303	2,372	2,478	2,536	2,681	2,775	2,889	3,034	3,122
Actual	2,271	2,348	2,416	2,508	2,608	2,709	2,828	2,936	2,965	3,037
Error = (ACT-FCST)	(18)	45	44	30	72	28	53	47	(69)	(85)
Percent Error = (Error/ACT)	-0.8%	1.9%	1.8%	1.2%	2.8%	1.0%	1.9%	1.6%	-2.3%	-2.8%

WH Customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 2										
Forecast	275	280	291	289	292	309	294	305	313	319
Actual	274	281	285	295	289	297	309	307	305	305
Error = (ACT-FCST)	(1)	1	(6)	6	(3)	(12)	15	2	(8)	(14)
Percent Error = (Error/ACT)	-0.4%	0.4%	-2.1%	2.0%	-1.0%	-4.0%	4.7%	0.7%	-2.6%	-4.6%

WH Customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 3										
Forecast	59	59	61	60	59	39	48	55	71	74
Actual	61	60	60	48	53	57	58	69	73	73
Error = (ACT-FCST)	2	1	(1)	(12)	(6)	18	10	14	2	(1)
Percent Error = (Error/ACT)	3.3%	1.7%	-1.7%	-25.0%	-11.3%	31.6%	16.9%	20.2%	2.7%	-1.4%

WH Customers	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 23										
Forecast					5	10	22	18	4	4
Actual				10	14	14	11	4	1	1
Error = (ACT-FCST)				10	9	4	(11)	(14)	(3)	(3)
Percent Error = (Error/ACT)					64.3%	28.6%	-100.0%	-350.0%	-300.0%	-300.0%

3.15 *WHISTLER NET CUSTOMER ADDITIONS*

WH Customer Additions	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 1										
Forecast	14	14	52	62	61	84	81	81	98	88
Actual	51	77	68	92	100	101	119	108	41	68
Error = (ACT-FCST)	37	63	16	30	39	17	38	27	(57)	(20)
Percent Error = (Error/ACT)	72.5%	81.8%	23.5%	32.6%	39.0%	16.8%	31.8%	25.4%	-139.5%	-28.9%

WH Customer Additions	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 2										
Forecast	5	5	9	4	4	7	3	4	6	6
Actual	-	7	5	10	(6)	8	12	(2)	(2)	-
Error = (ACT-FCST)	(5)	2	(4)	6	(10)	1	9	(6)	(8)	(6)
Percent Error = (Error/ACT)		28.6%	-80.0%	60.0%	166.7%	11.9%	77.4%	300.0%	400.0%	

WH Customer Additions	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 3										
Forecast				-	-	(5)	(2)	(1)	2	1
Actual	(0)	(1)	(0)	(12)	5	4	1	11	4	-
Error = (ACT-FCST)				(12)	5	9	3	12	2	(1)
Percent Error = (Error/ACT)					100.0%	225.0%	339.0%	109.1%	50.0%	

WH Customer Additions	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 23										
Forecast					-	-	4	2	-	-
Actual				10	4	-	(3)	(7)	(3)	-
Error = (ACT-FCST)				10	4	0	(7)	(9)	(3)	0
Percent Error = (Error/ACT)				100.0%	100.0%		233.3%	128.6%	100.0%	

3.16 WHISTLER NORMALIZED USE PER CUSTOMER

WH UPC, GJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 1										
Forecast	104.0	106.3	90.6	79.7	85.1	97.9	102.1	99.5	99.0	95.8
Actual	89.4	87.3	87.6	91.3	97.7	93.5	96.3	94.2	101.5	100.3
Error = (ACT-FCST)	(15)	(19)	(3)	12	13	(4)	(6)	(5)	2	4
Percent Error = (Error/ACT)	-16.3%	-21.8%	-3.4%	12.7%	12.9%	-4.7%	-6.1%	-5.6%	2.4%	4.5%

WH UPC, GJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 2										
Forecast	610.0	637.0	464.0	408.0	465.0	792.9	592.7	515.5	419.5	384.7
Actual	429.0	465.0	471.0	660.0	520.2	479.4	511.8	465.8	417.5	438.7
Error = (ACT-FCST)	(181)	(172)	7	252	55	(314)	(81)	(50)	(2)	54
Percent Error = (Error/ACT)	-42.2%	-37.0%	1.5%	38.2%	10.6%	-65.4%	-15.8%	-10.7%	-0.5%	12.3%

WH UPC, GJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 3										
Forecast	3,876.0	3,630.0	3,595.0	3,822.0	4,326.0	6,706.9	6,824.3	5,886.5	4,737.2	5,485.8
Actual	3,822.0	4,213.0	4,285.0	5,618.0	5,638.0	5,107.9	5,747.4	5,392.0	4,220.8	4,558.7
Error = (ACT-FCST)	(54)	583	690	1,796	1,312	(1,599)	(1,077)	(495)	(516)	(927)
Percent Error = (Error/ACT)	-1.4%	13.8%	16.1%	32.0%	23.3%	-31.3%	-18.7%	-9.2%	-12.2%	-20.3%

WH UPC, GJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 23										
Forecast					5,888.0	4,328.3	4,702.9	4,654.3	5,121.0	5,396.2
Actual				4,328.0	5,078.0	4,557.0	4,860.0	5,045.3	5,929.5	12,508.9
Error = (ACT-FCST)					(810)	229	157	391	808	7,113
Percent Error = (Error/ACT)					-16.0%	5.0%	3.2%	7.7%	13.6%	56.9%

3.17 *WHISTLER NORMALIZED DEMAND*

WH Demand, PJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 1										
Forecast	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3
Actual	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3
Error = (ACT-FCST)	(0.0)	(0.0)	(0.0)	0.0	0.0	(0.0)	(0.0)	(0.0)	0.0	0.0
Percent Error = (Error/ACT)	-14.2%	-21.5%	-1.4%	0.0%	14.6%	-4.1%	-5.3%	-4.6%	1.8%	2.4%
Abs. Percent Error	14.2%	21.5%	1.4%	0.0%	14.6%	4.1%	5.3%	4.6%	1.8%	2.4%

WH Demand, PJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 2										
Forecast	0.2	0.2	0.1	0.1	0.1	0.2	0.2	0.2	0.1	0.1
Actual	0.1	0.1	0.1	0.2	0.2	0.1	0.2	0.1	0.1	0.1
Error = (ACT-FCST)	(0.0)	(0.0)	0.0	0.1	0.0	(0.1)	(0.0)	(0.0)	(0.0)	0.0
Percent Error = (Error/ACT)	-33.3%	-30.8%	0.0%	36.8%	10.0%	-75.0%	-12.1%	-9.6%	-1.6%	8.3%

WH Demand, PJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 3										
Forecast	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.4
Actual	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Error = (ACT-FCST)	0.0	0.0	0.0	0.1	0.0	0.0	(0.0)	0.0	(0.0)	(0.1)
Percent Error = (Error/ACT)	0.0%	15.4%	15.4%	17.9%	13.3%	3.5%	-3.8%	5.5%	-11.5%	-18.4%

WH Demand, PJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Rate Schedule 23										
Forecast					0.03	0.04	0.09	0.08	0.02	0.02
Actual				0.03	0.06	0.06	0.06	0.05	0.02	0.01
Error = (ACT-FCST)					0.03	0.02	-0.03	-0.03	0.00	-0.01
Percent Error = (Error/ACT)					50.9%	32.2%	-44.7%	-73.7%	-7.7%	-72.6%

WH Demand, PJ	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Commercial										
Forecast	0.4	0.4	0.4	0.4	0.4	0.6	0.6	0.6	0.5	0.5
Actual	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.4	0.5
Error = (ACT-FCST)	(0.0)	0.0	0.0	0.2	0.1	(0.1)	(0.1)	(0.0)	(0.0)	(0.1)
Percent Error = (Error/ACT)	-11.4%	0.0%	10.3%	30.0%	16.8%	-15.0%	-11.1%	-5.4%	-8.5%	-12.4%
Abs. Percent Error	11.4%	0.0%	10.3%	30.0%	16.8%	15.0%	11.1%	5.4%	8.5%	12.4%

Appendix A3

Demand Forecast Methods

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List of Tables and Figures

1. INTRODUCTION

In this appendix, FEI provides a detailed description of its demand forecast method.

The following table shows the high level method used for each component of FEI's demand forecast.

Table A3-1: Summary of FEI Forecast Methods

Rate Group	Customer Additions	Customers	Use Rate	Demand
Residential	CBOC forecast by dwelling type	Prior year customers + customer adds	Exponential Smoothing method, using normalized historical UPC	Product of Customers and Use Rates
Commercial	3 Yr. Avg. historical additions	Prior year customers + customer adds	Exponential Smoothing method, using normalized historical UPC	Product of Customers and Use Rates
Industrial				Annual survey of industrial customers

FEI's demand forecast methods are consistent with the recommendations in the FEI Forecasting Method Study filed as Appendix B2 in FortisBC's 2020-2024 MRP Application. The Forecasting Method Study represented the culmination of a number of years of research and testing of alternative forecasting methods in response to the forecasting directives in Order G-86-15 and accompanying decision related to the FEI Annual Review for 2015 Rates Application. As a result of this study, FEI adopted the Exponential Smoothing method (ETS) for the purpose of forecasting residential and commercial use rates, as ETS proved to be the most accurate method for this purpose.

In the following sections, FEI provides background information, including a description of FEI's regions and rate classes, the time periods used in the forecast, and the weather normalization process, and then describes each of FEI's forecast methods used to derive the 2023 demand forecast, in the following order:

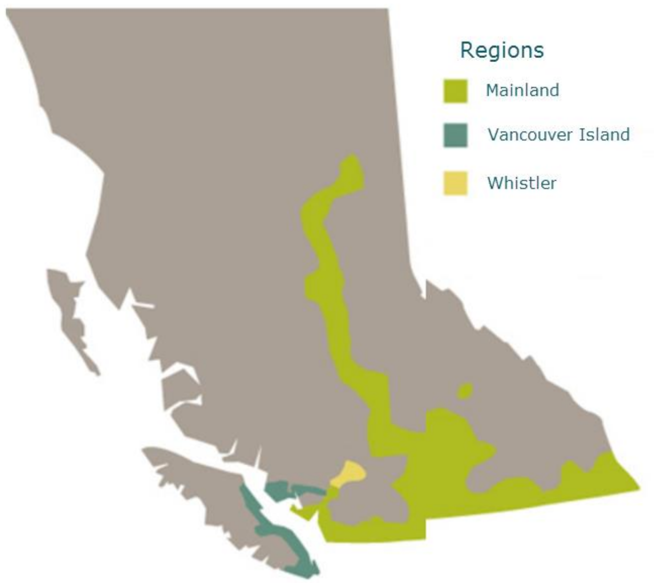
- Residential Customer Additions;
- Commercial Customer Additions;
- Residential and Commercial Use Rates;
- Residential and Commercial Demand Forecast; and
- Industrial Demand Forecast.

2. BACKGROUND INFORMATION

2.1 FEI REGIONS

FEI is divided into three regions as shown in Figure A3-1.

Figure A3-1: FEI Regions



The Mainland region is further divided into the following sub-regions:

- Lower Mainland
- Inland
- Columbia
- Revelstoke

Forecasting is performed at the sub-regional level for each rate schedule in the Mainland region and summed up to derive the Mainland region forecast, which is then added to the forecast for the Vancouver Island and Whistler regions to derive the total forecast for each rate schedule within FEI.

2.2 ACTUAL, SEED AND FORECAST YEARS

FEI's demand forecasts contain data from three time frames:

- **Actual Years:** Actual years are those for which actual data exists for the full calendar year.
- **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 two or more years depending on the filing.
- **Seed Year:** The Seed Year is the year prior to the first forecast year. The Seed Year is forecast based on the latest years of actual data available, and will be different than the original forecast for that year in the previous filing. For example, for this Application the Seed Year is 2022 and the Seed Year forecast is based on the latest actual years, including 2021. As such, the 2022 Seed Year forecast in this Application will differ from the 2022 Forecast presented in the Annual Review for 2022 Delivery Rates, for which 2021 year-end actual data was not available.

2.3 *RATE CLASSES*

The following residential, commercial and industrial rate classes are included in the annual demand forecast:

Table A3-2: Rate Classes

Residential	
Rate Schedule 1 - Residential	This rate schedule is applicable to firm gas supplied at one premise for use in approved appliances for all residential applications in single-family residences, separately metered single family townhouses, row houses, condominiums, duplexes and apartments and single metered apartment blocks with four or less apartments.
Commercial	
Rate Schedule 2 - Small Commercial	This rate schedule is applicable to customers with a normalized annual consumption at one premise of less than 2,000 gigajoules of firm gas, for use in approved appliances in commercial, institutional or small industrial operations.
Rate Schedule 3 - Large Commercial	This rate schedule is applicable to customers with a normalized annual consumption at one premise of greater than 2,000 gigajoules of firm gas, for use in approved appliances in commercial, institutional or small industrial operations.
Rate Schedule 23 - Commercial Transportation	This rate schedule is applicable to shippers with a normalized annual consumption at one premise of greater than 2,000 gigajoules of firm gas, for use in approved appliances in commercial, institutional or small industrial operations.

Industrial	
Rate Schedule 4 – Seasonal	This rate schedule applies to the sale of gas to one customer who, pursuant to this Rate Schedule, consumes gas during the off-peak period.
Rate Schedule 5 - General Firm	This rate schedule applies to the sale of firm gas through one meter station to a customer. Firm gas service under this Rate Schedule means the gas FEI is obligated to sell to a customer on a firm basis subject to interruption or curtailment.
Rate Schedule 7 - General Interruptible Sales	This rate schedule applies to the provision of a bundled interruptible transportation service and the sale of firm gas through one meter station to a customer.
Rate Schedule 22/22A/22B - Large Volume Transportation	This rate schedule applies to the provision of firm and/or interruptible transportation service (subject to a minimum of 12,000 gigajoules per month) through the FEI system and through one meter station to one shipper except as previously agreed upon.
Rate Schedule 25 - General Firm Transportation	This rate schedule applies to the provision of firm transportation service through the FEI system and through one meter station to one shipper.
Rate Schedule 27 - General Interruptible Transportation	This rate schedule applies to the provision of interruptible transportation service through the FEI system and through one meter station to one shipper.

2.4 WEATHER NORMALIZATION OF RESIDENTIAL AND COMMERCIAL USE RATES

Residential and commercial rate schedules (Rate Schedules (RS) 1, 2, 3 and 23) are weather sensitive. A weather normalization process is applied to all actual use rates for these rate schedules as described in this section. Separate normalization factors are developed for each region, rate schedule and month.

Actual UPC is weather normalized on a monthly basis for each region and rate class by dividing the actual UPC by a normalization factor. The normalization factor is derived from a non-linear regression model that estimates the impact of the monthly weather variation on the load. As the relationship between weather and the usage is not linear, FEI considers three non-linear models that are often used when modeling weather impact. One is based on the Gompertz distribution (the "Gompertz" model). The other two methods are variants based on the logit formulation with one (Logit-4) allowing for an additional parameter for optimal fitting. The models are:

- Gompertz

$$Estimated\ Monthly\ UPC = A \times e^{\left(-e^{-B \times (Avg.Monthly\ Temp. - C)}\right)}$$

- Logit-3

$$Estimated\ Monthly\ UPC = \frac{A}{1 + B \times e^{(-C \times Temp)}}$$

- Logit-4

$$Estimated\ Monthly\ UPC = \frac{(D + (A - D))}{1 + B \times e^{(-C \times Temp)}}$$

The A/B/C/D parameters are estimated through a least squares method to minimize the sum of squared errors (SSE). The optimization process to minimize the SSE is done using the Solver tool in Microsoft Excel.

The heat sensitivity estimated from the model assumes that the sensitivity varies not only depending on the weather but also on the rate class. For example, the residential rate schedule shows higher sensitivity to weather compared to the commercial rate schedules, and FEI's normalization factors account for the difference.

3. RESIDENTIAL CUSTOMER ADDITIONS

The residential net customer additions forecast was developed based on housing starts data from the CBOC, Facing the Sequence of Challenges, Provincial Outlook to 2045 Impact Paper : February 11th, 2022. The housing starts data was as follows:

Table A3-3: BC Housing Starts Data

BRITISH COLUMBIA	2020	2021	2022	2023
Housing Starts, Singles, British Columbia (Thousands ('000s))	8,519	10,710	8,275	7,273
Forecast Percent Change		**25.7%**	**-22.7%**	**-12.1%**
Housing Starts, Multiples, British Columbia (Thousands ('000s))	29,215	36,706	29,340	27,776
Forecast Percent Change		**25.6%**	**-20.1%**	**-5.3%**
Total	37,734	47,416	37,615	35,049

From the above housing starts forecast, the 2023F SFD growth rate is calculated as follows:

$$2023F\ SFD\ Growth\ Rate = \left(\frac{7{,}273}{8{,}275}\right) - 1 = -12.1\%$$

The remainder of the growth rates are calculated the same way and the results are shown in the following table:

Table A3-4: Growth Rates

Housing Type	2022S	2023F
SFD Forecast Percentage Change	-22.7%	-12.1%
MFD Forecast Percentage Change	-20.1%	-5.3%

The following table incorporates the FEI proportions of the actual account additions by single family dwelling (SFD) and multi-family (MFD) based on historical percentages from internal data in columns A and B. The 2021 actual total additions are shown in column C, followed by the SFD and MFD proportions in columns D and E. Finally, the CBOC growth rates for 2022 are applied to the SFD and MFD proportions for 2022 in column F and G and for 2023 in column I and J.

Table A3-5: FEI Proportions of Actual Account Additions by SFD and MFD

				Internal Split		Actual Adds 2021			2022S			2023F		
Region	2019A	2020A	2021A	SFD	MFD	Total	SFD	MFD	SFD	MFD	Total	SFD	MFD	Total
Mainland				A	B	C	D	E	F	G	H	I	J	K
Lower Mainland	562,541	567,372	569,546	36.7%	63.3%	2,174	799	1,375	617	1,099	1,716	543	1,041	1,584
Inland*	231,880	235,063	237,600	78.8%	21.2%	2,537	2,000	537	1,545	429	2,278*	1,358	406	1,764
Columbia	21,828	22,077	22,316	69.8%	30.2%	239	167	72	129	58	187	113	54	167
Revelstoke	1,568	1,630	1,716	94.7%	5.3%	86	81	5	63	4	67	55	4	59
Whistler	2,936	2,977	3,045	75.6%	24.4%	68	51	17	39	14	53	35	13	48
Vancouver Island	119,998	124,627	129,764	81.0%	19.0%	5,137	4,163	974	3,217	779	3,995	2,827	737	3,564
Total FEU	**940,751**	**953,746**	**963,987**			**10,241**	**7,261**	**2,980**	**5,611**	**2,382**	**8,296**	**4,931**	**2,255**	**7,186**

For example, the Lower Mainland 2023F SFD value of 543 (column I) is derived as follows:

- Lower Mainland 2021 Internal Split – SFD percentage = 37% (column A);
- Lower Mainland 2021 Actual additions = 2,174 (column C)

$$LML\ 2021 Actual\ SFD = 36.7\% \ \times 2{,}174 = 799\ (column\ D)$$

$$LML\ 2022\ Seed\ SFD = (1 - 22.7\%) \times 799 = 617\ (column\ F)$$

$$LML\ 2023\ Forecast\ SFD = (1 - 12.1\%) \times 617 = 543\ (column\ I)$$

4. COMMERCIAL CUSTOMER ADDITIONS

Commercial customer additions are calculated as an average of the net customer additions by region and rate class from the prior three years.

The following table shows the customer additions for Lower Mainland RS 2.

Table A3-6: Customer Additions for Lower Mainland RS 2

	Year	Customers	Customer Additions	Average 2019-2021
		A	B	C
1	2018	54,055		
2	2019	54,211	156	
3	2020	54,619	408	
4	2021	54,671	52	205
5	2022S	54,876		205
6	2023F	55,081		205

Customer additions are calculated in column B. The three-year average of additions is shown in C4 and is 205. 205 additions are forecast in each of 2022 and 2023.

$$2022S\ Customers = 2021\ Customers\ + 3\ Yr\ Avg\ Additions$$

Using the data above:

$$2022S = 54{,}876 = 54{,}671 + 205$$

Identical calculations are completed for all regions and all small commercial rate schedules.

However, due to rate switching between the large commercial rate schedules (specifically RS 3 and RS 23), forecasting for these two classes was done as a group and then proportioned per 2021 customers distribution.

The following table shows how the Lower Mainland large commercial customer additions forecast was developed. Other regions are similar.

Table A3-7: Lower Mainland Large Commercial Customer Additions Forecast Development

		Customers					Proportion	
	Accounts	RS 3	RS 23	Total	Total	3 Yr. Average	RS 3	RS 23
		A	B	C	D	E	F	G
1	2018	4,575	1,144	**5,719**				
2	2019	5,347	505	**5,852**	133			
3	2020	5,075	430	**5,505**	(347)			
4	2021	5,240	391	**5,631**	126	(29)	(27)	(2)
5	2022S	5,213	389				(27)	(2)
6	2023F	5,186	387				(27)	(2)

For each actual year (rows 1-4) the rate class customers from columns A and B are summed in column C.

Aggregate customer additions are shown in column D.

The three year average customer additions is (29) and shown in column E, row 4.

The 2021 proportion is calculated from columns A/C on row 4.

For example, the RS 3 proportion is:

$$RS\ 3\ Proportion = \frac{5{,}240}{5{,}631} = 0.93$$

The proportion of the aggregate customer additions (29) is assigned to RS 3 is then:

$$RS\ 3\ Customer\ Additions = 0.93\ \times (-29) = -27$$

A similar calculation is performed for RS 23 to arrive at (2) customer additions.

On row 5 the 2022S customer additions for RS 3 are shown in column A and calculated as:

$$2022S =\ 5{,}213 = 5{,}240 - 27$$

The remaining calculations are similar.

5. RESIDENTIAL AND COMMERCIAL USE RATES

5.1 THE EXPONENTIAL SMOOTHING METHOD

FEI develops its use rate forecasts based on ten years of annual use rates by region and rate class. The UPC values are weather-normalized using the process set out in section 2 above.

The ten years of data is used to calculate the UPC forecast using ETS, as implemented in Microsoft Excel.

ETS is implemented as both a formula and “wizard” in Excel 2016. Intermediate calculations and steps are not exposed or reproducible. Microsoft has not published, and is unlikely to publish, the specific algorithms and procedures used in its software.

The UPC method for Lower Mainland RS 1 (residential) is demonstrated below. All residential and commercial use rate forecasts in all regions are developed using the same method.

5.1.1 Lower Mainland RS 1 UPC Example

The forecast UPCs for Lower Mainland RS 1 were calculated as follows:

Start with ten years of weather normalized annual UPCs:

LOWER MAINLAND	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
RATE1	98.6	96.0	94.7	94.2	98.2	96.4	95.8	92.1	97.3	96.3

In Excel, the "forecast.ets()" function is used to calculate the 2021 and 2022 forecasts.

LOWER MAINLAND	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
RATE1	98.6	96.0	94.7	94.2	98.2	96.4	95.8	92.1	97.3	96.3	=FORECAST.ETS(O$4,$C9:$L9,$C$4:$L$4,0,0,1)	

FORECAST.ETS(target_date, values, timeline, [seasonality], [data_completion], [aggregation])

The resulting forecasts for 2022 and 2023 are shown:

LOWER MAINLAND	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022S	2023F
RATE1	98.6	96.0	94.7	94.2	98.2	96.4	95.8	92.1	97.3	96.3	**95.5**	**95.4**

5.2 *AMALGAMATION OF UPCS IN FIS*

Once the use rates are seasonalized and developed for each region and each rate schedule (RS 1, RS 2, RS 3 and RS 23), they are entered into FIS. The amalgamated use rates are calculated using the following relationship:

$$Use\ Rate = \frac{\sum Volume}{\sum Accounts}$$

FIS calculates both the monthly volume and accounts by region and rate class. In an external spreadsheet the volumes and accounts are summed by month and by rate class for all regions.

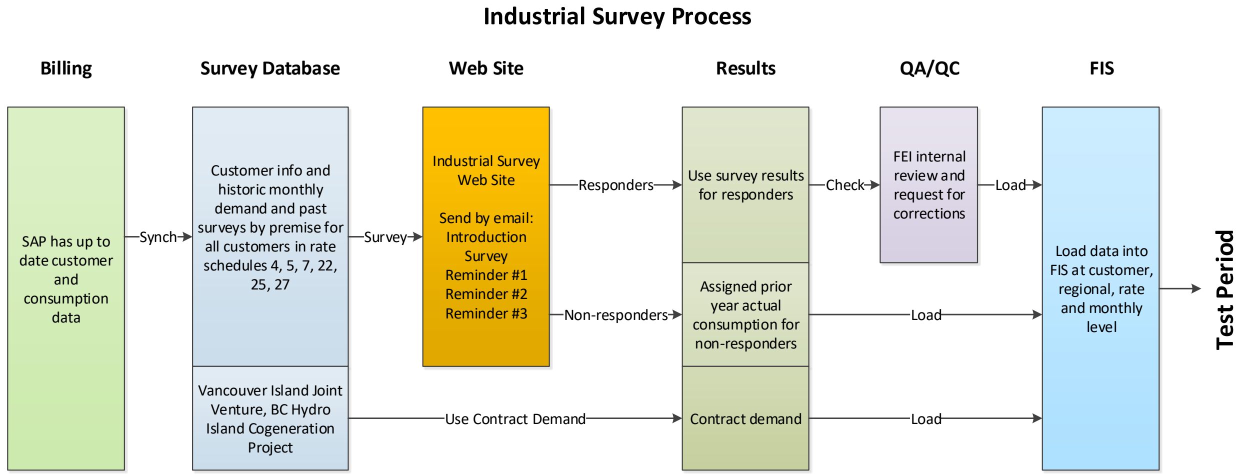
6. RESIDENTIAL AND COMMERCIAL DEMAND FORECAST

The residential and commercial demand forecasts are the products of the monthly customer forecast and the corresponding monthly use rates forecast at the sub-regional level. The sub-regions, regions and months are then summed to arrive at the amalgamated demand forecast.

7. INDUSTRIAL DEMAND FORECAST

The industrial demand is forecast using a web-based survey system. The following diagram shows the main steps of process.

Figure A3-2: Industrial Forecast Process



Each customer in each industrial class receives a customized email message with a secure link to their individual survey. The customer then uses the web based survey to complete their forecast of demand for the next five years and submits it to FEI. Once the survey is closed (typically after six weeks duration), the survey responses are checked and then the data is loaded into the FIS system. The following sections describe the process in detail.

7.1 CREATE THE SURVEY

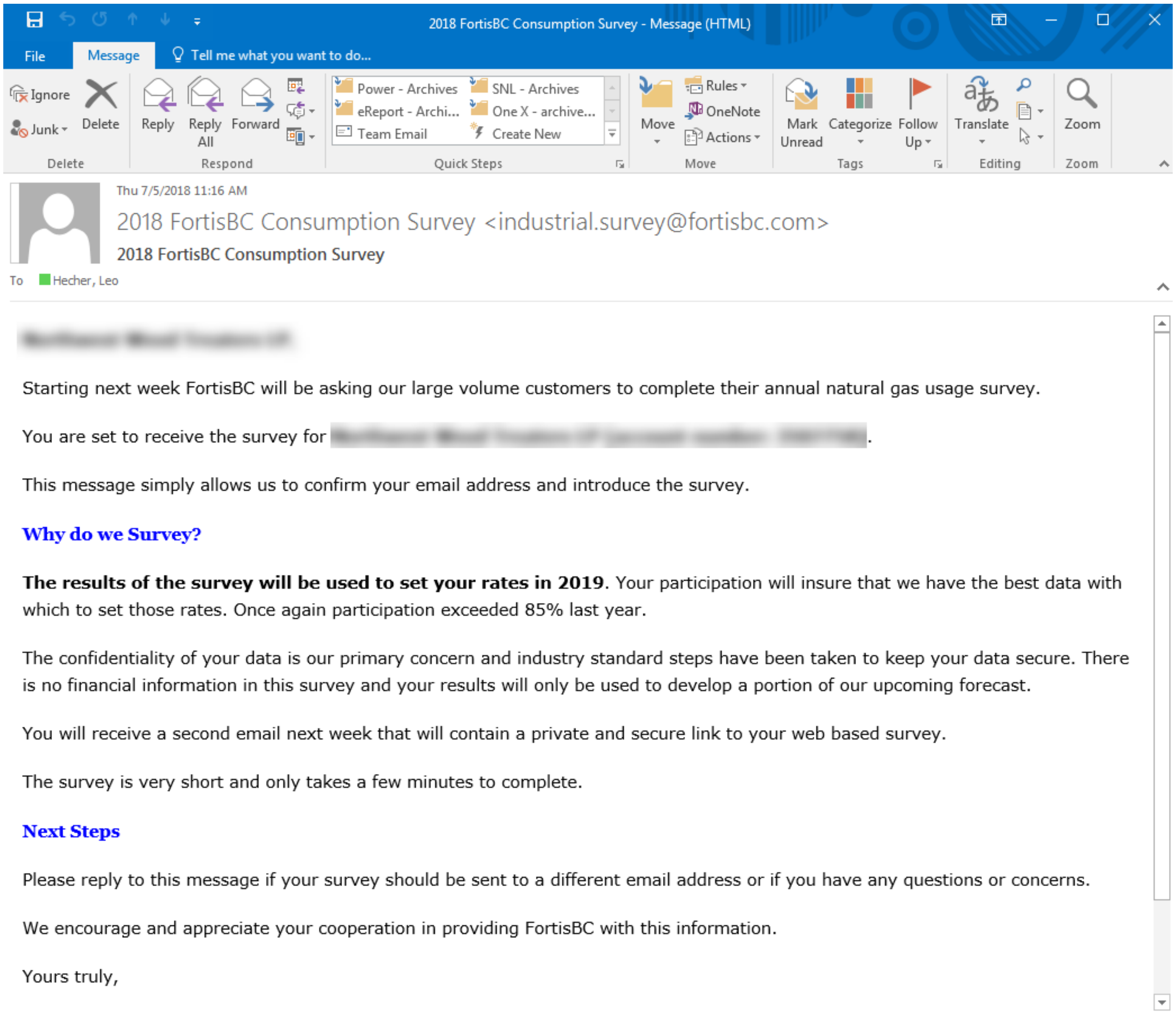
Prior to the start of the survey FEI creates a new survey using a web-based application. For the annual survey all industrial classes are selected. Commercial and residential customers are not surveyed.

7.2 SEND OUT THE INTRODUCTION EMAIL

The customer is introduced to the survey several days before the actual surveys are sent out. This allows the customer time to update their contact information and possibly to assign the survey to a different employee if there have been staffing changes. FEI has found this to be an important step and contributes to the high success rate because a minimal number of surveys are sent to the wrong person.

The survey web site creates the form letters and manages the send out. The following is an example of the introductory email.

Figure A3-3: Survey Introductory Email Example



2018 FortisBC Consumption Survey - Message (HTML)

Thu 7/5/2018 11:16 AM
2018 FortisBC Consumption Survey <industrial.survey@fortisbc.com>
2018 FortisBC Consumption Survey
To Hecher, Leo

[redacted]

Starting next week FortisBC will be asking our large volume customers to complete their annual natural gas usage survey.

You are set to receive the survey for [redacted].

This message simply allows us to confirm your email address and introduce the survey.

Why do we Survey?

The results of the survey will be used to set your rates in 2019. Your participation will insure that we have the best data with which to set those rates. Once again participation exceeded 85% last year.

The confidentiality of your data is our primary concern and industry standard steps have been taken to keep your data secure. There is no financial information in this survey and your results will only be used to develop a portion of our upcoming forecast.

You will receive a second email next week that will contain a private and secure link to your web based survey.

The survey is very short and only takes a few minutes to complete.

Next Steps

Please reply to this message if your survey should be sent to a different email address or if you have any questions or concerns.

We encourage and appreciate your cooperation in providing FortisBC with this information.

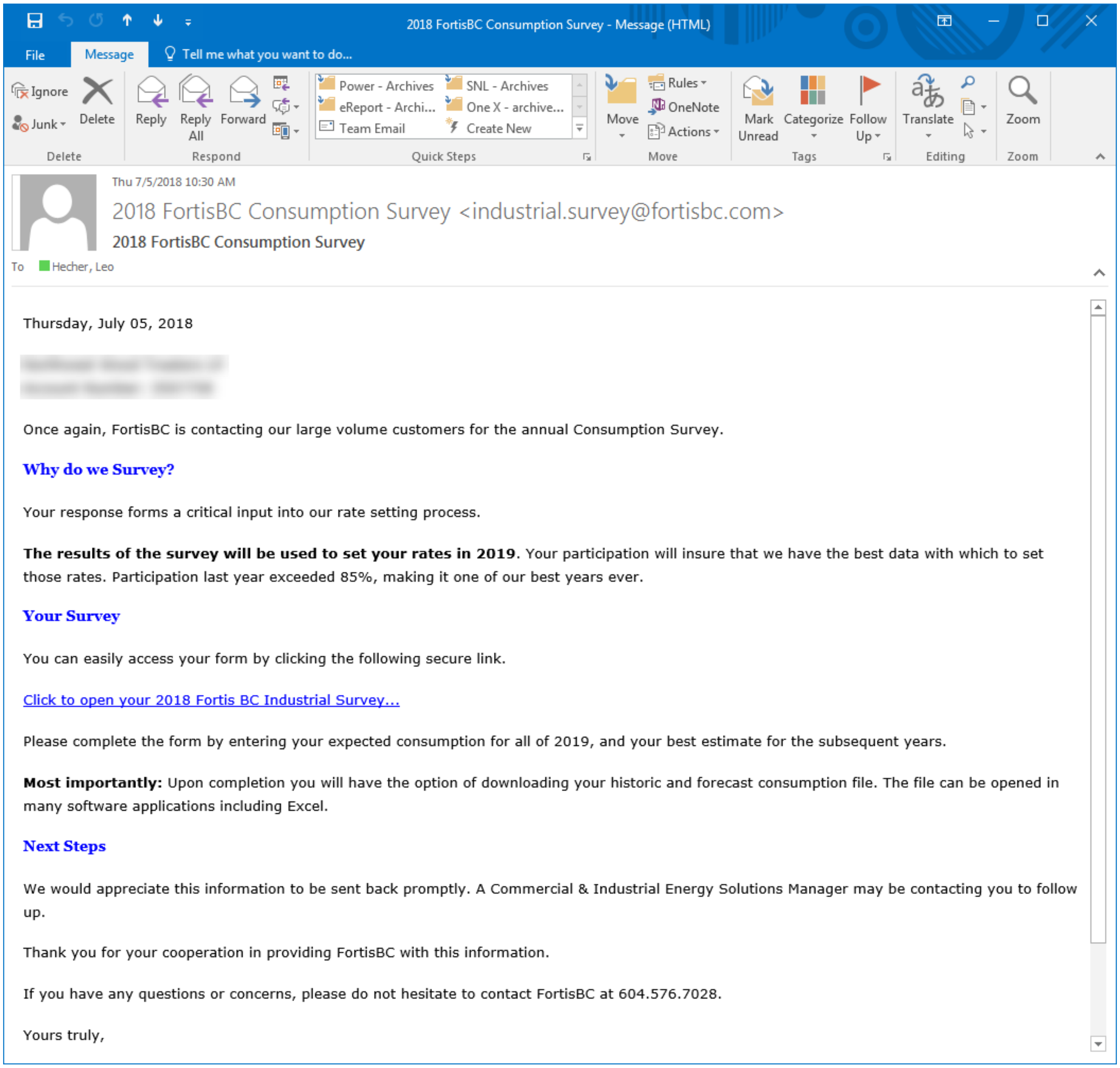
Yours truly,

Replies to these emails are used to update the contact and other information in the survey web site.

7.3 *SEND OUT THE SURVEY EMAIL*

An email with a customized link to the survey is sent out several days after the reminder. The survey is not sent until all the changes that resulted from the introductory email have been processed. As in the following sample email, each customer is sent an HTML link to the survey. An encrypted globally unique identifier in the link insures that customers cannot access surveys from other customers.

Figure A3-4: Survey Email Example



Thursday, July 05, 2018

Once again, FortisBC is contacting our large volume customers for the annual Consumption Survey.

Why do we Survey?

Your response forms a critical input into our rate setting process.

The results of the survey will be used to set your rates in 2019. Your participation will insure that we have the best data with which to set those rates. Participation last year exceeded 85%, making it one of our best years ever.

Your Survey

You can easily access your form by clicking the following secure link.

Click to open your 2018 Fortis BC Industrial Survey...

Please complete the form by entering your expected consumption for all of 2019, and your best estimate for the subsequent years.

Most importantly: Upon completion you will have the option of downloading your historic and forecast consumption file. The file can be opened in many software applications including Excel.

Next Steps

We would appreciate this information to be sent back promptly. A Commercial & Industrial Energy Solutions Manager may be contacting you to follow up.

Thank you for your cooperation in providing FortisBC with this information.

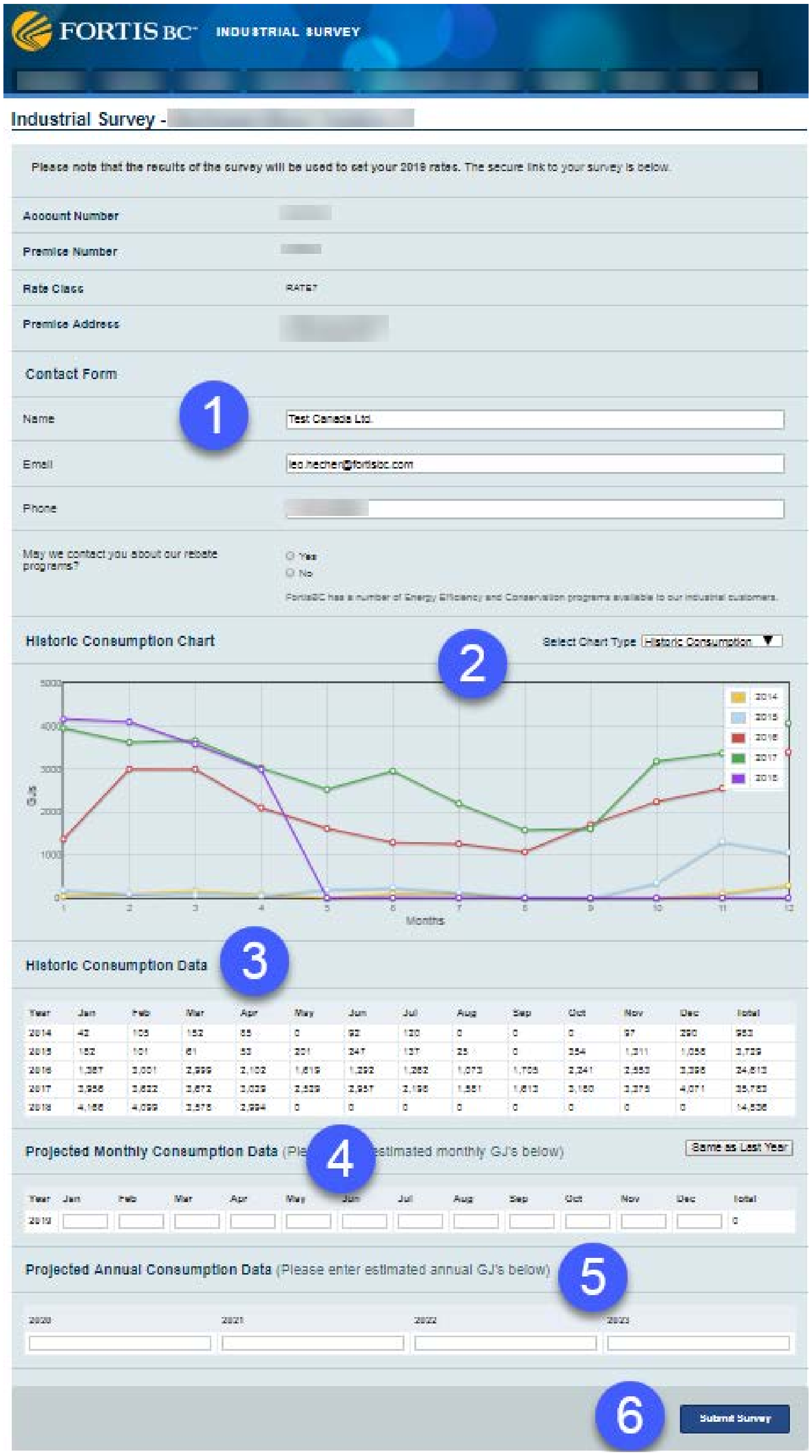
If you have any questions or concerns, please do not hesitate to contact FortisBC at 604.576.7028.

Yours truly,

7.4 SURVEY FORM

The following web form is displayed to the user after the link in the email has been clicked.

Figure A3-5: Survey (Web) Form Example



Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2014	42	105	152	65	0	92	120	0	0	0	97	290	953
2015	152	101	61	53	201	247	137	25	0	354	1,311	1,058	3,729
2016	1,387	3,001	2,999	2,102	1,619	1,292	1,282	1,073	1,705	2,241	2,553	3,398	24,613
2017	3,958	3,622	3,672	3,029	2,529	2,957	2,198	1,581	1,613	3,160	3,375	4,071	35,783
2018	4,168	4,099	3,575	2,994	0	0	0	0	0	0	0	0	14,836

Notes:

1) The user can change the contact name (normally a person's name), email and phone number. It is saved and will be used in subsequent years. This allows the recipient to redirect next year's survey.

2) A line chart showing the customer's actual historic consumption is shown for the prior 5 years. The customer can use the pick list to show a chart that shows last year's actual consumption and last year's survey. This allows the customer to see any variance in their survey from last year.

3) A table of historical consumption is shown for the prior five years. Zeroes are shown in this example because the survey database is not updated until the start of a real survey.

4) The customer is asked for monthly consumption for the coming year. The total at the right side is automatically updated to reduce typing errors. If the customer believes that its consumption is not changing, they can use the "Same as last year" button as a fast alternative to typing in the same values.

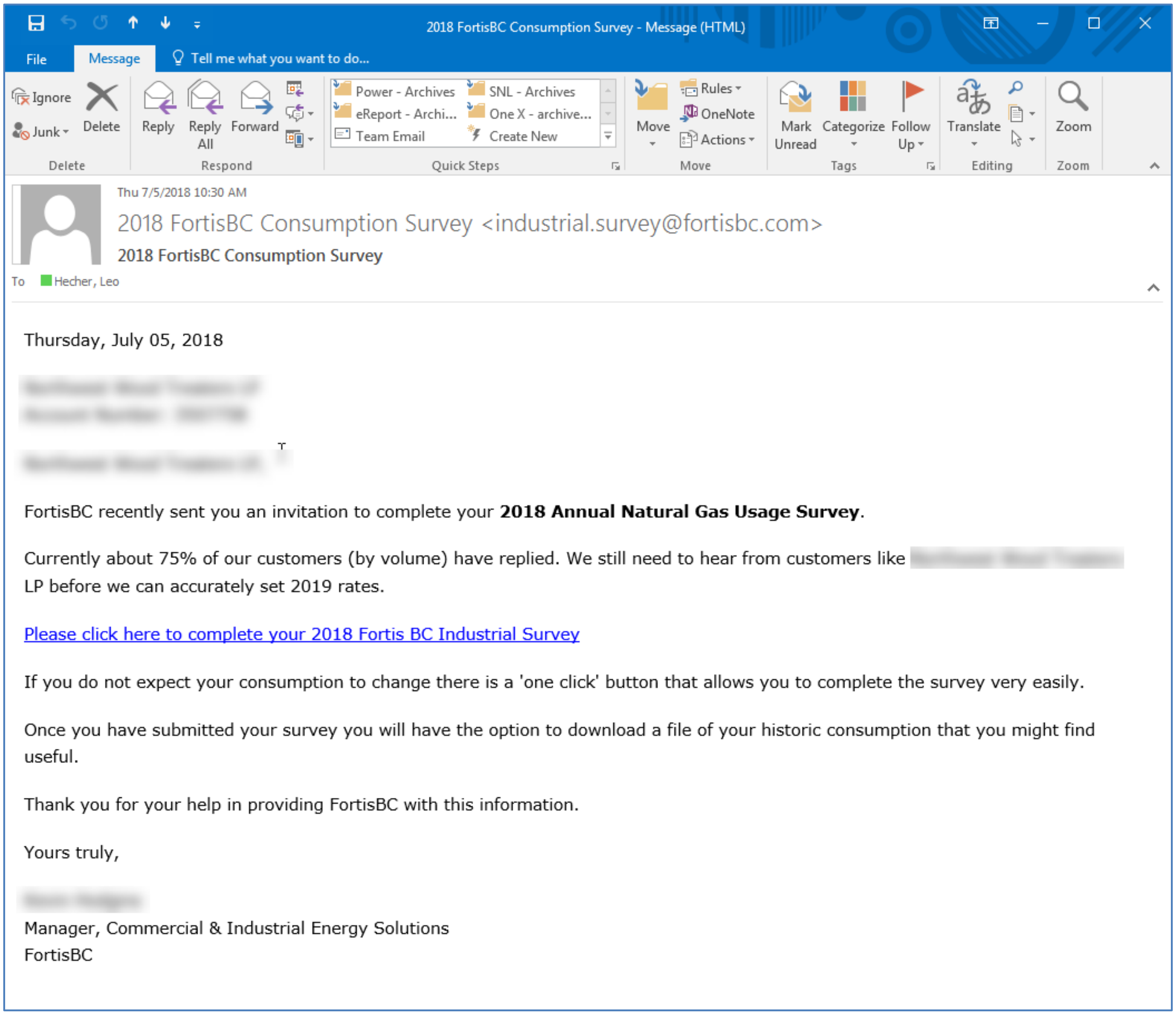
5) Annual forecasts are requested for the remaining 4 years of the survey.

6) Once the data has been entered the user clicks the Submit button to save the survey. Upon submitting the survey the user will be able to download a Microsoft Excel file containing the data from Step 3 above.

7.5 NON RESPONDERS AND THE REMINDER EMAIL

Once the survey is started, responses start coming in within the hour. A steady response rate normally continues for several days, but eventually slows. The survey system tracks the status of each survey and at all times FEI knows the response rate. Until the target response rate is reached, FEI sends out a weekly reminder email to those customers that have not yet responded. The reminder email contains the same link to the survey. The reminder step enhances the response rate of the survey. A sample is shown below:

Figure A3-6: Example of Survey Reminder Email



Thursday, July 05, 2018

[redacted]

FortisBC recently sent you an invitation to complete your **2018 Annual Natural Gas Usage Survey**.

Currently about 75% of our customers (by volume) have replied. We still need to hear from customers like [redacted] LP before we can accurately set 2019 rates.

Please click here to complete your 2018 Fortis BC Industrial Survey

If you do not expect your consumption to change there is a 'one click' button that allows you to complete the survey very easily.

Once you have submitted your survey you will have the option to download a file of your historic consumption that you might find useful.

Thank you for your help in providing FortisBC with this information.

Yours truly,

[redacted]
Manager, Commercial & Industrial Energy Solutions
FortisBC

7.6 MONITORING THE RESPONSE RATE

The response rate for the survey is measured in terms of number of respondents and the volume from those respondents. FEI is not only concerned with the number of customers that reply but also the volume those customers represent. The response rate from a volumetric perspective is always higher than the customer count response rate because large customers (for example those in RS 22) are more likely to reply to the survey.

The response rate is measured by counting the number of responses compared to the number of customers in the survey. Some customers will not respond because the survey has been sent to an invalid email address. In these cases, FEI attempts to correct the address so that a survey can be completed. FEI notes that if an address cannot be corrected during the time of the survey, then the customer remains in the denominator of the response calculation ratio.

The following screen shot is for demonstration purposes only.

Figure A3-7: Example of Survey Results Dashboard

7.7 *REVIEWING THE SURVEYS*

Surveys from large volume customers are reviewed by the Forecast Manager and one or more Commercial and Industrial Energy Solutions Managers. The Commercial and Industrial Energy Solutions Managers are well informed about the issues with each individual customer and are able to rationalize the survey received from the customer. Where surveys are contrary to the information the Commercial and Industrial Energy Solutions Managers have, a follow up call is made and the survey is adjusted if required.

7.8 *CLOSING OFF THE SURVEY AND LOADING FIS*

Once the target response rate has been achieved in early July, the survey is closed. The data in the survey web site is then transferred automatically to the current forecast in FIS. Industrial rate classes are forecast by individual customer so the data for each customer is copied.

Checks are completed to make sure that that data was copied properly and that the survey web site and that the current FIS forecast are in sync.

Customers that do not respond to the survey are assigned their prior year's consumption.

FIS then sums the individual customer demand forecasts by rate class and region to develop the industrial demand forecast.

8. SUMMARY OF DEMAND FORECAST

Once the customer additions, use rates and industrial demand calculations and data have been completed, they are entered into FIS. FIS then aggregates the demand by month, region and rate class to prepare the overall forecast of demand.

Appendix B

FEI 2023 CMAE BUDGET REVIEW

FEI 2023 CORE MARKET ADMINISTRATION EXPENSE (CMAE) BUDGET REVIEW

1.1 *INTRODUCTION*

The CMAE budget funds the costs that FEI's Gas Supply department incurs to plan, manage and optimize the commodity and midstream gas supply portfolios, mitigate unneeded resources, manage the credit exposure to counterparties, and minimize the impact of unfavourable upstream regulatory developments. As these activities serve core market customers and directly impact commodity and midstream costs, the CMAE budget is recovered separately from delivery costs through gas cost recovery rates.[1] FEI's 2018-2021 Actual, 2022 Approved, 2022 Projected, and 2023 Forecast for CMAE is set out in Schedule 1 to this appendix, in the format prescribed in Appendix B to Order G-23-15.

As set out in the Approvals Sought (Section 1.2 of the Application) and in Section 4, FEI requests BCUC approval of the following, effective January 1, 2023:

- approval of the 2023 forecast CMAE budget of $5.795 million, as set out in Schedule 1; and
- approval of the allocation of the 2023 forecast CMAE budget and actual costs between the Commodity Cost Reconciliation Account (CCRA) and Midstream Cost Reconciliation Account (MCRA) based on the allocation percentages of 30 percent and 70 percent, respectively.

In compliance with the BCUC's Decision and Order G-79-14, FEI will continue to seek annual approval of the CMAE budget as part of the Annual Review filings.

Further, pursuant to the BCUC's direction in the FEI Annual Review for 2020 and 2021 Delivery Rates Decision and Order G-319-20, FEI will include a comprehensive review of the CMAE (Comprehensive CMAE Review) in its next revenue requirements or multi-year rate plan (MRP) application following the MRP term.

The following describes the 2023 Forecast CMAE budget.

[1] The Gas Supply department is primarily funded through the CMAE budget. However, activities not directly related to the commodity and midstream portfolio functions, such as the on-system transportation work supporting the transportation services business, are included in FEI's O&M costs and recovered through delivery rates.

1.2 *DESCRIPTION OF CMAE BUDGET*

The principal purpose of activities funded by CMAE is to identify and secure safe, reliable and cost effective gas supply resources that are required to meet the demand for natural gas by core customers.

The CMAE budget is required for FEI staff and resources that are necessary:

- to plan and optimize gas supply requirements, and to prepare FEI's Annual Contracting Plans and Price Risk Management applications;
- to secure and manage the gas supply resources on a daily basis and mitigate any unneeded resources;
- to establish appropriate contracts with counterparties and manage any associated credit exposure;
- to manage upstream regulatory developments in order to protect the interests of customers, including minimizing unfavourable outcomes and identifying and supporting opportunities that are beneficial to customers; and
- to complete the support activities related to the gas supply technology platforms, financial reconciliations and settlements with counterparties, as well as the finance, regulatory, tax, and other reporting and compliance requirements.

Carrying out these responsibilities is critical given that the gross cost of the commodity and midstream gas supply portfolios is currently in excess of $1,400 million per year.[2] These costs can change dramatically given commodity price volatility and changes in transportation and storage costs.

Developing and maintaining effective gas supply portfolios requires the evaluation of resources available to meet normal, design winters, and peak day core load requirements. This work includes:

- support activities such as portfolio modelling and resource assessment;
- regional supply and demand analysis, discussions and meetings with pipeline and storage operators, and the maintenance of strong relationships with gas producers and marketers;
- negotiation and administration of commodity, pipeline and storage contracts;
- staying apprised of new regional infrastructure developments; and
- seeking opportunities for contracting resources related to cost-effective pipeline or storage capacity expansions or additions.

[2] Based on the commodity and midstream costs for the prospective 12-month period forecast in the FEI 2022 Second Quarter Gas Cost Report dated June 1, 2022.

The general availability of these resources is influenced by the upstream regulatory framework that underpins the investment in regional infrastructure and supports commercial activity. Active involvement in upstream regulatory matters is required to manage the evolution of this regulatory framework so that the interests of FEI and its customers continue to be protected. This work is also important because it enables effective ongoing mitigation activities to be performed by gas supply. The specialized expertise required to complete these activities enables the achievement of incremental revenue that offsets the cost of gas. Depending on market conditions, this effort can result in substantial cost-reducing revenue. Customers benefit directly from this work through lower rates.

Table B-1 below provides a summary of the 2022 Approved, 2022 Projected and 2023 Forecast CMAE amounts. Schedule 1 included in this appendix provides a breakdown of the expense components and amounts summarized in Table B-1. Section 1.5 of this appendix provides further descriptions of the various expense components comprising the Labour, Non-Labour, and Shared Services groupings.

Table B-1: CMAE Summary ($ millions)

	Approved 2022	Projected 2022	Forecast 2023
Labour	$ 3.038	$ 2.988	$ 3.114
Non-Labour	1.851	1.901	1.967
Shared Services	0.686	0.686	0.714
Total CMAE	$ 5.575	$ 5.575	$ 5.795

The level of the CMAE budget is determined by the scope of work required to meet the responsibilities described above, as well as annual inflationary increases and changes in the US to Canadian currency exchange rate. The Consulting and Legal component of the CMAE budget, for example, is typically variable year-over-year and may need to increase in a year when significant upstream regulatory developments require intervention in proceedings to ensure the interests of customers are protected. Conversely, the budget requirement will generally decrease when the overall level of upstream regulatory intervention is lower.

The CMAE activities are provided on the basis of a common administrative function and their cost are allocated to the gas supply commodity and midstream portfolios. Consistent with previous years, this allocation assigns 30 percent of CMAE costs to the CCRA and 70 percent to the MCRA. The allocation percentages will be reviewed as part of the scope of the Comprehensive CMAE Review.

1.3 *REGULATORY TREATMENT OF CMAE*

The forecast CMAE costs are included as a component of the forecast gas costs for the purposes of determining the commodity and midstream (storage and transport) cost recovery charges.

Variances between the actual gas costs incurred and the forecast gas costs embedded in recovery rates are captured in the gas cost deferral accounts and, subject to BCUC approval, these variances are refunded to or recovered from customers as part of future commodity and midstream rates.

At the end of each year, the Company files its gas cost status report with the BCUC, which provides a summary of the cost and recovery variances and provides explanations for any material variances. The actual year-end 2022 CMAE costs and variances to the approved budget will be submitted, in the format prescribed by the BCUC, as part of the FEI 2022 CCRA and MCRA Status Report due to be filed by April 30, 2023.

1.4 *PROJECTED 2022 CMAE COSTS*

While Table B-1 offers a high level summary of the CMAE costs for 2022 and 2023, Schedule 1 provides greater detail and has been prepared in the prescribed format of Appendix B to Order G-23-15. The schedule presents the 2022 Approved and 2022 Projected CMAE amounts, including variances and explanations. As well, Schedule 1 provides a summary of the Actual 2018-2021 CMAE costs, and the 2023 Forecast CMAE budget.

The year-end costs shown in the 2022 Projected column in Schedule 1 are based on the actual costs incurred to May 31, 2022 and the projected costs for the remainder of the year. The Company projects that overall the 2022 CMAE costs will total $5.575 million, consistent with the 2022 Approved amount. Schedule 1 provides a breakdown of the variances, including explanations, between 2022 Approved and 2022 Projected CMAE amounts at the individual cost component level.

The year-end 2022 Projected CMAE costs, including all variances at the cost component level from the 2022 Approved CMAE budget, reflect the prudent and effective management of commodity and midstream gas supply costs. Consistent with past practice, the actual costs will flow through to customers as part of future commodity and midstream rates.

1.5 *FORECAST 2023 CMAE COSTS*

As reflected in Schedule 1 in the 2023 Budget Request column, the Company is seeking approval of the 2023 CMAE budget in the amount of $5.795 million, which is $0.220 million higher than 2022 Approved. The increase from 2022 Approved is primarily related to inflation based on the forecast labour and non-labour inflation factors. As well, the forecast includes changes in the service levels related to various non-labour components that have been identified. Explanations of the 2023 CMAE budget by cost component are set out below.

1.5.1 Information Systems

The 2023 Forecast Information Systems (IS) budget of $0.408 million is $0.086 million higher than 2022 Approved. The new Energy Trading and Risk Management (ETRM) system, Horizon, was successfully implemented and became the gas supply system of record effective May 1, 2022. The budget includes the forecast costs of the annual software maintenance and support requirements for the Horizon system. The savings related to completing the transition off the Entegrate system as the gas supply system of record, including the upcoming retirement of the Entegrate system and archiving of the historical data, are embedded in the 2023 Forecast amounts.

1.5.2 Consulting and Legal

The 2023 Forecast Consulting and Legal budget of $0.700 million is based on the forecast of upstream regulatory work anticipated to occur in 2023; it also includes a forecast for the consulting and legal work required to support the gas supply portfolio, including impacts related to renewable gas supply, and the Annual Contracting Plan.

Upstream regulatory matters impact FEI in a variety of ways, including its ability to transact for gas supply at fair market prices and through the costs that are reflected in fixed transportation tolls. The Company's participation in such proceedings, either directly or as a member of the Western Export Group (WEG), provides significant benefit to customers, as increases to the commodity market prices and upstream pipeline tolls and tariffs directly impact FEI's rates.

The degree of involvement in upstream regulatory matters that may be required in any given year is typically difficult to foresee with accuracy as it is driven by third party applications to national regulators (the Canada Energy Regulator (CER) in Canada and the Federal Energy Regulatory Commission (FERC) in the United States), who determine the scope and timeline of any review. The nature of these applications, and issues they potentially create, drive the scope of FEI's involvement, ranging from simple monitoring to full participation in oral hearings. The costs incurred by this involvement are, as a result, highly variable. To help manage the costs of this involvement, FEI is a member of the WEG, which shares costs relating to matters concerning TC Energy's NOVA Gas Transmission Ltd. (NGTL) and FoothillsBC systems.

1.5.3 Subscriptions & Memberships

The 2023 Forecast for Subscriptions & Memberships of $0.693 million has slightly increased compared to 2022 Approved. The budget is based on the forecast costs for the required service levels and continues to include savings related to sharing the costs of some subscriptions with Aitken Creek Gas Storage ULC (ACGS). The 2023 Forecast includes inflationary increases to the various subscriptions and membership dues, as well as the contractual increases that are related to sole source subscriptions for commodity price services, while the US to Canadian currency exchange rate assumption has remained unchanged from that used in the 2022 Approved amount.

1.5.4 Sundries

The 2023 Forecast for Sundries of $0.041 million has decreased from the 2022 Approved amount. The budget is based on the forecast regulatory proceeding costs related to BCUC gas supply applications during the year, as well as the recurring expenditures for facilities communications and data charges, and other miscellaneous costs.

1.5.5 Training & Travel

The 2023 Forecast for Training & Travel of $0.125 million has increased from the 2022 Approved. The 2023 Forecast is based on a resumption of travel activity closer to the pre-pandemic level, including inflation.

1.5.6 MoveUP Labour

The 2023 Forecast for MoveUP Labour of $0.652 million has increased slightly compared to the 2022 Approved amount. The 2023 Forecast is based on the forecast of labour, including cross-charging, inflation, and benefits loadings.

1.5.7 M&E Labour

The 2023 Forecast for M&E Labour of $2.462 million has increased slightly compared to the 2022 Approved amount. The 2022 Forecast is based on the forecast of labour, including cross-charging, inflation, and benefits loadings.

1.5.8 Shared Services

The 2023 Forecast for Shared Services of $0.714 million has increased from the 2022 Approved. The 2023 Forecast is based on the same service level requirements as 2022 with inflationary increases related the labour and facilities workspace costs. The Shared Services charge relates to the transfer of costs for services provided to gas supply from other areas of the Company. The Shared Services include the provision of management oversight, core customer load forecasting, office workspace and technology requirements, and internal legal, tax and treasury support for counterparty contracts and credit analysis.

1.6 *SUMMARY*

The Company has reviewed its requirements for 2023 and forecast its CMAE costs accordingly. The level of the 2023 Forecast CMAE is required to ensure that the Company is able to prudently and effectively manage commodity and midstream gas supply costs for the benefit of customers. Finally, the methodology used for allocating CMAE costs to the gas supply commodity and midstream portfolios remains consistent with that of previous years.

Schedule 1

Line #	CMAE Cost Component	2018	2019	2020	2021	2022					2023
2	**($000, unless specified otherwise)**	**Actual**	**Actual**	**Actual**	**Actual**	**Approved**	**Projected**	**Variance**	**Variance %**	**Variance Explanation**	**Budget Request**
3	IS (Information Systems)	311	342	482	278	322	395	73	23%	IS costs higher due to higher support costs related to the new Horizon Energy Trading and Risk Management (ETRM) system.	408
4	Consulting & Legal	363	523	424	758	750	700	(50)	-7%	Consulting and Legal costs lower due to timing of CER regulatory proceedings.	700
5	Subscriptions & Memberships	287	395	595	565	629	658	29	5%	Subscriptions and Memberships costs higher primarily due to higher services subscription fees and unbudgeted PST amounts.	693
6	Sundries	1,432	110	119	22	60	48	(12)	-20%	Sundries lower due to lower BCUC assessments and cost awards for Gas Supply applications.	41
7	Training & Travel	119	125	34	11	90	100	10	11%	Training & Travel higher due to cost increases and the partial resumption of travel activity after the lifting of COVID-19 pandemic travel restrictions.	125
8	MoveUP Salaries before Benefits & Incentives	445	445	493	381	457	439	(18)	-4%	MoveUP Salaries lower due to temporarily unfilled position, partially offset by higher overtime. Benefits lower due to lower salary costs and lower than budgeted loadings.	467
9	MoveUP Benefits (3)	152	166	180	145	181	164	(17)	-9%		185
10	MoveUP Incentives (3) (4)	-	-	-	-						
11	M&E Salaries before Benefits & Incentives	1,349	1,268	1,350	1,517	1,598	1,608	10	1%	M&E Salaries slightly higher due to lower cross-charging out. Benefits lower due to lower than budgeted loadings.	1,628
12	M&E Benefits (3)	463	469	478	491	802	777	(25)	-3%		834
13	M&E Incentives (3)	215	289	234	200						
14	Energy Management Service Revenue	-	-	-	-	-	-	-			-
15	Shared Services	632	686	686	686	686	686	-	0%		714
16	**Total**	5,768	4,818	5,075	5,054	5,575	5,575	-	0%		5,795
17											
18	**CMAE FTE**	**2018**	**2019**	**2020**	**2021**	**2022**					**2023**
19	**(Number)**	**Actual**	**Actual**	**Actual**	**Actual**	**Approved**	**Projected**	**Variance**	**Variance %**	**Variance Explanation**	**Budget Request**
20	MoveUP	4.9	4.9	4.9	4.0	5.0	4.6	(0.4)	-9%	Due to temporarily unfilled MoveUP position during the year.	5.0
21	M&E	13.8	14.4	13.7	14.4	15.0	15.0	-	0%		15.0
22	**Total**	18.7	19.3	18.6	18.4	20.0	19.6	(0.4)	-2%		20.0
23											
24	**Comparative Labour Loading**	**2018**	**2019**	**2020**	**2021**	**2022**					**2023**
25	**(percentages, except for salaries which is $000)**	**Actual**	**Actual**	**Actual**	**Actual**	**Approved**	**Projected**	**Variance**	**Variance %**	**Variance Explanation**	**Budget Request**
26	**Company-wide MoveUP Benefits as percentage of salaries (1)**	30%	38%	40%	41%						
27	**Company-wide MoveUP Incentives as percentage of salaries (1) (4)**	0%	0%	0%	0%						
28	**Subtotal Company-wide MoveUP Benefits & Incentives as percentage of salaries (1) (3)**	30%	38%	40%	41%	40%	39%				40%
29	**Company-wide M&E Benefits as percentage of salaries (1)**	34%	32%	33%	31%						
30	**Company-wide M&E Incentives as percentage of salaries (1) (4)**	15%	17%	15%	16%						
31	**Subtotal Company-wide M&E Benefits & Incentives as percentage of salaries (1) (3)**	49%	49%	49%	46%	49%	48%				49%
32	**CMAE MoveUP Salaries before cross-charging (2)**	$ 428	$ 437	$ 445	$ 358	$ 457	$ 414				$ 467
33	**CMAE MoveUP Benefits as percentage of salaries before cross-charging (2)**	35%	38%	41%	41%						
34	**CMAE MoveUP Incentives as percentage of salaries before cross-charging (2) (4)**	0%	0%	0%	0%						
35	**Subtotal CMAE MoveUP Benefits & Incentives as percentage of salaries (2) (3)**	35%	38%	41%	41%	40%	39%				40%
36	**CMAE M&E Salaries before cross-charging (2)**	$ 1,435	$ 1,513	$ 1,462	$ 1,497	$ 1,647	$ 1,616				$ 1,713
37	**CMAE M&E Benefits as percentage of salaries before cross-charging (2)**	32%	31%	33%	33%						
38	**CMAE M&E Incentives as percentage of salaries before cross-charging (2) (4)**	15%	19%	16%	13%						
39	**Subtotal CMAE M&E Benefits & Incentives as percentage of salaries (2) (3)**	47%	50%	49%	46%	49%	48%				49%

Notes: Canadian Office and Professional Employees Union, Local 378 (COPE) known as Movement of United Professionals (MoveUP).

(1) Company-wide Salaries have been adjusted for items not attracting benefit loading such as overtime, premiums, retiring allowance, temporary MoveUP employee salary, and other adjustments.

(2) CMAE Salaries before cross-charging have been adjusted for items not attracting benefit loading such as overtime, premiums, retiring allowance, temporary MoveUP employee salary, and other adjustments.

(3) Approved, Projected, and Budgeted Benefits & Incentives are included in a single labour loading rate based on budgeted amounts; breakdown is not available until after year-end.

(4) Data shown reflects incentive payments are made in the following fiscal year (e.g. 2018 payment amounts based on 2017 performance results). Effective April 1, 2015 MoveUP Gas employees no longer receive incentives.

Appendix C

PROJECTS AND BUSINESS CASE

Appendix C1

WOOD MACKENZIE MARKET REPORT

Wood Mackenzie
A Verisk Business

Market Report: Gas and Electric Transmission and Distribution Cost Impacts 2020-2024

May 2022

The Engagement

FortisBC has engaged Wood Mackenzie Supply Chain Consulting to provide a market report detailing how market factors have impacted and are anticipated to impact North American utility spend between 2020 and 2024. Wood Mackenzie is a global research and consulting firm that provides energy clients with data, analytics, and insights that they rely on for their decision making. Wood Mackenzie Supply Chain Consulting (SCC), formerly PowerAdvocate, utilizes proprietary cloud-based software solutions and bespoke consulting services to enable our clients to leverage data analysis and assist them in navigating an ever-changing marketplace.

Market dynamics over the last two years have created significant inflationary pressures across both materials and services. This market report is specific to two portfolios: electric transmission and distribution (T&D) and gas T&D capital expenditures at Canadian utilities, with labour specific to British Columbia, Canada. In both portfolios, market escalation has been observed since FortisBC's initial Multi-Year Rate Plan (MRP) filing (Quarter 1, 2020 through Quarter 1, 2022). This report also includes a forecast of potential impacts from Quarter 2, 2022 through Quarter 4, 2024.

Qualifications

Wood Mackenzie Supply Chain Intelligence is a suite of cloud-based software solutions that includes a product, Cost Intelligence, which enables our clients to identify market-based risks and opportunities. Cost Intelligence includes thousands of cost models and indices that enable users to understand what a project or item should cost in a dynamic market. Wood Mackenzie Cost Intelligence models were developed to support the energy market. The Wood Mackenzie team starts with industry specifications, technical drawings, supplier 10ks, and other industry information to develop detailed items that tie cost inputs to dynamic market indices. Those indices are then weighted and loaded on the cloud-based platform. The items are combined into categories and sub-categories that reflect clients spend profiles, or specific capital project expenditures.

Methodology

North American Gas and Electric Utility Cost Models

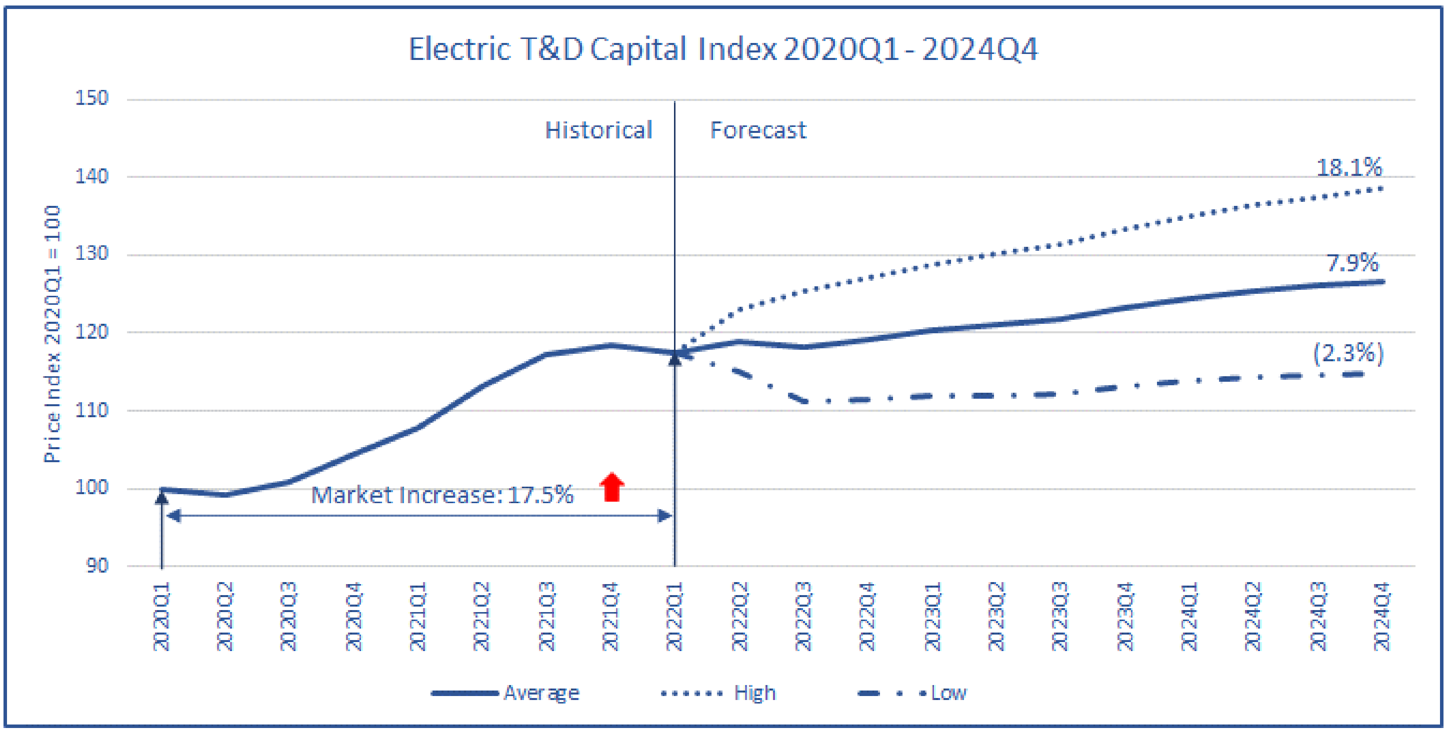
Wood Mackenzie built two customized cost models – Electric Transmission and Distribution and Gas Transmission and Distribution. Each cost model is built from aggregated spend from utilities across North America and over $550M (CAD) in total spend. The models apply indices to spend at an item level and roll up to sub-category, category, and facility level. Each model incorporates over 150 indices tracked monthly by Wood Mackenzie.

Customization for British Columbia Specific Labour Pool

British Columbia (BC) has a unique labour pool and, where appropriate, the models incorporate indices specific to BC, particularly around trade labour and any other labour activities specific to the BC province.

Market Insights

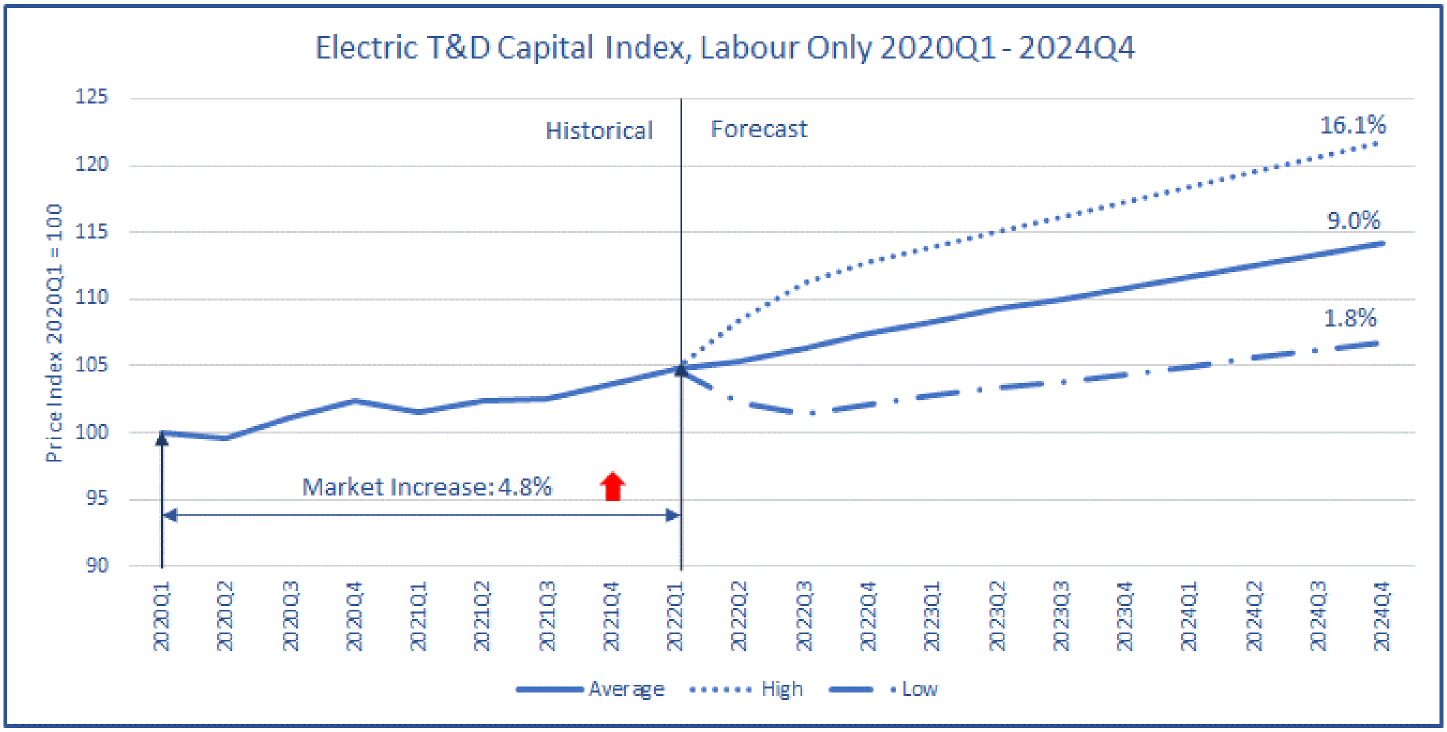
Electric Transmission and Distribution 2020Q1-2024Q4



*This graph includes an aggregate of multiple indices, including both labour and material cost components.
**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

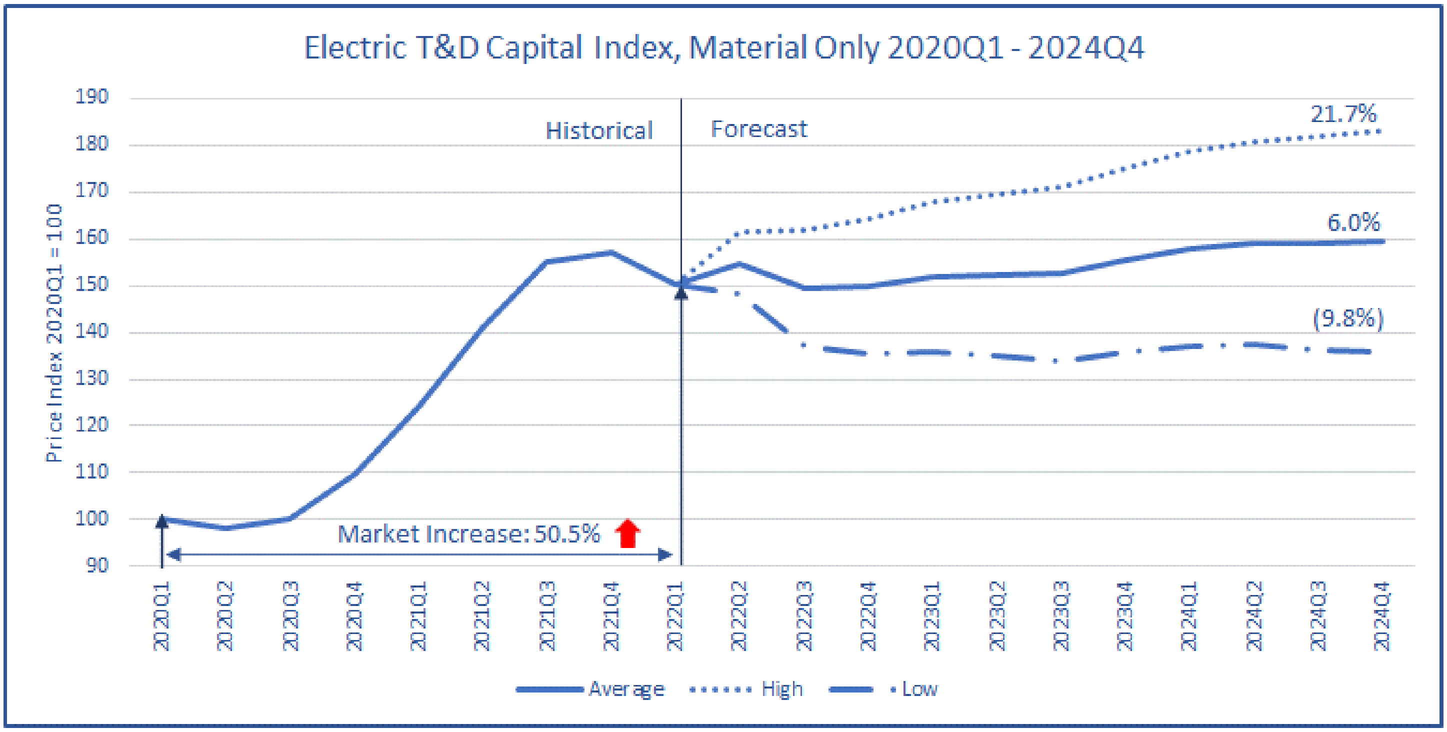
Since execution of FortisBC's MRP (Q1 2020 – Q1 2022), market factors have caused an escalation in capital costs for electric T&D of 17.5%. Forward-looking forecasts for Q1 2022 – Q4 2024 average 7.9%. Table 1 shows the ten most impactful commodities and services in the electric T&D model, and their individual escalations since the beginning of the MRP. Sharp increases in steel and aluminum prices starting in Q3 2020 drove escalations through Q3 2021. Prices of steel and aluminum have leveled off since Q4 2022 which is reflected in the forecast through 2024. The total market split for Electric T&D between labour and materials is 65% and 35% respectively. Labour costs are expected to continue to rise, while material costs level out.

Electric Transmission and Distribution - Labour 2020Q1-2024Q4



**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

Electric Transmission and Distribution - Material 2020Q1-2024Q4



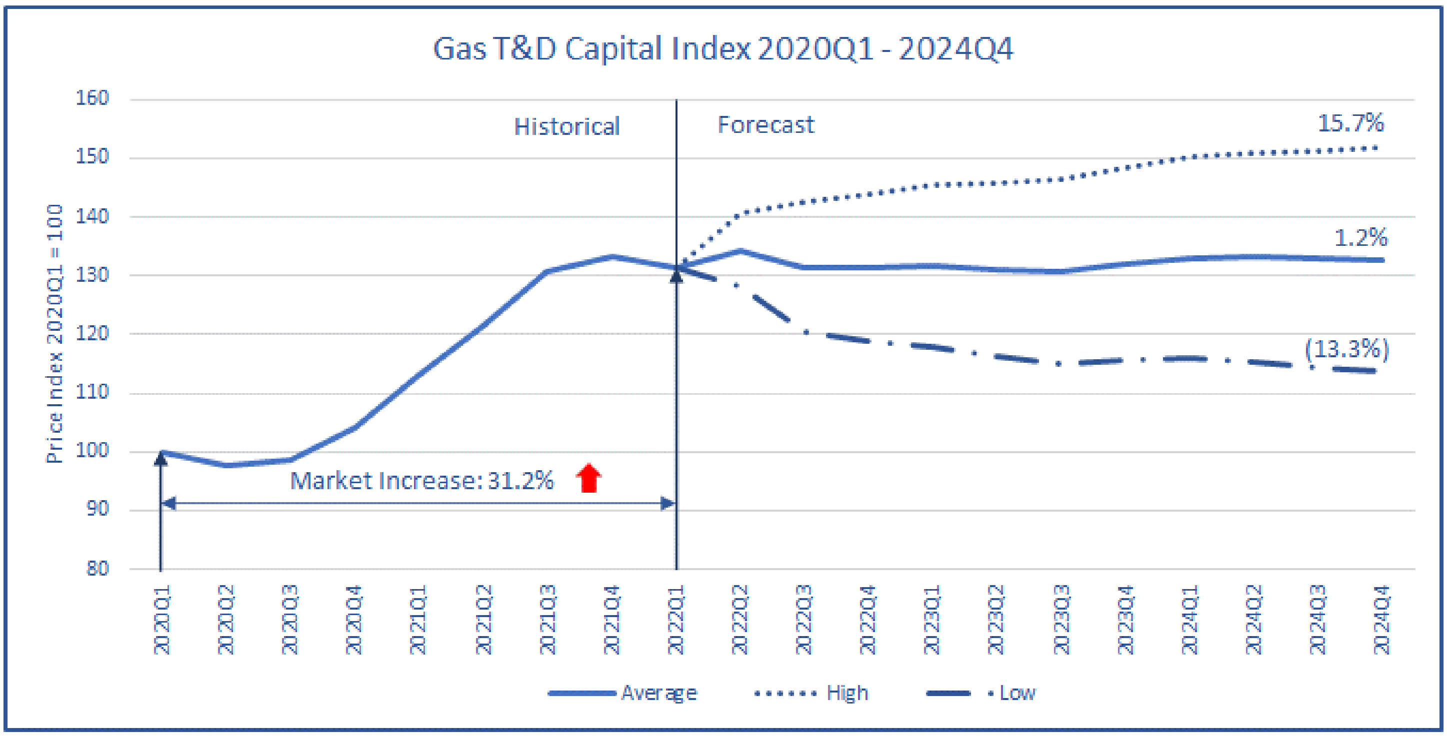
**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

Table 1. Electric T&D High-impact Commodities and Services

Electric T&D High Impact Commodities and Services	Q1 2020 – Q2 2022 (%)
AHE: Mechanical and Electrical Trades, Basic Construction Union Wages, BC	1.5
AHE: Construction, Private Compensation, BC	10.8
ECEC: Benefits, Private Construction	3.3
SPM: Steel, Hot-Rolled Coil	117.3
PPI: Cement, Canada	(3.4)
AHE: Heavy Equipment Operator, Basic Construction Union Wages, BC	2.6
AWE: Repair and Maintenance, BC	4.3
SPM: Aluminum, High Grade	83.2
PPI: Springs and Wire Products, Canada	42.2
IM: Transmission Conductor	160.4

AHE: Average Hourly Earnings, Employer Costs for Employee Compensation, SPM: Spot Price Metal, IPPI: Producer Price Index, AWE: Average Weekly Earnings, IM: Industry Margin

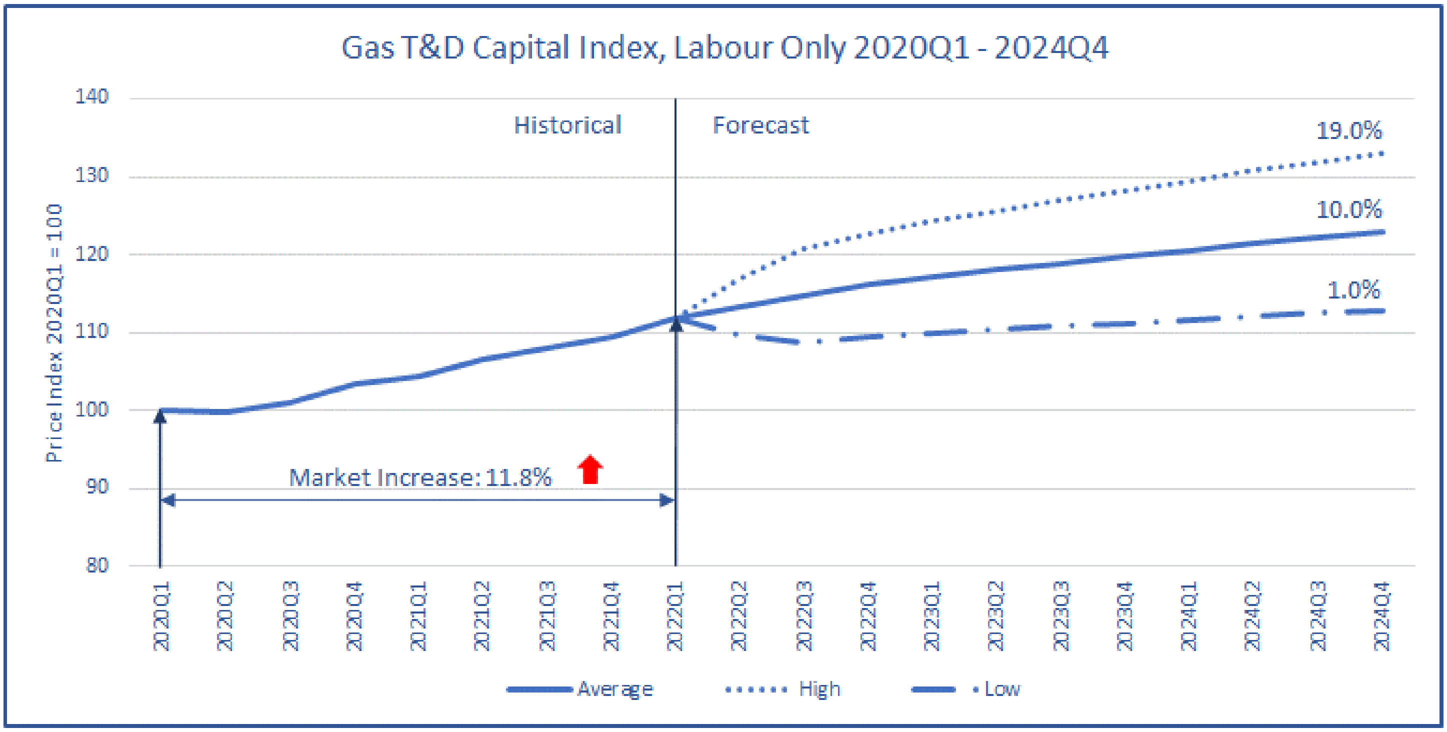
Gas Transmission and Distribution 2020Q1 – 2024Q4



*This graph includes an aggregate of multiple indices, including both labour and material cost components.
**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

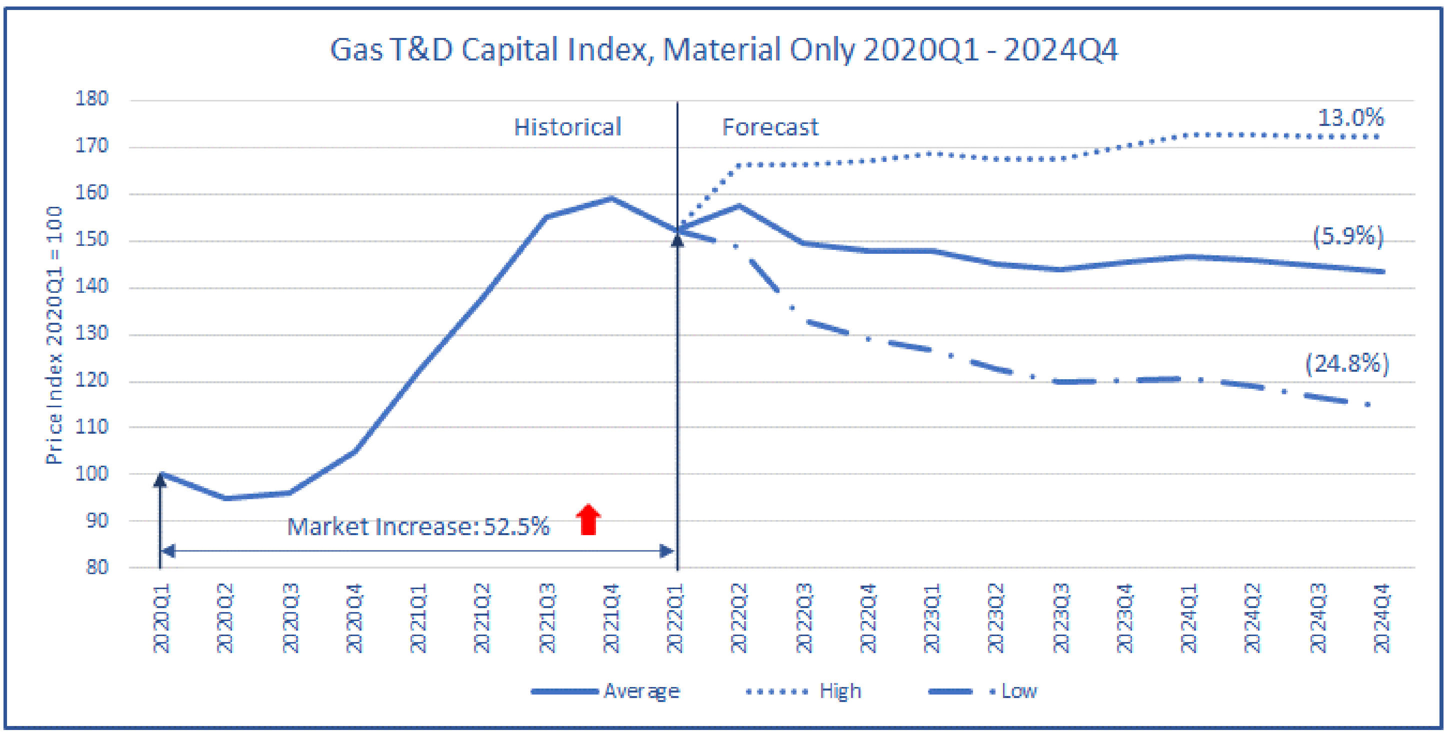
Since execution of FortisBC's MRP (Q1 2020 – Q1 2022), market factors have caused an escalation in capital costs for gas T&D of 31.2%. Forward-looking forecasts for Q1 2022 – Q4 2024 average 1.2%. Table 2 shows the ten most impactful commodities and services in the gas T&D model, and their individual escalations since the beginning of the MRP. Sharp increases in steel and aluminum prices starting in Q3 2020 drove escalations through Q3 2021. Prices of steel and aluminum have leveled off since Q4 2022 which is reflected in the forecast through 2024. The total market split for Gas T&D Construction between labour and materials is 44% and 56% respectively. Labour costs are expected to continue to rise, while material costs are expected to drop slightly, driven by declining steel prices.

Gas Transmission and Distribution - Labour 2020Q1 – 2024Q4



**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

Gas Transmission and Distribution - Material 2020Q1 – 2024Q4



**Forecasted percentage increases or decreases are based on index 2022Q1 = 100

Table 2. Gas T&D High-impact Commodities and Services

Gas T&D High Impact Commodities and Services	Q1 2020 – Q2 2022 Escalation (%)
AHE: Construction, Private, Compensation, BC	10.8
SPM: Steel Plate, Cut-to-Length	173.7
SPM: Steel, Hot-Rolled Coil	117.3
PPI: Hand and Edge Tools	2.7
PPI: Commercial and Industrial Machinery and Equipment Rental	(2.2)
AHE: Professional, Scientific and Technical Services, BC	11.6
SPM: Steel Plate, Coiled	117.3
AHE: Architectural and Finishing Trades, Basic Construction, BC	1.4
AHE Manufacturing, BC	9.8
PPI: Metal Building and Construction Materials, Canada	51.1

AHE: Average Hourly Earnings, SPM: Spot Price Metal, PPI: Producer Price Index

Pre-MRP Market Escalations

The market conditions for both electric and gas T&D vary significantly from the five years prior to the execution of the MRP. Table 3 uses the same models as above to observe the market between Q1 2015 through Q4 2019. Two years (2015 and 2019) experienced a decrease in market price, and the total escalations over this period were 7.6% and 7.5% for electric T&D and gas T&D, respectively.

Table 3. Annual Market Adjustments for Electric and Gas T&D

Year Q1 – Q4	Electric T&D Market Change (%)	Gas T&D Market Change (%)
2019	(0.2)	(3.6)
2018	1.0	4.5
2017	1.8	1.2
2016	4.1	3.6
2015	(1.7)	(3.5)

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Appendix C2

Project Descriptions for Forecast Sustainment Capital

July 2022

Table of Contents

List of Tables and Figures

1. INTRODUCTION

In this appendix, FEI provides descriptions of sustainment capital projects over $2 million. As described in Section 7 of the Application, FEI's sustainment capital is divided into the following portfolios:

1. Customer Measurement
2. Transmission System Reliability & Integrity
3. Distribution System Reliability
4. Distribution System Integrity

The projects over $2 million in each of these categories are described below.

2. CUSTOMER MEASUREMENT

There are no projects over $2 million that have been completed or are planned to be completed during the MRP term.

3. TRANSMISSION SYSTEM RELIABILITY & INTEGRITY

The Transmission System Reliability & Integrity capital category includes activities related to the ongoing safe and reliable operation of the transmission system. The main areas of expenditure under this category include:

- Pipeline alterations to mitigate the threat of natural hazards, comply with codes and standards, and facilitate maintenance and inspections;
- Alterations to transmission facilities, including pressure control, compression, and LNG to ensure safe, reliable, and efficient operation; and
- Pipeline major inspections including inline inspections and marine crossing inspections.

The table below shows the original spend profile of the projects greater than $2 million in this category during the MRP term, as provided in the MRP Application[1].

[1] MRP Application, Section 3.3.2.1.2, Table C3-10, p. C-68.

Table C2-1: FEI Transmission System Reliability & Integrity Capital Expenditures on Projects Greater than $2 million in MRP Application ($000s)

	Portfolio	2020	2021	2022	2023	2024
Grand Forks to Trail 273 Pipeline Alteration	Pipeline Alterations	3,480	109			
V1 Compressor Unit 1, 2 & 3 Engine Overhaul and Emissions Reduction to 15 PPM	Compressor Unit Overhauls	-	278	2,468	2,435	2,708
TIlbury LNG Air Cooler Upgrade	LNG Plant Alterations	-	-	-	3,184	-
5 Year Turnaround at Tilbury LNG Expansion	LNG Plant Alterations	-	-	612	1,873	-
Huntingdon to Nichol In Line Inspection	Pipeline Inspections	-	-	-	2,760	-

The table below shows the updated forecast spend profile of the projects greater than $2 million in this category during the MRP term.

Table C2-2: Updated FEI Transmission System Reliability & Integrity Capital Expenditures on Projects Greater than $2 million ($000s)

	Portfolio	2020	2021	2022	2023	2024
Grand Forks to Trail 273 Pipeline Alteration	Pipeline Alterations	350	5,094	70	-	-
5 Year Turnaround at Tilbury LNG Expansion	LNG Plant Alterations	-	120	4,194	50	-
V1 Compressor Unit 1, 2 & 3 Seal Gas GHG Emissions Reduction	Compressor Station Alterations	-	10	70	2,090	10
V3 Compressor Engine Overhaul	Compressor Unit Overhauls	-	-	5	2,023	12
Savona Compressor Fire Protection	Compressor Station Alterations	-	15	51	51	1,968
River Road Valve Assembly – New Valve & Automation	Pipeline Alterations	70	240	45	615	3,325
Savona to Vernon 323 Pipeline SN-1-1 Valve Assembly Upgrade	Pipeline Alterations	-	50	5	520	1,763
Lantzville New TP / DP Station	Pipeline Station Alterations	-	115	900	1,401	3,480

Each of these projects is described further below.

- **Grand Forks to Trail 273 Pipeline Alteration:** The replacement of approximately 2.7 km of the Grand Forks to Trail pipeline was completed in 2021 to increase safety in response to population encroachments around the pipeline. The actual costs of this project were approximately $5.5 million with the bulk of capital expenditures occurring in 2021.

- **V1 Compressor Unit 1, 2 & 3 Engine Overhauls:** This project involves the regularly scheduled compressor overhaul of the engines at V1 Compressor Station based on run time hours. This project has been deferred as units 1 and 2 have not reached the run-time required for overhaul. The timing of unit 3 is being scheduled to align with other projects and optimizing the use of a spare engine. This project is therefore not included Table C2-2.
- **Air Cooler Upgrade at Tilbury LNG:** The boil off fan at the Tilbury LNG facility is the original installed and is showing signs of corrosion. Further analysis was conducted, and repair or replacement options were evaluated. As other equipment on site was decommissioned, it was determined that the capacity of the current cooling system was adequate, and the current corrosion risk did not result in any operational concerns. It was therefore determined that the project could be cancelled. This project is thus not included in Table C2-2.
- **5 Year Turnaround at Tilbury LNG Expansion:** The pressure vessels at the Expanded Tilbury LNG Facility are currently undergoing inspection as per the five-year inspection plan. The inspection will require drawing down the plant, depressurizing and isolating each pressure vessel, cleaning the vessels and performing inspections, and recommissioning the plant. The plant is expected to be offline for one to two weeks. The estimated cost of this project is approximately $4.4 million with spending primarily in 2022.
- **Huntingdon to Nichol ILI:** The Huntingdon to Nichol pipeline will undergo in-line inspection using Magnetic Flux Leakage (MFL), Circumferential Magnetic Flux Leakage (CMFL) and Geometry tools as per the seven-year inspection program for this pipeline. The estimated cost of this project has been reduced to $0.940 million in 2023 and is therefore not included in Table C2-2.
- **V1 Compressor Unit 1, 2 and 3 Seal Gas GHG Emissions Reductions:** The *Drilling and Production Regulation* under the *Oil and Gas Activities Act* was recently amended and seal gas emissions need to be reduced to comply with the amended regulation. This will involve upgrading the existing seal gas system to have a methane emissions recapture system. The estimated cost of this project is approximately $2.1 million with spending primarily in 2024.
- **V3 Compressor Unit Overhaul:** This project involves the regularly scheduled compressor overhaul of the engine at V3 Compressor Station based on run time hours. This project was previously planned to be completed in the MRP term; however, initial cost forecasts had the total project costs estimated less than $2 million. The estimated cost of this project is approximately $2 million with spending primarily in 2023.
- **Savona Compressor Fire Protection:** This project involves installing a foam fire suppression system, nitrogen fire suppression system, and fire, gas and heat detector

upgrades in the control building of Savona Compressor. The estimated cost of this project is approximately $2.1 million with spending primarily in 2024.

- **River Road Valve Assembly – New Valve & Automation:** FEI has identified River Road Station as a location for a new mainline block valve that would allow remotely actuated security shutdown. The valve addition is meant to enable isolation of the TIL FRA 508 pipeline crossing of the Fraser River in case of emergency. The estimated cost of this project is $4.3 million with spending primarily in 2024.

- **Savona to Vernon 323 Pipeline SN-1-1 Valve Assembly Upgrade:** The Savona to Vernon NPS 12 diameter transmission pressure pipeline runs from the Savona compressor station to Vernon block valve station. Within the Savona compressor station yard, there is a station bypass valve, SN1-1, installed below grade that has an active leak. This valve is normally closed, and the leak is allowing gas to bypass the closed valve and enter piping that is intended to be shut in. The valve is required to be upgraded to an above grade ball valve, with a modern actuator and associated accessories. A bypass must be installed to complete this installation. The estimated cost of this project is $2.4 million with spending primarily in 2024.

  Lantzville New TP / DP Station: Development within the Lantzville area of Nanaimo is currently expanding, and developers have plans to install a total of 750 residential units. FEI has determined that a new TP/DP station is required to supply the community due to additional loads. The new station will also address tail end pressure on the Northwest side of Nanaimo, provide alternative pressure sources to the system, and reduce the need for IP looping within Nanaimo. The estimated cost of this project is $6 million with spending primarily in 2023 and 2024.

4. DISTRIBUTION SYSTEM RELIABILITY

Distribution System Reliability expenditures consist primarily of new pressure control stations or improvements to existing pressure control stations due to condition, load change, obsolescence and regulatory compliance. Also included in this category are alterations or improvements to distribution telemetry installations and distribution sectioning valves.

The table below shows the original spend profile of the projects greater than $2 million in this category during the MRP term, as provided in the MRP Application.[2]

[2] MRP Application, Section 3.3.2.1.3, Table C3-11, p. C-69.

Table C2-3: FEI Distribution System Reliability Capital Expenditures on Projects Greater than $2 Million in MRP Application ($000s)

	Portfolio	2020	2021	2022	2023	2024
240 St & 102 Ave Station - Insufficient Capacity	Distribution Stations Alterations	260	2,184	78	-	-
SI - 1850m x 168 IPST McLeod	Distribution System Capacity Alterations	-	53	2,351	-	-
SI - 1300m x 323 IPST Riverside	Distribution System Capacity Alterations	-	-	-	51	3,536
Penticton Second Supply	Distribution Stations New	2,100	-	-	-	-

The table below shows the updated forecast spend profile of the projects greater than $2 million in this category during the MRP term.

Table C2-4: Updated FEI Distribution System Reliability Capital Expenditures on Projects Greater than $2 Million ($000s)

	Portfolio	2020	2021	2022	2023	2024
Penticton Second Supply	Distribution Stations New	12	6	130	300	4,750
Bradner & Downes New District Station	Distribution Stations New	-	65	130	200	2,429
Richmond IP River Road to Cambie Rd Capacity Upgrade	Distribution System Capacity Alterations	280	33	115	200	3,200

Each of these projects is described further below.

- **240 St. & 102 Ave. Station, Maple Ridge – Insufficient Capacity:** The station vault at 240 St. & 102 Ave. Station is approaching its first run capacity limit and requires upgrades to continue to serve customers in the area. Due to issues finding a suitable location for the new station, FEI is considering alternative solutions to the capacity constraints of Maple Ridge System as a whole. This project is therefore not included in Table C2-4.
- **SI – 1850m x 168 IPST McLeod, Chilliwack:** This system is experiencing significant load growth and is expected to require a system improvement in order to meet growing capacity demands. This upgrade involves installation of 1850m of 168 IPST from Yale Rd to Chilliwack Central Rd parallel to the existing 114mm DP main. Due to the precise location of growth in the Chilliwack system, FEI has been able to reschedule this work for outside the MRP term. This project is therefore not included in Table C2-4.
- **SI – 1300m x 323 IPST Riverside, Abbotsford:** This upgrade involves looping the existing 168mm IP with 1300m of 323mm STIP on Riverside Road from Hallert Road to Grace Road. Due to the precise location of growth in the Abbotsford system, FEI has been able to reschedule this work for outside the MRP term. This project is therefore not included in Table C2-4.

- **Penticton Second Supply:** The City of Penticton and surrounding area are currently supplied through a single station. This project includes the installation of a second source of supply for the Penticton area to ensure reliable service to customers. Due to difficulties acquiring land in this area, the project has been delayed. The estimated cost of this project is approximately $5.2 million in 2024.
- **Bradner & Downes New District Station:** Due to increased demand in the Abbotsford area, a new station is required to meet future capacity needs. FEI will install a new IP/DP station at or near the intersection of Bradner Road and Downes Road in Abbotsford. In addition, the project scope includes increasing the operating pressure of the existing pipeline on Bradner Road from 420 kPa to 1900 kPa. This pipeline will serve as the gas supply to the new station. The estimated cost of this project is approximately $2.8 million with spending primarily in 2024.

Richmond IP River Road to Cambie Road Capacity Upgrade: Due to increased demand in the Richmond area, low tail end pressures have been forecast, resulting in capacity shortfalls at the end of the Richmond distribution network. FEI will install additional IP pipe in the River Road area of Richmond to provide additional capacity in the area. The estimated cost of this project is approximately $4.9 million, with the majority of costs forecast in 2024.

5. DISTRIBUTION SYSTEM INTEGRITY

Distribution System Integrity expenditures consist primarily of main and service alterations and replacements due to condition or at the request of third parties.

The table below shows the original spend profile of the projects greater than $2 million in this category during the MRP term, as provided in the MRP Application[3].

Table C2-5: FEI Distribution System Integrity Capital Expenditures on Projects Greater than $2 Million in MRP Application ($000s)

	Portfolio	2020	2021	2022	2023	2024
NW Kamloops Secondary Supply	Distribution Main Alterations	-	-	542	3,315	11

The table below shows the updated forecast spend profile of the projects greater than $2 million in this category during the MRP term.

[3] MRP Application, Section 3.3.2.1.4, p. C-72.

Table C2-6: Updated FEI Distribution System Integrity Capital Expenditures on Projects Greater than $2 Million ($000s)

	Portfolio	2020	2021	2022	2023	2024
Main Renewal – Moncton Street, Richmond	Distribution Mains Renewal	24	240	2,260	140	-
Second Narrows Shorted Flange Upgrade	Distribution System Cathodic Protection	27	212	655	2,680	30
Highway 97 Quesnel River Bridge Crossing Replacement	Distribution Mains Alterations	-	10	255	104	2,784
Highway 11 Main Alteration – 3rd Party Alteration	Distribution Main Alterations	-	42	4,044	10	-

Each of these projects is described in further detail below:

- **NW Kamloops Secondary Supply:** The North-West Kamloops distribution system is currently supplied by a single IP gas pipeline, through the City of Kamloops. FEI will install a secondary supply to NW Kamloops by installing an IP pipeline across the North Thompson River at Rayleigh to Westsyde and install a new IP/DP district station on Westsyde Road to support the distribution system. A variety of options exist for the pipeline route and further investigation is required to narrow down the project details. This project is therefore not included in Table C2-6.
- **Main Renewal – Moncton Street, Richmond:** Approximately 1.9 km of vintage steel DP pipe in Richmond is planned to be renewed with PE pipe to address integrity concerns with this aging infrastructure. This project was previously planned for completion within the MRP term; however initial cost forecasts had the total project costs estimated less than $2 million. This project was competitively bid, and project costs have escalated to $2.6 million, with the majority of expenditures occurring in 2022.
- **Second Narrows Shorted Flange Upgrade:** A pair of isolating flanges on the IP pipeline feeding North Vancouver and West Vancouver at the south abutment of the Second Narrows Bridge have shorted, resulting in a section of pipeline no longer receiving adequate cathodic protection. This IP pipeline is the sole gas supply to customers on the North Shore. The recommended solution is to remove and replace a short spool of piping at the south abutment. Cathodic protection will be reinstalled. Due to suspected corrosion issues at the existing anchor block at the location, the construction work will additionally install a new anchor block downstream of the current location. Significant site preparation will be required to provide adequate site access for the personnel and equipment required to complete mechanical construction activities. The IP pipeline will be locally isolated, and a bypass tool will be installed to maintain gas flow during construction. The estimated cost of this project is approximately $3.6 million, with the majority of expenditures occurring in 2023.

- **Highway 97 Quesnel River Bridge Crossing Replacement:** The Ministry of Transportation and Infrastructure has informed FEI that the Quesnel River Bridge on Highway 97 will be replaced. A 2020 inspection of the bridge has identified that the pipe wall thickness is deteriorating rapidly, and that the pipe hangers are in poor condition. FEI is planning to replace the existing bridge crossing with a horizontal directional drill crossing. The estimated cost of this project is approximately $3.2 million, with the majority of expenditures forecast in 2024.
- **Highway 11 Main Alteration:** The City of Abbotsford and the Ministry of Transportation and Infrastructure are widening Highway 11, and have requested that FEI relocate approximately 1.2 km of DP 114 mm main to accommodate this widening. The estimated cost of this project is approximately $4.1 million, with the majority of expenditures occurring in 2022.

Appendix C3

Gibsons Capacity Upgrade Business Case

July 2022

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1. PROJECT OVERVIEW AND BACKGROUND

1.1 *OVERVIEW*

FEI is planning to construct the Gibsons Capacity Upgrade (GCU) project, which consists of the installation of a slow filling peak shaving Compressed Natural Gas (CNG) facility in Gibsons. Its purpose will be to create extra capacity in the system by generating and storing CNG during periods of low gas demand to supplement the system during periods of high demand. The purpose of the GCU project is to provide a cost-effective long-term capacity solution to address the current capacity shortfall in the Gibsons community. The total Class 3 cost estimate for the project is $12.194 million, which is below FEI's Certificate of Public Convenience and Necessity (CPCN) threshold. FEI is therefore seeking approval of the GCU as a Major Project in this Annual Review pursuant to section 44.2(3) of the *Utilities Commission Act*.

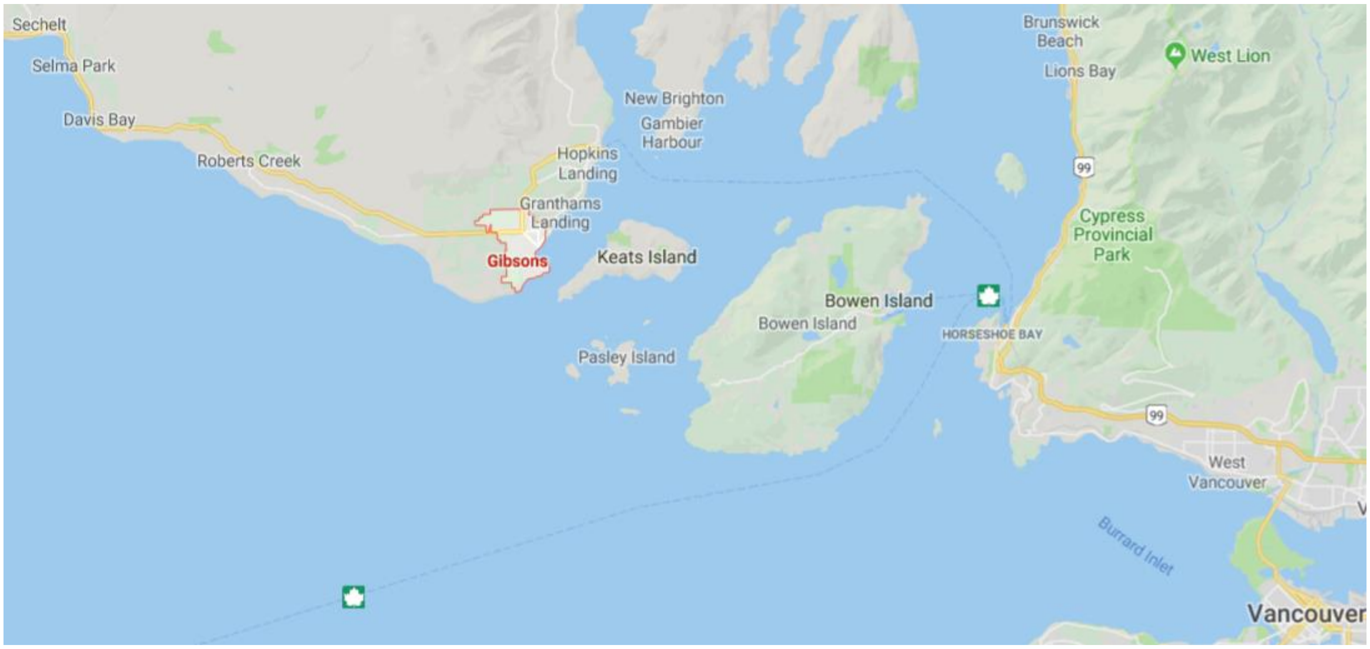
The proposed schedule for this project is for the detailed design and engineering to be completed in 2022 and the facility construction completed in 2023, with an in-service date of October 1, 2023. Final site works and project close out will occur in 2024.

1.2 *BACKGROUND*

Gibsons is a coastal community with a population of approximately 5,000 in the southern part of the Sunshine Coast. Historically, Gibsons' population has been augmented by seasonal summer travelers but has overall seen a slow rate of growth. In recent years the booming housing market in the Lower Mainland has meant that the population of Gibsons (where housing has been less costly, but still within a reasonable commute from the Lower Mainland) has grown more quickly than it has historically. As a result, FEI is currently unable to supply sufficient capacity to the community during design conditions without the support of a temporary contracted CNG trailer on site during winter months.

Figure C3-1 shows the location of Gibsons and its proximity to the Lower Mainland. Since there is no road access to the Mainland, Gibsons is typically accessed via Horseshoe Bay Ferry Terminal.

Figure C3-1: Location of Gibsons, BC



Since 1990, the Gibsons area has been serviced by a 20 km 88 mm Intermediate Pressure (IP) pipe that starts at the town of Sechelt (shown in the upper left corner of Figure C3-1 above). The IP pipe operates at 3,100 kPag which is the standard IP pressure for the Vancouver Island and Sunshine Coast system. Currently there is insufficient inlet pressure available to the Gibsons District Station during FEI design conditions. FEI has been managing this shortfall through the current availability of higher than contracted heating values present in the natural gas network, and by contracting a CNG trailer to be available on short notice during winter months to supplement low inlet pressures at the Gibsons District Station.

2. ALTERNATIVES ANALYSIS

FEI undertook an alternatives analysis to address the capacity shortfall requirements. The three alternatives identified were as follows:

Alternative 1:

- Install 10.2 km of 168 mm (NPS 6) IP pipe between Sechelt and Gibsons.
- Repurpose the existing 10.2 km of 88 mm IP pipe between Sechelt and Gibsons by downgrading it to distribution pressure and connecting it to the Sechelt Distribution Pressure (DP) system.

Alternative 2:

- Install a TP/IP/DP Control Station at Port Mellon Compression Station (V3). This alternative has two options:
  - **Option A:** Install 11.1 km of IP pipe from the V3 station to the north part of Gibsons, IP/DP station in Gibsons, and 4.4 km of DP pipe.
  - **Option B:** Install 9.1 km of IP pipe from the V3 station to the north part of Gibsons, IP/DP station in Langdale, and 7 km of DP pipe.

Alternative 3:

- Install a peak shaving CNG facility near the current Gibsons District Station to generate and store CNG during periods of low gas demand to supplement the system during periods of high demand. The facility outlet will be tied into the existing 168 mm DP system. Two potential locations were identified for the peak shaving CNG station – one location off of the IP system and one location off of the DP system.

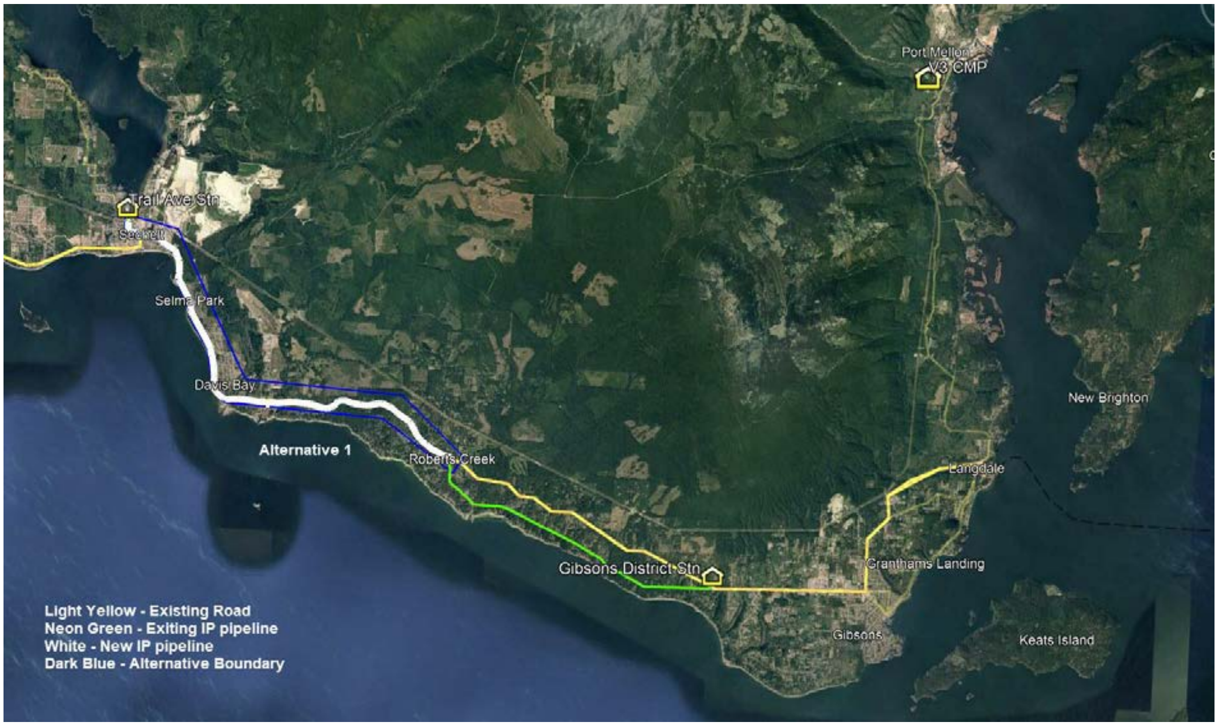
The three alternatives were evaluated based on criteria in the following categories: (i) Community & Stakeholder; (ii) Environmental; (iii) Construction; (iv) Asset Management; and (v) Cost, using a weighted-scoring methodology to evaluate each alternative. Based on the results of the evaluation, Alternative 3 was identified as the preferred alternative.

Each alternative is described further below.

2.1 *ALTERNATIVE 1: PIPELINE REPLACEMENT SECHELT TO GIBSONS*

Alternative 1, as shown in Figure C3-2 below, includes replacing a minimum of 10.2 kilometres of the existing 88 mm IP with 168 mm IP between Sechelt and Gibsons. This would increase the capacity available in the system, ensuring sufficient inlet pressure at Gibsons District Station based on the 20 year capacity forecast.

Figure C3-2: Alternative 1 Routing



The new 168 mm IP pipe would start at Trail Avenue Gate Station in Sechelt and end approximately 150 metres southeast of the Pell Road & Sunshine Coast Highway intersection in Roberts Creek. The proposed IP pipe would parallel the existing 88 mm IP line within the Sunshine Coast Highway road allowance. The 168 mm IP pipe would be connected to the existing 88 mm IP pipe, continuing to the existing Roberts Creek District Station and ending at the Gibsons District Station. With commissioning of the 168 mm IP pipe, the portion of the existing 88 mm IP pipe adjacent to the newly constructed 168mm IP pipe would be downgraded to distribution pressure and connected to the Sechelt distribution system. To accommodate the pipe size increase and the additional flow rates, station upgrades would be required at the Trail Avenue Control Station, Trail Avenue Gate Station, and Gibsons District Station. The Maximum Operating Pressure (MOP) of the new line would be 3,100 kPag.

The Class 4 capital cost estimate for this alternative is $48.3 million (2020$), including AFUDC and removal costs.

2.1.1 Key Features

- Installation of 10.2 km of new 168 mm IP pipe
- Repurpose the existing 88 mm as a DP main at Trail Avenue Station
- Facility upgrades at Trail Avenue Gate Station and Gibsons District Station

- 201 powerline crossings
- 29 road crossings
- 4 watercourse crossings
- 46 pipeline crossings

2.1.2 Advantages

- No incremental O&M costs as new infrastructure would be similar in scope to existing infrastructure.
- Easily accessed throughout construction.
- No additional land acquisition required.

2.1.3 Disadvantages

- Risk of negative public relations/community impact during the construction activity due to significant traffic impacts.
- Difficulty acquiring crossing permits for Chapman Creek due to cultural sensitivity and creek classification with environmental regulators. Chapman Creek is an identified Sensitive Stream under the *BC Fisheries Protection Act*, one of 15 in the Province.
- Potential for damaging existing Sechelt infrastructure due to close proximity during construction.
- The route must pass through the Sechelt First Nation Band Land. There is risk that the First Nation will not allow FEI to install any additional facilities on their land.

2.2 *ALTERNATIVE 2: CONTROL STATION AND PIPELINE PORT MELLON TO GIBSONS*

Alternative 2 involves construction of a new TP/IP/DP station at Port Mellon Compression Station (V3), and a 168 mm IP pipeline from V3 to the community of Gibsons. The MOP of the new pipeline would be 3,100 kPag. The Port Mellon Highway and a BC Hydro Statutory Right of Way (SRW) run approximately parallel along the proposed pipeline corridor. FEI's existing transmission SRW runs parallel to these 200 metre wide corridors for a portion of the route. The pipeline ROW utilizes portions of FEI's existing transmission SRW, BC Hydro's SRW, and the Port Mellon Highway corridor.

There are two potential endpoints (Option A and Option B) for this alternative. The first 8 km of the IP pipeline routing, from V3 to Hutchinson Creek, would be the same for both options.

2.2.1 Option A: Port Mellon to Hutchinson Creek: Langdale Creek to Gibsons Station

As shown in Figure C3-3 below, Option A for Alternative 2 would continue southwest of Hutchinson Creek to Langdale Creek where a new IP/DP station would be installed adjacent to the Sunshine Coast Highway turnout. The new DP pipeline would be routed throughout the city of Gibson and terminate at the tie-in location at Payne Road and Sunshine Coast Highway. The total length of Alternative 2, Option A would be 11.1 km of IP pipeline and 4.4 km of DP pipeline.

Figure C3-3: Alternative 2 Option A Routing

The Class 4 capital cost estimate for this alternative is $35.4 million (2020$), including AFUDC and removal costs.

2.2.1.1 Key Features

- Installation of a new TP/IP/DP station at V3;
- Installation of a new IP/DP Station in Gibsons;
- Installation of 11.1 kilometres of new IP 168 mm pipe;
- Installation of 4.4 kilometres of new DP 168 mm pipe;
- 110 powerline crossings;

- 26 road crossings;
- 37 watercourse crossings; and
- 8 pipeline crossings.

2.2.1.2 Advantages

- Results in supply to Gibsons and Sechelt communities from two separate IP pipelines in two separate locations, increasing security of supply;
- The Port Mellon Highway has limited traffic; impacts to traffic will be unlikely to cause concern in the community; and
- Moderate incremental O&M costs due to new pipeline in a new location.

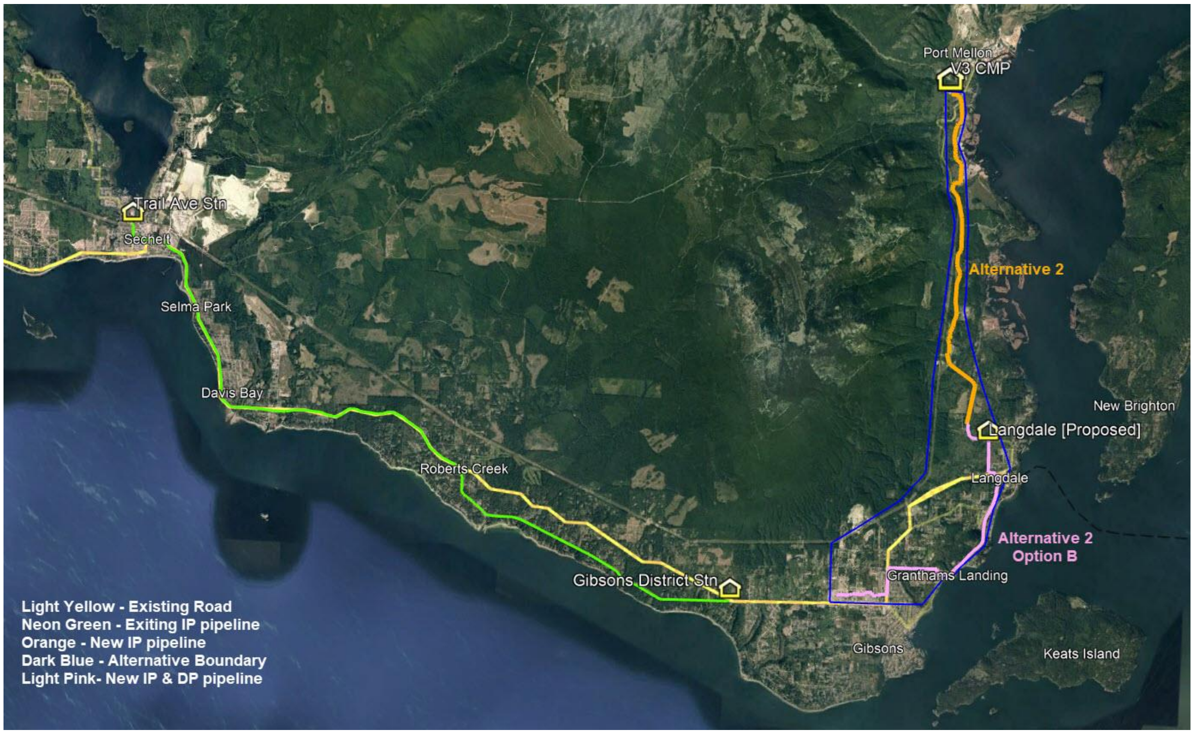
2.2.1.3 Disadvantages

- 19 HDD crossings;
- Limited space within V3 for the TP/IP station;
- Potential for difficult land acquisition near Hutchinson Creek;
- High ground water table could affect trench stability; and
- Land acquisition required for new IP/DP District station.

2.2.2 Option B: Hutchinson Creek to Langdale

As shown in Figure C3-4 below, Option B for Alternative 2 would follow the Port Mellon Highway to the new IP/DP station north of the town of Langdale. The new DP pipeline would be routed along Marine Drive and then through a residential area to Chamberlin Road then west through the city of Gibsons to the tie in location at Payne Road and Sunshine Coast Highway. The total length of Alternative 2, Option B would be 9.1 km of IP pipeline and 7 km of DP pipeline.

Figure C3-4: Alternative 2 Option B Routing



The Class 4 capital cost estimate for this alternative is $40.9 million (2020$), including AFUDC and removal costs.

2.2.2.1 Key Features

- Installation of a new TP/IP/DP Station;
- Installation of a new IP/DP Station in Langdale;
- Installation of approximately 9.1 kilometres of new IP 168 mm pipe;
- Installation of approximately 7 kilometres of new DP 168 mm pipe;
- 161 powerline crossings;
- 26 road crossings;
- 41 watercourse crossings; and
- 9 pipeline crossings.

2.2.2.2 Advantages

- Results in supply to Gibsons and Sechelt communities from two separate IP pipelines in two separate locations, increasing security of supply;
- The Port Mellon Highway has limited traffic; impacts will be unlikely to cause concern in the community; and
- Moderate incremental O&M costs due to new pipeline in a new location.

2.2.2.3 Disadvantages

- 21 HDD crossings;
- Limited space within V3 for the TP/IP station;
- Potential for difficult land acquisition near Hutchinson Creek'
- High ground water table could affect trench stability; and
- The DP route is near several sites on the shore with high potential for archaeological finds.

2.3 ALTERNATIVE 3: CNG PEAK SHAVING STATION

Alternative 3 is a slow filling peak shaving facility. The facility would draw gas from the gas system during periods of low system demand, compress it and store it in high-pressure storage vessels. During periods of high gas demand, the stored gas would be depressurized, heated, and injected back into the 168 mm DP system to supplement the supply. This is the same principle used for the Tilbury and Mount Hayes peak shaving facilities, but on a smaller scale, utilizing different technology.

Two locations were considered during the Class 4 study for the proposed CNG station. One potential location (called the IP Station) is 6 kilometres west of Gibsons just off Lower Road and is shown in Figure C3-5 below. The other location (called the DP station) is 2 kilometres north of Gibsons just off the Sunshine Coast Highway and is shown in Figure C3-6 below. FEI selected the DP station property due to its immediate proximity to the existing 168 mm DP main, which reduces the length of DP main extension work that needs to be done to tie the station into the DP system.

Figure C3-5: Alternative 3 IP Station Location

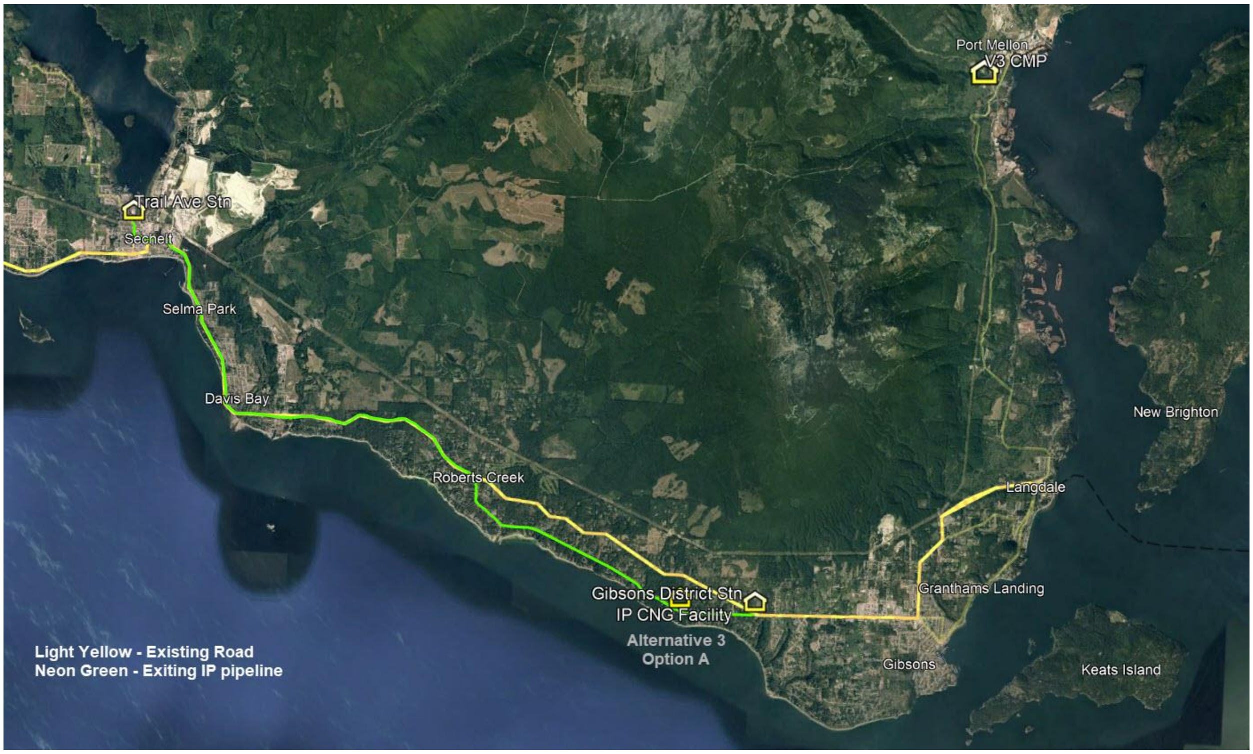
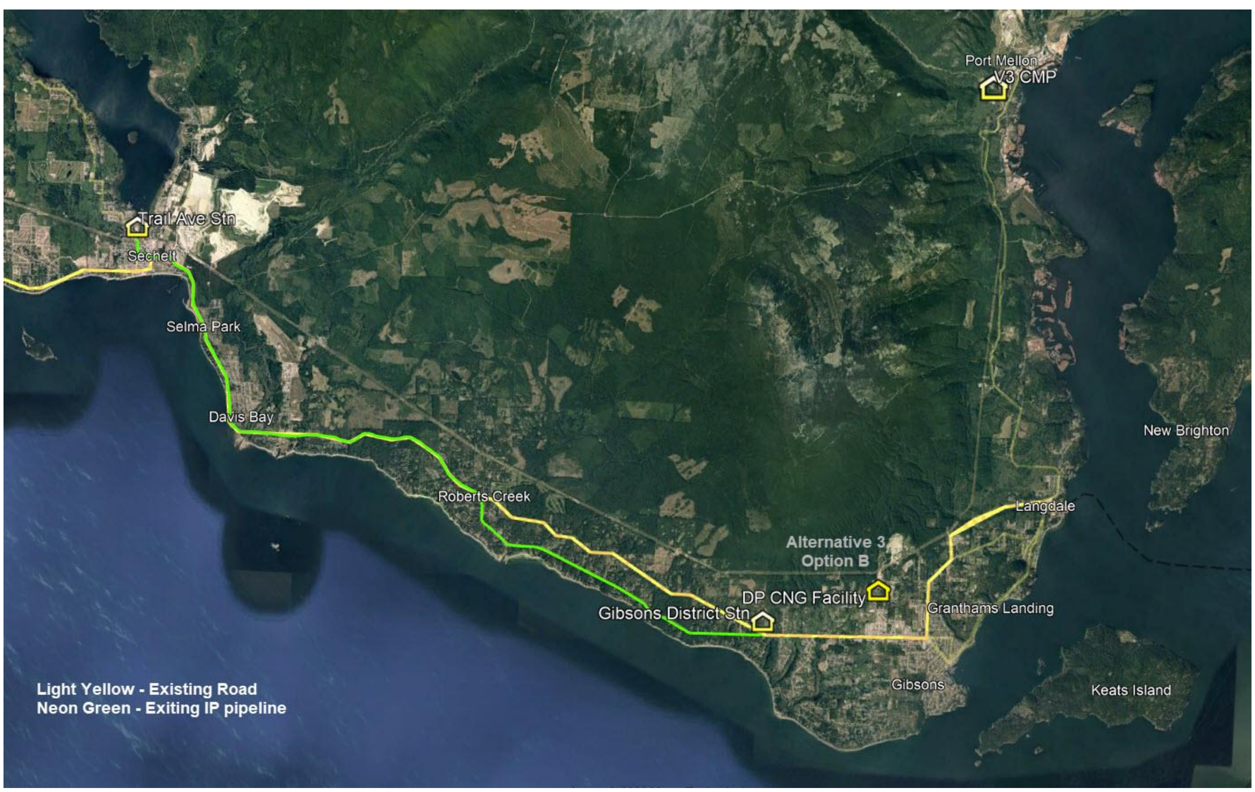


Figure C3-6: Alternative 3 DP Station Location



As demand in Gibsons increases, additional storage capacity would be required. Two storage vessels would be installed initially with additions tentatively planned in 2037 and 2042 based on current projections. At this stage, the design does not include commercial CNG supply or truck filling capability.

The Class 4 capital cost estimate for this alternative is $8.9 million (2020$), including AFUDC and removal costs.

2.3.1 Key Features

- A gas dryer skid with a single-tower desiccant dryer;
- 2 x 100% compressor skids with electric-driven reciprocating CNG compressors;
- 4 x 1,945 Sm^3 CNG storage vessels with gas management panel;
- 2 x 100% pressure reduction skids with natural gas-fired water bath heater and metering;
- Dual main-monitor regulator runs;
- Decant post with connection port to a CNG transport trailer in case of an emergency outage;
- Natural gas backup generator;
- MCC building and storage shed; and
- 50 square metres of new land required.

2.3.2 Advantages

- Opportunity to implement new technology within FEI as a non-pipe solution to a capacity shortfall;
- Minimizes amount of new pipeline required, and maximizes utilization of existing assets; and
- Significantly lower cost than the other alternatives.

2.3.3 Disadvantages

- Insufficient capacity for commercial/industrial load growth beyond what is included the SCP 20-year forecast. At some point beyond the 20-year forecast, there will be inadequate off peak capacity available for filling; and
- Higher O&M costs than other options due to use of new technology, and maintenance requirements for this type of facility.

2.4 COST SUMMARY AND RATE IMPACTS

Tables C3-1 and C3-2 below summarize the Class 4 cost estimates and the present value of the incremental revenue requirement over a 64-year analysis period[1] for each option. It can be seen that Alternative 3 is significantly less expensive in terms of both the project capital costs and the incremental revenue requirement over the long-term than the other alternatives.

Table C3-1: Class 4 Capital Cost Estimate Summary ($ millions)

Particular ($ millions)	Alternative 1: Sechelt to Roberts Creek	Alternative 2A: Port Mellon to Gibsons	Alternative 2B: Port Mellon to Langdale	Alternative 3: CNG Peak Shaving Station
Project Services	14.700	6.600	5.800	1.500
Engineering	3.400	3.200	3.600	0.600
Pipline Construction	22.100	18.600	21.400	0.900
Facilities Construction	1.000	2.000	2.000	4.200
Removal Costs	0.500	-	-	-
Contingency	6.600	4.800	8.200	1.600
Total Capital Costs ($ millions)	**48.300**	**35.200**	**41.000**	**8.800**

Table C3-2: Summary of Financial Analysis

Particular ($ millions)	Alternative 1: Sechelt to Roberts Creek	Alternative 2A: Port Mellon to Gibsons	Alternative 2B: Port Mellon to Langdale	Alternative 3: CNG Peak Shaving Station
Total Capital Costs ($ millions)	48.300	35.200	41.000	8.800
Incremental Annual O&M ($ millions)	-	0.016	0.016	0.112
PV of Incremental Revenue Requirement; 64 years, excl. O&M ($ millions)	52.400	38.500	44.400	12.400
PV of Incremental O&M; 64 years ($ millions)	-	0.300	0.300	2.300
PV of Total Incremental Revenue Requirement; 64 years ($ millions)	**52.400**	**38.800**	**44.700**	**14.700**

2.5 ALTERNATIVES EVALUATION AND RECOMMENDATION

FEI applied a weighted-scoring methodology to evaluate the performance of each alternative in relation to the evaluation criteria. The score computed for each alternative was recommended and validated by FEI internal subject matter experts for each alternative, and a sensitivity analysis was conducted. The components of the evaluation methodology are described as follows:

<u>Community & Stakeholder</u>

The factors evaluated within this category are as follows:

[1] 64-year analysis period includes 60 post-project years and 4 project years.

- Health and Safety: considers the risks to the community, stakeholders, employees, and contractors during construction of the pipeline or station;
- Traffic Impacts: considers the direct and indirect effects of the project on traffic and commercial/residential access during construction of the pipeline or station; and
- Socio-Economic: considers the effect of the project on the cultural values, economic well-being and daily life for local stakeholders and citizens during construction of the pipeline or station.

Environmental

The factors evaluated within this category are as follows:

- Ecology: considers the impact during construction of the pipeline to the environment including environmentally sensitive areas in and around the project site and long-term detrimental impacts to the surrounding environment (e.g., vegetation, soil, watercourses); and
- Cultural Heritage: considers the impact during construction that could cause damages to known archaeological and culturally sensitive areas.

Construction

The factors evaluated within this category are as follows:

- Engineering: considers the use of non-routine and/or complex solutions or methods, novel integration of otherwise proven processes, or implementation of non-commercially proven equipment in similar applications to meet statutory codes, regulations and project objectives;
- Construction: considers the requirement for non-standard higher risk construction techniques, construction footprint, fabrication, and procurement;
- Lands and Right-of-Way Impacts: considers the complexity and risk associated with various lands-related factors such as acquisition of temporary and/or permanent land rights; and
- Project Execution Certainty: considers the impact of compounding risks associated with each of the criteria in Community & Stakeholder, Environmental, and Construction categories. Additionally, considers the likelihood of receiving the necessary permits to proceed with the alternative.

Asset Management

The factors evaluated within this category are as follows:

- Operation and Maintenance: considers long-term impacts and complexity including those to employees and contractors to maintain the asset integrity and complete maintenance and repairs;
- System Resiliency and Capacity: considers the ability to maintain gas supply during unplanned disruptions within acceptable parameters. Also considers longevity of gas supply beyond the design lifetime of the pipeline; and
- Natural Hazards: considers the vulnerability during operation of the pipeline and built facilities to natural hazards including seismic impacts, ground contamination, tree root encroachment, washout, etc.

Cost

The factor evaluated within this category is as follows:

- Cost: considers the least cost project solution that meets community, environmental, and asset management while cognizant of impacts to the rate base.

2.5.1 Development of the Selection Criteria Weighting

The development of the selection criteria weighting discussed below was determined in collaboration with various FEI business unit subject matter leads. These FEI business units were comprised were Project Management, Engineering, Asset Management, Property Services, Regulatory, Community & Indigenous Relations, Environmental & Archeology, Joint Health & Safety, System Capacity Planning, Integrity Management, and Operations. The final weighting was determined by the following steps;

1. The 12 non-financial evaluation criteria were arranged in a table, both in a vertical manner and again in a transposed horizontal line. Then row by row, each vertical criterion was compared to a criterion found in the horizontal line and either was assigned a “more” or “less” value to determine the level of importance the criterion has to the project.
2. Once the table was filled out, the total scores for each criterion that had the “more” value selected was determined.
3. Based on the total score result, each criterion was assigned a rank number ranging from 1-12. The largest total score found in Step 2 above was assigned the lowest rank value and the smallest total score was assigned the largest rank value. If numerous criteria had the same total score, their rank value was the same and any sub-sequential numbering was skipped.
4. A pre-determined weighting section of 5 percent, 10 percent, or 15 percent was assigned as follows to the ranking values determined in Step 3: rank 1-3 was assigned 15 percent; rank 4 and 5 was assigned 10 percent; and the remaining ranks (6-12) were assigned 5 percent.

Upon completion of the scoring of the non-financial criteria, the financial implications of each alternative were considered. The Present Value of Total Incremental Revenue Requirement for each alternative was compared to the alternative with the lowest revenue requirement to determine a relative financial impact for each alternative.

To calculate a final score in a benefit-to-cost ratio manner, FEI divided the non-financial score by the relative financial impact. FEI uses a similar value to cost ratio methodology when comparing sustainment capital projects.

Table C3-3 shows the results for each alternative when utilizing the weighted-scoring methodology.

Table C3-3: Scored Selection Criteria

Criteria	Weighting	Alternative 1 Sechelt to Gibsons		Alternative 2 Port Mellon to Gibsons		Alternative 3 CNG Peak Shaving	
Criteria Weighting	**Weight**	**Raw Score**	**Weighted Score**	**Raw Score**	**Weighted Score**	**Raw Score**	**Weighted Score**
Community & Stakeholder							
Health & Safety	10	1	0.1	2	0.2	2	0.2
Traffic Impacts	5	1	0.05	3	0.15	2	0.1
Socio-Economics	5	1	0.05	3	0.15	2	0.1
Environmental							
Ecology	5	1	0.05	2	0.1	2	0.1
Cultural Heritage	5	1	0.05	2	0.1	2	0.1
Construction							
Engineering	5	3	0.15	3	0.15	2	0.1
Construction	5	1	0.05	2	0.1	3	0.15
Lands & Right of Way	5	1	0.05	2	0.1	2	0.1
Project Execution Certainty	10	1	0.1	2	0.2	2	0.2
Asset Management							
Operations &Maintenance	15	3	0.45	2	0.3	1	0.15
System Resiliency & Capacity	15	2	0.3	3	0.45	1	0.15
Natural Hazards	15	2	0.3	1	0.15	3	0.45

Criteria	Weighting	Alternative 1 Sechelt to Gibsons	Alternative 2 Port Mellon to Gibsons		Alternative 3 CNG Peak Shaving
Total (A)	100	**1.7**		**2.15**	**1.9**
Non-Financial Ranking		**3**	**1**		**2**
Financial Criteria					
Alternatives			**Option A**	**Option B**	
PV of Total Incremental Revenue Requirement ($millions)		$52.400	$38.800	$44.700	$14.700
Relative Financial Impact (B)		3.56	2.64	3.04	1.00
Combined Financial & Non-Financial Score (A/B)		0.48	0.81	0.71	1.90
Combined Ranking		**4**	**2**	**3**	**1**

All alternatives provide a long-term capacity solution to address the current capacity shortfall in the Gibsons community and meet the project objectives. Based on the results of the non-financial criteria found in Table C3-3 above, Alternative 2 is ranked highest. However, the disparity in the PV of the Total Incremental Revenue Requirement between the alternatives is substantial, and Alternative 3 has a significantly lower revenue requirement than the other alternatives. By dividing the non-financial rankings by the relative financial impact, Alternative 3 becomes the recommended alternative for the GCU project.

Upon completion of the Class 4 study used in the above alternatives analysis, FEI progressed Alternative 3 to an AACE Class 3 level of development and cost estimate, and selected the DP site located off the Sunshine Coast Highway on Keith Road. The Class 3 cost estimate is provided in Section 4 below.

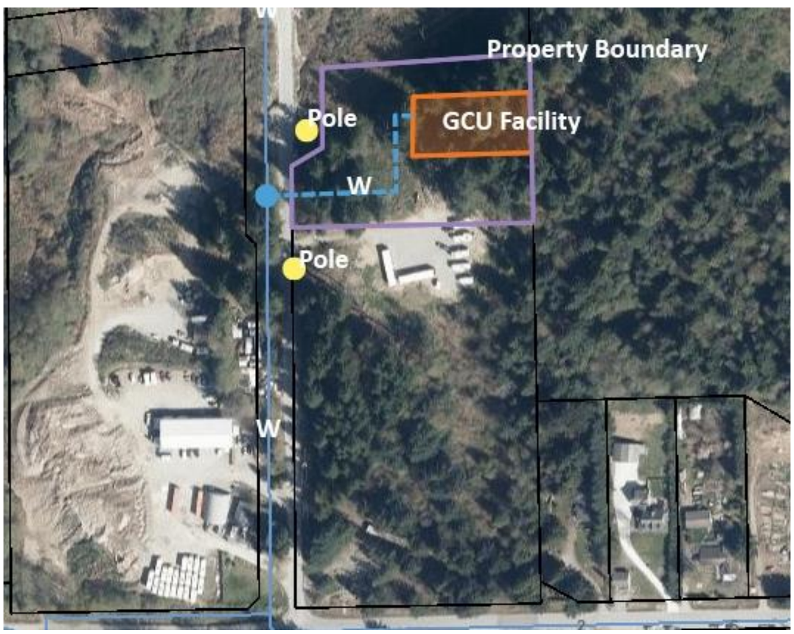
3. PROJECT DESCRIPTION

The GCU project consists of a slow filling peak shaving facility and associated tie-ins to the existing network. The facility will draw gas from the 168 mm DP network during periods of low system demand, compress it, and store it in high-pressure storage vessels. During periods of high gas demand, the stored gas will be depressurized, heated, and injected back into the DP system to supplement the supply.

3.1 *FACILITY LOCATION*

As shown in Figure C3-7 below, the facility will be located on the north end of Keith Road and be tied into the existing 168 mm DP system and will draw and return gas to the same location. This property was selected for its immediate proximity to the existing 168 mm DP main. This reduces the length of DP main extension work that needs to be done to tie the station into the DP system.

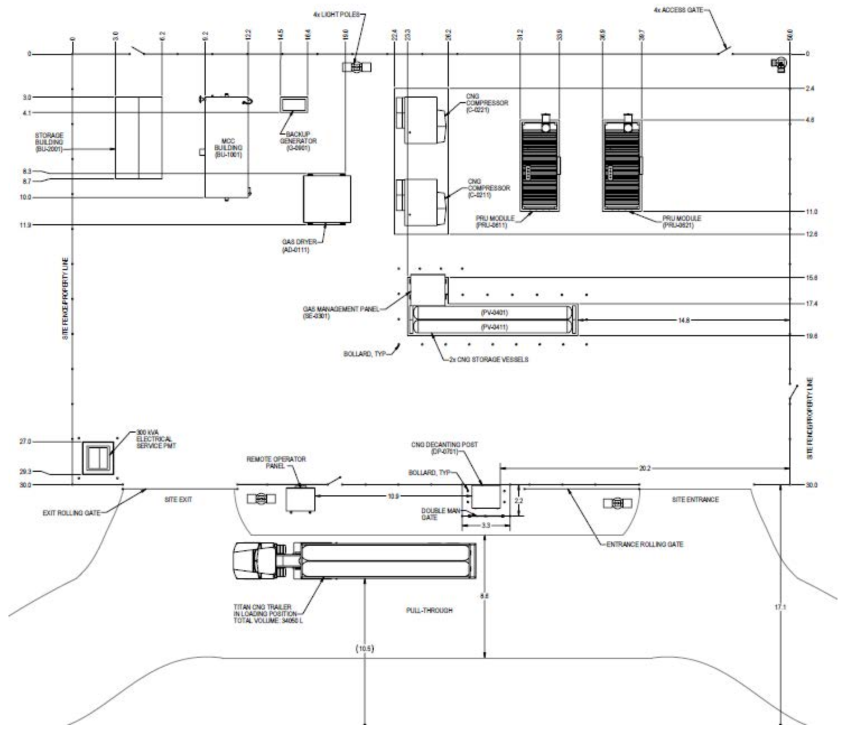
Figure C3-7: Future Site of GCU Slow Filling Station



3.2 *STATION WORK*

As demand in Gibsons increases, additional storage capacity will be required. The proposed site layout (Figure C3-8) accommodates additional storage vessels to be installed. The design does not include commercial CNG supply or truck filling capability, as it was determined there is limited to no demand for this on the Sunshine Coast at this time.

Figure C3-8: Proposed Site Arrangement of GCU Slow Filling Station



The key features of the station design include:

- A gas dryer skid with a single-tower desiccant dryer;
- 2 x 100% compressor skids with electric-driven reciprocating CNG compressors;
- 4 x 1,945 Sm^3 CNG storage vessels with gas management panel;
- 2 x 100% pressure reduction skids with natural gas-fired water bath heater and metering;
- Decant post with connection port to a CNG transport trailer in case of an emergency outage;
- Natural gas backup generator;
- Motor Control Centre building and storage shed;
- Washroom facility and septic tank;
- 30 m x 50 m facility footprint on newly acquired 2.65 acre property; and
- Site access road with a 30-metre truck turning area adjacent to the facility.

3.3 GCU PROJECT RISK MANAGEMENT

Preliminary risk assessment interviews were completed with representatives from Operations, External Relations, Environment, PMO, Engineering, Asset Management, System Integrity, Procurement, Regulatory, OHS Health & Safety, SCP, Property Services and the engineering consultants.

Early in the Class 3 phase, land was identified as a significant risk. Private land has been secured, removing the biggest source of uncertainty from the GCU project.

4. GCU PROJECT COST ESTIMATE AND PROJECT SCHEDULE

The estimate is a Class 3, as defined by the AACE International Estimate Classification. This Class of estimate is considered a study or feasibility cost estimate with an expected level of accuracy of -20% to +30% for feasibility. AACE bases the accuracy ranges on the extent of the project design.

4.1 *COST ESTIMATE SUMMARY*

The cost estimate is summarized in Table C3-4 below.

Table C3-4: Class 3 Capital Cost Estimate ($ millions)[2]

Particular	$ millions
Project Development	1.600
Project Management	1.218
Engineering	1.089
Pipeline Construction	0.247
Facilities Construction	5.986
Project Capital Costs	**$ 10.140**
Contingency	0.832
Escalation	0.320
AFUDC	0.902
Total Project Costs	**$ 12.194**

4.2 *GCU PROJECT SCHEDULE*

Table C3-5 below shows the preliminary project schedule and Table C3-6 shows the expenditure profile of the respective calendar year.

Table C3-5: Preliminary Project Schedule

	2021				2022				2023				2024			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Alternative 3																
Class 3 & 4 Studies																
Procurement																
Engineering																
Construction																
Final Site Clean Up Closing																

2 The cost for the land discussed in Section 3.1 above is included in the Project Management category, with closing and final payment in the first part of 2022.

Table C3-6: Spend Profile ($ millions)

	Prior Years Actuals	2022 Projected	2023 Forecast	2024 Forecast	Total
Preliminary Development (Deferred Costs)	0.978	-	-	-	0.978
Project Capital	0.794	2.380	6.950	0.190	10.314
Subtotal ($ millions)	**1.772**	**2.380**	**6.950**	**0.190**	**11.292**
AFUDC	0.018	0.129	0.457	0.298	0.902
TOTAL Project Costs ($ millions)	**1.790**	**2.509**	**7.407**	**0.488**	**12.194**

5. ENERGY OBJECTIVES AND LONG TERM RESOURCE PLAN

Under section 42(5) of the UCA, in considering whether to accept an expenditure schedule filed by a public utility other than the authority, the commission must consider:

a) the applicable of British Columbia's energy objectives,

b) the most recent long-term resource plan filed by the public utility under section 44.1, if any,

c) the extent to which the schedule is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act* (CEA),

d) if the schedule includes expenditures on demand-side measures, whether the demand-side measures are cost-effective within the meaning prescribed by regulation, if any, and

e) the interests of persons in British Columbia who receive or may receive service from the public utility.

Sections 6 and 19 of the CEA, as referred to in (c) above, do not apply to FEI, and paragraph (d) is not relevant to the GCU Project. With regard to (a), British Columbia's energy objectives do not have any particular bearing on the GCU Project given the relatively small scale and scope of the Project.

Regarding paragraphs (b) and (d), the GCU Project is identified in Section 7.5.3.4 of FEI's 2022 Long Term Gas Resource Plan, and FEI submits that the material in this business case supports the conclusion that the GCU Project is in the interest of persons in British Columbia.

6. CONCLUSION

FEI respectfully submits that the GCU project is a necessary, cost-effective solution to address the current capacity shortfall in the Gibsons community. Based on the evaluation of all feasible alternatives, Alternative 3 with a CNG peak shaving station provides the best solution that would allow FEI to meet all project objectives and requirements at the lowest cost. The station is scheduled to be in service by December 2023, with project completion and close-out by early 2024.

Appendix D

PRIOR YEAR DIRECTIVES

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
G-79-14 – FEI 2014 CORE MARKET ADMINISTRATION EXPENSE (CMAE) BUDGET						
1.	10	2	CMAE Budget Review	The Panel finds that the appropriate review process for the CMAE Budget is as part of the FEI revenue requirements applications. Therefore, until such time as FEI files its next revenue requirements application, the Panel directs FEI to submit future CMAE budgets separately to the Commission at least two weeks prior to the fourth quarter gas cost report to allow the Commission sufficient time to review the CMAE Budget, and to determine if there are sufficient variances from the previous CMAE Budget to warrant a more fulsome review. The Panel directs that the CMAE Budget review and approval process be included within the FEI revenue requirements application starting with the next such application by FEI.	Ongoing	Appendix B
G-165-20 – FEI MULTI-YEAR RATE PLAN FOR 2020 THROUGH 2024						
2.	75	24	General Flow-through Deferral Account	The Panel directs FEI to provide a detailed analysis of the individual forecast variances recorded in the Flow-through deferral account in each Annual Review.	Ongoing during the MRP term	Section 12.4.2
3.	87	32	Efficiency Carry-Over Mechanism	Therefore, the Panel determines the following process for the handling of an ECM application: 1. An ECM can be applied for at any time in the last three years of the MRPs, either in advance or following the action or initiative being undertaken. 2. For proposed activities where identifiable savings are expected to extend beyond the term of the MRP, FortisBC is to file an ECM proposal describing the initiative, its timing, costs and benefits and savings. 3. Parties will have the opportunity to review and comment on the proposal and the BCUC will determine whether to approve the ECM proposal (an Approved ECM Initiative). 4. FortisBC must submit details of continued savings annually under an Approved ECM Initiative as part of the Annual Review process. The net savings will be shared equally between ratepayers and the Utilities will carry forward past the end of the MRP for a maximum period of three years.	No Approved ECM Initiative to report on	n/a

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
4.	99-100	37	SQI Informational Indicators	In addition to the SQIs, the Panel approves the following informational indicators for the Utilities: • Customer Satisfaction Index (measures overall customer satisfaction) – FEI and FBC. • Average Speed of Answer (average number of seconds to answer emergency and non-emergency calls) – FEI and FBC. • Transmission Reportable Incidents (number of reportable incidents to outside agencies) – FEI only. • Leaks per KM of Distribution System Mains (number of leaks on the distribution system per KM of distribution system mains) – FEI only. The Utilities are directed to report on these informational indicators along with the SQIs as part of the Annual Review process.	Ongoing during the MRP term	Section 13
5.	115	40	Systems Operations, Integrity and Security Expenditures	The Panel directs FEI to provide the following information related to System Operations, Integrity and Security expenditures in its future revenue requirements applications over the term of the Proposed MRPs: 1. A breakdown and explanation of both annual and cumulative variances between forecast/actual and formula O&M related to System Operations, Integrity and Security expenditures, which quantify the variances attributable to the following areas: • Integrity management; • Maintaining system infrastructure; • Operations compliance and safety; • Cyber security; • Data analytics; • Gas control; • Canadian Energy Pipelines Association (CEPA) participation; and • Any other significant factors or miscellaneous items. 2. A description of how FEI is prioritizing its System Operations, Integrity and Security expenditures.	Ongoing during the MRP term	Section 6.2.1
6.	131	49	Forecast Capital Expenditures	The Panel directs FortisBC to file an updated forecast of the 2023 to 2024 capital expenditures in the 2023 Annual Review.	Complete	Section 7.2.1
7.	157	62	Innovation Fund	The Panel further directs FEI to include progress preports on the operation of FEI's Innovation Fund and projects funded thereby.	Ongoing during the MRP term	Section 10.3.3.

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
G-319-20 – FEI ANNUAL REVIEW FOR 2020 AND 2021 DELIVERY RATES						
8.	11		Revenue Deficiency	The Panel directs FEI to present the amortization of flow-through and other deferral accounts separately from depreciation and amortization in future Annual Reviews.	Ongoing during the MRP term	Section 1.5
9.	16	9	CMAE Budget	The Panel directs FEI to include, in it next revenue requirements or MRP application following the MRP term, a comprehensive review of the CMAE costs including consideration of whether these costs are conducive to a formulaic approach or whether they should continue to be forecast with flow-through treatment, and whether the current allocation percentages to the CCRA and MCRA remain appropriate.	Will be reviewed in FEI's next Revenue Requirements or MRP application	n/a
10.	17	10	COVID-19 Customer Recovery Fund Deferral Account	FEI is approved to record COVID-19 incremental costs and related savings from 2020 and 2021 into the previously approved COVID-19 Customer Recovery Fund Deferral Account as discussed in Section 12.2.1 of the Application.	Status of COVID-19 exogenous factor treatment provided in this Application	Section 12.2.1

Appendix E

DRAFT ORDER

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ORDER NUMBER
G-xx-xx

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc.
Annual Review for 2023 Delivery Rates

BEFORE:
A. K. Fung, QC, Panel Chair
W. M. Everett, QC, Commissioner
B. A. Magnan, Commissioner

on Date

ORDER

WHEREAS:

A. On June 22, 2020, the British Columbia Utilities Commission (BCUC) issued its Decision and Order G-165-20 approving a Multi-Year Rate Plan (MRP) for 2020 through 2024 (2020-2024 MRP Decision) for FortisBC Energy Inc. (FEI). In accordance with the 2020-2024 MRP Decision, FEI is to conduct an annual review (Annual Review) process to set the delivery rates for each year;

B. By letter dated June 28, 2022, FEI proposed a regulatory timetable for the Annual Review of its 2023 delivery rates;

C. By Order G-194-22 dated July 15, 2022, the BCUC established the regulatory timetable for the Annual Review of FEI's 2023 delivery rates, which included FEI filing its Annual Review materials, intervener registration, one round of information requests, a workshop, FEI's response to undertakings at the workshop, and written final and reply arguments;

D. On July 29, 2022, FEI submitted its materials for the Annual Review for 2023 Delivery Rates Application (Application). In the Application, FEI requests a 7.42 percent delivery rate increase over the 2022 delivery rates, effective January 1, 2023, among other things; and

E. The BCUC has reviewed the Application, evidence and arguments filed in the proceeding and makes the following determinations.

NOW THEREFORE pursuant to sections 44.2(3), 59 to 61, 89 and 99 of the *Utilities Commission Act*, for the reasons stated in the decision issued concurrently with this order, the BCUC orders as follows:

1. FEI is approved to recover the 2023 revenue requirement and resultant delivery rate change on an interim basis, effective January 1, 2023, as filed in the Application and subject to any adjustments identified by FEI during the regulatory process and from any directives or determinations made by the BCUC in its decision on the Application. Delivery rates will remain interim pending the outcomes of Stage 1 of the BCUC's current generic cost of capital (GCOC) proceeding and FEI's 2023 Demand Side Management (DSM) Plan proceeding.

2. The level of forecast sustainment and other capital to be incorporated in rates for the years 2023 and 2024, as set out in Section 7.2.1, is approved.

3. FEI is approved to:

    a. Create a rate base deferral account titled the Gibsons Capacity Upgrade (GCU) Preliminary Stage Development Costs deferral account and amortize the deferral account over three years commencing January 1, 2023;

    b. Amortize the existing COVID-19 Customer Recovery Fund Deferral Account over three years commencing January 1, 2023;

    c. Change the amortization period of the existing Emissions Regulations deferral account from five years to one year, commencing January 1, 2023.

4. FEI is approved to cease reporting on the COVID-19 Customer Recovery Fund Deferral Account.

5. FEI is approved to set the Biomethane Variance Account Rate Rider for 2023 in the amount of $0.132 per gigajoule (GJ) as calculated in Section 10.3.1.

6. FEI is approved to set the Revenue Stabilization Adjustment Mechanism riders for 2023 in the credit amount of $0.209 per GJ as set out in Table 10-5 in Section 10.3.2.

7. FEI's 2023 Core Market Administration Expense (CMAE) budget of $5.795 million is approved, as set out in Schedule 1 of Appendix B, and FEI is approved to continue to allocate the CMAE costs between FEI's Commodity Cost Reconciliation Account and Midstream Cost Reconciliation Account at 30 percent and 70 percent, respectively.

8. The capital expenditure schedule for the Gibsons Capacity Upgrade Project, as described in Section 7.2.3.2.2 and in Appendix C3, is accepted.

9. Directive 10 of Order G-319-20 is varied as follows: "FEI is approved to record COVID-19 incremental costs and related savings from 2020 and 2021 into the Flow-through deferral account".

10. Directive 2 of Order G-83-14 is varied as follows: "Approval is granted until such time as FEI no longer has an exemption to prepare and file its financial statements in accordance with US GAAP or is no longer reporting under US GAAP for financial reporting purposes".

11. FEI is directed to file as a compliance filing the finalized financial schedules and tariff continuity and billing impact schedules for 2023 no later than 10 days from the date of the issuance of this order.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner