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July 28, 2023

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

Attention: Patrick Wruck, Commission Secretary

Dear Patrick Wruck:

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 2024 Delivery Rates

In accordance with the MRP Plan and BCUC Order G-194-23 setting out the Regulatory Timetable for FEI's Annual Review, FEI hereby attaches its Annual Review for 2024 Delivery Rates Application materials.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Registered Interveners in the FEI Annual Review for 2023 Delivery Rates proceeding.

FortisBC Energy Inc.

Multi-Year Rate Plan for 2020 through 2024

Annual Review for 2024 Delivery Rates

July 28, 2023

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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 $6.989 million[1] in earnings sharing to customers in 2024.

The proposed delivery rates for 2024 flowing from the approved formulas and forecasts set out in the Application, including returning the actual 2022 earnings sharing to customers, result in a 4.50 percent delivery rate increase from 2023 delivery rates. After consideration of the delivery rate riders, the annual bill impact is an increase of approximately $45.18 or 4.21 percent for a residential customer.[2] The increase is primarily due to higher income tax expense, amortization of FEI's deferral accounts, and formula-driven O&M expenses, partially offset by increases in revenue due to growth in customers and volume, and reduced earned return due to a reduction in FEI's rate base. These drivers are further explained in Section 1.5.

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 2022 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 2024 and a summary of the SQI results. These matters are addressed in more detail in subsequent sections of the Application.

1.2 APPROVALS SOUGHT

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

1. Approval to recover the 2024 revenue requirement and resultant delivery rate change on a permanent basis, effective January 1, 2024, as filed in the Application and subject to

[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 $31.50 or 2.93 percent.

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.

2. The following deferral account approvals as described in Section 7.5:
   - Creation of rate base deferral accounts for the following regulatory proceedings:
     - 2025 Multi-year Rate Plant (MRP) Application, with the amortization period to be determined in a future proceeding;
     - 2023 Cost of Service Allocation (COSA) Study, with the amortization period to be determined in a future proceeding;
     - 2024-2027 Demand Side Management (DSM) Expenditure Plan Application, with amortization over a four-year period commencing January 1, 2024; and
     - PST Rebate on Select Machinery and Equipment, with amortization over a one-year period commencing January 1, 2024.
   - Approval of a one-year amortization period for the existing Transportation Service Report deferral account, commencing January 1, 2024.
3. A Biomethane Variance Account (BVA) Rate Rider for 2024 in the amount of $0.181 per gigajoule (GJ) as calculated in Section 10.3.1.2.
4. Revenue Stabilization Adjustment Mechanism (RSAM) riders for 2024 in the credit amount of $0.106 per GJ as set out in Table 10-5 in Section 10.3.2.
5. Fort Nelson Residential Customer Common Rate Phase-in Rate Rider for 2024 in the amount of $0.863 per GJ as calculated in Section 10.3.3.
6. The 2024 Core Market Administration Expense (CMAE) budget of $6.050 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.

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
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 10.3.4
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 2022 Formula O&M Savings

For 2022, 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 $7.3 million, excluding the COVID-19 pandemic approved exogenous factor credit for net O&M cost reductions of approximately $3.9 million.

Of the approximate $7.3 million in formula O&M savings realized in 2022, approximately $2 million are due to savings achieved as the result of productivity initiatives, including the Willingdon Park Redesign, Paperless Billing Customer Campaigns, and Operational Field Excellence[3], which were described in the Annual Review for 2023 Delivery Rates. Additionally, approximately $3 million of the overall O&M savings are due to estimated general overall labour savings. The remaining savings are the result of various factors, including: $0.3 million in lower spending compared to the formula amount for incremental expenditures related to System Operations, Integrity and Security (refer to Section 6.2.1 for further details); $0.4 million of lower employee expenses, $0.5 million of lower spending on Connect to Gas rebates due to lower customer participation; and savings due to general timing of expenditures. While some of the savings are one-time in nature (e.g., required time to fill vacancies from turnover), 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 described in FEI's Annual Review for 2022 Delivery Rates, 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 productivity initiatives. Following is a summary of these productivity initiatives.

1. **Operational Field Excellence:** This initiative targets improvements to overall field operations efficiency through better prioritization of emergency repairs, improved work planning and reducing low value activities such as wait times and pulled work orders. In 2022, FEI provided Operations Excellence training to all Regional Managers, Operations Managers and Operations Supervisor-Field employees. This training was designed to improve efficiency in the field and is now complete. In addition, in 2022 FEI conducted a data-driven analysis on the after-hour shift schedules of emergency responses, and optimized leak survey frequency of its special premises in some regions. These improvement initiatives resulted in annual O&M savings for FEI of approximately $0.4 million in 2022.

2. **Methane Leak Detection**: FEI executed a robust satellite-based methane leak detection pilot in 2022. The successful pilot confirmed the technology's capabilities of methane detection on above ground assets, and potential customer driven home emissions and appliance emissions for commercial and industrial customers. Another highlight from the pilot was understanding the required number and ideal time of year for data captures. The critical outstanding question from the pilot remains understanding the ability to

[3] Two phases to date for Operational Field Excellence initiative, 2021 and 2022, totaling to approximately $0.9 million in annual O&M savings.

detect methane leaks on below ground assets. Due to a low volume of below ground leaks within the pilot area, the technology's capability could not be verified with reasonable accuracy. Below ground leak detection capabilities must be adequate before implementation of any scale can take place. An overall financial assessment, alongside the below ground leak detection capability, are the primary focuses of this project moving forward. FEI is encouraged with the results of the pilot and maintains the goal of partial or full implementation of the technology in the future.

3. **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. FortisBC uses data to inform decision making, but its current data is spread across dozens of disparate systems. Data is often siloed within departments and the volume, variety, and velocity of data coming into FortisBC is increasing. It can be difficult and time consuming to gather, clean, and filter the data needed to create useful information. As part of the solution, Enterprise Analytics creates a data fabric atop core FortisBC source and storage systems to facilitate advanced analytics opportunities. It addresses key barriers by integrating existing data into a single, scalable platform to deliver easily accessible and reliable data. It also simplifies connecting data assets to reduce cost and effort to create reports that can be easily updated and enables automation of reporting. Enterprise Analytics enables improvement in key performance indicators selected by each business area, and provides enhanced data quality, and work efficiency. Benefits are realized from shared information and sharing of insight across business units. Additionally, quality assurance is better enabled as information is reconciled and standardized.

   In 2022, efforts focused on developing solutions for two business areas in FEI: Customer Service and Major Projects. For Customer Service, Enterprise Analytics is delivering a new reporting dashboard displaying key Customer Service data all in one place (gas and electric). Benefits include providing a clear and easily accessible view of factors contributing to performance, insights identifying strengths and opportunities to grow FortisBC's relationships with its customers, operational savings through more efficient customer interactions, and less effort to share metrics with parties outside of customer service. This is only the starting point, as more data sources could be included, and new ways of using the dashboard will be discovered, providing the potential to optimize continuous improvement with additional available, integrated data. For the Major Projects area, Enterprise Analytics is enabling it to provide analytical insight through dashboarding and reporting on Major Projects project budgets, schedule overruns, and project development. FEI expects to realize total O&M savings of approximately $0.375 million by the end of 2025.

   Enterprise Analytics will also support streamlining existing reporting processes for financial and management reporting. Currently, the reporting processes work well with clearly defined requirements and processes but rely on manual effort. Enterprise Analytics provides an automated solution that reduces the effort required to generate reports, with expected productivity gains. This automation is achieved through the use of a data model to aggregate data sources and a reporting tool to allow for self-service. FEI plans to implement two or three automated reporting solutions in 2023.

4. **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.

   In 2022, the Company initiated the first phase of RPA implementation, working to automate several repetitive and manual processes in the Finance department and one in the Engineering department. The processes chosen were small, low-risk opportunities to introduce RPA to the organization. The first Finance process went into production in mid-2022 with others following throughout the remainder of the year. The Engineering process went into production in the first half of 2023. The automation of the Finance processes has resulted in: faster and more timely processing of monthly journal entries, allowing for earlier and increased analysis and review time; a shift in how time is spent, moving from data-entry-style rote work on several processes; a reduction in time spent reperforming work due to human errors; and an overall reduction in time spent on certain processes. The operational efficiency value gained by RPA is incremental but compounds as more processes are automated.

   In 2023, the Company is adding to automation within the Finance area as well as evaluating opportunities in other business areas to grow the RPA initiative. Additional process opportunities include populating Financial and Internal Audit reports and filings, application of customer bill payments, processing of rebate applications, onboarding of new users within IS systems, and automating manual document control processes within Engineering projects. A governance structure will also be established to prioritize and control RPA implementations, as well as ensuring that RPA implementations align with the overall business strategy and objectives, and that the necessary resources and support are available for successful implementation and ongoing maintenance of the automated processes. FEI expects to realize total O&M savings of approximately $0.075 million by the end of 2024.

5. **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 2022, FEI had approximately 524,000 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 36,000 customers choosing this option

in 2022. This increase equates to approximately $0.25 million in printing and postage cost savings in 2022 for FEI as compared to 2021.[4]

6. **Other Initiatives**: FortisBC is continuously looking for efficiencies and improvements in its activities, in a larger scale as the initiatives described above, or at a smaller scale as described in the following initiatives.

Mobile enabling applications: FortisBC has different initiatives to digitize forms and provide the ability to complete these forms on mobile devices in the field or office. Digitizing these forms supports effective data capture, and improves consistency, reliability, comprehension of data collected and reduces risk of manual errors. Additionally, it reduces the administrative efforts that occur with paper forms. FortisBC expects to realize minor savings by the end of 2023, and additional savings will be realized as FortisBC continues to mobile-enable and digitize other paper forms.

Automated patching: FortisBC has started taking advantage of technologies for automated patching. Moving to automated patching has streamlined the patching process for several applications in the FortisBC environment. With automated patching, the process can be scheduled to run during a more appropriate business outage window with no user involvement required. Repetitive tasks can be automated, eliminating human error, increasing productivity, and decreasing administrative costs. FortisBC expects to realize minor O&M savings by the end of 2023 with increased patch cadence and accuracy. Additional time savings will be seen as more systems transition to automated patching.

Other IS Initiatives: A High Availability (HA) operating environment enables applications to continue to operate even if one of the information technology components fails, and to ensure continuous operation and uptime. HA allows IS to schedule upgrades, patches, and release tasks during business hours, ultimately improving business operations and reducing overtime costs. IS has also expanded the use of automated testing. The expanded use of automation allows for an increase in system testing and improved product quality with a decrease in proportionate need for additional testing resources. Automation is expected to continue to expand in use at FortisBC in the future.

Customer Service Initiatives: Ongoing smaller initiatives include automating the tracking of collections and refund cases, and improving training materials for high volume call types. While on a smaller scale, these initiatives contribute to improving customers' experience with FortisBC and the Company maintaining a focus on being cost effective in its use of resources.

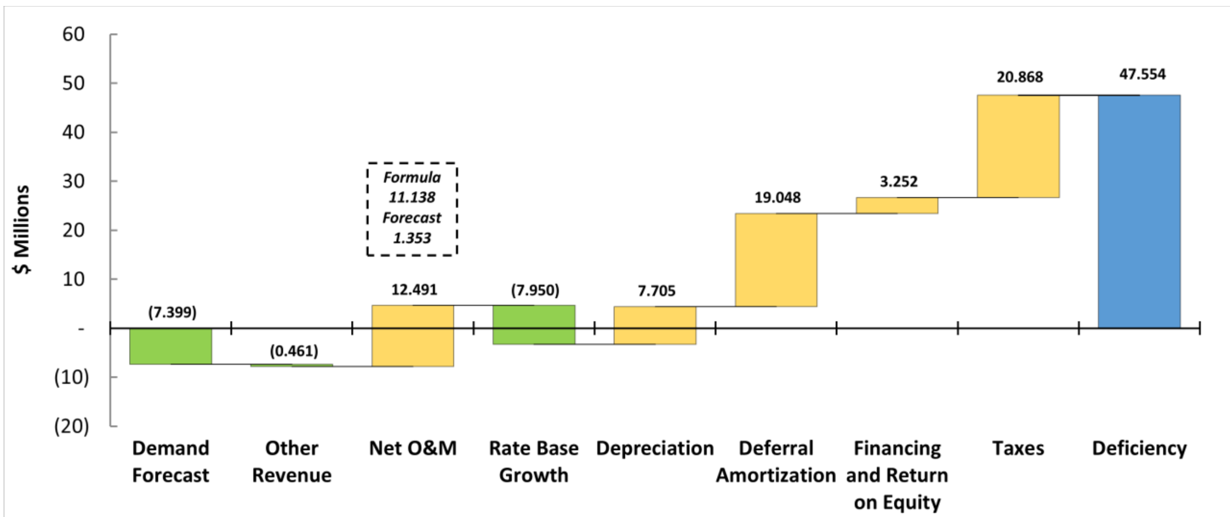
[4] Calculation is a high-level estimate based on the incremental monthly paperless billing growth at an average savings of approximately $1.09 per bill.

1.5 REVENUE REQUIREMENT AND RATE CHANGES FOR 2024

The revenue requirement components set out in the Application result in an effective delivery rate increase of 4.50 percent for 2024 compared to 2023 Approved. The effective delivery rate increase results from a revenue deficiency of $47.554 million.

The following chart summarizes the items that contribute to the 2024 revenue deficiency. The chart shows each item that increases the deficiency in yellow and each item that decreases the deficiency in green. The 2024 deficiency of $47.554 million is then the sum of all the previous bars and is shown at the end of the chart in blue.

Figure 1-1: 2024 Delivery Revenue Deficiency ($ millions)



Each of the categories is discussed briefly below.

1.5.1 Demand Forecast (Section 3)

In 2024, demand is forecast to decrease by approximately 1.6 PJ (or 0.72 percent) compared to 2023 Approved, primarily due to forecast decreases in Rate Schedule (RS) 46 Liquefied Natural Gas (LNG) and RS 22 large volume transportation bypass customers. These decreases are mostly offset by increases in demand from non-bypass residential, commercial, and industrial customers. Overall, FEI's 2024 Forecast margin at 2023 Approved rates is estimated to increase by approximately $7.399 million compared to 2023 Approved, primarily due to the increases in customers and demand from the non-bypass residential, commercial, and industrial customers, despite an overall reduction in demand due to RS 46 LNG and RS 22 bypass customers.

1.5.2 Other Revenue (Section 5)

Other Revenue is forecast to decrease the 2024 deficiency by approximately $0.461 million, primarily due to increases in the earned return associated with the City of Vancouver biomethane upgrading assets. NGT-related recoveries and late payment charges are also forecast to increase in 2024 when compared to 2023 Approved.

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 2024, the formula incorporates a net inflation factor of 3.854 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,[5] for a total increase in formula O&M of $13.259 million[6] (4.4 percent) from 2023 Formula O&M. O&M forecast outside of the formula is increasing by $2.301 million[7] (4.2 percent) compared to 2023 Approved. The 2024 increase in total O&M expense net of capitalized overhead and Biomethane O&M transferred to the BVA is $12.491 million.

1.5.4 Rate Base Growth (Section 7)

The 2024 rate base is forecast to decrease by approximately $127.531 million when compared to the 2023 Approved rate base, which results in a decrease to the 2024 Forecast earned return and the 2024 deficiency of approximately $7.950 million. The decrease in rate base is primarily due to decreases in the mid-year balance of FEI's deferral accounts by approximately $214.107 million and working capital by $38.619 million when compared to 2023 Approved. The decrease in the mid-year balance of FEI's deferral accounts is primarily due to the credit balances of the MCRA and CCRA, driven by strong mitigation performance by FEI at the end of 2022 as well as favourable forward commodity gas prices. The decreases in rate base due to deferral accounts and working capital are partially offset by the increase in FEI's plant in service by $134.127 million[8], primarily due to the additions of a number of CPCN and Major projects, including the Tilbury 1A Expansion, Inland Gas Upgrades (IGU), Gibsons Capacity Upgrade (GCU), Lower Mainland Intermediate Pressure System Upgrades (LMIPSU), and Pattullo Gasline Replacement (PGR) projects.

1.5.5 Depreciation (Section 7)

Depreciation expense in 2024 is forecast to increase the 2024 deficiency by $7.803 million compared to 2023 Approved. This increase is primarily due to the additions of the CPCN and Major projects noted above. The increase in depreciation expense is partially offset by approximately $0.098 million of CIAC from net additions, resulting in a net increase of $7.705 million in depreciation expense.

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5 Modified by 75 percent.
6 Increase of formula O&M by $11.138 million net of capitalized overhead.
7 Decrease of forecast O&M by $1.353 million net of capitalized overhead and biomethane O&M transferred to BVA.
8 Increase in mid-year net plant-in-service by $225.469 million less adjustment of $91.342 million for timing of capital additions.

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

Amortization of deferral accounts in 2024 increased by $19.048 million, primarily due to the increased amortization of the Demand-Side Management (DSM) deferral account resulting from increased DSM expenditures, and the reduced credit amortization from the Emissions Regulation deferral account resulting from reduced carbon credits available for monetization. These increases were partially offset by reduced amortization from the Pension & OPEB Variance deferral account, the credit amortization from the proposed new PST Rebate on Select Machinery and Equipment deferral account, and reduced amortization expense from the non-rate base Flow-through deferral account and the MRP Earnings Sharing deferral account.

1.5.7 Financing and Return on Equity (Section 8)

Financing and Return on Equity (ROE) increased the 2024 deficiency by $3.252 million through changes in financing rates, as well as changes in the ratio of long-term debt versus short-term debt.

For 2024, FEI forecasts a mid-year long-term debt issue of $200 million and forecasts a short-term debt rate of 5.56 percent, which is an increase from the 3.95 percent short-term debt rate embedded in the 2023 Approved revenue requirement. Overall, the 2024 deficiency is increased by $2.838 million due to financing rate changes and increased by $0.414 million as a result of the ratio change between long-term and short-term debt.

In calculating its 2024 revenue deficiency, FEI has utilized its currently approved capital structure and ROE of 38.5 percent and 8.75 percent, respectively, as approved by Order G-129-16. As explained in Section 8.1, FEI is currently awaiting a decision on Stage 1 of the BCUC-initiated Generic Cost of Capital (GCOC) proceeding which is expected to be issued in the upcoming months. FEI will provide an update to its rate calculations as part of an Evidentiary Update subsequent to the GCOC decision being issued.

1.5.8 Taxes (Section 9)

FEI's 2024 property taxes are forecast to increase by $4.215 million or 5.3 percent from 2023 Approved. The increase is primarily driven by higher assessed values of distribution lines and transmission lines, as well as an increase in in-lieu taxes.

There has been no change in the income tax rate of 27 percent from 2023. Taxes are forecast to increase in 2024 by $16.653 million or 32.2 percent from 2023 Approved. The largest driver of the increase in 2024 is lower income tax deductible through CCA, which led to an increase in income tax expense by $12.284 million. The lower CCA is partly due to reduced undepreciated capital cost (UCC) additions in higher rate CCA classes in the 2024 Forecast compared to 2023 Approved, and partly due to the phase-out of Canada's Accelerated Investment Incentive starting from 2024 (i.e., enhanced 50 percent first-year allowance to be phased out in 2024). Income taxes are also higher as a result of higher amortization of deferred charges as well as depreciation, which is partially offset by lower taxable temporary differences associated with pension and higher non-taxable temporary differences associated with removal costs.

1.6 SERVICE QUALITY INDICATORS (SECTION 13)

FEI reports on its 2022 and June 2023 year-to-date SQI results in Section 13. In 2022, for the nine SQIs with benchmarks, seven performed at or better than the approved benchmarks, with two, Meter Reading Accuracy and Telephone Service Factor (Non-Emergency), lower than the threshold due to the broader impacts of the COVID-19 pandemic, higher than normal attrition levels being experienced at the contact centre, and an increased amount of high bill inquiries over the year. For the four SQIs that are informational only, the Average Speed of Answer results were higher due to the same challenges impacting the Telephone Service Factor (Non-Emergency), while performance in 2022 for the other three informational metrics generally remains at a level consistent with prior years. In 2023 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 2024 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.[9]

The MRP Decision approved the use of a forecast of growth[10] 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 2024, FEI has used July 2021 through June 2023 inflation data for the 2024 revenue requirement calculations, using the Statistics Canada tables included in Appendix A1 of the Application.

Section 2.2 below explains how FEI determined the 2024 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 2023 for AWE-BC has been used as a placeholder, as results to June 2023 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 2022 labour weighting of 49 percent, the calculation of the 2023 I-Factor is (6.031 percent x 51 percent) + (2.609 percent x 49 percent) = 4.354 percent.

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9 FEI's most recent year of completed actuals is 2022 so that ratio has been used for the 2024 I-Factor calculation.

10 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-2021	136.7	1,143.76								
2	Aug-2021	137.0	1,143.96								
3	Sep-2021	137.2	1,142.37								
4	Oct-2021	137.9	1,140.94								
5	Nov-2021	138.1	1,129.51								
6	Dec-2021	138.0	1,132.93								
7	Jan-2022	139.4	1,155.32								
8	Feb-2022	140.4	1,153.57								
9	Mar-2022	143.0	1,161.00								
10	Apr-2022	144.2	1,164.51								
11	May-2022	146.1	1,159.89								
12	Jun-2022	146.5	1,167.14	140.4	1,149.58						
13	Jul-2022	147.6	1,162.26								
14	Aug-2022	147.0	1,171.52								
15	Sep-2022	147.8	1,171.94								
16	Oct-2022	148.6	1,174.29								
17	Nov-2022	148.1	1,176.97								
18	Dec-2022	147.1	1,153.31								
19	Jan-2023	148.1	1,180.04								
20	Feb-2023	149.1	1,175.83								
21	Mar-2023	149.7	1,191.20								
22	Apr-2023	150.4	1,199.14								
23	May-2023	151.0	1,199.14								
24	Jun-2023	151.6	1,199.14	148.8	1,179.57	6.031%	2.609%	51%	49%	4.354%	2024

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 (GCA) to determine formula growth capital.

The calculation of the average customers used to determine 2024 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 2024 (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	Actual 2022	Projected 2023	Forecast 2024	Total for 2024 Rate Setting	Reference
1	Prior Year Ending Customer Count	1,038,354	1,051,752	1,062,480	1,073,302	1,084,905		Appendix A2 Table A2-1 FEI Customers
2	Adj: Fort Nelson				2,297			G-278-22
3	Additions:							
4	January	1,544	2,043	1,399	1,724	1,912		
5	February	1,028	1,162	1,107	863	970		
6	March	403	1,178	868	525	604		
7	April	722	395	73	1	38		
8	May	726	(37)	170	(27)	(10)		
9	June	921	(167)	289	(28)	(17)		
10	July	824	(507)	(227)	(406)	(439)		
11	August	848	256	73	145	170		
12	September	338	862	770	582	641		
13	October	2,006	1,797	1,905	1,811	1,985		
14	November	2,010	2,035	2,658	2,390	2,591		
15	December	2,028	1,711	1,737	1,726	1,883		
16	Total Additions	13,398	10,728	10,822	9,306	10,328		Appendix A2 Table A2-1 FEI Customer Additions
17	12-month Weighted Average Additions	6,268	5,334	4,711	6,262	4,466		
18								
19	Current Year Ending Customer Count	1,051,752	1,062,480	1,073,302	1,084,905	1,095,233		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	1,067,191	1,079,564		2020: G-319-20; Sch 3, Ln 13; 2021-2024: Prior Year, Ln 22
22	Average Customers for the Year	1,044,622	1,057,086	1,067,191	1,079,564	1,089,371		Line 1 + Line 17
23	Change in Average Customers	12,760	12,464	10,105	12,373	9,807	**57,509**	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						**43,132**	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**						**1,074,994**	Line 28 + Line 26
30								
31	2022 Approved Average Customers for Rate Setting			1,059,333				2022: G-366-21; Sch 3, Line 22
32	2022 Actual Average Customers for Rate Setting			1,058,359				Line 21(2020) + Sum of Line 23 (2020 & 2021 & 2022) x 0.75
33	**2022 True Up**			**(974)**				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	2022 Approved	20,000	
2	2022 Actual	16,477	
3	2022 True-up	(3,523)	Section 7, Table 7-2, line 14
4			
5	2023 Approved	16,000	
6			
7	2024 Forecast	15,000	Schedule 4, line 5

FEI is forecasting gross customer additions of 15,000 for 2024, which is lower than the 2023 Approved amount of 16,000 but is reflective of FEI's expectation of its 2023 customer growth, which is projected at 15,450. As explained in Section 7.2.1, the calculation of formula growth capital includes the true-up of gross customer additions from two years prior (i.e., 2022). While the 2023 Projected additions are lower than 2023 Approved, and have informed FEI's forecast for 2023, they do not impact the calculation of formula growth capital in this annual review; instead, 2023 additions will be trued up when setting 2025 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 2024 GCA forecast, FEI has reviewed 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 also 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. For the 2024 forecast, FEI assumed that the market capture rate for new construction is likely to retreat from previous years due to the continued impacts of building policies and codes, and strong financial incentives provided for home electrification. Further, FEI has assumed that conversion activities will be reduced from previous years due to factors such as high financing costs, which potentially are still rising, and the strong financial incentives being offered for home electrification. All of these factors are reflective of FEI's current expectation of the 2023 projected and 2024 forecast customer growth.

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	2024	Reference
1	CPI	6.031%	Table 2-1, Line 24
2	AWE	2.609%	Table 2-1, Line 24
3			
4	Non Labour	51%	Table 2-1, Line 24
5	Labour	49%	Table 2-1, Line 24
6			
7	CPI/AWE Inflation	4.354%	(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	3.854%	Line 7 + Line 9
12			
13	Average Customers for 2023 Formula O&M purposes	1,074,994	Table 2-2, Line 29
14			
15	Gross Customer Additions for 2023 Formula Growth Capital purposes	15,000	Table 2-3

In summary, the Net Inflation Factor for 2024 is 3.854 percent. FEI's formula O&M for 2024 is determined using average customers of 1,074,994, and the formula growth capital for 2024 is determined using gross customer additions of 15,000.

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 2024 Forecast (2024F) compared to the 2023 Approved. The 2024F normalized load is forecast to be approximately 220.2 PJ, which is a decrease of 1.6 PJ (decrease of 0.72 percent) compared to the 2023 Approved forecast. The decrease in 2024F is due to decreases in both industrial and NGT forecasts.

Based on the 2023 Approved rates for each customer class, FEI's 2024 revenue forecast is $1,830 million and FEI's 2024 gross margin forecast is $1,086 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;[11]
- 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

[11] 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 load forecast. In the figures provided in the load 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 2022 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[12], and will be different than the original forecast for that year in the previous filing. For example, for this Application the Seed Year is 2023 (2023S) and the Seed Year forecast is based on the latest actual years, including 2022. As such, the 2023 Seed Year forecast in this Application will differ from the 2023 Forecast presented in the Annual Review for 2023 Delivery Rates, for which 2022 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 2024 (2024F).
- Also included in the figures in this section is the prior year's forecast (shown as the green Approved lines in the figures below), as presented in the Annual Review for 2023 Delivery Rates.

3.3 DEMAND FORECAST

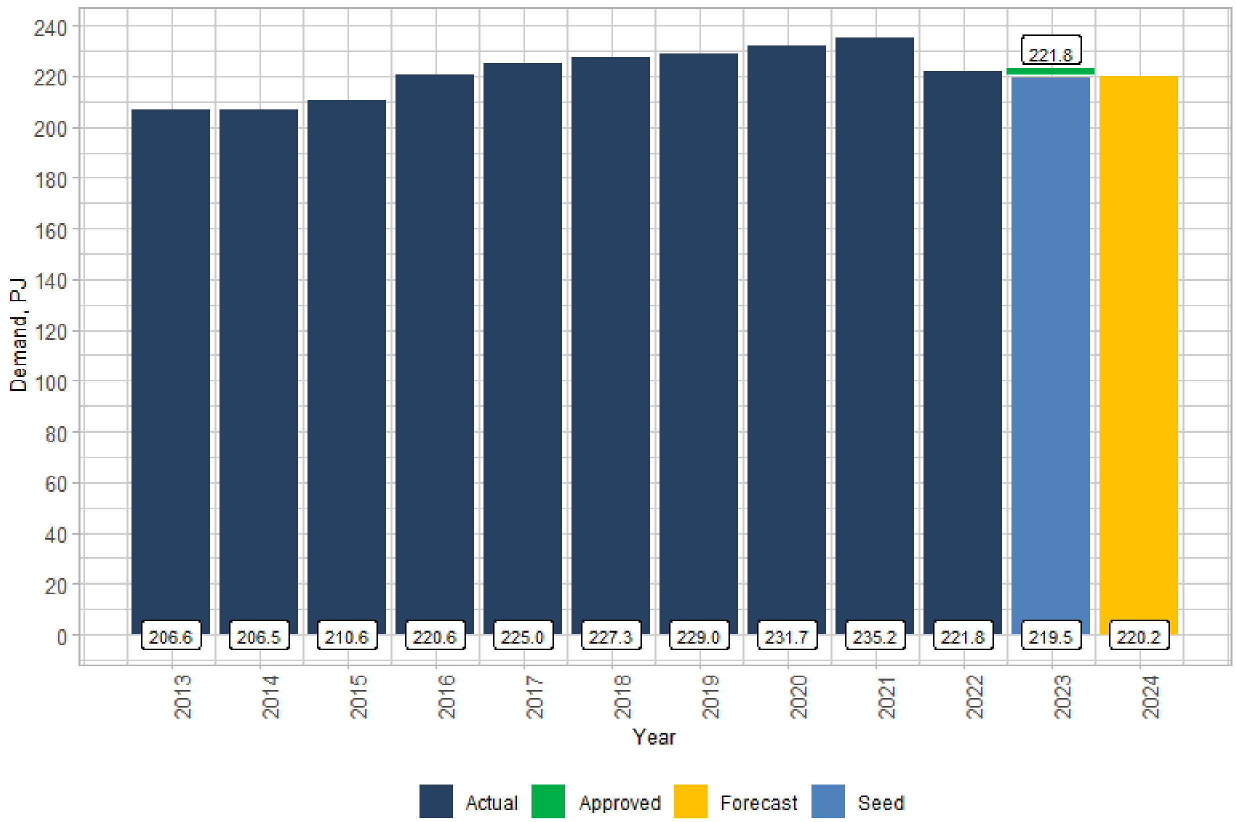
FEI's total energy demand consists of the weather normalized residential and commercial demand, and the customer-specific industrial, NGT, and non-NGT (LNG) demand. In aggregate, the absolute demand forecast variance in 2022 was 5.5 percent.[13]

[12] FEI's load forecast is developed using only complete years of historical data. FEI requires the complete year of demand data in order to validate it, including the review of and potential adjustments to unbilled energy. For this reason, partial year data is not used in forecasting.

[13] The primary driver of the 5.5 percent variance between 2022 Forecast and 2022 Actual demand is the impact of the expiry of FEI's contract with BC Hydro Island Generation (IG). The 2022 Forecast was prepared in the spring of 2021. At that time, it was not known that BC Hydro would not renew the IG contract and that the contract would

As shown in Figure 3-1 below, the total load is forecast to be 220.2 PJ in 2024F, which is an increase of 0.7 PJ from 2023S.

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

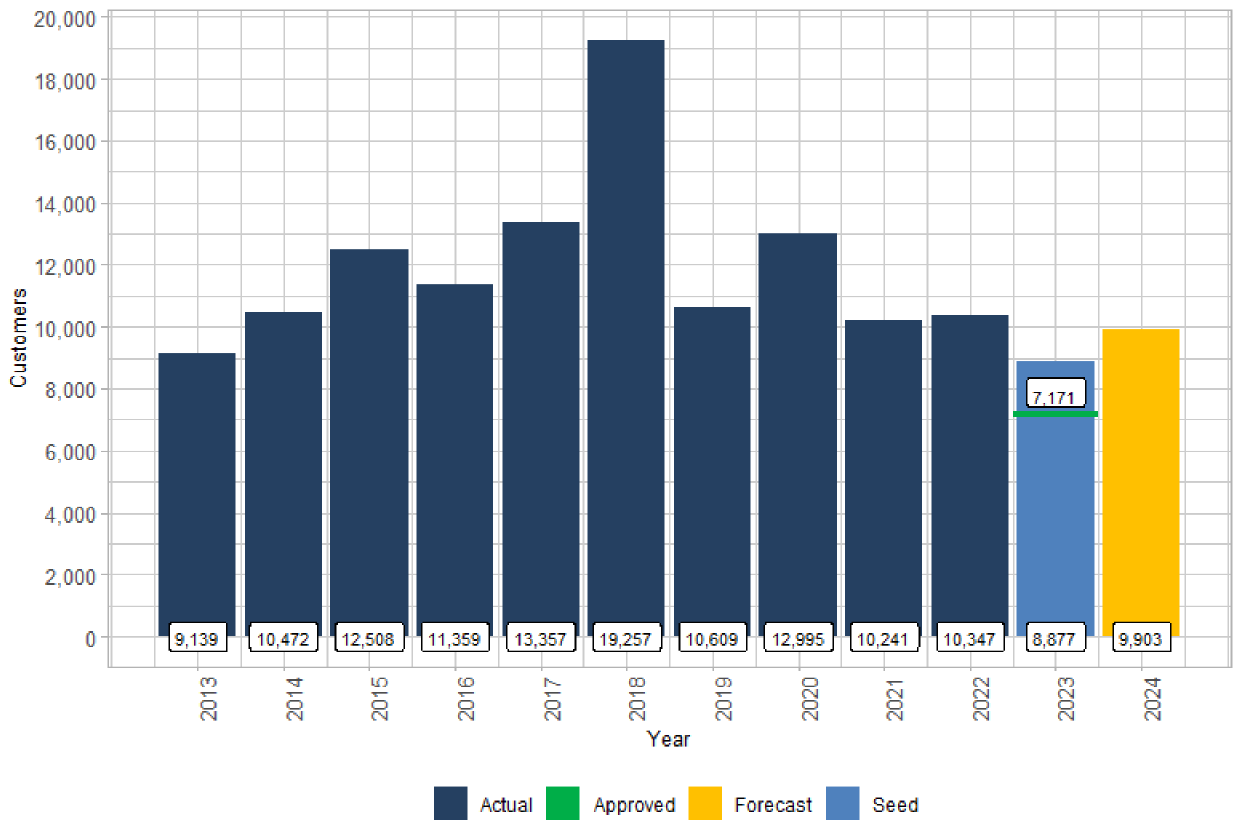
3.3.1.1 Residential Customer Additions

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 February 2023. The 2024 forecast of 9,903 additions reflects the actual residential additions recorded in 2022 and the single family and multi-family growth rate forecasts from the CBOC forecast.

instead expire in April 2022. As a result, the 2022 Forecast included a full year of demand from BC Hydro IG while the actual demand was only from January 2022 to April 2022 (i.e., up to the point of termination). Excluding the impact of BC Hydro IG, the aggregate variance drops to 1.3 percent, consistent with recent years' variance results.

As shown in Figure 3-2, residential customer additions are forecast to increase by 1,026 in 2024F compared to 2023S. Figure 3-2 provides the residential net customer additions for 2013 through 2024.

Figure 3-2: Residential Net Customer Additions

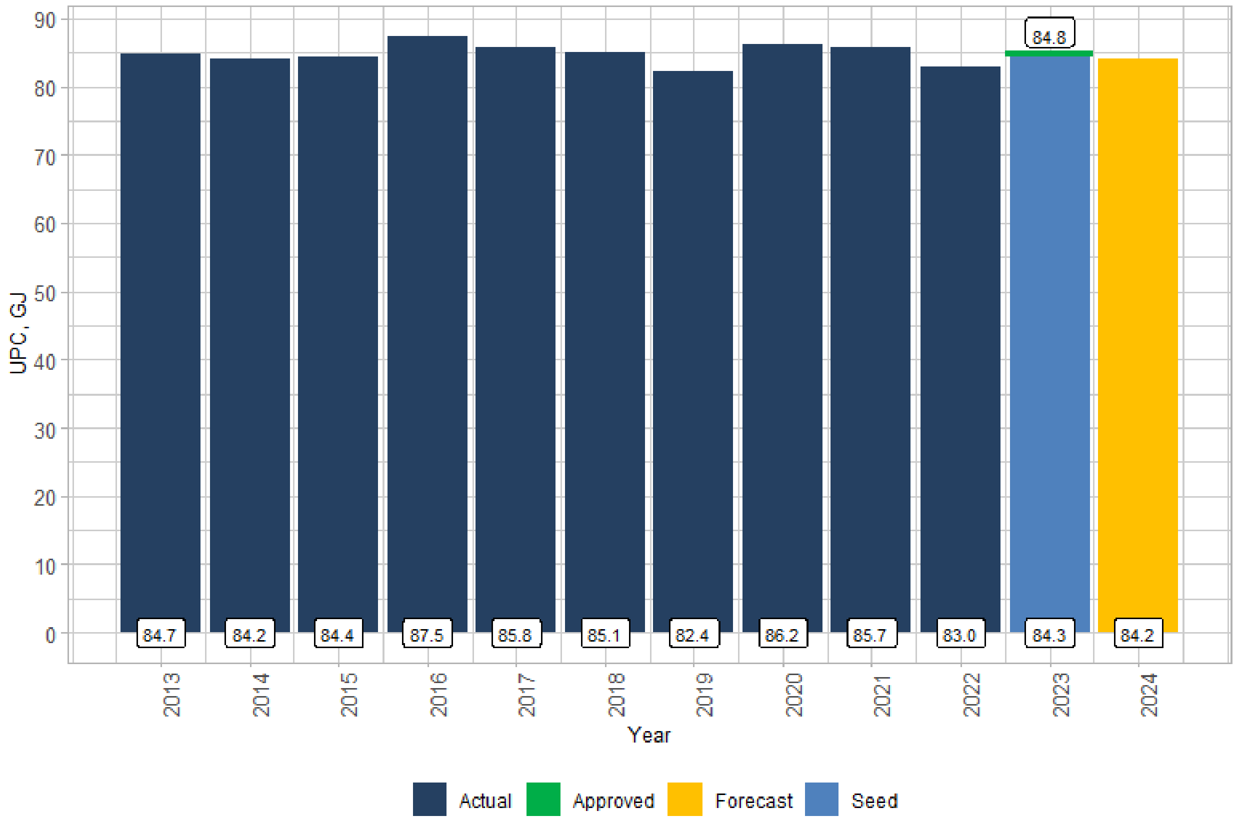


3.3.1.2 Residential UPC

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 slightly by approximately 0.1 GJ in 2024F compared to 2023S.

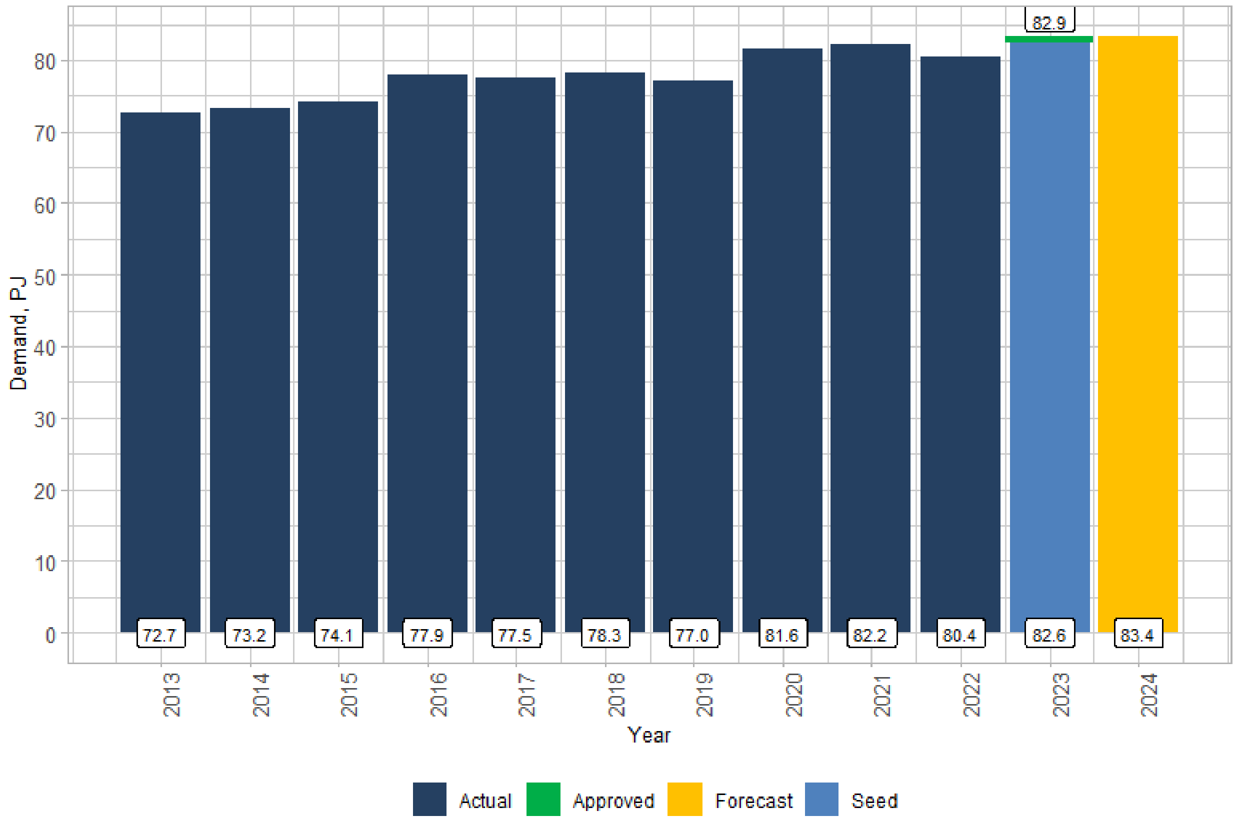
Figure 3-3: Rate Schedule 1 UPC



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 0.8 PJ in 2024F compared to 2023S.

Figure 3-4: Normalized Residential Demand



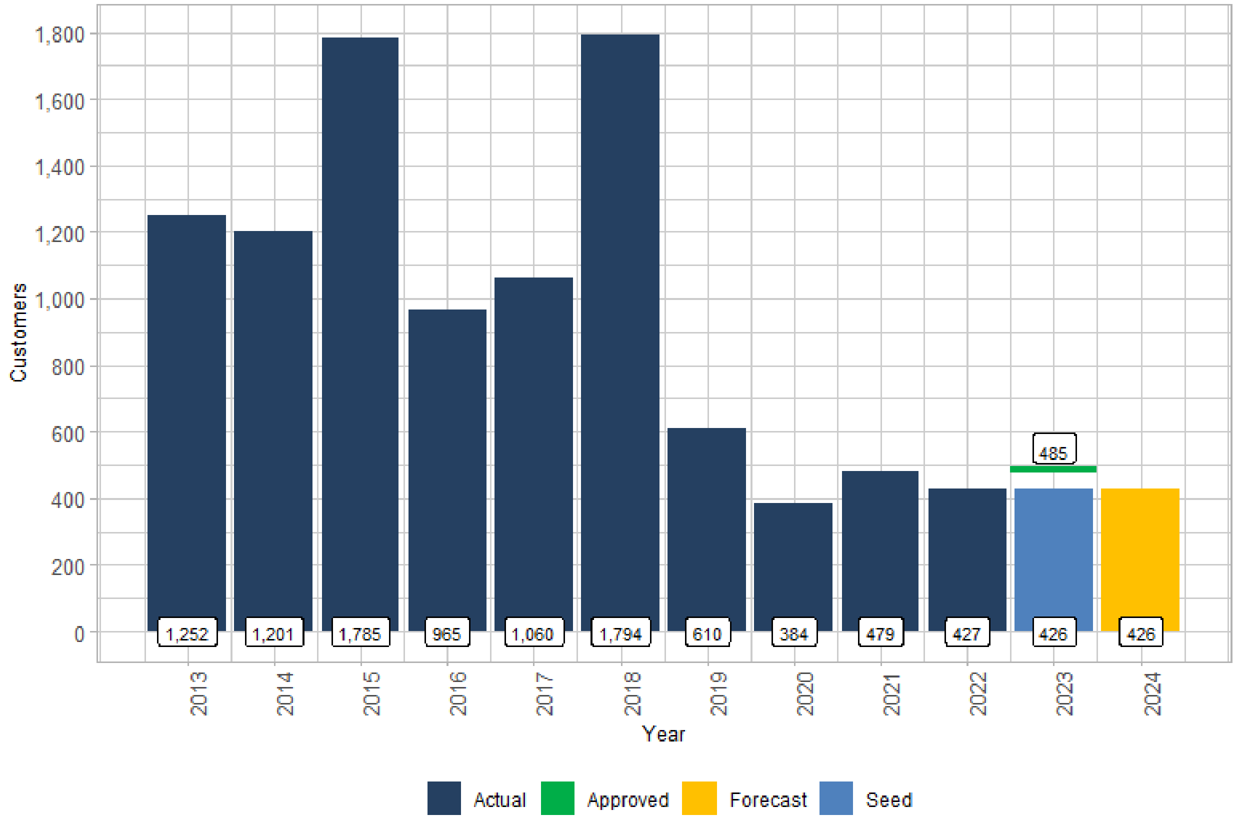
3.3.2 Commercial

3.3.2.1 Commercial Customers

The commercial (i.e., Rate Schedules 2, 3, and 23) 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., 2020 to 2022). The commercial forecast does not include NGT customers that are taking service under Rate Schedule 3 or 23. Please refer to Section 3.3.4 for forecasts related to NGT customers.

As shown in Figure 3-5 below, FEI is forecasting 426 net commercial customer additions in 2024F, consistent with 2023S.

Figure 3-5: Commercial Net Customers Additions (Rate Schedule 2, 3, and 23)

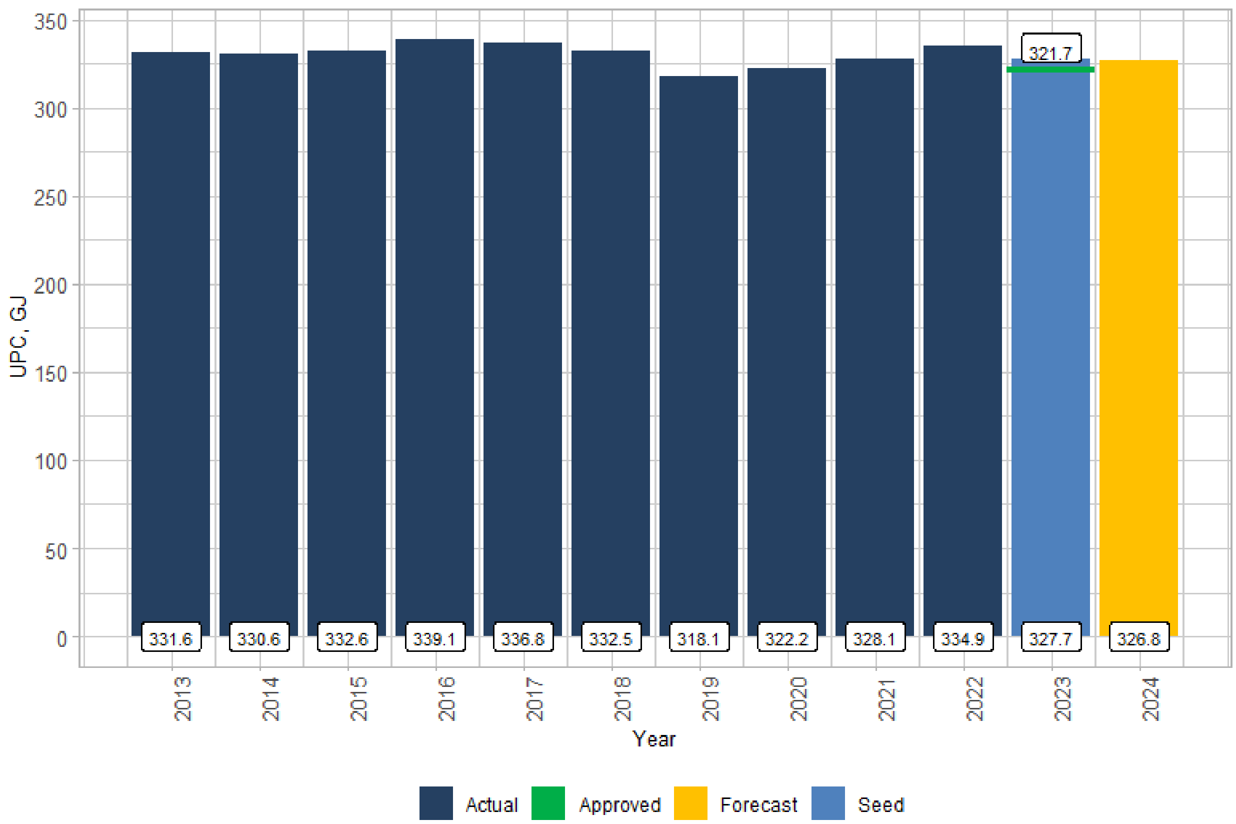


3.3.2.2 Commercial UPC

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

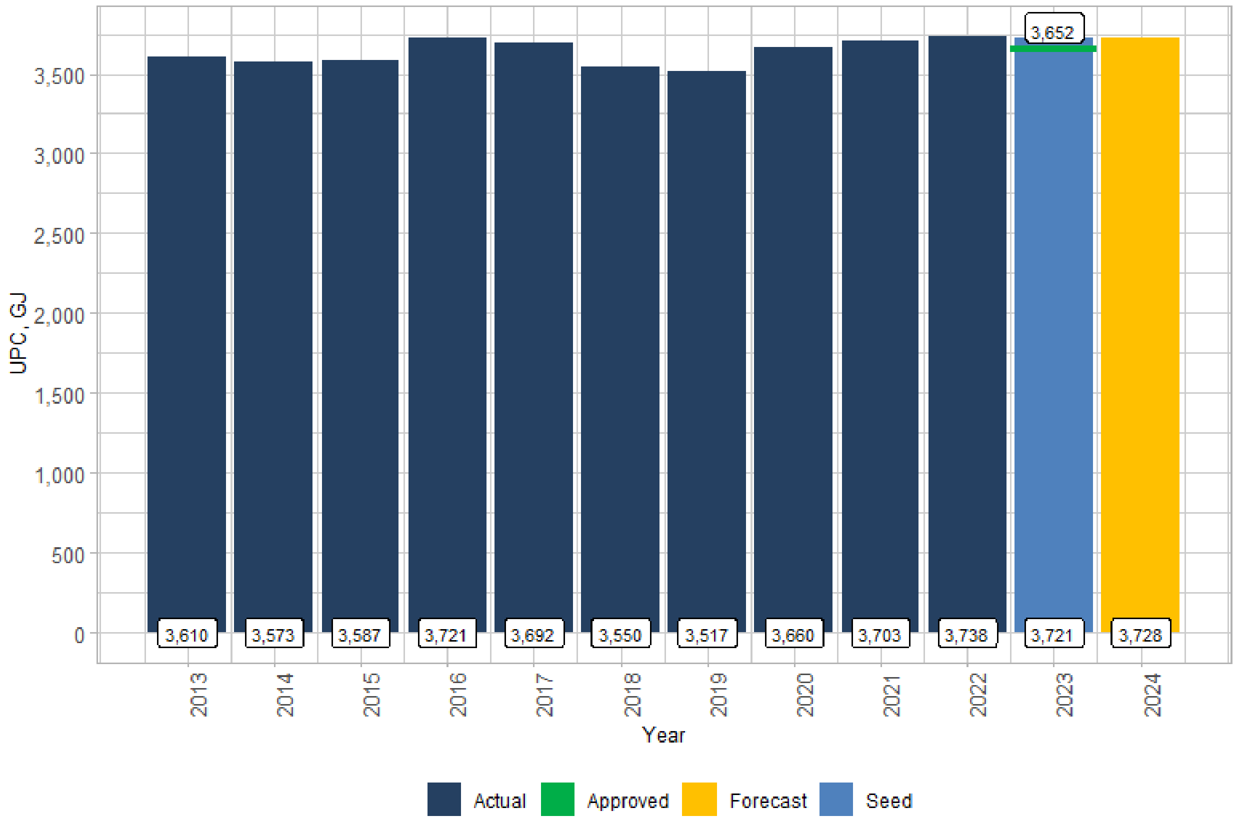
As shown in Figure 3-6, the Rate Schedule 2 UPC is forecast to decrease slightly by 0.9 GJ in 2024F compared to 2023S.

Figure 3-6: Rate Schedule 2 UPC



As shown in Figure 3-7, the Rate Schedule 3 UPC is forecast to increase by approximately 7 GJ in 2024F compared to 2023S.

1 **Figure 3-7: Rate Schedule 3 UPC**[14]

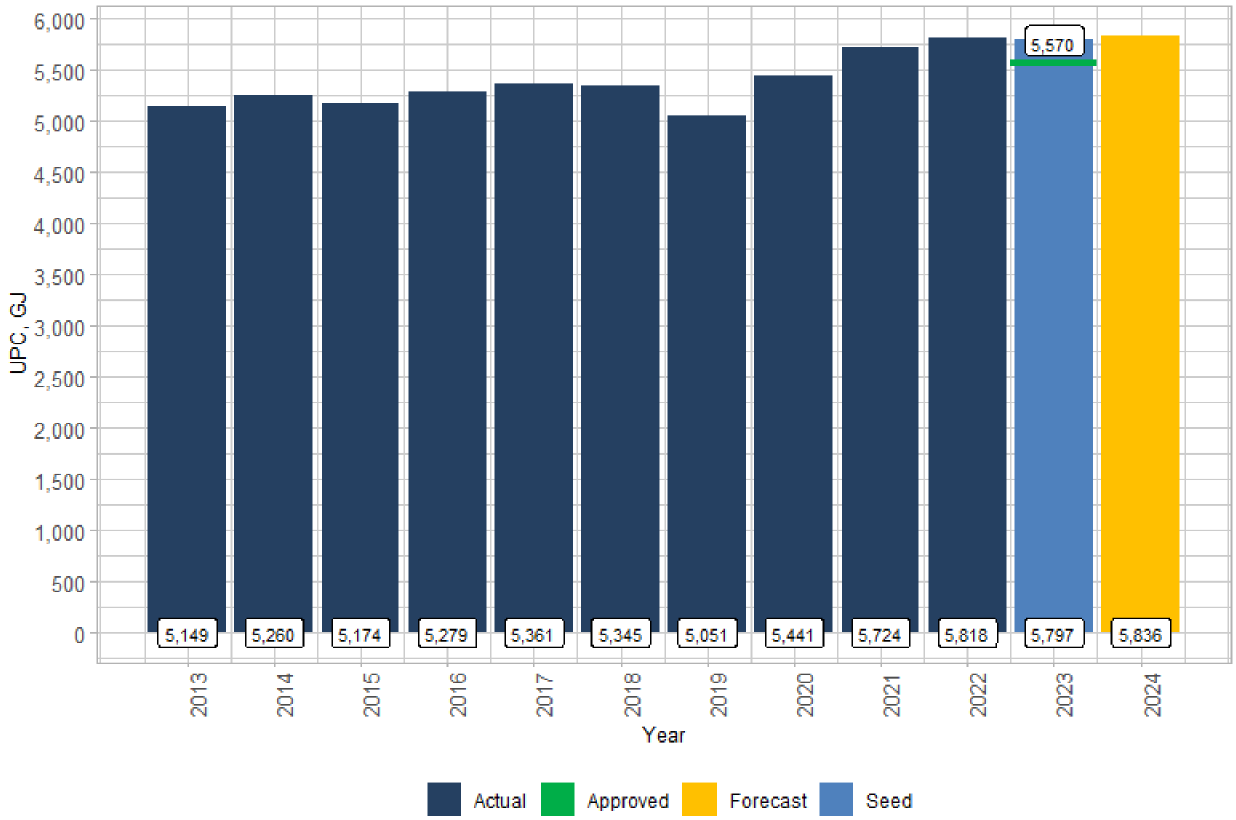


2

3 As shown in Figure 3-8, the Rate Schedule 23 UPC is forecast to increase by approximately
4 39 GJ in 2024F compared to 2023S.

[14] Excludes NGT customers under Rate Schedule 3.

Figure 3-8: Rate Schedule 23 UPC[15]

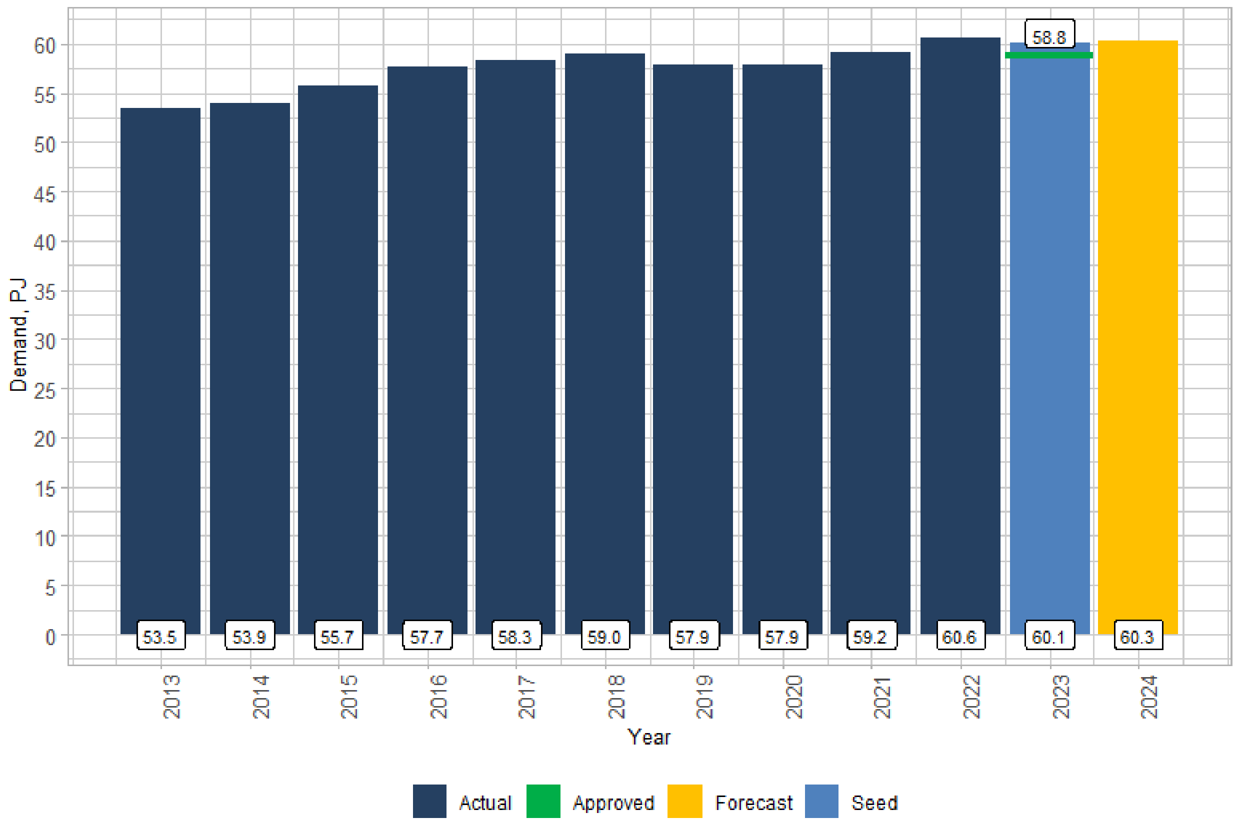


3.3.2.3 Commercial Demand

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 slightly by 0.2 PJ in 2024F compared to 2023S.

[15] Excludes NGT customers under Rate Schedule 23.

Figure 3-9: Commercial Demand[16]



3.3.3 Industrial Demand

The 2024F demand for industrial customers was forecast using the Industrial Survey.

For the 2024 Forecast, customers responded to the survey in May and June of 2023. 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, 2023 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 15, 2023.

As shown in Table 3-1 below, the response rate achieved in 2023 was approximately 89.9 percent of industrial volumes, representing 48.5 percent of customers. There was no reply from 49.5 percent of industrial customers who received the survey after three reminder notifications; this group represents only 9.9 percent of the industrial demand. Surveys could not be delivered to 2 percent of the industrial customers due to issues such as incorrect email addresses; this group represents 0.2 percent of the total industrial demand.

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

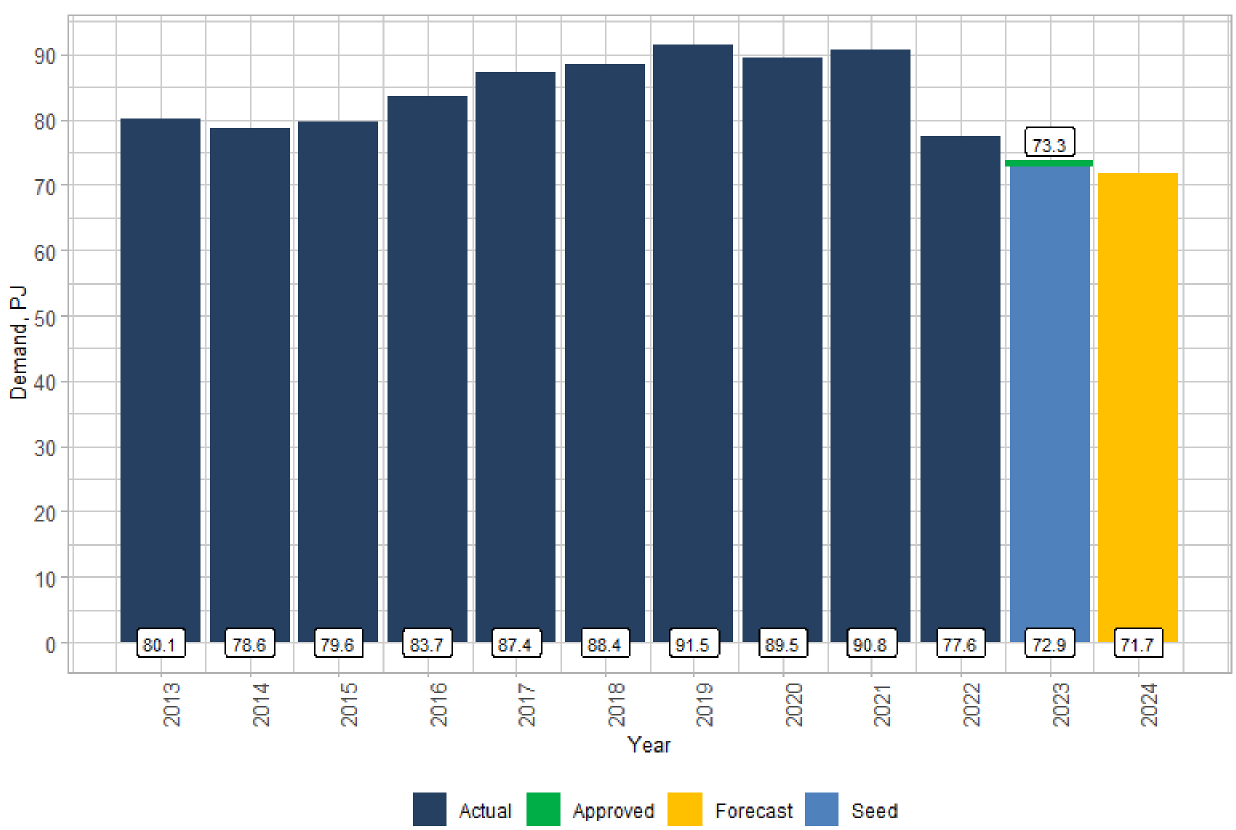
Table 3-1: Industrial Survey Response Rates

Industrial Survey	Description	Customers	Demand
Survey Completed	The survey was delivered and completed.	48.5%	89.9%
Survey delivered but not completed	The survey was delivered, but after three follow-up emails was not completed.	49.5%	9.9%
Survey undeliverable	The survey was not deliverable. This can be a result of invalid email addresses, faulty email servers etc.	2.0%	0.2%
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 10.1 percent of the total industrial demand) was set to equal 2022 Actual consumption.

As shown in Figure 3-10 below, the demand from the industrial rate schedules is forecast to be 71.7 PJ in 2024F, which is a decrease of 1.2 PJ from 2023S and a decrease of 1.6 PJ from 2023 Approved.

Figure 3-10: Industrial Demand[17]



[17] Excludes NGT customers under Rate Schedules 5 and 25, and LNG customers under Rate Schedule 46.

3.3.4 Natural Gas for Transportation and LNG Demand

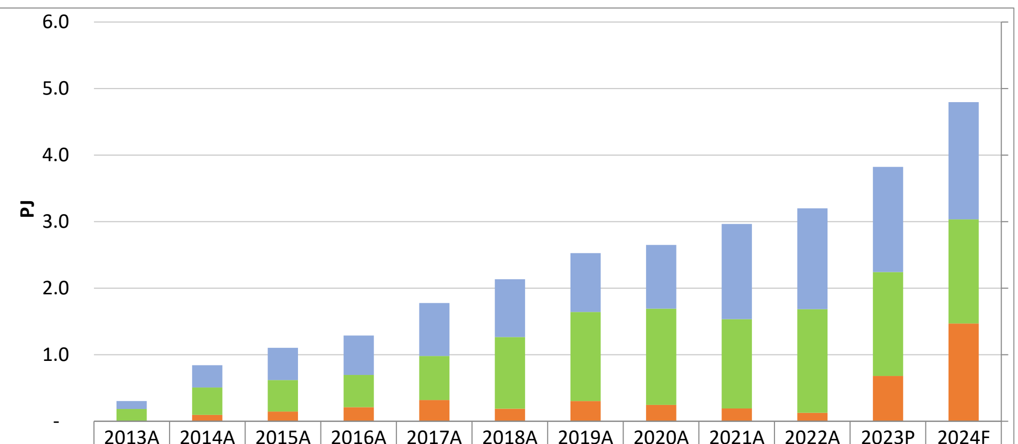
This section summarizes the CNG and LNG demand forecasts related to demand from NGT customers for CNG and LNG, as well as non-NGT related demand for LNG supplied under Rate Schedule 46. Table 3-2 below provides the 2023 Approved, 2023 Projected and 2024 Forecast total NGT and non-NGT LNG demand. As directed by Order G-86-15, the forecast of the total NGT and non-NGT LNG demand includes the forecast volume provided to customers under spot purchase agreements (i.e., LNG demand that exceeds the Contract Demand of the individual Rate Schedule 46 customer).

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

GJ	2023 Approved	2023 Projected	2024 Forecast
CNG	1,468,479	1,580,569	1,762,069
LNG	1,527,696	1,561,900	1,562,600
Total NGT Demand (GJ)	**2,996,175**	**3,142,469**	**3,324,669**
Non-NGT LNG (export)	3,690,789	682,000	1,471,000
Total NGT and Non-NGT Demand (GJ)	**6,686,964**	**3,824,469**	**4,795,669**

The following figure shows the most recent 10-year Actuals from 2013 to 2022, 2023 Projected and 2024 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 customers.

Figure 3-11: Actual (A), Projected (P) and Forecast (F) Demand for CNG & LNG[18]



	2013A	2014A	2015A	2016A	2017A	2018A	2019A	2020A	2021A	2022A	2023P	2024F
RS 3/5/23/25/6P - CNG (NGT)	0.1	0.3	0.5	0.6	0.8	0.9	0.9	1.0	1.4	1.5	1.6	1.8
RS 46 - LNG (NGT)	0.2	0.4	0.5	0.5	0.7	1.1	1.3	1.4	1.3	1.6	1.6	1.6
RS 46 - LNG (Non-NGT)	-	0.1	0.1	0.2	0.3	0.2	0.3	0.2	0.2	0.1	0.7	1.5
Total CNG & LNG	0.3	0.8	1.1	1.3	1.8	2.1	2.5	2.7	3.0	3.2	3.8	4.8

18 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.

The 2023 Projected demand of 3.8 PJ is 0.6 PJ higher than the 2022 Actual demand of 3.2 PJ, as shown in Figure 3-11 above. This increase is primarily related to the projected increase in non-NGT LNG export deliveries by ISO containers in 2023.

For CNG demand, the 2024 Forecast is 0.2 PJ higher than the 2023 Projected level, primarily due to increasing demand by customers at existing CNG stations. It can be seen from Figure 3-11 above that the CNG demand has been gradually increasing each year since 2013.

For LNG demand, the 2024 Forecast is 0.8 PJ higher than the 2023 Projected level. This is primarily driven by non-NGT LNG demand as NGT customers are expected to remain consistent with the 2023 Projected level. The increase in the non-NGT LNG 2024F demand from 2023P is a result of FEI successfully completing trial shipments of LNG via ISO containers with multiple new customers in Asia during the winter of 2022/23. These customers have all expressed interest to increase their purchases over the winter of 2023/24, as demand for LNG in Asia increases. FEI is continuing discussions with existing and potential customers and expects to secure firm contracts later in 2023.

3.4 REVENUE AND MARGIN FORECAST

The forecast of revenues and margins has been developed by considering the total 2024 Forecast energy in GJ applied at 2023 Approved delivery rates and applicable 2023 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 2023 Approved, 2023 Projected and 2024 Forecast revenue, by customer segment, at currently approved 2023 rates.

Table 3-3: Forecast Sales Revenue at 2023 Approved Rates (Commodity, Midstream, and Delivery)

Revenue ($ millions)	Approved 2023	Projected 2023	Forecast 2024
Residential[1]	1,257.965	1,111.137	1,040.799
Commercial[2]	697.400	615.794	562.438
Industrial[3]	293.752	233.884	226.655
Total	**2,249.117**	**1,960.815**	**1,829.892**

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, Byron Creek, 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 2023 Approved, 2023 Projected and 2024 Forecast margin, by customer segment, at currently approved 2023 delivery rates.

Table 3-4: Forecast Gross Margin at 2023 Approved Delivery Rates

Margin ($ millions)	Approved 2023	Projected 2023	Forecast 2024
Residential[1]	643.916	642.883	649.096
Commercial[2]	294.040	299.372	300.281
Industrial[3]	140.388	129.823	136.366
Total	**1,078.344**	**1,072.078**	**1,085.743**

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, Byron Creek, 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. FEI's forecast provides a reasonable estimate of future natural gas demand for 2024. Based on these methods, FEI is forecasting a decrease in consumption in 2024F of 1.6 PJ compared to the 2023 Approved level. Based on the 2023 Approved rates for each customer class, FEI's 2024 Forecast revenue is approximately $1,830 million, which is a decrease of approximately $419 million from the 2023 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, 2024:

- Approval of the 2024 CMAE Budget of $6.050 million, as set out in Schedule 1 of Appendix B; and
- Approval of the allocation of the 2024 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 current natural gas commodity cost recovery rate for the Mainland and Vancouver Island service area and the Fort Nelson service area became effective July 1, 2023 pursuant to Order G-148-23, dated June 15, 2023. 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 and the Fort Nelson service area became effective January 1, 2023 pursuant to Order G-347-22, dated December 1, 2022.

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[19,20]

Cost of Gas ($ millions)	Approved 2023	Projected 2023	Forecast 2024
Residential[1]	614.049	468.254	391.703
Commercial[2]	403.360	316.422	262.157
Industrial[3]	153.364	104.061	90.289
Total	**1,170.773**	**888.737**	**744.149**

Notes to table:

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

The 2023 Approved, 2023 Projected and 2024 Forecast cost of gas amounts shown in Table 4-1 above are based on the following:

- The 2023 Approved cost of gas was included as part of FEI's 2023 Annual Review which was filed with the BCUC in the Summer of 2022. It was calculated based on the approved[21] commodity cost recovery rate that was effective at the time of filing, which was $5.907 per GJ effective July 1, 2022.
- For the 2023 Projected cost of gas, since the commodity cost recovery rate is reviewed by the BCUC on a quarterly basis, instead of using the same commodity cost recovery rate as was approved by Order G-154-22 ($5.907 per GJ), FEI used the approved commodity cost recovery rates for 2023. The rates used for the 2023 Projected cost of gas are:
  - $5.159 per GJ as approved by Order G-347-22 for January to April 2023;
  - $4.159 per GJ as approved by Order G-54-23 for April to June 2023; and
  - $3.159 per GJ as approved by Order G-148-23 effective from July 1, 2023.
- The 2024 Forecast cost of gas is based on the currently effective commodity cost recovery rate, which is $3.159 per GJ as approved by Order G-148-23 effective July 1, 2023.

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).

19 Biomethane commodity costs are excluded from the table because they are allocated directly to the Biomethane Variance Account (BVA).
20 Cost of gas from transportation customers (i.e., RS 22, 23, 25 and 27) is resulting from UAF.
21 Approved by Order G-154-22.

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[22] 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.

[22] 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 2023, primarily due to an increase in Late Payment Charges, NGT Related Recoveries, and Biomethane Other Revenue.

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

	Approved 2023	Projected 2023	Forecast 2024
Late Payment Charge	$ 3.385	$ 3.576	$ 3.607
Application Charge	2.020	1.781	1.797
NSF Returned Cheque Charges	0.028	0.028	0.028
Other Recoveries	0.288	0.288	0.288
Tilbury Insurance Proceeds	-	6.135	-
NGT Related Recoveries	4.460	4.545	4.638
Biomethane Other Revenue	0.512	1.069	0.762
SCP Third Party Revenue	13.286	13.286	13.320
LNG Capacity Assignment	18.039	18.039	18.039
Total Other Operating Revenue	**$ 42.018**	**$ 48.747**	**$ 42.479**

In the following sections, FEI summarizes the methods used to forecast the line items included in the table above, and discusses a new one-time item included in the 2023 Projected Other Revenue.

5.2 OTHER REVENUE COMPONENTS

5.2.1 Late Payment Charge

As explained in the Annual Review for 2023 Delivery Rates, Late Payment Charges were historically 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, the actual amounts collected have fluctuated significantly from year to year. As these fluctuations would still be present in the most recent three years of actual results (i.e., 2020, 2021 and 2022), FEI has utilized the same approach used to calculate the 2023 Approved Late Payment Charges in the Annual Review for 2023 Delivery Rates. Accordingly, the 2024 Forecast for Late Payment Charges is calculated based on the average of 2022 Actual Late Payment Charges of $3.638 million and 2023 Projected of $3.576 million. This results in a forecast increase in Late Payment Charges of $0.222 million compared to 2023 Approved and is slightly higher than the 2023 Projected amount by approximately $31 thousand.

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 2024 Forecast amounts are expected to decrease by $0.223 million compared to 2023 Approved, which is consistent with FEI's forecast of reduced gross customer additions in 2024 as discussed in Section 2.3 of the Application.

5.2.3 NSF Returned Cheque Charges and Other Recoveries

The 2024 Forecast amounts for NSF Returned Cheque Charges and other miscellaneous income items are consistent with 2023 levels.

5.2.4 Tilbury Insurance Proceeds

FEI has included an additional flow-through item for 2023 Projected, which is a one-time credit of $6.135 million which FEI is flowing 100 percent to customers. The credit represents the actual insurance proceeds that FEI received in 2023 due to the delayed completion of the Tilbury 1A Expansion Project (T1A Project).

The T1A Project had an original in-service date of 2017; however, as explained in FEI's Annual Review for 2018 Delivery Rates proceeding, the completion of the project was delayed to 2018 due to an incident that occurred on August 19, 2017.[23] FEI filed an insurance claim in March 2018 and received confirmation in early 2023 that these proceeds would be paid out, with the final proceeds received in March 2023. These insurance proceeds will be treated as flow-through and fully returned to customers, as shown in Section 12, Table 12-4.

5.2.5 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

[23] FEI Annual Review for 2018 Delivery Rates, Exhibit B-6, CEC IR1 19.2.

in the Flow-through deferral account and the CNG & LNG Service Revenues deferral account, respectively.

Table 5-2: 2023 and 2024 NGT Related Recoveries ($ millions)

	Approved 2023	Projected 2023	Forecast 2024
NGT Overhead and Marketing Recovery	$ 0.273	$ 0.322	$ 0.341
NGT Tanker Rental Revenue	0.926	1.008	1.021
CNG & LNG Service Revenues	3.261	3.215	3.276
Total NGT Related Recoveries	**$ 4.460**	**$ 4.545**	**$ 4.638**

The following subsections discuss each of the NGT related recoveries.

5.2.5.1 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 2024 is $0.341 million. This revenue is calculated by multiplying the approved OH&M rate of $0.52 per GJ by the applicable[24] 2024 Forecast CNG and LNG sales volumes.

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

	2023 Approved	2023 Projected	2024 Forecast
Applicable Volume (GJ)	525,898	619,000	655,899
Rate ($/GJ)	$ 0.52	$ 0.52	$ 0.52
Total NGT OH&M Revenue ($ millions)	**$ 0.273**	**$ 0.322**	**$ 0.341**

5.2.5.2 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.

[24] 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.

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

Tanker Rental Revenue		2023 Approved		2023 Projected		2024 Forecast
Standard Tanker Rental Deliveries		96		120		96
Rate ($/Delivery)	$	308	$	321	$	327
Sub Total ($ millions)	$	0.030	$	0.039	$	0.031
Tridem Tanker Rental Deliveries		-		-		-
Rate ($/Delivery)	$	368	$	384	$	392
Sub Total ($ millions)	$	-	$	-	$	-
Marine Equipped Tridem Tanker Rental Deliveries		1,728		1,792		1,792
Rate ($/Delivery)	$	519	$	541	$	552
Sub Total ($ millions)	$	0.897	$	0.969	$	0.989
Total Tanker Rental Revenue ($ millions)	**$**	**0.926**	**$**	**1.008**	**$**	**1.021**

For the Standard tankers, the 2023 Projected rental revenue is forecast to be slightly higher than the 2023 Approved, primarily due to short-term operational issues at LNG stations which resulted in an increased use of the Standard tankers to ensure supply at these stations. For 2024, FEI is forecasting the Standard tanker rental revenue to be consistent with 2023 Approved, as the short-term operational issues at the LNG stations are not expected to continue.

The Tridem tanker rental revenue continues to be zero. As explained in previous annual review applications, 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 outside of BC and is therefore expecting the 2023 Projected and 2024 Forecast Tridem tanker rental revenue to be zero.

For the Marine Equipped Tridem tankers, the increase in the 2023 Projected deliveries is due to new marine vessels being commissioned by customers in 2022 and 2023. FEI expects this increased level of tanker deliveries to continue in 2024.

5.2.5.3 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).[25]

[25] 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.

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

	2023 Approved	2023 Projected	2024 Forecast
CNG Station	$ 2.570	$ 2.543	$ 2.594
LNG Station	0.525	0.524	0.535
Subtotal - NGT Stations	**$ 3.095**	**$ 3.067**	**$ 3.128**
Surrey Ops CNG Pump	0.166	0.148	0.148
Total	**$ 3.261**	**$ 3.215**	**$ 3.276**

As discussed in Section 3.3.4 of the Application, FEI is forecasting a small increase in NGT demand from CNG customers while the NGT demand from LNG customers will remain mostly flat between 2023 Projected and 2024 Forecast. As such, the small forecast increase in the recoveries for 2024 is primarily due to the approved annual increase in the fuelling rates at each individual station (i.e., the capital rate escalates at two percent per year and the O&M rate escalates by BC CPI per year).

5.2.6 Biomethane Other Revenue

The Other Revenue amounts of $1.069 million for 2023 Projected and $0.762 million for 2024 Forecast shown in Table 5-1 above are the transfers 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.

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:[26]

- Upgrading plant cost of service;
- Interconnection cost of service; and
- Program overhead costs.[27]

The 2023 Projected amount of $1.069 million is comprised of $0.824 million of earned return and $0.245 million of income tax expense related to FEI's biomethane assets. The 2024 Forecast of $0.762 million is comprised of $2.825 million of earned return, which is offset by a total income tax expense credit of $2.063 million. The primary driver of the increased earned return and the shift in income tax expense from a debit position in 2023 to a credit position in 2024 is the City of Vancouver (COV) biomethane project. As discussed further in Section 7.2.3.1 of the Application, the COV project is now expected to be complete and enter FEI's rate base in 2024, resulting in the increase in the 2024 forecast earned return. The COV biomethane assets will also create a large income tax credit in 2024 due to their high capital cost allowance

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

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

(i.e., 50 percent). The 2024 Forecast includes an income tax expense credit due to the COV project of approximately $2.148 million, which results in an overall income tax expense credit of $2.063 million when combining the income tax expense of other biomethane projects.

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: 2023 and 2024 SCP Revenue Components ($ millions)

	Approved 2023	Projected 2023	Forecast 2024
MCRA	$ 13.284	$ 13.284	$ 13.320
Net Other Mitigation - West to East Capacity	0.002	0.002	-
Total SCP Revenue	**$ 13.286**	**$ 13.286**	**$ 13.320**

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 $13.320 million[28] 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 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.

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.

The forecast mitigation revenue for the SCP west to east capacity for 2024 is based on the forward market price differentials for summer 2024. Huntingdon currently remains a higher

[28] The increase in the 2024 Forecast of MCRA Other Revenue compared to previous years is because 2024 is a leap year, i.e., $346.617 per MMcfd x 105 MMcfd x 366 days / 1,000,000 = $13.320 million.

priced market than Kingsgate, thus supporting east to west movement across SCP during the summer rather than west to east flow. Therefore, FEI forecasts generating no west to east mitigation revenue in 2024.

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.[29]

5.5 SUMMARY

FEI has forecast the Other Revenue components for 2024 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 5.2.6), the CNG/LNG Recoveries deferral account (for excess revenue from the CNG & LNG Service Recoveries forecast discussed in Section 5.2.5.3), and the Flow-through deferral account (for any remaining variances from forecast in Section 5.2.5.3 and all variances from forecast in Section 5.2.5.2 and 5.4). All remaining variances in Other Revenue, with the exception of the one-time Tilbury insurance recoveries which are being returned 100 percent to customers through the Flow-through deferral account (as discussed in Section 5.2.4), are shared with customers through the ESM.

[29] 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 2024, the Formula O&M is $312.561 million, representing a 4.4 percent increase from the 2023 Formula O&M, primarily driven by the net inflation factor. For the O&M expenses tracked outside of the formula (i.e., Forecast O&M), the 2024 forecast is $57.646 million, representing a 4.2 percent increase from the amount approved for 2023. Overall, the increase in gross O&M expense from 2023 Approved to 2024 Forecast is 4.4 percent.

The components of 2024 O&M expense are shown in Table 6-1 below.

Table 6-1: 2024 O&M Expense ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024	Reference
1	Formula O&M	$ 299.302	$ 299.302	$ 312.561	Section 11, Schedule 20, Line 12
2	Forecast O&M	55.345	57.931	57.646	Section 11, Schedule 20, Line 23
3	Total Gross O&M	354.647	357.233	370.207	Line 1 + Line 2
4	Capitalized Overhead (16%)	(56.744)	(56.744)	(59.233)	Section 11, Schedule 20, Line 27
5	Biomethane O&M transferred to BVA	(5.237)	(5.075)	(5.817)	Section 11, Schedule 20, Line 26
6	Net O&M	$ 292.666	$ 295.414	$ 305.157	Line 3 through 5

In the sections below, FEI provides further details on its formula and forecast O&M expenses for 2024. Additionally, in compliance with the BCUC's directive in the MRP Decision[30], 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 2024 inflation based on prior year's BC-CPI and BC-AWE, less the productivity improvement factor, is 3.854 percent.

For 2024, the annual operating and maintenance expense under the formula is calculated as:

[30] MRP Decision, p. 115.

2023 Approved formula UCOM x [1 + (I Factor – X Factor)] x [Prior Year Average Customers + (0.75 x growth in average customers)] + 2022 Formula O&M True-up

Table 6-2 below shows the calculation of the 2024 Formula O&M, including the calculation of the 2022 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 2022.

Table 6-2: Calculation of 2024 Formula O&M ($ millions)

Line No.	Description	Forecast 2024	Reference
1	Prior Year Base Unit Cost O&M ($/customer)	$ 280	G-352-22 2023 FEI Annual Review Decision
2	I-Factor	3.854%	Section 2, Table 2-4
3	Current Year Unit Cost O&M ($/customer)	$ 291	
4	Average Customer Forecast	1,074,994	Section 2, Table 2-2
5	2024 Inflation-Indexed O&M before 2022 True-up	$ 312.823	Line 3 x Line 4
6	2022 True-up O&M	$ (0.262)	Line 16
7	Inflation-Indexed O&M	$ 312.561	Line 5 + Line 6
8			
9	2022 O&M True-up		
10	2022 Actual 12 month Average Customers	1,067,191	FEI 2022 Annual Report
11	2022 Forecast 12 month Average Customers	1,068,490	G-366-21 2022 FEI Annual Review Decision
12	Difference	(1,299)	Line 10 - Line 11
13	Growth Factor	75%	G-165-20 MRP Decision
14	Change in Customers - True-up	(974)	Line 12 x Line 13
15	2022 Unit Cost ($/customer)	$ 269	G-366-21 2022 FEI Annual Review Decision
16	O&M True-up for 2024	$ (0.262)	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 2022 Formula O&M, 2022 Actual O&M, and the resulting variances, as well as the Cumulative Forecast/Actual Variance for the first three years of the MRP.

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

Line No.	Description		2022 Formula O&M		Actual 2022 O&M		2022 Forecast/Actual Variance		Cumulative Forecast/Actual Variance[2]
1	Integrity Management	$	1.475	$	1.986	$	0.511	$	1.182
2	Maintaining System Infrastructure	$	0.765	$	0.857	$	0.092	$	0.156
3	Operations, Compliance and Safety	$	0.655	$	0.609	$	(0.047)	$	0.334
4	Cyber Security	$	0.555	$	0.855	$	0.300	$	0.910
5	Data Analytics	$	0.328	$	0.100	$	(0.228)	$	(0.851)
6	Gas Control	$	0.710	$	0.103	$	(0.607)	$	(1.824)
7	CEPA Participation	$	0.765	$	0.416	$	(0.348)	$	(1.094)
8	Other	$	-	$	-	$	-	$	-
9	Total	$	5.252	$	4.925	$	(0.327)	$	(1.188)

Notes to table:

[1] 2022 Formula O&M is the approved 2021 formula for incremental funding with Net Inflation factor applied (3.420%).

[2] Cumulative Forecast/Actual variance is the 2020, 2021 and 2022 Actual variance.

For the first three years of the MRP, FEI spent $1.188 million less than the formula amount. Total actual spending in 2022 was $4.925 million, which is $0.327 million lower than the 2022 Formula O&M amount. Areas with notable variances in 2022 include integrity management, cyber security, data analytics, gas control and CEPA participation.

For integrity management, FEI spent $0.511 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.

Higher spending for cyber security of $0.300 million was for additional consulting resources in the following areas: an additional consulting resource to augment cybersecurity requirements due to additional threat management needs; emergency management consulting for emergency exercises; physical security threat intelligence services to manage security risks; and the use of consulting services to update the business continuity program.

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

With regard to data analytics, FEI spent $0.228 million less than the formula amount in 2022 primarily due to a delay in hiring. In 2022, FEI focused on building solutions in business areas, including providing enhanced reporting using dashboards. For further details on data analytics, please refer to Section 1.4.2 of the Application. While no expenditures for additional staffing were incurred in 2022, incremental expenditures of approximately $100 thousand were incurred for an external change management consulting resource to support the development of the Enterprise Data and Analytics System (EDAS) requirements.

For gas control, FEI spent $0.607 million less than the formula amount in 2022. As explained in the Annual Review for 2023 Delivery Rates,[31] FEI hired one gas controller in 2021 and had intended to hire one net new gas controller per year going forward. However, FEI was unable to hire another net new gas controller in 2022 due to a combination of recruitment challenges, staff turnover, and coordinating the timing of new hires with retirements of existing employees. Hiring gas controllers is challenging as it is difficult to locate candidates with appropriate experience and skills within BC, particularly due to the high-cost housing market in the Lower Mainland and, to varying extents, in FEI's other operating territories. FEI continues to strive to increase its gas control staffing to ensure the utility will be able to meet the requirements of its customers, align with industry standards, and continue to operate in a safe and reliable manner within a progressively complex and demanding operational environment.

With regard to CEPA participation, FEI spent $0.348 million less than the formula amount in 2022. As noted in the 2023 Annual Review, CEPA has ceased operations; however, the work related to CEPA-driven activities continues. In 2022, FEI continued with implementing control room management improvements and activities for Integrity First self-assessments.

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 2023.

Table 6-4: 2024 Forecast O&M ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Pension/OPEB (O&M Portion)	$ 9.577	$ 9.577	$ 2.555
2	Insurance	12.242	12.406	13.328
3	Integrity O&M	8.000	9.000	11.200
4	BCUC Levies	8.493	8.493	9.955
5	**Clean Growth Initiatives:**			
6	Biomethane O&M	5.237	5.075	5.817
7	Renewable Gas Development	2.000	3.069	4.052
8	NGT O&M	1.937	2.412	2.604
9	Variable LNG Production Costs	7.859	7.899	8.135
10	Forecast O&M	$ 55.345	$ 57.931	$ 57.646

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.

[31] FEI Annual Review for 2023 Delivery Rates, Exhibit B-2, p. 43.

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 2024 is based upon actuarial estimates using a range of assumptions as of December 31, 2022. 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 2023	Projected 2023	Forecast 2024
1	O&M	$ 9.577	$ 9.577	$ 2.555
2	Capital - Growth	1.034	1.034	0.871
3	Capital - Other	3.045	3.045	2.566
4	Deferred - Asset Removal Costs	1.201	1.201	1.012
5	Deferred - CMAE	0.363	0.363	0.306
6	Total	$ 15.220	$ 15.220	$ 7.310

The variance between the 2023 Approved/Projected and actual pension and OPEB expense 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 2024 Forecast pension and OPEB expense is lower than 2023 Approved by $7.910 million. The difference is primarily due to the following factors:

- A decrease of approximately $7 million due to an increase in investment returns as a result of a higher balance of pension plan assets; and
- A decrease of approximately $5 million due to a reduction in current service costs as well as a higher amortization of actuarial gains, both of which are primarily the result of a higher 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 4.50 percent, which was used to determine the 2023 Approved expense, to 5.25 percent, which is used to determine the 2024 Forecast expense.

The above decreases are offset in part by:

- An approximate increase of $4 million in interest costs due to the increased 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 2023	Projected 2023	Forecast 2024
1	Insurance Premiums	$ 12.242	$ 12.406	$ 13.328

FEI's annual insurance renewal occurs in July of each year. The 2023 Projected insurance premium expense of $12.406 million is $0.164 million higher than 2023 Approved, as it incorporates the first six months of FEI's actual July 2023 to June 2024 insurance renewals. The 2024 Forecast is $13.328 million, which is an increase of $0.922 million from 2023 Projected. The 2024 Forecast is calculated based on the six months of actual annual insurance premiums from July 2023 to June 2024 of $6.501 million and applying a 5 percent increase for the remaining six months.[32]

6.3.3 Integrity O&M

In the MRP Decision and Order G-165-20,[33] 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, consistent with the 2023 Approved integrity O&M included in the 2023 Annual Review and as approved in the MRP Decision,[34] FEI has included the incremental expenditures related to the two integrity-driven CPCN projects which have been approved subsequent to the commencement of the MRP term – the Inland Gasline Upgrades (IGU) Project and the Coastal Transmission System Transmission Integrity Management Capabilities (CTS TIMC) Project.

The 2024 Forecast for integrity digs and incremental integrity activities is $11.2 million, which is an increase of $3.2 million from 2023 Approved and $2.2 million from 2023 Projected. The 2024 Forecast includes approximately $10.2 million for integrity digs and $1 million for incremental integrity activities related to the IGU and CTS TIMC Projects. The 2024 Forecast for the incremental integrity activities is consistent with 2023 Approved and 2023 Projected. 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.

[32] $13.002 million/2 = $6.501 million x 1.05 = $6.826 million. $6.501 million + $6.827 million = $13.328 million.
[33] MRP Decision and Order G-165-20, p. 74.
[34] MRP Decision and Order G-165-20, pp. 132-133.

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).

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 Actuals	2023 Approved	2023 Projected	2024 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.	27	13	32	50	36	85
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.	47	25	15	30	40	30
3	**ILI Digs – Established Tools and Practices:** ILI digs identified through previously established technologies, tools, and practices	45	87	68	40	61	35
4	**Non-ILI Digs:** Digs identified through above-ground cathodic protection and coating surveys.	27	17	12	20	27	10
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	1	5	2	2
6	**Total Integrity Digs**	**146**	**142**	**129**	**145**	**166**	**162**
7	Total Integrity Dig Expenditures ($ millions)	5.9	7.2	6.2	7.0	8.0	10.2
8	Cost per dig ($000s)	40	51	48	48	48	63

FEI's forecast of **ILI Digs – New Tools** is an estimate of the integrity digs resulting from first-time in-line inspections, such as those associated with the IGU Project[35] and CTS TIMC Project.[36] As there is no sufficient technical basis for estimating the number of digs from a first-time in-line inspection, FEI has based its projections on the engineering judgement of qualified staff, which is informed by various information sources, including:

- Knowledge of populations of imperfections from other in-line inspected pipelines, while recognizing that one pipeline's condition is not an accurate predictor of another pipeline's condition;
- Knowledge of imperfections that the IGU Project is endeavouring to locate and remove prior to in-line inspection to ensure passage of ILI tools (e.g., inside diameter restrictions, such as could be caused by a severe dent); and
- Estimates of timing of in-line inspection activities, with a primary input being the timing of IGU and CTS TIMC Project activities to prepare pipelines for running ILI tools.

In this category, FEI is forecasting EMAT-driven integrity digs on the Huntingdon-Roebuck 1067 mm pipeline in 2024 as part of its CTS TIMC post-Project activities. Integrity digs on this 1067 mm outside-diameter pipeline traversing higher-developed areas are forecast to be higher-cost than digs on smaller-diameter pipelines that traverse lesser-developed areas, which is influencing the 2024 Forecast of total integrity dig expenditures and the 2024 Forecast of cost per dig.

FEI's forecast related to **ILI Digs – New Practices** continues to be influenced by the adoption of the strain-based criteria for dents as per current industry practice and standards. FEI's 2023 Projection and 2024 Forecast incorporates FEI's analysis to-date, with the increase from 2023 Approved to 2023 Projected also reflecting ILI data received since the initial estimate was developed. FEI is still in the process of adopting a modified dent repair method.

FEI's forecast of **ILI Digs – Established Tools and Practices** results from FEI's analysis of its existing technology 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 Projected and 2024 Forecast incorporate FEI's analysis to-date (i.e., ILI and integrity dig results), while also fluctuating due to influences including the number and timing of in-line inspections. The 2023 Projected is higher than 2023 Approved due to the need to investigate site-specific issues that were not known at the time of the initial estimate, as well as to minimize landowner disruption and optimize operating costs. For example, three digs were advanced from future years since they were in proximity to 2023 digs and could be completed with less landowner disruption if they were performed concurrent with the 2023 digs. An additional three digs were advanced from a future year as installation of

[35] FEI Application for a CPCN for the IGU Project Decision and Order G-12-20.
[36] FEI Application for a CPCN for the CTS TIMC Project Decision and Order C-3-22.

a berm to mitigate a geotechnical hazard will make future integrity dig access more complex and costly.

FEI's forecast of **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) and timing of surveys, as reflected by a reduction in the 2024 Forecast. The 2023 Projected amount incorporates incremental condition monitoring of the Trail Lateral 168 following a leak in December 2022.

FEI's forecast of **Facilities Digs** reflects FEI's expansion of its Integrity Management Program (IMP) to include facilities (e.g., compressor stations and control stations). Consistent with its current 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. The 2023 Projected amount shows a reduction in the number of digs; however, Facilities digs can encompass relatively longer lengths of pipe at a single site (relative to typical digs on linear pipeline assets). FEI is forecasting that its two 2023 Facilities Digs will inspect approximately 50 metres of facilities piping at two facility sites, prioritized on the basis of factors including construction (e.g., age, expected external coating) and operating characteristics (e.g., station criticality, operating stress). FEI is anticipating a similar level of activity in 2024.

FEI continues to experience a range of scope and costs associated with its integrity digs. Factors that impact dig costs include site access, site management during the dig, site restoration, and pipeline repairs (if necessary). The 2023 Projected and 2024 Forecast reflect estimates developed by Transmission Operations staff, and consider the average cost to complete similar integrity digs, as well as utilizing knowledge and/or estimates of future costs, such as those associated with contractors or equipment. The similarities, decreases or increases in FEI's average costs per dig from 2021 through 2024 are not indicative of trends; rather, fluctuations in average costs will occur due to year-to-year variability in dig categories and the geographic locations of the digs. The estimates reflect Operations' understanding of cost pressures, including fuel and contractors.

6.3.3.2 CPCN-related Integrity Expenditures

FEI is forecasting a total of $1 million in integrity management costs in 2024 due to incremental 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 IGU 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.[37] Incremental operating costs are associated with both the ongoing ILI activities and pressure regulating station aspects of the project.

For 2024, FEI is continuing to forecast $0.300 million for incremental O&M resources associated with the IGU Project, consistent with 2023 Approved and 2023 Projected levels. These costs are primarily for 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 CTS TIMC PROJECT

In 2022, the BCUC approved a CPCN for the CTS TIMC Project (Order C-3-22). This project is providing 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 conduct ongoing QRAs on its transmission pipelines. FEI has procured software for performing QRAs (these costs were included in the approved Information Systems capital budget) and is initiating its ongoing QRA activities with internal staff. FEI's implementation of QRA of its transmission pipelines is an iterative process, as the data and learnings from previous steps inform the next steps in FEI's integrity planning.

FEI is continuing to define further resources for enhancing its risk-informed and risk-based decision-making of its transmission pipelines, which will include incremental technical staff for performing ongoing analysis of each of FEI's three transmission systems (the Coastal, Interior and Island transmission systems) and enhanced capabilities for ensuring that suitable and validated data inputs are fed into the risk model.

For 2024, FEI is continuing to forecast $0.700 million in incremental O&M, consistent with 2023 Approved and 2023 Projected levels, which is primarily associated with initial engineering resources for performing ongoing QRAs.

6.3.4 BCUC Levies

FEI's 2024 Forecast for BCUC levies is $9.955 million. The 2024 Forecast is based on Order G-134-23 for the BCUC's Fiscal 2023/24 year, which represents the best information available at this time, as the BCUC levy calculation for Fiscal 2024/25 will not be available until early or mid 2024.

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.

[37] Decision and Order G-12-20, Section 5.1, Table 3, p. 25.

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:

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

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Program Overhead	2.648	3.880	3.986
2	City of Surrey	0.010	0.016	0.017
3	Kelowna	0.512	0.703	0.745
4	Salmon Arm	0.200	0.268	0.283
5	Fraser Valley Biogas	0.012	0.013	0.013
6	Seabreeze Farms	0.012	0.013	0.013
7	Lulu Island WWTP	0.012	0.013	0.013
8	Dickland Farms	0.012	0.013	0.013
9	City of Vancouver	0.340	-	0.572
10	REN Energy	-	0.013	0.013
11	Capital Regional District	0.004	0.013	0.013
12	Net Zero Waste	0.009	-	-
13	Delta RNG (MAS Energy)	1.467	0.133	0.133
14	Total Biomethane O&M	5.237	5.075	5.817

The 2023 Projected Biomethane O&M is lower than 2023 Approved. This is due to lower than forecast O&M for various projects, including the City of Vancouver (COV) and Delta RNG (MAS Energy) projects. The lower projected O&M for the Delta RNG project is due to a delay by the supplier in the start-up of the project. These decreases are partially offset by an increase in program overhead which is primarily due to increased costs related to staffing, legal fees for new biomethane agreements, increased costs for customer awareness, and development costs for new in-Province projects.

For 2024, FEI is forecasting the Biomethane O&M to be $5.817 million, which is $0.742 million higher than the 2023 Projected level. The increase is primarily due to the additional operation costs for the COV biomethane production project at approximately $0.572 million, which is expected to be in service in 2024.

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 2023	Projected 2023	Forecast 2024
1	Renewable Gas Development	2.000	3.069	4.052

Since the commencement of the current MRP term, government policies and regulations regarding climate action have continued to progress, re-enforcing the need to prepare FEI's system for the introduction of hydrogen, lignin and synthesis gas as energy options. The GGRR was amended in May 2021 to include hydrogen, synthesis gas and lignin as low carbon fuels. In October 2021, the Province announced in its CleanBC update that it is targeting a 47 percent reduction in GHGs in building and industry by 2030, to be implemented through a Greenhouse Gas Reduction Standard (GHGRS). These policy initiatives will expand the resources that are required to support renewable gas development and FEI continues to progress, in a measured way, various activities to enable the introduction of these energy options into its system. The increased costs for renewable gas development reflect this increased work. For 2023 and 2024, FEI expects to continue to progress potential opportunities to develop the supply and use of hydrogen, lignin, and syngas, including the following:

- Advancing technical and non-technical activities to evaluate the feasibility of pursuing the development of facilities to produce renewable and low-carbon hydrogen, including production technology and project applications, project economics, joint venture opportunities, and offtake requirements on several different hydrogen supply opportunities;
- Evaluating several third-party hydrogen and lignin offtake supply opportunities; and
- Continuing a broad-based program of feasibility and system readiness assessments to distribute hydrogen, end-use impacts, workforce training, and customer and stakeholder education that will enable the safe distribution and customer end-use of hydrogen.

The 2023 Projected expenditures are approximately $3.069 million, which is an increase of $1.069 million from 2023 Approved. The 2023 Projected O&M costs include $1.25 million in internal labour resources (consistent with the amount included in 2023 Approved) as well as increased costs for the use of external consultants to successfully execute on planned activities to meet business goals and objectives. FEI engaged external contractors and professional service providers to provide additional multi-disciplined and specialized resources to assist FEI internal resources with various activities and projects, as described below. The 2023 Projected expenditures include $1.8 million for work related to requirements to continue progressing the ongoing hydrogen development activities on supply acquisition, offtake and end-use feasibility, safety, codes and standards, feasibility, and business development. Actual expenditures in 2023 may vary from that projected depending on the timing of contractor awards and completion of work scope activities and deliverables.

The 2024 Forecast is $4.052 million, which represents an approximately $0.983 million increase from 2023 Projected, and is related to requirements to continue work to progress feasibility, safety, codes and standards, and business development. The 2024 Forecast includes an increase in labour costs to approximately $1.4 million for one incremental resource and an increase in non-labour costs to approximately $2.6 million. The main drivers for the increase in non-labour costs are related to the activities and projects described below. 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.

FEI is undertaking the following specific activities and projects related to the development of hydrogen and lignin which require increased non-labour resources in 2023 and 2024.

Hydrogen Production Supply Opportunities – 2023 Projected and 2024 Forecast Non-Labour Resource Activities to Progress Production Project Preliminary Feasibility:

- 2023 – continue feasibility evaluation of various hydrogen production facility development opportunities in FEI's Interior and Lower Mainland service areas. Review potential policy, regulatory and permitting requirements to offtake hydrogen from the production facilities, including distribution in the natural gas distribution system, or supply hydrogen directly to industrial customers other than through the natural gas distribution system to replace natural gas.

- 2024 – continue progress from 2023 with goal to reach Final Investment Decision on a commercial pilot.

Hydrogen Offtake Supply Opportunities – 2023 Projected and 2024 Forecast Non-Labour Resource Activities to Progress Procurement Feasibility:

- 2023 – continue evaluation of several potential third-party proposals that are considering developing projects to produce clean hydrogen for supply to offtakes such as FEI. Review regulatory and permitting requirements to offtake hydrogen from third-party production facilities for distribution in the natural gas distribution system, or supply hydrogen directly to industrial customers other than through the natural gas distribution system to replace natural gas.

- 2024 – continue from 2023 with goal to advance one opportunity to definitive agreement.

Lignin Offtake Supply Opportunities – 2023 Projected and 2024 Forecast Non-Labour Resource Activities to Progress Procurement Feasibility:

- 2023 – continue to evaluate a potential third-party supplier that is considering developing a project to produce lignin from black liquor which would be used by the industrial customer to replace, in part, natural gas used at the site. Review policy, regulatory and permitting requirements for energy measurement and billing to support the commercial transaction and develop draft commercial and legal requirements for a lignin supply agreement.

- 2024 – continue from 2023 with goal to advance one opportunity to definitive agreement.

Hydrogen Distribution and Customer End-Use Service – 2023 Projected and 2024 Forecast Non-Labour Activities to Progress Gas System Hydrogen Readiness Assessment and Conversion:

- 2023 – FEI intends to select a preferred vendor and negotiate a contract to award the project to determine the overall requirements to distribute hydrogen in the gas system, address any end-use impacts, and customer and stakeholder education that will enable the safe distribution and customer end-use of hydrogen. The intent of the project is to enable hydrogen blending initially at relatively low percentage blend levels and increase the blend percentage over time in line with the provincial regulatory approval requirements.

- 2024 – FEI expects to commence the project in the first half of 2024 and it will run for a number of years.

Concurrent Hydrogen Development Enabling Initiatives – 2023 Projected and 2024 Forecast Non-Labour Resource Activities to Achieve Progress:

- 2023 and 2024 – continue progressing various concurrent activities including workforce education and training initiatives, engaging with technical regulators in BC, Canadian Standards Association (CSA), Canadian Gas Association, NRCan, and various other authorities having jurisdiction regarding various initiatives on hydrogen safety, codes and standards.

Hydrogen Demonstration Pilot Projects – 2023 Projected and 2024 Forecast Non-Labour Resource Activities to Progress Preliminary Feasibility:

- 2023 and 2024 – continue to progress from preliminary feasibility to more detailed feasibility and project development for hydrogen blending projects that would blend hydrogen into a relatively small, isolated section of FEI's distribution system in the Interior and the Lower Mainland. Also continue engaging with multiple collaborators to advance preliminary feasibility and project definition for a hydrogen blending project that would blend hydrogen to replace natural gas use at an industrial site on Vancouver Island.

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 2023	Projected 2023	Forecast 2024
1	CNG Stations	0.980	1.352	1.531
2	LNG Stations	0.272	0.319	0.323
3	LNG Tankers	0.615	0.670	0.680
4	Emergency Response and Preparedness (ERAP)	0.070	0.070	0.070
5	Total NGT O&M	1.937	2.412	2.604

The 2023 Projected O&M expense is $0.475 million higher than the 2023 Approved. This is primarily due to a projected increase in CNG load at the GFL Environmental Inc. Fuelling Station located in Abbotsford to the end of 2023.[38]

The 2024 Forecast NGT O&M expense is $0.192 million higher than the 2023 Projected amount, primarily due to an expected increase in CNG load at the Annacis Island Fuelling Station.

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.

[38] Increasing throughput at CNG stations will increase the runtime of the compressors as well as other equipment at the station, resulting in an expected increase in O&M expenses.

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

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Tilbury Plant:			
2	Labour	1.775	2.253	2.339
3	Materials	0.794	0.600	0.623
4	Contractor	0.637	0.230	0.239
5	Power	3.634	3.826	3.909
6	Fees and Employee Expenses	0.332	0.186	0.193
7	Sub-total	7.172	7.095	7.304
8	Mt. Hayes Plant			
9	Labour	0.339	0.360	0.374
10	Materials	0.028	0.025	0.026
11	Contractor	0.060	0.183	0.190
12	Power	0.261	0.236	0.241
13	Fees and Employee Expenses	0.000	0.000	0.000
14	Sub-total	0.687	0.804	0.831
15	Total O&M	7.859	7.899	8.135

The Variable LNG Production O&M expense required for operation of the expanded Tilbury LNG facility[39] 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. The 2023 Projected variable labour is higher than 2023 Approved, as additional new hires to support LNG loading are expected to contribute to higher labour costs. Labour costs are also expected to increase to reflect the full cost of staffing and labour required. The increase in the 2024 Forecast compared to 2023 Projected is due to salary increases.

The materials costs are for materials related to the production of LNG. In 2023, expenditures are projected to be slightly lower compared to the 2023 Approved. In 2024, compared to 2023 Projected, materials costs are expected to increase due to inflation.

Contractor costs are for variable contractor services used for truck loading and support of production related activities. For Tilbury, the contractor costs in 2023 are projected to be lower than the 2023 Approved level based on the anticipated work for the year. FEI expects contractor services at Tilbury for 2024 will be consistent with the 2023 Projected level. For Mt. Hayes, the contractor costs are projected to be higher than the 2023 Approved level. The increase is

[39] 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.

primarily due to increased road maintenance and snow removal work on the gravel road leading to and from the plant for improving safety and driving conditions for LNG tankers. FEI expects the contractor costs at Mt. Hayes in 2024 will be similar to the 2023 Projected level plus inflation.

Other variable costs include power (i.e., electricity) costs and consumables. Electricity costs vary with production. The 2023 Approved electricity costs were forecast based on approximately 1.5 PJ of LNG sales, which was a conservative estimate as it did not include all forecast LNG sales at the time of the 2023 Annual Review due to the uncertainty of non-NGT LNG exports. The 2023 Projected electricity costs are based on 2.1 PJ of LNG sales, resulting in higher electricity costs when compared to 2023 Approved. The 2.1 PJ of LNG sales includes approximately 1.5 PJ of NGT LNG sales and approximately 0.6 PJ of non-NGT LNG exports. The electricity costs associated with the non-NGT LNG exports included in the 2023 Projected amount are based on six months of actual non-NGT LNG sales volumes in 2023. For 2024, FEI continues to use 2.1 PJ of LNG sales to forecast electricity costs but assumes higher electricity rates from BC Hydro, with an increase of approximately 2 percent. Actual electricity costs will vary depending on the demand for LNG exports. Please refer to Section 3.3.4 of the Application for further discussion.

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 Order G-165-20, the capitalized overhead rate is set at 16 percent for FEI. After capitalized overhead and the transfer of $5.817 million of Biomethane O&M to the BVA, the net O&M expense for 2024 is $305.157 million.

6.5 SUMMARY

Overall, the increase in gross O&M expense from 2023 Approved to 2024 Forecast is 4.4 percent. The formula-driven O&M is increasing at a rate of 4.4 percent and the O&M forecast outside of the formula is increasing by 4.2 percent. The capitalized overhead rate of 16 percent remains unchanged from 2023, as approved by Order G-165-20.

7. RATE BASE

7.1 INTRODUCTION AND OVERVIEW

Rate Base for FEI is forecast to be $5.816 billion for 2024. 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, and deferred income tax.

FEI's 2024 Rate Base includes the full-year impacts of the 2023 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 $359.691 million;
- Mid-year impact of plant depreciation, net of CIAC amortization of $223.244 million; and
- Capital additions of CPCN and Major Projects of $62.185 million as discussed in Section 7.2.3.2 below, which include:
    - Mid-year impact of $3.959 million for the final commissioning components of the Tilbury 1A Expansion Project;
    - Full-year impact of $45.578 million of capital expenditures and related AFUDC for the IGU Project;
    - Full-year impact of $12.489 million of capital expenditures and related AFUDC for the Gibsons Capacity Upgrade (GCU) Project; and
    - Full-year impact of $0.006 million and $0.153 million of final close out costs and related AFUDC for the Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) Project and Pattullo Gas Line Replacement (PGR) Project, respectively.

In addition, various changes in deferred charges, working capital and other items reduce Rate Base by a net amount of $261.658 million in 2024.

Details of the 2024 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;
- 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, as part of the FEI Annual Review for 2023 Delivery Rates Decision and Order G-352-22, FEI received approval of its forecasts of regular sustainment and other capital expenditures for the years 2023 and 2024.

The components of FEI's 2024 regular capital expenditures are shown in Table 7-1 below.

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

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024	Reference
1	Formula Growth Capex	87.531	87.531	54.639	Section 11, Schedule 4, Line 10
2	Forecast Sustainment & Other Capex	183.850	183.850	181.880	Section 11, Schedule 4, Lines 16 + 17
3	Flow through Capex	64.992	31.117	48.939	Section 11, Schedule 4, Sum of Lines 13 to 15
4	Total Gross Regular Capex	336.373	302.498	285.458	Sum of Line 1 to 3; Section 11, Schedule 4, Line 20
5	Less: Formula CIAC	(2.453)	(2.453)	(2.388)	Section 11, Schedule 9, Line 2
6	Less: Forecast CIAC	(4.342)	(4.342)	(12.542)	Section 11, Schedule 9, Line 3 to 5
7	Net Regular Capex	329.578	295.703	270.528	Sum of Line 4 to 6

In the subsections below, FEI provides further details on its regular capital expenditures for 2024.

7.2.1 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., 2022).

As calculated in Section 2, the 2024 net inflation factor based on prior year's BC-CPI and BC-AWE is 3.854 percent. Forecast gross customer additions in 2024 of 15,000 are then multiplied by the unit cost for growth capital.

For 2024, the annual growth capital expenditures under the formula are calculated as:

> 2023 Approved formula UCGC x [1 + Net Inflation Factor] x 2024 Gross Customer Additions + 2022 Formula Growth Capital True-up + 2024 Formula CIAC + 2024 Forecast SEF

Table 7-2 below shows the calculation of the resulting 2024 Formula growth capital expenditures.

Table 7-2: Calculation of 2024 Formula Growth Capital ($ millions)

Line No.	Description	Forecast 2024	Reference
1	Prior Year Base Unit Cost Growth Capital	4,205	G-352-22 and Section 11, Schedule 4, Line 2
2	Net Inflation Factor	3.854%	Section 11, Schedule 3, Line 9, Column 7
3	Current Year Unit Cost Growth Capital	4,367	Line 1 x (1 + Line 2)
4	Gross Customer Addition Forecast	15,000	Section 11, Schedule 4, Line 5
5	Inflation Indexed Growth Capital	65.505	Line 3 x Line 4 / 1,000,000
6	2022 Growth Capital True-up	(14.254)	Line 16
7	Formulaic CIAC	2.388	Section 11, Schedule 9, Line 2, Column 5
8	System Extension Fund	1.000	G-338-20 SEF Decision
9	Gross Formula Growth Capex	54.639	Sum of Line 5 to Line 8
10			
11	2022 Growth Capital True-up		
12	2022 Actual Gross Customer Addition	16,477	Section 2, Table 2-3
13	2022 Forecast Gross Customer Addition	20,000	G-366-21 2022 FEI Annual Review Decision
14	Difference	(3,523)	Line 12 - Line 13
15	2022 Unit Cost Growth Capital ($/customer)	4,046	G-366-21 2022 FEI Annual Review Decision
16	Growth Capital True-up in 2023	(14.254)	Line 14 x Line 15 / 1,000,000

The 2024 Gross Formula growth capital amount is $54.639 million. This amount includes the 2022 growth capital true-up reduction of $14.254 million, the formulaic CIAC amount of $2.388 million, and the forecast SEF amount for 2024 of $1 million[40].

7.2.2 Forecast Capital Expenditures

The level of forecast capital expenditures approved for 2024 as part of the Annual Review for 2023 Delivery Rates Decision and Order G-352-22 is shown in Table 7-3 below. The 2023 Approved and Projected are also shown for information purpose.

Table 7-3: Forecast Capital Expenditures ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024	Reference
1	Sustainment Capital	129.336	129.336	130.628	Section 11, Schedule 4, Line 16
2	Other Capital	54.514	54.514	51.252	Section 11, Schedule 4, Line 17
3	Total	183.850	183.850	181.880	Line 1 + Line 2

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.

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

The amounts for 2024 are shown in Table 7-4 below along with a comparison to 2023.

Table 7-4: Flow-Through Regular Capital Expenditures ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024	Reference
1	Pension/OPEB (Growth Capital Portion)	1.034	1.034	0.871	Section 11, Schedule 4, Line 13
2	Biomethane Assets	58.571	29.583	43.068	Section 11, Schedule 4, Line 14
3	NGT Assets	5.387	0.500	5.000	Section 11, Schedule 4, Line 15
4	Forecast Regular Capex	64.992	31.117	48.939	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 $0.871 million represent the forecast growth capital portion of the total Pension and OPEB costs for 2024. Pension and OPEB costs are described in Section 6.3.1.

Biomethane Capital

Table 7-5 below provides the 2023 Approved, 2023 Projected and 2024 Forecast for Biomethane capital expenditures, including the Order approving each project.

Table 7-5: Biomethane Capital Expenditures ($ millions)

Line No.	Description	BCUC Order	Approved 2023	Projected 2023	Forecast 2024
1	Kelowna	E-19-12	-	0.250	0.500
2	REN Energy	G-60-20	-	-	0.500
3	Foothill LF (RDFFG)	E-2-22	10.000	2.000	2.000
4	Dickland Farms	E-13-20	-	0.700	-
5	Capital Regional District	E-15-21	3.000	7.000	3.000
6	City of Vancouver	G-235-19	21.771	17.533	16.613
7	Net Zero Waste	E-21-21	1.000	-	5.000
8	Delta RNG	E-3-22	6.000	1.500	4.205
9	Comox Valley LF	To be filed	10.800	0.500	2.000
10	Andion - Semiahmoo	To be filed	2.000	0.100	2.000
11	Vernon LF	To be filed	4.000	-	2.000
12	Fraser Valley Biogas Expansion	To be filed	-	-	4.250
13	Ecowaste	To be filed	-	-	1.000
14	**Total Biomethane CAPEX**		**58.571**	**29.583**	**43.068**

The 2023 Projected and 2024 Forecast Biomethane capital expenditures are $29.583 million and $43.068 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 2023 Projected capital expenditures are less than 2023 Approved by $28.988 million. The variance between 2023 Projected and Approved is the result of a delay in spending on various projects, as summarized in Table 7-5 above, which was partially offset by additional spending on the Capital Regional District (CRD) project. For the CRD project, FEI built a pipeline and station which are expected to be substantially complete in 2023, ahead of the CRD facility completion which is expected to come online in 2024. The lower 2023 Projected expenditures for Foothill LF (RDFFG) are a result of a refreshed schedule which will delay the in-service date. The lower projected capital for the Comox Valley LF, Andion – Semiahmoo, and Vernon LF projects are due to delays in finalizing agreements with these counterparties. The Delta RNG project pipeline has been delayed due to permitting, but FEI has completed the interconnection station and expects to begin taking delivery via a virtual pipeline in 2023; the capital spend on the pipeline will be incurred at a future time.

For the 2024 Forecast capital expenditures of $43.068 million, approximately 39 percent of this amount is related to the final capital costs of the COV project. FEI is now expecting the COV project to be complete and in-service in 2024. The remainder of the 2024 Forecast capital expenditures are related to spending on existing projects such as Kelowna, REN, RDFFG, CRD, Net Zero Waste and Delta RNG, as well as new projects that are expected to be filed for acceptance late in 2023.

Natural Gas for Transportation (NGT) Assets

Table 7-6 provides additional detail by project for the 2023 and 2024 NGT Assets capital expenditures.

Table 7-6: NGT Assets Capital Expenditures ($ millions)

Line No.	Description	BCUC Order	Approved 2023	Projected 2023	Forecast 2024
1	T1A Truck Load-out	GGRR	5.387	0.500	5.000
2	**Total NGT Capital Expenditures**		**5.387**	**0.500**	**5.000**

The 2023 Projected and 2024 Forecast NGT Assets capital expenditures are $0.500 million and $5.000 million, respectively.

The Tilbury T1A truck load-out project has been delayed and the majority of the remaining expenditures are forecast to be incurred in 2024. The reason for the delay is the contractor executing the project filed for bankruptcy protection in April 2023. As a result, completion of this project has been delayed until a path forward with the surety company and stakeholders is established. As of December 2022, FEI had incurred approximately $12.947 million (excluding AFUDC) of capital expenditures for the Tilbury T1A truck load-out project. FEI incurred a further $500 thousand (excluding AFUDC) in early 2023 (as shown in Table 7-6 above under 2023 Projected) prior to the contractor filing for bankruptcy. FEI is expecting to complete the project in

2024. FEI notes the Tilbury T1A truck load-out is a Prescribed Undertaking under the GGRR;[41] as such, 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.

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.[42]

7.2.3.2.1 APPROVED MAJOR PROJECTS

In 2024, FEI is forecasting capital expenditures related to the following approved projects:

- Tilbury 1A Expansion Project;
- Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) Project;
- Inland Gas Upgrade (IGU) Project;
- Pattullo Gas Line Replacement (PGR) Project;
- Coastal Transmission System (CTS) Transmission Integrity Management Capabilities (TIMC) Project;
- Gibsons Capacity Upgrade (GCU) Project; and
- Advanced Metering Infrastructure (AMI) 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 the Tilbury 1A Expansion Project to be within the authorized amount, at a total of approximately $495 million ($425 million excluding AFUDC and feasibility and

[41] BC GGRR Prescribed Undertaking 2(3)(a)(ii).
[42] MRP Decision and Order G-165-20, pp. 132-133.

development costs). A total of $488.982 million was added to rate base by the end of 2022.[43] FEI forecasts 2023 expenditures of $2.041 million that will be added to rate base in 2023 and final 2024 expenditures of $3.959 million that will be added to rate base in 2024.[44] These expenditures are the close out costs for the process scrubber as well as for 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 and the Fraser Gate IP project. 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 $0.941 million and $0.006 million (excluding AFUDC) in 2023 and 2024, 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 $429.859 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 upgraded the Cranbrook-Kimberley loop, Salmon Arm loop and lateral and Cariboo Pulp lateral with a cost of $67.361 million being added to rate base on January 1, 2023. For 2023, FEI is projecting expenditures of $58.884 million ($61.002 million including AFUDC), with $45.578 million (including AFUDC) expected to be added to rate base on January 1, 2024. For 2024, FEI is forecasting $20.721 million (excluding AFUDC) of capital expenditures. As provided

[43] The amounts that entered rate base in 2019, 2020, 2021, and 2022 were $481.992 million, $3.966 million, $2.516 million, $0.508 million, respectively.

[44] Including prior years capital additions of $488.982 million up to the end of 2022, plus $2.041 million for 2023 and $3.959 million for 2024 equals to $494.982 million (including AFUDC).

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 new NPS 20 (508 mm) gas line and associated facilities in the City of Burnaby have been completed in 2022 with approximately $150.8 million added to rate base on January 1, 2023. The remaining project scope includes decommissioning and/or abandonment of existing infrastructure that are no longer required due to the removal of the Pattullo Gas Line crossing of the Fraser River. FEI forecasts expenditures of $3.704 million and $0.153 million (excluding AFUDC) in 2023 and 2024, respectively, related to the decommissioning and/or abandonment work of the existing infrastructure.

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 CTS 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 capital expenditures forecast to be $22.746 million and $63.107 million (excluding AFUDC), respectively. There are no capital additions to rate base in 2024 as the project is expected to be completed by the end of 2025. As described in the CTS TIMC Project CPCN application, the total estimated capital cost for the project, including AFUDC, is approximately $137.8 million.

GCU Project

The GCU Project was filed with the BCUC as part of the 2023 Annual Review and the forecast capital expenditures were approved by Order G-352-22. The GCU Project involves a new local CNG peak shaving facility to address the shortfall of capacity supplied to the community of Gibsons during design conditions. The GCU Project is expected to be complete in 2023 with a forecast total capital cost of $12.489 million, including AFUDC, which will be added to rate base on January 1, 2024. FEI is not expecting capital expenditures in 2024 related to the GCU Project.

AMI Project CPCN

The AMI Project CPCN application was filed with the BCUC in May 2021 and was approved by Order C-2-23 on May 15, 2023. The AMI Project involves installation of approximately 1 million residential, commercial, and industrial advanced gas meters and meter retrofits of communication modules capable of remote gas consumption measurement. The project also includes installation of approximately 1,100 communication modules on FEI's gas network as well as installation of the AMI network and infrastructure for communication with the AMI meters.

Given the timing of the decision, initiation of the AMI Project is in the very early stages and FEI is not expecting to have any capital additions to rate base in 2024. FEI is currently developing the final capital budget and schedule; on July 21, 2023, FEI requested BCUC approval to defer the first semi-annual progress report to January 31, 2024. FEI will provide the updated capital budget and schedule as part of the first semi-annual progress report. According to the forecast provided in the CPCN application, the total capital expenditures during the pre-deployment and deployment stages are estimated to be $752.5 million up to 2026[45].

7.3 2024 PLANT ADDITIONS

The 2024 Plant Additions are comprised of: (i) FEI's 2024 regular capital expenditures from Section 7.2 above; (ii) the change in work in progress which adjusts for capital expenditures for projects that are still in progress at year end; (iii) AFUDC; (iv) overhead capitalized for the year; and (v) the additions from Major Projects on January 1, 2024 related to the Tilbury 1A Expansion Project, LMIPSU Project, IGU Project, PGR Project, and GCU Project as discussed in Section 7.2.3.2 above.[46] A reconciliation of capital expenditures to plant additions is shown in Table 7-7 below and is also provided in Section 11, Schedule 5.

[45] AMI CPCN Application, Evidentiary Update, Appendix A, Table 6-1.
[46] No plant additions in 2024 related to the CTS TIMC Project and the AMI Project.

Table 7-7: Reconciliation of 2024 Capital Expenditures to Plant Additions ($ millions)

Line No.	Description	2024 Forecast	Reference
1	Formula Growth Capex	54.639	Section 11, Schedule 4, Line 10
2	Forecast Sustainment & Other Capex	181.880	Section 11, Schedule 4, Line 16 + Line 17
3	Flow through Capex	48.939	Section 11, Schedule 4, Sum of Line 13 to Line 15
4	Total Gross Regular Capex	285.458	Sum of Line 1 to 3
5	Capitalized Overheads	59.233	Section 11, Schedule 5, Line 21
6	AFUDC	9.526	Section 11, Schedule 5, Line 22
7	Change in Work in Progress	20.404	Section 11, Schedule 5, Line 24
8	Total Regular Additions to Plant	**374.621**	Sum of Line 4 to 7
9			
10	Special Projects and CPCN Capex		
11	Tilbury Expansion Project	3.959	Section 11, Schedule 5, Line 7
12	IGU Project	20.721	Section 11, Schedule 5, Line 9
13	CTS-TIMC Project	63.107	Section 11, Schedule 5, Line 10
14	AMI Project	55.000	Section 11, Schedule 5, Line 12
15	LMIPSU	0.006	Section 11, Schedule 5, Line 8
16	PGR	0.153	Section 11, Schedule 5, Line 11
17	AFUDC	7.166	Section 11, Schedule 5, Line 28
18	Change in Special Projects and CPCN Work in Progress	(87.927)	Section 11, Schedule 5, Line 30
19	Total Special Projects and CPCN Additions to Plant	**62.185**	Sum of Line 11 to 18
20			
21	Total Plant Additions	**436.806**	

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 2024 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 2024 depreciation expense is calculated as $219.593 million.[47]

7.5 DEFERRED CHARGES

On May 3, 2017, the BCUC issued its Regulatory Account Filing Checklist.[48] 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.

[47] $228.416 million depreciation expense as calculated in Section 11, Schedule 21, Line 5 less $8.823 million amortization of CIAC as calculated in Section 11, Schedule 21, Lines 11 and 12.

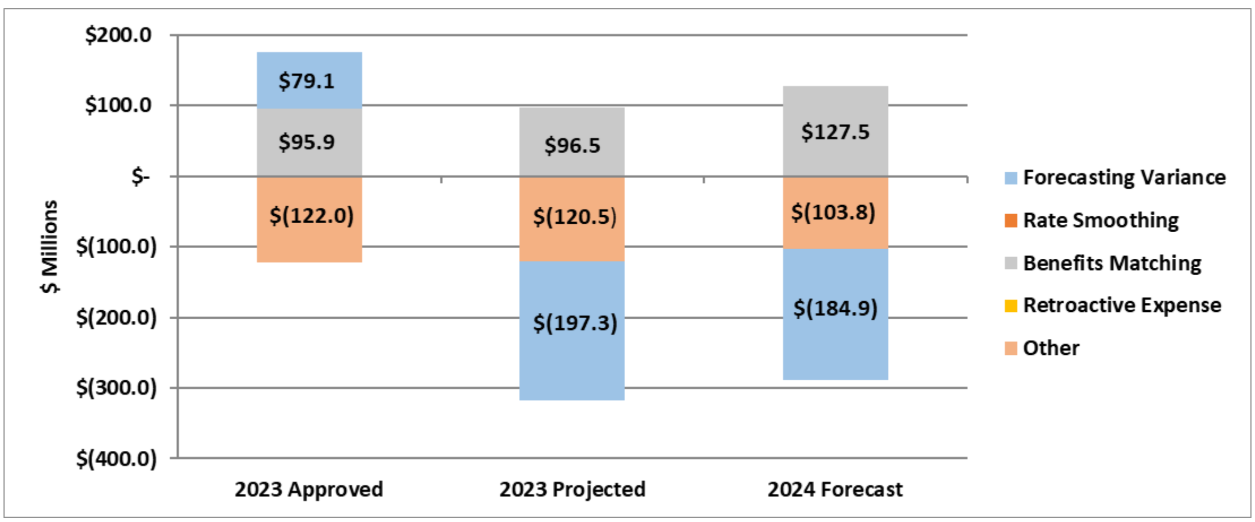
[48] Log No. 53608, Appendix B.

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 2024 Forecast mid-year balance of unamortized deferred charges in rate base for FEI is a credit of $161.137 million.

Figure 7-1 below provides the mid-year deferral account balances summarized by deferral account category. The largest drivers of the 2024 Forecast credit balance are forecasting variance deferral accounts, in particular, the MCRA and CCRA. The large reduction in the mid-year balances of the MCRA and CCRA is mainly due to strong mitigation performance by FEI at the end of 2022 when there were large price spreads that occurred between FEI's supply markets (i.e., Station 2 and AECO/NIT) and the market demand centres (i.e., Huntingdon/Sumas and Kingsgate), as well as a favourable forward commodity gas prices. Other deferral accounts contributing to the credit balance are the Net Salvage Provision deferral account and the net variance between the Pension and OPEB Funding accounts. The credit balance is partially offset by the debit balances in several deferral accounts, in particular, the DSM deferral account and the Greenhouse Gas Reduction Regulation Incentives deferral account.

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



Based on the approved amortization of each deferral account and the 2024 opening balances, the 2024 amortization expense to be recovered as part of the proposed 2024 delivery margin is calculated as $134.012 million, including both rate base and non-rate base deferral accounts.[49] 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.

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

7.5.1 New Deferral Accounts

FEI is seeking approval of four new rate base deferral accounts in this Application:

- 2025 Multi-year Rate Plan (MRP) Application;
- 2023 Cost of Service Allocation (COSA) Study;
- 2024-2027 Demand Side Management (DSM) Expenditure Plan; and
- PST Rebate on Select Machinery and Equipment.

The purpose of the first three new deferral accounts is to capture costs related to the regulatory processes for the applications associated with each account. The final new deferral account is for capturing the PST rebates from the Province of BC. Table 7-8 below addresses the considerations identified in the BCUC Regulatory Account Filing Checklist, as they pertain to the deferral accounts requested in Sections 7.5.1.1 to 7.5.1.4 below.

Table 7-8: Deferral Account Filing Considerations

Item	Consideration	Regulatory Proceeding Costs (2025 MRP, 2023 COSA, and 2024-2027 DSM Expenditures)	PST Rebate on Select Machinery and Equipment
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.	The three regulatory proceeding cost accounts are new deferral accounts, consistent with previously approved regulatory proceeding deferral accounts. Please refer to Sections 7.5.1.1 to 7.5.1.3 for additional information.	The PST Rebate on Select Machinery and Equipment is a new deferral account. Please refer to Section 7.5.1.4 for additional information.
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	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 accounts are regulatory proceeding cost accounts, which are routinely sought by utilities to capture external costs related to the preparation, filing, and regulatory review of applications.	The requested account will capture PST Rebates on Select Machinery and Equipment received from the Province of BC.

Item	Consideration	Regulatory Proceeding Costs (2025 MRP, 2023 COSA, and 2024-2027 DSM Expenditures)	PST Rebate on Select Machinery and Equipment
II.	Propose a term (i.e. length of time) that the regulatory account should be approved for and explain why that term is appropriate.	The term of each account encompasses the preparation and filing of the relevant regulatory application and its review by the BCUC.	The term of the account encompasses the required time for the Province of BC to approve the qualified claim filed by FEI and issue the refund payment.
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 deferral accounts for regulatory proceedings, the costs of regulatory proceedings would have to be forecast as an O&M expense (outside of the MRP index-based O&M since regulatory proceeding costs are not included in Base O&M Expense) and trued up annually by way of the Flow-through deferral account. FEI considers this to be a more cumbersome and less efficient means of accounting for regulatory proceeding costs. It is accepted regulatory practice to defer the costs of regulatory applications for review and recovery following the regulatory review of the application itself. Review and recovery after the completion of the regulatory process allows for more transparency as the history of the costs is simpler to track and report.	In the absence of a deferral account, the rebate would be recorded as an offset in the applicable accounts where the original PST costs were recorded, whether those accounts were O&M or capital. FEI considers this to be a less transparent way of recording the rebates as it is the cost of service impacts of the amounts credited to capital that would be returned to customers over a longer timeframe, rather than the rebate amount itself over one year as proposed using the deferral account approach.

Item	Consideration	Regulatory Proceeding Costs (2025 MRP, 2023 COSA, and 2024-2027 DSM Expenditures)	PST Rebate on Select Machinery and Equipment
IV a)	Address: whether, or to what extent, the item is outside of management's control;	Regulatory proceeding cost accounts are necessary because the number and type of regulatory proceedings can vary significantly by year. Further, once a regulatory proceeding is identified, the costs of that proceeding cannot be accurately forecast by the utility given that they can vary substantially, are not known at the time of making the regulatory account request, are unique to the circumstances for each application, may change as the regulatory review process unfolds, and are dependent on factors not within the utility's control. Factors not within the control of the utility include the regulatory process determined by the BCUC and the degree of involvement of interveners.	The final amount of PST rebates claimed by FEI are subject to approval by the Province of BC.
b)	the degree of forecast uncertainty associated with the item;	Refer to IV. a). FEI forecasts additions to the deferral accounts based on the expected type of review process and degree of intervener involvement. Actual costs are recorded in the account so that actual, not forecast, costs are recovered in rates.	Refer to IV. a). FEI forecasts additions to the deferral account based on the rebates received to date plus those claimed and expected to be received. Actual expected rebates will be recorded in the account so that actual, not forecast, rebates are returned in rates.
c)	the materiality of the costs	The number and size of regulatory proceedings vary from year to year, and represent costs not included in Base O&M for the purpose of determining formula O&M Expense under the MRP. Please refer to Sections 7.5.1.1 to 7.5.1.3.	FEI expects rebates of approximately $2.173 million ($1.586 million after-tax). Please refer to Section 7.5.1.4 for additional information.
d)	any impact on intergenerational equity	Generally, FEI recovers the costs of regulatory proceedings over the period of time related to the application, which serves to match the costs and benefits. Please refer to Sections 7.5.1.1 to 7.5.1.3. There are no intergenerational inequities inherent in this practice.	FEI expects to return the rebates over the same period of time as the qualifying period to make the PST rebate claims. There are no intergenerational inequities in this practice.

Item	Consideration	Regulatory Proceeding Costs (2025 MRP, 2023 COSA, and 2024-2027 DSM Expenditures)	PST Rebate on Select Machinery and Equipment
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 generally classifies regulatory proceeding accounts as benefit matching accounts since the costs are recovered over the period of time related to the applications, which serves to match the costs and benefits of the application.	The account is classified as "other".
VI.	Identify if the regulatory account is a cash or non-cash account.	Regulatory proceeding cost accounts are cash accounts.	The PST Rebate on Select Machinery and Equipment is a cash account.
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 costs include the BCUC's direct costs, notice publication costs, fees for consultants or experts, external legal counsel fees, courier and miscellaneous administrative costs, and participant cost awards incurred in the preparation, filing and regulatory review of the applications. Regular labour and staff expenses related to regulatory applications are included in formula O&M expense.	PST Rebates received from the Province of BC for claims filed by FEI for the qualifying period. Please refer to Section 7.5.1.4 for additional information.
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 will be recovered in revenue requirements by way of amortization expense.	Rebates will be refunded 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.	Generally, FEI proposes to amortize the costs of regulatory proceedings over the period of time related to the application, which serves to match the timing of costs and benefits. Please refer to Sections 7.5.1.1 to 7.5.1.3.	FEI proposes to refund the rebates over one year beginning January 1, 2024, to match the approximate qualifying period of eligible PST paid on purchases. Please refer to Section 7.5.1.4 for additional information.
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).	Rate base deferral accounts are included in rate base and therefore implicitly financed using the weighted average cost of capital (WACC).

Item	Consideration	Regulatory Proceeding Costs (2025 MRP, 2023 COSA, and 2024-2027 DSM Expenditures)	PST Rebate on Select Machinery and Equipment
XI.	Outline a recommended regulatory process for the Commission's review of the application.	The proposed deferral accounts can be reviewed as part of the present proceeding. Deferral account approvals and disposition are generally determined in revenue requirements proceedings.	

7.5.1.1 2025 Multi-year Rate Plan (MRP) Application

FEI's current Multi-year Rate Plan (MRP) approved by Order G-165-20 will end in 2024. FEI has started developing its next rate plan and expects to file this rate plan with the BCUC in early 2024. FEI will incur regulatory costs related to the development of the application and is requesting approval to establish a rate base deferral account to capture these costs, which will include BCUC costs, participant funding costs, external legal fees, expert/consulting costs, notice publication costs, and miscellaneous facilities, stationery, and supplies costs. FEI forecasts costs of $0.350 million ($0.256 million after-tax) in 2023 and $1.200 million ($0.876 million after-tax) in 2024. Actual costs will vary depending on how the application progresses and will be confirmed after the regulatory process is completed.

FEI is only requesting approval to establish this deferral account. FEI will propose an amortization period for the deferral account in a future rate-setting application (i.e., subsequent to the completion of the 2025 MRP application proceeding).

7.5.1.2 2023 Cost of Service Allocation (COSA) Study

In the BCUC's Decision and Order G-4-18, dated January 9, 2018 (2016 COSA Decision), FEI was directed to file a comprehensive and updated COSA study for review by the BCUC five years after the release of its decision on FEI's 2016 Rate Design Application (RDA).[50] The BCUC issued its final Decision and Order G-135-18 (2016 RDA Decision) on July 20, 2018. In accordance with the 2016 COSA Decision and 2016 RDA Decision, FEI submitted its 2023 COSA Study and Revenue Rebalancing Application on July 20, 2023.

FEI is requesting approval to establish a rate base deferral account to capture the regulatory costs associated with the 2023 COSA Study and Revenue Rebalancing Application. These costs include BCUC costs, participant funding costs, external legal fees, and miscellaneous facilities, stationery, and supplies costs. FEI forecasts costs of $0.056 million (0.041 million after-tax) in 2023 and $0.084 million ($0.061 million after-tax) in 2024. Actual costs will vary depending on how the regulatory proceeding progresses and will be confirmed after the regulatory process is completed.

[50] 2016 COSA Decision, page 22 and Directive 5 of Order G-4-18.

FEI is only requesting approval to establish this deferral account. FEI will propose the disposition of this account in a future rate-setting application once the regulatory process is complete (or substantially complete).

7.5.1.3 2024-2027 DSM Expenditures Schedule Application

On July 12, 2023, FEI filed the 2024-2027 Demand Side Management (DSM) Expenditures Application. FEI is requesting approval to establish a rate base deferral account to capture regulatory costs associated with the 2024-2027 DSM Expenditures Application. These costs include BCUC costs, participant funding costs, external legal fees, expert/consulting costs, notice publication costs, and miscellaneous facilities, stationery, and supplies costs. FEI forecasts costs of $0.100 million ($0.073 million after-tax) in 2023 and $0.100 million ($0.073 million after-tax) in 2024.

Consistent with past practice, FEI proposes to amortize the costs over four years, beginning in 2024, which represents the four-year time period of the DSM plan. Any variances between the forecast account balances and the actual incurred costs will be amortized in rates in the following years.

7.5.1.4 PST Rebate on Select Machinery and Equipment

The BC PST Rebate on Select Machinery and Equipment is a provincial government program to help corporations recover from the financial impacts of the COVID-19 pandemic. Eligible businesses can receive as a rebate the PST paid on purchases of specified equipment and software during the qualifying period between September 17, 2020, and March 31, 2022.

FEI is eligible to claim a BC PST Rebate on Select Machinery and Equipment on capital purchases of software and equipment and has filed for these rebates for the qualifying periods as set out by the Province of BC. To date, FEI has received $1.071 million ($0.782 million after-tax) in rebates and expects additional rebates of approximately $1.102 million ($0.804 million after-tax) to be received by December 31, 2023.

FEI is requesting approval to establish a rate base deferral account to capture the PST Rebates on Select Machinery and Equipment received from the Province of BC. Further, FEI is proposing to amortize these rebates to customers over one year beginning January 1, 2024, to match the approximate qualifying period of eligible PST paid on purchases.

7.5.2 Existing Deferral Accounts

In the discussion below, FEI requests an amortization period for one existing deferral account.

7.5.2.1 Transportation Service Report

On July 20, 2018, the BCUC issued the 2016 RDA Decision, approving a number of rate design changes to FEI's Transportation Service model. The decision directed FEI to file a report on the Transportation Service Model by June 1, 2022, assessing the impact of the approved rate design changes, and to engage with stakeholders to review the Transportation Service Model in the preparation of the report. Subsequent to the 2016 RDA Decision, the BCUC issued its Decision and Order G-210-20 dated August 10, 2020, in the matter of a complaint filed by a marketer group directing that FEI address additional items in the Transportation Service Report.

As part of the Annual Review for 2022 Delivery Rates Decision and Order G-366-21, FEI received approval to establish the Transportation Service Report deferral account to capture the costs related to filing the Transportation Services Report. FEI filed the report on June 15, 2022 and incurred total costs of $0.236 million ($0.173 million after-tax) for consulting fees, legal expenses and BCUC costs.

In this Application, FEI is seeking approval to amortize these costs over one year commencing January 1, 2024.

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 by 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 2023 gas cost report and historical volumes. All other 2024 amounts are forecast based on 2022 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 7.5.1, FEI requested four new deferral accounts, and in Section 7.5.2, FEI requested an amortization period for one existing deferral 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 awaiting a decision on Stage 1 of the BCUC-initiated Generic Cost of Capital (GCOC) proceeding which it expects to be issued in the upcoming months. FEI will provide an update to its rate calculations as part of an Evidentiary Update subsequent to the GCOC decision being issued.

The 2024 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 2024 (which is equal to its after-tax weighted average cost of capital) is 5.50 percent[51]. 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 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 2024. FEI will use the funds to repay existing indebtedness and finance the Company's capital expenditure program. The 2024 debt issuance is reflected in the financial schedules in July 2024 at a rate of 4.70 percent[52]. The exact timing, amount and rate of the issuances will depend on future market conditions and capital expenditure requirements.

[51] As part of the Evidentiary Update, FEI will update the AFUDC rate for 2024 to reflect any changes resulting from the GCOC decision.

[52] Section 11, Schedule 27, Line 19 (effective rate 4.763 percent).

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 2027.[53] 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 2024 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 2024 is 4.27 percent, which is an increase from the 3.14 percent approved in 2023. FEI continues to face a rising interest rate environment due to high inflation and the Bank of Canada continuing to raise its policy interest rate in an attempt to slow economic growth and reduce core inflation. While the inflation in Canada eased to 3.40 percent in May 2023 from a high of 8.10 percent from a year ago, the downward movement was driven largely by lower energy prices rather than easing underlying inflation. The Bank of Canada's

[53] On July 14, 2023, FEI filed an application with the BCUC to increase the principal amount of the credit facility from $700 million to $900 million and to extend the maturity date of the credit facility to July 2028. If this application is approved, FEI will include any related impacts in the Evidentiary Update which FEI expects to file subsequent to the GCOC decision being issued.

latest interest rate increase in July 2023 brings the overnight rate to 5.0 percent, which was the tenth interest rate increase since March 2022 when the overnight rate was at 0.25 percent.

For 2024, FEI forecasts higher Other Financing Fees than the 2023 Approved amount due to higher customer deposit interest, resulting from a higher prime rate in 2023. 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 2023	Projected 2023	Forecast 2024
3-Month T-Bill Rate [1]	3.14%	5.04%	4.27%
Spread to CDOR	0.36%	0.41%	0.41%
CDOR Rate	3.50%	5.45%	4.69%
Spread to CP	-0.34%	-0.22%	-0.22%
CP Dealer Commission	0.10%	0.10%	0.10%
ST Interest Rate on Credit Facilities	**3.26%**	**5.34%**	**4.57%**
Fixed Financing Fees [2]			
Standby fee on Undrawn Credit [3]	0.44%	0.72%	0.57%
Renewal Fee on Undrawn Credit	0.16%	0.26%	0.20%
Other Financing Fees [4]	0.10%	0.26%	0.22%
ST Interest Rate on Fixed Financing Fee	**0.69%**	**1.24%**	**0.99%**
FEI Short Term Rate	**3.95%**	**6.58%**	**5.56%**

Notes to table:

[1] 3-month T-Bill rate for 2024 is a weighted average rate based on forecasts provided by Canadian Chartered banks in July 2023.

[2] Fixed financing fees represent the costs of maintaining the 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 planning to discontinue using 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.[54] The Canadian Alternative Reference Rate (CARR) Working Group was established to coordinate the transition to a new risk-free rate benchmark. In January 2023, the CAAR Working Group announced the development of a Term Canadian Overnight Repo Rate Average (Term CORRA), a risk-free interest rate benchmark for one- and three-month terms. Term CORRA is expected to replace CDOR and will become available in the latter half of 2023. As the Term CORRA rate is not yet available, FEI continues to use the CDOR methodology, consistent with its previous Annual Reviews, to forecast the short-term interest rate for 2024.

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 2024 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 2024 (which is equal to its after-tax weighted average cost of capital) is 5.50 percent. The calculation of the rate is shown in the following table.

Table 8-2: Calculation of AFUDC Rate for 2024

	Weight	Pre Tax Rate	After Tax Rate	Earned Return
Short Term Debt	3.39%	5.56%	4.06%	5.56%
Long Term Debt	58.11%	4.69%	3.42%	4.69%
Common Equity	38.50%	11.99%	8.75%	8.75%
Weighted Average	100.00%	7.53%	5.50%	6.28%

8.4 SUMMARY

FEI's equity financing and ROE have been forecast for 2024 at the same percentages as approved by Order G-129-16. FEI's debt financing costs on rate base are primarily determined 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 decrease slightly in 2024 compared to 2023

[54] https://www.bankofcanada.ca/markets/canadian-alternative-reference-rate-working-group/.

(4.69 percent forecast for 2024 compared to 2023 Approved of 4.70 percent). FEI expects a decision on Stage 1 of the BCUC-initiated GCOC proceeding to be issued in the upcoming months. FEI will provide an update to its equity financing and ROE forecast as well as the calculation for AFUDC as part of an Evidentiary Update which FEI will file subsequent to the GCOC decision being issued.

9. TAXES

9.1 INTRODUCTION AND OVERVIEW

This section discusses FEI's forecasts of property taxes and income tax which have been completed on a basis consistent with prior years. In 2024, property taxes are forecast to increase by 5.3 percent from 2023 Approved, and income tax is forecast to increase by 32.2 percent compared to 2023 Approved.

9.2 PROPERTY TAXES

The 2024 Forecast of property taxes is approximately $83.359 million which is based on the Company's 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 Components ($ millions)

Line No.	Description	Approved 2023	Projected 2023	Forecast 2024
1	Distribution Assets	$ 27.938	$ 29.252	$ 30.247
2	Transmission Assets	20.167	20.951	21.434
3	Gas Storage Assets	7.818	8.408	8.597
4	Manufactured Gas Assets	0.051	0.062	0.065
5	General Assets	6.652	6.092	6.289
6	In-Lieu	16.323	12.820	16.510
7	BCER Fees	0.287	0.292	0.295
8	Total Property Taxes	79.236	77.877	83.436
9	Less: Property Tax Transferred to BVA	(0.092)	(0.092)	(0.077)
10	Net Property Tax	79.144	77.785	83.359
11				
12	Forecast Change from 2023 Approved			5.3%
13	Forecast Change from 2023 Projected			7.2%

As shown in the above table, in 2024 property taxes are forecast to increase by 5.3 percent from 2023 Approved and increase by 7.2 percent compared to 2023 Projected. Approximately two-thirds of the increase in the 2024 Forecast compared to 2023 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. The most significant drivers of the forecast changes are as follows:

1. ***Changes in Tax Rates***. Tax rates are expected to change for 2024 as follows:

    a) Municipal tax rates are expected to increase on average by 3.0 percent across FEI's operating municipalities; however, these increases will be tempered by the legislated rate cap on Utility properties of $40.00 / $1,000.00, as many municipalities are already at the rate cap;

    b) School rates are expected to decrease by 1.2 percent based on the actual legislated utility rate change in 2023 of $12.57 / $1,000.00 from the 2022 rate of $12.72 / $1,000.00;

    c) Rural general rates are expected to decrease by 0.3 percent based on the historical 10-year compounded average growth rate;

    d) Tax rates on First Nations are expected to decrease by 0.1 percent; and

    e) Other rates are expected to range from increases of 2.2 percent for some First Nations to decreases of 2.0 percent for rural areas.

2. ***Changes in Revenues to Calculate Grants In-lieu of Taxes.*** Revenues reported to municipalities are expected to increase by 28.8 percent compared to 2023 Projected based on actual revenues applicable to the taxation year. Increases in the cost of gas led to higher revenues used to derive the 2024 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. Increases forecast are based on the historical five year compounded annual growth rate. For 2024, land and improvements have been included together:

    a) A 6.5 percent increase in assessed values of distribution lines and services plus additional new construction;

    b) An 11.3 percent increase in assessed values of transmission lines;

    c) A 9.7 percent increase in assessed values for LNG land and improvements; and

    d) A 9.7 percent increase in office properties.

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 2024, which is unchanged from 2023. 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 2024 is forecast to increase by $16.653 million or 32.2 percent compared to 2023 Approved. The largest driver of the increase in 2024 is lower income tax deductible through capital cost allowance (CCA) by approximately $12.284 million. The lower deductibility is partly due to reduced undepreciated capital cost (UCC) additions in higher rate CCA classes in the 2024 Forecast compared to 2023 Approved, and partly due to the phase-out of Canada's Accelerated Investment Incentive starting from 2024 (i.e., enhanced 50 percent first-year allowance to be phased out in 2024).[55]

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.

[55] https://www.canada.ca/en/revenue-agency/services/tax/businesses/topics/sole-proprietorships-partnerships/report-business-income-expenses/claiming-capital-cost-allowance/accelerated-investment-incentive.html#AppPhaseOut

10. EARNINGS 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 $6.989 million pre-tax credit ($5.102 million after-tax) earnings sharing amount to customers as part of 2024 delivery rates. FEI has also set out the BVA, RSAM, Fort Nelson Residential Common Rate Phase-in and Clean Growth Innovation Fund (CGIF) rate riders for 2024 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 2024 delivery rates, it is the 2022 formula O&M, 2022 growth capital, and 2022 earnings sharing amounts that are calculated and impact rates in 2024.

For 2024, FEI proposes to distribute a $6.989 million pre-tax credit ($5.102 million after-tax) to customers, comprised of:

- The $4.579 million credit difference between the projected 2022 deferral account after-tax credit addition of zero embedded in 2023 delivery rates, and the actual 2022 deferral account after-tax credit addition of $4.579 million as provided in FEI's 2022 Annual Report to the BCUC;
- The $0.134 million credit difference between the projected 2022 financing addition of $0.049 million credit[56] and the actual 2022 financing addition of $0.183 million credit, as provided in FEI's 2022 Annual Report to the BCUC;
- The $0.257 million credit difference between the forecast 2023 financing addition of $0.007 million credit[57] embedded in 2023 delivery rates, and the projected 2023 financing addition of $0.264 million credit embedded in this Application; and
- 2024 forecast financing of a $0.132 million credit.[58]

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[56] Annual Review for 2023 Delivery Rates, Section 10.2.
[57] Annual Review for 2023 Delivery Rates, Evidentiary Update dated October 24, 2022, Schedule 12, Line 22, Column 4.
[58] Section 11, Schedule 12, Line 24, Column 4.

FEI proposes to distribute $6.989 million to customers in 2024 as a reduction in 2024 revenue requirements through amortization of the projected 2024 opening after-tax balance and 2024 financing of $5.102 million in the MRP Earnings Sharing deferral account.

As part of future rate filings, the actual earnings sharing for 2023 will be distributed to or collected from customers in a similar manner as described above, which will account for the actual 2023 ROE variance from approved.

10.3 RATE RIDERS

There are three delivery rate riders that are set through the annual review process. These are the BVA Rate Rider, the RSAM Rate Riders, and the Fort Nelson Residential Common Rate Phase-in Rate Rider. 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 CGIF activities.

10.3.1 BVA Rate Rider

The 2023 BVA rate rider was approved on a permanent basis by Order G-352-22. The following supports the BVA rate rider for 2024.

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 2023 balance of the BVA rate rider account, and the calculation of the BVA Rate Riders for 2024.

10.3.1.1 BVA Rate Rider Account

The BVA balance at the end of December 31, 2023 is projected to be a debit of $84.158 million before-tax.[59] This balance consists of the 2022 ending inventory balance of $20.298 million plus a projected $89.186 million in costs to acquire biomethane less $25.326 million of recoveries by way of the BERC. FEI projects 3,165.7 TJ of biomethane to remain in inventory at the end of 2023.

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 $61.435 million.[60]

The following table summarizes the BVA rate rider account and shows both the projected after-tax ending 2023 balance of $34.013 million[61] and the $27.422 million[62] transfer to the BVA rate rider account.

[59] Table 10-1, Line 17.
[60] Table 10-1, Line 26.
[61] Table 10-1, Line 30.
[62] Table 10-1, Line 28.

Table 10-1: BVA Rate Rider Account

Line No	BVA Continuity	Note	2023 Projected (a) ($000s)	Reference
1	**BVA Opening Balance**	**(b)**		
2	Pre-Tax Balance (Before Adjustment for Unsold Biomethane)		$ 20,297.9	
3	Pre-Tax Adjustment for Unsold Biomethane		(20,297.9)	
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		$ 89,185.8	
11	Biomethane Costs Recovered		(25,325.9)	
12	Total Activities - Pre-Tax		**$ 63,859.9**	Line 10 + Line 11
13				
14	Pre-Tax Opening Balance of Unsold Biomethane	**(c)**	20,297.9	- Line 3
15	Pre-Tax Balance of Unsold Biomethane	**(c)**	$ 26,295.2	
16	Pre-Tax Balance After Adjustment for Unsold Biomethane		37,564.7	Line 12 - Line 15
17	**BVA Ending Balance**		**$ 84,157.8**	Line 14 + Line 15 + Line 16
18				
19	Tax Recovery Rate		27%	
20				
21	Tax Recovery on Balance of Unsold Biomethane		$ (12,580.1)	-(Line 14 + Line 15) x Line 19
22	Tax Recovery on Balance after adjustment		(10,142.5)	- Line 16 x Line 19
23				
24	After-Tax Balance of Unsold Biomethane		34,013.0	Line 14 + Line 15 + Line 21
25	After-Tax Balance After adjustment for Unsold Biomethane		27,422.2	Line 16 + Line 22
26	**Net of Tax BVA Balance before Transfer to BVA Rider Account**		**$ 61,435.2**	Line 24 + Line 25
27				
28	**Transfer to BVA Rate Rider Account**	**(d)**	**$ (27,422.2)**	- Line 25
29				
30	**Net of Tax Balance (After transfer to BVA Rider Account)**		**$ 34,013.0**	Line 26 + Line 28

Notes

(a) The annual forecast is an updated 2023 forecast

(b) Recorded opening balance reconciles to the December 31, 2022 balance in the FortisBC Energy Inc. 2022 BVA Status Report.

(c)

Calculation of Adjustment for Unsold Biomethane	2022 Recorded	2023 Projected
Beginning Quantity Unsold Biomethane (in TJ)	208.7	1,379.1
Biomethane Purchased (in TJ)	2,294.8	3,809.7
Biomethane Sold (in TJ)	(1,124.3)	(2,023.1)
Ending Total Biomethane Unsold (in TJ)	1,379.1	3,165.7
BERC rate in effect at forecast (in $/GJ)		
January 1st effective BERC rate (in $/GJ)	$ 14.718	$ 14.718
Value of Unsold Biomethane at December 31st	$ 20,297.9	$ 46,593.1

(d) Pursuant to Order G-133-16, and the Decision issued concurrently, the net of tax balance at December 31, 2023, 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 2024 is forecast at $36.368 million and is recovered from non-bypass customers through a rate rider based on 2024 Forecast volumes. The $36.368 million to be collected consists of the 2022 Projected recovery credit variance of $1.197 million[63] plus the $27.422 million after-tax debit transferred from the BVA grossed up to a before-tax debit value of $37.565 million.[64]

To calculate the BVA rate rider, the projected BVA rate rider account balance of $36.368 million is divided by the 2024 Forecast non-bypass customer volume of 201,034 TJ, which results in a BVA rate rider of $0.181 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 2023 ($000s) Net of Tax	($000s) Grossed Up	Non-Bypass Forecast 2024 Vol (TJ)
1	**BVA Rider Account Balance**			
2	**BVA Balance Transfer Deferral Account Balance Dec 31, 2022 - Actual**	18,355.0	$ 25,143.8	
3	Less Projected 2023 BVA Rider recoveries for 2022 using 2023 Projected Non-bypass volumes	(19,228.7)	(26,340.6)	
4	**2023 projected true up adjustment - 2022 projected recovery variance**	(873.7)	(1,196.8)	
5	BVA Balance transferred to BVA Balance Transfer Deferral Account Dec 31, 2023 - Projected	27,422.2	$ 37,564.7	
6	**BVA Balance Transfer Deferral Account Balance Dec 31, 2023 - Projected**	**26,548.6**	**36,367.9**	**201,033.8**
7				
8	**Residential**			
9	Rate Schedule 1		$ 15,083.5	83,378.5
10	**Commercial**			
11	Rate Schedule 2		$ 5,369.0	29,678.8
12	Rate Schedule 3		$ 4,884.8	27,002.0
13	Rate Schedule 23		$ 658.0	3,637.1
14	**Industrial**			
15	Rate Schedule 4		$ 32.1	177.7
16	Rate Schedule 5		$ 2,147.4	11,870.1
17	Rate Schedule 6		$ 3.3	18.1
18	Rate Schedule 7		$ 1,230.0	6,799.4
19	Rate Schedule 22- Firm Service		$ 1,889.5	10,444.7
20	Rate Schedule 22- Interruptible Service		$ 2,962.1	16,373.7
21	Rate Schedule 25		$ 1,406.9	7,777.0
22	Rate Schedule 27		$ 701.3	3,876.7
23				
24	**Total BVA Rider (Non-Bypass)**		**$ 36,367.9**	**201,033.8**
25				
26	**Calculation BVA Rider Per ($/GJ) Flat Rate**		**$ 0.181**	

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.

63 The $1.197 million represents a combined adjustment for the 2022 Actual and Projected BVA balance transfer variance and the 2023 recovery variance because of the 2023 volume projection variance.

64 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 2023, the projected recoveries are $25.326 million attributable to sales volumes of 2,023 TJ from 11,964 RNG customers. The expected sales volume from existing and projected long-term contracts is included in the 2023 Projected volume and revenue in Table 10-3 below.

Table 10-3: BERC Revenue and Volume

Line No.	Volume and Revenue	2022 Actual	2022 Projected	2022 Variance	2023 Projected
1	**Volume (TJ)**				
2	**Short-term**				
3	Rate Schedule 1B	120.2	112.1	8.1	140.5
4	Rate Schedule 2B	42.4	88.8	(46.4)	63.1
5	Rate Schedule 3B	104.5	56.1	48.4	251.5
6	Rate Schedule 5B	422.5	1,077.8	(655.3)	749.3
7	Rate Schedule 11B	50.2	57.0	(6.8)	22.4
8	Rate Schedule 46B	-	-	-	-
9	Rate Schedule 30	-	-	-	-
10	Sub-total	739.8	1,391.7	(651.9)	1,226.8
11					
12	**Long Term**				
13	Rate Schedule 5B	260.9	-	260.9	646.6
14	Rate Schedule 11B	123.7	342.0	(218.3)	149.7
15	Sub-total	384.6	342.0	42.6	796.3
16					
17	**Total Sales Volume (TJ)**	1,124.3	1,733.7	(609.3)	2,023.1
18					
19	**Recoveries ($000s)**				
20	**Short-term**				
21	Rate Schedule 1B	$ 1,659.2	$ 1,448.7	$ 210.4	$ 1,905.6
22	Rate Schedule 2B	584.1	1,097.9	(513.8)	852.7
23	Rate Schedule 3B	1,231.3	692.9	538.5	3,198.7
24	Rate Schedule 5B	5,737.4	12,866.7	(7,129.3)	9,692.6
25	Rate Schedule 11B	693.2	695.5	(2.3)	294.1
26	Rate Schedule 46B	-	-	-	-
27	Rate Schedule 30	-	-	-	-
28	Sub-total	9,905.2	16,801.7	(6,896.5)	15,943.8
29					
30	**Long Term**				
31	Rate Schedule 5B	2,531.7	-	2,531.7	7,675.4
32	Rate Schedule 11B	1,292.3	3,967.2	(2,674.9)	1,706.6
33	Sub-total	3,824.0	3,967.2	(143.2)	9,382.0
34				-	
35	**Total Sales**	$ 13,729.2	$ 20,768.9	$ (7,039.7)	$ 25,325.9

In the 2016 Biomethane Decision, FEI was also directed to provide the number of customers by rate schedule. The following table sets out the 2023 Projected number of renewable natural gas customers by rate schedule.

Table 10-4: RNG Customers by Rate Schedule

2023 RNG Projected Participation (Rate Schedule)	Customer Enrollment
Short Term	
Rate Schedule 1B	11,586
Rate Schedule 2B	297
Rate Schedule 3B	57
Rate Schedule 11B	2
Rate Schedule 5B	18
Rate Schedule 30 Off System	-
Long Term	
Rate Schedule 11B	4
Total	**11,964**

In summary, the 2024 BVA rate rider attributable to the cumulative December 31, 2023 transfers from the BVA is $0.181 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 2023 is a credit of $22.248 million. The calculation of the 2024 RSAM riders is shown in Table 10-5.

Table 10-5: 2024 RSAM Riders

2023 RSAM + Interest Closing Balance ($000)	(22,248)
Amortization Period (Years)	2
2024 Amortization Post-Tax ($000)	(11,124)
Tax Rate	27%
2024 Amortization Pre-Tax ($000)	(15,238)

RSAM (Rider 5) Calculation

Rate Class	RSAM Amortization (S000)	2024 Volume (TJ)	Rider ($/GJ)
Rate 1/1BU/1U/1X		83,378.5	(0.106)
Rate 2/2BU/2U/2X		29,678.8	(0.106)
Rate 3/3BU/3U/3X		27,002.0	(0.106)
Rate 23		3,637.1	(0.106)
	(15,238)	143,696.4	(0.106)

The differences that result from the actual 2023 ending RSAM balance varying from the projection, and the actual 2024 volumes varying from the forecast set out in this filing, will be included in the calculation of the 2025 RSAM Riders and, in this way, refunded to or collected from customers.

10.3.3 Fort Nelson Residential Customer Common Rate Phase-in Rate Rider

Pursuant to Order G-278-22, FEI is approved to phase-in the implementation of common rates to the Fort Nelson service area (FEFN) residential customers over a five-year period through the Fort Nelson Residential Customer Common Rate Phase-in Rate Rider. The rider is to be calculated each year as part of FEI's Annual Review and is based on the updated forecast of FEFN's residential customer demand and the remaining balance of the deferral account each year over the five-year phase-in period.

Table 10-6 below provides the calculation of the Fort Nelson Residential Customer Common Rate Phase-in Rate Rider, which is a credit of $0.863 per GJ for 2024:

Table 10-6: 2024 Fort Nelson Residential Customer Common Rate Phase-in Rider

Line	Particular	Reference	2024
1	FEFN (RS 1) Delivery Margin @ Existing Rate w/o Rider ($000s)		1,678
2	FEFN (RS 1) Delivery Margin (RS 1) @ Existing Rate w/ Rider ($000s)		1,440
3	Incremental Delivery Margin from FEFN RS 1 ($000s)	Line 1 - Line 2	238
4			
5	Effective Incremental Delivery Rate ($/GJ)	Line 3 / Line 12	1.016
6	Annual Incremental of Phase-In ($/GJ)	Line 5 / 4 Years (Remaining)	0.254
7			
8	FEFN Residential Common Rate Phase-in ($/GJ)	-(Line 5 - Line 6)	(0.762)
9	2021 FEFN Surplus Revenue ($/GJ)	2023 Annual Review - Evidentiary Update; Table A-6; Line 9	(0.101)
10	**Total FEFN Residential Common Rate Phase-in Rider ($/GJ)**	**Line 8 + Line 9**	**(0.863)**
11			
12	2024 FEFN Residential Demand Forecast (TJ)		234.3

10.3.4 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 approximately $5.229 million in 2024 based on the forecast average non-bypass customer count for 2024.

Table 10-7 below shows the amounts collected and the amounts expended for clean growth projects since the inception of the Fund to the end of 2024. In total, approximately $3.681 million of actual expenditures have been invested up to June 2023, with a further $3.267 million projected to the end of 2023, and $5.773 million for 2024.

Table 10-7: Clean Growth Innovation Fund 2021-2024 Deferral Account Continuity ($ millions)

	Actual 2020	Actual 2021	Actual 2022	Actual Jan-June 2023	Projected July-Dec 2023	Forecast 2024
Opening Balance	**$ -**	**$ (0.791)**	**$ (3.816)**	**$ (7.186)**	**$ (8.888)**	**$ (8.594)**
Gross Additions	1.022	1.127	0.972	0.560	3.267	5.773
Rider recoveries	(2.099)	(5.093)	(5.176)	(2.591)	(2.591)	(5.229)
Tax	0.291	1.071	1.135	0.548	(0.182)	(0.147)
AFUDC	(0.005)	(0.130)	(0.301)	(0.219)	(0.200)	(0.458)
Closing Balance	**$ (0.791)**	**$ (3.816)**	**$ (7.186)**	**$ (8.888)**	**$ (8.594)**	**$ (8.655)**

To date, FEI has completed seven portfolio reviews with approved spending of $8.5 million. FEI anticipates that it will approve two additional portfolios by year-end 2023. 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.

Pursuant to the MRP Decision and Order G-165-20, FEI is directed to return any unused balance in the CGIF at the end of the MRP term through a disposal mechanism subject to approval by the BCUC. FEI will address this directive from the MRP Decision in its upcoming multi-year rate plan application which will be filed early in 2024. At that time, FEI will have a more accurate estimate of the unused balance in the CGIF, as FEI will have a full year of 2023 actual spending information and will have more certainty on the projected spending for 2024.

10.3.4.1 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:

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

10.3.4.2 Spending Commitments

Since the Annual Review for 2023 Delivery Rates, approximately $4.3 million has been approved for spending in Portfolios 5, 6 and 7. As is common during the evaluation of CGIF portfolios, a number of proposals were rejected at various stages of review because they did not meet CGIF criteria.

Table 10-8: Approved and Actual/Forecast Expenditures ($ millions)

	Actual 2020	Actual 2021	Actual 2022	Actual Jan-June 2023	Projected July-Dec 2023	Forecast 2024
Portfolio Approvals	$ 1.500	$ 2.200	$ 1.526	$ 3.348	$ 2.850	$ 8.000
Portfolio Expenditures	$ 1.022	$ 1.127	$ 0.972	$ 0.560	$ 3.267	$ 5.773

Note to Table:

Portfolio Expenditures are equal to the Gross Additions in Table 10-7.

As can be seen from Table 10-8, Portfolio Approvals have been steadily increasing since the approval of the CGIF, with a total of $6.198 million projected in 2023 and an additional $8 million in 2024.

The forecast 2024 Portfolio Approvals are based on several expectations. First, the $10 million NGIF Global Cleantech Challenge[65] is currently underway and FEI expects to approve approximately $1 million in grants based on assessment of proposals thus far. This is in addition to the 2024 annual NGIF operating fees, expected to be approximately $0.35 million, and two additional NGIF calls for proposals in 2024 (approximately $1.5 million). FEI has also initiated its first collaborative call for innovation with the BC Centre for Innovation and Clean Energy (CICE). As part of a $6 million Forest Residue Management challenge[66], CICE and the CGIF are encouraging proposals that will help promote the sustainable utilization of wood waste and in the process reduce wildfire risks. In particular, FEI will invest up to $3 million in proposals that meet CGIF criteria and create biomethane, hydrogen and syngas or provide nature-based carbon sequestration. In addition, FEI expects to approve up to $4 million in grants for FEED studies and pre-commercial-scale projects such as low-carbon gaseous fuel production facilities and hydrogen end-use projects similar to those mentioned below.

Expenditures have lagged approvals, with approximately $3.681 million of actual expenditures versus $8.574 million of approvals to the end of June 2023. FEI expects expenditures of $3.267 million to occur by the end of 2023, which comprise the following[67]:

- **$0.3 million** for the University of British Columbia / University of Victoria Hydrogen Blending Lab approved in Portfolio 1;
- **$0.4 million** for FEI's membership in the Low Carbon Resources Initiative approved in Portfolio 3;
- **$1.4 million** for projects approved in Portfolios 5, 6 and 7;
- **$0.8 million** on an advanced hydrogen electrolyzer pilot in Burnaby that was approved in Portfolio 7, but is awaiting confirmation of PacifiCan funding and a contribution agreement;
- **$0.3 million** on a hydrogen pyrolysis FEED study for a BC deployment of the technology which is tentatively approved pending a contribution agreement; and
- **$0.2 million** on a hydrogen refuelling pre-FEED study for a BC deployment of the technology which is tentatively approved pending a contribution agreement.

65 https://www.ngif.ca/global-cleantech-challenge/.
66 https://cice.ca/knowledge-hub/cice-fortisbc-cgif-call-for-innovation-forestry-residue-management/.
67 Amounts listed below total to $3.4 million due to rounding.

10.3.4.3 Investment Profile

Grants from the CGIF are focused on several application areas critical for decarbonizing FEI's gas system: production, distribution and end-use. Production applications are related to creating renewable, low-carbon hydrogen, RNG and syngas for distribution through the gas network or direct end-use near the production facility. Distribution applications focus on accommodating renewable hydrogen in the existing gas system. Finally, end-use applications focus on more effective uses of energy sources and the ability to use renewable fuels in end-use applications (with a specific category for transportation), creating hybrid energy systems that efficiently use both gaseous fuels and electricity.

Overlaying these three application areas are generalized low-carbon investments and carbon capture, utilization and storage (CCUS), categories described in further detail below.

The total approved investment in these application categories, and subcategories, is shown in Table 10-9.

Table 10-9: CGIF Approved Investment by Application ($ millions)[68]

Application	Sub-Application	Approved Grant
Production	Renewable Hydrogen	2.237
	Renewable Natural Gas	1.388
	Renewable Syngas	0.370
	Subtotal	**3.995**
Distribution	Renewable Hydrogen	**0.500**
	Subtotal	**0.500**
End-Use	Renewable Hydrogen	0.407
	Hybrid Systems	0.280
	Renewable Natural Gas	0.120
	Subtotal	**0.808**
Carbon Capture	End-Use	0.345
	Storage	0.600
	Subtotal	**0.945**
General Low-Carbon	General Initiatives	**2.326**
	Subtotal	**2.326**
TOTAL		**8.574**

These five areas of investment are detailed below.

68 The total approved amount of $8.574 million equals the actual approvals up to June 30, 2023 (i.e., sum of Actual 2020, Actual 2021, Actual 2022 and Actual Jan-June 2023 in Table 10-8).

Production (Upstream)

These investments are related to the production of low-carbon gases for use in the existing FEI gas distribution network or for direct consumption by larger customers.

The CGIF has been providing grants for novel methods of producing renewable, low-carbon hydrogen in two ways: electrolysis and pyrolysis. Electrolysis requires water and low-carbon electricity and produces hydrogen by splitting water into hydrogen and oxygen molecules. Pyrolysis produces low-carbon hydrogen by “cracking” methane and other hydrocarbons (the main component of natural gas) into hydrogen and solid carbon.

In total, the CGIF approved grants to 13 different renewable hydrogen production projects. One example is a Vancouver-based company that makes a novel non-catalytic pulse methane pyrolysis system for low-cost, clean, H2 production using natural gas as a feedstock, and with a solid carbon by-product. The CGIF grants (along with other funding) allowed the start-up to build a proof-of-concept reactor in 2021 and to complete the commissioning of a brass board system in 2023. The nominal capacity of the brass-board system will be 200 kgH2/day. Developments thus far have resulted in the Vancouver-based company receiving $79 million in equity investments from a diverse set of investors.

The CGIF has also been providing grants for organizations that are advancing the production of low-carbon RNG (or biomethane). These expenditures have been focused on two primary areas: improving the efficiency of existing RNG production facilities and expanding the range of feedstocks from which RNG can be created.

An example of an RNG efficiency project in which the CGIF is investing is the Metro Vancouver effort to develop technology that will boost the methane content of RNG produced by anaerobic digestion at their wastewater treatment plants.

The CGIF has also approved funding for an effort by UBC and the BC Bio-Alliance to advance a two-stage steam-oxygen gasification technology that creates RNG and syngas from woody biomass. Woody biomass is a potential significant source of RNG in BC that is largely untapped.

Similarly, the CGIF is providing a grant to a BC-based company and an Interior pulp mill to scale-up a technology to create low-carbon syngas from wood waste and displace natural gas use in the existing lime kiln.

Distribution

Approved in Portfolio 1 is the Hydrogen Lab that has been established at UBC Okanagan and the University of Victoria.

The Hydrogen Lab is providing valuable insights into seven specific areas that are important to understand as FEI moves toward blending low-carbon hydrogen into the existing natural gas infrastructure (hydrogen-enriched natural gas or HENG).

Subproject 1: Analytical modelling of injection and transmission of HENG.

Subproject 2: Detonation and flammability of HENG.

Subproject 3: Hydrogen embrittlement of metal alloys and welded joints.

Subproject 4: Real-time portable sensing system for monitoring of HENG mixing and leak detection.

Subproject 5: Machine learning-based modelling and design of an integrated HENG process control system based on simulation and operational data.

Subproject 6: Effect of HENG on thermoacoustic oscillations and burning rate of partially premixed flames.

Subproject 7: Separation of hydrogen gas from HENG.

End-Use

CGIF end-use grants are provided for three sub-applications: HENG or hydrogen end-use product development; hybrid system development; and transportation.

Approved HENG and hydrogen-compatible end-use investments include development and testing by a Calgary-based company of a 100 percent hydrogen compatible residential furnace in addition to two approved investments in companies making HENG-compatible combined heat and power (CHP) units for residential and small commercial deployments. CHP units can produce both electric power and heat, so they are both a low-carbon end-use product and a technology capable of mitigating peak demand and providing resiliency in the electric system.

A hybrid system grant was provided for testing of a commercial building installation of a CHP combined with solar panels and a custom control system. As previously reported, the system functioned well but the underlying costs were too high. Continued reductions in technology costs are likely to favourably change the cost-effectiveness of these types of solutions.

The CGIF also funded a study initiated by the Greenhouse Growers' Association members and United Flower Growers members who rely heavily on the use of natural gas for the provision of heat and plant growth (currently accounting for approximately 12 percent of the cost structure for greenhouses). The grant for the study focused on:

- Low-carbon heating options, including RNG and associated reduced GHGs;
- Emerging technology review (including energy storage, heating, carbon capture, and conservation and efficiency);
- Lighting and heating, including examination of the use of CHPs for meeting heating loads and offsetting electricity costs;
- Heating decarbonization options (technology and fuel supply);

- GHG emissions including carbon capture and offsets;
- Hydrogen generation and CO_2 to produce synthetic methane;
- Carbon capture and use, as well as storage and sequestration; and
- Evaluation of the cost impacts and energy implications of HENG.

Finally, the CGIF provided a grant for university research which characterized the GHG emission reductions from the use of natural gas/RNG instead of diesel in marine engines. The research has been helpful in establishing LNG as a lower-carbon marine transportation fuel in BC.

Carbon Capture

Grants in this category have been divided into two sub-categories: end-use and storage. End-use carbon capture expenditures focus on capturing and purifying carbon dioxide post-combustion. In some cases, the carbon dioxide is converted into other marketable products and in others the carbon dioxide is being selectively captured for permanent storage.

Carbon capture storage grants are focused on taking captured carbon dioxide and permanently transforming it into a non-GHG form such as a mineral or permanently storing it.

CGIF funding was approved for a carbon capture project being undertaken by a Calgary company developing modular, containerized carbon capture systems using patented membrane contactors to replace conventional spray tower and absorbers. The result is expected to be a 30 percent increase in efficiency and a 50 percent reduction in absorber size, significantly decreasing carbon capture capital and operating costs. The company is currently raising capital for a significant expansion and move to commercialization.

The CGIF has also provided funding for two GeoscienceBC-led initiatives related to carbon storage. One is for a pilot that will test the ability of certain rock formations to permanently mineralize (and therefore sequester) gaseous carbon dioxide, and the other is for a comprehensive geological study of the Georgia basin to assess the potential for permanent carbon storage.

Generalized 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 annual operating expenses of the Canadian Gas Association's NGIF, of which FEI is a member with several other Canadian utilities and oil and gas producers. In total, 27 of the 40 proposals approved for funding by the CGIF are NGIF projects that are co-funded with 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, approved in Portfolio 3.

10.4 SUMMARY

As discussed in Section 10.2 above, FEI proposes to distribute a $6.989 million pre-tax credit ($5.102 million after-tax) earnings sharing amount to customers as part of 2024 delivery rates. In Section 10.3, FEI updated all of the 2024 delivery rate riders for 2023 Projected ending balances and 2024 Forecast volumes. Based on these updates, FEI has calculated a BVA rate rider of $0.181 per GJ, an RSAM credit rate rider of $0.106 per GJ, and the Fort Nelson Residential Customer Common Rate Phase-in rate rider of $0.863 per GJ for 2024. FEI has also provided details on the CGIF in Section 10.3.4, which is funded through the collection of the basic charge CGIF rider.

11. FINANCIAL SCHEDULES

SUMMARY OF RATE CHANGE
FOR THE YEAR ENDING DECEMBER 31, 2024
($millions)

Schedule 1

Line No.	Particulars	2024 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	$ (7.399)		
3	Change in Other Revenue	(0.461)	(7.860)	
4				
5	**O&M CHANGES**			
6	Gross O&M Change	14.980		
7	Capitalized Overhead Change	(2.489)	12.491	
8				
9	**DEPRECIATION EXPENSE**			
10	Depreciation from Net Additions		7.803	
11				
12	**AMORTIZATION EXPENSE**			
13	CIAC from Net Additions	(0.098)		
14	Deferrals	19.048	18.950	
15				
16	**FINANCING AND RETURN ON EQUITY**			
17	Financing Rate Changes	2.838		
18	Financing Ratio Changes	0.414		
19	Rate Base Growth	(7.950)	(4.698)	
20				
21	**TAX EXPENSE**			
22	Property and Other Taxes	4.215		
23	Other Income Taxes Changes	16.653	20.868	
24				
25				
26	**REVENUE DEFICIENCY (SURPLUS)**		**$ 47.554**	Schedule 16, Line 11, Column 4
27				
28	Non-Bypass Margin at 2023 Approved Rates		1,056.786	Schedule 19, Line 17, Column 3
29	Rate Change		4.50%	

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 2

Line No.	Particulars	2023 Approved	2024 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 8,229,457	$ 8,723,480	$ 494,023	Schedule 6.2, Line 35, Column 3
2	Opening Balance Adjustment	-	-	-	Schedule 6.2, Line 35, Column 4
3	Net Additions	597,313	369,697	(227,616)	Schedule 6.2, Line 35, Columns 5+6+7
4	Plant in Service, Ending	8,826,770	9,093,177	266,407	
5					
6	Accumulated Depreciation Beginning	$ (2,576,982)	$ (2,726,314)	$ (149,332)	Schedule 7.2, Line 35, Column 5
7	Opening Balance Adjustment	-	-	-	Schedule 7.2, Line 35, Column 6
8	Net Additions	(156,392)	(164,986)	(8,594)	Schedule 7.2, Line 35, Columns 7+8
9	Accumulated Depreciation Ending	(2,733,374)	(2,891,300)	(157,926)	
10					
11	CIAC, Beginning	$ (459,077)	$ (464,929)	$ (5,852)	Schedule 9, Line 6, Column 2
12	Opening Balance Adjustment	-	-	-	
13	Net Additions	(6,795)	(14,930)	(8,135)	Schedule 9, Line 6, Columns 5+6
14	CIAC, Ending	(465,872)	(479,859)	(13,987)	
15					
16	Accumulated Amortization Beginning - CIAC	$ 196,884	$ 205,638	$ 8,754	Schedule 9, Line 13, Column 2
17	Opening Balance Adjustment	-	-	-	
18	Net Additions	8,753	8,851	98	Schedule 9, Line 13, Columns 5+6
19	Accumulated Amortization Ending - CIAC	205,637	214,489	8,852	
20					
21	Net Plant in Service, Mid-Year	$ 5,611,722	$ 5,837,191	$ 225,469	
22					
23	Adjustment for timing of Capital additions	$ 122,435	$ 31,093	$ (91,342)	
24	Capital Work in Progress, No AFUDC	42,846	33,914	(8,932)	
25	Unamortized Deferred Charges	52,970	(161,137)	(214,107)	Schedule 11.1, Line 29, Column 10
26	Working Capital	113,461	74,842	(38,619)	Schedule 13, Line 14, Column 3
27	Deferred Income Taxes Regulatory Asset	747,445	738,346	(9,099)	Schedule 15, Line 6, Column 3
28	Deferred Income Taxes Regulatory Liability	(747,445)	(738,346)	9,099	Schedule 15, Line 6, Column 3
29					
30	Mid-Year Utility Rate Base	$ 5,943,434	$ 5,815,903	$ (127,531)	

FORMULA INFLATION FACTORS
FOR THE YEARS ENDING DECEMBER 31, 2020 to 2024
($000s)

Line No.	Particulars	Reference	2020	2021	2022	2023	2024	Total for 2024 Rate Setting	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	**Formula Cost Drivers**								
2	CPI		2.692%	1.596%	1.281%	4.940%	6.031%		
3	AWE		2.881%	5.745%	6.455%	3.944%	2.609%		
4	Labour Split								
5	Non Labour		48.000%	48.000%	49.000%	49.000%	51.000%		
6	Labour		52.000%	52.000%	51.000%	51.000%	49.000%		
7	CPI/AWE	(Line 2 x Line 5) + (Line 3 x Line 6)	2.790%	3.753%	3.920%	4.432%	4.354%		
8	Productivity Factor	G-165-20	-0.500%	-0.500%	-0.500%	-0.500%	-0.500%		
9	Net Inflation Factor	Line 7 + Line 8	2.290%	3.253%	3.420%	3.932%	3.854%		
10									
11									
12	**Growth in Average Customer Calculation**								
13	Actual/Projected Prior Year Average Customers		1,031,862	1,044,622	1,057,086	1,067,191	1,079,564		
14	Average Customers for the Year	Schedule 19, Line 29, Column 9	1,044,622	1,057,086	1,067,191	1,079,564	1,089,371		
15	Change in Average Customers	Line 14 - Line 13	12,760	12,464	10,105	12,373	9,807	57,509	
16	Customer Growth Factor Multiplier	G-165-20						75%	
17	Change in Customers - Rate Setting Purposes	Line 15 x Line 16						43,132	
18									
19	**Average Customer Continuity for Rate Setting Purposes**								
20	Average Customers Used to Determine Starting UCOM	Line 13, Column 3 (Year 2020)						1,031,862	
21									
22	Average Customer Forecast - Rate Setting Purposes	Line 17 + Line 20						1,074,994	

CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 4

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	2023 Unit Cost Growth Capital	$ 4,205				
3	2024 Net Inflation Factor	3.854%				Schedule 3, Line 9, Column 7
4	2024 Unit Cost Growth Capital	$ 4,367				
5	2024 Gross Customer Additions	15,000				
6	2024 Inflation Indexed Growth Capital	$ 65,505			$ 65,505	
7	2022 Growth Capital Customer True-Up				(14,254)	
8	2024 System Extension Fund				1,000	
9	2024 Growth CIAC				2,388	
10	2024 Inflation Indexed Gross Growth Capital				$ 54,639	
11						
12	**Capital Tracked Outside of Formula**					
13	Pension & OPEB (Growth Capital Portion)			$ 871		
14	Biomethane Assets			43,068		
15	NGT Assets			5,000		
16	Sustainment Capital			130,628		
17	Other Capital			51,252		
18	Sub-total			$ 230,819	230,819	
19						
20	**Total Capital Expenditures Before CIAC**				$ 285,458	

CAPITAL EXPENDITURES TO PLANT RECONCILIATION
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 5

Line No.	Particulars		2024 Formula	Cross Reference
	(1)		(2)	(3)
1	**CAPEX**			
2	Growth Capital Expenditures	$	54,639	Schedule 4, Line 10, Column 5
3	Forecast Capital Expenditures		230,819	Schedule 4, Line 18, Column 5
4	Total Capital Expenditures	$	285,458	
5				
6	**Special Projects and CPCN's**			
7	Tilbury 1A Expansion	$	3,959	
8	LMIPSU CPCN		6	
9	Inland Gas Upgrade		20,721	
10	Transmission Integrity Program (CTS TIMC)		63,107	
11	Pattullo Gasline Replacement		153	
12	FEI AMI CPCN		55,000	
13	Total Capital Expenditures	$	142,946	
14				
15	**Total Capital Expenditures**	$	428,404	
16				
17				
18	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**			
19				
20	Regular Capital Expenditures	$	285,458	Line 4
21	Add - Capitalized Overheads		59,233	Schedule 20, Line 27, Column 4
22	Add - AFUDC		9,526	
23	Gross Capital Expenditures		354,217	
24	Change in Work in Progress		20,404	
25	**Total Regular Additions to Plant**	$	374,621	
26				
27	Special Projects and CPCN's Capital Expenditures	$	142,946	Line 13
28	Add - AFUDC		7,166	
29	Gross Capital Expenditures		150,112	
30	Change in Work in Progress		(87,927)	
31	**Total Special Projects and CPCN Additions to Plant**	$	62,185	
32				
33	**Grand Total Additions to Plant**	$	436,806	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Account	Particulars	12/31/2023	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2024	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**INTANGIBLE PLANT**							
2	175-10	Unamortized Conversion Expense	$ 109	$ -	$ -	$ -	$ -	$ 109	
3	178-00	Organization Expense	728	-	-	-	-	728	
4	401-01	Franchise and Consents	197	-	-	-	-	197	
5	402-03	Other Intangible Plant	1,907	-	-	-	-	1,907	
6	440-02	Water/Land Rights Tilbury	4,299	-	-	-	-	4,299	
7	461-01	Transmission Land Rights	53,073	-	-	-	-	53,073	
8	461-02	Transmission Land Rights - Mt. Hayes	609	-	-	-	-	609	
9	461-12	Transmission Land Rights - Byron Creek	16	-	-	-	-	16	
10	461-13	IP Land Rights Whistler	24	-	-	-	-	24	
11	471-01	Distribution Land Rights	3,515	-	-	-	-	3,515	
12	471-11	Distribution Land Rights - Byron Creek	1	-	-	-	-	1	
13	402-01	Application Software - 12.5%	71,580	-	-	9,464	(7,331)	73,713	
14	402-02	Application Software - 20%	44,026	-	-	9,241	(3,520)	49,747	
15			$ 180,084	$ -	$ -	$ 18,705	$ (10,851)	$ 187,938	
16									
17		**MANUFACTURED GAS / LOCAL STORAGE**							
18	430-00	Manufact'd Gas - Land	$ 31	$ -	$ -	$ -	$ -	$ 31	
19	432-00	Manufact'd Gas - Struct. & Improvements	1,199	-	-	-	-	1,199	
20	433-00	Manufact'd Gas - Equipment	610	-	-	-	-	610	
21	434-00	Manufact'd Gas - Gas Holders	2,955	-	-	-	-	2,955	
22	436-00	Manufact'd Gas - Compressor Equipment	367	-	-	-	-	367	
23	437-00	Manufact'd Gas - Measuring & Regulating Equipment	1,714	-	-	-	-	1,714	
24	440-00	Land in Fee Simple and Land Rights (Tilbury)	15,164	-	-	-	-	15,164	
25	442-00	Structures & Improvements (Tilbury)	101,167	-	-	-	-	101,167	
26	443-00	Gas Holders - Storage (Tilbury)	181,579	-	-	-	-	181,579	
27	448-11	Piping (Tilbury)	48,636	-	-	-	-	48,636	
28	448-21	Pre-treatment (Tilbury)	38,818	-	2,420	-	-	41,238	
29	448-31	Liquefaction Equipment (Tilbury)	93,333	-	1,539	-	-	94,872	
30	449-00	Local Storage Equipment (Tilbury)	27,862	-	-	-	-	27,862	
31	440-01	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	-	-	-	-	1,083	
32	442-01	Structures & Improvements (Mount Hayes)	19,045	-	-	-	-	19,045	
33	443-05	Gas Holders - Storage (Mount Hayes)	61,774	-	-	-	-	61,774	
34	448-41	Send out Equipment(Tilbury)	7,773	-	-	-	-	7,773	
35	448-51	Sub-station and Electric (Tilbury)	36,910	-	-	-	-	36,910	
36	448-61	Control Room (Tilbury)	3,819	-	-	-	-	3,819	
37	448-10	Piping (Mount Hayes)	12,455	-	-	-	-	12,455	
38	448-20	Pre-treatment (Mount Hayes)	29,238	-	-	-	-	29,238	
39	448-30	Liquefaction Equipment (Mount Hayes)	28,880	-	-	-	-	28,880	
40	448-40	Send out Equipment (Mount Hayes)	23,552	-	-	-	-	23,552	
41	448-50	Sub-station and Electric (Mount Hayes)	21,788	-	-	-	-	21,788	
42	448-60	Control Room (Mount Hayes)	6,425	-	-	-	-	6,425	
43	448-65	MH Inspection (Mount Hayes)	-	-	-	-	-	-	
44	449-01	Local Storage Equipment (Mount Hayes)	5,727	-	-	-	-	5,727	
45			$ 771,904	$ -	$ 3,959	$ -	$ -	$ 775,863	

PLANT IN SERVICE CONTINUITY SCHEDULE Schedule 6.1
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Account	Particulars	12/31/2023	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2024	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**TRANSMISSION PLANT**							
2	460-00	Land in Fee Simple	$ 10,805	$ -	$ -	$ -	$ -	$ 10,805	
3	461-00	Transmission Land Rights	-	-	-	-	-	-	
4	462-00	Compressor Structures	40,772	-	-	2,275	(345)	42,702	
5	463-00	Measuring Structures	20,274	-	-	-	-	20,274	
6	464-00	Other Structures & Improvements	14,694	-	-	1,899	(3)	16,590	
7	465-00	Mains	1,713,752	-	45,578	33,771	(2,901)	1,790,200	
8	465-20	Mains - INSPECTION	62,979	-	-	11,038	(7,190)	66,827	
9	465-11	IP Transmission Pipeline - Whistler	58,689	-	-	-	-	58,689	
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	206,231	-	-	3,663	(887)	209,007	
13	466-10	Compressor Equipment - OVERHAUL	5,880	-	-	4	(3,802)	2,082	
14	467-00	Mt. Hayes - Measuring and Regulating Equipment	9,350	-	-	1,268	-	10,618	
15	467-10	Measuring & Regulating Equipment	115,342	-	-	8,036	(298)	123,080	
16	467-20	Telemetering	18,306	-	-	-	-	18,306	
17	467-31	IP Intermediate Pressure Whistler	437	-	-	39	-	476	
18	467-30	Measuring & Regulating Equipment - Byron Creek	291	-	-	-	-	291	
19	468-00	Communication Structures & Equipment	16,859	-	-	3,141	-	20,000	
20			$ 2,302,339	$ -	$ 45,578	$ 65,134	$ (15,426)	$ 2,397,625	
21									
22		**DISTRIBUTION PLANT**							
23	470-00	Land in Fee Simple	$ 5,457	$ -	$ -	$ -	$ -	$ 5,457	
24	472-00	Structures & Improvements	65,215	-	9,824	1,831	(60)	76,810	
25	472-10	Structures & Improvements - Byron Creek	124	-	-	-	-	124	
26	473-00	Services	1,580,032	-	-	72,463	(3,656)	1,648,839	
27	474-00	House Regulators & Meter Installations	152,842	-	-	-	(5,785)	147,057	
28	474-02	Meters/Regulators Installations	261,466	-	-	21,566	-	283,032	
29	475-00	Mains	2,282,378	-	422	58,852	(3,411)	2,338,241	
30	476-00	Compressor Equipment	614	-	-	-	-	614	
31	477-10	Measuring & Regulating Equipment	251,967	-	1,866	13,909	(776)	266,966	
32	477-20	Telemetering	24,771	-	536	781	(44)	26,044	
33	477-30	Measuring & Regulating Equipment - Byron Creek	153	-	-	-	-	153	
34	478-10	Meters	330,478	-	-	16,884	(5,873)	341,489	
35	478-20	Instruments	16,965	-	-	696	-	17,661	
36	479-00	Other Distribution Equipment	-	-	-	-	-	-	
37			$ 4,972,462	$ -	$ 12,648	$ 186,982	$ (19,605)	$ 5,152,487	
38									
39		**BIO GAS**							
40	472-20	Bio Gas Struct. & Improvements	$ 1,526	$ -	$ -	$ 18,897	$ -	$ 20,423	
41	475-10	Bio Gas Mains – Municipal Land	2,761	-	-	18,014	-	20,775	
42	475-20	Bio Gas Mains – Private Land	410	-	-	-	-	410	
43	418-10	Bio Gas Purification Overhaul	21	-	-	1	-	22	
44	418-20	Bio Gas Purification Upgrader	10,263	-	-	27,435	-	37,698	
45	477-40	Bio Gas Reg & Meter Equipment	4,338	-	-	2,578	-	6,916	
46	478-30	Bio Gas Meters	84	-	-	91	-	175	
47	474-10	Bio Gas Reg & Meter Installations	807	-	-	1,316	-	2,123	
48	483-25	RNG Comp S/W	-	-	-	-	-	-	
49	465-40	Bio Gas Transmission Pipe	-	-	-	2,745	-	2,745	
50	466-40	Bio Gas Compressor Equipment	-	-	-	2,516	-	2,516	
51			$ 20,210	$ -	$ -	$ 73,593	$ -	$ 93,803	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 6.2

Line No.	Account	Particulars	12/31/2023	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2024	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Natural Gas for Transportation**							
2	476-10	NG Transportation CNG Dispensing Equipment	$ 17,121	$ -	$ -	$ -	$ -	$ 17,121	
3	476-20	NG Transportation LNG Dispensing Equipment	13,714	-	-	-	-	13,714	
4	476-30	NG Transportation CNG Foundations	3,161	-	-	-	-	3,161	
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	804	-	-	-	-	804	
8	476-70	NG Transportation LNG Dehydrator	-	-	-	-	-	-	
9			$ 35,926	$ -	$ -	$ -	$ -	$ 35,926	
10									
11		**GENERAL PLANT & EQUIPMENT**							
12	480-00	Land in Fee Simple	$ 31,307	$ -	$ -	$ -	$ -	$ 31,307	
13	482-10	Frame Buildings	25,365	-	-	-	-	25,365	
14	482-20	Masonry Buildings	131,698	-	-	3,100	(79)	134,719	
15	482-30	Leasehold Improvement	3,170	-	-	-	(2,224)	946	
16	483-30	GP Office Equipment	3,826	-	-	405	(263)	3,968	
17	483-40	GP Furniture	25,354	-	-	3,093	(55)	28,392	
18	483-10	GP Computer Hardware	39,534	-	-	9,270	(12,047)	36,757	
19	483-20	GP Computer Software	3,508	-	-	-	(778)	2,730	
20	484-00	Vehicles	70,466	-	-	7,941	-	78,407	
21	484-10	Vehicles - Leased	11,463	-	-	-	(2,500)	8,963	
22	485-10	Heavy Work Equipment	750	-	-	-	-	750	
23	485-20	Heavy Mobile Equipment	9,277	-	-	-	-	9,277	
24	486-00	Small Tools & Equipment	62,590	-	-	4,820	(1,746)	65,664	
25	487-20	Equipment on Customer's Premises	-	-	-	-	-	-	
26	488-10	Telephone	1,084	-	-	-	(767)	317	
27	488-20	Radio	21,163	-	-	1,578	(768)	21,973	
28	489-00	Other General Equipment	-	-	-	-	-	-	
29			$ 440,555	$ -	$ -	$ 30,207	$ (21,227)	$ 449,535	
30									
31		**UNCLASSIFIED PLANT**							
32	499-00	Plant Suspense	-	-	-	-	-	-	
33			$ -	$ -	$ -	$ -	$ -	$ -	
34									
35		**Total Plant in Service**	$ 8,723,480	$ -	$ 62,185	$ 374,621	$ (67,109)	$ 9,093,177	
36									
37		Cross Reference			Schedule 5, Line 31, Column 2	Schedule 5, Line 25, Column 2			

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE Schedule 7
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2023	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2024	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%	$ 67	$ -	$ 1	$ -	$ -	$ -	$ 68	
3	178-00	Organization Expense	728	1.00%	472	-	7	-	-	-	479	
4	401-01	Franchise and Consents	197	1.08%	150	-	2	-	-	-	152	
5	402-03	Other Intangible Plant	1,907	2.50%	1,341	-	48	-	-	-	1,389	
6	440-02	Water/Land Rights Tilbury	4,299	0.00%	-	-	-	-	-	-	-	
7	461-01	Transmission Land Rights	53,073	0.00%	1,766	-	-	-	-	-	1,766	
8	461-02	Transmission Land Rights - Mt. Hayes	609	0.00%	-	-	-	-	-	-	-	
9	461-12	Transmission Land Rights - Byron Creek	16	0.00%	19	-	-	-	-	-	19	
10	461-13	IP Land Rights Whistler	24	0.00%	-	-	-	-	-	-	-	
11	471-01	Distribution Land Rights	3,515	0.00%	248	-	-	-	-	-	248	
12	471-11	Distribution Land Rights - Byron Creek	1	0.00%	1	-	-	-	-	-	1	
13	402-01	Application Software - 12.5%	71,580	12.50%	30,786	-	8,948	(7,331)	-	-	32,403	
14	402-02	Application Software - 20%	44,026	20.00%	9,231	-	8,805	(3,520)	-	-	14,516	
15			$ 180,084		$ 44,081	$ -	$ 17,811	$ (10,851)	$ -	$ -	$ 51,041	
16												
17		**MANUFACTURED GAS / LOCAL STORAGE**										
18	430-00	Manufact'd Gas - Land	$ 31	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
19	432-00	Manufact'd Gas - Struct. & Improvements	1,199	2.50%	485	-	30	-	-	-	515	
20	433-00	Manufact'd Gas - Equipment	610	5.00%	406	-	30	-	-	-	436	
21	434-00	Manufact'd Gas - Gas Holders	2,955	2.50%	1,025	-	74	-	-	-	1,099	
22	436-00	Manufact'd Gas - Compressor Equipment	367	4.00%	213	-	15	-	-	-	228	
23	437-00	Manufact'd Gas - Measuring & Regulating Equipment	1,714	5.00%	1,416	-	86	-	-	-	1,502	
24	440-00	Land in Fee Simple and Land Rights (Tilbury)	15,164	0.00%	1	-	-	-	-	-	1	
25	442-00	Structures & Improvements (Tilbury)	101,167	2.20%	15,519	-	2,225	-	-	-	17,744	
26	443-00	Gas Holders - Storage (Tilbury)	181,579	1.23%	25,048	-	2,233	-	-	-	27,281	
27	448-11	Piping (Tilbury)	48,636	2.45%	5,475	-	1,192	-	-	-	6,667	
28	448-21	Pre-treatment (Tilbury)	41,238	3.84%	6,702	-	1,584	-	-	-	8,286	
29	448-31	Liquefaction Equipment (Tilbury)	94,872	2.45%	10,824	-	2,324	-	-	-	13,148	
30	449-00	Local Storage Equipment (Tilbury)	27,862	2.77%	21,265	-	772	-	-	-	22,037	
31	440-01	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	0.00%	-	-	-	-	-	-	-	
32	442-01	Structures & Improvements (Mount Hayes)	19,045	3.85%	9,028	-	733	-	-	-	9,761	
33	443-05	Gas Holders - Storage (Mount Hayes)	61,774	1.65%	12,675	-	1,019	-	-	-	13,694	
34	448-41	Send out Equipment(Tilbury)	7,773	2.41%	883	-	187	-	-	-	1,070	
35	448-51	Sub-station and Electric (Tilbury)	36,910	2.41%	4,418	-	890	-	-	-	5,308	
36	448-61	Control Room (Tilbury)	3,819	6.09%	1,142	-	233	-	-	-	1,375	
37	448-10	Piping (Mount Hayes)	12,455	2.45%	3,720	-	305	-	-	-	4,025	
38	448-20	Pre-treatment (Mount Hayes)	29,238	3.84%	14,314	-	1,123	-	-	-	15,437	
39	448-30	Liquefaction Equipment (Mount Hayes)	28,880	2.45%	8,969	-	707	-	-	-	9,676	
40	448-40	Send out Equipment (Mount Hayes)	23,552	2.41%	7,202	-	568	-	-	-	7,770	
41	448-50	Sub-station and Electric (Mount Hayes)	21,788	2.41%	6,716	-	525	-	-	-	7,241	
42	448-60	Control Room (Mount Hayes)	6,425	6.09%	4,979	-	391	-	-	-	5,370	
43	448-65	MH Inspection (Mount Hayes)	-	20.00%	-	-	-	-	-	-	-	
44	449-01	Local Storage Equipment (Mount Hayes)	5,727	3.08%	1,349	-	176	-	-	-	1,525	
45			$ 775,863		$ 163,774	$ -	$ 17,422	$ -	$ -	$ -	$ 181,196	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE Schedule 7.1
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2023	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2024	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	40,772	3.32%	22,232	-	1,354	(345)	-	-	23,241	
5	463-00	Measuring Structures	20,274	2.13%	9,531	-	432	-	-	-	9,963	
6	464-00	Other Structures & Improvements	14,694	3.62%	4,788	-	532	(3)	-	-	5,317	
7	465-00	Mains	1,759,330	1.46%	515,939	-	25,686	(2,901)	-	-	538,724	
8	465-20	Mains - INSPECTION	62,979	15.20%	20,472	-	9,573	(7,190)	-	-	22,855	
9	465-11	IP Transmission Pipeline - Whistler	58,689	1.54%	10,046	-	904	-	-	-	10,950	
10	465-30	Mt Hayes - Mains	6,307	1.54%	1,272	-	97	-	-	-	1,369	
11	465-10	Mains - Byron Creek	1,371	5.03%	1,704	-	69	-	-	-	1,773	
12	466-00	Compressor Equipment	206,231	2.42%	114,197	-	4,991	(887)	-	-	118,301	
13	466-10	Compressor Equipment - OVERHAUL	5,880	10.19%	4,394	-	598	(3,802)	-	-	1,190	
14	467-00	Mt. Hayes - Measuring and Regulating Equipment	9,350	2.34%	2,225	-	218	-	-	-	2,443	
15	467-10	Measuring & Regulating Equipment	115,342	2.12%	34,682	-	2,445	(298)	-	-	36,829	
16	467-20	Telemetering	18,306	8.97%	18,162	-	1,642	-	-	-	19,804	
17	467-31	IP Intermediate Pressure Whistler	437	2.26%	145	-	10	-	-	-	155	
18	467-30	Measuring & Regulating Equipment - Byron Creek	291	2.41%	59	-	7	-	-	-	66	
19	468-00	Communication Structures & Equipment	16,859	0.00%	4,393	-	-	-	-	-	4,393	
20			$ 2,347,917		$ 764,744	$ -	$ 48,558	$ (15,426)	$ -	$ -	$ 797,876	
21												
22		**DISTRIBUTION PLANT**										
23	470-00	Land in Fee Simple	$ 5,457	0.00%	$ (13)	$ -	$ -	$ -	$ -	$ -	$ (13)	
24	472-00	Structures & Improvements	75,039	2.15%	14,974	-	1,612	(60)	-	-	16,526	
25	472-10	Structures & Improvements - Byron Creek	124	4.67%	94	-	6	-	-	-	100	
26	473-00	Services	1,580,032	2.18%	448,641	-	34,445	(3,656)	-	-	479,430	
27	474-00	House Regulators & Meter Installations	152,842	7.45%	119,120	-	11,387	(5,785)	-	-	124,722	
28	474-02	Meters/Regulators Installations	261,466	4.55%	66,088	-	11,897	-	-	-	77,985	
29	475-00	Mains	2,282,800	1.35%	613,778	-	30,818	(3,411)	-	-	641,185	
30	476-00	Compressor Equipment	614	0.00%	1,444	-	-	-	-	-	1,444	
31	477-10	Measuring & Regulating Equipment	253,833	2.51%	76,555	-	6,371	(776)	-	-	82,150	
32	477-20	Telemetering	25,307	3.59%	9,305	-	909	(44)	-	-	10,170	
33	477-30	Measuring & Regulating Equipment - Byron Creek	153	0.00%	210	-	-	-	-	-	210	
34	478-10	Meters	330,478	6.06%	209,064	-	20,027	(5,873)	-	-	223,218	
35	478-20	Instruments	16,965	2.92%	8,594	-	495	-	-	-	9,089	
36	479-00	Other Distribution Equipment	-	0.00%	-	-	-	-	-	-	-	
37			$ 4,985,110		$ 1,567,854	$ -	$ 117,967	$ (19,605)	$ -	$ -	$ 1,666,216	
38												
39		**BIO GAS**										
40	472-20	Bio Gas Struct. & Improvements	$ 1,526	2.69%	$ 207	$ -	$ 41	$ -	$ -	$ -	$ 248	
41	475-10	Bio Gas Mains – Municipal Land	2,761	1.56%	221	-	43	-	-	-	264	
42	475-20	Bio Gas Mains – Private Land	410	1.56%	25	-	7	-	-	-	32	
43	418-10	Bio Gas Purification Overhaul	21	5.00%	10	-	1	-	-	-	11	
44	418-20	Bio Gas Purification Upgrader	10,263	5.00%	4,350	-	514	-	-	-	4,864	
45	477-40	Bio Gas Reg & Meter Equipment	4,338	3.22%	853	-	140	-	-	-	993	
46	478-30	Bio Gas Meters	84	4.89%	22	-	4	-	-	-	26	
47	474-10	Bio Gas Reg & Meter Installations	807	5.32%	159	-	43	-	-	-	202	
48	483-25	RNG Comp S/W	-	20.00%	-	-	-	-	-	-	-	
49	465-40	Bio Gas Transmission Pipe	-	1.46%	-	-	-	-	-	-	-	
50	466-40	Bio Gas Compressor Equipment	-	2.42%	-	-	-	-	-	-	-	
51			$ 20,210		$ 5,847	$ -	$ 793	$ -	$ -	$ -	$ 6,640	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE Schedule 7.2
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2023	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2024	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	17,121	5.00%	$ 5,112	-	856	-	-	-	$ 5,968	
3	476-20	NG Transportation LNG Dispensing Equipment	13,714	5.00%	5,591	-	686	-	-	-	6,277	
4	476-30	NG Transportation CNG Foundations	3,161	5.00%	1,012	-	158	-	-	-	1,170	
5	476-40	NG Transportation LNG Foundations	1,049	5.00%	498	-	52	-	-	-	550	
6	476-50	NG Transportation LNG Pumps (Pumps only apply to LNG)	77	10.00%	57	-	1	-	-	-	58	
7	476-60	NG Transportation CNG Dehydrator	804	5.00%	226	-	40	-	-	-	266	
8	476-70	NG Transportation LNG Dehydrator	-	5.00%	-	-	-	-	-	-	-	
9			$ 35,926		$ 12,496	$ -	$ 1,793	$ -	$ -	$ -	$ 14,289	
10												
11		**GENERAL PLANT & EQUIPMENT**										
12	480-00	Land in Fee Simple	$ 31,307	0.00%	$ 17	$ -	$ -	$ -	$ -	$ -	$ 17	
13	482-10	Frame Buildings	25,365	3.17%	15,231	-	804	-	-	-	16,035	
14	482-20	Masonry Buildings	131,698	1.52%	38,648	-	2,002	(79)	-	-	40,571	
15	482-30	Leasehold Improvement	3,170	9.49%	2,154	-	198	(2,224)	-	-	128	
16	483-30	GP Office Equipment	3,826	6.67%	1,574	-	255	(263)	-	-	1,566	
17	483-40	GP Furniture	25,354	5.00%	6,859	-	1,268	(55)	-	-	8,072	
18	483-10	GP Computer Hardware	39,534	25.00%	15,664	-	9,883	(12,047)	-	-	13,500	
19	483-20	GP Computer Software	3,508	12.50%	3,173	-	334	(778)	-	-	2,729	
20	484-00	Vehicles	70,466	11.07%	32,916	-	7,801	-	-	-	40,717	
21	484-10	Vehicles - Leased	11,463	9.44%	11,463	-	-	(2,500)	-	-	8,963	
22	485-10	Heavy Work Equipment	750	5.14%	565	-	39	-	-	-	604	
23	485-20	Heavy Mobile Equipment	9,277	6.09%	5,848	-	565	-	-	-	6,413	
24	486-00	Small Tools & Equipment	62,590	5.00%	24,628	-	3,130	(1,746)	-	-	26,012	
25	487-20	Equipment on Customer's Premises	-	6.67%	-	-	-	-	-	-	-	
26	488-10	Telephone	1,084	6.67%	1,025	-	60	(767)	-	-	318	
27	488-20	Radio	21,163	6.67%	7,753	-	1,412	(768)	-	-	8,397	
28	489-00	Other General Equipment	-	0.00%	-	-	-	-	-	-	-	
29			$ 440,555		$ 167,518	$ -	$ 27,751	$ (21,227)	$ -	$ -	$ 174,042	
30												
31		**UNCLASSIFIED PLANT**										
32	499-00	Plant Suspense	-	0.00%	-	-	-	-	-	-	-	
33			$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	
34												
35		**Total**	$ 8,785,665		$ 2,726,314	$ -	$ 232,095	$ (67,109)	$ -	$ -	$ 2,891,300	
36		Less: Depreciation & Amortization Transferred to Biomethane BVA					(793)					
37		Less: Vehicle Depreciation Allocated To Capital Projects					(2,886)					
38		**Net Depreciation Expense**					$ 228,416					
39												
40		Cross Reference	Schedule 6.2, Line 35, Columns 3+4+5									

NON-REG PLANT CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars			12/31/2023	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2024	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, 2024**
11 **($000s)**
12
13

Line No.	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2023	Opening Bal Adjustment	Depreciation Expense	Depreciation Retirements	Cost of Removal	12/31/2024	Cross Reference
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%	146,891	-	4,238	-	-	151,129	
21									-	
22	**Total**	$ 177,648		$ 146,891	$ -	$ 4,238	$ -	$ -	$ 151,129	

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 9

Line No.	Particulars	12/31/2023	CPCN / Open Bal Adjt	Adjustment	Additions	Retirements	12/31/2024	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CIAC**							
2	Distribution Contributions	$ 301,783	$ -	$ -	$ 2,388	$ -	$ 304,172	
3	Transmission Contributions	160,181	-	-	4,342	-	164,522	
4	Others	2,399	-	-	-	-	2,399	
5	Biomethane	566	-	-	8,200	-	8,766	
6	**Total**	$ 464,929	$ -	$ -	$ 14,930	$ -	$ 479,859	
7								
8	**Amortization**							
9	Distribution Contributions	$ (140,788)	$ -	$ -	$ (6,357)	$ -	$ (147,145)	
10	Transmission Contributions	(63,291)	-	-	(2,346)	-	(65,637)	
11	Others	(1,230)	-	-	(120)	-	(1,350)	
12	Biomethane	(329)	-	-	(28)	-	(357)	
13	**Total**	$ (205,638)	$ -	$ -	$ (8,851)	$ -	$ (214,489)	
14								
15	**Net CIAC**	$ 259,291	$ -	$ -	$ 6,079	$ -	$ 265,370	
16								
17								
18	Total CIAC Amortization Expense per Line 13, Column 5				$ (8,851)			
19	Less: CIAC Amortization Transferred to Biomethane BVA				28			
20	**Net CIAC Amortization Expense**				$ (8,823)			

NET SALVAGE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2023	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2024	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**INTANGIBLE PLANT**							
2	471-01	Distribution Land Rights	$ -	0.00%	$ -	$ -	$ -	$ -	
3			$ -		$ 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)	101,167	0.68%	3,544	688	-	4,232	
8	443-00	Gas Holders - Storage (Tilbury)	181,579	1.12%	9,620	2,034	-	11,654	
9	448-11	Piping (Tilbury)	48,636	0.28%	842	136	-	978	
10	448-21	Pre-treatment (Tilbury)	41,238	0.50%	1,139	206	-	1,345	
11	448-31	Liquefaction Equipment (Tilbury)	94,872	0.57%	3,392	541	-	3,933	
12	449-00	Local Storage Equipment (Tilbury)	27,862	0.82%	1,807	228	-	2,035	
13	442-01	Structures & Improvements (Mount Hayes)	19,045	0.49%	607	93	-	700	
14	443-05	Gas Holders - Storage (Mount Hayes)	61,774	0.36%	1,520	222	-	1,742	
15	448-41	Send out Equipment(Tilbury)	7,773	0.28%	107	22	-	129	
16	448-51	Sub-station and Electric (Tilbury)	36,910	0.56%	1,197	207	-	1,404	
17	448-10	Piping (Mount Hayes)	12,455	0.28%	233	35	-	268	
18	448-20	Pre-treatment (Mount Hayes)	29,238	0.50%	981	146	-	1,127	
19	448-30	Liquefaction Equipment (Mount Hayes)	28,880	0.57%	1,124	164	-	1,288	
20	448-40	Send out Equipment (Mount Hayes)	23,552	0.28%	450	66	-	516	
21	448-50	Sub-station and Electric (Mount Hayes)	21,788	0.56%	839	122	-	961	
22	449-01	Local Storage Equipment (Mount Hayes)	5,727	0.32%	126	18	-	144	
23			$ 744,210		$ 27,506	$ 4,928	$ -	$ 32,434	

NET SALVAGE CONTINUITY SCHEDULE Schedule 10.1
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2023	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2024	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**TRANSMISSION PLANT**							
2	462-00	Compressor Structures	$ 40,772	0.11%	$ 605	$ 45	$ -	$ 650	
3	463-00	Measuring Structures	20,274	0.62%	883	125	-	1,008	
4	464-00	Other Structures & Improvements	14,694	0.29%	185	43	-	228	
5	465-00	Mains	1,759,330	0.42%	45,229	7,389	-	52,618	
6	465-11	IP Transmission Pipeline - Whistler	58,689	0.34%	1,230	199	-	1,429	
7	465-30	Mt Hayes - Mains	6,307	0.30%	136	19	-	155	
8	466-00	Compressor Equipment	206,231	0.07%	2,719	144	-	2,863	
9	467-00	Mt. Hayes - Measuring and Regulating Equipment	9,350	0.21%	90	20	-	110	
10	467-10	Measuring & Regulating Equipment	115,342	0.16%	1,337	185	-	1,522	
11	467-20	Telemetering	18,306	0.00%	(28)	-	-	(28)	
12	467-31	IP Intermediate Pressure Whistler	437	0.35%	7	2	-	9	
13	468-00	Communication Structures & Equipment	16,859	0.00%	401	-	-	401	
14			$ 2,266,591		$ 52,794	$ 8,171	$ -	$ 60,965	
15									
16		**DISTRIBUTION PLANT**							
17	470-00	Land in Fee Simple	$ 5,457	0.00%	$ (2,099)	$ -	$ -	$ (2,099)	
18	472-00	Structures & Improvements	75,039	0.52%	1,116	390	-	1,506	
19	473-00	Services	1,580,032	2.09%	99,250	33,024	(22,644)	109,630	
20	474-00	House Regulators & Meter Installations	152,842	3.37%	4,354	5,151	-	9,505	
21	474-02	Meters/Regulators Installations	261,466	0.00%	749	-	-	749	
22	475-00	Mains	2,282,800	0.50%	67,027	11,414	-	78,441	
23	476-00	Compressor Equipment	614	0.00%	706	-	-	706	
24	477-10	Measuring & Regulating Equipment	253,833	0.45%	6,386	1,142	-	7,528	
25	477-20	Telemetering	25,307	0.48%	444	121	-	565	
26	478-10	Meters	330,478	0.00%	2,750	-	-	2,750	
27			$ 4,967,868		$ 180,683	$ 51,242	$ (22,644)	$ 209,281	
28									
29		**BIO GAS**							
30	472-20	Bio Gas Struct. & Improvements	$ 1,526	0.29%	$ 15	$ 4	$ -	$ 19	
31	475-10	Bio Gas Mains – Municipal Land	2,761	0.39%	62	11	-	73	
32	475-20	Bio Gas Mains – Private Land	410	0.39%	5	2	-	7	
33	418-20	Bio Gas Purification Upgrader	10,263	0.24%	176	25	-	201	
34	477-40	Bio Gas Reg & Meter Equipment	4,338	0.00%	(6)	-	-	(6)	
35	474-10	Bio Gas Reg & Meter Installations	807	1.44%	38	12	-	50	
36			$ 20,105		$ 290	$ 54	$ -	$ 344	

NET SALVAGE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2023	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2024	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Natural Gas for Transportation**							
2	476-10	NG Transportation CNG Dispensing Equipment	$ 17,121	0.00%	$ (1)	$ -	$ -	$ (1)	
3	476-20	NG Transportation LNG Dispensing Equipment	13,714	0.00%	10	-	-	10	
4	476-40	NG Transportation LNG Foundations	1,049	0.00%	9	-	-	9	
5	476-50	NG Transportation LNG Pumps (Pumps only apply to LNG)	77	0.00%	16	-	-	16	
6			$ 31,961		$ 34	$ -	$ -	$ 34	
7									
8		**GENERAL PLANT & EQUIPMENT**							
9	482-10	Frame Buildings	$ 25,365	0.37%	$ (48)	$ 94	$ -	$ 46	
10	482-20	Masonry Buildings	131,698	0.08%	1,137	105	-	1,242	
11	482-30	Leasehold Improvement	3,170	0.00%	(74)	-	-	(74)	
12	483-30	GP Office Equipment	3,826	0.00%	1	-	-	1	
13	483-40	GP Furniture	25,354	0.00%	(94)	-	-	(94)	
14	484-00	Vehicles	70,466	-3.70%	(4,126)	(2,607)	-	(6,733)	
15	485-10	Heavy Work Equipment	750	-0.67%	(31)	(5)	-	(36)	
16	485-20	Heavy Mobile Equipment	9,277	-1.80%	(1,176)	(167)	-	(1,343)	
17	486-00	Small Tools & Equipment	62,590	0.00%	52	-	-	52	
18	487-20	Equipment on Customer's Premises	-	0.00%	(2)	-	-	(2)	
19	488-20	Radio	21,163	0.00%	(7)	-	-	(7)	
20			$ 353,659		$ (4,368)	$ (2,580)	$ -	$ (6,948)	
21									
22		**Total**	$ 8,384,394		$ 257,085	$ 61,815	$ (22,644)	$ 296,256	
23		Less: Depreciation & Amortization Transferred to Biomethane BVA				(54)			
24		**Net Salvage Depreciation Expense**				$ 61,761			
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, 2024
($000s)

Line No.	Particulars	12/31/2023	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2024	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)	$ (169,421)	$ -	$ -	$ -	$ -	$ 116,042	$ (31,331)	$ (84,710)	$ (127,066)	
3	Commodity Cost Reconciliation Account (CCRA)	(64,827)	-	88,804	(23,977)	-	-	-	-	(32,414)	
4	Revenue Stabilization Adjustment Mechanism (RSAM)	(21,596)	-	-	-	-	14,791	(3,993)	(10,798)	(16,197)	
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(9,467)	-	4,135	(1,116)	10	4,413	(1,191)	(3,216)	(6,342)	
6	SCP Mitigation Revenues Variance Account	214	-	-	-	(214)	-	-	-	107	
7	Pension & OPEB Variance	(2,681)	-	-	-	(1,305)	-	-	(3,986)	(3,334)	
8	BCUC Levies Variance	788	-	-	-	(788)	-	-	-	394	
9		$ (266,990)	$ -	$ 92,939	$ (25,093)	$ (2,297)	$ 135,246	$ (36,515)	$ (102,710)	$ (184,852)	
10											
11	**2. Rate Smoothing Accounts**										
12											
13	**3. Benefits Matching Accounts**										
14	Demand-Side Management (DSM)	$ 303,602	$ 60,800	$ 60,000	$ (16,200)	$ (51,736)	$ -	$ -	$ 356,466	$ 360,434	
15	NGV Conversion Grants	9	-	3	(1)	(3)	-	-	8	9	
16	Emissions Regulations	(759)	-	-	-	759	-	-	-	(380)	
17	Greenhouse Gas Reduction Regulation Incentives	20,963	-	950	(257)	(4,223)	-	-	17,433	19,198	
18	CNG and LNG Recoveries	(720)	-	(1,851)	500	720	-	-	(1,351)	(1,036)	
19	2025 Multi-year Rate Plan Application	256	-	1,200	(324)	-	-	-	1,132	694	
20	BCUC Initiated Inquiry Costs	(33)	-	-	-	33	-	-	-	(17)	
21	PGR Application and Preliminary Stage Development Costs	110	-	-	-	(151)	-	-	(41)	35	
22	Transportation Service Report	173	-	-	-	(173)	-	-	-	87	
23	2021 Generic Cost of Capital Proceeding	805	-	-	-	-	-	-	805	805	
24	2023 DSM Expenditures Schedule Application	100	-	-	-	(100)	-	-	-	50	
25	City of Coquitlam Application Proceeding	43	-	-	-	(43)	-	-	-	22	
26	2024-2027 DSM Expenditures Schedule Application	73	-	100	(27)	(18)	-	-	128	101	
27	2023 Cost of Service Allocation Study	41	-	84	(23)	-	-	-	102	72	
28	AMI Application and Feasibility Costs	-	9,126	-	-	(3,042)	-	-	6,084	7,605	
29		$ 324,663	$ 69,926	$ 60,486	$ (16,332)	$ (57,977)	$ -	$ -	$ 380,766	$ 387,679	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 11.1

Line No.	Particulars	12/31/2023	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2024	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	$ 4,237	$ -	$ -	$ -	$ (737)	$ -	$ -	$ 3,500	$ 3,869	
3	Gas Asset Records Project	278	-	-	-	(117)	-	-	161	220	
4	Gains and Losses on Asset Disposition	523	-	-	-	(523)	-	-	-	262	
5	Net Salvage Provision/Cost	(257,085)	-	22,644	-	(61,815)	-	-	(296,256)	(276,671)	
6	PCEC Start Up Costs	524	-	-	-	(44)	-	-	480	502	
7	2022 Long Term Gas Resource Plan Application	1,211	-	175	(47)	-	-	-	1,339	1,275	
8	2020–2024 MRP Application	136	-	-	-	(136)	-	-	-	68	
9	2021 Renewable Gas Program Comprehensive Review	1,319	-	1,040	(281)	-	-	-	2,078	1,699	
10	GCU Preliminary Stage Development Costs	517	-	-	-	(259)	-	-	258	388	
11	Transmission Integrity Management Capabilities	9,214	-	-	-	(2,347)	-	-	6,867	8,041	
12	Annual Review of 2020-2024 Rates	133	-	120	(32)	(134)	-	-	87	110	
13	FEFN - Common Rates and 2022 Revenue Requirement Application Costs	45	-	-	-	(45)	-	-	-	23	
14		$ (238,948)	$ -	$ 23,979	$ (360)	$ (66,157)	$ -	$ -	$ (281,486)	$ (260,214)	
15											
16	**4. Retroactive Expense Accounts**										
17											
18	**5.Other Accounts**										
19	Pension & OPEB Funding	$ (61,891)	$ -	$ 11,356	$ -	$ -	$ -	$ -	$ (50,535)	$ (56,213)	
20	US GAAP Pension & OPEB Funded Status	(60,527)	-	-	-	-	-	-	(60,527)	(60,527)	
21	BVA Balance Transfer	(874)	27,422	-	-	-	(36,368)	9,820	-	13,274	
22	COVID-19 Customer Recovery Fund	722	-	-	-	(433)	-	-	289	506	
23	Stargas Assets Acquisition Deferral Account	13	-	-	-	(13)	-	-	-	7	
24	PST Rebate on Select Machinery and Equipment	(1,586)	-	-	-	1,586	-	-	-	(793)	
25	Residual Delivery Rate Riders	-	-	-	-	-	-	-	-	-	
26	FEFN - Transitional Balance	(8)	-	-	-	8	-	-	-	(4)	
27		$ (124,151)	$ 27,422	$ 11,356	$ -	$ 1,148	$ (36,368)	$ 9,820	$ (110,773)	$ (103,750)	
28											
29	**Total**	$ (305,426)	$ 97,348	$ 188,760	$ (41,785)	$ (125,283)	$ 98,878	$ (26,695)	$ (114,203)	$ (161,137)	
30	Less: Net Salvage Amortization Transferred to Biomethane BVA					54					
31	**Net Rate Base Deferred Amortization Expense**					$ (125,229)					

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE Schedule 12
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	12/31/2023	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2024	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	$ 61,435	$ (27,422)	$ -	$ -	$ -	$ -	$ -	$ 34,013	$ 34,013	
3	Flowthrough (2020-2024)	13,427	-	357	-	(13,784)	-	-	-	6,714	
4	Marketer Cost Variance	(52)	-	71	(19)	-	-	-	-	(26)	
5		$ 74,810	$ (27,422)	$ 428	$ (19)	$ (13,784)	$ -	$ -	$ 34,013	$ 40,701	
6	**2. Rate Smoothing Accounts**										
7	City of Vancouver Biomethane Purchase Agreement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
8	Fort Nelson Residential Customer Common Rate Phase-in Rate Rider	101	-	7	-	(101)	202	(55)	154	128	
9		$ 101	$ -	$ 7	$ -	$ (101)	$ 202	$ (55)	$ 154	$ 128	
10											
11	**3. Benefits Matching Accounts**										
12	Demand-Side Management (DSM) - Non Rate Base	$ 60,800	$ (60,800)	$ 108,998	$ (28,855)	$ -	$ -	$ -	$ 80,143	$ 40,072	
13	PEC Pipeline Development Costs and Commitment Fees	(2,398)	-	-	-	-	-	-	(2,398)	(2,398)	
14	AMI Application and Feasibility Costs	9,126	(9,126)	-	-	-	-	-	-	-	
15	Transmission Integrity Management Capabilities	(485)	-	(26)	-	-	-	-	(511)	(498)	
16	Regional Gas Supply Diversity Project Development Costs	2,282	-	125	-	-	-	-	2,407	2,345	
17	Clean Growth Innovation Fund	(8,594)	-	5,315	(1,559)	-	(5,229)	1,412	(8,655)	(8,625)	
18		$ 60,731	$ (69,926)	$ 114,412	$ (30,414)	$ -	$ (5,229)	$ 1,412	$ 70,986	$ 30,896	
19											
20	**4. Retroactive Expense Accounts**										
21											
22	**5.Other Accounts**										
23	Mark to Market - Hedging Transactions	$ 59,552	$ -	$ -	$ -	$ -	$ -	$ -	$ 59,552	$ 59,552	
24	MRP Earnings Sharing Account	(4,970)	-	(132)	-	5,102	-	-	-	(2,485)	
25	US GAAP Uncertain Tax Positions	-	-	-	-	-	-	-	-	-	
26	FEFN - Right-Of-Way Agreement	173	-	9	-	-	-	-	182	178	
27		$ 54,755	$ -	$ (123)	$ -	$ 5,102	$ -	$ -	$ 59,734	$ 57,245	
28											
29											
30	**Total Non Rate Base Deferral Accounts**	$ 190,397	$ (97,348)	$ 114,724	$ (30,433)	$ (8,783)	$ (5,027)	$ 1,357	$ 164,887	$ 128,970	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 19,750	$ 25,837	$ 6,087	Schedule 14, Line 30, Column 5
3					
4	Add/Less: Funds Unavailable/(Funds Available)				
5	Employee Loans	1,894	1,802	(92)	
6	Employee Withholdings	(6,888)	(7,688)	(800)	
7					
8	**Other Working Capital Items**				
9	Transmission Line Pack Gas	5,869	2,703	(3,166)	
10	Gas In Storage	90,540	49,854	(40,686)	
11	Inventories - Materials and Supplies	2,608	2,616	8	
12	Refundable Contributions	(312)	(282)	30	
13					
14	Total	$ 113,461	$ 74,842	$ (38,619)	

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 14

Line No.	Particulars	2024 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	$ 1,070,006	40.3	$ 43,121,242		
4	Commercial Tariff Revenue	575,950	37.8	21,770,910		
5	Industrial Tariff Revenue	189,921	47.7	9,059,231		
6	Bypass and Special Rates	41,569	37.6	1,562,994		
7						
8	**Other Revenue**					
9	Late Payment Charges	3,607	53.8	194,057		
10	Application Charges	1,797	39.0	70,083		
11	Other Utility Income	37,075	39.0	1,445,925		
12						
13	Total	$ 1,919,925		$ 77,224,442	40.2	
14						
15	**EXPENSES**					
16	Energy Purchases	$ 744,149	(40.0)	$ (29,765,960)		
17	Operating and Maintenance	305,157	(31.8)	(9,703,993)		
18	Property Taxes	83,359	(1.3)	(108,366)		
19	Operating Fees	11,997	(352.9)	(4,233,693)		
20	Carbon Tax	615,283	(30.7)	(18,889,188)		
21	GST	47,796	(39.7)	(1,897,487)		
22	PST	48,479	(45.8)	(2,220,352)		
23	Income Tax	68,401	(15.2)	(1,039,695)		
24						
25	Total	$ 1,924,620		$ (67,858,734)	(35.3)	
26						
27	Net Lag (Lead) Days				4.9	
28	Total Expenses				$ 1,924,620	
29						
30	Cash Working Capital				$ 25,837	

DEFERRED INCOME TAX LIABILITY / ASSET
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 15

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Total DIT Liability- After Tax	$ (567,344)	$ (556,038)	$ 11,306	
2	Tax Gross Up	(209,840)	(205,658)	4,182	
3	DIT Liability/Asset - End of Year	$ (777,184)	$ (761,696)	$ 15,488	
4	DIT Liability/Asset - Opening Balance	(717,706)	(714,996)	2,710	
5					
6	DIT Liability/Asset - Mid Year	$ (747,445)	$ (738,346)	$ 9,099	

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 16

Line No.	Particulars	2023 Approved	2024 Forecast at 2023 Approved Rates	2024 Forecast Revised Revenue	2024 Forecast at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (TJ)	160,101	161,958		161,958	1,858	
3	Transportation Volume (TJ)	61,672	58,206		58,206	(3,466)	
4		221,773	220,165	-	220,165	(1,608)	Schedule 17, Line 23, Column 3
5							
6	**REVENUE AT EXISTING RATES**						
7	Sales	$ 2,162,318	$ 1,749,217	$ -	$ 1,749,217	$ (413,101)	
8	Deficiency (Surplus)	-	-	44,251	44,251	44,251	
9	Transportation	86,799	80,675	-	80,675	(6,124)	
10	Deficiency (Surplus)	-		3,303	3,303	3,303	
11	Total	2,249,117	1,829,892	47,554	1,877,446	(371,671)	Schedule 19, Line 29, Column 8
12				-			
13	**COST OF ENERGY**	1,170,773	744,149	-	744,149	(426,624)	Schedule 18, Line 23, Column 3
14							
15	**MARGIN**	1,078,344	1,085,743	47,554	1,133,297	54,953	
16							
17	**EXPENSES**						
18	O&M Expense (net)	292,666	305,157	-	305,157	12,491	Schedule 20, Line 28, Column 4
19	Depreciation & Amortization	326,852	353,605	-	353,605	26,753	Schedule 21, Line 15, Column 3
20	Property Taxes	79,144	83,359	-	83,359	4,215	Schedule 22, Line 8, Column 3
21	Other Revenue	(42,018)	(42,479)	-	(42,479)	(461)	Schedule 23, Line 12, Column 3
22	Utility Income Before Income Taxes	421,700	386,101	47,554	433,655	11,955	
23							
24	Income Taxes	51,748	55,563	12,838	68,401	16,653	Schedule 24, Line 13, Column 3
25							
26	**EARNED RETURN**	$ 369,952	$ 330,538	$ 34,716	$ 365,254	$ (4,698)	Schedule 26, Line 5, Column 7
27							
28	**UTILITY RATE BASE**	$ 5,943,434	$ 5,815,727		$ 5,815,903	$ (127,531)	Schedule 2, Line 30, Column 3
29	**RATE OF RETURN ON UTILITY RATE BASE**	6.23%	5.68%		6.28%	0.05%	Schedule 26, Line 5, Column 6

VOLUME AND REVENUE Schedule 17
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (TJ)**				
2	Residential				
3	Rate Schedule 1	82,889.5	83,378.5	489.0	
4	Commercial				
5	Rate Schedule 2	29,204.3	29,678.8	474.5	
6	Rate Schedule 3	25,770.1	27,002.0	1,231.9	
7	Rate Schedule 23	3,903.8	3,637.1	(266.7)	
8	Industrial				
9	Rate Schedule 4	166.1	177.7	11.6	
10	Rate Schedule 5	10,826.9	11,870.1	1,043.2	
11	Rate Schedule 6	20.9	18.1	(2.8)	
12	Rate Schedule 7	6,004.2	6,799.4	795.2	
13	Rate Schedule 22 - Firm Service	10,378.3	13,874.6	3,496.3	
14	Rate Schedule 22 - Interruptible Service	17,144.2	12,943.7	(4,200.5)	
15	Rate Schedule 25	8,303.3	7,777.0	(526.3)	
16	Rate Schedule 27	4,289.1	3,876.7	(412.4)	
17	Bypass and Special Rates				
18	Rate Schedule 22 - Firm Service	11,945.6	10,421.1	(1,524.5)	
19	Rate Schedule 25	951.3	905.5	(45.8)	
20	Rate Schedule 46	5,218.5	3,033.6	(2,184.9)	
21	Byron Creek	11.6	12.6	1.0	
22	VIGJV	4,745.0	4,758.0	13.0	
23	Total	221,772.7	220,164.5	(1,608.2)	
24					
25	**REVENUE AT EXISTING RATES**				
26	Residential				
27	Rate Schedule 1	$ 1,257,965	$ 1,040,799	$ (217,166)	
28	Commercial				
29	Rate Schedule 2	382,100	307,741	(74,359)	
30	Rate Schedule 3	298,578	239,154	(59,424)	
31	Rate Schedule 23	16,722	15,543	(1,179)	
32	Industrial				
33	Rate Schedule 4	1,555	1,163	(392)	
34	Rate Schedule 5	105,948	84,972	(20,976)	
35	Rate Schedule 6	209	132	(77)	
36	Rate Schedule 7	51,904	40,140	(11,764)	
37	Rate Schedule 22 - Firm Service	9,036	14,263	5,228	
38	Rate Schedule 22 - Interruptible Service	22,796	14,408	(8,388)	
39	Rate Schedule 25	23,709	22,503	(1,206)	
40	Rate Schedule 27	8,283	7,505	(778)	
41	Bypass and Special Rates				
42	Rate Schedule 22 - Firm Service	799	799	-	
43	Rate Schedule 25	424	421	(3)	
44	Rate Schedule 46	64,059	35,116	(28,943)	
45	Byron Creek	134	134	-	
46	VIGJV	4,896	5,099	203	
47	Total	$ 2,249,117	$ 1,829,892	$ (419,225)	

COST OF ENERGY
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**COST OF GAS**				
2	Residential				
3	Rate Schedule 1	$ 614,049	$ 391,703	$ (222,346)	
4	Commercial				
5	Rate Schedule 2	217,315	140,732	(76,583)	
6	Rate Schedule 3	185,898	121,353	(64,545)	
7	Rate Schedule 23	147	72	(75)	
8	Industrial				
9	Rate Schedule 4	1,133	725	(408)	
10	Rate Schedule 5	73,578	48,358	(25,220)	
11	Rate Schedule 6	127	60	(67)	
12	Rate Schedule 7	40,943	27,769	(13,174)	
13	Rate Schedule 22 - Firm Service	571	276	(295)	
14	Rate Schedule 22 - Interruptible Service	466	257	(209)	
15	Rate Schedule 25	313	155	(158)	
16	Rate Schedule 27	162	77	(85)	
17	Bypass and Special Rates				
18	Rate Schedule 22 - Firm Service	450	207	(243)	
19	Rate Schedule 25	36	18	(18)	
20	Rate Schedule 46	35,585	12,387	(23,198)	
21	Byron Creek	-	-	-	
22	VIGJV	-	-	-	
23	Total	$ 1,170,773	$ 744,149	$ (426,624)	

MARGIN AND REVENUE AT EXISTING AND REVISED RATES Schedule 19
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved Margin	2024 Forecast Margin at 2023 Approved Rates	2024 Forecast Effective Increase	2024 Forecast Margin at Revised Rates	2024 Forecast Revenue at 2023 Approved Rates	2024 Forecast Effective Increase	2024 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	$ 643,916	$ 649,096	$ 29,207	$ 678,303	$ 1,040,799	$ 29,207	$ 1,070,006	989,825	83,378.5	
4	Commercial										
5	Rate Schedule 2	164,785	167,009	7,515	174,524	307,741	7,515	315,256	90,551	29,678.8	
6	Rate Schedule 3	112,680	117,801	5,301	123,102	239,154	5,301	244,455	7,234	27,002.0	
7	Rate Schedule 23	16,575	15,471	696	16,167	15,543	696	16,239	623	3,637.1	
8	Industrial										
9	Rate Schedule 4	422	438	20	458	1,163	20	1,183	17	177.7	
10	Rate Schedule 5	32,370	36,614	1,648	38,262	84,972	1,648	86,620	677	11,870.1	
11	Rate Schedule 6	82	72	3	75	132	3	135	18	18.1	
12	Rate Schedule 7	10,961	12,371	557	12,928	40,140	557	40,697	46	6,799.4	
13	Rate Schedule 22 - Firm Service	8,465	13,987	630	14,617	14,263	630	14,893	26	13,874.6	
14	Rate Schedule 22 - Interruptible Service	22,330	14,151	637	14,788	14,408	637	15,045	12	12,943.7	
15	Rate Schedule 25	23,396	22,348	1,006	23,354	22,503	1,006	23,509	244	7,777.0	
16	Rate Schedule 27	8,121	7,428	334	7,762	7,505	334	7,839	66	3,876.7	
17	Total Non-Bypass	$ 1,044,103	$ 1,056,786	$ 47,554	$ 1,104,340	$ 1,788,323	$ 47,554	$ 1,835,877	1,089,339	201,033.7	
18											
19											
20	**Bypass and Special Rates**										
21	Rate Schedule 22 - Firm Service	$ 349	$ 592		$ 592	$ 799		$ 799	6	10,421.1	
22	Rate Schedule 25	388	403		403	421		421	3	905.5	
23	Rate Schedule 46	28,474	22,729		22,729	35,116		35,116	21	3,033.6	
24	Byron Creek	134	134		134	134		134	1	12.6	
25	VIGJV	4,896	5,099		5,099	5,099		5,099	1	4,758.0	
26	Total Bypass & Special	$ 34,241	$ 28,957	$ -	$ 28,957	$ 41,569	$ -	$ 41,569	32	19,130.8	
27											
28											
29	Total	$ 1,078,344	$ 1,085,743	$ 47,554	$ 1,133,297	$ 1,829,892	$ 47,554	$ 1,877,446	1,089,371	220,164.5	
30											
31	**Effective Increase**			4.50%			2.66%				

OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2024
($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	2023 Base Unit Cost O&M	$ 280			
3	2024 Net Inflation Factor	3.854%			Schedule 3, Line 9, Column 7
4	2024 Base Unit Cost O&M	$ 291			Line 2 x (1 + Line 3)
5					
6	2024 Average Customer Forecast - Rate Setting Purpose	1,074,994			Schedule 3, Line 22, Column 8
7					
8	2024 Inflation Indexed O&M before prior year True-up	$ 312,823			Line 4 x Line 6 / 1000
9					
10	2022 Average Customer True-up	(262)			
11					
12	2024 Inflation Indexed O&M	$ 312,561		$ 312,561	Sum of Lines 8 and 10
13					
14	**O&M Tracked Outside of Formula**				
15	Pension & OPEB (O&M Portion)		$ 2,555		
16	Insurance		13,328		
17	Biomethane O&M		5,817		
18	NGT O&M		2,604		
19	Variable LNG Production		8,135		
20	Integrity O&M		11,200		
21	Renewable Gas Development		4,052		
22	BCUC fees		9,955		
23	Sub-total		$ 57,646	57,646	Sum of Lines 15 through 22
24					
25	**Total Gross O&M**			$ 370,207	Line 12 + Line 23
26	O&M Transferred to Biomethane BVA			(5,817)	
27	Capitalized Overhead			(59,233)	-16 % x Line 25
28	**Net O&M Expense**			$ 305,157	Sum of Lines 25 through 27

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 21

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 223,974	$ 232,095	$ 8,121	Schedule 7.2, Line 35, Column 7
3	Depreciation & Amortization Transferred to Biomethane BVA	(821)	(793)	28	Schedule 7.2, Line 36, Column 7
4	Vehicle Depreciation Allocated To Capital Projects	(2,540)	(2,886)	(346)	Schedule 7.2, Line 37, Column 7
5		220,613	228,416	7,803	
6					
7	**Amortization**				
8	Rate Base Deferrals	$ 95,782	$ 125,283	$ 29,501	Schedule 11.1, Line 29, Column 6
9	Rate Base Deferrals - Net Salvage Amortization Transferred to Biomethane BVA	(55)	(54)	1	Schedule 11.1, Line 30, Column 6
10	Non-Rate Base Deferrals	19,237	8,783	(10,454)	Schedule 12, Line 30, Column 6
11	CIAC	(8,753)	(8,851)	(98)	Schedule 9, Line 13, Column 5
12	CIAC Amortization Transferred to Biomethane BVA	28	28	-	Schedule 9, Line 19, Column 5
13		106,239	125,189	18,950	
14					
15	Total	$ 326,852	$ 353,605	$ 26,753	

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	General School and Other	$ 62,913	$ 66,926	$ 4,013	
2	1% In-Lieu of Municipal Taxes	16,323	16,510	187	
3					
4	Total	$ 79,236	$ 83,436	$ 4,200	
5					
6	Total Property Tax Expense per Line 4	$ 79,236	$ 83,436	$ 4,200	
7	Less: Property Tax Transferred to Biomethane BVA	(92)	(77)	15	
8	**Net Property Tax Expense**	$ 79,144	$ 83,359	$ 4,215	

OTHER REVENUE Schedule 23
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Late Payment Charge	$ 3,385	$ 3,607	$ 222	
2	Application Charge	2,020	1,797	(223)	
3	NSF Returned Cheque Charges	28	28	-	
4	Other Recoveries	288	288	-	
5	SCP Third Party Revenue	13,286	13,320	34	
6	NGT Tanker Rental Revenue	926	1,021	95	
7	NGT Overhead and Marketing Recovery	273	341	68	
8	Biomethane Other Revenue	512	762	250	
9	LNG Capacity Assignment	18,039	18,039	-	
10	CNG & LNG Service Revenues	3,261	3,276	15	
11					
12	Total	$ 42,018	$ 42,479	$ 461	

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 24

Line No.	Particulars	2023 Approved	2024 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 369,952	$ 365,254	$ (4,698)	Schedule 16, Line 26, Column 5
2	Deduct: Interest on Debt	(169,733)	(169,331)	402	Schedule 26, Lines 1+2, Column 7
3	Adjustments to Taxable Income	(60,308)	(10,987)	49,321	Line 36
4	Accounting Income After Tax	$ 139,911	$ 184,936	$ 45,025	
5					
6	1 - Current Income Tax Rate	73.00%	73.00%	0.00%	
7	Taxable Income	$ 191,659	$ 253,337	$ 61,678	
8					
9	Current Income Tax Rate	27.00%	27.00%	0.00%	
10	Income Tax - Current	$ 51,748	$ 68,401	$ 16,653	
11					
12	Previous Year Adjustment	-	-	-	
13	**Total Income Tax**	$ 51,748	$ 68,401	$ 16,653	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Non-tax Deductible Expenses	$ 1,200	$ 1,200	$ -	
19	Depreciation	220,613	228,416	7,803	Schedule 21, Line 5, Column 3
20	Amortization of Deferred Charges	114,964	134,012	19,048	Schedule 21, Lines 8+9+10, Column 3
21	Amortization of Debt Issue Expenses	984	1,110	126	
22	Vehicles: Interest & Capitalized Depreciation	2,545	2,886	341	
23	Pension Expense	10,167	3,088	(7,079)	
24	OPEB Expense	5,020	4,222	(798)	
25					
26	Deductions:				
27	Capital Cost Allowance	(330,330)	(297,117)	33,213	Schedule 25, Line 23, Column 6
28	CIAC Amortization	(8,725)	(8,823)	(98)	Schedule 21, Lines 11+12, Column 3
29	Debt Issue Costs	(1,984)	(1,287)	697	
30	Vehicle Lease Payment	(73)	-	73	
31	Pension Contributions	(14,361)	(15,233)	(872)	
32	OPEB Contributions	(3,171)	(3,433)	(262)	
33	Overheads Capitalized Expensed for Tax Purposes	(28,262)	(29,617)	(1,355)	
34	Removal Costs	(17,265)	(22,644)	(5,379)	Schedule 11.1, Line 5, Column 4
35	Major Inspection Costs	(11,630)	(7,767)	3,863	
36	Total	$ (60,308)	$ (10,987)	$ 49,321	

CAPITAL COST ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Schedule 25

Line No.	Class	CCA Rate	12/31/2023 UCC Balance	2024 Additions	Adjustments	2024 CCA	Forecast 12/31/2024 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 975,015	$ -	$ -	$ (39,001)	$ 936,014
2	1(b)	6%	15,886	27,802	-	(2,621)	41,067
3	2	6%	72,294	-	-	(4,338)	67,956
4	3	5%	1,456	-	-	(73)	1,383
5	6	10%	193	-	-	(19)	174
6	7	15%	19,681	2,898	-	(3,387)	19,192
7	8	20%	32,340	9,852	-	(8,438)	33,754
8	10	30%	15,646	7,941	-	(7,076)	16,511
9	10.1	30%	63	-	-	(19)	44
10	12	100%	-	18,365	-	(18,365)	-
11	13	manual	1,991	-	-	(764)	1,227
12	14.1 (pre 2017)	7%	13,207	-	-	(924)	12,283
13	14.1 (post 2016)	5%	4,809	-	-	(240)	4,569
14	17	8%	814	-	-	(65)	749
15	38	30%	735	-	-	(221)	514
16	43.2	50%	49	18,917	9,458	(14,212)	4,754
17	47	8%	129,475	-	-	(10,358)	119,117
18	47 (LNG Plant - post Feb 2015)	8%	136,374	-	-	(10,910)	125,464
19	49	8%	522,493	129,640	-	(52,171)	599,962
20	50	55%	3,396	9,183	-	(6,918)	5,661
21	51	6%	1,771,792	178,156	-	(116,997)	1,832,951
22							
23	Total		$ 3,717,709	$ 402,754	$ 9,458	$ (297,117)	$ 3,823,346

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2024
($000s)

Line No.	Particulars	2023 Approved Earned Return	2024 Amount	2024 Ratio	2024 Average Embedded Cost	2024 Cost Component	2024 Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 159,754	$ 3,379,517	58.11%	4.69%	2.72%	$ 158,363	$ (1,391)	Schedule 27, Lines 24&26, Columns 5&6&7
2	Short Term Debt	9,979	197,263	3.39%	5.56%	0.19%	10,968	989	
3	Common Equity	200,219	2,239,123	38.50%	8.75%	3.37%	195,923	(4,296)	
4									
5	Total	$ 369,952	$ 5,815,903	100.00%		6.28%	$ 365,254	$ (4,698)	
6									
7	Cross Reference		Schedule 2, Line 30, Column 3						

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2024
($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	133,130	133,971	2.644%	3,542	
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 - Series 35	November 28, 2022	November 28, 2052	148,700	150,000	4.732%	7,098	
19	2024 Medium Term Debt Issue	July 1, 2024	July 1, 2054	198,000	100,546	4.763%	4,789	
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	Total				$ 3,379,517		$ 158,363	
25								
26	Average Embedded Cost					4.69%		
27								
28	* 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, providing an update on the potential exogenous factor for the impacts of flooding in 2021. 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 Regional Gas Supply Diversity (RGSD) Development deferral account and 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.

12.2.1 Update on 2021 Flooding Damage Exogenous Factor

In the Annual Review for 2023 Delivery Rates, FEI identified one new potential exogenous factor related to the flooding damages in 2021 caused by a series of atmospheric rivers that brought heavy rain to parts of southern British Columbia. Details were provided on the damage to FEI’s assets and the impact to customers, along with the estimated total costs associated with repairing damage to its facilities and restoring service to affected customers.

As explained in the 2023 Annual Review, FEI filed an insurance claim to recover the total O&M and capital costs related to the flooding event which also included a claim to recover 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.

Current Status of Flood Damage Claim

FEI submitted a flood damage claim in the amount of approximately $3.7 million to its insurers in October 2022. The claim represents costs incurred to repair damaged assets and customer bill evacuation credits. Table 12-1 below provides a breakdown of each component of the claim. The total costs recoverable are subject to the $1 million insurance deductible.

Table 12-1: Breakdown of Flooding Repair Costs Insurance Claim

Zone/Department	City/Region		Damage/Loss Claim
Zone 3	Abbotsford	$	772,804
Zone 4	Merritt	$	745,888
Zone 5	Princeton	$	667,513
Zone 6	Roberts Creek	$	431,147
Engineering	Across all regions above	$	111,951
Transmission	Across all regions above	$	178,218
Customer Service	Across all regions above	$	826,139
Total Claim Submission		**$**	**3,733,660**

The Insurers continue to review FEI's claim submission. Requests for additional information, or responses to inquiry, have been provided by FEI on a timely basis. At this time, the amount of the claim settlement, and timeframe, is uncertain; however, FEI is expecting a final decision before the end of 2023.

When 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 an Evidentiary Update or 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 2014-2019 PBR Plan Decision and Order G-138-14, 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 2024.

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).

In the following section, FEI provides information on the Regional Gas Supply Diversity (RGSD) Development and Flow-through deferral accounts. 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 subsections below, FEI discusses the RGSD Development deferral account and the Flow-through deferral account.

12.4.2.1 Regional Gas Supply Diversity Development Deferral Account

On September 14, 2022, the BCUC issued Order G-253-22 granting approval to establish the RGSD Development deferral account, a non-rate base deferral account attracting FEI's WACC return, to capture actual development costs incurred with respect to the potential RGSD Project, with disposition of the deferral account balance to be determined in a future proceeding.

Order G-253-22 directed FEI to provide quarterly progress reports on work completed, anticipated work, and material developments on the potential RGSD Project, starting with the fourth quarter ending December 31, 2022, by no later than 30 days after the date of the quarter end. Order G-253-22 further directed that in lieu of the July 2023 quarterly report, FEI was to provide as part of the Annual Review for 2024 Delivery Rates (this Application) the following information:

a. Reporting on work completed, anticipated work, and material developments on the potential RGSD Project;

b. An update of the costs incurred to date; and

c. A proposal for the method and timing of the recovery of those incurred costs.

Please refer to Appendix C for item (a). In Appendix C, which is in a similar format as previous quarterly progress repots on the RGSD Project, FEI describes the work completed and anticipated as well as material developments.

With regard to items (b) and (c), FEI provides the following update on the costs incurred to date and a proposal for the method and timing of the recovery of incurred costs.

12.4.2.1.1 PROJECT DEVELOPMENT COSTS INCURRED TO DATE FOR THE RGSD PROJECT

In the RGSD Development Account Application filed on June 1, 2022, FEI forecast total project development spending of $23.7 million by Q3 2023, which would coincide with the timing of the 2024 Annual Review and thus be an appropriate time to seek cost recovery of the incurred costs. However, as of the end of Q2 2023, FEI has spent a total of $2.93 million, including AFUDC. Table 12-2 provides a summary of the development costs on an annual and a project phase gate basis. For further information on the activities that FEI has undertaken thus far, please refer to Appendix C.

Table 12-2: Project Development Cost Summary

Actual Cost Summary – Calendar Year Basis			
2021	**2022**	**2023**	**Total Cost**
$0.47 million	$1.43 million	$1.03 million	$2.93 million

Actual Cost Summary – Phase Gate Basis		
Preliminary and Conceptual Phase (Pre-Phase 1) Nov 2021 to Sep 2022	**Screening and Pre-FEED Phase (Phase 1) Oct 2022 to Jun 2023**	**Total Cost**
$1.40 million	$1.53 million	$2.93 million

12.4.2.1.2 RECOVERY OF INCURRED COSTS FOR THE RGSD PROJECT

As noted above and discussed in Section 2.3.3 of Appendix C, FEI has incurred approximately $2.93 million as of the end of Q2 2023. In comparison, in the RGSD Development Account Application, FEI had forecast incurring costs of $23.7 million for work up to Q3 of 2023. While there are still two months remaining until the end of Q3 2023, FEI does not anticipate incurring significant amounts of costs in these upcoming two months (and therefore does not expect to achieve the $23.7 million in project development spending by Q3 2023).

In consideration of the amount spent to date and the screening analysis that FEI needs to undertake to have meaningful and comprehensive engagement and collaboration with stakeholders and Indigenous Nations prior to beginning the Project approval processes (as explained in Appendix C), and to have reasonable support and confidence on the Project concept and design, FEI considers it most appropriate to file for recovery of the RGSD Project development costs in a future application. The timing of when FEI will file for recovery of the costs will be driven by factors such as progress on the Project and costs incurred (and forecast to be incurred) to further advance Project development. Thus, FEI may file for recovery of the costs in a separate application or in a future annual review (or revenue requirement) application, depending on timing.

12.4.2.2 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.

Table 12-3: 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 2023 Projected Flow-through amount of $0.920 million debit is shown in Table 12-4 below. To calculate the amount to be collected from customers, FEI has also included the following adjustments:

- The $11.837 million debit difference between the projected ending 2022 deferral account debit balance of $19.006 million[69] embedded in 2023 delivery rates, and the actual ending 2022 deferral account debit balance of $30.843 million. A more detailed breakout of the 2022 variance is provided in Table 12-5 below;
- The $0.670 million debit difference between the forecast 2023 financing addition of $0.506 million debit[70] embedded in 2023 delivery rates, and the projected 2023 financing addition of $1.176 million debit embedded in this Application; and
- 2024 forecast financing of a $0.357 million debit.[71]

[69] Annual Review for 2023 Delivery Rates, Evidentiary Update, Appendix B, Schedule 12, Line 3, Column 2.
[70] Annual Review for 2023 Delivery Rates, Evidentiary Update, Appendix B, Schedule 12, Line 3, Column 4.
[71] Section 11, Schedule 12, Line 3, Column 4.

Table 12-4: 2023 Projected Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	2023 Approved	2023 Projected	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Delivery Margin**			
2	Residential (Rate 1)	$ (643.916)	$ (645.472)	$ (1.556)
3	Commercial (Rate 2, 3, 23)	(294.040)	(301.191)	(7.151)
4	Industrial (All Others)	(140.388)	(133.738)	6.650
5				
6	**Net O&M Expense**			
7	Pension & OPEB	9.577	9.577	-
8	Insurance	12.242	12.406	0.164
9	Biomethane	5.237	5.075	(0.162)
10	NGT	1.937	2.412	0.475
11	Variable LNG Production Costs	7.859	7.899	0.040
12	Integrity O&M	8.000	9.000	1.000
13	Renewable Gas Development	2.000	3.069	1.069
14	BCUC Levies	8.493	8.493	-
15	Biomethane O&M transferred to BVA	(5.237)	(5.075)	0.162
16	Capitalized Overhead	(56.744)	(56.744)	-
17				
18	**Depreciation and Amortization**			
19	Amortization of Deferrals	114.964	114.964	-
20	Depreciation variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
21	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
22				
23	**Total Property Taxes**	79.144	77.785	(1.359)
24				
25	**Other Revenues**			
26	Tilbury insurance proceeds	-	(6.135)	(6.135)
27	SCP Third Party Revenue	(13.286)	(13.286)	-
28	NGT Tanker Rental Revenue	(0.926)	(1.008)	(0.082)
29	Biomethane Other Revenue	(0.512)	(1.069)	(0.557)
30	LNG Capacity Assignment	(18.039)	(18.039)	-
31	CNG & LNG Service Revenues	(3.261)	(3.215)	0.046
32				
33	**Interest Expense**			
34	Long-term debt interest expense variance	159.754	153.500	(6.254)
35	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
36	Short-term debt rate variance	-	6.644	6.644
37	Short-term debt volume variance from long-term debt issue variance	-	8.266	8.266
38	Short-term debt timing variance from long-term debt issue timing	-	-	-
39				
40	**Income Tax Expense**			
41	Income tax variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
42	Income tax/CCA rate changes	-	-	-
43	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	-	(0.340)	(0.340)
44				
45	**2023 After-Tax Flow-Through Addition to Deferral Account (excluding Financing)**			**0.920**
46				
47	2022 Ending Deferral Account Balance True-up			11.837
48	2023 Financing True-up			0.670
49	2024 Financing Addition to Deferral Account			0.357
50				
51	**2024 After-Tax Amortization**			**13.784**

12.4.2.2.1 2023 PROJECTED FLOW-THROUGH VARIANCES

As shown in Table 12-4 above, the 2023 Projected flow-through variance is $0.920 million. The variances in each flow-through category are described below.

The projected variances in delivery margin are primarily due to unfavourable industrial margin as a result of lower LNG demand as described in Section 3, which is mostly offset by favourable commercial and residential margin mainly as a result of higher customers than forecast.

The flow-through O&M amounts are discussed in Section 6. Amortization expense is equal to the approved value. Variances in property taxes are explained in Section 9. Variances in Other Revenue are explained in Section 5. The projected interest expense variances are derived from FEI issuing a lower amount of debt in the fourth quarter of 2022 than forecast in the 2023 Annual Review, not projecting to issue any debt in 2023 whereas $300 million was forecast to be issued in the fourth quarter of 2023 in the 2023 Annual Review, 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 2023 subject to flow-through will be recorded in the deferral account in 2023 and amortized in 2025 rates.

12.4.2.2.2 2022 FLOW-THROUGH DEFERRAL ACCOUNT TRUE-UP

As mentioned above, FEI provides a breakout of the 2022 true-up amount of $11.837 million debit in Table 12-5 below, along with an explanation of the variances.

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

Line No.	Particulars	2022 Projected	2022 Actual	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Delivery Margin**			
2	Residential (Rate 1)	$ (588.539)	$ (588.430)	$ 0.109
3	Commercial (Rate 2, 3, 23)	(269.214)	(268.914)	0.300
4	Industrial (All Others)	(135.619)	(120.247)	15.372
5				
6	**Net O&M Expense**			
7	Pension & OPEB	9.537	9.537	-
8	Insurance	11.552	11.485	(0.067)
9	Biomethane	3.249	4.156	0.907
10	NGT	1.944	2.193	0.249
11	Variable LNG Production Costs	7.053	6.708	(0.345)
12	Integrity Digs	6.000	6.236	0.236
13	Renewable Gas Development	1.750	2.583	0.833
14	BCUC Levies	7.408	7.408	-
15	COVID-19 Pandemic	(3.860)	(3.860)	-
16	Biomethane O&M transferred to BVA	(3.249)	(4.156)	(0.907)
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	-	(0.381)	(0.381)
22	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	-	-
23				
24	**Total Property Taxes**	73.600	71.983	(1.617)
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	(0.850)	(0.718)	0.132
30	Biomethane Other Revenue	(0.812)	(0.812)	-
31	LNG Capacity Assignment	(18.039)	(18.039)	-
32	CNG & LNG Service Revenues	(3.270)	(3.010)	0.260
33				
34	**Interest Expense**			
35	Long-term debt interest expense variance	148.555	146.761	(1.794)
36	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.354)	(0.354)
37	Short-term debt rate variance	1.886	1.120	(0.766)
38	Short-term debt volume variance from long-term debt issue variance	-	0.843	0.843
39	Short-term debt timing variance from long-term debt issue timing	2.042	2.061	0.019
40				
41	**Income Tax Expense**			
42	Income tax variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	2.574	2.574
43	Income tax/CCA rate changes	-	-	-
44	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	(2.859)	(6.575)	(3.716)
45				
46	**2022 After-Tax Flow-Through Addition to Deferral Account (excluding Financing)**			**11.887**
47				
48	2022 Financing True-up			(0.050)
49				
50	**2022 Ending Deferral Account Balance True-up**			**11.837**

The variances in delivery margin are primarily due to unfavourable industrial margin as a result of lower LNG demand and the termination of the BC Hydro Island Cogeneration plant demand, as discussed in Section 3 of the Application.

The flow-through components of O&M expense were $0.906 million higher than projected, with the main variance related to renewable gas development, which was $0.833 million higher than projected. The variance was mainly due to higher than expected contractor and professional services costs required to assist with various activities in the areas of hydrogen and lignin investigation and development. Please also refer to Section 6.3.6 of the Application.

Actual property tax expenses were $1.617 million lower than projected due to differences in tax rates. 2022 Projected amounts were calculated using actual 2022 assessment values but estimated 2022 tax rates.

The flow-through components of Other Revenue were $0.392 million lower than projected, with the main variance related to CNG & LNG Service Revenues, which were $0.260 million lower than projected. The variance in CNG & LNG Service Revenues was mainly due to lower CNG Station demand than forecast.

The variance between the actual (3.34 percent) and projected (4.05 percent) short-term debt interest rates results in an amount to be returned to customers of $0.766 million,[72] shown on Line 37 of Table 12-5 above. The long-term debt interest expense variance of $1.794 million to be returned to customers is due to lower issue costs than projected on the 2022 long-term debt issuance. The net variance of $0.862 million recoverable from customers on Lines 38 and 39 of Table 12-5 above is due to a lower amount of long-term debt issued than projected, consequently resulting in a higher short-term debt balance than projected.

The favourable income tax variance of $3.716 million is calculated as 27 percent of the aforementioned variances.

The combined unfavourable variance of $1.840 million related to depreciation/CIAC amortization, interest and tax variances on Clean Growth/CPCN/exogenous capital amounts, shown on Lines 21, 22, 36 and 42, respectively, in Table 12-5 above, were derived for 2022 by comparing the actual 2022 cost of service impacts of the NGT Assets and the IGU, Tilbury 1A Expansion, LMIPSU and CTS TIMC projects to the amounts forecast for those same projects.

12.5 SUMMARY

FEI has provided an update on the potential exogenous factor related to flooding damages. FEI has also provided an update on the RGSD Project Development deferral account, as well as information related to the Flow-through deferral account.

[72] (3.3433% - 4.05%) x $108.374 million forecast 2022 short-term debt in Schedule 26 of Annual Review for 2022 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 2022 and June 2023 year-to-date performance as measured against the SQI benchmarks and thresholds. In 2022, for the nine SQIs with benchmarks, seven performed at or better than the approved benchmarks. Two of the SQIs with benchmarks – Meter Reading Accuracy and Telephone Service Factor (Non-Emergency) – were lower than the threshold. The below-threshold Meter Reading Accuracy performance was primarily due to the broader impacts of the COVID-19 pandemic,[73] including staffing challenges and the need for physical distancing and enhanced hygiene practices by meter readers. The Telephone Service Factor (Non-Emergency) performance was impacted by higher than normal attrition levels in the contact centre and an increased amount of high bill inquiries over the year. Regarding the four SQIs that are informational only, the Average Speed of Answer results in 2022 were higher due to the same challenges impacting the Telephone Service Factor (Non-Emergency), while performance for the other three informational metrics generally remains at a level consistent with prior years. In 2023 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,[74] FEI has provided 2022 and year-to-date 2023 SQI results in this annual review.

13.2 REVIEW OF THE PERFORMANCE OF SERVICE QUALITY INDICATORS

For each SQI, Table 13-1 provides a comparison of FEI's 2022 and June year-to-date performance for 2023 to the proposed benchmarks and thresholds approved as part of the MRP. Actual 2022 and June year-to-date results for 2023 are also provided for the four informational SQIs.

[73] 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.

[74] 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".

1 **Table 13-1: Approved SQIs, Benchmarks and Actual Performance**

Performance Measure	Description	Benchmark	Threshold	2022 Results	2023 June YTD Results
Safety SQIs					
Emergency Response Time	Percent of calls responded to within one hour	>= 97.7%	96.2%	97.7%	97.6%
Telephone Service Factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	>= 95%	92.8%	97.1%	97.7%
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	1.59	1.72
Public Contacts with Gas Lines	Current year average of number of line damages per 1,000 BC One calls received	<= 8	12	6	4
Responsiveness to the Customer Needs SQIs					
First Contact Resolution	Percent of customers who achieved call resolution in one call	>= 78%	74%	78%	77%
Billing Index	Measure of customer bills produced meeting performance criteria	<= 3.0	5.0	1.0	0.63
Meter Reading Accuracy	Number of scheduled meters that were read	>= 95%	92%	88%	95%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	>= 70%	68%	62%	67%
Meter Exchange Appointment	Percent of appointments met for meter exchanges	>= 95%	93.8%	98.5%	98.9%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.6	8.5
Average Speed of Answer	Informational indicator – amount of time it takes to answer a call (seconds)	-	-	106	88
Reliability SQIs					
Transmission Reportable Incidents	Informational indicator – number of reportable incidents to outside agencies	-	-	3	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	-	-	0.0058	0.0034

2

In the following sections, FEI reviews each SQI's year-to-date individual performance in 2022 and 2023. 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 2022 result was 97.7 percent which met the benchmark. The 2022 performance was consistent with the performance in 2020 and 2021. The June 2023 year-to-date performance is 97.6 percent, which is better than the threshold.

For comparison, the Company's annual results under the 2014-2019 PBR Plan, the 2020, 2021, and 2022 results and the June 2023 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	2022	June 2023 YTD
Results	96.7%	97.3%	97.4%	97.8%	97.8%	97.9%	97.7%	97.7%	97.7%	97.6%
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 2022 result was 97.1 percent which was better than the benchmark of 95 percent. The June 2023 year-to-date performance is 97.7 percent which is also better than the benchmark.

For comparison, the Company's annual results under the 2014 to 2019 PBR Plan, the 2020, 2021, and 2022 results and the June 2023 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	2022	June 2023 YTD
Results	95.8%	97.6%	98.5%	97.6%	97.9%	97.2%	96.9%	96.9%	97.1%	97.7%
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 2022 (three-year rolling average) result was 1.59 which was better than the benchmark of 2.08. The 2022 annual AIFR was 1.36 which reflected 8 Medical Treatments and 16 Lost Time Injuries.

The June 2023 year-to-date performance (three-year rolling average) result is 1.72 which is better than the benchmark. The June 2023 year-to-date performance (annual) is 1.43 and reflects 3 Medical Treatments and 10 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 the Company's safety management system through the implementation and sustainment of robust safety defences and controls.

The AIFR result for 2022 was better than the benchmark and was slightly better than 2021 and 2020. FEI continues to seek opportunities to improve the AIFR through its ongoing commitment to proactive hazard mitigation, particularly in regard to manual labour tasks and slip/trip/fall prevention. FEI has adopted multiple mitigation measures, including enhanced digital safe work planning, task specific training and education across areas of the business that have been identified as having a higher risk of injury, additional ergonomic assessments, injury prevention strategies, and a range of technology solutions.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 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	2022	June 2023 YTD
Annual Results	1.73	2.52	2.13	1.36	1.74	1.82	1.43	1.99	1.36	1.43
Three year rolling average	2.22	2.42	2.13	2.00	1.74	1.64	1.66	1.75	1.59	1.72
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 2022 result was 6, which is better than the benchmark. The June 2023 year-to-date performance is 4, 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, 2021 and 2022 results, and June 2023 year-to-date results are provided below. The annual result has been trending downward (i.e., performance has been trending positively).

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 and WorkSafeBC to reduce line hits. While 2023 year-to-date volume (83,923) is higher than 2022 (82,699), it is lower than 2021 (86,673), and fairly consistent with 2019 (79,654) and 2020 (72,034) 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	2022	June 2023 YTD
Annual Results	9	8	8	9	8	7	7	6	6	4
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	157,174	83,923
Line Damages	954	1,035	1,086	1,247	1,201	1,069	973	1,034	896	403

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 2022 result was 78 percent which met the benchmark. The minor reduction in FCR for 2022 as compared to previous years, as shown in Table 13-6 below, is largely attributable to the increased volume of high bill inquiries in the early and latter months of 2022 as well as rate and carbon tax changes. For further details on the factors causing an increased volume of high bills, please refer to Section 13.2.2.4 – Telephone Service Factor (Non-Emergency). Depending on the nature of the high bill, there may be a need for customers to follow up on their billing, resulting in more than one contact to resolve their concerns. As well, high bill calls can require longer term payment arrangements which at times may require changes, leading to customers connecting with FEI multiple times for the same reason. Further, with respect to the impact on FCR from rate changes, while customers may appreciate the conversation and understand the reasons for such changes, some customers do not consider the issue resolved without the rate reverting back. The June 2023 year-to-date performance is 77 percent, which is slightly below benchmark, but above threshold.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-6: Historical First Contact Resolution Levels

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	80%	81%	81%	80%	83%	81%	81%	79%	78%	77%
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:

d. Billing completion (percent of accounts billed within two days of the billing due date);

e. Billing timeliness (percent of invoices delivered to Canada Post within two days of file creation); and

f. 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 2022 result was 1.02 which was better than the benchmark of 3.0. No significant billing issues occurred in 2022. The June 2023 year-to-date result is 0.63 which is also better than the benchmark.

The 2022 Billing Index sub-measures calculation is as follows.

Table 13-7: Calculation of 2022 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%	100.00%	If (PA≥99.9%,5000*(1 - PA),100*(1.05-PA))	=5000*(1-100%)	0.00
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%	96.94%	(100%-PA)*100	= (100%-96.94%)*100	3.06
Billing Service Quality Indicator; Target < 3		(Accuracy PA+Timeliness PA+Completion PA)/3	=(0+0+3.06) / 3	1.02

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-8: Historical Billing Index Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	0.89	1.06	0.57	0.75	2.63	0.44	0.62	0.94	1.02	0.63
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 2022 result was 87.8 percent, which is below the benchmark and threshold and the third 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 2022 reflect continued challenges as a result of the broader impacts of the COVID-19 pandemic which included staffing challenges and the need for physical distancing and enhanced hygiene practices by meter readers.[75] Olameter continued to experience staffing challenges throughout 2022, including periods where subsequent variants of the virus affected their employees. In addition, meter reading efforts in 2022 were significantly impacted by extreme weather events in the early part of the year and then again in December. All of these weather events contributed to a larger percentage of estimated reads due to the inability to safely access meters. For these reasons, FEI's meter accuracy results for 2022 being below threshold are attributable to the broader impacts of the COVID-19 pandemic and extreme weather conditions in 2022, rather than any action or inaction of FEI.

FEI has continued to mitigate the potential service quality impact on customers as a result of the higher number of estimated reads. Measures used in 2022 and continuing in 2023 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.[76]

The June 2023 year-to-date performance is 95.0 percent which meets the benchmark. Olameter's ability to hire and retain staff along with challenges attributable to the impacts of the COVID-19 pandemic have improved. FEI has continued to apply the mitigation measures described above throughout 2022 and year-to-date 2023. Significant improvement in the monthly performance of this metric has been experienced starting in April of 2022 and leading

[75] 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."

[76] 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.

into 2023, with the exception of December 2022 where extreme weather events contributed to a larger percentage of estimated reads due to the inability to safely access meters. 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.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-9: Historical Meter Reading Accuracy Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	97.0%	97.5%	96.9%	96.2%	95.4%	95.2%	89.2%	88.0%	87.8%	95.0%
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 2022 result was 62 percent which was below the benchmark and threshold. The June 2023 year-to-date performance is 67 percent which is lower than the threshold.

FEI experienced several challenging circumstances in 2022 that contributed to the year-end performance being below the threshold. These challenges included higher than expected attrition in the contact centre compounded by an increased amount of high bill inquiries over the year. Each of these is described further below.

Customer Service is experiencing higher than expected levels of attrition, having lost 76 Customer Service employees in 2022, compared to 65 lost in 2021. Most of these employee exits were concentrated in the second and third quarters of 2022, resulting in fewer and less experienced employees prepared to support call volumes in the third and fourth quarters of 2022. To mitigate the impact of this attrition, FEI accelerated the timing of planned new hire classes as well as the size of new hire classes in both 2022 and 2023. While FEI has had some success, FEI continued to face challenges with 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 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.

FEI also saw an 88 percent increase in high bill call volume in 2022, as compared to 2021. 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 throughout the year. The contributing factors to the higher volume of this call type included heavy snowfall in several parts of the Province in late 2021 and also in December 2022, resulting in a larger volume of bills based on estimated reads in the early and latter parts of 2022, coupled with rate and carbon tax increases. 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 and a significantly higher volume of this call type, resulting in overall longer average wait times and a lower percentage of calls answered within 30 seconds or less.

Although the start of 2023 has continued to be 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 the lower TSF on customer experience and service quality. Further, beginning in March, FEI achieved a non-emergency TSF above benchmark and positive progress continues (83 percent for the months of March and April, 85 percent for the month of May, and 84 percent for the month of June). FEI expects to recover to threshold levels on a year-to-date basis within the fourth quarter. Finally, the customer service index has remained high throughout 2022 and 2023 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, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-10: Historical TSF (Non-Emergency) Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	75%	71%	71%	71%	71%	71%	70%	70%	62%	67%
Benchmark[77]	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 2022 result was 98.5 percent which was better than the benchmark of 95 percent. The June 2023 year-to-date performance is 98.9 percent, which is also better than the benchmark.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-11: Historical Meter Exchange Appointment Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	95.5%	96.6%	96.9%	97.0%	96.3%	96.0%	98.1%	98.3%	98.5%	98.9%
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

[77] 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 overall satisfaction, 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 10.

The annual CSI score for 2022 was 8.6, lower than the 8.7 obtained in 2021. There were no statistically significant shifts from 2021 to 2022 in the five measures that make up the overall customer satisfaction score. The scores for overall satisfaction and satisfaction with the accuracy of meter reading decreased from 8.7 in 2021 to 8.6 in 2022 and 8.4 in 2021 to 8.3 in 2022, respectively. In addition, the scores for the satisfaction with energy conservation and satisfaction with contact centre metrics decreased from 7.7 in 2021 to 7.5 in 2022 and 8.7 in 2021 to 8.6 in 2022, respectively. The score for the satisfaction with field services metric remained static at 9.3.

The score for 2023 year-to-date is 8.5, slightly lower than the annual score recorded for 2022 at 8.6. Of the five measures that make up the overall customer satisfaction score, the results for June 2023 year-to-date were lower in four areas and static in one when compared to the annual 2022 scores. The scores for overall satisfaction decreased from 8.6 to 8.4, satisfaction with the accuracy of meter reading went from 8.3 to 8.2, satisfaction with the contact centre decreased from 8.6 to 8.4, and field services decreased from 9.3 to 9.2. The score for satisfaction with energy conservation information remained static at 7.5.

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2021 results and the June 2023 year-to-date results are provided below.

Table 13-12: Historical Customer Satisfaction Results

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	8.5	8.6	8.8	8.4	8.7	8.7	8.7	8.7	8.6	8.5
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 2022 result was 106 seconds. The June 2023 year-to-date performance is 88 seconds. As described above, challenges in the contact centre resulted in monthly non-emergency TSF performance levels being below the threshold. Comparatively, the ASA also experienced challenges, and so far in 2023, calls are being answered in under two minutes on average. Aligned with the recovery to threshold levels of the TSF, the monthly ASA also returned to typical levels of less than one minute in March and FEI expects this metric to continue to improve 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, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-13: Average Speed of Answer

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results	34	37	40	34	35	39	72	65	106	88
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 British Columbia Energy Regulator (BCER). The metric is intended to be an indicator of the integrity of the transmission system.

There were 3 recorded incidents in 2022. The first incident took place during an isolation on the 6-inch transmission pressure gas line near Salmon Arm, BC (SAL LOP 168). An FEI contractor drilled the cutter head through the side of the pipe and fitting, causing gas release which resulted in the need to isolate an approximate 11 km section of the pipeline for the repair activities. No customer outages resulted from the incident. The second incident was a mechanical line strike by an FEI contractor on the 6-inch transmission pressure gas line near Kamloops, BC (KA1 LTL 168), causing gas release which resulted in the need to isolate an approximate 2.6 km section of the pipeline for repair activities. One industrial customer outage resulted from the incident as the impacted line was shut-in for the repair activities. The third incident was a leak discovered on the 6-inch transmission pressure gas line near Trail, BC (TRA LTL 168), which resulted in the need to install a bypass to avoid a customer outage. A 6-metre segment of gas line was removed and replaced.

There have been no recorded incidents so far in 2023 (June 2023 year-to-date).

For comparison, the Company's results under the 2014 to 2019 PBR Plan, the 2020, 2021 and 2022 results and the June 2023 year-to-date results are provided below.

Table 13-14: Historical Transmission Reportable Incidents

Description	2014	2015	2016	2017	2018	2019	2020	2021	2022	June 2023 YTD
Annual Results – Level 1	1	3	3	4	2	0	1	0	0	0
Annual Results – Level 2	1	0	0	0	0	0	0	0	3	0
Annual Results – Level 3	0	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. Using newer, more sensitive leak detection technology may also result in more leaks being detected. This new technology has been in use since 2022.

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 2023 year-to-date five-year rolling average result of 0.0061 calculated using data from July 2018 to June 2023.

Table 13-15: June 2023 Year-to-Date Five-Year Rolling Average

Period	Metric
July – December 2018	0.0035
January – December 2019	0.0060
January – December 2020	0.0065
January – December 2021	0.0055
January – December 2022	0.0058
January – June 2023	0.0034
Five Year Rolling Average	0.0061

The Company's 2014 to 2022 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 2022 five-year average is calculated using 2018 to 2022 annual data). The June 2023 year-to-date result is 0.0034 based on 82 leaks detected year-to-date, which is higher than the 2022 (75) and 2021 (70) results for the similar time period. The number of leaks on DP mains will vary from year to year.

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	2022	June 2023 YTD
Leaks	114	102	107	108	140	139	152	131	138	82
Total km	19,172	22,602	22,813	22,951	23,060	23,268	23,460	23,707	23,734	23,913
Leaks per km	0.0059	0.0045	0.0047	0.0047	0.0061	0.0060	0.0065	0.0055	0.0058	0.0034
5 year average	0.0077	0.0071	0.0063	0.0055	0.0052	0.0051	0.0056	0.0058	0.0060	0.0061

13.3 SUMMARY

In summary, FEI's 2022 results and June 2023 year-to-date SQI results indicate that the Company's overall performance is representative of a high level of service quality. In 2022, for those SQIs with benchmarks, seven performed at or better than the approved benchmarks. The Meter Reading Accuracy metric performance was lower than the threshold due to the broader impacts of the COVID-19 pandemic, including staffing challenges, and the Telephone Service Factor (Non-Emergency) was impacted by higher than normal attrition levels in the contact centre and an increased amount of high bill inquiries over the year. While the Average Speed of Answer results were higher for the same reasons as the Telephone Service Factor (Non-Emergency), performance in 2022 for the other three informational metrics generally remains at a level consistent with prior years.

Appendix A

DEMAND FORECAST SUPPLEMENTARY INFORMATION

Table A1-1: Consumer Price Index (CPI)

Reference period	
	2002=100
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
July 2022	147.6
August 2022	147.0
September 2022	147.8
October 2022	148.6
November 2022	148.1
December 2022	147.1
January 2023	148.1
February 2023	149.1
March 2023	149.7
April 2023	150.4
May 2023	151.0
June 2023	151.6

Table A1-2: Average Weekly Earnings (AWE)

Reference period	Dollars
July 2021	1,143.76[B]
August 2021	1,143.96[B]
September 2021	1,142.37[B]
October 2021	1,140.94[B]
November 2021	1,129.51[B]
December 2021	1,132.93[B]
January 2022	1,155.32[B]
February 2022	1,153.57[B]
March 2022	1,161.00[B]
April 2022	1,164.51[B]
May 2022	1,159.89[B]
June 2022	1,167.14[B]
July 2022	1,162.26[B]
August 2022	1,171.52[B]
September 2022	1,171.94[B]
October 2022	1,174.29[B]
November 2022	1,176.97[B]
December 2022	1,153.31[B]
January 2023	1,180.04[B]
February 2023	1,175.83[B]
March 2023	1,191.20[B]
April 2023	1,199.14[B]

Table A1-3: Provincial Outlook Long-Term Economic Forecast 2023

BRITISH COLUMBIA	2021	2022	2023	2024
Housing Starts, Singles, British Columbia (Thousands ('000s))	11,025	9,109	7,733	8,483
Forecast Percent Change		**-17.4%**	**-15.1%**	**9.7%**
Housing Starts, Multiples, British Columbia (Thousands ('000s))	36,582	34,752	30,534	34,972
Forecast Percent Change		**-5.0%**	**-12.1%**	**14.5%**
Total	47,607	43,861	38,267	43,455

The Conference Board of Canada. The Growth to Slow as Province Climbs the Population Pyramid: British Columbia's Outlook to 2045. Ottawa: The Conference Board of Canada, 2023

Single and Multi-Family Dwelling Housing Starts respectively can be obtained Via e-data completed in 2022-16-12 and released 2022-22-12 through CBOC subscription

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. 2013 – 2022 Actual data
    b. 2023 Seed data
    c. 2024 Forecast data
2. Percent Error
    a. 2013 - 2022 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

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023-S*	2024-F*
RS 1	863,189	873,661	886,169	897,528	910,885	930,142	940,751	953,746	963,987	974,334	985,047	994,950
RS 2	82,452	83,625	85,076	86,074	86,973	88,244	88,686	89,363	89,683	89,976	90,846	91,271
RS 3	5,134	5,169	5,301	5,189	5,441	6,028	6,973	6,805	7,013	7,224	7,239	7,237
RS 23	1,529	1,522	1,724	1,803	1,712	1,648	871	746	697	620	622	624
Industrial	981	977	976	955	976	989	1,020	1,023	1,026	1,050	1,045	1,045
NGT	10	18	31	42	56	41	53	69	74	98	106	106
Total	953,295	964,971	979,277	991,591	1,006,043	1,027,092	1,038,354	1,051,752	1,062,480	1,073,302	1,084,905	1,095,233

FEI Customer Additions

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023-S*	2024-F*
RS 1	9,139	10,472	12,508	11,359	13,357	19,257	10,609	12,995	10,241	10,347	8,877	9,903
RS 2	1,329	1,173	1,450	998	899	1,271	442	677	320	293	425	425
RS 3	-86	35	132	-112	252	587	945	-168	208	211	-2	-2
RS 23	9	-7	202	79	-91	-64	-777	-125	-49	-77	2	2
Industrial	27	-4	-1	-21	21	13	31	3	3	24	-5	0
NGT	5	8	13	11	14	-15	12	16	5	24	8	0
Total	10,423	11,676	14,305	12,314	14,452	21,049	11,262	13,398	10,728	10,822	9,306	10,328

FEI Normalized Use Per Customer (GJ)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023-S*	2024-F*
RS 1	84.7	84.2	84.4	87.5	85.8	85.1	82.4	86.2	85.7	83.0	84.3	84.2
RS 2	331.6	330.6	332.6	339.1	336.8	332.5	318.1	322.2	328.1	334.9	327.7	326.8
RS 3	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	3,737.6	3,720.7	3,728.0
RS 23	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	5,818.1	5,796.7	5,835.5

FEI Energy (PJ)(1)

	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023-S*	2024-F*
RS 1	72.7	73.2	74.1	77.9	77.5	78.3	77.0	81.6	82.2	80.4	82.6	83.4
RS 2	27.0	27.5	28.0	29.0	29.1	29.1	28.1	28.7	29.3	30.0	29.6	29.7
RS 3	18.7	18.5	19.2	19.4	19.7	20.9	22.5	24.6	25.7	26.7	26.9	27.0
RS 23	7.9	8.0	8.6	9.3	9.5	9.0	7.3	4.6	4.2	3.9	3.6	3.6
Industrial	80.1	78.6	79.6	83.7	87.4	88.4	91.5	89.5	90.8	77.6	72.9	71.7
Sub-Total	206.3	205.7	209.5	219.3	223.3	225.8	226.4	229.0	232.2	218.6	215.7	215.4
NGT	0.3	0.8	1.1	1.3	1.8	1.6	2.6	2.6	3.0	3.2	3.8	4.8
Total	206.6	206.5	210.6	220.6	225.0	227.3	229.0	231.7	235.2	221.8	219.5	220.2

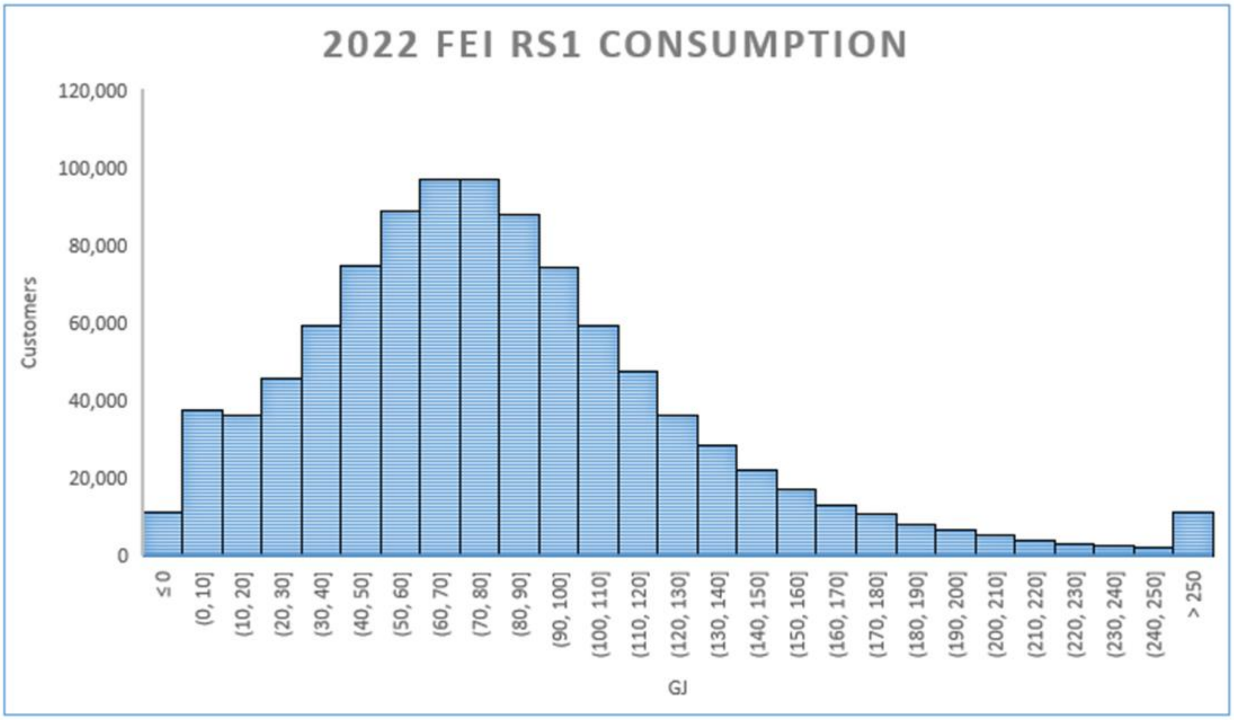
Note:
1 Rate Schedule 1,2,3 and 23 are weather normalized
*2023S and 2024F Includes FTN

Table A2-2: FEI 2023F Industrial Forecast Demand by Region[2]

Industrial	2024 Forecast Demand by Region (PJ)
Fort Nelson	0.0
Mainland	65.2
Vancouver Island	6.4
Whistler	0.1
Total	**71.7**

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 2022



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	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 1										
Forecast	880,331	866,852	883,371	892,830	909,727	916,365	934,804	950,330	958,899	974,625
Actual	863,189	873,661	886,169	897,528	910,885	930,142	940,751	953,746	963,987	974,334
Error = (ACT-FCST)	(17,142)	6,809	2,798	4,698	1,158	13,777	5,947	3,416	5,088	(291)
Percent Error = (Error/ACT)	-2.0%	0.8%	0.3%	0.5%	0.1%	1.5%	0.6%	0.4%	0.5%	0.0%

FEI Customers	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 2										
Forecast	85,627	81,923	84,651	85,667	87,712	88,494	89,203	89,558	90,430	90,956
Actual	82,452	83,625	85,076	86,074	86,973	88,244	88,686	89,363	89,683	89,976
Error = (ACT-FCST)	(3,175)	1,702	425	407	(739)	(250)	(517)	(195)	(747)	(980)
Percent Error = (Error/ACT)	-3.9%	2.0%	0.5%	0.5%	-0.8%	-0.3%	-0.6%	-0.2%	-0.8%	-1.1%

FEI Customers	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 3										
Forecast	5,597	5,147	5,117	5,035	5,354	5,223	5,623	7,221	7,469	7,034
Actual	5,134	5,169	5,301	5,189	5,441	6,028	6,973	6,805	7,013	7,224
Error = (ACT-FCST)	(463)	22	184	154	87	805	1,350	(416)	(456)	190
Percent Error = (Error/ACT)	-9.0%	0.4%	3.5%	3.0%	1.6%	13.4%	19.4%	-6.1%	-6.5%	2.6%

FEI Customers	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 23										
Forecast	1,586	1,634	1,552	1,670	1,760	1,934	1,744	906	941	782
Actual	1,529	1,522	1,724	1,803	1,712	1,648	871	746	697	620
Error = (ACT-FCST)	(57)	(112)	172	133	(48)	(286)	(873)	(160)	(244)	(162)
Percent Error = (Error/ACT)	-3.7%	-7.4%	10.0%	7.4%	-2.8%	-17.4%	-100.2%	-21.4%	-35.0%	-26.1%

3.2 AMALGAMATED NET CUSTOMER ADDITIONS

FEI Customer Additions	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 1										
Forecast	9,352	6,647	9,710	9,461	11,522	9,141	10,724	9,579	8,569	10,096
Actual	9,139	10,472	12,508	11,359	13,357	19,257	10,609	12,995	10,241	10,347
Error = (ACT-FCST)	(213)	3,825	2,798	1,898	1,835	10,116	(115)	3,416	1,672	251
Percent Error = (Error/ACT)	-2.3%	36.5%	22.4%	16.7%	13.7%	52.5%	-1.1%	26.3%	16.3%	2.4%

FEI Customer Additions	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 2										
Forecast	145	411	1,026	1,026	1,318	1,210	1,115	872	872	797
Actual	1,329	1,173	1,450	998	899	1,271	442	677	320	293
Error = (ACT-FCST)	1,184	762	424	(28)	(419)	61	(673)	(195)	(552)	(504)
Percent Error = (Error/ACT)	89.1%	65.0%	29.2%	-2.8%	-46.6%	4.8%	-152.3%	-28.8%	-172.5%	-171.9%

FEI Customer Additions	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 3										
Forecast	44	4	(52)	(51)	26	19	91	248	248	115
Actual	(86)	35	132	(112)	252	587	945	(168)	208	211
Error = (ACT-FCST)	(130)	31	184	(61)	226	568	854	(416)	(40)	96
Percent Error = (Error/ACT)	151.2%	88.6%	139.4%	54.5%	89.7%	96.8%	90.4%	247.6%	-19.2%	45.6%

FEI Customer Additions	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 23										
Forecast	60	57	30	30	18	66	16	35	35	18
Actual	9	(7)	202	79	(91)	(64)	(777)	(125)	(49)	(77)
Error = (ACT-FCST)	(51)	(64)	172	49	(109)	(130)	(793)	(160)	(84)	(95)
Percent Error = (Error/ACT)	-566.7%	914.3%	85.1%	62.0%	119.8%	203.1%	102.1%	128.0%	171.4%	123.3%

3.3 AMALGAMATED NORMALIZED USE PER CUSTOMER

FEI UPC, GJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 1										
Forecast	85.2	86.0	83.1	81.6	82.2	89.1	87.0	85.7	83.1	84.1
Actual	84.7	84.2	84.4	87.5	85.8	85.1	82.4	86.2	85.7	83.0
Error = (ACT-FCST)	(0.5)	(1.8)	1.3	5.9	3.7	(4.0)	(4.6)	0.4	2.6	(1.1)
Percent Error = (Error/ACT)	-0.6%	-2.1%	1.5%	6.7%	4.3%	-4.7%	-5.6%	0.5%	3.1%	-1.3%

FEI UPC, GJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 2										
Forecast	314.5	340.0	333.7	329.5	328.4	345.2	341.3	324.9	321.8	320.4
Actual	331.6	330.6	332.6	339.1	336.8	332.5	318.1	322.2	328.1	334.9
Error = (ACT-FCST)	17.1	(9.4)	(1.1)	9.6	8.3	(12.7)	(23.2)	(2.7)	6.3	14.6
Percent Error = (Error/ACT)	5.2%	-2.8%	-0.3%	2.8%	2.5%	-3.8%	-7.3%	-0.8%	1.9%	4.3%

FEI UPC, GJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 3										
Forecast	3,435	3,872	3,754	3,593	3,488	3,842	3,831	3,648	3,551	3,557
Actual	3,610	3,573	3,587	3,721	3,692	3,550	3,517	3,660	3,703	3,737.6
Error = (ACT-FCST)	175	(299)	(167)	128	205	(292)	(314)	12	151	181
Percent Error = (Error/ACT)	4.8%	-8.4%	-4.7%	3.4%	5.5%	-8.2%	-8.9%	0.3%	4.1%	4.8%

FEI UPC, GJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 23										
Forecast	4,927	5,546	5,309	5,382	5,227	5,399	5,492	5,480	5,278	5,365
Actual	5,149	5,260	5,174	5,279	5,361	5,345	5,051	5,441	5,724	5,818
Error = (ACT-FCST)	222	(286)	(135)	(103)	133	(54)	(440)	(39)	447	453
Percent Error = (Error/ACT)	4.3%	-5.4%	-2.6%	-2.0%	2.5%	-1.0%	-8.7%	-0.7%	7.8%	7.8%

3.4 AMALGAMATED DEMAND

FEI Demand,PJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 1										
Forecast	74.6	74.2	73.1	72.5	74.3	81.2	80.8	81.1	79.3	81.5
Actual	72.7	73.2	74.1	77.9	77.5	78.3	77.0	81.6	82.2	80.4
Error = (ACT-FCST)	(1.9)	(1.0)	1.0	5.4	3.3	(2.9)	(3.7)	0.5	2.9	(1.1)
Percent Error = (Error/ACT)	-2.6%	-1.4%	1.3%	7.0%	4.2%	-3.7%	-4.9%	0.6%	3.5%	-1.3%
Abs. Percent Error	2.6%	1.4%	1.3%	7.0%	4.2%	3.7%	4.9%	0.6%	3.5%	1.3%

FEI Demand,PJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 2										
Forecast	26.9	27.7	28.1	28.0	28.5	30.3	30.2	28.9	28.9	29.0
Actual	27.0	27.5	28.0	29.0	29.1	29.1	28.1	28.7	29.3	30.0
Error = (ACT-FCST)	0.1	(0.2)	(0.1)	1.0	0.6	(1.2)	(2.1)	(0.2)	0.4	1.0
Percent Error = (Error/ACT)	0.4%	-0.7%	-0.4%	3.4%	2.0%	-4.3%	-7.4%	-0.8%	1.2%	3.5%

FEI Demand,PJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 3										
Forecast	19.1	19.9	19.2	18.1	18.7	20.1	21.5	25.2	26.2	24.9
Actual	18.7	18.5	19.2	19.4	19.7	20.9	22.5	24.6	25.7	26.7
Error = (ACT-FCST)	(0.4)	(1.4)	(0.0)	1.3	1.0	0.9	1.0	(0.6)	(0.5)	1.8
Percent Error = (Error/ACT)	-2.1%	-7.6%	-0.2%	6.7%	5.2%	4.1%	4.3%	-2.4%	-1.8%	6.8%

FEI Demand,PJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 23										
Forecast	7.5	8.7	8.3	9.0	9.2	10.3	9.6	4.8	4.9	4.1
Actual	7.9	8.0	8.6	9.3	9.5	9.0	7.3	4.6	4.2	3.9
Error = (ACT-FCST)	0.4	(0.7)	0.3	0.3	0.4	(1.3)	(2.3)	(0.2)	(0.7)	(0.2)
Percent Error = (Error/ACT)	5.1%	-8.7%	3.5%	3.2%	3.9%	-13.9%	-31.3%	-5.2%	-16.1%	-4.5%

FEI Demand,PJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Commercial										
Forecast	53.5	56.3	55.6	55.1	56.4	60.7	61.3	59.0	60.0	58.0
Actual	53.6	54.0	55.8	57.7	58.3	59.0	57.9	57.9	59.200	60.6
Error = (ACT-FCST)	0.1	(2.3)	0.2	2.6	2.0	(1.6)	(3.4)	(1.1)	(0.8)	2.7
Percent Error = (Error/ACT)	0.2%	-4.3%	0.3%	4.5%	3.4%	-2.8%	-5.9%	-1.9%	-1.3%	4.4%
Abs. Percent Error	0.2%	4.3%	0.3%	4.5%	3.4%	2.8%	5.9%	1.9%	1.3%	4.4%

FEI Demand,PJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate 5										
Forecast	4.0	3.9	3.5	2.2	2.2	2.5	2.9	7.6	7.6	8.7
Actual	3.8	3.4	2.3	2.4	2.8	3.8	4.8	8.1	9.1	9.8
Error = (ACT-FCST)	(0.2)	(0.5)	(1.2)	0.3	0.7	1.3	1.9	0.5	1.6	1.1
Percent Error = (Error/ACT)	-5%	-15%	-52%	11%	23%	34%	40%	6%	17%	11%

FEI Demand,PJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate 25										
Forecast	13.5	13.3	13.9	13.8	13.8	14.4	14.8	10.3	10.8	9.9
Actual	13.1	13.4	13.7	13.9	14.5	13.9	13.2	9.9	9.324	9.1
Error = (ACT-FCST)	(0.4)	0.1	(0.2)	0.1	0.7	(0.5)	(1.7)	(0.4)	(1.5)	(0.8)
Percent Error = (Error/ACT)	-3%	1%	-1%	1%	5%	-3%	-13%	-4%	-16%	-9%

FEI Demand,PJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate 22										
Forecast	29.6	43.2	33.2	36.3	38.2	38.5	43.3	41.0	37.4	37.8
Actual	36.4	36.0	37.0	40.5	40.9	42.0	43.3	39.0	40.070	38.6
Error = (ACT-FCST)	6.8	(7.2)	3.8	4.2	2.6	3.5	0.1	(2.0)	2.7	0.8
Percent Error = (Error/ACT)	19%	-20%	10%	10%	6%	8%	0%	-5%	7%	2%

FEI Demand,PJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate 27										
Forecast	5.8	6.5	6.6	6.5	6.4	7.3	7.9	4.7	4.8	4.5
Actual	7.5	6.6	7.2	6.8	7.5	6.2	5.9	4.6	4.4365	4.3
Error = (ACT-FCST)	1.7	0.1	0.5	0.3	1.1	(1.1)	(2.0)	(0.1)	(0.4)	(0.2)
Percent Error = (Error/ACT)	23%	2%	7%	4%	14%	-17%	-34%	-1%	-8%	-4%

FEI Demand,PJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Industrial*										
Forecast	72.1	86.2	76.4	78.1	82.1	84.3	90.6	91.9	87.8	88.9
Actual	80.1	78.6	79.6	83.7	87.4	88.4	91.5	89.5	90.8	77.6
Error = (ACT-FCST)	8.0	(7.6)	3.2	5.6	5.3	4.2	0.9	(2.4)	2.9	(11.3)
Percent Error = (Error/ACT)	10.0%	-9.7%	4.0%	6.7%	6.0%	4.7%	1.0%	-2.7%	3.2%	-14.6%
Abs. Percent Error	10.0%	9.7%	4.0%	6.7%	6.0%	4.7%	1.0%	2.7%	3.2%	14.6%

FEI Demand,PJ*	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
FEI										
Forecast	200.2	216.7	205.2	205.7	212.8	226.2	232.6	232.0	227.1	228.4
Actual	206.4	205.8	209.5	219.3	223.3	225.8	226.4	229.0	232.2	218.6
Error = (ACT-FCST)	6.2	(10.9)	4.3	13.6	10.5	(0.4)	(6.2)	(2.9)	5.1	(9.7)
Percent Error = (Error/ACT)	3.0%	-5.3%	2.1%	6.2%	4.7%	-0.2%	-2.7%	-1.3%	2.2%	-4.5%
Abs. Percent Error	3.0%	5.3%	2.1%	6.2%	4.7%	0.2%	2.7%	1.3%	2.2%	4.5%

*Excld NGT and Burrard

3.5 *MAINLAND NET CUSTOMERS*

Mainland Customers	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 1										
Forecast	780,005	768,622	780,972	787,836	799,732	803,319	813,959	823,255	828,146	839,746
Actual	766,668	774,083	782,914	790,562	798,917	811,696	817,817	826,142	831,178	838,403
Error = (ACT-FCST)	(13,337)	5,461	1,942	2,726	(815)	8,377	3,858	2,887	3,032	(1,343)
Percent Error = (Error/ACT)	-1.7%	0.7%	0.2%	0.3%	-0.1%	1.0%	0.5%	0.3%	0.4%	-0.2%

Mainland Customers	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 2										
Forecast	76,175	72,922	75,315	76,166	77,597	78,228	78,767	79,027	79,703	80,203
Actual	73,480	74,464	75,451	76,326	77,047	78,044	78,351	78,941	79,108	79,358
Error = (ACT-FCST)	(2,695)	1,542	136	160	(550)	(184)	(416)	(86)	(595)	(845)
Percent Error = (Error/ACT)	-3.7%	2.1%	0.2%	0.2%	-0.7%	-0.2%	-0.5%	-0.1%	-0.8%	-1.1%

Mainland Customers	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 3										
Forecast	5,002	4,577	4,560	4,497	4,667	4,608	5,029	6,545	6,799	6,239
Actual	4,598	4,625	4,671	4,605	4,867	5,478	6,291	6,046	6,243	6,443
Error = (ACT-FCST)	(404)	48	111	108	200	870	1,262	(499)	(556)	204
Percent Error = (Error/ACT)	-8.8%	1.0%	2.4%	2.3%	4.1%	15.9%	20.1%	-8.3%	-8.9%	3.2%

Mainland Customers	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 23										
Forecast	1,586	1,634	1,552	1,582	1,609	1,669	1,562	836	872	742
Actual	1,529	1,522	1,573	1,614	1,546	1,458	800	708	661	587
Error = (ACT-FCST)	(57)	(112)	21	32	(63)	(211)	(762)	(128)	(211)	(155)
Percent Error = (Error/ACT)	-3.7%	-7.4%	1.3%	2.0%	-4.1%	-14.5%	-95.3%	-18.1%	-31.9%	-26.4%

3.6 *MAINLAND NET CUSTOMER ADDITIONS*

Mainland Customer Additions	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 1										
Forecast	6,774	4,594	6,889	6,863	8,250	6,203	6,756	5,438	4,891	6,622
Actual	6,956	7,415	8,831	7,648	8,355	12,779	6,121	8,325	5,036	7,225
Error = (ACT-FCST)	182	2,821	1,942	785	105	6,576	(635)	2,887	145	603
Percent Error = (Error/ACT)	2.6%	38.0%	22.0%	10.3%	1.3%	51.5%	-10.4%	34.7%	2.9%	8.3%

Mainland Customer Additions	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 2										
Forecast	49	331	851	851	1,072	951	860	676	676	631
Actual	1,245	984	987	875	721	997	307	590	167	250
Error = (ACT-FCST)	1,196	653	136	24	(351)	46	(553)	(86)	(509)	(381)
Percent Error = (Error/ACT)	96.1%	66.4%	13.7%	2.7%	-48.7%	4.6%	-180.1%	-14.6%	-304.8%	-152.5%

Mainland Customer Additions	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 3										
Forecast	40	-	(65)	(64)	(1)	2	81	254	254	97
Actual	(77)	27	46	(66)	262	611	813	(245)	197	200
Error = (ACT-FCST)	(117)	27	111	(2)	263	609	732	(499)	(57)	103
Percent Error = (Error/ACT)	151.9%	100.0%	241.3%	3.0%	100.4%	99.7%	90.0%	203.7%	-28.9%	51.7%

Mainland Customer Additions	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 23										
Forecast	60	57	30	30	18	28	8	36	36	17
Actual	9	(7)	51	41	(68)	(88)	(658)	(92)	(47)	(74)
Error = (ACT-FCST)	(51)	(64)	21	11	(86)	(116)	(666)	(128)	(83)	(91)
Percent Error = (Error/ACT)	-566.7%	914.3%	41.2%	26.8%	126.5%	131.8%	101.2%	139.1%	176.6%	123.0%

3.7 *MAINLAND NORMALIZED USE PER CUSTOMER*

Mainland UPC GJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 1										
Forecast	89.9	90.7	88.1	86.3	86.2	93.5	91.5	90.8	88.2	89.2
Actual	89.3	88.8	88.7	92.0	90.4	89.7	87.1	91.1	90.8	88.1
Error = (ACT-FCST)	(0.6)	(1.9)	0.6	5.7	4.2	(3.8)	(4.5)	0.3	2.6	(1.0)
Percent Error = (Error/ACT)	-0.7%	-2.1%	0.7%	6.2%	4.6%	-4.2%	-5.1%	0.4%	2.8%	-1.1%

Mainland UPC GJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 2										
Forecast	306	334	329	329	327	345	339	324	320	320
Actual	330	330	330	338	335	329	316	322	327	334
Error = (ACT-FCST)	23	(3)	1	10	8	(15)	(23)	(2)	7	13
Percent Error = (Error/ACT)	7.0%	-1.0%	0.2%	2.8%	2.4%	-4.6%	-7.3%	-0.6%	2.2%	4.0%

Mainland UPC GJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 3										
Forecast	3,316	3,769	3,599	3,537	3,517	3,770	3,746	3,640	3,501	3,591
Actual	3,517	3,529	3,524	3,658	3,625	3,477	3,468	3,682	3,704	3,728
Error = (ACT-FCST)	201	(240)	(75)	121	108	(293)	(278)	42	202	137
Percent Error = (Error/ACT)	5.7%	-6.8%	-2.1%	3.3%	3.0%	-8.4%	-8.0%	1.1%	5.5%	3.7%

Mainland UPC GJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 23										
Forecast	4,927	5,546	5,309	5,348	5,197	5,416	5,521	5,537	5,362	5,418
Actual	5,149	5,260	5,157	5,304	5,388	5,357	5,127	5,497	5,699	5,811
Error = (ACT-FCST)	222	(286)	(152)	(44)	191	(59)	(394)	(41)	336	393
Percent Error = (Error/ACT)	4.3%	-5.4%	-2.9%	-0.8%	3.5%	-1.1%	-7.7%	-0.7%	5.9%	6.8%

3.8 *MAINLAND NORMALIZED DEMAND*

Mainland Demand, PJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 1										
Forecast	69.8	69.5	68.5	67.7	68.6	74.8	74.2	74.5	72.8	74.6
Actual	68.1	68.5	68.9	72.3	71.8	72.2	70.9	74.9	75.2	73.6
Error = (ACT-FCST)	(1.7)	(1.0)	0.4	4.6	3.2	(2.6)	(3.2)	0.4	2.4	(1.0)
Percent Error = (Error/ACT)	-2.5%	-1.5%	0.5%	6.4%	4.5%	-3.6%	-4.6%	0.5%	3.2%	-1.4%
Abs. Percent Error	2.5%	1.5%	0.5%	6.4%	4.5%	3.6%	4.6%	0.5%	3.2%	1.4%

Mainland Demand, PJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 2										
Forecast	23.3	24.2	24.7	24.9	25.2	26.7	26.5	25.5	25.4	25.6
Actual	23.9	24.5	24.6	25.6	25.7	25.5	24.7	25.3	25.8	26.4
Error = (ACT-FCST)	0.6	0.2	(0.0)	0.7	0.5	(1.3)	(1.8)	(0.1)	0.5	0.8
Percent Error = (Error/ACT)	2.5%	0.9%	-0.2%	2.7%	2.0%	-5.0%	-7.3%	-0.5%	1.7%	3.1%

Mainland Demand, PJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 3										
Forecast	16.5	17.3	16.4	16.0	16.4	17.4	18.8	22.6	23.5	22.3
Actual	16.3	16.3	16.5	16.8	17.3	18.5	20.1	22.1	22.9	23.7
Error = (ACT-FCST)	(0.2)	(1.0)	0.0	0.8	0.9	1.2	1.3	(0.5)	(0.5)	1.4
Percent Error = (Error/ACT)	-1.2%	-6.1%	0.3%	5.0%	5.4%	6.3%	6.4%	-2.4%	-2.3%	6.0%

Mainland Demand, PJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 23										
Forecast	7.5	8.7	8.3	8.4	8.3	9.0	8.6	4.5	4.6	4.0
Actual	7.9	8.0	8.0	8.4	8.6	8.1	6.6	4.3	4.0	3.7
Error = (ACT-FCST)	0.4	(0.7)	(0.3)	-	0.3	(0.8)	(2.0)	(0.2)	(0.6)	(0.2)
Percent Error = (Error/ACT)	5.1%	-8.7%	-3.3%	0.0%	3.1%	-10.4%	-30.8%	-4.8%	-15.9%	-5.8%

Mainland Demand, PJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Commercial										
Forecast	47.3	50.2	49.3	49.3	49.9	53.1	53.9	52.6	53.4	51.8
Actual	48.1	48.8	49.1	50.8	51.6	52.2	51.3	51.7	52.7	53.8
Error = (ACT-FCST)	0.8	(1.5)	(0.3)	1.5	1.7	(0.9)	(2.5)	(0.9)	(0.7)	2.0
Percent Error = (Error/ACT)	1.6%	-3.0%	-0.5%	3.0%	3.3%	-1.8%	-5.0%	-1.6%	-1.4%	3.8%
Abs. Percent Error	1.6%	3.0%	0.5%	3.0%	3.3%	1.8%	5.0%	1.6%	1.4%	3.8%

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

FEVI Customers	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 1										
Forecast	98,023	95,858	99,921	102,458	107,314	110,270	117,957	124,041	127,631	131,838
Actual	94,173	97,162	100,747	104,358	109,259	115,618	119,998	124,627	129,764	132,861
Error = (ACT-FCST)	(3,850)	1,304	826	1,900	1,945	5,348	2,041	586	2,133	1,023
Percent Error = (Error/ACT)	-4.1%	1.3%	0.8%	1.8%	1.8%	4.6%	1.7%	0.5%	1.6%	0.8%

FEVI Customers	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 2										
Forecast	9,172	8,710	9,047	9,209	9,808	9,971	10,131	10,218	10,408	10,443
Actual	8,691	8,875	9,330	9,459	9,629	9,891	10,028	10,117	10,270	10,312
Error = (ACT-FCST)	(481)	165	283	250	(179)	(80)	(103)	(101)	(138)	(131)
Percent Error = (Error/ACT)	-5.53%	1.86%	3.03%	2.64%	-1.86%	-0.81%	-1.03%	-1.00%	-1.34%	-1.27%

FEVI Customers	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 3										
Forecast	536	509	497	479	647	567	539	605	597	720
Actual	476	484	582	531	517	492	613	686	697	711
Error = (ACT-FCST)	(60)	(25)	85	52	(130)	(75)	74	81	100	(9)
Percent Error = (Error/ACT)	-12.61%	-5.17%	14.60%	9.79%	-25.15%	-15.24%	12.06%	11.81%	14.35%	-1.29%

FEVI Customers	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 23										
Forecast				83	141	243	164	66	65	39
Actual			141	175	152	179	67	37	35	32
Error = (ACT-FCST)			141	92	11	(64)	(97)	(29)	(30)	(7)
Percent Error = (Error/ACT)				52.57%	7.24%	-35.75%	-144.78%	-78.38%	-85.71%	-21.38%

3.11 *VANCOUVER ISLAND NET CUSTOMER ADDITIONS*

FEVI Customer Additions	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 1										
Forecast	2,564	2,001	2,759	2,537	3,188	2,857	3,888	4,043	3,590	3,443
Actual	2,106	2,989	3,583	3,611	4,901	6,359	4,380	4,629	5,137	3,097
Error = (ACT-FCST)	(458)	988	824	1074	1713	3502	492	586	1547	(346)
Percent Error = (Error/ACT)	-21.7%	33.1%	23.0%	29.8%	35.0%	55.1%	11.2%	12.7%	30.1%	-11.2%

FEVI Customer Additions	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 2										
Forecast	91	71	171	171	239	256	251	190	190	163
Actual	78	184	453	129	170	262	137	89	153	42
Error = (ACT-FCST)	(13)	113	282	(42)	(69)	6	(114)	(101)	(37)	(121)
Percent Error = (Error/ACT)	-16.4%	61.1%	62.2%	-32.6%	-40.6%	2.3%	-83.2%	-113.5%	-24.2%	-287.3%

FEVI Customer Additions	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 3										
Forecast	4	4	13	13	32	19	11	(8)	(8)	17
Actual	(8)	8	98	(51)	(14)	(25)	121	73	11	14
Error = (ACT-FCST)	(12)	4	85	(64)	(46)	(44)	110	81	19	(3)
Percent Error = (Error/ACT)	150.0%	50.0%	86.6%	125.5%	328.6%	176.0%	90.9%	111.0%	172.7%	-22.0%

FEVI Customer Additions	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 23										
Forecast				-	-	34	6	(1)	(1)	1
Actual			141	34	(23)	27	(112)	(30)	(2)	(3)
Error = (ACT-FCST)			141	34	(23)	(7)	(118)	(29)	(1)	(4)
Percent Error = (Error/ACT)				100.0%	100.0%	-25.9%	105.4%	96.7%	50.0%	130.7%

3.12 *VANCOUVER ISLAND NORMALIZED USE PER CUSTOMER*

FEVIUPC, GJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 1										
Forecast	46.9	45.0	44.0	45.1	51.3	56.3	54.7	51.2	49.6	50.9
Actual	47.3	47.1	50.5	52.6	51.5	51.6	49.7	52.3	52.7	49.7
Error = (ACT-FCST)	0.4	2.1	6.5	7.5	0.3	(4.7)	(5.0)	1.1	3.1	(1.2)
Percent Error = (Error/ACT)	0.8%	4.5%	12.9%	14.3%	0.5%	-9.1%	-10.1%	2.1%	5.8%	-2.3%

UPC, GJs	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 2										
Forecast	372	390	372	334	323	343	357	332	333	319
Actual	344	328	346	343	345	351	333	322	331	338
Error = (ACT-FCST)	(28.0)	(62.0)	(26.0)	9.0	22.0	8.7	(24.3)	(9.7)	(2.2)	19.8
Percent Error = (Error/ACT)	-8.1%	-18.9%	-7.5%	2.6%	6.4%	2.5%	-7.3%	-3.0%	-0.7%	5.9%

UPC, GJs	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 3										
Forecast	6,398	5,896	5,187	4,031	3,069	4,171	4,411	3,629	3,882	3,197
Actual	4,431	3,901	3,894	4,060	4,181	4,074	3,827	3,404	3,604	3,708
Error = (ACT-FCST)	(1967)	(1995)	(1293)	29	1112	(97)	(584)	(225)	(278)	511
Percent Error = (Error/ACT)	-44.4%	-51.1%	-33.2%	0.7%	26.6%	-2.4%	-15.3%	-6.6%	-7.7%	13.8%

UPC, GJs	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 23										
Forecast				5,996.2	5,635.7	5,343.6	5,281.6	4,799.8	4,169.3	4,338.1
Actual			5,636.0	5,052.0	5,157.5	5,260.4	4,368.5	4,726.7	6,022.6	5,751.4
Error = (ACT-FCST)				(944.2)	(478.2)	(83.3)	(913.1)	(73.1)	1853.3	1413.4
Percent Error = (Error/ACT)				-18.7%	-9.3%	-1.6%	-20.9%	-1.5%	30.8%	24.6%

3.13 *VANCOUVER ISLAND NORMALIZED DEMAND*

FEVI Demand, PJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 1										
Forecast	4.5	4.3	4.3	4.6	5.4	6.1	6.3	6.2	6.2	6.6
Actual	4.4	4.5	5.0	5.4	5.5	5.8	5.9	6.4	6.7	6.5
Error = (ACT-FCST)	(0.1)	0.2	0.6	0.8	0.1	(0.3)	(0.5)	0.1	0.5	(0.1)
Percent Error = (Error/ACT)	-2.3%	4.4%	12.9%	15.6%	1.5%	-5.6%	-8.3%	2.3%	6.9%	-1.4%
Abs. Percent Error	2.3%	4.4%	12.9%	15.6%	1.5%	5.6%	8.3%	2.3%	6.9%	1.4%

FEVI Demand, PJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 2										
Forecast	3.4	3.3	3.3	3.0	3.1	3.4	3.6	3.4	3.4	3.3
Actual	3.0	2.9	3.2	3.2	3.3	3.4	3.3	3.2	3.4	3.5
Error = (ACT-FCST)	(0.4)	(0.5)	(0.2)	0.2	0.2	0.0	(0.3)	(0.1)	(0.1)	0.2
Percent Error = (Error/ACT)	-14.9%	-16.0%	-4.7%	6.3%	5.4%	1.4%	-8.0%	-3.4%	-1.8%	5.1%

FEVI Demand, PJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 3										
Forecast	2.4	2.4	2.5	1.9	2.0	2.4	2.4	2.3	2.3	2.3
Actual	2.1	1.9	2.4	2.2	2.1	2.1	2.0	2.2	2.5	2.6
Error = (ACT-FCST)	(0.3)	(0.5)	(0.1)	0.3	0.1	(0.3)	(0.3)	(0.0)	0.2	0.3
Percent Error = (Error/ACT)	-13.7%	-28.3%	-5.0%	13.6%	6.5%	-14.6%	-16.8%	-1.9%	6.9%	13.2%

FEVI Demand, PJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 23										
Forecast				0.5	0.8	1.2	0.8	0.3	0.3	0.2
Actual			0.5	0.8	0.9	0.8	0.6	0.3	0.2	0.2
Error = (ACT-FCST)			(0.5)	(0.3)	(0.1)	0.4	0.2	0.0	0.1	(0.0)
Percent Error = (Error/ACT)				-37.5%	-9.2%	44.9%	32.2%	11.0%	24.6%	-16.1%

FEVI Demand, PJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Commercial										
Forecast	5.8	5.7	5.9	5.4	5.9	7.0	6.8	5.9	6.0	5.7
Actual	5.1	4.8	6.2	6.2	6.3	6.3	6.0	5.8	6.1	6.3
Error = (ACT-FCST)	(0.7)	(1.0)	0.3	0.8	0.4	(0.6)	(0.8)	(0.2)	0.1	0.6
Percent Error = (Error/ACT)	-14.4%	-20.8%	4.4%	12.9%	6.3%	-10.0%	-13.6%	-3.2%	1.0%	8.8%
Abs. Percent Error	14.4%	20.8%	4.4%	12.9%	6.3%	10.0%	13.6%	3.2%	1.0%	8.8%

3.14 *WHISTLER NET CUSTOMERS*

WH Customers	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 1										
Forecast	2,303	2,372	2,478	2,536	2,681	2,775	2,889	3,034	3,122	3,041
Actual	2,348	2,416	2,508	2,608	2,709	2,828	2,936	2,977	3,045	3,070
Error = (ACT-FCST)	45	44	30	72	28	53	47	(57)	(77)	29
Percent Error = (Error/ACT)	1.9%	1.8%	1.2%	2.8%	1.0%	1.9%	1.6%	-1.9%	-2.5%	0.9%

WH Customers	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 2										
Forecast	280	291	289	292	309	294	305	313	319	310
Actual	281	285	295	289	297	309	307	305	305	306
Error = (ACT-FCST)	1	(6)	6	(3)	(12)	15	2	(8)	(14)	(4)
Percent Error = (Error/ACT)	0.4%	-2.1%	2.0%	-1.0%	-4.0%	4.7%	0.7%	-2.6%	-4.6%	-1.4%

WH Customers	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 3										
Forecast	59	61	60	59	39	48	55	71	74	75
Actual	60	60	48	53	57	58	69	73	73	70
Error = (ACT-FCST)	1	(1)	(12)	(6)	18	10	14	2	(1)	(5)
Percent Error = (Error/ACT)	1.7%	-1.7%	-25.0%	-11.3%	31.6%	16.9%	20.2%	2.7%	-1.4%	-7.1%

WH Customers	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 23										
Forecast				5	10	22	18	4	4	1
Actual			10	14	14	11	4	1	1	1
Error = (ACT-FCST)			10	9	4	(11)	(14)	(3)	(3)	(0)
Percent Error = (Error/ACT)				64.3%	28.6%	-100.0%	-350.0%	-300.0%	-300.0%	-2.0%

3.15 *WHISTLER NET CUSTOMER ADDITIONS*

WH Customer Additions	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 1										
Forecast	14	52	62	61	84	81	81	98	88	31
Actual	77	68	92	100	101	119	108	41	68	25
Error = (ACT-FCST)	63	16	30	39	17	38	27	(57)	(20)	(6)
Percent Error = (Error/ACT)	81.8%	23.5%	32.6%	39.0%	16.8%	31.8%	25.4%	-139.5%	-28.9%	-23.5%

WH Customer Additions	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 2										
Forecast	5	9	4	4	7	3	4	6	6	3
Actual	7	5	10	(6)	8	12	(2)	(2)	-	1
Error = (ACT-FCST)	2	(4)	6	(10)	1	9	(6)	(8)	(6)	(2)
Percent Error = (Error/ACT)	28.6%	-80.0%	60.0%	166.7%	11.9%	77.4%	300.0%	400.0%		

WH Customer Additions	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 3										
Forecast			-	-	(5)	(2)	(1)	2	1	1
Actual	(1)	(0)	(12)	5	4	1	11	4	-	(3)
Error = (ACT-FCST)			(12)	5	9	3	12	2	(1)	(4)
Percent Error = (Error/ACT)				100.0%	225.0%	339.0%	109.1%	50.0%		

WH Customer Additions	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 23										
Forecast				-	-	4	2	-	-	0
Actual			10	4	-	(3)	(7)	(3)	-	-
Error = (ACT-FCST)			10	4	0	(7)	(9)	(3)	0	(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	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 1										
Forecast	106.3	90.6	79.7	85.1	97.9	102.1	99.5	99.0	95.8	101.8
Actual	87.3	87.6	91.3	97.7	93.5	96.3	94.2	101.5	100.3	103.6
Error = (ACT-FCST)	(19)	(3)	12	13	(4)	(6)	(5)	2	4	2
Percent Error = (Error/ACT)	-21.8%	-3.4%	12.7%	12.9%	-4.7%	-6.1%	-5.6%	2.4%	4.5%	1.8%

WH UPC, GJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 2										
Forecast	637.0	464.0	408.0	465.0	792.9	592.7	515.5	419.5	384.7	356.2
Actual	465.0	471.0	660.0	520.2	479.4	511.8	465.8	417.5	438.7	499.8
Error = (ACT-FCST)	(172)	7	252	55	(314)	(81)	(50)	(2)	54	144
Percent Error = (Error/ACT)	-37.0%	1.5%	38.2%	10.6%	-65.4%	-15.8%	-10.7%	-0.5%	12.3%	28.7%

WH UPC, GJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 3										
Forecast	3,630.0	3,595.0	3,822.0	4,326.0	6,706.9	6,824.3	5,886.5	4,737.2	5,475.7	4,179.4
Actual	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	4,869.8
Error = (ACT-FCST)	583	690	1,796	1,312	(1,599)	(1,077)	(495)	(516)	(917)	690
Percent Error = (Error/ACT)	13.8%	16.1%	32.0%	23.3%	-31.3%	-18.7%	-9.2%	-12.2%	-20.1%	14.2%

WH UPC, GJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 23										
Forecast				5,888.0	4,328.3	4,702.9	4,654.3	5,121.0	5,396.2	5,934.6
Actual			4,328.0	5,078.0	4,557.0	4,860.0	5,045.3	5,929.5	12,508.9	12,901.9
Error = (ACT-FCST)				(810)	229	157	391	808	7,113	6,967
Percent Error = (Error/ACT)				-16.0%	5.0%	3.2%	7.7%	13.6%	56.9%	54.0%

3.17 *WHISTLER NORMALIZED DEMAND*

WH Demand, PJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 1										
Forecast	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3
Actual	0.2	0.2	0.2	0.2	0.2	0.3	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)	-21.5%	-1.4%	0.0%	14.6%	-4.1%	-5.3%	-4.6%	1.8%	2.4%	2.8%
Abs. Percent Error	21.5%	1.4%	0.0%	14.6%	4.1%	5.3%	4.6%	1.8%	2.4%	2.8%

WH Demand, PJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 2										
Forecast	0.2	0.1	0.1	0.1	0.2	0.2	0.2	0.1	0.1	0.1
Actual	0.1	0.1	0.2	0.2	0.1	0.2	0.1	0.1	0.1	0.2
Error = (ACT-FCST)	(0.0)	0.0	0.1	0.0	(0.1)	(0.0)	(0.0)	(0.0)	0.0	0.0
Percent Error = (Error/ACT)	-30.8%	0.0%	36.8%	10.0%	-75.0%	-12.1%	-9.6%	-1.6%	8.3%	27.9%

WH Demand, PJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 3										
Forecast	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.3
Actual	0.3	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	0.1	0.0	0.0	(0.0)	0.0	(0.0)	(0.1)	0.0
Percent Error = (Error/ACT)	15.4%	15.4%	17.9%	13.3%	3.5%	-3.8%	5.5%	-11.5%	-18.4%	11.2%

WH Demand, PJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate Schedule 23										
Forecast				0.03	0.04	0.09	0.08	0.02	0.02	0.01
Actual			0.03	0.06	0.06	0.06	0.05	0.02	0.01	0.01
Error = (ACT-FCST)				0.03	0.02	-0.03	-0.03	0.00	-0.01	0.01
Percent Error = (Error/ACT)				50.9%	32.2%	-44.7%	-73.7%	-7.7%	-72.6%	53.4%

WH Demand, PJ	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Commercial										
Forecast	0.4	0.4	0.4	0.4	0.6	0.6	0.6	Plot Area	0.5	0.4
Actual	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.4	0.5	0.5
Error = (ACT-FCST)	0.0	0.0	0.2	0.1	(0.1)	(0.1)	(0.0)	(0.0)	(0.1)	0.1
Percent Error = (Error/ACT)	0.0%	10.3%	30.0%	16.8%	-15.0%	-11.1%	-5.4%	-8.5%	-12.4%	17.2%
Abs. Percent Error	0.0%	10.3%	30.0%	16.8%	15.0%	11.1%	5.4%	8.5%	12.4%	17.2%

3.18 *FORT NELSON NET CUSTOMER*

Rate Schedule 1 - Residential	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forecast	1,973	1,971	1,984	1,997	1,965	1,966	1,941	1,918	1,864	1,853
Actual	1,959	1,962	1,963	1,945	1,927	1,919	1,898	1,880	1,860	1,836
Error = (ACT-FCST)	(14)	(9)	(21)	(52)	(38)	(47)	(43)	(38)	(4)	(17)
Percent Error = (Error/ACT)	-0.7%	-0.5%	-1.1%	-2.7%	-2.0%	-2.4%	-2.3%	-2.0%	-0.2%	-0.9%

Rate Schedule 2 - Small Commercial	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forecast Rate Schedule 2.1	454	457	468	479	478	480				
Forecast Rate Schedule 2							465	468	450	445
Actual Rate Schedule 2.1	446	446	474	478	476	473				
Actual Rate Schedule 2							460	452	445	445
Error = (ACT-FCST)	(8)	(11)	6	(1)	(2)	(7)	(5)	(16)	(5)	(0)
Percent Error = (Error/ACT)	-1.8%	-2.5%	1.3%	-0.2%	-0.4%	-1.5%	-1.1%	-3.5%	-1.1%	-0.1%

Rate Schedule 3- Small Commercial	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forecast Rate Schedule 2.2	28	32	33	34	7	7				
Forecast Rate Schedule 3							19	19	17	13
Actual Rate Schedule 2.2	31	31	7	7	6	4				
Actual Rate Schedule 3							14	17	17	16
Error = (ACT-FCST)	3	(1)	(26)	(27)	(1)	(3)	(5)	(2)	-	3
Percent Error = (Error/ACT)	9.7%	-3.2%	-371.4%	-385.7%	-16.7%	-75.0%	-35.7%	-11.8%	0.0%	16.7%

3.19 *FORT NELSON NET CUSTOMER ADDITIONS*

Rate Schedule 1 - Residential	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forecast	13	12	13	13	1	1	32	(23)	(16)	(13)
Actual	12	3	1	(18)	(18)	(8)	(21)	(18)	(20)	(24)
Error = (ACT-FCST)	(1)	(9)	(12)	(31)	(19)	(9)	(53)	5	(4)	(11)
Percent Error = (Error/ACT)	-8.3%	-300.0%	-1200.0%	172.2%	105.6%	112.5%	252.4%	-27.8%	20.0%	45.8%

Rate Schedule 2.1/2 - Small Commercial	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forecast Rate Schedule 2.1	11	11	11	11	2	2				
Forecast Rate Schedule 2							9	3	(1)	(3)
Actual Rate Schedule 2.1	3	-	28	4	(2)	(3)				
Actual Rate Schedule 2							3	(8)	(7)	-
Error = (ACT-FCST)	(8)	(11)	17	(7)	(4)	(5)	(6)	(11)	(6)	3
Percent Error = (Error/ACT)	-266.7%		60.7%	-175.0%	200.0%	166.7%	-200.0%	137.5%	85.7%	

Rate Schedule 2.2/3 - Large Commercial	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forecast Rate Schedule 2.2	-	1	1	1	-	-				
Forecast Rate Schedule 3							(1)	-		(1)
Actual Rate Schedule 2.2	-	-	(24)	-	(1)	(2)				
Actual Rate Schedule 3							(6)	3	-	(1)
Error = (ACT-FCST)	-	(1)	(25)	(1)	(1)	(2)	(5)	3	-	-
Percent Error = (Error/ACT)			104.2%		100.0%	100.0%	83.3%	100.0%		0.0%

3.20 *FORT NELSON USE PER CUSTOMER*

Rate Schedule 1 - Residential	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forecast	140	138	136	135	133	132	125	123	126	126
Actual	139	137	136	134	130	128	128	129	129	129
Error = (ACT-FCST)	(1)	(1)	(1)	(1)	(3)	(5)	3	6	3	4
Percent Error = (Error/ACT)	-1.0%	-0.8%	-0.5%	-0.4%	-2.6%	-3.7%	2.2%	4.6%	2.2%	2.7%

Rate Schedule 2.1/2 - Small Commercial	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forecast Rate Schedule 2.1	465	463	453	443	444	425				
Forecast Rate Schedule 2							349	323	370	337
Actual Rate Schedule 2.1	460	456	482	466	448	435				
Actual Rate Schedule 2							402	383	382	390
Error = (ACT-FCST)	(5)	(7)	29	23	4	9	53	60	12	53
Percent Error = (Error/ACT)	-1.1%	-1.6%	6.1%	4.9%	0.8%	2.2%	13.2%	15.7%	3.1%	13.5%

Rate Schedule 2.2/3 - Small Commercial	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forecast Rate Schedule 2.2	3,726	3,487	3,535	3,584	8,081	8,103				
Forecast Rate Schedule 3							3,164	2,802	5,307	6,378
Actual Rate Schedule 2.2	3,555	3,425	6,616	7,869	8,086	9,169				
Actual Rate Schedule 3							4,910	4,643	5,328	7,049
Error = (ACT-FCST)	(171)	(62)	3,081	4,285	4	1,066	1,746	1,842	21	671
Percent Error = (Error/ACT)	-4.8%	-1.8%	46.6%	54.5%	0.1%	11.6%	35.6%	39.7%	0.4%	9.5%

3.21 *FORT NELSON NORMALIZED DEMAND*

Rate Schedule 1 - Residential	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forecast	274,309	270,571	268,635	267,546	261,825	259,874	244,160	236,900	235,314	233,889
Actual	270,062	267,589	265,419	262,275	251,350	245,434	244,434	243,175	239,912	238,860
Error = (ACT-FCST)	(4,247)	(2,982)	(3,216)	(5,271)	(10,475)	(14,440)	274	6,275	4,598	4,971
Percent Error = (Error/ACT)	-1.6%	-1.1%	-1.2%	-2.0%	-4.2%	-5.9%	0.1%	2.6%	1.9%	2.1%

Rate Schedule 2.1/2- Small Commercial	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forecast Rate Schedule 2.1	207,927	208,999	208,315	208,642	211,897	203,742				
Forecast Rate Schedule 2							160,160	150,377	166,828	150,115
Actual Rate Schedule 2.1	204,488	203,517	222,697	221,733	214,211	205,955				
Actual Rate Schedule 2							185,202	173,841	171,131	173,378
Error = (ACT-FCST)	(3,440)	(5,482)	14,382	13,091	2,314	2,213	25,042	23,464	4,302	23,263
Percent Error = (Error/ACT)	-1.7%	-2.7%	6.5%	5.9%	1.1%	1.1%	13.5%	13.5%	2.5%	13.4%

Rate Schedule 2.2/3 - Small Commercial	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forecast Rate Schedule 2.2	104,320	109,660	115,656	120,843	56,570	56,722				
Forecast Rate Schedule 3							61,061	53,232	90,216	87,068
Actual Rate Schedule 2.2	109,821	106,168	64,924	55,081	48,357	41,919				
Actual Rate Schedule 3							70,419	71,320	90,569	115,562
Error = (ACT-FCST)	5,502	(3,492)	(50,732)	(65,762)	(8,213)	(14,804)	9,358	18,088	353	28,494
Percent Error = (Error/ACT)	5.0%	-3.3%	-78.1%	-119.4%	-17.0%	-35.3%	13.3%	25.4%	0.4%	24.7%

Commercial	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forecast	312,247	318,658	323,972	329,485	268,467	260,464				
Forecast							221,221	203,609	257,044	237,183
Actual	314,309	309,685	287,621	276,814	262,568	247,874				
Actual							255,621	245,161	261,699	288,940
Error = (ACT-FCST)	2,062	(8,973)	(36,351)	(52,672)	(5,899)	(12,591)	34,400	41,552	4,655	51,757
Percent Error = (Error/ACT)	0.7%	-2.9%	-12.6%	-19.0%	-2.2%	-5.1%	13.5%	16.9%	1.8%	17.9%

Rate Schedule 25* - General Firm Transportation	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forecast	54,995	67,084	55,832	55,832	39,685	39,684	41,500	41,500		
Actual	60,756	67,598	49,790	41,110	41,847	43,197	37,105	29,541		
Error = (ACT-FCST)	5,761	515	(6,042)	(14,722)	2,162	3,513	(4,395)	(11,959)		
Percent Error = (Error/ACT)	9.5%	0.8%	-12.1%	-35.8%	5.2%	8.1%	-11.8%	-40.5%		

Note: Single remaining customer switched to RS 3 in 2020

Total Demand	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Forecast	641,551	656,313	648,439	652,863	569,978	560,023	506,881	482,009	492,358	471,072
Actual	645,127	644,872	602,830	580,199	555,765	536,505	537,160	517,877	501,611	527,801
Error = (ACT-FCST)	3,576	(11,441)	(45,609)	(72,664)	(14,212)	(23,517)	30,279	35,868	9,253	56,729
Percent Error = (Error/ACT)	0.6%	-1.8%	-7.6%	-12.5%	-2.6%	-4.4%	5.6%	6.9%	1.8%	10.7%

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 four 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, Whistler and Fort Nelson 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 2023 and the Seed Year forecast is based on the latest actual years, including 2022. As such, the 2023 Seed Year forecast in this Application will differ from the 2023 Forecast presented in the Annual Review for 2023 Delivery Rates, for which 2022 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 Conference Board of Canada (CBOC).[1] The housing starts data was as follows:

Table A3-3: BC Housing Starts Data

BRITISH COLUMBIA	2021	2022	2023	2024
Housing Starts, Singles, British Columbia (Thousands ('000s))	11,025	9,109	7,733	8,483
Forecast Percent Change		**-17.4%**	**-15.1%**	**9.7%**
Housing Starts, Multiples, British Columbia (Thousands ('000s))	36,582	34,752	30,534	34,972
Forecast Percent Change		**-5.0%**	**-12.1%**	**14.5%**
Total	47,607	43,861	38,267	43,455

From the above housing starts forecast, the 2024F SFD growth rate is calculated as follows:

$$2024F\ SFD\ Growth\ Rate = \left(\frac{8{,}483}{7{,}733}\right) - 1 = 9.7\%$$

The remainder of the growth rates are calculated the same way and the results are shown in the following table:

[1] The Growth to Slow as Province Climbs the Population Pyramid: British Columbia's Outlook to 2045. Ottawa: The Conference Board of Canada, 2023. Data released on December 22, 2012.

Table A3-4: Growth Rates

Housing Type	2023S	2024F
SFD Forecast Percentage Change	-15.10%	9.70%
MFD Forecast Percentage Change	-12.14%	14.53%

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 2022 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 2023 and 2024 are applied to the SFD and MFD proportions for 2023 in columns F and G and for 2024 in columns I and J.

Table A3-5: FEI Proportions of Actual Account Additions by SFD and MFD

				Internal Split		Actual Adds 2022			2023S			2024F		
Region	2020A	2021A	2022A	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	567,372	569,546	573,352	36.6%	63.4%	3,806	1,394	2,412	1,184	2,119	3,303	1,299	2,427	3,726
Inland	235,063	237,600	240,693	77.3%	22.7%	3,093	2,391	702	2,030	617	2,647	2,227	707	2,934
Columbia	22,077	22,316	22,595	72.2%	27.8%	279	201	78	171	68	239	188	78	266
Revelstoke	1,630	1,716	1,763	100.0%	0.0%	47	47	-	40	-	40	44	-	44
Whistler	2,977	3,045	3,070	75.8%	24.2%	25	19	6	16	5	21	18	6	24
Vancouver Island	124,627	129,764	132,861	79.0%	21.0%	3,097	2,447	650	2,077	571	2,648	2,278	654	2,932
Fort Nelson	1,880	1,860	1,836	75.0%	25.0%	(24)	(18)	(6)	(15)	(5)	- 21	(17)	(6)	(23)
Total FEU	**955,626**	**965,847**	**976,170**			**10,323**	**6,482**	**3,841**	**5,503**	**3,375**	**8,877**	**6,037**	**3,866**	**9,903**

For example, the Lower Mainland 2024F SFD value of 1,299 (column I) is derived as follows:

- Lower Mainland 2022 Internal Split – SFD percentage = 36.6% (column A);
- Lower Mainland 2022 Actual additions = 3,806 (column C)

$$LML\ 2022Actual\ SFD = 36.6\% \ \times 3{,}806 = 1{,}394\ (column\ D)$$

$$LML\ 2023\ Seed\ SFD = (1 - 15.1\%\%) \times 1{,}394 = 1{,}184\ (column\ F)$$

$$LML\ 2024\ Forecast\ SFD = (1 + 9.7\%) \times 1{,}184 = 1{,}299\ (column\ I)$$

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 2020-2022
		A	B	C
1	2019	54,211		
2	2020	54,619	408	
3	2021	54,671	52	
4	2022	54,702	31	164
5	2023S	54,866		164
6	2024F	55,030		164

Customer additions are calculated in column B. The three-year average of additions is shown in C4 and is 164. 164 additions are forecast in each of 2023 and 2024.

$$2023S\ Customers = 2022\ Customers\ + 3\ Yr\ Avg\ Additions$$

Using the data above:

$$2023S = 54{,}866 = 54{,}702 + 164$$

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 2022 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	2019	5,347	505	**5,852**				
2	2020	5,075	430	**5,505**	(347)			
3	2021	5,240	391	**5,631**	126			
4	2022	5,415	320	**5,735**	104	(39)	(37)	(2)
5	2023S	5,378	318				(37)	(2)
6	2024F	5,341	316				(37)	(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 (39) and shown in column E, row 4.

The 2022 proportion is calculated from columns A/C on row 4.

For example, the RS 3 proportion is:

$$RS\ 3\ Proportion = \frac{5{,}415}{5{,}735} = 0.94$$

The proportion of the aggregate customer additions (37) is assigned to RS 3 is then:

$$RS\ 3\ Customer\ Additions = 0.93\ \times (-39) = -37$$

A similar calculation is performed for RS 23 to arrive at (2) customer additions.

On row 5 the 2023S customer additions for RS 3 are shown in column A and calculated as:

$$2023S =\ 5{,}378 = 5{,}415 - 37$$

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 10 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 10 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	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022
Rate 1	96.0	94.7	94.2	98.2	96.4	95.8	92.1	97.3	96.3	93.6

In Excel, the "forecast.ets()" function is used to calculate the 2023 and 2024 forecasts.

LML	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate 1	96.0	94.7	94.2	98.2	96.4	95.8	92.1	97.3	96.3	93.6	=FORECAST.ETS(M8,C9:L9,C8:L8,0,0,1)	

FORECAST.ETS(target_date, values, timeline, [seasonality], [data_completion], [aggregation])

The resulting forecasts for 2023 and 2024 are shown:

LML	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023S	2024F
Rate 1	96.0	94.7	94.2	98.2	96.4	95.8	92.1	97.3	96.3	93.6	95.2	95.1

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.

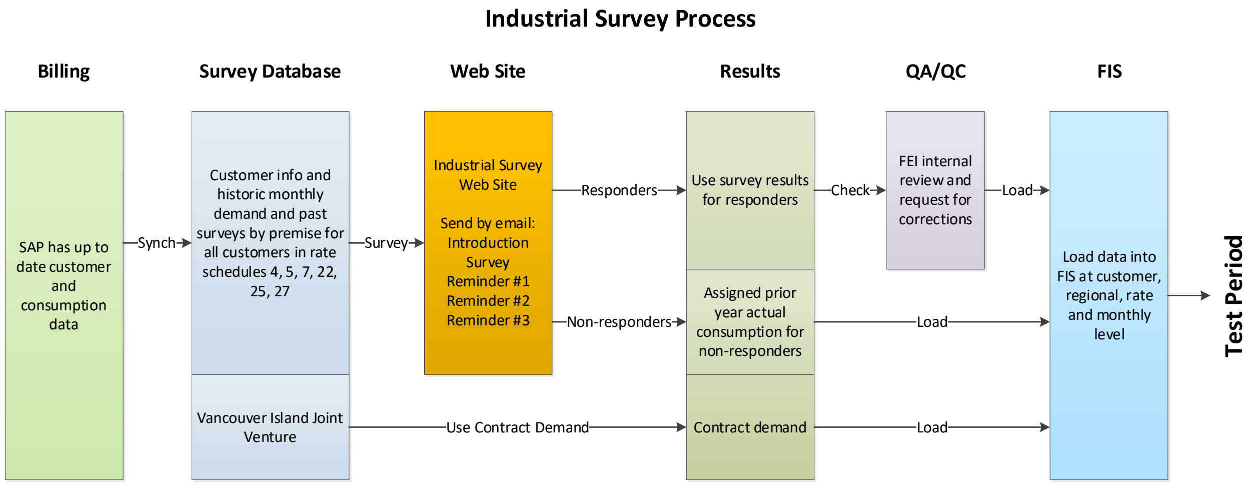
6. RESIDENTIAL AND COMMERCIAL DEMAND FORECAST

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

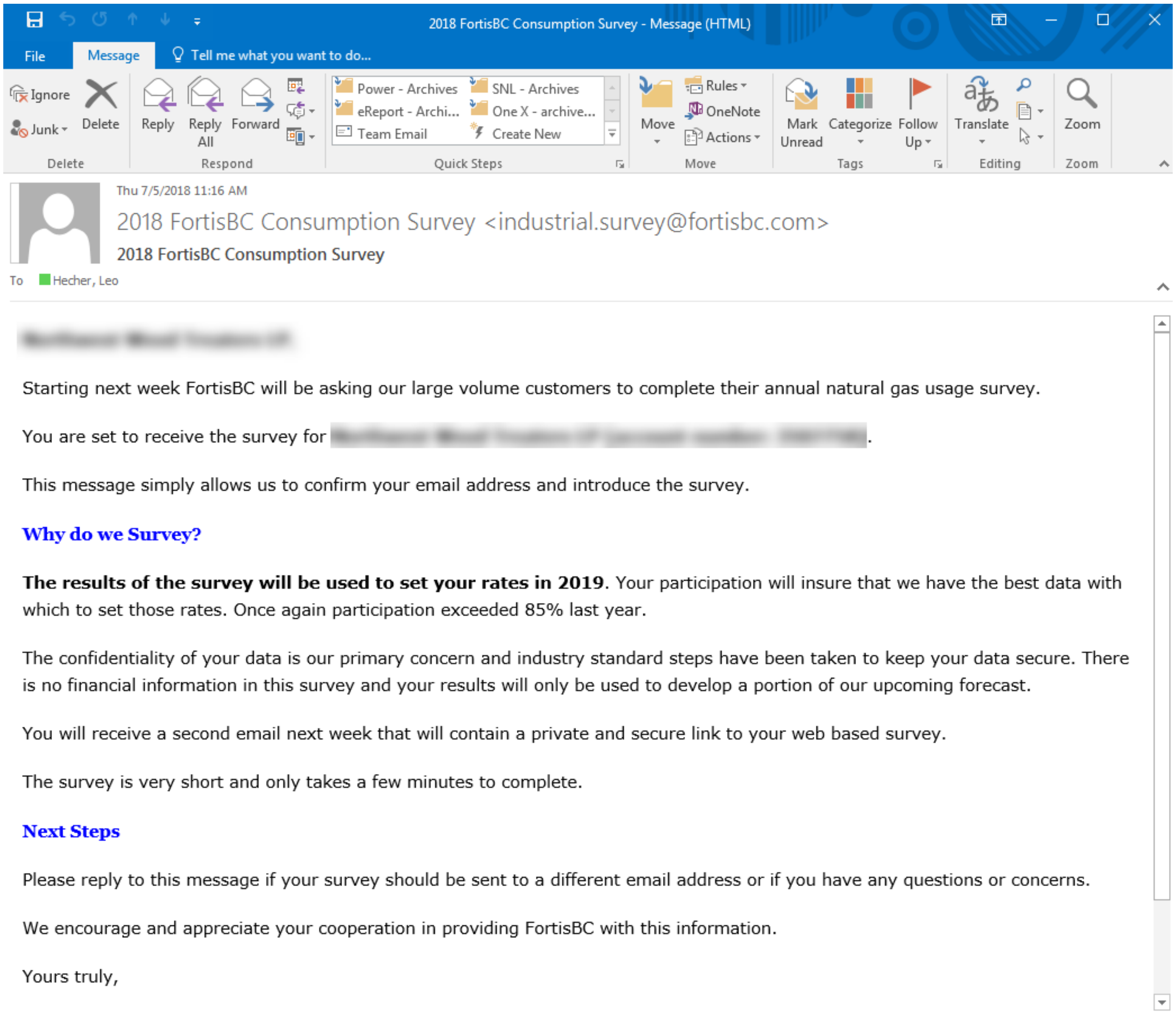
Prior to the start of the survey FEI creates a new survey using a web-based application. For the annual survey all industrial classes are selected. Commercial and residential customers are not surveyed.

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.

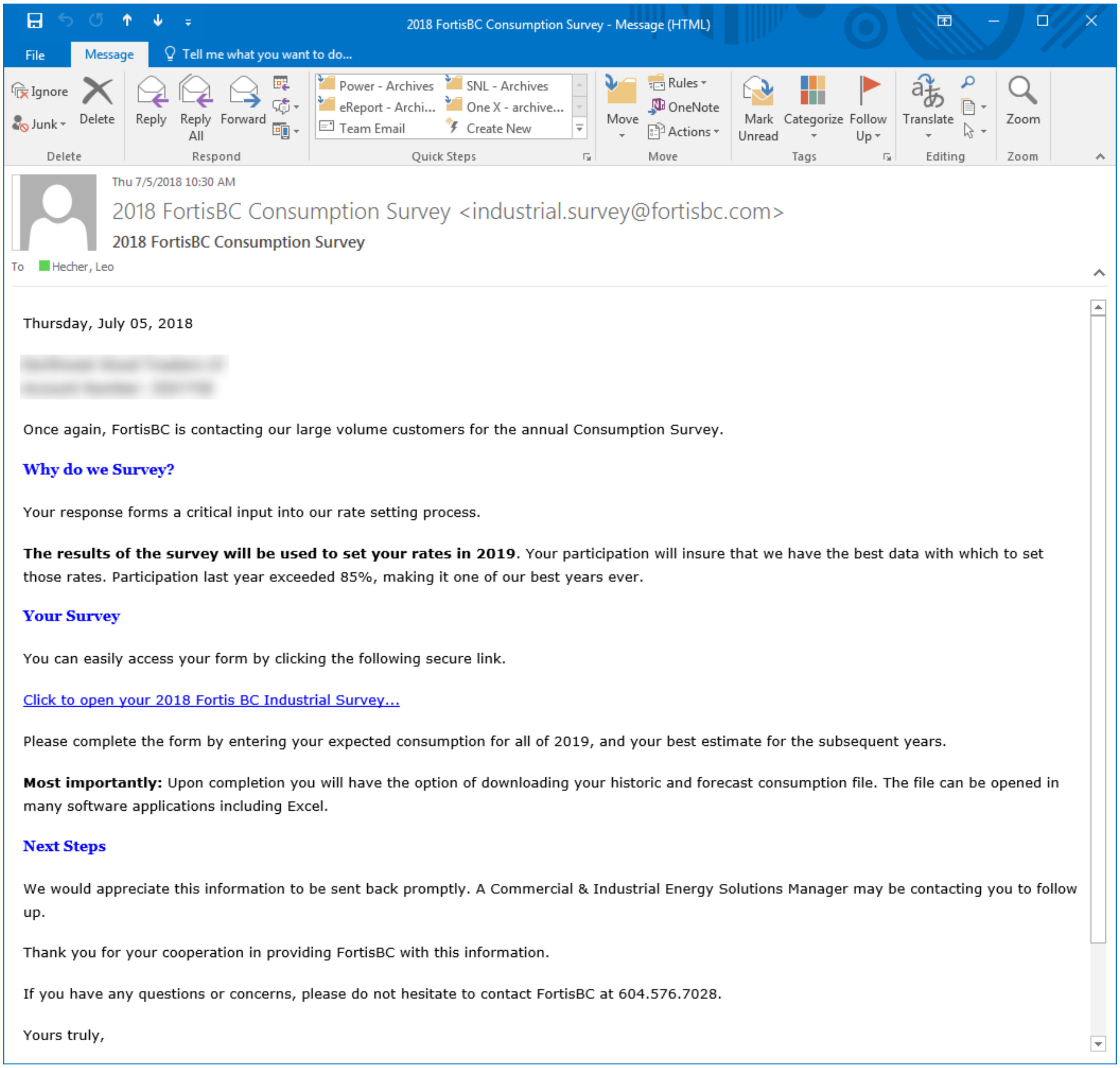
Yours truly,

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.

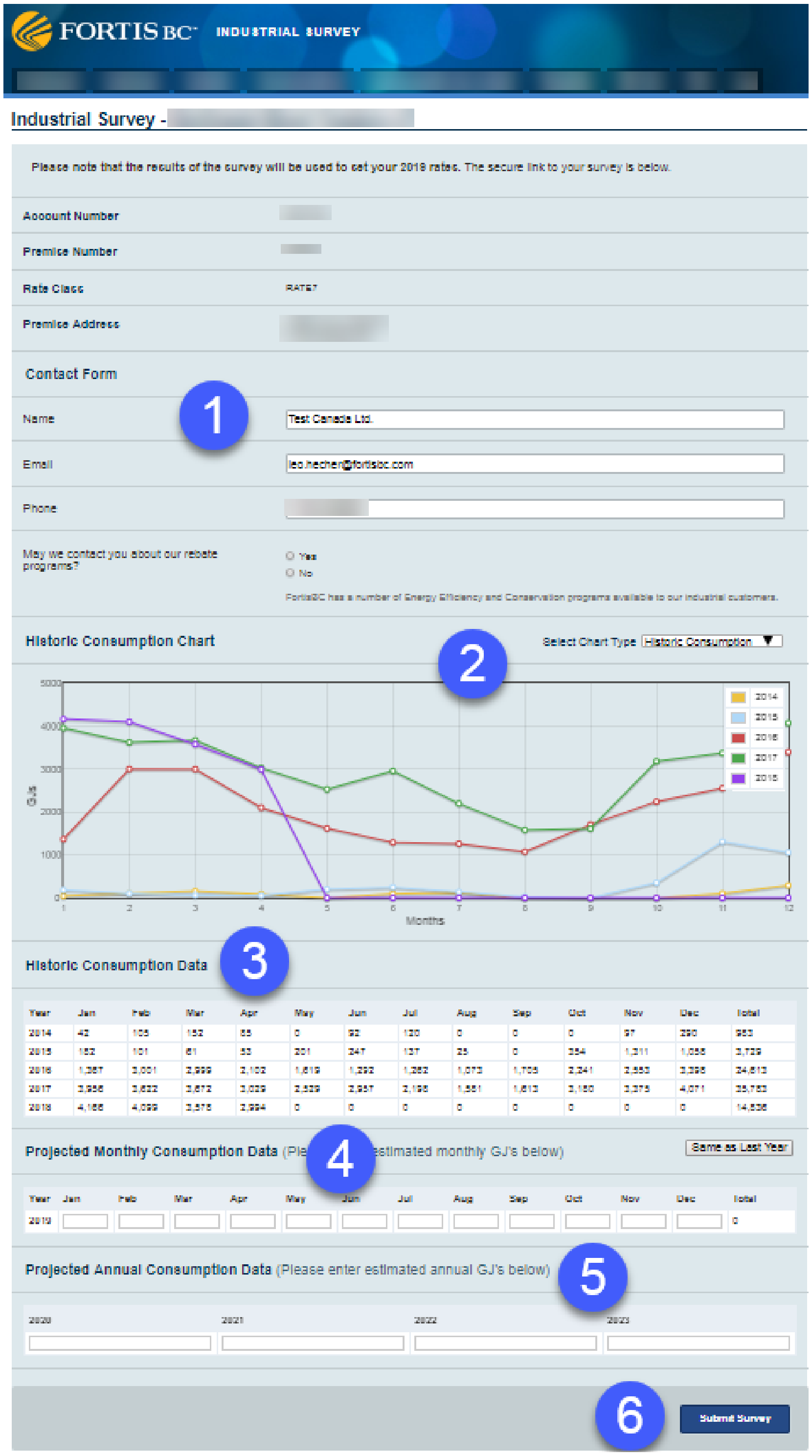
If you have any questions or concerns, please do not hesitate to contact FortisBC at 604.576.7028.

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


FORTIS BC INDUSTRIAL SURVEY

Industrial Survey -

Please note that the results of the survey will be used to set your 2019 rates. The secure link to your survey is below.

Account Number	
Premise Number	
Rate Class	RATE7
Premise Address	

Contact Form

Name	Test Canada Ltd.
Email	leo.hecher@fortisbc.com
Phone	
May we contact you about our rebate programs?	Yes / No

FortisBC has a number of Energy Efficiency and Conservation programs available to our industrial customers.

Historic Consumption Chart

Select Chart Type: Historic Consumption

Historic Consumption Data

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2014	42	105	152	85	0	92	120	0	0	0	97	290	983
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	3,150	3,375	4,071	35,783
2018	4,168	4,099	3,578	2,994	0	0	0	0	0	0	0	0	14,838

Projected Monthly Consumption Data (Ple... estimated monthly GJ's below)

Same as Last Year

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
2019													0

Projected Annual Consumption Data (Please enter estimated annual GJ's below)

2020	2021	2022	2023

Submit Survey

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 five 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.

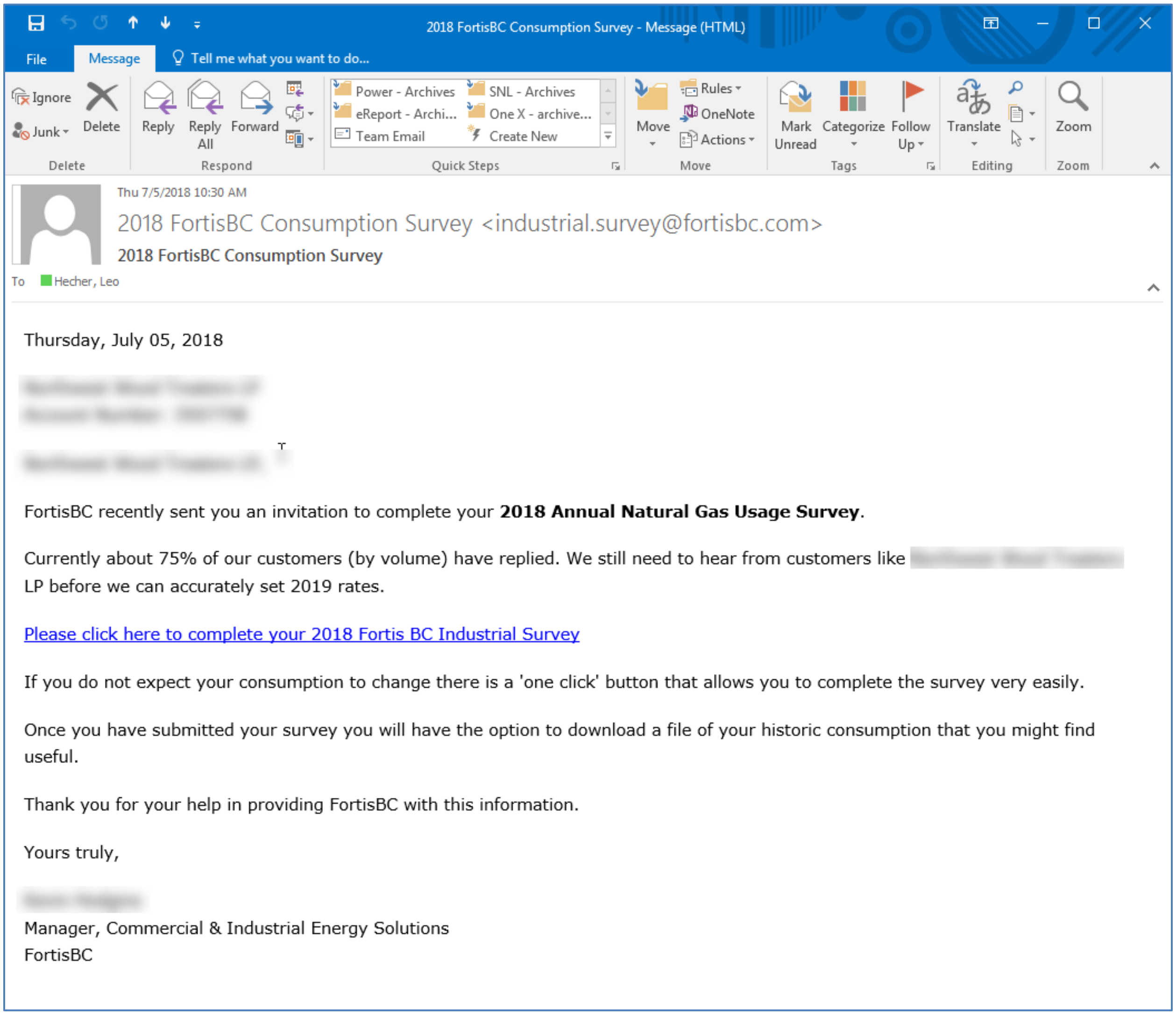
5) Annual forecasts are requested for the remaining four years of the survey.

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


2018 FortisBC Consumption Survey - Message (HTML)

Thu 7/5/2018 10:30 AM

2018 FortisBC Consumption Survey <industrial.survey@fortisbc.com>

2018 FortisBC Consumption Survey

To Hecher, Leo

Thursday, July 05, 2018

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 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,

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 2024 CMAE BUDGET REVIEW

FEI 2024 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 2019-2022 Actual, 2023 Approved, 2023 Projected, and 2024 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, 2024:

- approval of the 2024 forecast CMAE budget of $6.050 million, as set out in Schedule 1; and
- approval of the allocation of the 2024 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 2024 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 approximately $700 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 2023 Second Quarter Gas Cost Report dated June 7, 2023.

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 2023 Approved, 2023 Projected and 2024 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 2023	Projected 2023	Forecast 2024
Labour	$ 3.114	$ 3.018	$ 3.180
Non-Labour	1.967	2.063	2.152
Shared Services	0.714	0.714	0.718
Total CMAE	$ 5.795	$ 5.795	$ 6.050

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. 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 the costs 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. This allocation 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 2023 CMAE costs and variances to the approved budget will be submitted, in the format prescribed by the BCUC, as part of the FEI 2023 CCRA and MCRA Status Report due to be filed by April 30, 2024.

1.4 *PROJECTED 2023 CMAE COSTS*

While Table B-1 offers a high level summary of the CMAE costs for 2023 and 2024, 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 2023 Approved and 2023 Projected CMAE amounts, including variances and explanations. As well, Schedule 1 provides a summary of the Actual 2019-2022 CMAE costs, and the 2024 Forecast CMAE budget.

The year-end costs shown in the 2023 Projected column in Schedule 1 are based on the actual costs incurred to May 31, 2023 and the projected costs for the remainder of the year. The Company projects that overall the 2023 CMAE costs will total $5.795 million, consistent with the 2023 Approved amount. Schedule 1 provides a breakdown of the variances, including explanations, between 2023 Approved and 2023 Projected CMAE amounts at the individual cost component level.

The year-end 2023 Projected CMAE costs, including all variances at the cost component level from the 2023 Approved CMAE budget, reflect the prudent 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 2024 CMAE COSTS*

As reflected in Schedule 1 in the 2024 Budget Request column, the Company is seeking approval of the 2024 CMAE budget in the amount of $6.050 million, which is $0.255 million higher than 2023 Approved. The increase from 2023 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 2024 CMAE budget by cost component are set out below.

1.5.1 Information Systems

The 2024 Forecast Information Systems (IS) budget of $0.420 million is $0.012 million higher than the 2023 Approved. The budget includes the forecast costs of the annual software maintenance and support requirements for the Horizon Energy Trading and Risk Management (ETRM) system. The Horizon ETRM system implemented for Gas Supply in 2022 was also being used by Aitken Creek Gas Storage ULC (ACGS). Enbridge ACGS Acquisition Inc. has applied to the BCUC to acquire control of the shares of ACGS. FEI has assumed for the purposes of the 2024 CMAE Forecast that the acquisition will be approved, and has therefore increased the allocation of the forecast annual Horizon ETRM software maintenance costs to FEI. This increase is substantially offset by lower support requirements being forecast for Gas Supply as post-implementation stabilization occurs.

1.5.2 Consulting and Legal

The 2024 Forecast Consulting and Legal budget of $0.700 million is based on the forecast of upstream regulatory work anticipated to occur in 2024; 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 gas supply portfolio costs.

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 2024 Forecast for Subscriptions & Memberships of $0.858 million has increased substantially compared to the 2023 Approved. The budget is based on the forecast costs for the required services. The 2024 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. The inflationary increases on the subscriptions denominated in US dollars are partially offset by the US to Canadian currency exchange rate assumption improving from that used in the 2023 Approved amount. The 2024 Forecast also reflects, due to the anticipated sale of ACGS, the loss of cost savings related to sharing the costs of some subscriptions with ACGS. Due to the nature of these subscriptions, there is generally no reduction in the cost of the subscription associated with a decrease in the number of individual users.

1.5.4 Sundries

The 2024 Forecast for Sundries of $0.039 million has decreased slightly from the 2023 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 2024 Forecast for Training & Travel of $0.135 million has increased from the 2023 Approved. The 2024 Forecast is based on the forecast activity, including inflation.

1.5.6 MoveUP Labour

The 2024 Forecast for MoveUP Labour of $0.654 million has remained generally unchanged from the 2023 Approved amount, with lower forecast benefits loadings substantially offsetting forecast salary inflation. The 2024 Forecast is based on the forecast of labour, including cross-charging, inflation, and benefits loadings.

1.5.7 M&E Labour

The 2024 Forecast for M&E Labour of $2.526 million has increased slightly compared to the 2023 Approved amount primarily due to forecast salary inflation. The 2024 Forecast is based on the forecast of labour, including cross-charging, inflation, and benefits loadings.

1.5.8 Shared Services

The 2024 Forecast for Shared Services of $0.718 million has increased slightly compared to the 2023 Approved. The 2024 Forecast is based on a minor reduction in the forecast service level requirements substantially offsetting the inflationary increases related to 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 2024 and forecast its CMAE costs accordingly. The level of the 2024 Forecast CMAE is required to ensure that the Company is able to prudently manage commodity and midstream gas supply costs. Further, 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	2019	2020	2021	2022	2023					2024
2	($000, unless specified otherwise)	Actual	Actual	Actual	Actual	Approved	Projected	Variance	Variance %	Variance Explanation	Budget Request
3	IS (Information Systems)	342	482	278	393	408	408	-	0%		420
4	Consulting & Legal	523	424	758	673	700	700	-	0%		700
5	Subscriptions & Memberships	395	595	565	668	693	789	96	14%	Subscriptions and Memberships costs higher due to subscription fee increases.	858
6	Sundries	110	119	22	15	41	41	-	0%		39
7	Training & Travel	125	34	11	98	125	125	-	0%		135
8	MoveUP Salaries before Benefits & Incentives	445	493	381	386	467	447	(20)	-4%	MoveUP Salaries lower due to temporarily unfilled position. Benefits lower due to lower salary costs and lower than budgeted loadings.	484
9	MoveUP Benefits [3]	166	180	145	152	185	142	(43)	-23%		170
10	MoveUP Incentives [3] [4]	-	-	-	-						
11	M&E Salaries before Benefits & Incentives	1,268	1,350	1,517	1,523	1,628	1,622	(6)	0%	M&E Salaries lower due to temporarily unfilled position; partially offset by lower cross-charging out. Benefits lower due to lower salary costs and lower than budgeted loadings.	1,688
12	M&E Benefits [3]	469	478	491	505	834	807	(27)	-3%		838
13	M&E Incentives [3]	289	234	200	227						
14	Energy Management Service Revenue	-	-	-		-	-	-			-
15	Shared Services	686	686	686	686	714	714	-	0%		718
16	**Total**	4,818	5,075	5,054	5,326	5,795	5,795	-	0%		6,050

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Line #	CMAE FTE	2019	2020	2021	2022	2023					2024
19	(Number)	Actual	Actual	Actual	Actual	Approved	Projected	Variance	Variance %	Variance Explanation	Budget Request
20	MoveUP	4.9	4.9	4.0	4.0	5.0	4.8	(0.2)	-3%	Due to temporarily unfilled MoveUP position during the year.	5.0
21	M&E	14.4	13.7	14.4	14.5	15.0	14.8	(0.3)	-2%	Due to temporarily unfilled M&E position during the year.	15.0
22	**Total**	19.3	18.6	18.4	18.5	20.0	19.6	(0.4)	-2%		20.0

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Line #	Comparative Labour Loading	2019	2020	2021	2022	2023					2024
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]	38%	40%	41%	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]	38%	40%	41%	41%	40%	32%				35%
29	Company-wide M&E Benefits as percentage of salaries [1]	32%	33%	31%	33%						
30	Company-wide M&E Incentives as percentage of salaries [1] [4]	17%	15%	16%	15%						
31	Subtotal Company-wide M&E Benefits & Incentives as percentage of salaries [1] [3]	49%	49%	46%	48%	49%	47%				48%
32	CMAE MoveUP Salaries before cross-charging [2]	$ 437	$ 445	$ 358	$ 370	$ 467	$ 447				$ 484
33	CMAE MoveUP Benefits as percentage of salaries before cross-charging [2]	38%	41%	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]	38%	41%	41%	41%	40%	32%				35%
36	CMAE M&E Salaries before cross-charging [2]	$ 1,513	$ 1,462	$ 1,497	$ 1,518	$ 1,713	$ 1,697				$ 1,762
37	CMAE M&E Benefits as percentage of salaries before cross-charging [2]	31%	33%	33%	33%						
38	CMAE M&E Incentives as percentage of salaries before cross-charging [2] [4]	19%	16%	13%	18%						
39	Subtotal CMAE M&E Benefits & Incentives as percentage of salaries [2] [3]	50%	49%	46%	51%	49%	47%				48%

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

REGIONAL GAS SUPPLY DIVERSITY PROJECT
QUARTERLY PROGRESS REPORT FOR THE PERIOD
APRIL 1, 2023 TO JUNE 30, 2023

FORTISBC ENERGY INC.

Regional Gas Supply Diversity Project

Quarterly Progress Report for the Period
April 1, 2023 to June 30, 2023

Submitted to the
British Columbia Utilities Commission

July 28, 2023

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List of Tables and Figures

1. PROJECT BACKGROUND

1.1 *PROJECT BACKGROUND*

On June 1, 2022, pursuant to sections 59 to 61 of the *Utilities Commission Act* (UCA), FortisBC Energy Inc. (FEI) filed an application (RGSD Application) with the British Columbia Utilities Commission (BCUC), for approval of a new non-rate base deferral account called the Regional Gas Supply Diversity (RGSD) Development Account, to capture actual development costs incurred for a potential RGSD Project (Project). In the Application, FEI proposed to file quarterly progress reports to the BCUC on work completed, anticipated work, and material developments, starting with the quarter ending at least three months after the BCUC's decision on the Application.

On September 14, 2022, the BCUC issued Order G-253-22 granting approval to establish the RGSD Development Account, a non-rate base deferral account attracting FEI's WACC return, to capture actual development costs incurred with respect to the potential RGSD Project, with disposition of the deferral account balance to be determined in a future proceeding.

Order G-253-22 directed FEI to provide Quarterly Progress Reports to the BCUC on work completed, anticipated work, and material developments on the potential RGSD Project, starting with the fourth quarter ending December 31, 2022, by no later than 30 days after the date of the quarter end. Order G-253-22 further directed that in lieu of the July 2023 quarterly report, FEI was to provide the update in the Annual Review for 2024 Delivery Rates process, including an update of costs incurred to date and a proposal for the method and timing of the recovery of those incurred costs.

This is the third Quarterly Progress Report for the Project (Report) which covers the period April 1, 2023 to June 30, 2023.

2. PROJECT DEVELOPMENT UPDATE, WORK COMPLETED AND COSTS INCURRED TO DATE

2.1 RGSD PROJECT DEVELOPMENT UPDATE

As described in the RGSD Application, preliminary engineering assessment and meaningful and comprehensive engagement and collaboration with stakeholders and Indigenous Nations prior to beginning Project approval processes is critical to ensure the RGSD Project, at the point of readiness for submission for approvals, has reasonable support and confidence on the Project concept and design. Engineering assessment work and supporting documentation on the RGSD Project has progressed in a measured and prudent manner. FEI's project phase gate processes require that the RGSD Project go through a complex and detailed screening analysis to evaluate all RGSD sub-variants (i.e., evaluating other delivery points,[1] such as tie-ins to T-South at Kingsvale or Hope as described in Section 4.1.2 of the RGSD Application) prior to further advancing the pre-FEED work. As part of its screening analysis, FEI will also be exploring an integrated regional pipeline infrastructure solution, as these sub-variations of the RGSD Project might require capacity upgrades from Enbridge on T-South between Kingsvale or Hope and Huntingdon in order to deliver the incremental volume sourced from SCP.

Federal and provincial policies continue to progressively decarbonize emissions from all sectors, including the gas system. FEI anticipates that the RGSD Project will need to continue to identify, investigate, design and support appropriate infrastructure solutions that will help to meet clean energy targets and maintain the reliability of gas flows through BC, thereby improving marketplace liquidity, security and overall supply competitiveness.

These project development activities and regional market developments require time to complete and are in the best interests of FEI and its customers as they will allow FEI to utilize its recent discussions with stakeholders to avoid or adequately mitigate issues that may be related to pipeline capacity, design, route selection and construction activities.

The following sections provide an update on the project development work completed to date, including the work completed during this reporting period, anticipated work for the next reporting period and an update to the costs incurred to date.

2.2 PROJECT DEVELOPMENT WORK COMPLETED IN THIS PERIOD

In Q2 of 2023 the Project development work focussed on initiating screening analysis and activities as discussed below:

[1] As currently envisioned, the RGSD Project involves an extension of the SCP from its current endpoint at Oliver to a new endpoint at Huntingdon.

- FEI engaged five external consultants to initiate specialist technical work on all sub-variants of the RGSD Project;
- FEI completed two risk workshops to identify risks and opportunities to inform a project risk register; and
- FEI continued to provide information on the Project to First Nations through meetings and other communications and identified next steps for further engagement.

2.3 *SUMMARY OF PROJECT DEVELOPMENT WORK COMPLETED TO DATE*

The project development work completed to date spans a period from November 2021 to June 2023 and is divided into two phase gates: a Preliminary and Conceptual Phase (Pre-Phase 1); and a Screening and Pre-Feed Phase (Phase 1). Project development activities completed to date under each phase are summarized in the sections below.

2.3.1 Pre-Phase 1 Work Completed

As discussed in Section 6.2.1.1 of the RGSD Application, the RGSD Project is an evolution of previous work related to assessing an extension of the SCP. FEI had already completed some assessment work over the past few years, both internally and with the assistance of engineering, geotechnical and environmental consultants. FEI has been able to use some of the historical information to assist in completing the following activities for the RGSD Project related to the SCP compressor upgrades and a new pipeline segment between Oliver and Huntington:

- Class 5 capital cost estimate for the pipeline extension and compressor station additions;
- A desktop geotechnical hazard assessment;
- Environmental constraints analysis;
- Land and right of way requirement assessment to inform cost estimates; and
- Ongoing analysis of FEI's system to understand implications of hydrogen transportation.

2.3.2 Phase 1 Work Completed to Date

The Project development activities completed by FEI to date during Phase 1 are as follows:

- Continued to build out the Project team and appointed a team focussed on the development of the Project.
- Advanced the vetting of qualified pre-Feed consultants by completing a request of expressions of interest procurement process.
- Advanced consultancy scopes to support screening activities and analysis.

- Developed a plan and schedule for an assessment to include all the delivery point sub-variants, namely T-South connections at Kingsvale and Hope.
- Developed a concept for a path to determine and mitigate carbon footprint and schedule for all of the Project's sub-variants.
- Continued to engage with First Nations on the Project concept. Through meetings and other communications, provided information on the Project, discussed challenges and opportunities, and identified next steps for further engagement. The summary of Indigenous engagement completed to date is discussed further in Section 2.3.2.1 below.

2.3.2.1 Indigenous Engagement Completed to Date

Indigenous engagement and participation is a critical component of the RGSD Project. As a result, FEI began engagement with Indigenous communities early on by sharing the project concept. The purpose of this was to gather feedback from First Nations and incorporate that into the conceptual project design. FEI's approach to collaboration was informed by its Statement of Indigenous Principles, commitment to reconciliation, and understanding of the need for free, prior, and informed consent.

FEI gathered information from the British Columbia Consultative Areas Database to identify which Indigenous communities to engage. In addition, FEI had consultants review the approach. After conducting an analysis, FEI decided to engage with the Nations most proximal to the proposed project. Since early 2021, FEI has reached out to 30 First Nations and 6 tribal councils to discuss the Project. FEI was successful in connecting with all tribal councils and 14 of the 30 First Nations. FEI will continue to seek to connect with the remaining 16 First Nations.

FEI has held 56 meetings with Chief and Council and staff, conducted two aerial tours with two Nations to review the route and gather feedback, and presented the project concept at an open house to community members of another Nation. These meetings began as project introductions and progressed into routing and compressor station location reviews, knowledge sharing and partnership discussions. Some of the meetings evolved into working groups with staff members and another Nation held regular meetings with FEI for project updates.

FEI understands First Nations require capacity funding agreements (CFA) to engage; therefore, based on requests, a total of 13 CFAs were extended to First Nations of which 6 CFAs have been confirmed.

In addition to the CFAs, FEI responded to community requests made by Nations and provided funding for Indigenous community initiatives. FEI staff have attended over 15 local Indigenous community events to learn and build stronger relationships.

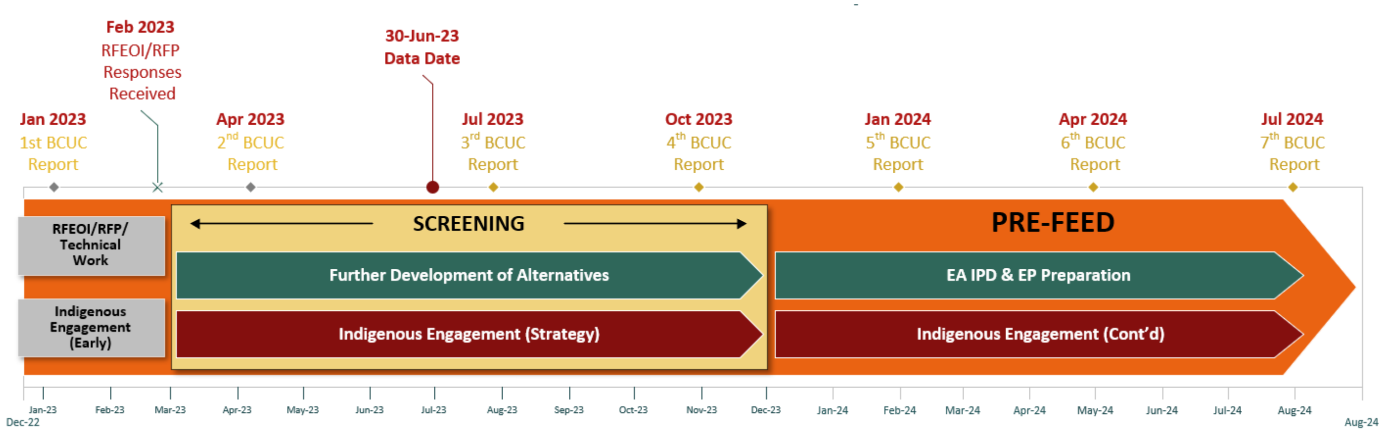
2.3.2.2 Project Schedule Summary

Table 2-1 below provides a summary of development activities that have been completed to the end of Q2 2023. FEI has initiated a detailed screening analysis to advance the Project to the point where FEI can decide which sub-variants of the RGSD Project need to be further evaluated for Pre-Feed. FEI has updated the preliminary Project Pre-Feed activities timeline (Figure 2-1 below) and plans to update the overall Project schedule in subsequent reports after the completion of screening analysis.

Table 2-1: Status of Project Development Activities to Date

Activities	Status
Advance Indigenous Nations engagement and stakeholder consultation efforts	In Progress
Initiate screening analysis for all three RGSD sub-variations	In Progress
Advance commercial discussions with prospective shippers for potential capacity on RGSD Project pipeline	In Progress
Develop Project Risk Register	In Progress

Figure 2-1: Updated Preliminary RGSD Project's Pre-Feed Activities Timeline



2.3.3 Project Development Costs Incurred to Date

FEI has used a measured, prudent and diligent approach in progressing the initial phases of the Project development work completed to date to evaluate the RGSD Project and its sub-variants. As of the end of Q2 2023, FEI has spent a total of $2.93 million including AFUDC and taxes. This compares to the $23.7 million that FEI forecast at the time of the RGSD Deferral Account Application for work up to Q3 of 2023. Table 2-2 summarizes the development costs on an annual and a project phase gate basis.

Table 2-2: Project Development Cost Summary

<table>
<tr><th colspan="12">Annual Cost Summary</th></tr>
<tr><th colspan="3">2021</th><th colspan="3">2022</th><th colspan="3">2023</th><th colspan="3">Total Cost</th></tr>
<tr><td colspan="3">$0.47 million</td><td colspan="3">$1.43 million</td><td colspan="3">$1.03 million</td><td colspan="3">$2.93 million</td></tr>
<tr><th colspan="12">Phase Gate Cost Summary</th></tr>
<tr><th colspan="4">Preliminary and Conceptual Phase
(Pre-Phase 1)
Nov 2021 to Sep 2022</th><th colspan="4">Screening and Pre-FEED Phase
(Phase 1)
Oct 2022 – Jun 2023</th><th colspan="4">Total Cost</th></tr>
<tr><td colspan="4">$1.40 million</td><td colspan="4">$1.53 million</td><td colspan="4">$2.93 million</td></tr>
</table>

3. ANTICIPATED PROECT DEVELOPMENT WORK AND TREATMENT OF SUBSEQUENT COSTS

3.1 *ANTICIPATED WORK PLAN FOR NEXT PERIOD*

The next quarterly reporting period will cover the period from July 1, 2023 to September 30, 2023, and FEI anticipates that the following activities will be initiated and developed during the next quarterly reporting period.

Screening Analysis

The project development work completed to date has provided FEI with a good understanding of the SCP compressor additions and the new pipeline segment from Oliver to Huntington. As mentioned in Section 2.1 above, FEI is undertaking a comprehensive screening analysis to evaluate all options prior to initiating further Pre-Feed work. For the next stage of project development, FEI will continue to advance its screening analysis to include the alternative delivery points described in Section 4.1.2 of the RGSD Application, namely T-South tie ins to Kingsvale and Hope.

The screening analysis will consist of multifunctional assessments of each of the delivery options and will seek to bring into focus option(s) that would be viable candidate(s) for further consideration. The work covered under this assessment will be comprised of but not be limited to: pipeline engineering, geotechnical, environmental, regulatory, stakeholder and Indigenous engagement, risk, construction, scheduling and cost estimating activities. Factored into the assessment will be any impacts of these options on FEI's resiliency scenarios and commercial agreements, and a long-term demand forecast.

In addition, with the introduction of the Province's plan related to GHG emissions reductions, all options require a carbon footprint assessment, plan and schedule to achieve net zero. The results of this work will be used to assist in the selection of the option(s) to be considered in the Pre-Feed work to follow.

Indigenous Engagement

Indigenous engagement is a priority for advancing this Project and FEI will maintain dialogue with the Indigenous Nations affected. Engagement will continue to focus on FEI having conversations with First Nations to discuss interests and opportunities, setting up mutually agreed upon pre-application engagement processes with First Nations, and continuing engagement according to those plans.

Public Consultation

FEI plans to commence engagement with local governments and communities, once the screening activities are developed, beginning with those most impacted by the Project.

4. MATERIAL DEVELOPMENTS ON THE PROJECT

4.1 REGIONAL MARKET AND PIPELINE INFRASTRUCTURE UPDATE

Developments with respect to regional infrastructure have an impact on FEI and the US Pacific Northwest operating marketplace. As discussed in the RGSD Application, the following market conditions have become even more pronounced, are outside of FEI's control, and continue to drive the critical need for the new regional pipeline infrastructure.

1. **Constrained Capacity on T-South System:** The BC and US Pacific Northwest (Region) as a whole, including FEI, rely on Enbridge's T-South system for the majority of their daily gas supply. The T-South system remains fully subscribed due to high demand in the Region. Over the past several years, market conditions have caused increased supply and pricing risks in the Region. The pricing volatility at the Huntingdon/Sumas market that occurred during and after the T-South Incident confirms FEI's view that there is a limited amount of supply available at Huntingdon. The 2022/23 winter season demonstrated significant pricing scarcity across natural gas and power markets in the US Pacific Northwest demonstrating supply challenges that stemmed from lack of infrastructure and pipeline capacity. FEI's strategy to incur demand tolls on the T-South system instead of purchasing gas at the Sumas hub has been a prudent choice, however, maintaining this strategy in the future would be challenging unless additional pipeline infrastructure is built.

2. **Forthcoming Increases in Regional Demand:** Constrained capacity in the Region will be further exacerbated by a number of major infrastructure projects proposed, including Woodfibre LNG, that require large volumes of baseload gas supply as feedstock. As well, natural gas usage for power generation has increased in the US Pacific Northwest, due to the retirement of coal plants. As the Region continues to try to replace the power generated by coal with renewable projects, it is uncertain what the future usage will be, as renewables are not sufficiently available at this time, and will be intermittent, depending on weather conditions. Natural gas and the power market in the US Pacific Northwest will continue to become more interconnected, as reliance on natural gas as the marginal resource is expected to continue.

3. **Decarbonization Initiatives:** A review of increasingly regional and federal public policy initiatives seeking to reduce GHG emissions presents FEI with an opportunity to continue to play a key role to innovate and implement solutions that help to create a lower-carbon future.

FEI will continue to monitor these ongoing changes to the regional market as they have a significant impact on maintaining access to cost-effective and reliable gas supply.

4.1.1 Westcoast T-South Expansion Update (Sunrise Expansion Program)

As discussed in the RGSD Application, FEI is mindful of the pace of development on Westcoast's proposed T-South Expansion project. Westcoast provided indication in early 2022 of its intention to seek shipper interest in a further expansion of T-South through a binding "open season" that was conducted later in the year. The T-South expansion was initially expected to be a $2.5 billion expansion to provide up to 300 MMcf/day from pipeline looping and additional compression along the line. On November 4, 2022, Enbridge confirmed that the open season was fully subscribed for 300 MMcf/day, with a weighted average term of 65 years. Enbridge will not publicly disclose the names of the successful bidders who were awarded the capacity until the expansion in-service date. The cost of the expansion, originally estimated at $2.5 billion earlier in 2022 by Enbridge, has since been revised to up to $3.6 billion in November 2022, which would lead to an even higher toll increase for all T-South shippers than originally anticipated. Based on internal analysis, the proposed expansion at a current estimated cost of $3.6 billion will result in major toll increases of over $0.30/Mcf (over current 2023 tolls) for all full path T-South shippers. In May 2023, Enbridge announced plans to file an application with the Canada Energy Regulator (CER) by mid-2024 which is expected to include updated cost estimates based on detailed studies that will include Indigenous consultation and greater technical scoping. Enbridge anticipates that the expansion capacity could be in-service no earlier than Q4 2028, contingent upon CER approval.

This T-South expansion, planned for as early as 2028, is being proposed to maintain gas flows to the US Pacific Northwest region at current levels after the planned Woodfibre LNG project comes online in 2027. It is expected that this capacity expansion will involve the construction of extensive new loops and additional compression.

4.2 *FEI MUST CONTINUE WITH THE RGSD PROJECT DEVELOPMENT WORK*

FEI has long recognized that the extension of FEI's Southern Crossing Pipeline (SCP) – now referred to as the RGSD Project – would provide additional regional capacity in a way that provides significant benefits to FEI and its customers and reduces risks for them. In contrast, the T-South Expansion project will have significant impacts on FEI customers with little to no benefits, and FEI customers still face the potential for additional – and potentially even larger – T-South expansions to address unresolved regional demand growth in the region. It is in the best interest of FEI and its customers for FEI to continue to proceed with the project development work on the RGSD Project.

5. CONCLUSION

As discussed in this Report, FEI has taken a diligent, prudent and measured approach to the project development activities completed to date (i.e., until Q2 2023). The costs incurred to date have been reasonable and prudently incurred to develop the Project concept.

In this initial phase of the development work, FEI primarily focused on the Indigenous engagement activities, as early engagement and developing Indigenous support for the Project is key to its success. FEI also successfully completed a request for expressions of interest and identified three potential proponents capable of completing Pre-Feed work. In order to have meaningful and comprehensive engagement and collaboration with stakeholders and Indigenous Nations prior to beginning Project approval processes and to have reasonable support and confidence on the Project concept and design, FEI determined to complete a detailed screening analysis on all three sub-variations of the RGSD Project (i.e., to assess other delivery points, such as tie-ins to T-South at Kingsvale or Hope) prior to advancing further Pre-Feed work.

Furthermore, to help manage the potential impact of decarbonization initiatives and policies introduced by federal and provincial government, FEI will need to continue to identify, investigate, and support appropriate infrastructure solutions that will help to meet these clean energy targets and maintain the reliability of gas flows through BC and thereby improve marketplace liquidity, security and overall supply competitiveness.

FEI's project development activities will allow FEI to utilize its recent discussions with stakeholders to avoid or adequately mitigate issues that may be related to pipeline capacity, design, route selection and construction activities.

FEI is also mindful of the proposed Westcoast's T-South Expansion project. The RGSD Project development work must continue and proceed in a timely way so as to avoid FEI having to underwrite the cost of the announced T-South Expansion, which as proposed, comes with little, if any, upside for FEI and its customers in terms of access to supply, supply cost, resiliency, or progress towards a renewable and low-carbon energy future.

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 12.4.2.2
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	System 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.	156	61	Clean Growth Innovation Fund	The Panel directs any unused balance in the deferral account to be returned to customers at the end of the Proposed MRP term through a disposal mechanism subject to approval by the BCUC.	Will be reviewed in FEI's 2025 MRP application	n/a
7.	157	62	Clean Growth 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 10.3.4

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 2025 MRP application	n/a
G-253-22 – FEI Application for approval of Regional Gas Supply Diversity (RGSD) Development Account						
10.		3	RGSD Project	In lieu of the July 2023 quarterly report, FEI must provide as part of the FEI 2024 Annual Review: a. Reporting to the BCUC on work completed, anticipated work, and material developments on the potential RGSD Project: b. An update of the costs incurred to date; and c. A proposal for the method and timing of the recovery of those incurred costs.	Complete	Section 12.4.2.1 and Appendix C
11.		4	RGSD Project	The recoverability and disposition of any costs recorded in the RGSD Development Account will be subject to BCUC review and determination in a future application, such as a subsequent FEI annual review or in a CPCN application for the RGSD Project.	Will be proposed in future application	n/a
G-278-22 – FEI Application for Common Rates and 2022 Revenue Requirements for the Fort Nelson Service Area						
12.	32	3	Fort Nelson Residential Customer Common Rate Phase-in Rate Rider	The Panel approves FEI to establish, for BCUC review, the actual Fort Nelson Residential Customer Common Rate Phase-in Rider each year in FEI's regulatory review process to set delivery rates, commencing in 2023, based on an updated forecast of FEFN's residential customer demand and the remaining balance of the deferral account each year for the five-year phase-in period.	Ongoing	Section 10.3.3

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
G-352-22 – FEI ANNUAL REVIEW FOR 2023 DELIVERY RATES						
13.	35		Public Contact with Gas Lines	Although this SQI is performing better than the benchmark, the Panel agrees with RCIA's comment on the need for FEI to provide a better explanation as to why it nonetheless experiences higher numbers of gas line hits than its counterparts in other provinces. The Panel also agrees with both RCIA and FEI that further discussion regarding this SQI and any possible changes is best addressed during the next MRP application.	Will be addressed in FEI's 2025 MRP application	n/a

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 2024 Delivery Rates

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

A. On June 22, 2020, the British Columbia Utilities Commission (BCUC) issued its Decision and Order G-165-20 for FortisBC Energy Inc. (FEI) and Order G-166-20 for FortisBC Inc. (FBC), approving a Multi-Year Rate Plan (MRP) for 2020 through 2024 (MRP Decision). In accordance with the 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, 2023, FEI proposed a regulatory timetable for the Annual Review of its 2024 delivery rates;

C. By Order G-194-23, the BCUC established the regulatory timetable for the Annual Review of FEI's 2024 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 28, 2023, FEI submitted its materials for the Annual Review for 2024 Delivery Rates Application (Application). In the Application, FEI requests a 4.50 percent delivery rate increase over the 2023 delivery rates, effective January 1, 2024, 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 59 to 61 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 2024 revenue requirement and resultant delivery rate change on a permanent basis, effective January 1, 2024, 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.

2. FEI is approved to:

    a. Establish the following rate base deferral accounts:

        i. 2025 Multi-year Rate Plan (MRP) Application deferral account, with the amortization period to be determined in a future proceeding;

        ii. 2023 Cost of Service Allocation (COSA) Study deferral account, with the amortization period to be determined in a future proceeding;

        iii. 2024-2027 Demand Side Management (DSM) Expenditure Plan Application deferral account, with amortization over a four-year period commencing January 1, 2024; and

        iv. PST Rebate on Select Machinery and Equipment deferral account, with amortization over a one-year period commencing January 1, 2024.

    b. Amortize the existing Transportation Service Report deferral account over a one-year period commencing January 1, 2024.

3. FEI is approved to set the Biomethane Variance Account Rate Rider for 2024 in the amount of $0.181 per gigajoule (GJ) as set out in Section 10.3.1.2 of the Application.

4. FEI is approved to set the Revenue Stabilization Adjustment Mechanism riders for 2024 in the credit amount of $0.106 per GJ as set out in Table 10-5 in Section 10.3.2 of the Application.

5. FEI is approved to set the Fort Nelson Residential Customer Common Rate Phase-in Rate Rider for 2024 in the amount of $0.863 per GJ as set out in Section 10.3.3 of the Application.

6. FEI's 2024 Core Market Administration Expense (CMAE) budget of $6.050 million is approved, as set out in Appendix B to the Application, 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.

7. FEI is directed to file as a compliance filing, the tariff continuity and billing impact schedules for 2024 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