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July 24, 2025

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

Dear Commission Secretary:

Re: FortisBC Energy Inc. (FEI)

Rate Setting Framework for the Years 2025 to 2027 approved by British Columbia Utilities Commission (BCUC) Order G-69-25 (Rate Framework)

Annual Review for 2025 and 2026 Delivery Rates

In accordance with the Rate Framework and BCUC Order G-179-25 setting out the Regulatory Timetable for FEI's Annual Review, FEI hereby attaches its Annual Review for 2025 and 2026 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 FortisBC 2025 to 2027 Rate Setting Framework proceeding.

FORTISBC ENERGY INC.

Rate Setting Framework for 2025 through 2027

Annual Review for 2025 and 2026 Delivery Rates

July 24, 2025

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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) Decision and Order G-69-25, which approved a Rate Setting Framework (RSF or Rate Framework) for FEI for the years 2025 to 2027 (RSF Decision). In accordance with the RSF Decision, an Annual Review process is required to set rates for each year of the RSF.

By Order G-313-24, the BCUC approved FEI's 2025 delivery rates on an interim basis, pending a decision on the RSF. With the filing of this Application, FEI seeks to commence the Annual Review process to set permanent delivery rates for 2025 and 2026.

In this section, FEI sets out its approvals sought and provides an overview of the requirements for the Annual Review process. This is followed by a summary of FEI's proposed revenue requirements and rate changes for 2025 and 2026 and a summary of the service quality indicator (SQI) results. These matters are addressed in more detail in subsequent sections of the Application.

1.1.1 Permanent 2025 Delivery Rates

FEI was approved to increase delivery rates by 7.75 percent on an interim basis, effective January 1, 2025 (2025 Interim Approved). The 2025 Interim Approved was based on the forecast 2025 revenue requirement at the time the interim rate application was filed on November 5, 2024 (i.e., prior to the RSF Decision).

FEI has now calculated the 2025 revenue requirement based on the approved formulas and forecasts in the RSF Decision, the actual 2024 results from the final year of the 2020-2024 Multi-Year Rate Plan (MRP) and five months of actual results in 2025 where applicable. The resulting permanent delivery rate increase for 2025 is 9.10 percent compared to the 2024 Approved delivery rates. Included in the calculation of the 2025 revenue requirement is $12.460 million (before tax) in earnings sharing, which FEI proposes to distribute to customers in 2025. Please refer to Section 10.2 of the Application for further details.

The primary driver of the increased deficiency and delivery rate increase compared to the 2025 Approved Interim (i.e., 9.10 percent compared to 7.75 percent) is the reduced demand projected for 2025 in this Application compared to what was forecast in the interim rate application filed in November 2024. The 2025 Projected demand forecast in this Application includes actual demand for 2024, whereas the interim rate application only included actual demand up to 2023. The other main driver of the difference is the delay in the in-service date of the City of Vancouver (CoV) Landfill RNG Project (delayed from 2024 to 2025), the impact of which is described in Section 5.2.5 of the Application.

Due to the expected timing of a decision on this Application (i.e., November or December of 2025), FEI is proposing to set permanent 2025 delivery rates at the existing interim levels and to capture the revenue deficiency greater than the 7.75 percent increase (approximately $15.352 million) in the existing 2023-2024 Revenue Deficiency deferral account (and to rename the account the 2023-2025 Revenue Deficiency deferral account), as further discussed in Section 12.4.2.1 of the Application.

FEI considers this approach to be the most reasonable for customers. If FEI were instead approved to increase 2025 delivery rates by 9.10 percent on a permanent basis, effective January 1, 2025, FEI would need to collect the incremental 2025 deficiency of $15.352 million from customers through a one-time bill adjustment in the first billing cycle subsequent to the BCUC's decision on the Application, which would likely mean that FEI would be applying the one-time bill adjustment in January 2026, at a time when customers will already be experiencing both delivery and gas cost rate increases.

1.1.2 Permanent 2026 Delivery Rates

The delivery rate change for 2026 flowing from the approved formulas and forecasts set out in the Application is a 10.07 percent increase from 2025 delivery rates. This increase includes the proposed revenue deficiency deferred from 2025 as discussed above, but does not include the amortization of the 2023-2025 Revenue Deficiency deferral account because, as explained below and in Section 12.4.2.1, FEI is proposing to commence amortizing the 2023-2025 Revenue Deficiency deferral account in 2027. For an average residential customer,[1] the increase in 2026 is equivalent to an annual bill impact of approximately $83.22 or 7.04 percent. After consideration of the delivery rate riders, the annual bill impact, which includes the cost of gas and storage & transport (S&T) charges, is an increase of approximately $88.89 or 7.52 percent. FEI notes that the annual bill impact does not include the impact of the elimination of the Carbon Tax, which took effect on April 1, 2025. When factoring in the elimination of the Carbon Tax, the annual bill impact to an average residential customer is a savings of $259.08 or 16.93 percent.[2]

As further discussed in Section 1.4 below, the 2026 deficiency and the resulting delivery rate increase is primarily due to deferral amortization, particularly the amortization of the Demand Side Management (DSM) deferral account, growth in rate base due to the additions of approved major project capital expenditures, and increased income tax expenses.

FEI recognizes that a delivery rate increase of 10.07 percent, effective January 1, 2026, will result in a significant bill impact for customers, especially as the increase coincides with changes to the S&T charges and cost of gas charges, both of which typically change on January 1 of each year.

FEI explored a number of options to recover the 2026 revenue deficiency, including deferring a portion of the 2026 deficiency to future years through the use of deferral accounts and spreading the 2026 delivery rate increase over multiple increases during 2026. However, as outlined below,

1 Based on consuming approximately 90 gigajoules (GJ) per year.
2 Based on the natural gas carbon tax rate of $3.986 per GJ as of March 31, 2025.

FEI does not believe that continuing to defer revenue deficiencies is the best approach for customers, as the deferred balance will continue to grow and put pressure on future delivery rates. As discussed in Option 1 below, the balance in the 2023-2025 Revenue Deficiency deferral account (assuming that FEI is approved to add the 2025 deficiency to the account as discussed in Section 1.1.1) at the end of 2025 will be $78.781 million. As part of FEI's proposal to mitigate the delivery rate increase in 2026, FEI is proposing to delay the amortization of the deferral account until 2027. Adding a further deficiency to this deferral account (i.e., deferring some of the 2026 deficiency) will create even greater rate pressures for customers in the future and extend the length of time until the deferral account balance is fully recovered.

The following describes the four options FEI considered for recovering the 2026 revenue deficiency, as well as the advantages and disadvantages of each option.

- **Option 1:** While not the proposed option, FEI considered commencing the amortization of the 2023-2025 Revenue Deficiency deferral account in 2026 in addition to fully recovering the 2026 revenue requirement in 2026. This would result in a delivery rate increase of 11.82 percent, effective January 1, 2026, which is equivalent to an annual bill impact of approximately $103.38 or 8.74 percent, inclusive of delivery rate riders, S&T charges, and cost of gas. The advantages of Option 1 are that it enables FEI to fully recover the 2026 revenue requirement in 2026 and immediately commence recovery of the prior year deferred deficiencies. While Option 1 results in the highest delivery rate increase on January 1, 2026 out of the options explored, it lessens the rate pressures in future years, in particular 2027. Under Option 1, based on preliminary estimates, the 2027 delivery rate increase is forecast to be in the range of 6 to 8 percent. The primary disadvantage of Option 1, and why it is not the proposed option, is that it results in the highest delivery rate increase (and thus bill impact) for customers in January, which is typically when customer consumption is at its highest. Another disadvantage is that it creates some rate volatility, as delivery rates will increase from 7.75 percent in 2025 (if approved on a permanent basis as proposed) to 11.82 percent in 2026, and then will drop again in 2027 to a range of 6 to 8 percent.

- **Option 2 (Proposed):** Recover the full 2026 revenue requirement in 2026 but delay the amortization of the 2023-2025 Revenue Deficiency deferral account until 2027. This results in a delivery rate increase of 10.07 percent on January 1, 2026, which is equivalent to an annual bill impact of approximately $88.89 or 7.52 percent, inclusive of delivery rate riders, S&T charges, and cost of gas. The primary advantage of Option 2 is that no additional revenue deficiencies will be deferred, enabling 2026 delivery rates to fully reflect the cost of service in the applicable test year. Further, by delaying the amortization of the 2023-2025 Revenue Deficiency deferral account to 2027, the delivery rate increase in 2026 is mitigated compared to Option 1, and the year-over-year delivery rate increases from 2025 to 2027 will be less volatile (i.e., 7.75 percent in 2025, 10.07 percent in 2026, and 8 to 10 percent in 2027). The primary disadvantages of this option are that it puts more rate pressure on 2027 compared to Option 1 and extends the time until the deferred deficiencies are fully recovered (i.e., 2031 assuming a 5-year amortization period), thus impacting future rates for an additional year compared to Option 1.

- **Option 3:** FEI explored two options that are similar to Options 1 and 2 but would mitigate the delivery rate impact on January 1, 2026, which is typically when customer bills are higher due to the combination of delivery, cost of gas and S&T cost changes, as well as higher consumption due to cold weather conditions. Under Options 3a and 3b, FEI would divide the delivery rate increase into two parts and implement delivery rate increases on January 1 and July 1, 2026. Together, these increases would be equivalent to the full year delivery rate increase.

  - **Option 3a:** Divide the delivery rate increase described in Option 1 (i.e., 11.82 percent) into two parts – an 8.00 percent increase effective January 1, 2026 and a further 7.81 percent[3] increase effective July 1, 2026. Together, these increases are equivalent to a full year increase of 11.82 percent when compared to the 2025 Approved Interim rates. Under this option, an average residential customer will see a bill impact (inclusive of delivery rate riders, S&T charges and cost of gas) of $71.79 or 6.07 percent starting on January 1, 2026, followed by a further $31.49 or 5.65 percent increase on July 1, 2026, for a total increase of $103.28 or 8.73 percent in 2026. The advantages of this option are that it enables the full recovery of the 2026 revenue requirement in 2026 while reducing the impact to customers on January 1, 2026. This option also results in FEI commencing recovery of the accumulated revenue deficiencies from prior years. The disadvantages of this option are the potential rate volatility that may occur between 2026 and 2027, and that the approach may result in greater customer dissatisfaction due to the increased complexity of multiple rate changes and the fact that customers will experience a higher than typical bill increase in July. The rate volatility is created because the rate increase in the second half of the year must be set higher to recover both the last six months' revenue deficiency as well as the uncollected deficiency from the first six months, even though the total revenue deficiency collected is the same regardless of whether the increase is applied once at the beginning of the year or split into two increases during the year. Due to the higher rates at the end of 2026 (i.e., a higher starting point for 2027), all else being equal, the rate increase for 2027 will be lower. FEI estimates the 2027 delivery rate increase could be as low as 2 to 4 percent.

  - **Option 3b:** Divide the delivery rate increase described in Option 2 (i.e., 10.07 percent) into two parts – an 8.00 percent increase effective January 1, 2026 and a further 4.24 percent[4] increase effective July 1, 2026. Together, these

[3] The delivery rate increase of 7.81 percent on July 1, 2026 is compared to the proposed January 1, 2026 rates with recovery based on a 6-month period from July 1 to December 31, 2026. When compared to the 2025 Approved Interim rates, the percentage increase on July 1, 2026 would be equivalent to 3.82 percent, thus a full-year increase of 11.82 percent (8.00 percent plus 3.82 percent).

[4] The delivery rate increase of 4.24 percent on July 1, 2026 is compared to the proposed January 1, 2026 rates with recovery based on a 6-month period from July 1 to December 31, 2026. When compared to the 2025 Approved

increases are equivalent to a full year increase of 10.07 percent when compared to the 2025 Approved Interim rates. Under this option, an average residential customer will see a bill impact (inclusive of delivery rate riders, S&T charges and cost of gas) of $71.79 or 6.07 percent starting on January 1, 2026, followed by a further $17.08 or 3.07 percent increase on July 1, 2026, for a total increase of $88.87 or 7.52 percent in 2026. The advantages and disadvantages of Option 3b compared to Option 3a are generally the same, with the exception that the delivery rate increase on July 1, 2026 is lower and there is less rate volatility (the delivery rate increase for 2027 would potentially be in the range of 4 to 6 percent). FEI acknowledges that Option 3 is a unique and more complex approach to setting delivery rates and thus may result in some customer dissatisfaction; however, FEI notes that gas customers are accustomed to multiple rate changes during the year as the commodity cost recovery charge can change up to four times per year.

- **Option 4:** Defer a portion of the 2026 revenue deficiency in order to smooth rate impacts. Under this option, FEI would propose to utilize the existing 2023-2025 Revenue Deficiency deferral account to capture the deficiency (similar to the proposed treatment of the 2025 deficiency discussed in Section 1.1.1). Under this option, FEI would likely propose to cap the 2026 delivery rate increase at 9.0 percent, which would result in a deficiency of approximately $13.247 million that would be added to the deferral account for future recovery. FEI would then propose to commence amortizing the 2023-2025 Revenue Deficiency deferral account (which would now become the 2023-2026 Revenue Deficiency deferral account) in 2027. The advantage of this option is that it enables the 2026 delivery rate increase to remain below 10 percent and at a level that is relatively consistent with recent years, thus providing some rate smoothing. The key disadvantage to this approach is that a further deficiency will be deferred to future years. Under Option 4, the deferral account balance at the end of 2026 would be approximately $93.659 million. Commencing amortization of the deferral account in 2027 would therefore put the greatest pressure on 2027 delivery rates of all the options. Assuming the same 5-year amortization period as was included in the other options, FEI estimates the 2027 delivery rate increase could be as high as 10 to 12 percent. Given the other options available (and in particular Option 2), FEI considers the disadvantages outweigh the advantages of this option.

Ultimately, FEI considers Option 2 provides the best balance between the considerations discussed above. Option 2 enables FEI to fully recover the 2026 revenue requirement in 2026, while providing some rate mitigation by delaying the amortization of the 2023-2025 Revenue Deficiency deferral account.

Interim rates, the percentage increase on July 1, 2026 would be equivalent to 2.07 percent, thus a full-year increase of 10.07 percent (8.00 percent plus 2.07 percent).

1.2 *APPROVALS SOUGHT*

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

1. Approval to make the existing 2025 interim delivery rates and rate riders permanent, effective January 1, 2025.
2. Approval to capture the revenue deficiency resulting from the difference between the 2025 interim and permanent revenue requirement in the existing 2023-2024 Revenue Deficiency deferral account, rename the deferral account the 2023-2025 Revenue Deficiency deferral account, and amortize the deferral account over a 5-year period starting January 1, 2027.
3. Approval to recover the 2026 revenue requirement and resultant delivery rate change on a permanent basis, effective January 1, 2026.
4. Continuation of the debiting of the Midstream Cost Reconciliation Account (MCRA) and crediting of Other Revenue in the amount of $346.617 per MMcfd (equivalent to approximately $0.3059/GJ per day), effective January 1, 2025 and for the duration of the 2025-2027 RSF term, as described in Section 5.3.1.
5. Approval to rename the Annual Review of 2020-2024 Rates deferral account to the Annual Review Proceeding Costs deferral account, and to use this deferral account to capture actual regulatory proceeding costs related to the Annual Reviews during the RSF term. Further, approval to continue to amortize the deferral account over a one-year period.
6. Amortization periods for the following previously approved rate base deferral accounts, as described in Section 7.7.2:
    - A three-year amortization period for the 2025 MRP Application deferral account, commencing January 1, 2025. FEI also seeks approval to rename the deferral account the 2025-2027 RSF Application deferral account;
    - A five-year amortization period for the 2021 Generic Cost of Capital Proceeding deferral account, commencing January 1, 2025;
    - A three-year amortization period for the 2021 Renewable Gas Program Comprehensive Review deferral account, commencing January 1, 2025;
    - A one-year amortization period for the 2023 Cost of Service Allocation (COSA) Study deferral account, commencing January 1, 2025; and
    - A three-year amortization period for the 2022 Long-Term Gas Resource Plan (LTGRP) deferral account, commencing January 1, 2025.

7. Approval to capture the actual after-tax costs of the 2025 equity issuance in the Flotation Costs deferral account and to amortize the balance in the Flotation Costs deferral account over five years, commencing January 1, 2026.
8. Approval to modify the existing RNG Account to attract financing costs at FEI's weighted-average cost of capital (WACC), effective January 1, 2025.
9. Approval to set the 2026 Revenue Stabilization Adjustment Mechanism (RSAM) rate rider at $0.212 per GJ, as set out in Table 10-1 of Section 10.3.1.
10. Approval to set the Fort Nelson Residential Customer Common Rate Phase-in Rate Rider for 2026 to be a credit of $0.355 per GJ, as calculated in Table 10-2 of Section 10.3.2.
11. Approval to transfer the 2024 ending balance of the 2020 CGIF deferral account to the existing approved Residual Delivery Rate Riders deferral account, effective January 1, 2025, and to record any unspent accrued committed amounts in the Residual Delivery Rate Riders deferral account.

A draft order is included in Appendix C.

1.3 *REQUIREMENTS FOR THE ANNUAL REVIEW*

On page 73 of the RSF Decision, the BCUC Panel stated that the Annual Review process should continue in the Rate Framework and that the content (list of items) set out in the 2020-2024 MRP Decision (page 167) remains appropriate. 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

Item	Description	Response or Reference
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.	N/A. For the term of the RSF, the BCUC approved FEI's request to remove the Efficiency Carryover Mechanism (ECM).
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 10.3.3
7	Assess and make recommendations to the BCUC on potential issues or topics for future Annual Reviews.	FEI does not have any recommendations at this time.

1.4 REVENUE REQUIREMENT AND DELIVERY RATE CHANGES FOR 2025 AND 2026

FEI has calculated the 2025 and 2026 revenue requirement using a combination of the approved formulas for O&M and Growth capital and the approved forecasts for Sustainment/Other capital from the RSF Decision as well as the 2025 Projected and 2026 Forecast amounts for items which are forecast annually. For the 2025 Projected revenue requirement, FEI includes five months of actual results up to May 31, 2025.

The delivery rates for 2025 flowing from the revenue requirement components set out in the Application result in a 9.10 percent increase from the 2024 delivery rates, with a revenue deficiency of $103.400 million. However, FEI is proposing to make permanent the existing interim delivery rates for 2025, effective January 1, 2025, and to capture the portion of the 2025 revenue deficiency that is greater than 7.75 percent (approximately $15.352 million) in the existing 2023-2025 Revenue Deficiency deferral account (formerly the 2023-2024 Revenue Deficiency deferral account), resulting in an overall deficiency of $88.048 million. FEI is also proposing to commence amortization of this deferral account on January 1, 2027 over five years.

The revenue requirement components for 2026 set out in the Application result in an effective delivery rate increase of 10.07 percent for 2026 compared to 2025 Interim Approved. The effective delivery rate increase results from a revenue deficiency of $124.421 million, which includes the 2025 deferred deficiency of $15.352 million as discussed above to maintain the 2025 effective delivery rate increase at 7.75 percent.

The following charts summarize the items that contribute to the 2025 and 2026 revenue deficiencies. The charts show each item that increases the deficiencies in yellow and each item that decreases the deficiencies in green. The 2025 and 2026 deficiencies of $88.048 million and $124.421 million, respectively, are then the sum of all the previous bars and are shown at the end of the charts in blue. For 2025, the final blue bar represents the sum required to bring the total revenue deficiency to the deficiency determined when setting interim rates for 2025 (7.75 percent).

Figure 1-1: 2025 Delivery Revenue Deficiency ($ millions)

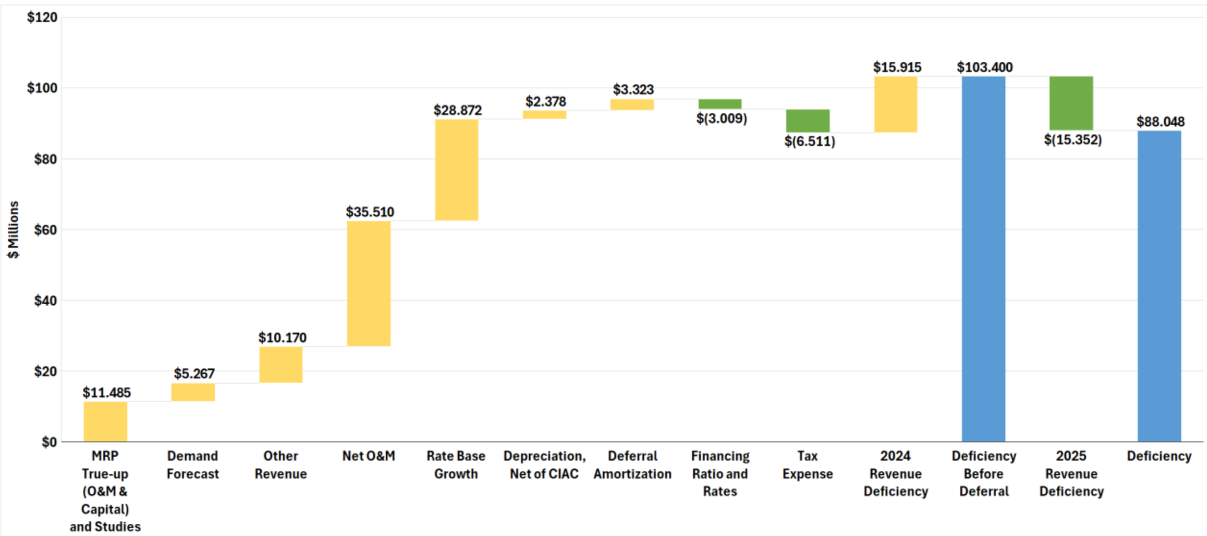
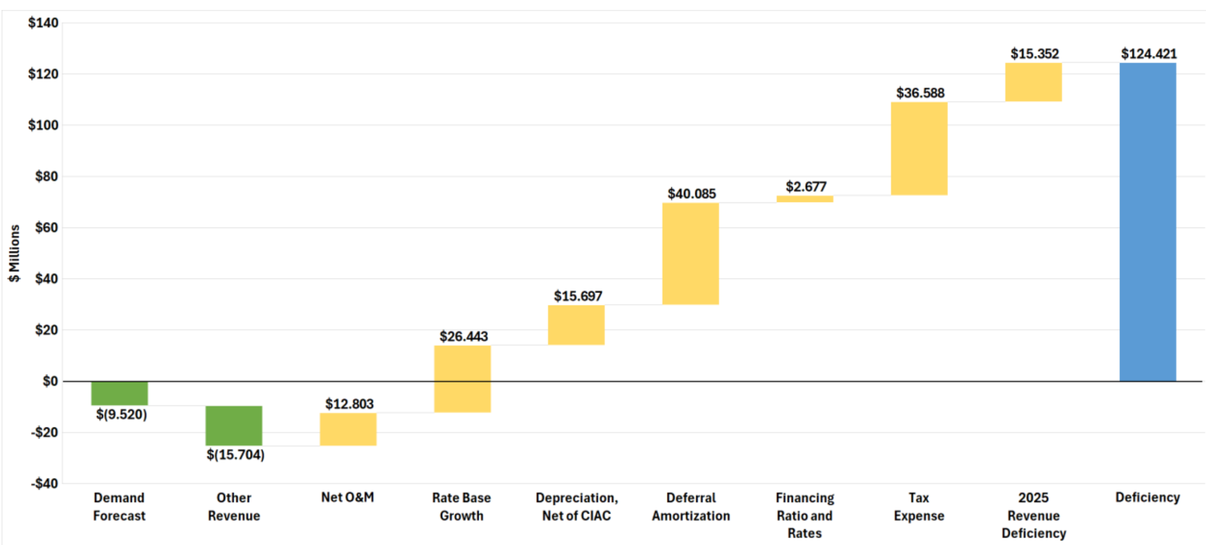


Figure 1-2: 2026 Delivery Revenue Deficiency ($ millions)



Each of the categories is discussed briefly below.

1.4.1 Resetting Base O&M for RSF Term, True-up of 2020-2024 MRP Rate Base, and New Studies (Sections 6 and 7)

The 2025 revenue deficiency includes approximately $11.485 million related to the true-up of FEI's rate base following the end of the 2020-2024 MRP term as well as the impact of resetting FEI's base O&M and the implementation of new studies (i.e., capitalized overhead study and depreciation study) from the RSF Decision.

The true-up of the 2020-2024 MRP rate base resulted in an increase to the 2025 revenue deficiency of approximately $14.758 million, which was mostly offset by the resetting of the 2024 Base O&M for FEI's formula O&M during the 2025-2027 RSF term of approximately $11.285 million.

As part of the RSF Decision, FEI was approved a new capitalized overhead rate and new depreciation rates, which contributed approximately $6.012 million and $2.000 million, respectively, to the 2025 revenue deficiency.[5]

1.4.2 Demand Forecast (Section 3)

For 2025, FEI incorporated actual demand up to May 2025[6] and is projecting total demand to be approximately 220.0 PJ, which is slightly lower than the 2024 Approved level of 220.2 PJ. FEI is projecting a reduction in demand from residential customers compared to the 2024 Approved level; however, this decrease is mostly offset by the projected increase in demand from commercial customers (particularly Large Commercial customers in Rate Schedule (RS) 3) and industrial customers (particularly General Firm Service customers in RS 5). Overall, the small decrease in the 2025 Projected demand from the 2024 Approved contributed approximately $5.267 million to the 2025 revenue deficiency when calculated based on 2024 Approved rates.

For 2026, FEI is forecasting total demand to be approximately 222.2 PJ, which is approximately 2.2 PJ higher than the 2025 Projected level. The increase is primarily due to a forecast increase in demand from residential and commercial customers (particularly from Large Commercial customers in RS 3). The increase in the 2026 Forecast demand reduced the 2026 deficiency by approximately $9.520 million when calculated based on the 2025 Approved Interim rates.

1.4.3 Other Revenue (Section 5)

Other Revenue is forecast to increase the 2025 deficiency by approximately $10.170 million but reduce the 2026 deficiency by approximately $15.704 million. The increase in 2025 and the decrease in 2026 are both primarily due to changes in the RNG Other Revenue related to the CoV Landfill RNG Project, which will be placed in service in 2025, generating a large income tax credit through the high capital cost allowance (CCA) rate related to RNG assets.

[5] Includes an increase of $5.9 million related to the changes to net salvage rates, offset by a decrease of $3.9 million related to the average reduction in depreciation rates.

[6] With the exception of LNG demand under Rate Schedule (RS) 46 which includes actuals up to June 30, 2025.

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

FEI establishes the majority of its O&M costs by formula during the RSF term. In the RSF Decision, the BCUC approved a Base 2024 O&M for FEI of $299.127 million. Based on the 2024 Actual average customer count of 1,093,663, the approved 2024 Base Unit Cost O&M (UCOM) is $274, which is used as the starting UCOM for FEI's formula O&M during the RSF term.

For 2025, by incorporating a net inflation factor (I-Factor) of 3.648 percent, which is inclusive of an X-Factor of 0.55 percent, and the 2025 Projected average customer count, the formula O&M is $312.846 million, which is approximately $13.719 million[7] or 4.6 percent higher than the approved 2024 Base O&M of $299.127 million. For the 2025 O&M forecast outside of the formula, FEI is projecting an amount of $87.940 million, which is approximately $30.294 million[8] or 52.6 percent higher than the 2024 Approved level. The increase is primarily the result of the reclassification of the Advanced Metering Infrastructure (AMI) related O&M costs from formula O&M as approved in the RSF Decision. The 2025 increase in total O&M expense net of capitalized overhead and RNG O&M transferred to the RNG Account is $30.237 million.

For 2026, by incorporating a net inflation factor of 2.726 percent, which is inclusive of the X-Factor of 0.55 percent, and the 2026 Forecast average customer count, the formula O&M is $325.220 million, which is approximately $12.374 million[9] or 4.0 percent higher than the 2025 Formula O&M. For the 2026 O&M forecast outside of the formula, FEI is forecasting an amount of $91.321 million, which is approximately $3.381 million[10] or 3.8 percent higher than the 2025 Projected level. The increase is primarily due to higher costs for integrity digs. The 2026 increase in total O&M expense net of capitalized overhead and RNG O&M transferred to the RNG Account is $12.803 million.

1.4.5 Rate Base Growth (Section 7)

The 2025 rate base is projected to increase by approximately $634.627 million compared to the 2024 Approved rate base, which results in an increase to the 2025 Forecast earned return and the 2025 deficiency of approximately $28.872 million. The increase is primarily due to capital additions related to FEI's approved regular capital (Growth, Sustainment, and Other capital) in 2025 under the RSF as well as a number of major projects, including the Inland Gas Upgrades (IGU) CPCN Project, the Coastal Transmission System (CTS) Transmission Integrity Management Capabilities (TIMC) CPCN Project, the Pattullo Gasline Replacement (PGR) CPCN Project, and the Gibsons Capacity Upgrade (GCU) Project. Further contributing to the increase is the increase in the mid-year balance of FEI's deferral accounts by approximately $17 million, primarily due to increasing balances in the MCRA, the RSAM account, and the DSM deferral account.

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7 Increase in formula O&M of $11.524 million net of capitalized overhead.

8 Increase in forecast O&M of $23.986 million net of capitalized overhead and RNG O&M transferred to the RNG Account.

9 Increase in formula O&M of $10.580 million net of capitalized overhead.

10 Increase in forecast O&M of $2.223 million net of capitalized overhead and RNG O&M transferred to the RNG Account.

The 2026 rate base is forecast to increase by approximately $383.264 million compared to the 2025 Projected rate base, which results in an increase to the 2026 Forecast earned return and the 2026 deficiency of approximately $26.443 million. The increase is primarily due to capital additions related to the approved regular capital (Growth, Sustainment, and Other capital) in 2026 as well as a number of major projects, including the CTS TIMC CPCN Project, the Interior Transmission System (ITS) TIMC CPCN Project, and the AMI CPCN Project.

1.4.6 Depreciation (Section 7)

Depreciation expense in 2025 is projected to increase the 2025 deficiency by $1.426 million. This increase is primarily due to the additions from the major projects noted in Section 1.4.5. The increase in depreciation expense is further impacted by a projected reduction of $0.952 million in contributions in aid of construction (CIAC), resulting in a net increase of $2.378 million in depreciation expense.

Depreciation expense in 2026 is forecast to increase the 2026 deficiency by $15.824 million when compared to 2025 Projected. This increase is primarily due to the additions of the major projects noted in Section 1.4.5. The increase in depreciation expense is partially offset by approximately $0.127 million of CIAC from net additions, resulting in a net increase of $15.697 million in depreciation expense.

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

Amortization of deferral accounts in 2025 is projected to increase by $3.323 million, primarily due to the increased amortization of the DSM deferral account resulting from increased DSM expenditures, and the amortization of the Okanagan Capacity Upgrade (OCU) Application Costs deferral account following the approval of the Okanagan Capacity Mitigation Plan (OCMP) CPCN Project in March 2025.[11] These increases are projected to be partially offset by higher amortization from the non-rate base Earnings Sharing deferral account as well as reduced amortization from the non-rate base Flow-through deferral account.

Amortization of deferral accounts in 2026 increased by $40.085 million. The largest contributor to the increase is the increased amortization of the DSM deferral account resulting from increased DSM expenditures. Another key contributor to the increase is the amortization of the Existing Meter Cost Recovery deferral account and the Previously Retired Meter Cost Recovery deferral account, both of which are related to the AMI Project, with amortization commencing on January 1, 2026.

1.4.8 Financing and Return on Equity (Section 8)

Financing impacts FEI's deficiency through changes in financing rates, as well as changes in the ratio of long-term debt versus short-term debt.

[11] Decision and Order C-2-25.

For 2025, FEI is projecting a long-term debt issue of $250 million in the second half of 2025 at a rate of 4.60 percent; however, the average long-term rate embedded in the 2025 Projected revenue requirement will remain at the same level as the average long-term rate embedded in the 2024 Approved revenue requirement, which is 4.68 percent. FEI is projecting a short-term debt rate of 3.58 percent for 2025, which is an increase from the 3.21 percent short-term debt rate embedded in the 2024 Approved revenue requirement. Overall, the 2025 deficiency is projected to increase by $0.674 million due to the projected increase in financing rates (short-term debt) but is entirely offset by a reduction of $3.683 million resulting from the changes in the financing ratio between long-term and short-term debt. Combining the impact of the financing rate changes and ratio changes, the 2025 deficiency is projected to be reduced by $3.009 million.

For 2026, FEI is forecasting a mid-year long-term debt issue of $450 million at a rate of 4.60 percent, which results in an average long-term rate embedded in the 2026 Forecast revenue requirement of 4.73 percent, which is higher than the average long-term debt rate of 4.68 percent embedded in the 2025 Projected revenue requirement. FEI is forecasting a short-term debt rate of 3.38 percent, which is a reduction from the 3.58 percent short-term debt rate embedded in the 2025 Projected revenue requirement. Overall, the 2026 deficiency is forecast to increase by $1.615 million due to the changes in financing rates (primarily due to the increase in the embedded average long-term debt rate) and a further increase by $1.062 million resulting from the changes in the financing ratio between long-term and short-term debt. Combining the impact of the financing rates changes and ratio changes, the 2026 deficiency is forecast to increase by $2.677 million.

Finally, FEI utilizes the approved capital structure and return on equity (ROE) of 45.0 percent and 9.65 percent, respectively, to develop the 2025 and 2026 revenue requirement.

1.4.9 Taxes (Section 9)

FEI's 2025 property taxes are projected to increase by $3.568 million or 4.3 percent from 2024 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. FEI's 2026 property taxes are forecast to increase by $1.649 million or 1.9 percent from 2025 Projected. The increase is primarily driven by higher assessed values of distribution lines and transmission lines, but partially offset by a forecast reduction in in-lieu taxes.

There has been no change in the income tax rate of 27 percent from 2024. Taxes are projected to decrease in 2025 by $10.079 million or 11.5 percent from 2024 Approved. The largest driver of the decrease in 2025 is the higher income tax deductible through CCA, which is mostly due to higher undepreciated capital cost (UCC) additions, especially for RNG assets with high CCA rates when compared to 2024 Approved. The decrease resulting from higher income tax deductible is partially offset by an increase in rate base return due to the projected increase in rate base from 2024 Approved to 2025 Projected, as discussed in Section 1.4.5 above. For 2026, FEI is forecasting income tax to increase by approximately $34.939 million or 45.2 percent from the 2025 Projected level. The increase is primarily due to higher amortization of deferral accounts and higher rate base return and depreciation expense resulting from the increase in rate base, as well as reduced income tax deductible resulting from lower UCC additions in assets classes with higher CCA rates.

1.5 *SERVICE QUALITY INDICATORS (SECTION 13)*

FEI reports on its 2024 and June 2025 year-to-date (YTD) SQI results in Section 13. Pursuant to the RSF Decision, eight of the SQIs have benchmarks and performance ranges set by a threshold level while ten of the SQIs are for information only and as such do not have benchmarks or performance ranges.

For 2024, FEI reports on the SQI performance based on the suite of SQIs (and, where applicable, their respective benchmarks and thresholds) approved for the 2020-2024 MRP term. For 2025, FEI reports on the YTD SQI performance based on the suite of SQIs (and, where applicable, their respective benchmarks and thresholds) approved in the RSF Decision.

In 2024, for the nine SQIs with benchmarks, eight performed at or better than the approved benchmarks, with one SQI (Emergency Response Time) only slightly below the benchmark but well above the threshold. Regarding the informational indicators, the performance generally remains at a level consistent with prior years. In 2025 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 2025 and 2026 O&M and Growth capital amounts according to the RSF formula.

In the RSF Decision and Order G-69-25, the BCUC approved an I-Factor which includes a fixed labour weighting of 50 percent and fixed non-labour weighting of 50 percent for FEI during the RSF term and uses the actual CPI-BC and BC-AWE indices from the previous year.

The RSF Decision approved the use of a forecast of growth[12] to determine formula O&M and formula Growth capital. Further, the RSF Decision approved the elimination of a growth factor multiplier for formula O&M.

The Inflation Factor and Growth Factor calculations utilize the above-described inputs and determinations. FEI has used July 2022 through June 2024 inflation data for the 2025 revenue requirement calculations and July 2023 through June 2025 inflation data for the 2026 revenue requirement calculations, using the Statistics Canada tables included in Appendix A1 of the Application.

Section 2.2 below explains how FEI determined the 2025 and 2026 Inflation Factors based on prior years' BC-CPI and BC-AWE that are used to calculate the formula O&M discussed in Section 6 and the 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 RSF Decision, the BCUC approved an I-Factor using the actual CPI-BC and BC-AWE indices from the previous year and using a fixed 50 percent weighting for each index. 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 2025 for AWE-BC has been used as a placeholder, as results for May and June 2025 have not been released by Statistics Canada. Once results for these periods are available, this placeholder will be replaced with actuals and included in the compliance filing to the BCUC's decision on this Application.

As shown in Table 2-1 below, the I-Factor has been calculated utilizing actual CPI-BC and AWE-BC data. Applying the fixed labour weighting of 50 percent, the calculation of the 2025 I-Factor is

[12] 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 actuals in the following years.

(3.012 percent x 50 percent) + (5.384 percent x 50 percent) = 4.198 percent, and the calculation of the 2026 I-Factor is (2.397 percent x 50 percent) + (4.154 percent x 50 percent) = 3.276 percent.

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 %	RSF Year
1	Jul-2022	147.6	1,156.22								
2	Aug-2022	147.0	1,168.36								
3	Sep-2022	147.8	1,168.27								
4	Oct-2022	148.6	1,173.63								
5	Nov-2022	148.1	1,177.91								
6	Dec-2022	147.1	1,159.28								
7	Jan-2023	148.1	1,181.92								
8	Feb-2023	149.1	1,176.30								
9	Mar-2023	149.7	1,192.57								
10	Apr-2023	150.4	1,204.70								
11	May-2023	151.0	1,209.06								
12	Jun-2023	151.6	1,207.69	148.8	1,181.33	6.031%	2.762%	51%	49%	4.429%	2024
13	Jul-2023	152.1	1,221.78								
14	Aug-2023	152.6	1,222.39								
15	Sep-2023	152.7	1,234.00								
16	Oct-2023	152.6	1,232.42								
17	Nov-2023	152.8	1,235.47								
18	Dec-2023	152.1	1,239.48								
19	Jan-2024	152.6	1,248.60								
20	Feb-2024	153.0	1,253.16								
21	Mar-2024	153.8	1,256.76								
22	Apr-2024	154.7	1,256.94								
23	May-2024	155.4	1,266.79								
24	Jun-2024	155.5	1,271.37	153.3	1,244.93	3.012%	5.384%	50%	50%	4.198%	2025
25	Jul-2024	156.4	1,279.27								
26	Aug-2024	156.2	1,283.58								
27	Sep-2024	155.8	1,286.76								
28	Oct-2024	156.2	1,288.42								
29	Nov-2024	156.3	1,292.63								
30	Dec-2024	156.1	1,290.29								
31	Jan-2025	156.0	1,302.22								
32	Feb-2025	157.6	1,300.75								
33	Mar-2025	157.8	1,304.48								
34	Apr-2025	157.8	1,310.45								
35	May-2025	159.0	1,310.45								
36	Jun-2025	158.8	1,310.45	157.0	1,296.65	2.397%	4.154%	50%	50%	3.276%	2026

2.3 *GROWTH FACTOR CALCULATION SUMMARY*

As noted above, the BCUC approved the use of a forecast of average customers, without discount, to determine formula O&M, and a forecast of gross customer additions (GCA) to determine formula Growth capital.

Table 2-2 below provides the forecast 12-month customer counts and the calculation of the forecast average customer counts for 2025 and 2026. The 2025 and 2026 forecast average customer counts (shown on Line 22 of Table 2-2 below) are 1,102,958 and 1,114,373, respectively, which are used to determine FEI's 2025 and 2026 Formula O&M. Table 2-2 below also shows the 2023 and 2024 true-up of average customer counts of 2,532 and 3,219, respectively, which are reflected in the 2025 and 2026 Formula O&M, as discussed in Section 6.

Table 2-2: Calculation of 2025 and 2026 Average Customer (AC) Growth Factor

Line No.	Date	2025 Projected	2026 Forecast	Reference
1	Prior Year Ending Customer Count	1,098,373	1,109,432	Appendix A2 Table A2-1 FEI Customers
2				
3	Projected/Forecast Monthly Ending Customer Count			
4	January	1,100,351	1,111,558	
5	February	1,101,211	1,112,890	
6	March	1,101,249	1,113,429	
7	April	1,101,375	1,113,378	
8	May	1,101,197	1,113,673	
9	June	1,102,530	1,113,595	
10	July	1,101,834	1,112,898	
11	August	1,101,716	1,112,780	
12	September	1,102,268	1,113,331	
13	October	1,104,677	1,115,740	
14	November	1,107,651	1,118,714	
15	December	1,109,432	1,120,495	
16	Total Projected/Forecast Additions for the Year	11,059	11,063	Line 15 - Line 1; Appendix A2 Table A2-1
17				
18	Actual/Projected Prior Year Average Customers	1,093,663	1,102,958	2025: Sch 3, Line 13; 2026: Prior Year, Line 19
19	Average Customers for the Year	1,102,958	1,114,373	Average of Line 4 to Line 15
20	Change in Average Customers	9,295	11,415	Line 19 - Line 18
21				
22	**Average Customer Forecast for Rate Setting**	**1,102,958**	**1,114,373**	Line 19
23				
24	2023/2024 Approved Average Customers	1,077,003	1,089,371	2023: G-352-22; 2024: G-334-23 (Schedule 19)
25	2023/2024 Actual Average Customers	1,080,379	1,093,663	2023/2024 Annual Report
26	**2023/2024 True Up**	**2,532**	**3,219**	(Line 25 - Line 24) x 75%

The forecast for FEI's gross customer additions which is used to determine the formula Growth capital is provided in the table below.

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

Line	Gross Customer Additions		Reference
1	2023 Approved	16,000	
2	2023 Actual	15,610	
3	2023 True-up	(390)	Section 7, Table 7-3, line 14
4			
5	2024 Approved	15,000	
6	2024 Actual	12,363	
7	2024 True-up	(2,637)	Section 7, Table 7-3, line 14
8			
9	2025 Projected	10,000	Schedule 4, line 5
10	2026 Forecast	8,000	Schedule 4, line 5

FEI is projecting gross customer additions of 10,000 for 2025, which is lower than the 2024 Approved amount of 15,000 but is reflective of FEI's 2024 Actual customer growth, which is 12,363. FEI is forecasting a further reduction in gross customer additions for 2026 (i.e., GCA of 8,000), consistent with the downward trend being experienced in gross customer additions. As explained in Section 7.3.1, the calculation of formula Growth capital includes the true-up of gross customer additions from two years prior (i.e., 2023 for the 2025 revenue requirement and 2024 for the 2026 revenue requirement).

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 2025 and 2026 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 2025 Projected GCA, 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 higher financing costs and the strong financial incentives being offered for home electrification. All of these factors are reflective of the 2025 Projected and 2026 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 2025 and 2026 is provided in Table 2-4 below, including the I-Factor calculated in Section 2.2, the approved X-Factor of 0.55 percent, and the forecasts of average customers and gross customer additions determined in Section 2.3.

Table 2-4: Summary of Formula Drivers

Line	Particulars	2025	2026	Reference
1	CPI	3.012%	2.397%	Table 2-1, Line 24 & 36
2	AWE	5.384%	4.154%	Table 2-1, Line 24 & 36
3				
4	Non Labour	50%	50%	Table 2-1, Line 24 & 36
5	Labour	50%	50%	Table 2-1, Line 24 & 36
6				
7	CPI/AWE Inflation	4.198%	3.276%	(Line 1 x Line 4) + (Line 2 x Line 5)
8				
9	Productivity Factor	-0.550%	-0.550%	Order G-69-25
10				
11	Net Inflation Factor	3.648%	2.726%	Line 7 + Line 9
12				
13	Average Customers for Formula O&M purposes	1,102,958	1,114,373	Table 2-2, Line 22
14				
15	Gross Customer Additions for Formula Growth Capital purposes	10,000	8,000	Table 2-3

In summary, the Net Inflation Factors for 2025 and 2026 are 3.648 percent and 2.726 percent, respectively. FEI's formula O&M is determined using average customers of 1,102,958 in 2025 and 1,114,373 in 2026, and the formula Growth capital is determined using gross customer additions of 10,000 in 2025 and 8,000 in 2026.

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. These demand forecasts have been developed in accordance with the methods approved by the BCUC in the RSF Decision[13]. As determined in the RSF Decision, the merits of the approved demand forecasting methods are outside the scope of the Annual Reviews during the RSF term.

For 2025, FEI is projecting the normalized demand (2025P), with actuals up to May 31, 2025,[14] to be approximately 220.0 PJ, which is approximately 0.2 PJ less than the 2024 Approved demand of 220.2 PJ. FEI is projecting a reduction in demand from residential customers; however, the decrease is mostly offset by projected increases in commercial customer demand (particularly Large Commercial customers in Rate Schedule (RS) 3) and industrial customer demand (particularly General Firm Service customers in RS 5). At the 2024 Approved rates for each customer class, FEI's 2025 Projected revenue and delivery margin are estimated to be approximately $1,726 million and $1,165 million, respectively.

For 2026, FEI is forecasting the normalized demand (2026F) to be approximately 222.2 PJ, which is approximately 2.2 PJ higher than the 2025 Projected demand. The increase is primarily due to a forecast increase in demand from residential and commercial customers. At the 2025 Approved Interim rates, FEI's 2026 Forecast revenue and delivery margin are $1,827 million and $1,263 million, respectively.

The following sections set out the results of the demand forecasts. In the figures provided in the demand forecast sections, the following 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 the full year of actual data exists is the 2024 calendar year. For comparison, a green line is added in all figures below representing the approved forecast in the latest calendar year with actual data (i.e., 2024 Approved).
- **Projected Year:** The year prior to the first forecast year, which is 2025 for this Application (2025P). The Projected Year is forecast based on the latest years of actual data available (through 2024). The January through May forecast values were then replaced with Actual 2025 values.
- **Forecast Year:** This is the year or years for which the forecast is being developed. For this Application, the forecast year is 2026 (2026F).

Please refer to Appendix A2 of the Application for the historical actual and forecast demand over the past 10 years.

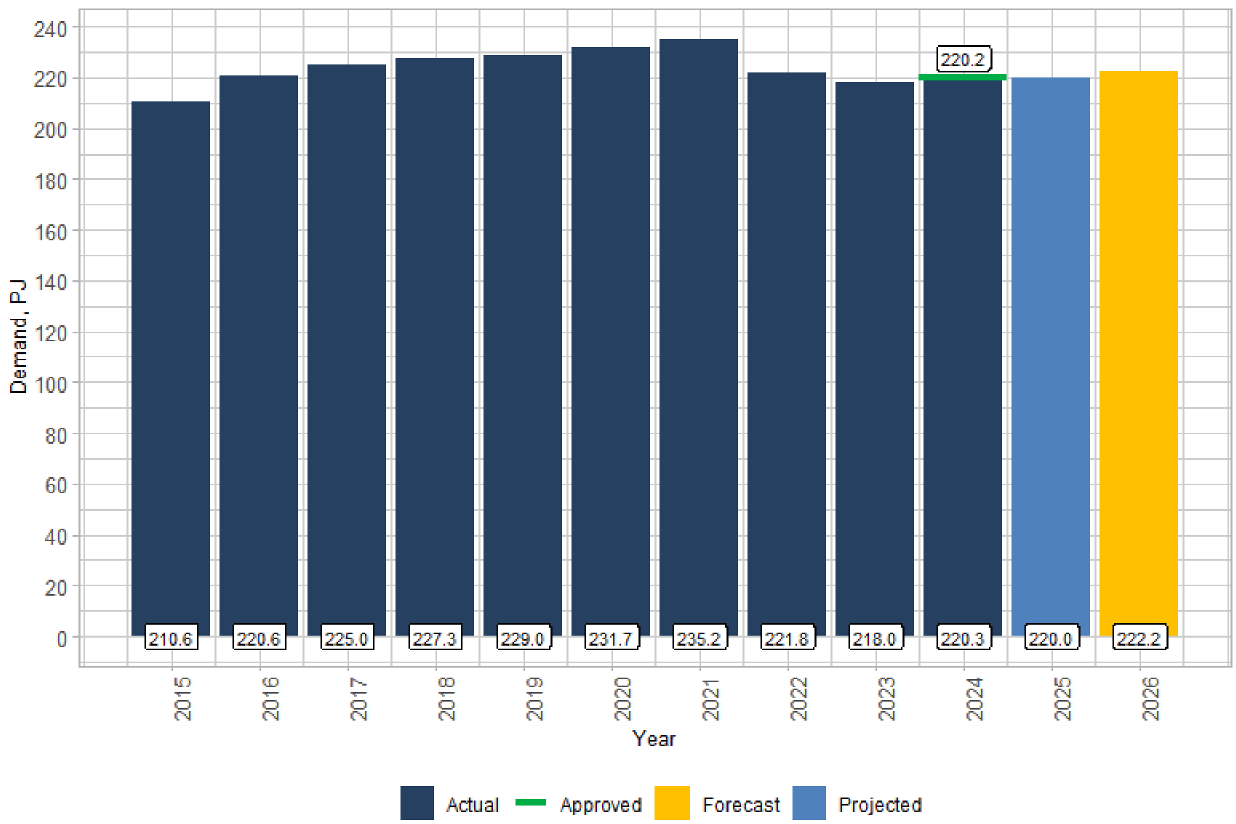
13 RSF Decision and Order G-69-25, pp. 73-74.
14 With the exception of LNG demand from Rate Schedule (RS) 46 which includes actuals up to June 30, 2025.

3.2 *DEMAND FORECAST*

FEI's total energy demand consists of the weather normalized residential and commercial demand, and the customer-specific industrial, natural gas for transportation (NGT), and non-NGT (liquefied natural gas (LNG)) demand.

As shown in Figure 3-1 below, the absolute demand forecast variance in 2024 was approximately 0.1 PJ or 0.04 percent. For 2025, the total load is projected to be 220.0 PJ, which is a decrease of 0.2 PJ or 0.1 percent from 2024 Approved. For 2026, the total load is forecast to be 222.2 PJ, which is an increase of 2.2 PJ or 1 percent from 2025 Projected.

Figure 3-1: Total Energy Demand in PJ



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

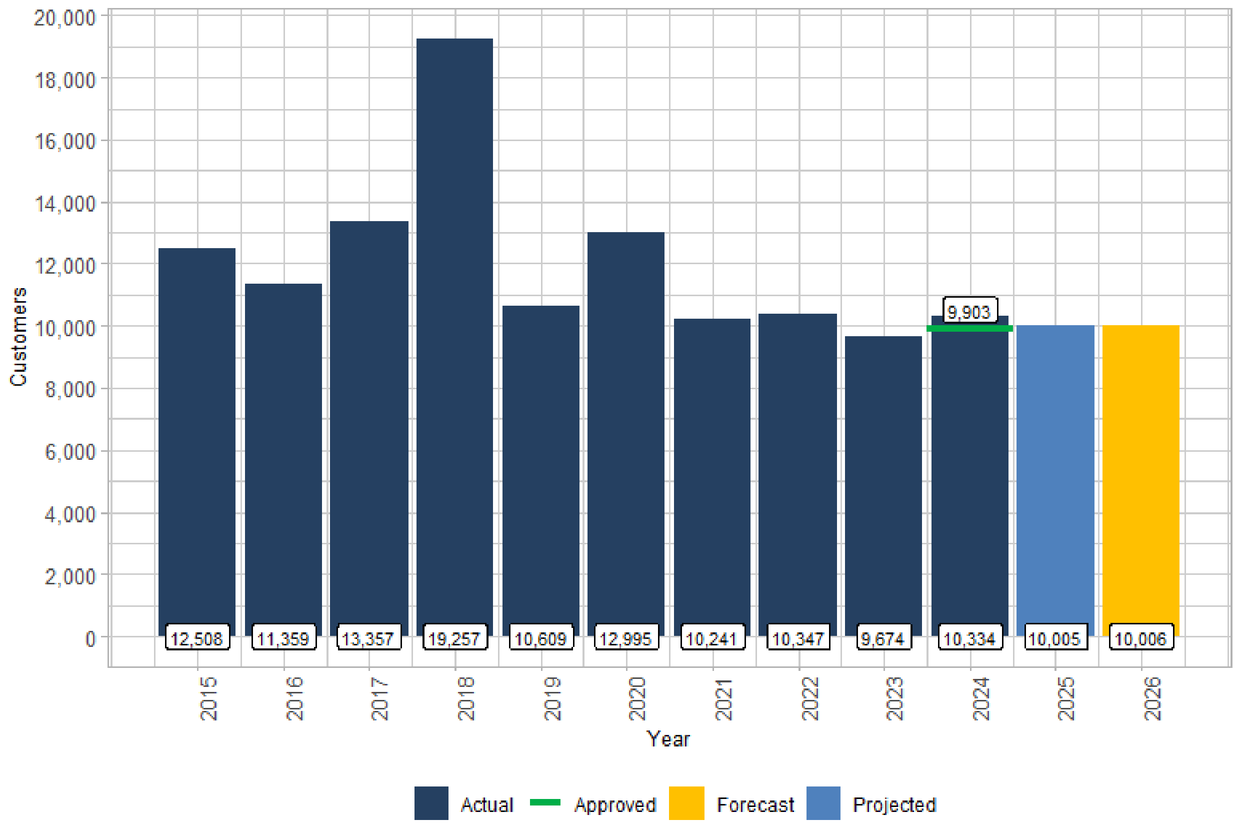
3.2.1 Residential

3.2.1.1 Residential Net Customer Additions

As shown in Figure 3-2 below, the 2025 Projected residential net customer additions are 10,005, which is an increase of 102 from 2024 Approved. The 2026 Forecast residential net customer additions are 10,006, which is consistent with 2025 Projected (an increase of one compared to 2025 Projected).

Figure 3-2 provides the residential net customer additions for 2015 through 2026.

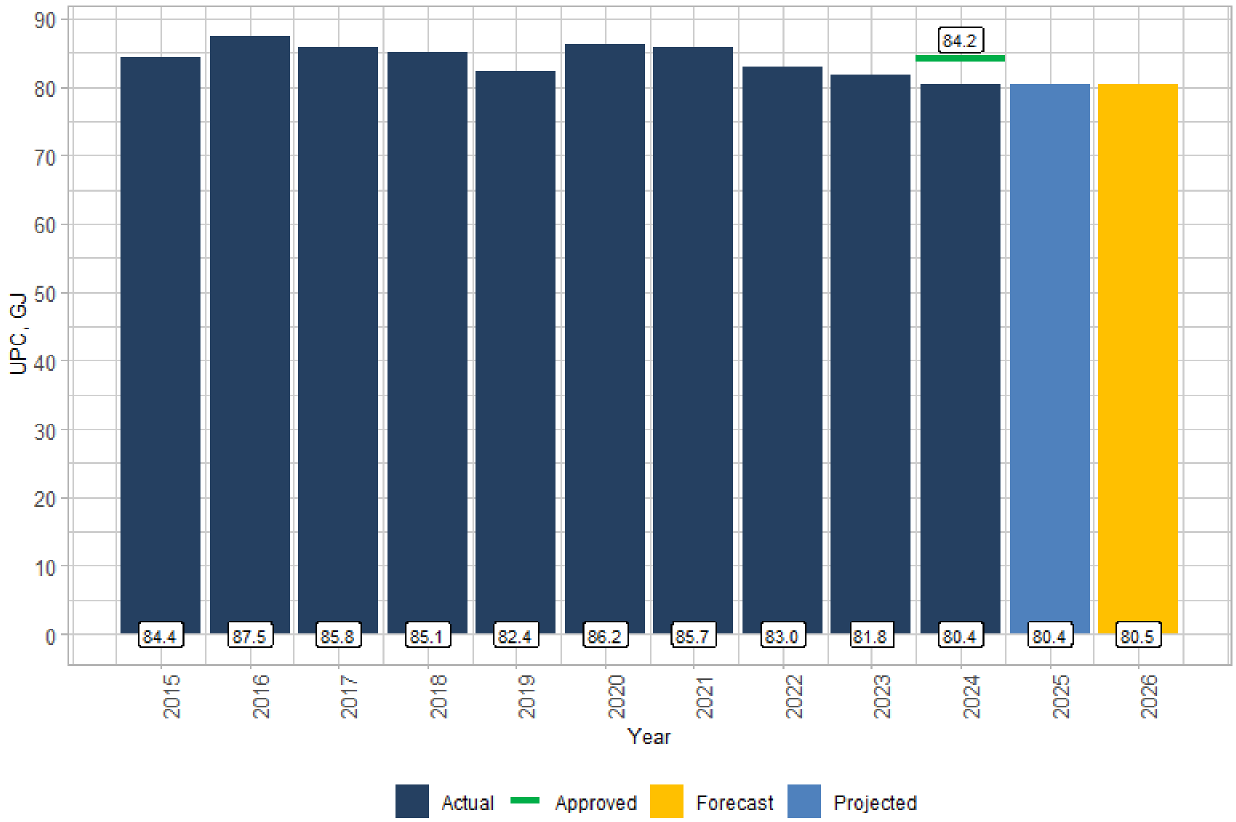
Figure 3-2: Residential Net Customer Additions



3.2.1.2 Residential UPC

As shown in Figure 3-3 below, the 2025 Projected residential use per customer (UPC) is 80.4 GJ, which is a decrease of 3.8 GJ from 2024 Approved but is consistent with 2024 Actual. The 2026 Forecast residential UPC is 80.5 GJ, which is an increase of 0.1 GJ from 2025 Projected.

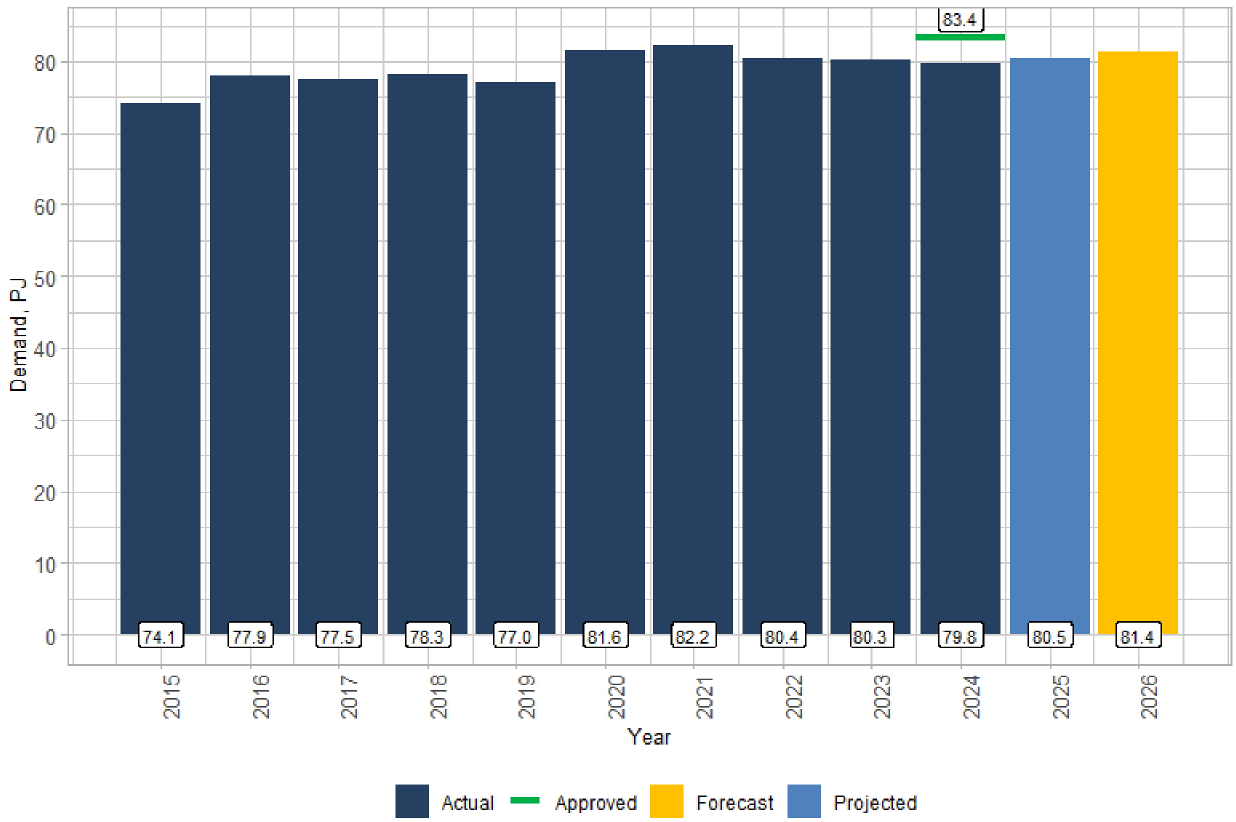
Figure 3-3: Rate Schedule 1 UPC



3.2.1.3 Residential Demand

Accounting for the net customer additions and UPC forecasts, as shown in Figure 3-4 below, the 2025 Projected residential demand is 80.5 PJ, which is a decrease of 2.9 PJ from 2024 Approved but is an increase of 0.7 PJ compared to 2024 Actual. The 2026 Forecast residential demand is 81.4 PJ, which is an increase of 0.9 PJ from 2025 Projected.

Figure 3-4: Normalized Residential Demand



3.2.2 Commercial

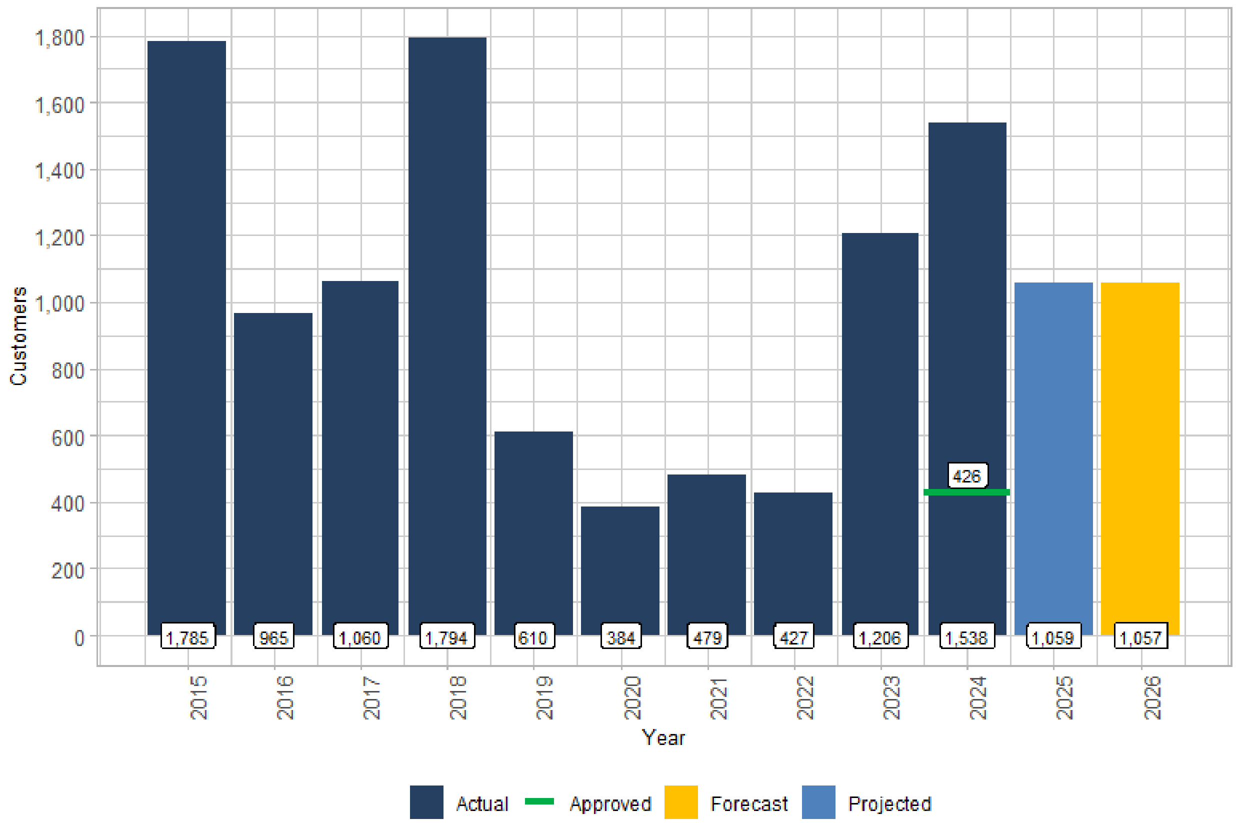
3.2.2.1 Commercial Customers

As shown in Figure 3-5 below, there were significant increases in the actual net commercial customer additions in 2023 and 2024 compared to the period from 2019 to 2022. However, FEI attributes the lower net commercial customer additions in years 2019 through 2022 in part to the COVID-19 pandemic and the resulting longer-term effects of the pandemic on the economy (for example, increased inflationary pressures). The 2023 and 2024 Actual results are more in line with the years prior to 2019, as shown in Figure 3-5.

The 2025 Projected net commercial customer additions are 1,059, which is an increase of 633 from 2024 Approved but a decrease of 479 from 2024 Actual. The 2026 Forecast net commercial customer additions are 1,057, which is consistent with the 2025 Projected level (a decrease of two from 2025P).

Consistent with the forecasting methodology approved in the RSF Decision, the 2025P and 2026F net commercial customer additions are based on a three-year average of actual net commercial customer additions from 2022 to 2024 (with the forecast net additions from January to May 2025 replaced with actual net additions over the same period).

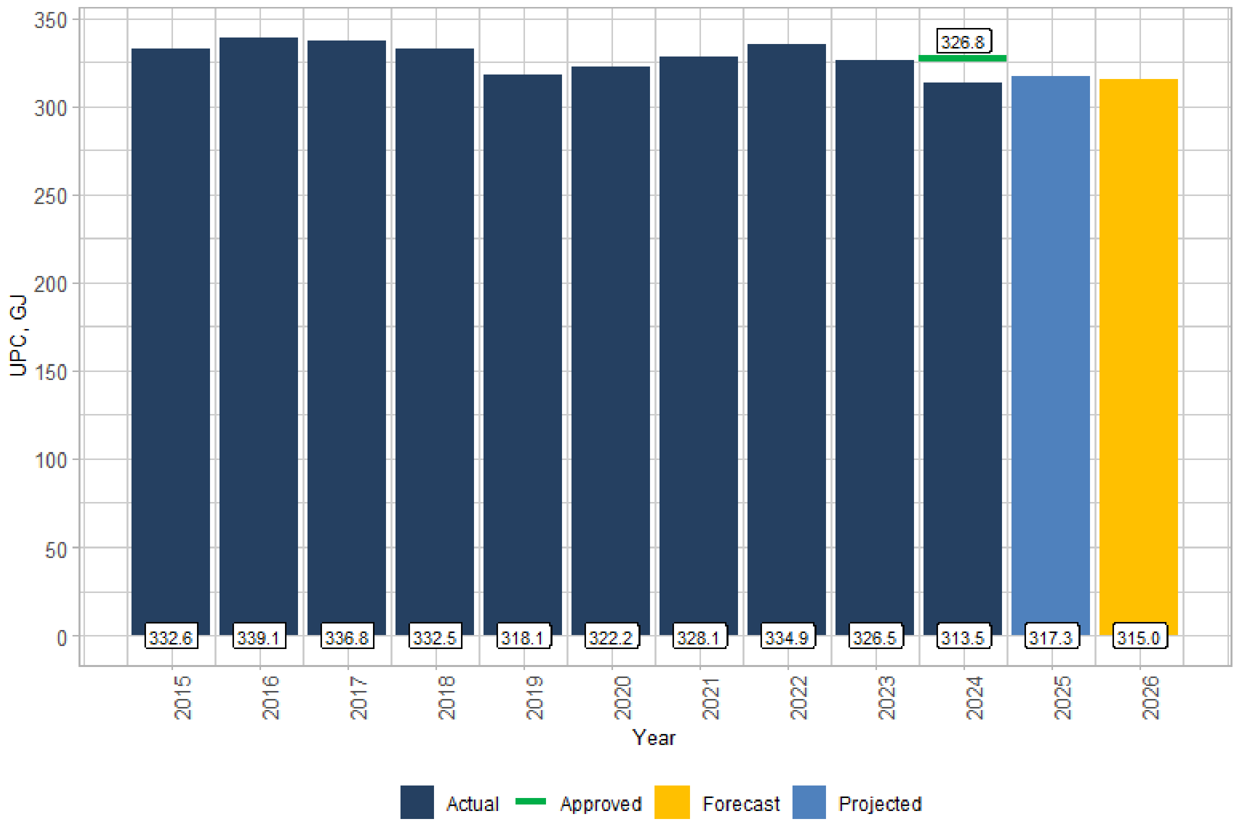
Figure 3-5: Commercial Net Customers Additions (Rate Schedules 2, 3, and 23)



3.2.2.2 Commercial UPC

As shown in Figure 3-6 below, the 2025 Projected RS 2 UPC is 317.3 GJ, which is a decrease of 9.5 GJ from 2024 Approved but is 3.8 GJ higher than 2024 Actual. The 2026 Forecast of 315.0 GJ is slightly lower than 2025 Projected (decrease of 2.3 GJ).

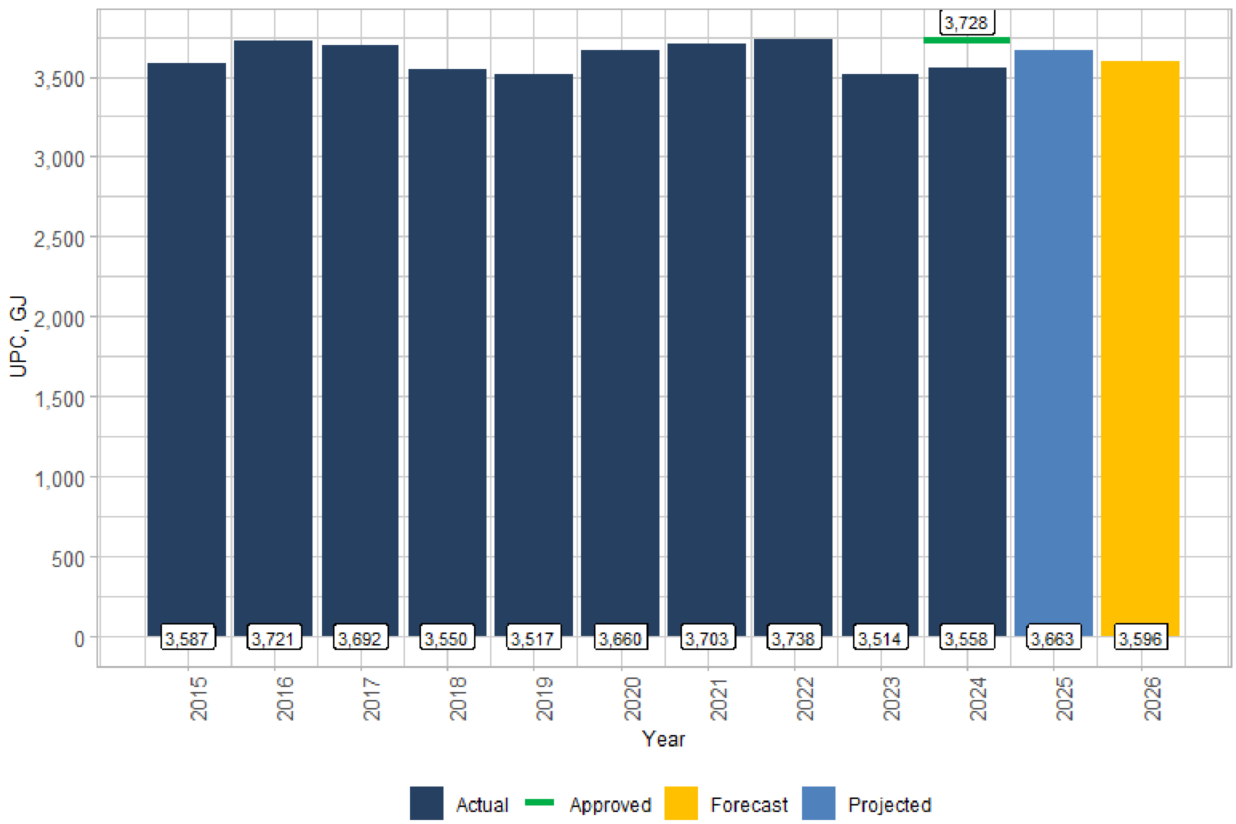
1 **Figure 3-6: Rate Schedule 2 UPC**



2

3 As shown in Figure 3-7 below, the 2025 Projected RS 3 UPC is 3,663 GJ, which is a decrease of
4 65 GJ from 2024 Approved but is an increase of 105 GJ from 2024 Actual. The 2026 Forecast
5 RS 3 UPC is 3,596 GJ, which is a decrease of 67 GJ from 2025 Projected.

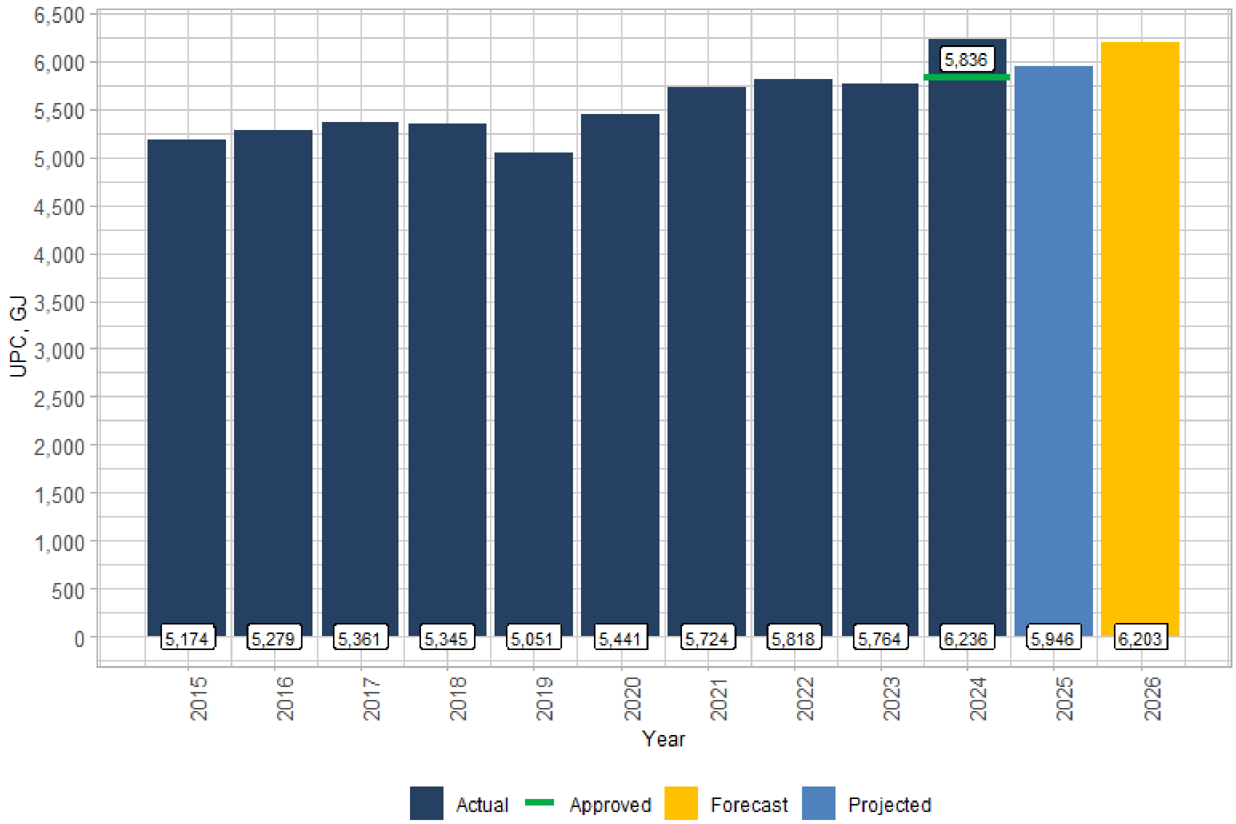
Figure 3-7: Rate Schedule 3 UPC[15]



As shown in Figure 3-8 below, the 2025 Projected RS 23 UPC is 5,946 GJ, which is an increase of 110 GJ from 2024 Approved. The 2026 Forecast RS 23 UPC is 6,203 GJ, which is an increase of 257 GJ from 2025 Projected.

[15] Excludes NGT customers under Rate Schedule 3.

Figure 3-8: Rate Schedule 23 UPC[16]

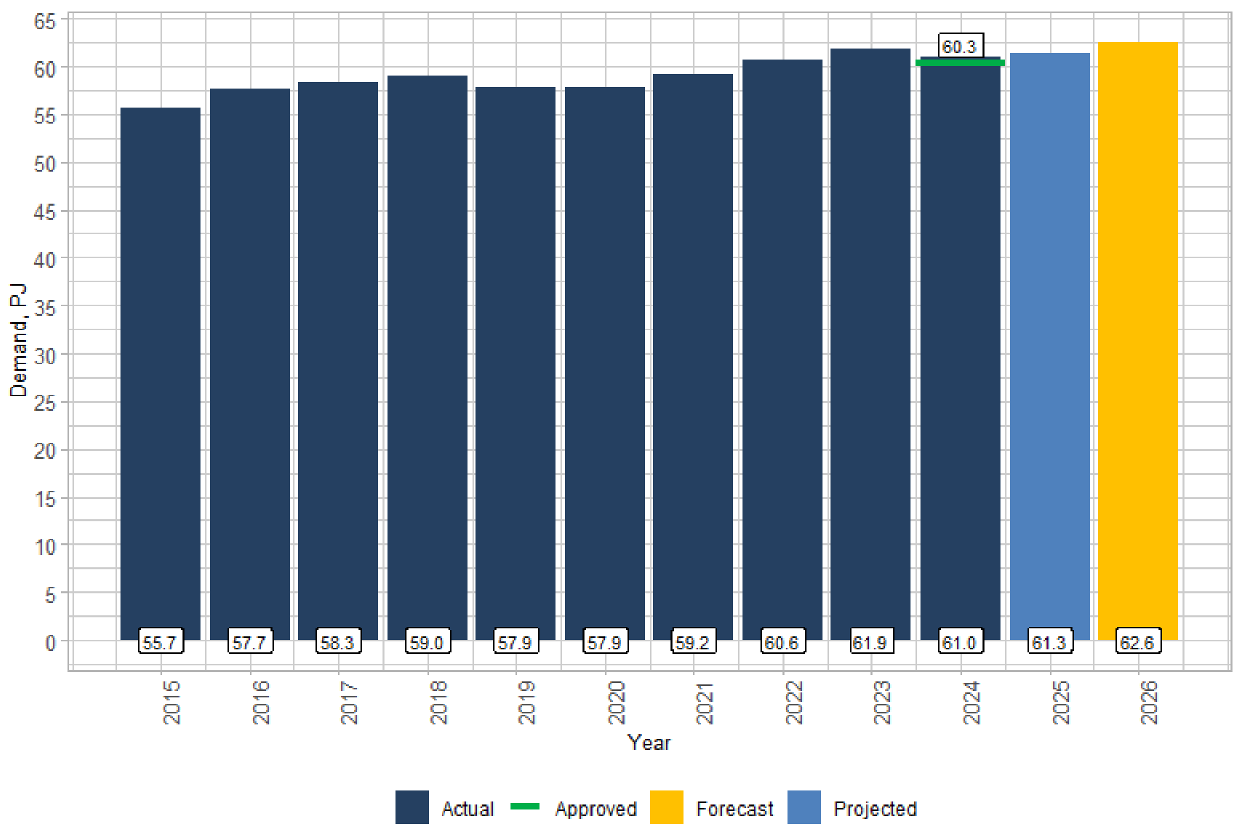


3.2.2.3 Commercial Demand

Accounting for the commercial customer additions and UPC forecasts, as shown in Figure 3-9 below, the 2025 Projected commercial demand is 61.3 PJ, which is an increase of 1 PJ from 2024 Approved, and the 2026 Forecast is 62.6 PJ, which is an increase of 1.3 PJ from 2025 Projected.

[16] Excludes NGT customers under Rate Schedule 23.

Figure 3-9: Commercial Demand[17]



3.2.3 Industrial Demand

Consistent with the forecasting methodology approved in the RSF Decision, the industrial demand is forecast based on a web-based demand survey completed by individual industrial customers.

Given that 2025 is well underway (and thus FEI did not complete a survey for the 2025 test year), the 2025 Projected industrial demand is based on actual results from January 2025 to May 2025 and actual results from June 2024 to December 2024.

For 2026, the demand forecast was developed based on the 2025 survey responded to by customers in May and June of 2025. The survey was launched as close as possible to the Annual Review filing date to mitigate potential variances in the forecast, and the deadline to complete the survey was June 21, 2025. Since the survey requires approximately five weeks to complete, it was launched on May 14, 2025.

As shown in Table 3-1 below, the response rate achieved in 2025 was 48.8 percent of industrial customers, representing approximately 90.6 percent of industrial volumes. There was no reply from 51 percent of industrial customers who received the survey after three reminder notifications;

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

this group represents only 9.3 percent of the industrial demand. Surveys could not be delivered to 0.2 percent of the industrial customers due to issues such as incorrect email addresses; this group represents only 0.1 percent of the total industrial demand.

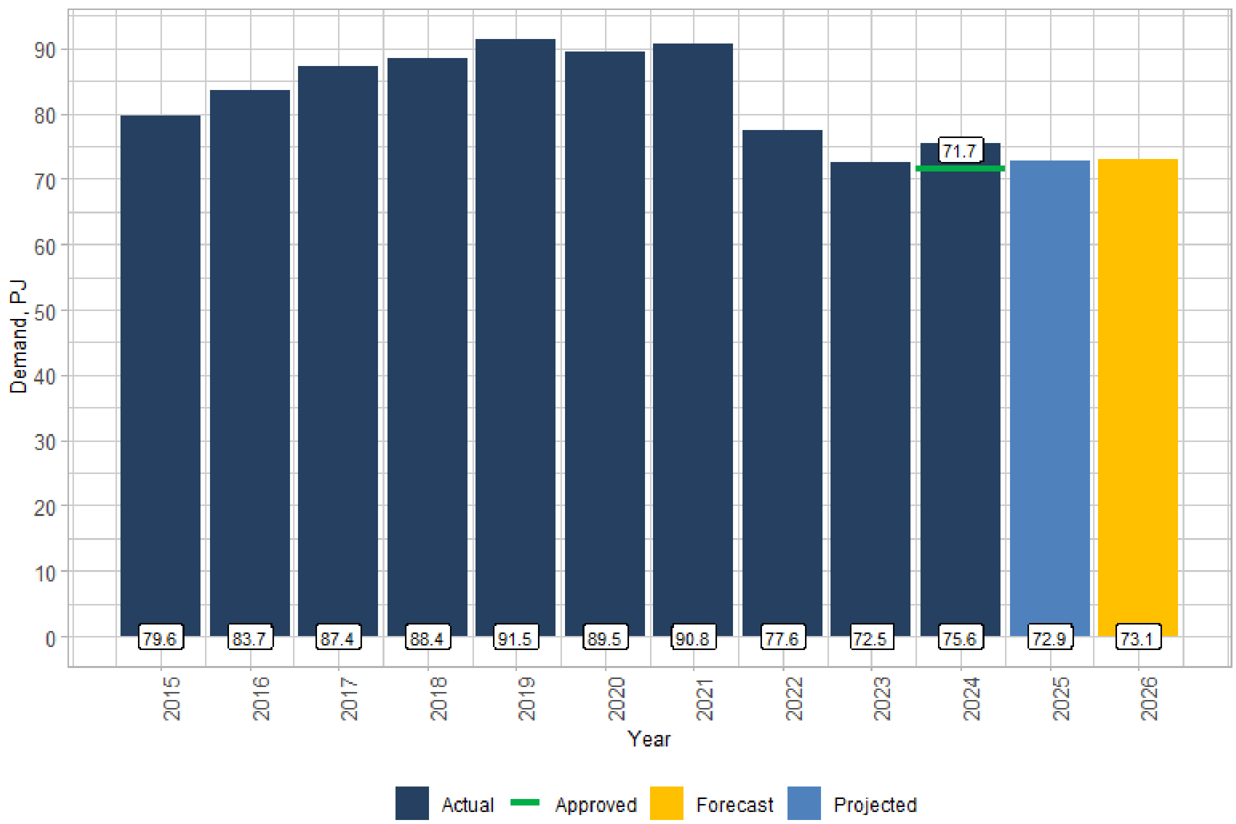
Table 3-1: Industrial Survey Response Rates

Industrial Survey	Description	Customers	Demand
Survey Completed	The survey was delivered and completed.	48.8%	90.6%
Survey delivered but not completed	The survey was delivered, but after three follow-up emails was not completed.	51.0%	9.3%
Survey undeliverable	The survey was not deliverable. This can be a result of invalid email addresses, faulty email servers etc.	0.2%	0.1%
Total		100.0%	100.0%

The forecast of demand for customers that either chose not to reply to the survey or could not be contacted (representing 9.4 percent of the total industrial demand) was set to equal 2024 Actual consumption.

As shown in Figure 3-10 below, the 2024 Actual demand from industrial customers was approximately 3.9 PJ higher than 2024 Approved. The increase is primarily due to an increase in demand from BC Hydro Island Generation (IG) under RS 22 compared to 2024 Approved demand (2024 Actual demand of 2.54 PJ compared to 2024 Approved demand of 0.01 PJ). Based on the industrial survey results, the 2025 Projected demand from industrial customers is 72.9 PJ, which is an increase of 1.2 PJ from 2024 Approved, and the 2026 Forecast demand is 73.1 PJ, which is an increase of 0.2 PJ from 2025 Projected.

Figure 3-10: Industrial Demand[18]



3.2.4 NGT and LNG Demand

This section summarizes the compressed natural gas (CNG) and liquefied natural gas (LNG) demand forecasts from FEI's NGT services as well as non-NGT related demand for LNG supplied under RS 46. Table 3-2 below provides the 2024 Approved, 2024 Actual, 2025 Projected, and 2026 Forecast of total NGT (CNG and LNG) and non-NGT LNG demand. The forecast of the total NGT and non-NGT LNG demand includes only actual volumes taken by customers under spot purchase agreements up to June 30, 2025, to align with the forecasting approach discussed in the RSF Application.

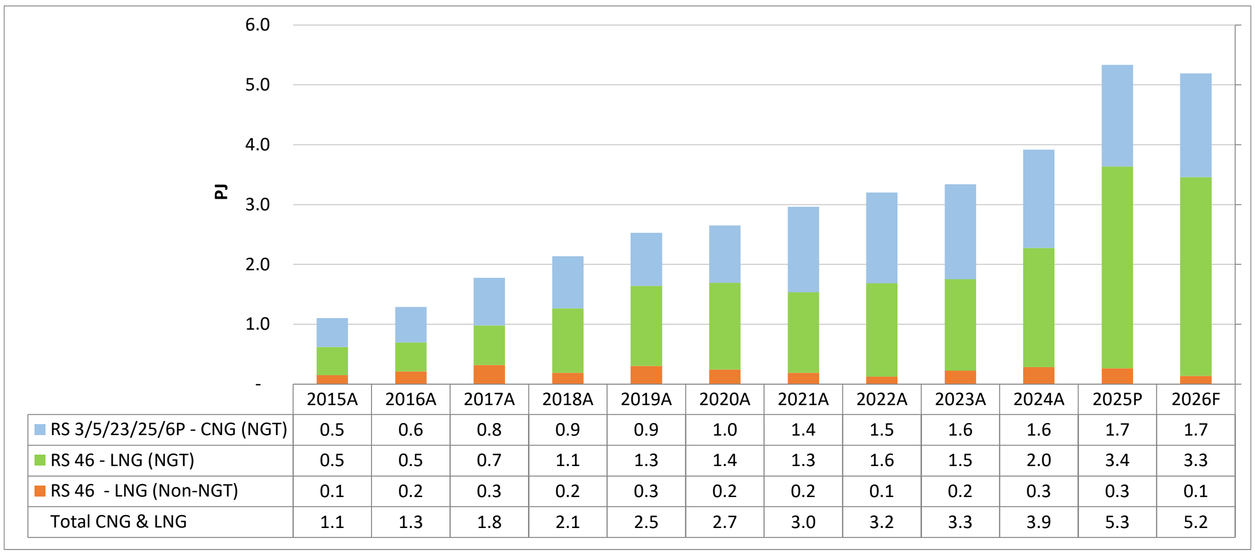
[18] Excludes NGT and non-NGT LNG customers under Rate Schedules 5, 25, and 46.

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

	2024 Approved	2024 Actual	2025 Projected	2026 Forecast
CNG	1,762.1	1,645.3	1,696.5	1,730.5
LNG	1,562.6	1,986.8	3,373.6	3,321.4
Total NGT Demand (TJ)	**3,324.7**	**3,632.0**	**5,070.1**	**5,051.9**
Non-NGT LNG	1,471.0	285.8	262.4	138.0
Total NGT and Non-NGT Demand (TJ)	**4,795.7**	**3,917.9**	**5,332.5**	**5,189.9**

Figure 3-11 below shows the most recent 10-year actual results, the 2025 Projected and the 2026 Forecast of 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 (PJ)[19]



The 2025 Projected demand of 5.3 PJ is 1.4 PJ higher than the 2024 Actual demand of 3.9 PJ. This increase is primarily related to the projected increase in LNG demand under FEI's NGT service from marine bunker vessels in 2025, as further explained below. The 2026 Forecast demand is 5.2 PJ.

For CNG demand, the 2025 Projected is 0.1 PJ higher than 2024 Actual, primarily due to increasing demand by customers at existing CNG stations, while the 2026 Forecast is consistent with the 2025 Projected level. As shown in Figure 3-11 above, the CNG demand has been gradually increasing since 2015.

For LNG demand, the 2025 Projected is 1.4 PJ higher than the 2024 Actual, primarily driven by LNG demand from marine bunker vessels owned and operated by Seaspan Energy under FEI's

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

NGT service. This demand is forecast at similar levels for 2026. The 2026 Forecast for non-NGT LNG demand is slightly lower than the 2025 Projected, as FEI has included only signed contract demand associated with ISO containers in the 2026 Forecast (consistent with the approach discussed in the RSF Application).

3.3 *REVENUE AND MARGIN FORECAST*

The forecasts of revenues and delivery margins have been developed by considering the total forecast of energy demand in GJ at the approved delivery rates, commodity, and storage and transport rates.

3.3.1 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 2024 Approved, 2024 Actual, 2025 Projected, and 2026 Forecast revenue, by customer segment, at the applicable approved rates.[20]

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

Revenue ($ millions)	2024 Approved	2024 Actual	2025 Projected	2026 Forecast
Residential[1]	$ 1,092.727	$ 934.811	$ 959.845	$ 1,025.459
Commercial[2]	586.461	528.414	528.613	564.950
Industrial[3]	235.247	219.372	237.801	236.437
Total	**$ 1,914.435**	**$ 1,682.597**	**$ 1,726.259**	**$ 1,826.846**

<u>*Notes to table:*</u>

[1] Rate Schedule 1.

[2] Rate Schedules 2, 3, 23.

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

3.3.2 Delivery Margin

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

[20] The 2025 Projected is based on 2024 Approved rates, and the 2026 Forecast is based on 2025 Approved Interim rates.

Table 3-4 below summarizes the 2024 Approved, 2024 Actual, 2025 Projected, and 2026 Forecast margin, by customer segment, at the applicable approved delivery rates.[21]

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

Delivery Margin ($ millions)	2024 Approved	2024 Actual	2025 Projected	2026 Forecast
Residential[1]	$ 701.024	$ 664.376	$ 683.422	$ 747.125
Commercial[2]	324.302	321.536	329.884	363.574
Industrial[3]	144.960	149.749	151.713	151.888
Total	**$ 1,170.286**	**$ 1,135.661**	**$ 1,165.019**	**$ 1,262.587**

Notes to table:

[1] Rate Schedule 1.

[2] Rate Schedules 2, 3, 23.

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

Variances between the delivery margin forecast in this section and the 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.

3.4 *SUMMARY*

FEI's forecast of demand for natural gas is based upon methods approved in the RSF Decision for 2025 to 2027. FEI's forecast provides a reasonable estimate of future natural gas demand for 2025 and 2026. Based on these methods, for 2025, FEI is projecting a small decrease in consumption of 0.2 PJ or 0.09 percent when compared to the 2024 Approved level, which results in a decrease in revenue of $188.2 million based on the 2024 Approved rates. For 2026, FEI is forecasting a small increase in consumption of 2.2 PJ or 1.0 percent when compared to the 2025 Projected level, which results in an increase in revenue of $100.6 million based on the 2025 Approved Interim rates.

[21] The 2025 Projected is based on 2024 Approved delivery rates, and the 2026 Forecast is based on 2025 Approved Interim delivery rates.

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. FEI is not requesting approval of forecast gas costs within this Application. Instead, any rate changes related to the flow through of gas costs and the CMAE[22] 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.

While FEI is not requesting approval of forecast gas costs 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 forecasts described in Section 3 by the current commodity gas recovery charge and the Storage and Transport (S&T) charge for each rate schedule.

Table 4-1 below summarizes, by customer segment, the 2024 Approved cost of gas that was forecast as part of FEI's Annual Review for 2024 Delivery Rates, the 2024 Actual cost of gas, and the 2025 Projected and 2026 Forecast cost of gas for the purposes of determining the total revenue requirements for 2025 and 2026. The cost of gas shown in Table 4-1 does not include the Renewable Natural Gas (RNG) supply costs associated with FEI's RNG Blend service and Voluntary RNG service. Pursuant to Decision and Order G-77-24,[23] RNG supply costs are now captured in the RNG Account and recovered from customers under Rate Schedules 1 to 7 and 46 through the S&T RNG Rider 8, and from customers under the Voluntary RNG service[24] through the RNG Charge. Similar to the commodity gas recovery charge and S&T charges, FEI seeks approval of the RNG Blend percentage, the S&T RNG Rider 8 and the RNG Charge in separate applications to the BCUC.

Table 4-1: Forecast Cost of Gas at Existing Rates[25]

Cost of Gas ($ millions)	2024 Approved	2024 Actual	2025 Projected	2026 Forecast
Residential[1]	$ 391.703	$ 270.434	$ 276.423	$ 278.334
Commercial[2]	262.157	206.876	198.729	201.376
Industrial[3]	90.289	69.626	86.088	84.549
Total	**$ 744.149**	**$ 546.936**	**$ 561.240**	**$ 564.259**

[22] Pursuant to Directive 4.c. of Order G-69-25, FEI is directed to "Submit the CMAE budget for approval, as well as review of prior year's forecast to actuals, as a separate application at or near the same time as FEI's third quarter gas cost report and remove these items from the Annual Reviews".

[23] Page 81 of Decision and Order G-77-24.

[24] Voluntary RNG service under RS 1RNG, 2RNG, 3RNG, 3VRNG, 5RNG, 5VRNG, 7RNG, 7VRNG, 11RNG, and RS 46.

[25] Cost of gas from transportation customers (i.e., RS 22, 23, 25 and 27) is resulting from unaccounted for gas (UAF).

Notes to table:

[1] Includes Rate Schedule 1

[2] Includes Rate Schedules 2, 3, and 23

[3] Includes Rate Schedules 4, 5, 6, 6P, 7, 22, 25, 27, and 46

The 2024 Approved, 2024 Actual, 2025 Projected, and 2026 Forecast cost of gas amounts shown in Table 4-1 above are based on the following:

- The 2024 Approved cost of gas was included as part of the Annual Review for 2024 Delivery Rates which was filed with the BCUC in July 2023. It was calculated based on the approved[26] commodity cost recovery charge of $3.159 per GJ effective July 1, 2023, and the approved[27] S&T charges applicable to RS 1 to 7 and 46 effective January 1, 2023.
- The 2024 Actual cost of gas was based on the 2024 Actual demand at the approved commodity cost recovery charge and the approved S&T charges in 2024. The approved commodity cost recovery charge was $2.230 per GJ, effective January 1, 2024, pursuant to Order G-327-23, and the charge remained the same throughout 2024. The S&T charges applicable to RS 1 to 7 and 46 were also approved by Order G-327-23[28]. As discussed above, the 2024 Actual cost of gas shown in Table 4-1 does not include the RNG supply costs related to the RNG Blend, which was approved to be set at 1 percent from July 1, 2024 to December 31, 2024 by Order G-242-24. The difference between the 2024 Approved and 2024 Actual cost of gas is primarily due to the variance in demand as well as the different cost of gas recovery rates used between the actual and forecast.
- The 2025 Projected cost of gas is calculated based on:
  - The 2025 Projected demand described in Section 3 of the Application, less the volume associated with the RNG Blend, which was approved to be set at 2 percent effective January 1, 2025[29] and at 3 percent effective July 1, 2025[30];
  - The approved commodity cost recovery charge of $2.230 per GJ by Order G-88-25, effective January 1, 2025[31]; and
  - The approved S&T charges applicable to RS 1 to 7 and 46 by Order G-88-25, effective January 1, 2025[32].

[26] Approved by Order G-148-23.
[27] Approved by Order G-347-22. For RS 1, the approved S&T charge was $1.534 per GJ.
[28] E.g., the approved S&T charge applicable to RS 1, effective January 1, 2024, was $1.102 per GJ.
[29] Order G-325-24A.
[30] Order G-181-25.
[31] By Letter L-9-25, FEI was approved to maintain the commodity cost recovery charge at the existing rate, effective July 1, 2025.
[32] E.g., the approved S&T charge applicable to RS 1, effective January 1, 2025, is $1.260 per GJ.

- The 2026 Forecast cost of gas is calculated based on:
    - The 2026 Forecast demand described in Section 3 of the Application, less the volume associated with the RNG Blend, which is currently set at 3 percent, as discussed above;
    - The currently approved commodity cost recovery charge of $2.230 per GJ effective July 1, 2025; and
    - The currently approved S&T charge applicable to RS 1 to 7 and 46, effective January 1, 2025.

The cost of gas shown in Table 4-1 above also includes the costs related to unaccounted for gas (UAF), which refers to gas that is not specifically accounted for in gas energy balance of receipts, deliveries, and operations use. 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 recovered from core customers[33] (i.e., RS 1 to 7 and 46) via the S&T charges. The cost of UAF related to the Transportation Service rate classes (i.e., RS 22, 23, 25, and 27) is included in the determination of their delivery rates to facilitate recovery of UAF costs as they do not pay S&T charges.

[33] 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 RSF Decision (page 18), 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 2020-2024 MRP term.

As shown in Table 5-1 below, FEI is projecting a decrease in Other Revenue of approximately $10.170 million from 2024 Approved to 2025 Projected, followed by an increase of approximately $15.704 million from 2025 Projected to 2026 Forecast. The decrease in 2025 and increase in 2026 are both primarily due to changes in RNG Other Revenue related to the City of Vancouver (CoV) Landfill RNG Project, which will be placed in service in 2025. Please refer to Section 5.2.5 for further details.

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

	2024 Approved	2024 Actual	2025 Projected	2026 Forecast
Late Payment Charge	$ 3.607	$ 3.393	$ 3.628	$ 3.511
Application Charge	1.797	1.496	1.569	1.533
NSF Returned Cheque Charges	0.028	0.046	0.028	0.028
Other Recoveries	0.288	0.250	0.288	0.288
NGT Related Recoveries	4.638	3.898	3.595	3.738
RNG Other Revenue	0.762	1.957	(8.122)	7.592
SCP Third Party Revenue	13.320	13.320	13.284	13.284
LNG Capacity Assignment	18.039	18.039	18.039	18.039
Total Other Operating Revenue	**$ 42.479**	**$ 42.399**	**$ 32.309**	**$ 48.013**

In the following sections, FEI summarizes the methods used to forecast the line items included in the table above.

5.2 OTHER REVENUE COMPONENTS

5.2.1 Late Payment Charge

The 2025 Projected Late Payment Charges are higher than 2024 Actual but are consistent with 2024 Approved. The 2025 Projected Late Payment Charges are calculated based on the average of the 2023 and 2024 Actual amounts.

Consistent with the method approved in the RSF Decision,[34] the 2026 Forecast for Late Payment Charges is calculated based on the average of the 2024 Actual Late Payment Charges of $3.393 million and the 2025 Projected amount of $3.628 million. This results in a forecast decrease in Late Payment Charges of $0.117 million compared to 2025 Projected.

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 2025 Projected amount is $0.228 million less than 2024 Approved but $0.073 million higher than 2024 Actual. The 2026 Forecast is slightly less than 2025 Projected (i.e., a decrease of $0.036 million).

5.2.3 NSF Returned Cheque Charges and Other Recoveries

The 2025 Projected and 2026 Forecast amounts for NSF Returned Cheque Charges and other miscellaneous income items are consistent with 2024 Approved levels.

5.2.4 NGT Related Recoveries

FEI has forecast recoveries associated with the NGT program related to the overhead and marketing (OH&M) 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 captured in the Flow-through deferral account and the CNG & LNG Service Revenues deferral account, respectively.

Table 5-2: 2025 and 2026 NGT Related Recoveries ($ millions)

	2024 Approved	2024 Actual	2025 Projected	2026 Forecast
NGT Overhead and Marketing Recovery	$ 0.341	$ 0.237	$ 0.227	$ 0.228
NGT Tanker Rental Revenue	1.021	0.869	0.971	1.067
CNG & LNG Service Revenues	3.276	2.792	2.397	2.443
Total NGT Related Recoveries	**$ 4.638**	**$ 3.898**	**$ 3.595**	**$ 3.738**

The following subsections discuss each of the NGT related recoveries.

5.2.4.1 NGT Overhead and Marketing Recovery

Pursuant to Order G-78-13, FEI has included a forecast of OH&M recoveries from FEI's NGT fuelling station customers. As shown in Table 5-3 below, the 2025 Projected NGT OH&M revenue is $0.227 million and the 2026 Forecast NGT OH&M revenue is $0.228 million. This revenue is

[34] RSF Decision and Order G-69-25, p. 56.

calculated by multiplying the approved OH&M rate of $0.52 per GJ by the applicable[35] 2025 Projected and 2026 Forecast CNG and LNG sales volumes.

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

	2024 Approved	2024 Actual	2025 Projected	2026 Forecast
Applicable Volume (GJ)	655,899	455,681	437,409	439,392
Rate ($/GJ)	0.52	0.52	0.52	0.52
Total NGT OH&M Revenue ($ millions)	**$ 0.341**	**$ 0.237**	**$ 0.227**	**$ 0.228**

5.2.4.2 NGT Tanker Rental Revenue

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

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

	2024 Approved	2024 Actual	2025 Projected	2026 Forecast
Standard Tanker Rental Deliveries	96	14	11	12
Rate ($/Delivery)	$ 327	$ 336	$ 345	$ 352
Sub Total ($ millions)	**$ 0.031**	**$ 0.005**	**$ 0.004**	**$ 0.004**
Tridem Tanker Rental Deliveries	-	-	-	-
Rate ($/Delivery)	$ 392	$ n/a	$ n/a	$ n/a
Sub Total ($ millions)	**$ -**	**$ n/a**	**$ n/a**	**$ n/a**
Marine Equipped Tridem Tanker Rental Deliveries	1,792	1,527	1,665	1,792
Rate ($/Delivery)	$ 552	$ 566	$ 581	$ 593
Sub Total ($ millions)	**$ 0.989**	**$ 0.864**	**$ 0.967**	**$ 1.063**
Total Tanker Rental Revenue ($ millions)	**$ 1.021**	**$ 0.869**	**$ 0.971**	**$ 1.067**

Consistent with the 2024 Actual standard tanker rental revenue, FEI is projecting/forecasting minimal revenue for 2025 and 2026 (i.e., $0.004 million in each of 2025 and 2026).

With regard to the Tridem tankers, as explained in previous Annual Reviews, these tankers are primarily used for long haul deliveries in Canada, such as to the Yukon, and they are not permitted in the US (due to weight restrictions in the US). Given these restrictions and that FEI did not expect Canadian deliveries to occur outside of BC, FEI sold the single Tridem tanker at the end of 2023 and retired it from FEI's rate base, with all gains from the sale returned to FEI's customers.

For the Marine Equipped Tridem tankers, the 2024 Actual revenue was lower than 2024 Approved, primarily due to outages and maintenance associated with marine customers which

[35] 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.

reduced their deliveries in 2024. For 2025, FEI projects deliveries to increase from 2024 Actual levels and, for 2026, FEI is forecasting deliveries to return to 2024 Approved levels.

5.2.4.3 CNG and LNG Service Revenue Forecast

The CNG and LNG Service Other Revenue forecast includes the FEI-owned CNG and LNG fuelling station recoveries (i.e., capital, O&M, and short-term fuelling rates) at the contracted minimum take-or-pay volumes of each station. Table 5-5 below provides a breakdown of the CNG and LNG fuelling station recoveries. The forecast of station recoveries as Other Revenue does not include recoveries from spot volume and excess volume (i.e., a fuelling customer uses more than their contracted minimum take-or-pay volume).[36]

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

	2024 Approved	2024 Actual	2025 Projected	2026 Forecast
CNG Station	$ 2.594	$ 2.360	$ 2.200	$ 2.243
LNG Station	0.535	0.292	0.034	0.035
Subtotal - NGT Stations ($ millions)	**$ 3.128**	**$ 2.652**	**$ 2.235**	**$ 2.278**
Surrey Ops CNG Pump	0.148	0.140	0.163	0.166
Total ($ millions)	**$ 3.276**	**$ 2.792**	**$ 2.397**	**$ 2.443**

For CNG stations, the 2024 Actual was lower than 2024 Approved primarily due to a higher forecast of minimum take-or-pay volume from McRae's Environmental Ltd. (McRae's) at the Langford CNG Fuelling Station at the time that the 2024 Approved forecast was developed in 2023. For 2025, FEI is projecting a further reduction when compared to 2024 Actual, primarily due to GFL Environmental Inc.'s (GFL) anticipated buy-out of the GFL Coquitlam CNG Fuelling Station from FEI. If complete, the assets associated with the fuelling station will be retired from FEI's rate base. FEI expects GFL will continue to operate the station currently served under RS 5, but there will be no further recoveries related to the station capital, O&M, and OH&M. For the 2026 Forecast, the small increase is primarily due to the approved annual increase in the fuelling rates at each station (i.e., the capital rate escalates at 2 percent per year and the O&M rate escalates by BC CPI per year).

For LNG stations, the reduction from 2024 Approved to 2024 Actual was primarily due to reduced recoveries from the Vedder Abbotsford LNG Fuelling Station following the decommissioning of the station in mid-2024, which was not anticipated at the time that the 2024 Approved forecast was developed in 2023. This reduced recovery was partially offset by new minimum take-or-pay demand from Dan Jones at the Port Kells LNG Fuelling Station.

FEI notes that, pursuant to Order G-162-25 which approved the discontinuance of the operation of the Vedder Abbotsford Fuelling Station, FEI was directed to provide an update regarding the recovery of the unrecovered capital cost of the station. To date, FEI has not recovered these

[36] 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.

costs, but FEI is engaged in constructive settlement discussions with Vedder. FEI will provide further updates in the Annual Review for 2027 Delivery Rates application.

For 2025, the further reduction in LNG Stations revenue is due to the full-year impact of the closure of the Vedder Abbotsford LNG Fuelling Station as well as no minimum take-or-pay volumes from Vedder Transport at the Port Kells Fuelling Station. For 2026, the small increase is due to the approved annual increase in the fuelling rates at each station (i.e., the capital rate escalates at 2 percent per year and the O&M rate escalates by BC CPI per year).

5.2.5 RNG Other Revenue

In accordance with Order G-210-13, which approved the RNG Program (formerly referred to as the Biomethane Program) on a permanent basis, the following delivery margin related costs are recorded in the RNG account:[37]

- Upgrading plant cost of service; [38]
- Interconnection cost of service; and
- Program overhead costs.[39]

The RNG Other Revenue represents the transfer of the earned return and income tax components of the cost of service of FEI's RNG capital assets from the delivery margin to the RNG Account.

The primary driver of the variance between 2024 Approved and 2024 Actual, and the changes in 2025 Projected and 2026 Forecast compared to 2024 Actual, is the timing of the COV Landfill RNG Project (formerly referred to as the COV Biomethane Project) going into service.

When the COV Landfill RNG Project goes into service in 2025, a large income tax credit will be generated due to the high capital cost allowance (CCA) associated with the COV Landfill RNG Project assets, as these assets are eligible for the enhanced first-year allowance under Canada's Accelerated Investment Incentive Program (AIIP).[40] The income tax credit offsets the earned return and income tax associated with RNG capital assets, which in turn reduces the overall RNG Other Revenue.

The 2024 Approved RNG Other Revenue included this expected income tax credit (as FEI had anticipated the COV Landfill RNG Project going into service in 2024 at the time of the Annual

[37] Renamed from the Biomethane Variance Account (BVA) to the RNG Account pursuant to Order G-77-24.
[38] The cost of procuring RNG supply does not need to be transferred because it is accounted for directly in the RNG Account.
[39] Program costs as defined in Order G-210-13 include education, marketing, direct administration, cost of enrollment and the cost of IT upgrades.
[40] For 2025, the enhanced first-year allowance is 75% for clean energy equipment, 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

Review for 2024 Delivery Rates); however, the project's in-service date was delayed to 2025, resulting in the 2024 Actual RNG Other Revenue being higher than 2024 Approved.

The COV Landfill RNG Project assets entering rate base in 2025 has resulted in the 2025 Projected RNG Other Revenue being in a debit (i.e., negative) position. The 2025 Projected debit amount of $8.122 million is comprised of a $4.210 million credit related to the earned return on RNG assets, offset by a $12.332 million debit due to the previously described income tax credit.

The 2026 Forecast of $7.592 million includes $6.481 million of earned return and $1.111 million of total income tax expense to be transferred to the RNG Account. The increase in the earned return amount compared to 2025 Projected reflects an increase in rate base, primarily due to the full year impact of the COV Landfill RNG Project assets in FEI's rate base (as the assets entered rate base in 2025, there was only a mid-year impact in 2025 Projected). The increase in the income tax expense reflects the significant reduction in the amount of income tax deductible through CCA in 2026 compared to 2025 associated with the COV Landfill RNG Project.

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: SCP Revenue Components ($ millions)

	2024 Approved	2024 Actual	2025 Projected	2026 Forecast
MCRA	$ 13.320	$ 13.320	$ 13.284	$ 13.284
Net Other Mitigation - West to East Capacity	-	-	-	-
Total SCP Revenue	**$ 13.320**	**$ 13.320**	**$ 13.284**	**$ 13.284**

The components of the SCP Third Party Revenue shown in Table 5-6 are discussed separately below. Any variances 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 2025 Projected and 2026 Forecast Other Revenue of $13.284 million[41] is related to the inclusion of the 105 MMcfd of SCP east to west capacity in the MCRA portfolio.

As part of the Annual Review for 2020 and 2021 Delivery Rates Decision and Order G-319-20,[42] FEI was approved, effective November 1, 2020, for the duration of the 2020-2024 MRP term, to

[41] The decrease in the 2025 Projected and 2026 Forecast of MCRA Other Revenue compared to 2024 is because 2024 was a leap year, i.e., the additional day in a leap year equates to approximately $346.617 per MMcfd x 105 MMcfd x 1 day / 1,000,000 = $0.036 million.

[42] Directive 7 to Order G-319-20.

debit the MCRA and credit Other Revenue in the amount of $346.617 per MMcfd for the 105 MMcfd of SCP east to west capacity held within the gas supply midstream portfolio.

For the duration of the 2025-2027 RSF term, FEI plans to continue to hold all of the 105 MMcfd of SCP east to west capacity within its gas supply midstream portfolio, which has been the approach since November 1, 2020 and is consistent with FEI's BCUC-accepted 2024/25 and 2025/26 Annual Contracting Plans.[43] Given that the BCUC only approved the previously described treatment for the duration of the 2020-2024 MRP term, FEI is seeking approval in this Application, effective January 1, 2025 and for the duration of the RSF term, to continue the same treatment.

5.3.2 Net Other Mitigation Revenue

FEI 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 2025 and 2026 is based on the forward market price differentials for summer 2025 and summer 2026, respectively. Huntingdon remains a higher 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 2025 and 2026.

5.4 *LNG CAPACITY ASSIGNMENT*

The $18.039 million in LNG capacity assignment Other Revenue shown in Table 5-1 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.[44]

[43] The 2024/25 Annual Contracting Plan (ACP) was accepted by Letter L-13-24 and the 2025/26 ACP was accepted by Letter L-7-25.

[44] 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.

5.5 SUMMARY

FEI has forecast the Other Revenue components for 2025 and 2026 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 RNG Account (for variances in the items discussed in Section 5.2.5), the CNG/LNG Recoveries deferral account (for excess revenue from the CNG & LNG Service Recoveries forecast discussed in Section 5.2.4.3), and the Flow-through deferral account (for any remaining variances from forecast in Section 5.2.4.3 and all variances from forecast in Sections 5.2.4.2 and 5.4). All remaining variances in Other Revenue are shared with customers through the Earning Sharing Mechanism.

6. O&M EXPENSE

6.1 *INTRODUCTION AND OVERVIEW*

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

In the RSF Decision, the BCUC approved a Base 2024 O&M for FEI based on the adjusted actual 2023 O&M plus net incremental funding in certain areas.[45] As provided in the compliance filing to the RSF Decision,[46] the resulting 2024 Approved Base O&M for FEI is $299.127 million, which, divided by the 2024 Actual average customer count, results in a 2024 Base Unit Cost O&M (UCOM) of $274.

The 2025 Formula O&M is $312.846 million, representing an increase of 0.1 percent from the 2024 Approved Formula O&M of $312.561 million. The drivers of the increase are the 2025 net inflation factor, the increase in the average customer count forecast from 2024 to 2025, and the elimination of the discount on the growth factor applied to formula O&M, all of which are mostly offset by the reduction in the Base O&M, which was reset to $299.127 million as part of the approved RSF. The 2026 Formula O&M is $325.220 million, representing a 4.0 percent increase from the 2025 Formula O&M, driven by the 2026 net inflation factor and the increase in the average customer count forecast from 2025 to 2026.

For the O&M expenses tracked outside of the formula (i.e., forecast O&M), the 2025 Projected amount is $87.940 million, representing a 52.6 percent increase from the amount approved for 2024. This increase is primarily the result of the reclassification of the Advanced Metering Infrastructure (AMI) related O&M costs from formula O&M to forecast O&M, as approved in the RSF Decision.[47] The 2026 Forecast O&M is $91.321 million, representing a 3.8 percent increase from the amount projected for 2025.

Overall, the increase in gross O&M expense from 2024 Approved to 2025 Projected is 8.3 percent, and the increase in gross O&M expense from 2025 Projected to 2026 Forecast is 3.9 percent.

The components of the 2025 and 2026 O&M expense are shown in Table 6-1 below.

[45] RSF Decision and Order G-69-25, pp. 29-30.
[46] Compliance Filing to Order G-69-25, p.1.
[47] RSF Decision and Order G-69-25, p. 29.

Table 6-1: 2025 and 2026 O&M Expense ($ millions)

Line No.	Description	2024 Approved	2024 Actual	2025 Projected	2026 Forecast	Reference
1	Formula O&M	$ 312.561	$ 309.994	$ 312.846	$ 325.220	Section 11, Schedule 20, Line 12
2	Forecast O&M	57.646	59.041	87.940	91.321	Section 11, Schedule 20, Line 24
3	Total Gross O&M	370.207	369.036	400.786	416.541	Line 1 + Line 2
4	Capitalized Overhead	(59.233)	(59.233)	(58.114)	(60.398)	Section 11, Schedule 20, Line 28
5	O&M transferred to RNG Account	(5.817)	(6.540)	(7.278)	(7.946)	Section 11, Schedule 20, Line 27
6	Net O&M	$ 305.157	$ 303.263	$ 335.394	$ 348.197	Line 3 through 5

In the sections below, FEI provides further details on its formula and forecast O&M expenses for 2025 and 2026.

6.2 *FORMULA O&M EXPENSE*

The formula-driven portion of O&M is calculated based on the prior year's Approved Base UCOM, escalated by the inflation factor (I-Factor) less the X-Factor of 0.55 percent, 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.

For 2025 and 2026, the formula O&M is calculated as follows:

> 2025 Formula O&M = 2024 Approved Base UCOM x [1 + (I Factor – X Factor)] x [2025 Forecast Average Customer Count] + 2023 Formula O&M True-up; and

> 2026 Formula O&M = 2025 Base UCOM x [1 + (I Factor – X Factor)] x [2026 Forecast Average Customer Count] + 2024 Formula O&M True-up

As discussed in Section 2 of the Application, the 2025 and 2026 net inflation factors based on prior year's BC-CPI and BC-AWE, less the X-Factor, are 3.648 percent and 2.726 percent, respectively.

Table 6-2 below shows the calculation of the 2025 and 2026 Formula O&M, including the calculation of the 2023 and 2024 Formula O&M true-ups.

Table 6-2: Calculation of 2025 and 2026 Formula O&M ($ millions)

Line No.	Description	2025 Projected	2026 Forecast	Reference
1	Prior Year Base Unit Cost O&M ($/customer)	$ 274	$ 283	2025: G-69-25 FEI RSF Decision; 2026: Line 3
2	Net Inflation Factor	3.648%	2.726%	Section 2, Table 2-4
3	Current Year Unit Cost O&M ($/customer)	$ 283	$ 291	Line 1 x (1 + Line 2)
4	Average Customer Forecast	1,102,958	1,114,373	2025: Sch 3, Line 14; 2026: Sch 3, Line 20
5	Inflation-Indexed O&M before True-up	$ 312.137	$ 324.283	Line 3 x Line 4 / 1,000,000
6	2023 and 2024 True-up O&M	0.709	0.937	Line 16
7	Inflation-Indexed O&M	$ 312.846	$ 325.220	Line 5 + 6
8				
9	2023/2024 O&M True-up			
10	2023/2024 Actual 12 month Average Customers	1,080,379	1,093,663	Table 2-2 Line 25
11	2023/2024 Forecast 12 month Average Customers	1,077,003	1,089,371	Table 2-2 Line 24
12	Difference	3,376	4,292	Line 10 - Line 11
13	Growth Factor	75%	75%	G-165-20 MRP Decision
14	Change in Customers - True-up	2,532	3,219	Line 12 x Line 13
15	2023/2024 Unit Cost ($/customer)	$ 280	$ 291	G-352-22 & G-334-23
16	O&M True-up for 2025/2026	$ 0.709	$ 0.937	Line 12 x Line 13 / 1,000,000

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 O&M, AMI-related O&M, BCUC levies, and O&M supporting Clean Growth Initiatives, as well as any exogenous factors. These amounts are shown in Table 6-3 below along with a comparison to 2024.

Table 6-3: 2025 and 2026 Forecast O&M ($ millions)

Line No.	Description	2024 Approved	2024 Actual	2025 Projected	2026 Forecast
1	Pension/OPEB (O&M Portion)	$ 2.555	$ 2.555	$ 6.790	$ 5.725
2	Insurance	13.328	12.871	12.623	12.748
3	Integrity O&M	11.200	12.401	9.700	12.000
4	AMI Flowthrough O&M	-	-	24.721	25.578
5	BCUC Levies	9.955	9.955	8.481	8.208
6	**Clean Growth Initiatives:**				
7	RNG O&M	5.817	6.540	7.278	7.946
8	Renewable Gas Development	4.052	2.250	4.584	5.084
9	NGT O&M	2.604	3.170	3.075	2.994
10	Variable LNG Production	8.135	8.234	10.688	11.038
11	**Exogenous Factors:**				
12	2021 Flooding Damage and Remediation	-	1.065	-	-
13	Total Forecast O&M	$ 57.646	$ 59.041	$ 87.940	$ 91.321

Each of the items that is forecast outside of the formula is discussed below. Variances in pension and OPEB expense are captured in the Pension and OPEB Variance deferral account and amortized into rates over a three-year period, as approved by Order G-138-14. Variances in BCUC fees are captured in the BCUC Levies Variance deferral account and amortized into rates in the subsequent year. Variances in insurance, integrity O&M, AMI-related O&M, 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 is based on actuarial estimates using a range of assumptions provided by FEI's actuary. 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 6-4.

Table 6-4: Pension and OPEB Expense ($ millions)

Line No.	Description	2024 Approved	2024 Actual	2025 Projected	2026 Forecast
1	O&M	$ 2.555	$ 2.555	$ 6.790	$ 5.725
2	Capital - Growth	0.871	0.871	1.176	1.095
3	Capital - Other	2.566	2.566	3.464	3.225
4	Deferred - Asset Removal Costs	1.012	1.012	1.366	1.272
5	Deferred - CMAE	0.306	0.306	0.413	0.385
6	Total	$ 7.310	$ 7.310	$ 13.210	$ 11.701

The total 2025 Projected pension and OPEB expense is $5.900 million higher than 2024 Approved. This increase is primarily due to the following:

- An increase of approximately $9.345 million, primarily driven by higher current service costs and lower amortization of actuarial gains. These changes are primarily the result of a decrease in the actuarially determined discount rate, which declined from 5.25 percent (used in the 2024 Approved expense) to 4.50 percent (used in the 2025 Projected expense). The discount rate is based on the market yield of high-quality debt instruments at a specific point in time.

This increase is partially offset by:

- A higher expected return on assets of $3.445 million, reflecting the growth in the pension plan asset values.

The total 2026 Forecast pension and OPEB expense is $1.509 million lower than 2025 Projected. This decrease is primarily due to the following:

- A reduction of approximately $4.072 million driven by lower current service costs and higher amortization of actual gains. These changes are largely due to an increase in the actuarially determined discount rate from 4.50 percent to 4.75 percent; and
- A higher expected return on assets of $1.275 million, reflecting continued growth in pension plan asset values.

These decreases are partially offset by:

- An increase in interest costs of $2.828 million, which also results from the higher discount rate; and
- A decrease in the amortization of prior year service credits of $1.010 million, as the remaining balance carried into 2026 will be fully amortized during 2026.

6.3.2 Insurance Expense

Insurance expense relates to the insurance premium expense allocated to FEI by Fortis Inc. as set out in Table 6-5 below.

Table 6-5: Insurance Expense ($ millions)

Line No.	Description	2024 Approved	2024 Actual	2025 Projected	2026 Forecast
1	Insurance Premiums	$ 13.328	$ 12.871	$ 12.623	$ 12.748

FEI's annual insurance renewal occurs in July of each year. The 2024 Actual insurance premiums were $0.457 million lower than 2024 Approved, as the insurance market softened in 2024 compared to recent years.

The 2025 Projected insurance premium expense of $12.623 million incorporates FEI's actual July 2024 to June 2025 insurance renewals (for the months of January to June 2025) and FEI's actual July 2025 to June 2026 insurance renewals (for the months of July to December). The 2026 Forecast insurance premium expense is $12.748 million, which is an increase of $0.125 million from 2025 Projected. The 2026 Forecast is calculated based on the actual insurance renewal from July 2025 to June 2026 plus 5 percent escalation for the insurance renewal from July 2026 to June 2027.[48]

6.3.3 Integrity O&M

As part of the RSF Decision[49], FEI was approved to continue to treat integrity digs as a flow-through item with variances between forecast and actual amounts captured in the Flow-through deferral account.

As shown in Table 6-3 above, the 2025 Projected Integrity O&M is $9.7 million, which is $1.5 million less than 2024 Approved. The reduction in 2025 Projected compared to 2024 Approved is due to the following:

- As part of the RSF Decision[50], FEI was approved to reclass the incremental integrity-driven expenditures related to the Inland Gas Upgrades (IGU) CPCN Project and the Coastal

[48] 2026 Forecast: $6.219 million (first 6 months in 2026) x 1.05 = $6.529 million. $6.219 million + $6.529 million = $12.748 million.
[49] RSF Decision and Order G-69-25, p. 18.
[50] RSF Decision and Order G-69-25, p. 29.

Transmission System (CTS) Transmission Integrity Management Capabilities (TIMC) CPCN Project from flow-through to formula O&M. The amount of incremental integrity O&M related to the IGU and CTS TIMC CPCN projects included in the 2024 Approved Integrity O&M flow-through was $1 million.

- FEI is projecting a reduced number of integrity digs for 2025, which has resulted in a projected reduction in integrity digs costs of $0.5 million.

For 2026, FEI is forecasting the integrity O&M to be $12 million, which is $2.3 million higher than 2025 Projected. The increase is due to an expected increase in the number of integrity digs and the average cost per dig, compared to 2025 Projected.

Table 6-6 below provides the forecast number of integrity digs with Reason for Dig categories as well as the total cost and average 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). FEI discusses the factors impacting the number of digs and the average cost per dig below the table.

Table 6-6: Integrity Digs Activities and Expenditures ($000s)

Line No.	Reason for Digs	2024 Approved	2024 Actuals	2025 Projected	2026 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.	85	23	43	59
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.	30	29	17	15
3	**ILI Digs – Established Tools and Practices:** ILI digs identified through previously established technologies, tools, and practices	35	64	39	36
4	**Non-ILI Digs:** Digs identified through above-ground cathodic protection and coating surveys.	10	17	6	6
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.	2	1	2	2
6	**Total Integrity Digs**	**162**	**134**	**107**	**118**
7	**Total Integrity Dig Expenditures ($ millions)**	**10.2**	**11.2**	**9.7**	**12.0**
8	Average Cost per Dig ($000s)	63	83	91	102

There continues to be significant uncertainty with respect to the number and complexity of integrity digs. FEI provides the following discussion for each Reason for Dig shown in Table 6-6 above.

- **ILI Digs – New Tools** is an estimate of the integrity digs resulting from first-time in-line inspections. For 2024, the actual dig numbers were lower than forecast due to a combination of schedule factors and results not warranting the number of digs estimated for this type of dig. For instance, archaeological Site Alteration Permits associated with the IGU CPCN Project resulted in some construction activities occurring later than originally anticipated. This had a corresponding impact on the timing of in-line inspections, analysis to identify integrity digs, and the completion of the digs themselves. The 2025 Projected and 2026 Forecast include digs associated with the IGU CPCN Project and the CTS TIMC CPCN Project. Factors that will impact the actual number of integrity digs required in 2025 and 2026, such as pipeline condition and inspection success, are unknown until after the first-time ILI tool runs are completed and data is analyzed by FEI, due to the large number of possible site-specific and pipeline-specific factors potentially impacting a pipeline's condition. 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;
    - Knowledge of imperfections that the IGU Project is endeavouring to locate and remove prior to ILI 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 ILI activities, with a primary input being the timing of IGU and CTS TIMC Project activities to prepare pipelines for running ILI tools.
- **ILI Digs – New Practices** continue to be influenced by the adoption of the strain-based criteria for dents as per current industry practice and standards. FEI's 2025 Projected and 2026 Forecast incorporates the analysis to date.
- **ILI Digs – Established Tools and Practices** result 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. In 2024, this dig category required a greater number of digs than initially estimated resulting from actual ILI results and analysis subsequent to the time of the initial estimate. The 2025 Projected and 2026 Forecast incorporate FEI's analysis to date (i.e., ILI and integrity dig results), while also fluctuating due to influences such as the number and timing of in-line inspections.
- **Non-ILI Digs** reflect assessments of transmission pipelines for which ILI 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.

- **Facilities Digs** reflect assessments of pipe condition within facility sites such as 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. Facilities digs can encompass relatively longer lengths of pipe at a single site (relative to typical digs on linear pipeline assets). Currently, FEI is forecasting two Facilities Digs per year, prioritized on the basis of factors including construction (e.g., age, expected external coating) and operating characteristics (e.g., station criticality, operating stress).

As shown in Table 6-6, the 2024 Actual average cost per dig was higher than 2024 Approved, and the average cost per dig is forecast to continue to increase in 2025 and 2026. There are a number of factors contributing to the increasing average cost per dig, including site-specific scope and cost factors as well as broader drivers.

Site-specific scope and cost factors that vary from dig to dig include site access, site management during the dig, site restoration, pipeline outside diameter, and pipeline repairs (if necessary). For example, digs resulting from the CTS TIMC CPCN Project are occurring in the more complex urban environment of the Lower Mainland. FEI also incurred costs for excavations on its largest diameter pipeline in 2024 – the Huntingdon-Roebuck 1067 mm (NPS 42) pipeline.

Broader drivers that are impacting the average cost per dig include changes in regulations and the evolution within the industry regarding environmental management. Regulatory amendments in 2023 introduced greater complexity and rigour regarding soil relocation and subsequently impacted FEI's soil management practices. For example, soil disposal has been required at some dig sites. Additionally, regulations have been evolving with respect to methane emissions. Most recently, the BC Pipeline Regulation (B.C. Reg. 281/210) was amended to include requirements pertaining to venting and depressurizing pipelines. As a result of these changes in regulations and environmental management practices, costs have increased (for example, specialized equipment is required to avoid venting gas to the atmosphere and more complex procedures increase the required labour hours), thus impacting the average cost per dig.

The 2025 Projected and 2026 Forecast reflect estimates developed by Transmission Operations staff and consider past and current costs to complete similar integrity digs, as well as utilizing knowledge and/or estimates of future costs where available.

6.3.4 AMI O&M

For the term of the RSF, FEI is approved to reclassify its O&M costs impacted by the AMI CPCN Project from formula to flow-through. The amount that was reclassified from formula O&M was based on the 2023 Actual O&M of $19.783 million.[51] The breakdown of these reclassified costs, as approved in the RSF Decision[52], is provided in Table 6-7 below. Deployment of new AMI meters began this year and is forecast to complete in 2028.

[51] See Section C2.2.2.2.1 of the RSF Application for further details.
[52] RSF Decision and Order G-69-25, p. 29.

Table 6-7: AMI O&M Expense ($ millions)

Line No.	Description	Reclass from Base O&M (RSF Decision)	2025 Projected	2026 Forecast
1	Meter Installation	$ 0.733	$ 1.263	$ 1.301
2	Meter Reading	15.142	16.700	16.000
3	Operations	2.122	2.165	2.230
4	Customer Service	1.480	1.114	1.343
5	Measurement	0.306	-	-
6	Subtotal	$ 19.783	$ 21.242	$ 20.874
7	New AMI Activities	-	3.479	4.704
8	Total AMI O&M	$ 19.783	$ 24.721	$ 25.578

As shown in Table 6-7 above, the 2025 Projected costs are $24.721 million and the 2026 Forecast costs are $25.578 million. FEI provides further discussion of each category below.

- **Meter Installation O&M:** FEI allocates 14 percent of the meter exchange costs related to exchanges completed by FEI's Operations to O&M, as discussed in the AMI Project CPCN application.[53] FEI Operations is expecting to complete more meter installations in 2025 and 2026 than originally contemplated in the RSF Application (which were based on 2023 actual meter installations), resulting in increasing O&M costs in 2025 and 2026. The majority of AMI meter installation costs are capitalized and included in FEI's AMI capital.

- **Meter Reading O&M:** This is the primary component of the AMI O&M and consists of the manual costs of reading meters and the cellular costs for current large commercial and industrial meters. The 2025 Projected Meter Reading O&M includes the cost of Olameter to perform manual meter reads. The increased cost for 2025 Projected reflects the contract negotiated with Olameter and the fact that AMI deployment has just started to occur in 2025. As the deployment of new AMI meters gradually increases moving into 2026, FEI is forecasting a reduction in meter reading costs in 2026 compared to 2025 Projected.

- **Operations O&M:** This is the cost for activities completed by FEI's field crews that are impacted by the AMI Project, specifically: meter trouble calls, meter reads, meter identifications, disconnects, unlocks, cathodic protection data gathering, and odour measurement. The 2025 Projected and 2026 Forecast costs are expected to remain relatively consistent with the amount reclassified from formula O&M.

- **Customer Service O&M:** This is the cost for the customer service activities impacted, including billing investigation and exceptions, meter reading coordinator workload, vacant

[53] FEI AMI CPCN Project Application, Exhibit B-1, Section 6.2.2.2, p. 106.

premise processing, and meter switching identification and validation. FEI is expecting a decrease in these costs for 2025 and 2026 as the AMI meters are deployed.

- **Measurement O&M:** This is the cost for activities related to the volume of meter exchanges and specifically, the meter sampling recall program. FEI will temporarily halt the meter sampling program during AMI deployment. While the program will resume after deployment, there will be a significant decrease in the volume of meters included in the sample as a result of the entire meter fleet being replaced.
- **New AMI Activities:** These are new costs incurred as a result of the AMI Project which include incremental internal labour, network and software costs, as discussed in the AMI Project CPCN application.[54] These new O&M costs will be phased in as the AMI Project is deployed. Incremental internal labour consists of a system engineer, and network and software support personnel. Network costs consist of managed network services, radio licences, backhaul bandwidth, lease costs and network security. Software costs consist of Software as a Service (SaaS) fees, licence costs and internal software updates needed after the implementation of initial system enhancements.

6.3.5 BCUC Levies

The 2025 Projected BCUC levies are $8.481 million. The 2025 Projected amount is based on the following:

- The levy amount in Order G-141-24 for the fourth quarter (Q4) of the BCUC's Fiscal 2024/25 year (January to March 2025); and
- For the remainder of 2025, the levy amount in Order G-117-25 for Q1 to Q3 of the BCUC's Fiscal 2025/26 year.

The 2026 Forecast for BCUC levies is $8.208 million. The 2026 Forecast is based on the annual levy amount in Order G-117-25, which represents the best information available at this time, as the BCUC levy calculation for Fiscal 2026/27 will not be available until early to mid 2026.

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

6.3.6 Clean Growth Initiative – RNG O&M

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

[54] FEI AMI CPCN Project Application, Exhibit B-1, Section 6.2.2.1, p. 106.

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

Line No.	Description	2024 Approved	2024 Actual	2025 Projected	2026 Forecast
1	Program Overhead	$ 3.986	$ 5.502	$ 5.538	$ 5.662
2	City of Surrey	0.017	0.014	0.014	0.014
3	Kelowna	0.745	0.562	0.575	0.587
4	Salmon Arm	0.283	0.374	0.383	0.390
5	Fraser Valley Biogas	0.013	0.012	0.013	0.013
6	Seabreeze Farms	0.013	0.014	0.014	0.015
7	Lulu Island WWTP	0.013	0.019	0.020	0.020
8	Dickland Farms	0.013	0.013	0.013	0.014
9	City of Vancouver	0.572	-	0.684	1.200
10	REN Energy	0.013	-	-	-
11	Capital Regional District	0.013	-	0.010	0.015
12	Delta RNG (MAS Energy)	0.133	0.030	0.015	0.015
13	Total RNG O&M	$ 5.817	$ 6.540	$ 7.278	$ 7.946

The 2024 Actual RNG O&M costs are $0.723 million higher than 2024 Approved. The increase is primarily due to higher program overhead costs. The increased program overhead costs are primarily attributable to higher spending on RNG awareness initiatives and staffing expenses associated with the RNG program development.

The 2025 Projected RNG O&M is $0.778 million higher than 2024 Actual and $1.461 million higher than 2024 Approved. With regard to program overhead, the costs are higher than 2024 Approved but are consistent with 2024 Actual amounts. FEI anticipates a reduction in spending in certain areas such as RNG awareness initiatives; however, these reductions are offset by an increase in staffing to support compliance activities related to production audits and to support the operations of upcoming in-BC projects; in particular, there is a projected increase in O&M (electricity costs, materials expense and labour) to support the operations for the COV Landfill RNG Project which is entering into service in 2025.

The increase in 2026 Forecast RNG O&M compared to 2025 Projected is primarily due to increases in O&M to support the operations of the COV Landfill RNG Project as it will be operational for the entire year.

Pursuant to Decision and Order G-77-24[55], RNG O&M is transferred to the RNG Account (formerly referred to as the Biomethane Variance Account) and recovered from customers under Rate Schedules 1 to 7 and 46 through the S&T RNG Rider 8, which is reviewed by the BCUC in separate applications.

[55] Decision and Order G-77-24, p. 81.

6.3.7 Clean Growth Initiative – Renewable Gas Development

FEI continues to progress various activities to enable the introduction of hydrogen into its system, and the increased costs for renewable and lower carbon gas development reflect this increased work. Table 6-9 below provides the 2024 Approved, 2024 Actual, 2025 Projected, and 2026 Forecast of FEI's Renewable Gas Development O&M expenditures.

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

Line No.	Description	2024 Approved	2024 Actual	2025 Projected	2026 Forecast
1	Renewable Gas Development	$ 4.052	$ 2.250	$ 4.584	$ 5.084

The 2024 Actual O&M was $1.230 million less than 2024 Approved. The decreased actual spending was primarily due to internal labour vacancies, lower actual consulting and legal costs for a number of ongoing projects, and funding from CleanBC and NRCan available in 2024 which offset actual expenditures.

The 2025 Projected O&M is $4.584 million, which is approximately $0.532 million higher than 2024 Approved. FEI is expecting to fill the internal labour vacancies in 2025 and is incurring increased consulting costs for ongoing development projects. For 2026, FEI is forecasting an increase of $0.500 million from the 2025 Projected level. The increase is related to the full year's salaries of new hires (as FEI expects to fill existing vacancies in 2025) and additional consulting and legal fees as FEI continues to progress in the development of hydrogen supply and use.

The following discussion summarizes the specific activities and projects that FEI is undertaking and expected to undertake in 2025 and 2026:

- **Hydrogen Production Supply Opportunities**:
  - 2025 – continue feasibility evaluation of 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.
  - 2026 – continue progress from 2025 to advance identified project opportunities.
- **Hydrogen Offtake Supply Opportunities (includes procurement feasibility):**
  - 2025 – continue evaluation of 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.

- 2026 – continue from 2025 with goal to advance one opportunity to definitive agreement.

- **Hydrogen Distribution and Customer End-Use Service (Gas System Hydrogen Readiness Assessment and Conversion):**
  - 2025 – FEI has been working with a consultant on a study to determine the overall requirements to distribute hydrogen blended into the natural 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.
  - 2026 – FEI will continue the system-wide hydrogen blending study with completion expected in 2027.

- **Concurrent Hydrogen Development Enabling Initiatives:**
  - 2025 and 2026 – continue progressing various concurrent activities including workforce education and training initiatives, engaging with technical regulators in BC, Canadian Standards Association (CSA), Canadian Gas Association (CGA), NRCan, and various other authorities having jurisdiction regarding various initiatives on hydrogen safety, codes and standards.

- **Hydrogen Demonstration Pilot Projects:**
  - 2025 and 2026 – continue 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 at FEI's Surrey Education Centre.

6.3.8 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 as well as FEI-owned LNG tankers available for rental to LNG customers. Table 6-10 below summarizes the NGT O&M for 2024 Approved, 2024 Actual, 2025 Projected, and 2026 Forecast.

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

Line No.	Description	2024 Approved	2024 Actual	2025 Projected	2026 Forecast
1	CNG Stations	$ 1.531	$ 2.077	$ 2.065	$ 1.979
2	LNG Stations	0.323	0.247	0.260	0.265
3	LNG Tankers	0.680	0.803	0.680	0.680
4	Emergency Response and Preparedness (ERAP)	0.070	0.044	0.070	0.070
5	Total NGT O&M	$ 2.604	$ 3.170	$ 3.075	$ 2.994

The 2025 Projected and 2026 Forecast NGT O&M expenses remain generally in line with 2024 Actuals, with a slight reduction in CNG Stations O&M costs due to fewer anticipated overhauls. This is partially offset by higher LNG Stations O&M costs, driven primarily by an expected increase in the LNG load as discussed in Section 3 of the Application.

6.3.9 Clean Growth Initiative – Variable LNG Production Costs

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 costs to operate the LNG plant, regardless of its use (for peak shaving storage, or LNG production for sales) while the variable costs include the liquefaction of natural gas, the dispensing of LNG, and the handling and loading of tankers with LNG which tend to fluctuate and are dependent on sales volumes.

Table 6-11 below summarizes the various components of the Variable LNG Production Costs for 2024 Approved, 2024 Actual, 2025 Projected, and 2026 Forecast.

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

Line No.	Description	2024 Approved	2024 Actual	2025 Projected	2026 Forecast
1	Tilbury Plant:				
2	Labour	$ 2.339	$ 2.640	$ 3.150	$ 3.253
3	Materials	0.623	0.686	0.850	0.878
4	Contractor	0.239	0.213	0.350	0.361
5	Power	3.909	3.658	5.100	5.267
6	Fees and Employee Expenses	0.193	0.148	0.205	0.212
7	Sub-total	$ 7.304	$ 7.345	$ 9.655	$ 9.971
8	Mt. Hayes Plant:	-	-	-	-
9	Labour	$ 0.374	$ 0.348	$ 0.396	$ 0.409
10	Materials	0.026	0.130	0.193	0.199
11	Contractor	0.190	0.193	0.198	0.204
12	Power	0.241	0.215	0.236	0.244
13	Fees and Employee Expenses	0.000	0.003	0.010	0.010
14	Sub-total	$ 0.831	$ 0.889	$ 1.033	$ 1.067
15	Total O&M	$ 8.135	$ 8.234	$ 10.688	$ 11.038

The Variable LNG Production O&M expense required for operation of the expanded Tilbury LNG facility[56] and the Mt. Hayes LNG facility consists of labour (includes LNG operators for truck loading and shunting of LNG, millwrights and electrical and instrumentation technicians to support production-related maintenance activities as well as operations management), materials, contractors (for truck loading and support of production related activities), power (includes electricity costs and consumables), and administration fees and employee expenses.

Tilbury LNG Facility

Overall, the 2024 Actual results were consistent with the 2024 Approved amounts. FEI discusses the 2025 Projected and 2026 Forecast variable costs below.

- **Labour:** 2025 Projected is expected to be higher than 2024 Approved due to increased LNG sales demand under RS 46, as discussed in Section 3 of the Application, necessitating additional support. The increase in the 2026 Forecast compared to 2025 Projected is due to salary increases.
- **Materials:** 2025 Projected is expected to be higher than 2024 Approved primarily due to more liquefaction runs requiring additional refrigerants to support the increase of LNG sales demand. For the 2026 Forecast, materials costs are expected to increase compared to 2025 Projected due to inflation.
- **Contractors:** FEI is projecting higher contractor services for 2025 compared to 2024 Approved primarily due to work on major equipment related to liquefaction. For 2026, FEI expects that contractor costs will be consistent with 2025, with a slight increase due to inflation.
- **Power:** For 2025, FEI is projecting an increase to the electrical costs due to the projected increase in LNG sales demand as discussed in Section 3 of the Application. For 2026, FEI expects the electricity costs to be slightly higher than 2025 Projected based on the small forecast increase in LNG sales demand for 2026.
- **Fees and Employee Expenses:** For 2025 and 2026, FEI is projecting/forecasting a small increase based on inflation.

Mt. Hayes LNG Facility

As shown in Table 6-11 above, the Mt. Hayes LNG Facility's O&M is a small component of the total Variable LNG Production O&M.

The primary drivers of the projected/forecast increases in 2025 and 2026 are inflation, annual salary increases, and BC Hydro rate changes.

[56] 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.

6.3.10 2021 Flooding Damage and Remediation

As part of the RSF Decision,[57] FEI was granted approval of exogenous factor treatment for the 2021 flooding damage and remediation costs and was directed to record the unrecovered costs in the Flow-through deferral account in 2024. The total unrecovered costs (less insurance proceeds) were $0.068 million plus the $1 million insurance deductible. Of this total, $1.065 million was related to O&M and was therefore recorded in 2024 Actual flow-through O&M, as shown in Table 6-3 above. The remaining $0.003 million was related to capital (see Section 7.3.2.4 of the Application).

6.4 *NET O&M EXPENSE*

Net O&M expense is gross O&M less capitalized overhead and RNG O&M transferred to the RNG Account. As approved by the RSF Decision, the capitalized overhead rate is set at 14.5 percent for FEI. After capitalized overhead and the transfer of the RNG O&M to the RNG Account, the net O&M expense for 2025 and 2026 is $335.394 million and $348.197 million, respectively.

6.5 *SUMMARY*

Overall, the increase in gross O&M expense from 2024 Approved to 2025 Projected is 8.3 percent, which includes a 0.1 percent increase in formula-driven O&M and a 52.6 percent increase in the O&M forecast outside of the formula (primarily related to the reclassification of O&M costs impacted by the AMI CPCN Project from formula O&M to flow-through O&M). The increase in gross O&M expense from 2025 Projected to 2026 Forecast is 3.9 percent, which includes a 4.0 percent increase in formula-driven O&M and a 3.8 percent increase in the O&M forecast outside of the formula.

[57] RSF Decision and Order G-69-25, p. 86.

7. RATE BASE

7.1 *INTRODUCTION AND OVERVIEW*

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 2025 Projected rate base is $6.452 billion. It includes the full-year impact of the 2024 closing plant balances as well as the impact of the following amounts:

- Mid-year impact of regular capital additions, net of Contributions in Aid of Construction (CIAC) additions of $419.235 million;
- Mid-year impact of plant depreciation, net of CIAC amortization of $220.937 million;
- Full-year impact of $158.314 million related to the true-up of rate base resulting from the end of the 2020-2024 MRP term;
- Capital additions of major projects of $151.300 million[58] as discussed in Section 7.4 below, which include:
    - Full-year impact of $68.612 million of capital expenditures and related AFUDC for the IGU CPCN Project;
    - Full-year impact of $13.517 million of capital expenditures and related AFUDC for the Gibsons Capacity Upgrade (GCU) Project; and
    - Full-year impact of $69.138 million of capital expenditures and related AFUDC for the CTS TIMC CPCN Project.

In addition, various changes in deferred charges, working capital and other items are forecast to increase rate base by a net amount of $225.864 million in 2025.

FEI's 2026 Forecast rate base is $6.835 billion. It includes the full-year impact of the 2025 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 $324.616 million;
- Mid-year impact of plant depreciation, net of CIAC amortization of $239.946 million;
- Capital additions of major projects of $217.214 million as discussed in Section 7.4 below, which include:

[58] The 2025 Projected capital additions also include $0.033 million for final expenditures and related AFUDC for the Pattullo Gasline Replacement (PGR) CPCN Project.

- Full-year impact of $30.257 million of capital expenditures and related AFUDC for the CTS TIMC CPCN Project;
- Full-year impact of $41.976 million of capital expenditures and related AFUDC for the Interior Transmission System (ITS) TIMC CPCN Project; and
- Full-year impact of $144.981 million of capital expenditures and related AFUDC for the AMI CPCN Project.

In addition, various changes in deferred charges, working capital and other items are forecast to increase rate base by a net amount of $123.715 million in 2026.

Details of the 2025 Projected and 2026 Forecast plant balances as well as depreciation, retirements, CIAC, working capital, and other rate base items are provided in Section 11.

7.2 TRUE-UP OF 2020-2024 MRP RATE BASE

During the term of the 2020-2024 MRP, capital expenditures in excess of the approved formula Growth capital and the approved forecast Sustainment and Other capital were excluded from rate base. As shown in Table 7-1 below, the cumulative amount of capital net of CIAC additions excluded from rate base was $158.314 million, which will be added to plant-in-service effective January 1, 2025.

Table 7-1: Summary of Rate Base True-up Amount from 2020-2024 MRP ($ millions)

Line No.	Particular	2020	2021	2022	2023	2024	Cumulative
1	Growth, Sustainment, and Other Capital						
2	Approved	$ 231.951	$ 227.703	$ 251.163	$ 271.381	$ 236.566	$ 1,218.764
3	Actual	248.486	257.514	278.061	301.267	297.831	1,383.159
4	Variance ($ million)	$ 16.535	$ 29.811	$ 26.898	$ 29.886	$ 61.265	$ 164.395
5							
6	CIAC Additions						
7	Approved	$ (5.814)	$ (5.354)	$ (5.852)	$ (4.595)	$ (6.732)	$ (28.347)
8	Actual	(5.336)	(6.398)	(6.482)	(9.837)	(6.375)	(34.428)
9	Variance ($ million)	$ 0.478	$ (1.044)	$ (0.630)	$ (5.242)	$ 0.357	$ (6.081)
10							
11	**Total Variance, net of CIAC ($ million)**	**$ 17.013**	**$ 28.767**	**$ 26.268**	**$ 24.644**	**$ 61.622**	**$ 158.314**

7.3 REGULAR CAPITAL EXPENDITURES

As part of the RSF Decision, FEI received the following approvals for regular capital expenditures:

- Growth capital to be set annually on a formula basis for the term of the RSF;
- Three-year forecasts of Sustainment and Other capital expenditures; and
- Flow-through capital for several items to be forecast on an annual basis.

The components of FEI's 2025 Projected and 2026 Forecast regular capital expenditures are shown in Table 7-2 below.

Table 7-2: Regular Capital Expenditures ($ millions)

Line No.	Description	2024 Approved	2024 Actual	2025 Projected	2026 Forecast	Reference
1	Formula Growth Capex	$ 54.686	$ 114.355	$ 99.264	$ 71.580	Section 11, Schedule 4, Line 10
2	Forecast Sustainment & Other Capex	181.880	183.476	193.503	194.429	Section 11, Schedule 4, Line 16 + 17
3	Flow through Capex	48.939	26.279	26.680	5.895	Section 11, Schedule 4, Sum of Line 13 to 15
4	Total Gross Regular Capex	$ 285.505	$ 324.109	$ 319.447	$ 271.904	Sum of Line 1 to 3; Section 11, Schedule 4, Line 20
5	Less: Formula CIAC	(2.390)	(6.245)	(3.514)	(2.888)	Section 11, Schedule 9, Line 2
6	Less: Forecast CIAC	(12.542)	(0.130)	(4.436)	(8.443)	Section 11, Schedule 9, Line 3 to 5
7	Net Regular Capex	$ 270.573	$ 317.734	$ 311.497	$ 260.573	Sum of Line 4 to 6

In the subsections below, FEI provides further details on its regular capital expenditures for 2025 and 2026.

7.3.1 Formula Growth Capital Expenditures

The formula-driven Growth capital expenditures are calculated based on the prior year's approved Unit Cost for Growth Capital (UCGC), escalated by the inflation factor (I-Factor) less an X-Factor of 0.55 percent, and multiplied by the forecast Gross Customer Additions (GCA), resulting in the forecast inflation-indexed Growth capital before the true-up of actual GCA from two years prior, the formulaic CIAC, and the forecast for the System Extension Fund (SEF).[59]

For 2025 and 2026, the formula Growth capital is calculated as follows:

> 2025 Formula Growth Capital = 2024 Approved Base UCGC x [1 + (2025 I-Factor – 2025 X-Factor)] x 2025 Projected GCA + 2023 Formula Growth Capital True-up + 2025 Formula CIAC + 2025 Forecast SEF; and

> 2026 Formula Growth Capital = 2025 Base UCGC x [1 + (2026 I-Factor – 2026 X-Factor)] x 2026 Forecast GCA + 2024 Formula Growth Capital True-up + 2026 Formula CIAC + 2026 Forecast SEF

As part of RSF Decision, the BCUC approved a 2024 Base UCGC of $9,300.[60] Further, as discussed in Section 2 of the Application, the 2025 and 2026 net inflation factor based on prior year's BC-CPI and BC-AWE, less the X-Factor, are 3.648 percent and 2.726 percent, respectively. As also discussed in Section 2 of the Application, the 2025 Projected and 2026 Forecast GCA are 10,000 and 8,000, respectively.

Table 7-3 below shows the calculation of the resulting 2025 and 2026 Formula Growth capital expenditures, which are $99.264 million and $71.580 million, respectively.

59 Pursuant to Order G-338-20, the SEF is approved to be up to $1 million per year.
60 RSF Decision and Order G-69-25, p. 32.

Table 7-3: Calculation of 2025 and 2026 Formula Growth Capital ($ millions)

Line No.	Description	2025 Projected	2026 Forecast	Reference
1	Prior Year Base Unit Cost Growth Capital	$ 9,300	$ 9,639	G-69-25 and Section 11, Sch 4, Line 2
2	Net Inflation Factor	3.648%	2.726%	Section 11, Schedule 3, Line 9
3	Current Year Unit Cost Growth Capital	$ 9,639	$ 9,902	Line 1 x (1 + Line 2)
4	Gross Customer Addition Forecast	10,000	8,000	Section 11, Schedule 4, Line 5
5	Inflation Indexed Growth Capital	$ 96.390	$ 79.216	Line 3 x Line 4 / 1,000,000
6	Gross Capital True-up	(1.640)	(11.524)	Line 16
7	Formulaic CIAC	3.514	2.888	Section 11, Schedule 9, Line 2
8	System Extension Fund	1.000	1.000	G-338-20 SEF Decision
9	Gross Formula Growth Capex	$ 99.264	$ 71.580	Sum of Line 5 to 8
10				
11	Gross Capital True-up			
12	2023/2024 Actual Gross Customer Addition	15,610	12,363	Section 2, Table 2-3
13	2023/2024 Forecast Gross Customer Addition	16,000	15,000	2023: G-352-22 & 2024: G-334-23
14	Difference	(390)	(2,637)	Line 12 - Line 13
15	2023/2024 Unit Cost Growth Capital ($/customer)	$ 4,205	$ 4,370	2023: G-352-22 & 2024: G-334-23
16	Growth Capital True-up in 2024/2025	$ (1.640)	$ (11.524)	Line 14 x Line 15 / 1,000,000

7.3.2 Forecast Capital Expenditures

The level of forecast capital expenditures approved for 2025 and 2026 by the RSF Decision is shown in Table 7-4 below. The 2024 Approved and 2024 Actual capital expenditures from the 2020-2024 MRP term are also shown for information purposes.

Table 7-4: Forecast Capital Expenditures ($ millions)

Line No.	Description	2024 Approved	2024 Actual	2025 Projected	2026 Forecast	Reference
1	Sustainment Capital	$ 130.628	$ 129.774	$ 125.599	$ 131.733	Section 11, Schedule 4, Line 16
2	Other Capital	51.252	53.702	67.904	62.696	Section 11, Schedule 4, Line 17
3	Total	$ 181.880	$ 183.476	$ 193.503	$ 194.429	Line 1 + Line 2

7.3.3 Flow-Through Capital Expenditures

In addition to FEI's formula Growth capital and forecast Sustainment and Other capital, FEI is approved flow-through treatment for a number of capital items, including pension and OPEB expense related to Growth capital, capital expenditures related to Clean Growth Initiatives (which currently include capital expenditures related to RNG and NGT), and any exogenous factors. These amounts are shown in Table 7-5 below along with a comparison to 2024.

Table 7-5: Flow-Through Capital Expenditures ($ millions)

Line No.	Description	2024 Approved	2024 Actual	2025 Projected	2026 Forecast	Reference
1	Pension/OPEB (Growth Capital Portion)	$ 0.871	$ 0.871	$ 1.176	$ 1.095	Section 11, Schedule 4, Line 13
2	RNG Capital Expenditures	43.068	25.341	19.181	4.800	Section 11, Schedule 4, Line 14
3	NGT Capital Expenditures	5.000	0.064	6.323	-	Section 11, Schedule 4, Line 15
4	2021 Flooding Damage and Remediation	-	0.003	-	-	G-69-25, p. 86
5	Total	$ 48.939	$ 26.279	$ 26.680	$ 5.895	Sum of Lines 1 through 4

Each of these items are discussed further below. The cost-of-service impact due to variances in pension and OPEB expenditures is captured 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 cost-of-service impact due to variances in Clean Growth Initiatives and exogenous factors are captured in the Flow-through deferral account.

7.3.3.1 Pension/OPEB (Growth Capital Portion)

The 2025 Projected and 2026 Forecast Growth capital portion of the total pension and OPEB costs are $1.176 million and $1.095 million, respectively. Please refer to Section 6.3.1 for details on the pension and OPEB costs.

7.3.3.2 RNG Capital Expenditures

Table 7-6 below provides the 2024 Approved, 2024 Actual, 2025 Projected and 2026 Forecast for RNG capital expenditures, including references to the BCUC order approving each project.

Table 7-6: RNG Capital Expenditures ($ millions)

Line No.	Description	BCUC Order	2024 Approved	2024 Actual	2025 Projected	2026 Forecast
1	Kelowna	E-19-12	$ 0.500	$ 0.144	$ 1.000	$ -
2	REN Energy	G-60-20	0.500	0.014	-	-
3	Foothills LF (RDFFG)	E-2-22	2.000	0.240	1.000	3.000
4	Dickland Farms	E-13-20	-	-	0.100	-
5	Capital Regional District	E-15-21	3.000	1.232	0.500	-
6	City of Vancouver	G-235-19	16.613	21.962	9.581	-
7	Net Zero Waste	E-21-21	5.000	0.013	-	-
8	Delta RNG (MAS Energy)	E-3-22	4.205	1.360	5.300	-
9	Seabreeze Farm	E-11-19	-	0.009	-	0.100
10	Lulu Island	E-16-21	-	-	-	0.100
11	City of Surrey	E-3-16	-	-	-	0.100
12	Fraser Valley Biogas Expansion	E-27-24	4.250	0.073	0.700	0.500
13	Salmon Arm Upgrader	G-235-19	-	0.291	-	-
14	Comox Valley LF	Signed, to be filed	2.000	0.003	1.000	1.000
15	Andion - Semiahmoo	Negotiation ongoing	2.000	-	-	-
16	Vernon LF	Negotiation ongoing	2.000	-	-	-
17	Ecowaste	Negotiation ongoing	1.000	-	-	-
18	Total RNG CAPEX		$ 43.068	$ 25.341	$ 19.181	$ 4.800

FEI's applications for each RNG project are filed and accepted individually by the BCUC; therefore, the capital estimates provided in the Annual Review are for information purposes as they reflect the current projected and forecast estimates for RNG capital expenditures in customer rates.

The 2024 Actual capital expenditures were $17.727 million less than 2024 Approved. This variance is due to several factors:

- the cancellation of the Net Zero Waste agreement;

- changes in project scope for the Fraser Valley Biogas Expansion;
- a refreshed schedule that delayed the in-service date for Foothills LF (RDFFG) and the Comox Valley LF project;
- pipeline permitting delays for the Delta RNG (MAS Energy) project, which are now resolved, resulting in final installation during 2025; and
- delays in finalizing agreements with various project counterparties.

The decrease in 2024 Actual expenditures compared to 2024 Approved was partially offset by additional spending on the City of Vancouver (COV) project. The increased spending occurred as a result of scheduling shifts, which resulted in some expenditures being moved from 2023 to 2024.

For the 2025 Projected capital expenditures of $19.181 million, approximately 50 percent is related to the final capital expenditures for the COV project, which FEI expects to complete in 2025 as previously discussed. Additionally, $5.300 million is forecast to be spent on completing the Delta RNG (MAS Energy) project. The remaining projected capital expenditures for 2025 include spending on various existing projects, as well as spending on the new Comox Valley LF project, which is expected to be filed for acceptance with the BCUC in late 2025 or early 2026.

The 2026 Forecast capital expenditures of $4.800 million are primarily related to capital expenditures for the Foothills LF (RDFFG) and Comox Valley LF projects. FEI is expecting both projects to be complete and in-service in 2027.

7.3.3.3 NGT Capital Expenditures

Table 7-7 provides additional details by project for the 2025 and 2026 NGT capital expenditures.

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

Line No.	Description	2024 Approved	2024 Actual	2025 Projected	2026 Forecast
1	T1A Truck Load-out (GGRR)	$ 5.000	$ 0.064	$ 6.323	$ -

The 2024 Approved, 2024 Actual and 2025 Projected NGT capital expenditures are all attributable to the Tilbury T1A truck load-out project, which is a prescribed undertaking under section (3)(a)(ii) of the *Greenhouse Gas Reduction (Clean Energy) Regulation* (GGRR).

As discussed in FEI’s Annual Review for 2024 Delivery Rates, the project was delayed as a result of the contractor filing for bankruptcy protection part way through the execution of the project (in April 2023). FEI is now expecting to complete the remaining project in 2025. As of December 2024, FEI had incurred approximately $13.677 million (excluding AFUDC) of capital expenditures and expects to incur the remainder of the eligible expenditure amount of $20 million in 2025. FEI is not requesting approval for the capital expenditures in this Application as the Tilbury T1A truck load-out project is a prescribed undertaking under the GGRR.

7.3.3.4 2021 Flooding Damage and Remediation

As discussed in Section 6.3.10, FEI was granted approval of exogenous factor treatment for the 2021 flooding damage and remediation costs in the RSF Decision and was directed to record the unrecovered cost-of-service impact related to the capital portion in the Flow-through deferral account in 2024. The total capital portion of the unrecovered costs (less insurance proceeds) was approximately $0.003 million.

7.4 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 RSF Decision, the BCUC approved the continuation of the current process of reviewing major projects outside of the RSF and approved the continuation of the existing financial threshold for CPCNs of $15 million for FEI for the RSF term.[61]

In 2025 and 2026, FEI is forecasting capital expenditures related to the following approved major projects:

- IGU CPCN Project;
- Pattullo Gas Line Replacement (PGR) CPCN Project;
- CTS TIMC CPCN Project;
- Gibsons Capacity Upgrade (GCU) Project;
- ITS TIMC CPCN Project;
- AMI CPCN Project;
- Okanagan Capacity Mitigation Plan (OCMP) CPCN Project;
- Tilbury 1B Expansion Project; and
- CTS Expansion Project.

Each project is discussed below.

7.4.1 IGU CPCN Project

The IGU Project CPCN application was filed with the BCUC in December 2018 and approved by Order G-12-20. The IGU CPCN Project includes upgrades to 29 pipeline laterals in the Interior of British Columbia that currently do not accommodate in-line inspection. This project addresses

[61] RSF Decision and Order G-69-25, pp. 15-18.

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.

The following is a timeline of the upgrades and additions to rate base:

- **2020:** Completed the Mackenzie, Cranbrook and Fording laterals at a cost of $54.572 million which were added to rate base on January 1, 2021;
- **2021:** Completed the Fording 2, Prince George 1, Kimberley and Skookumchuck laterals in 2021 at a cost of $63.782 million which were added to rate base on January 1, 2022;
- **2022:** Completed the Cranbrook-Kimberley loop, Salmon Arm loop and lateral and Cariboo Pulp lateral at a cost of $67.361 million which were added to rate base on January 1, 2023;
- **2023:** Completed the Coldstream lateral and loop, Kelowna 1, BC Forest Products, Prince George 2, Williams Lake, Trail, Castlegar Nelson, Celgar, and Elkview laterals at a cost of $101.438 million which were added to rate base on January 1, 2024;
- **2024:** Completed the remaining Northwood Pulp loop and lateral, Prince George 3, Prince George Pulp and Husky Oil laterals at a cost of $61.417 million which were added to rate base on January 1, 2025; and
- **2025:** Final forecast project expenditures related to close-out activities of $7.194 million which will be added in rate base in 2025.

Including the 2025 Projected capital expenditure amount, FEI is expecting the final project costs to be approximately $355.764 million. The total estimated capital cost for the project, including AFUDC and abandonment/demolition costs, was approximately $360 million in the IGU Project CPCN application.

7.4.2 PGR CPCN Project

The PGR Project CPCN application was filed with the BCUC in August 2020 and approved by Order C-2-21. The PGR CPCN 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 were completed in 2022, with approximately $150.8 million added to rate base on January 1, 2023. The remaining project scope related to decommissioning and/or abandonment of existing infrastructure that was no longer required due to the removal of the Pattullo Gas Line crossing of the Fraser River was completed in 2023.

FEI is forecasting final expenditures of $0.033 million in 2025 related to the project close-out costs which will be added to rate base in 2025. Including the 2025 Projected capital expenditure amount, FEI is expecting the final project cost to be approximately $150.833 million. The total estimated capital cost for the project, including AFUDC and abandonment/demolition costs, was approximately $175.354 million in the PGR Project CPCN application.

7.4.3 CTS TIMC CPCN Project

The CTS TIMC Project CPCN application was filed with the BCUC in February 2021 and approved by Order C-3-22. The project consists of the replacement of 13 heavy wall pipeline segments and alterations to 13 facilities that are necessary to ready the pipelines for electro-magnetic acoustic transducer (EMAT) ILI tools. The project also includes the installation of pressure regulating stations (PRS) and flow control stations to support the EMAT ILI activities.

In 2024, FEI completed pipeline replacements and alterations at various sites at a total cost of $69.138 million that were added into rate base on January 1, 2025. FEI expects to complete the remaining site alterations in 2025 for $25.598 million (excluding AFUDC) and to incur capital expenditures of $1.023 million (excluding AFUDC) in 2026 for close-out activities. FEI is forecasting approximately $30.257 million to enter rate base on January 1, 2026.

7.4.4 GCU Project

The GCU Project was filed with the BCUC as a major project in the Annual Review for 2023 Delivery Rates and was 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 was commissioned in 2024 with a total capital cost of $12.937 million (including AFUDC) added to rate base on January 1, 2025. FEI is forecasting final capital expenditures of $0.581 million in 2025 related to project close-out activities which will be added to rate base in the same year (i.e., 2025). Including the project close-out costs in 2025, FEI is estimating the final project cost for the GCU Project to be $13.517 million. In the Annual Review for 2023 Delivery Rates, FEI estimated the capital cost for the project, including AFUDC, would be approximately $12.194 million.

7.4.5 ITS TIMC CPCN Project

The ITS TIMC Project CPCN application was filed with the BCUC in September 2022 and approved by Order C-1-24. The project consists of the replacement of three heavy wall pipeline segments on two of the ITS pipelines, and modification to 13 transmission pressure facilities within the ITS that are necessary to ready the pipelines for EMAT ILI tools.

FEI is forecasting capital expenditures of $41.992 million in 2025 and $29.164 million in 2026 (excluding AFUDC), with $41.976 million expected to be added into rate base on January 1, 2026.

7.4.6 AMI CPCN Project

The AMI Project CPCN application was filed with the BCUC in May 2021 and was approved by Order C-2-23. The AMI CPCN 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.

The network installation has begun and is expected to be completed in 2026. Mass deployment of meters started in March 2025 utilizing four deployment contractors located across the service territory along with FEI Operations. Mass deployment will continue through to Q2 2028.

FEI forecasts capital expenditures of $194.157 million in 2025 and $306.634 million in 2026 (excluding AFUDC), with $144.981 million expected to be added to rate base on January 1, 2026.

7.4.7 OCMP CPCN Project

The OCMP Project CPCN application was filed with the BCUC on July 30, 2024 and approved by Order C-2-25. The project involves a small-scale LNG facility in Kelowna to address the capacity requirements in the Okanagan region. The project will be executed over a three-year period from 2025 to 2027. FEI is expecting detailed engineering and permitting work to complete in 2025. In 2026, FEI will begin site construction as well as acquiring mobile fleet trailers for transporting LNG from the Tilbury LNG facility to Kelowna. The final installation of five storage tanks, vaporization equipment, and other site modifications necessary to interconnect the new equipment will compete in 2027.

FEI is forecasting capital expenditures of $11.160 million in 2025 and $19.800 million in 2026 (excluding AFUDC) related to the engineering and design work and installation of the virtual pipeline interfacing equipment. There are no capital additions to rate base forecast in 2025 and 2026.

7.4.8 Tilbury 1A/1B Expansion Project

The cost recovery of expenditures associated with the Tilbury Expansion (1A/1B) Project is authorized by Direction No. 5 to the BCUC as amended by OIC No. 557 (2013), 749 (2014), and 162 (2017). Under Direction No. 5, FEI can spend up to $425 million and $400 million in capital costs for Tilbury 1A and 1B, respectively, plus AFUDC and feasibility and development costs, to construct storage and liquefaction facilities at Tilbury Island. The Tilbury 1A expansion has been in-service since 2018 while the Tilbury 1B expansion is expected to be completed in four stages with the first additions related to the On-Shore Facility Jetty entering rate base in 2028.

FEI forecasts capital expenditures of $23.108 million in 2025 and $22.700 million in 2026 (excluding AFUDC) related to development and capital costs. There are no capital additions to rate base forecast in 2025 and 2026.

7.4.9 CTS Expansion Project

The CTS Expansion Project at and between the Tilbury Gate Station and Tilbury LNG Facility is authorized by Direction No. 5 to the BCUC as amended by OIC No. 557 (2013), 749 (2014), and 162 (2017). The project involves the design and installation of a new 1.5 km bi-directional 30" pipeline to the Tilbury LNG Plant as well as facility modifications to tie-in both ends of the pipeline. The project is currently advancing engineering and developing an AACE class 3 cost estimate and schedule for execution. The project will advance into detailed design later this year or early 2026 and is tentatively planned for construction in 2027.

FEI is forecasting capital expenditures of $6.000 million in 2025 and $12.000 million in 2026 (excluding AFUDC) with no capital additions to rate base forecast until 2028.

7.5 *2025 AND 2026 PLANT ADDITIONS*

The 2025 and 2026 plant additions are comprised of: (i) FEI's 2025 and 2026 regular capital expenditures; (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, 2025 and/or 2026. A reconciliation of capital expenditures to plant additions is shown in Table 7-8 below and is also provided in Section 11, Schedule 5 (2025 and 2026).

Table 7-8: Reconciliation of 2025 and 2026 Capital Expenditures to Plant Additions ($ millions)

Line No.	Description	2025 Projected	2026 Forecast	Reference
1	Formula Growth Capex	$ 99.264	$ 71.580	Section 11, Schedule 4, Line 10
2	Forecast Sustainment & Other Capex	193.503	194.429	Section 11, Schedule 4, Line 16 + Line 17
3	Flow through Capex	26.680	5.895	Section 11, Schedule 4, Sum of Line 13 to 15
4	Total Gross Regular Capex	$ 319.447	$ 271.904	Sum of Line 1 to 3
5	Capitalized Overheads	58.114	60.398	Section 11, Schedule 5, Line 24
6	AFUDC	9.005	7.645	Section 11, Schedule 5, Line 25
7	Change in Work in Progress	40.619	(4.000)	Section 11, Schedule 5, Line 27
8	Total Regular Additions to Plant	$ 427.185	$ 335.947	Sum of Line 4 to 7
9				
10	Special Projects and CPCN Capex			
11	IGU CPCN	$ 7.194	$ -	Section 11, Schedule 5, Line 7
12	PGR CPCN	0.033	-	Section 11, Schedule 5, Line 8
13	CTS-TIMC Project	25.598	1.023	Section 11, Schedule 5, Line 9
14	GCU	0.581	-	Section 11, Schedule 5, Line 10
15	ITS-TIMC Project	41.992	29.164	Section 11, Schedule 5, Line 11
16	AMI CPCN	194.157	306.634	Section 11, Schedule 5, Line 12
17	OCMP CPCN	11.160	19.800	Section 11, Schedule 5, Line 13
18	Tilbury 1A/1B Expansion	23.108	22.700	Section 11, Schedule 5, Line 14
19	CTS Expansion Project	6.000	12.000	Section 11, Schedule 5, Line 15
20	Subtotal	$ 309.823	$ 391.321	Sum of Line 11 to 19
21	AFUDC	39.300	48.105	Section 11, Schedule 5, Line 31
22	Change in Work in Progress	(197.823)	(222.211)	Section 11, Schedule 5, Line 33
23	Total Additions to Plant	$ 578.485	$ 553.162	Sum of Line 20 to 22

7.6 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 2025 and 2026 were approved in the RSF Decision 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 2025 depreciation expense is calculated as $218.071 million[62] and the 2026 depreciation expense is calculated as $233.768 million.[63]

[62] $225.942 million depreciation expense as calculated in Section 11, Schedule 21, Line 5 less $7.871 million amortization of CIAC as calculated in Section 11, Schedule 21, Lines 11 and 12.

[63] $241.766 million depreciation expense as calculated in Section 11, Schedule 21, Line 5 less $7.998 million amortization of CIAC as calculated in Section 11, Schedule 21, Lines 11 and 12.

7.7 *DEFERRED CHARGES*

On May 3, 2017, the BCUC issued its Regulatory Account Filing Checklist.[64] 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.

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.

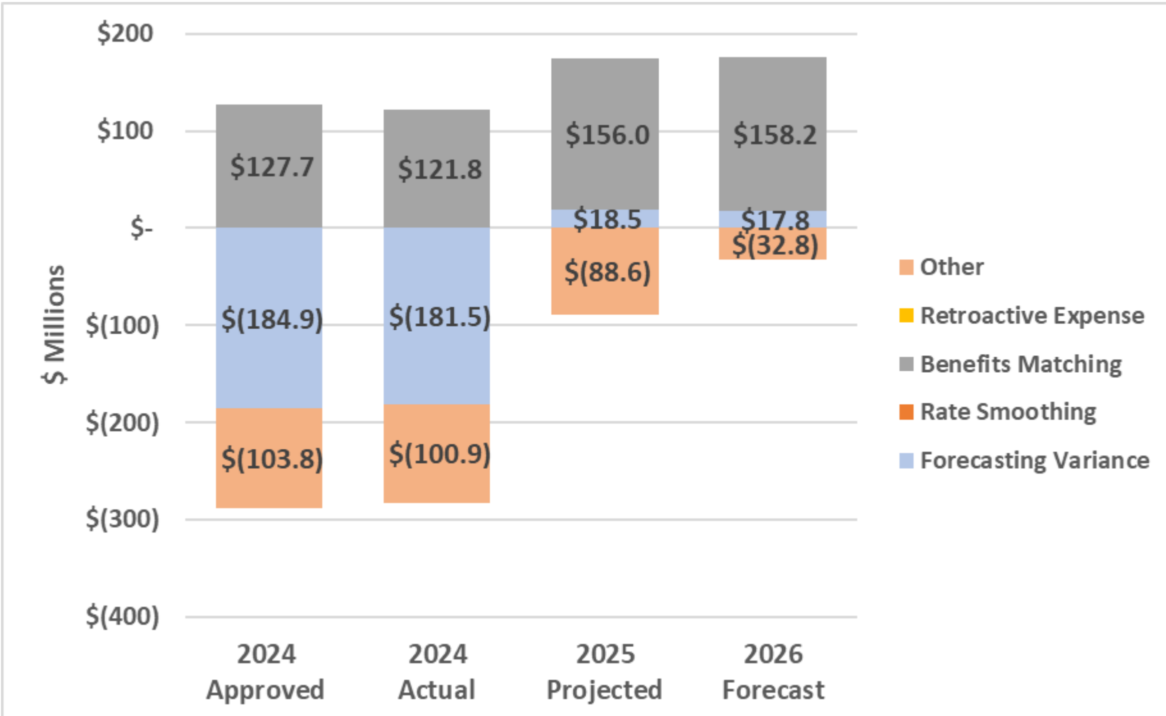
Figure 7-1 below provides the mid-year deferral account balances for 2024 Approved, 2024 Actual, 2025 Projected, and 2026 Forecast summarized by deferral account category.

For 2025, FEI is projecting a mid-year balance of unamortized deferred charges in rate base to be a debit of $85.905 million, which is an increase of $246.804 million from the 2024 Approved level. The largest driver of the increase in the 2025 Projected balance is the MCRA which is mainly due to the strong mitigation performance by FEI in 2022 being returned to customers through the S&T Rate Rider 6 in 2024. As the mitigation credits were returned to customers in 2024, the mid-year balance of the MCRA increased in 2025. Other deferral accounts contributing to the increase are the RSAM account, which is due to a debit variance between forecast and actual use rates of RS 1, 2, 3, and 23 customers, the DSM deferral account, and the OCU Application Costs deferral account.

For 2026, FEI is forecasting a mid-year balance of unamortized deferred charges in rate base to be a debit of $143.152 million, which is an increase of $57.247 million from the 2025 Projected level. The largest driver of the increase in the 2026 Forecast balance is the DSM deferral account. Other deferral accounts contributing to the increase are the Existing Meter Cost Recovery Account and the Previously Retired Meter Cost Recovery Account, both of which were approved as part of the AMI Project CPCN Decision and Order C-2-23. The increases from these accounts are partially offset by the reduced forecast balance of the RSAM account as well as the Net Salvage Provision deferral account.

[64] Log No. 53608, Appendix B.

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



Based on the approved amortization of each deferral account, the amortization expense including both rate base and non-rate base deferral accounts for 2025 and 2026 to be recovered as part of the proposed delivery margin is $138.746 million and $178.831 million, respectively.[65] 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.

7.7.1 New Deferral Accounts

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

7.7.2 Existing Deferral Accounts

In the discussion below, FEI requests to modify an existing deferral account, seeks amortization periods for five existing deferral accounts, and provides information on one existing deferral account.

7.7.2.1 Annual Review Proceeding Costs (formerly Annual Review of 2020-2024 Rates)

FEI is requesting approval to rename the Annual Review of 2020-2024 Rates deferral account to the Annual Review Proceeding Costs deferral account, and to use this deferral account to capture

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

the actual regulatory proceeding costs related the Annual Reviews during the RSF term. Consistent with the existing approved deferral account, the Annual Review Proceeding Costs deferral account will capture costs such as BCUC costs, intervener/participant funding costs, consulting costs, legal fees, and miscellaneous facilities, stationery and supplies costs. Also consistent with the existing deferral account, FEI proposes to continue amortizing the deferral account over one year.

FEI forecasts additions of $0.150 million ($0.110 million after tax) in each of 2025 and 2026.

7.7.2.2 2025-2027 RSF Application (formerly 2025 MRP Application)

As part of the Annual Review for 2024 Delivery Rates Decision and Order G-334-23, FEI was approved to establish the 2025 MRP Application deferral account to capture the costs related to filing that application and the related regulatory proceeding. In the Annual Review for 2024 Delivery Rates application, FEI stated that it would request an amortization period for this account in a future application.

In this Application, FEI is seeking approval to rename the deferral account to the 2025-2027 RSF Application deferral account, as this name better aligns with the RSF Application name, and to amortize the deferral account over three years commencing January 1, 2025. FEI considers a three-year amortization period to be appropriate because it aligns with the number of years of the RSF term. The balance of the account as of December 31, 2024 was approximately $0.575 million.

7.7.2.3 2021 Generic Cost of Capital Proceeding

On March 8, 2021, pursuant to Order G-66-21, the BCUC established a Generic Cost of Capital (GCOC) proceeding. The GCOC proceeding included three stages and concluded in January 2025.

In the Annual Review for 2022 Delivery Rates Decision and Order G-366-21, FEI was approved to establish the 2021 Generic Cost of Capital Proceeding deferral account to capture costs related to the GCOC proceeding. Further, FEI noted that it would apply for disposition of the account following completion of the regulatory process for the GCOC proceeding. The balance of the account as of December 31, 2024 was approximately $0.874 million.

With all stages of the GCOC proceeding now complete, FEI is proposing to amortize the 2021 Generic Cost of Capital Proceeding deferral account over five years commencing January 1, 2025. FEI believes a five-year amortization period is appropriate as it represents the average period between similar proceedings.

7.7.2.4 2021 Renewable Gas Program Comprehensive Review

On January 29, 2021, the BCUC issued Order G-35-21, determining that a regulatory review process with two stages was warranted, with the first stage reviewing the BERC Rate assessment report and the second stage consisting of a comprehensive review of FEI's Renewable Gas

Program. The BCUC issued its Decision and Order G-77-24 regarding FEI's renewable gas program in March of 2024, thus concluding the two-stage review.

In the Annual Review for 2022 Delivery Rates Decision and Order G-366-21, FEI was approved to establish the 2021 Renewable Gas Program Comprehensive Review deferral account to capture costs related to the application and expected regulatory proceeding costs. Further, FEI noted that it would apply for disposition of the account following completion of the regulatory process. The balance of the account as of December 31, 2024 was approximately $1.972 million.

FEI is seeking approval to amortize the 2021 Renewable Gas Program Comprehensive Review deferral account over three years commencing January 1, 2025. FEI believes a three-year amortization period is appropriate as it is consistent with the recovery period of other similar regulatory proceeding applications, and it balances potential rate impacts with the benefits of the application.

7.7.2.5 2023 Cost of Service Allocation Study

As part of the FEI Annual Review for 2024 Delivery Rates Decision and Order G-334-23, FEI was approved to establish the 2023 Cost of Service Allocation (COSA) Study deferral account to capture costs associated with the 2023 COSA Study and Revenue Rebalancing Application. Further, FEI noted that it would request an amortization period for this account in a future application.

The balance of this account as of December 31, 2024 was approximately $0.117 million. FEI is requesting to amortize this account over one year commencing January 1, 2025.

7.7.2.6 2022 Long-Term Gas Resource Plan

As part of the FEI Annual Review for 2020-2021 Delivery Rates Decision and Order G-319-20, FEI was approved to establish the 2022 Long-Term Gas Resource Plan (LTGRP) deferral account to capture costs associated with the 2022 LTGRP proceeding. Further, FEI noted that it would request an amortization period for this account in a future application.

The BCUC issued its decision on the 2022 LTGRP in March of 2024. The deferral account balance as of December 31, 2024 was approximately $1.707 million. FEI is seeking approval to amortize the 2022 LTGRP deferral account over three years commencing January 1, 2025. FEI believes a three-year amortization period is appropriate as it is consistent with the recovery period approved for past LTGRP proceeding cost deferral accounts (e.g., 2017 LTGRP).

7.7.2.7 Prince George Customer Service Centre Disposition

On December 10, 2024, pursuant to Order G-329-24, FEI was approved to sell the Prince George Customer Service Centre Office property (PGO Property), consisting of the land and building located on 1190 2nd Avenue in Prince George, BC, to the Carrier Sekani Family Services Society. FEI was also approved to establish the Prince George Customer Service Centre Disposition deferral account to capture the net proceeds of the sale less the net book value of the PGO

Property at the time of sale and to commence amortization of the deferral account over one year, beginning January 1, 2026. FEI was directed to provide details on the final balance in the Prince George Customer Service Centre Disposition deferral account in the Annual Review for 2026 Delivery Rates.

FEI received written notification of the removal of the Buyer's Subject Conditions on March 3, 2025, and completion of the sale of the Prince George Customer Service Centre was effective March 31, 2025. The final projected ending balance of the deferral account (i.e., projected to the end of 2025) is a loss on sale of $1.346 million, which will be amortized into FEI's 2026 delivery margin over a one-year period.

Table 7-9 below provides a breakdown of the net loss on the sale of the Prince George Customer Service Centre. FEI notes that the estimated net loss on sale at the time of filing the Application for Approval to Sell the Prince George Customer Service Centre Office Property was $1.588 million. The difference between the original estimate and the final projected ending balance is primarily due to lower costs of disposal and other expenses related to disposal.

Table 7-9: Breakdown of Final Net Loss on Sale of the Prince George Customer Service Centre

		$ millions
Sales Proceeds		5.300
Less:	Net Book Value of Land and Building	(6.399)
	Disposal Costs	(0.185)
	Taxes Payable	(0.062)
Loss on Sale		**(1.346)**

7.8 *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 the RSF Decision.

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 2025 gas cost report and historical volumes. All other 2025 and 2026 amounts are forecast based on 2024 Actual levels.

7.9 *SUMMARY*

FEI's rate base includes the impact of formula-driven Growth capital expenditures, regular forecast Sustainment and Other capital expenditures, flow-through capital expenditures 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 7.7.2, FEI requested to modify one existing deferral account and requested amortization periods for five existing deferral accounts. Finally, the rate base includes other working capital, comprised 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 55 percent debt and 45 percent equity and a Return on Equity (ROE) of 9.65 percent, as approved by Order G-236-23.

The 2025 Projected and 2026 Forecast financing costs, including the interest expense on issued long-term and short-term debt and on new issuances that are forecast, have been updated as described in Section 8.3 below. Based on the updated financing costs, FEI's AFUDC rates for 2025 and 2026 (which are equal to FEI's after-tax weighted average cost of capital) are 6.20 percent and 6.23 percent, respectively. 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*

FEI 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-236-23, the BCUC approved a benchmark capital structure of 55 percent debt and 45 percent equity with an allowed ROE of 9.65 percent, effective January 1, 2023, 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-term 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 $250 million in 2025 and $450 million[66] in 2026. FEI will use the funds to repay existing indebtedness and finance the Company's capital expenditure program. The 2025 debt issuance is reflected in the financial schedules in September 2025 at a rate of 4.60 percent[67] and the 2026 debt issuance is reflected in the financial schedules in July 2026 at a rate of 4.60 percent[68]. The exact timing, amount and rate of the issuances will depend on future market conditions and capital expenditure requirements. Variances in interest expense related to the timing and amount of the

[66] Only $439 million of which is financing FEI's rate base in 2026 as the remainder finances the non-rate base Lower Mainland Acquisition Premium.
[67] Section 11-2025, Schedule 27, Line 19 (effective rate of 4.662 percent).
[68] Section 11-2026, Schedule 27, Line 20 (effective rate of 4.662 percent).

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 $900 million committed credit facility that matures in July 2030. 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 2026 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 benchmark rate and the rate obtained by FEI under its commercial paper program. Canada has now fully discontinued the Canadian Deposit Overnight Rate (CDOR) as a benchmark for financial instruments, with the last publication date being June 28, 2024. The Term Canadian Overnight Repo Rate Average (CORRA), first published in September 2023, has replaced CDOR as the risk-free interest rate benchmark for one-month and three-month loan terms. For the purposes of forecasting the short-term interest rate for 2025 and 2026, a 3-year average approach was taken to factor in both CDOR through June 28, 2024, and CORRA post-June 28, 2024.

CORRA (previously CDOR) is used because FEI's short-term borrowings under its credit facility are priced based on CORRA/CDOR and therefore CORRA/CDOR is tracked relative to FEI's commercial paper borrowings. As both CORRA and CDOR are not forecast by economists, FEI must first obtain the 3-month T-Bill rate forecast and then convert it to a CORRA/CDOR forecast. FEI does this by taking the 3-year historical spread between CORRA/CDOR and the 3-month T-Bill rate. Then, to derive the short-term borrowing rate forecast, FEI adjusts the CORRA/CDOR forecast with the 3-year historical spread between CORRA/CDOR and rates of issuances under its commercial paper program.

The short-term borrowing rate forecast for 2025 and 2026 is shown in Table 8-1 below.

Table 8-1: Short Term Interest Rate Forecast

FEI Short Term Interest Rate	Approved 2024	Actual 2024	Projected 2025	Forecast 2026
3-Month T-Bill Rate/(Term Deposit Rate)[1]	-4.44%	-4.38%	2.40%	2.20%
Spread to CORRA	0.00%	0.00%	0.44%	0.44%
CORRA Rate	0.00%	0.00%	2.84%	2.64%
Spread to CP/Term Deposit	0.24%	-0.87%	-0.36%	-0.36%
CP Dealer Commission	0.00%	0.00%	0.10%	0.10%
ST Interest Rate on Credit Facility/(Term Deposits)	**-4.20%**	**-5.25%**	**2.58%**	**2.38%**
Fixed Financing Fees				
Standby fee on Undrawn Credit [2]	0.57%	5.42%	0.72%	0.72%
Renewal Fee [3]	0.20%	1.47%	0.16%	0.16%
Other Financing Fees [4]	0.22%	6.09%	0.12%	0.12%
ST Interest Rate on Fixed Financing Fee	**0.99%**	**12.98%**	**1.00%**	**1.00%**
FEI Short Term Rate	**-3.21%**	**7.73%**	**3.58%**	**3.38%**

Notes to table:

[1] In 2024, the 3-Month T-Bill rate was used as a benchmark for the Term Deposit rate. Therefore, negative rates for 2024 represent the Term Deposit Rate, positive rates for 2025 and 2026 represent the 3-Month T-Bill Rate. The 3-month T-Bill rate for 2025 and 2026 is an average rate based on forecasts provided by Canadian Chartered banks in June 2025.

[2] The forecast assumes FEI will borrow through commercial paper and a standby fee of 16 bps is charged on undrawn credit facility amounts. The fee has been converted into a short-term rate for forecast purposes.

[3] The Renewal fee is paid to extend the maturity date of the credit facility and is charged on the principal amount of $900 million. The renewal fee is paid regardless of whether FEI draws from the credit facility. The fee has been converted into a short-term rate for forecast purposes.

[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. The fees have been converted into a short-term rate for forecast purposes.

As shown in Table 8-1 above, the short-term borrowing rates for 2025 Projected and 2026 Forecast of 3.58 percent and 3.38 percent, respectively, are higher than 2024 Approved but lower than 2024 Actual. The short-term rate is comprised of the short-term interest rate on FEI's credit facility (or term deposit) and the short-term interest rate on fixed financing fees.

The 3-month T-Bill rate forecast for 2025 and 2026 is 2.40 percent and 2.20 percent, respectively, which is a decrease from the 4.38 percent actual 3-month T-Bill rate in 2024[69]. The lower 3-month T-Bill rates for 2025 and 2026 reflect Bank of Canada policy rate cuts in 2024 in response to inflation and a softer economic outlook. The Bank of Canada's interest rate reduction in March 2025 brought the overnight rate to 2.75 percent, which was the Bank of Canada's seventh consecutive rate cut from 5.0 percent in June 2024, when the Bank of Canada started cutting rates. The Canadian economy entered 2025 in a solid position, with inflation close to the 2 percent target and robust GDP growth. However, heightened trade tensions with the United States are

[69] In 2024, the 3-Month T-Bill rate was used as a benchmark for the Term Deposit Rate.

expected to slow the pace of economic activity and increase inflationary pressures in Canada. As a result, the economic outlook continues to be subject to increased uncertainty.

The forecast short-term interest rate on fixed financing fees for 2025 and 2026 is consistent with the 2024 Approved but significantly lower than the 2024 Actual rate. The increase in the 2024 Actual short-term interest rate on fixed financing fees compared to 2024 Approved (12.98 percent for 2024 Actual compared to 0.99 percent for 2024 Approved) was mostly a result of the calculation methodology where the fees are expressed as a percentage of the drawn balance. While the actual fixed financing fees were slightly higher than approved (2024 Actual fees of $3.2 million compared to 2024 Approved of $1.9 million) due to higher customer deposit interest expense and a higher standby fee as FEI expanded its credit facility to $900 million from $700 million in April 2024, it was the base on which the fixed fee percentages were calculated that changed significantly from 2024 Approved to 2024 Actual. In the 2024 Approved calculations, FEI used a forecast commercial paper balance of $200 million to calculate the short-term interest rate on fixed financing fees of 0.99 percent, while the 2024 Actual fees were calculated as a percentage of a $25 million cash balance.[70,71] FEI clarifies that while the actual fixed financing fee interest rates produced by this methodology can vary based on changes to the base (i.e., the actual short-term debt/cash amounts), ultimately the amount customers are charged are the actual fixed financing fee amounts (i.e., the $3.2 million discussed above).

8.3.4 Forecast of Interest Expense

The interest expense forecast reflects FEI's existing and forecast borrowing costs on long-term 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 2025 and 2026 long-term debt schedules for FEI are provided 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 rates for 2025 and 2026 (which are equal to its after-tax weighted average cost of capital) are 6.20 percent and 6.23 percent, respectively. The calculation of the rates is provided in the following table.

[70] $3.212 million fixed fees / $24.746 million negative short-term debt (cash) balance = 12.98 percent.

[71] FEI typically calculates the fixed financing fee rates using $200 million of short-term debt as it approximates the amount typically outstanding each year. As shown in Section 11, Schedule 26, Line 2, Column 3 of the Annual Review for 2024 Delivery Rates Application, FEI was forecasting to have $197.263 million in average short-term debt outstanding in 2024, which aligns with the $200 million used for the fixed financing fee rate calculation. However, FEI subsequently received the GCOC Stage 1 Decision which resulted in a change to the forecast short-term debt level and a final amount of -$79.832 million being included in the compliance filing for that proceeding. The 2024 forecast fixed fee percentages were not updated to reflect the new forecast short-term debt level.

Table 8-2: Calculation of AFUDC Rates for 2025 and 2026

	2025				2026			
	Weight	Pre Tax Rate	After Tax Rate	Earned Return	Weight	Pre Tax Rate	After Tax Rate	Earned Return
Short Term Debt	2.83%	3.58%	2.61%	3.58%	1.55%	3.38%	2.47%	3.38%
Long Term Debt	52.17%	4.68%	3.42%	4.68%	53.45%	4.73%	3.45%	4.73%
Common Equity	45.00%	13.22%	9.65%	9.65%	45.00%	13.22%	9.65%	9.65%
Weighted Average	100.00%	8.49%	6.20%	6.89%	100.00%	8.53%	6.23%	6.93%

8.4 SUMMARY

FEI's 2025 Projected and 2026 Forecast equity financing and ROE are based on the same percentages as approved by Order G-236-23. 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 for 2025 Projected is in line with 2024 Approved (i.e., 4.68 percent), while the 2026 Forecast rate is expected to increase to 4.73 percent. For the short-term interest rates, FEI is projecting an interest rate of 3.58 percent in 2025 and 3.38 percent in 2026.

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 2025, property taxes are projected to increase by approximately 4.3 percent from 2024 Approved, with a further increase of 1.9 percent forecast in 2026. Income tax is forecast to decrease by 11.5 percent in 2025 when compared to 2024 Approved, but will increase by approximately 45.2 percent in 2026 when compared to the 2025 Projected amount.

9.2 PROPERTY TAXES

The 2025 Projected and 2026 Forecast property taxes are approximately $86.927 million and $88.576 million, respectively. The property taxes are calculated by incorporating FEI'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	2024 Approved	2024 Actual	2025 Projected	2026 Forecast
1	Distribution Assets	$ 30.246	$ 30.049	$ 32.026	$ 33.292
2	Transmission Assets	21.434	24.406	21.998	23.484
3	Gas Storage Assets	8.597	7.392	7.860	8.393
4	Manufactured Gas Assets	0.065	0.050	0.071	0.072
5	General Assets	6.289	6.615	6.806	7.027
6	In-Lieu	16.510	19.993	17.999	16.203
7	BCER Fees	0.295	0.292	0.292	0.295
8	Total Property Taxes	83.436	88.796	87.053	88.766
9	Less: Property Tax Transferred to RNG	(0.077)	(0.077)	(0.126)	(0.190)
10	Net Property Tax	83.359	88.719	86.927	88.576
11					
12	2024 Actual Compared to 2024 Approved		6.4%		
13	2025 Projected Compared to 2024 Approved			4.3%	
14	2026 Forecast Compared to 2025 Projected				1.9%

As shown in the above table, 2025 property taxes are projected to increase by 4.3 percent from 2024 Approved. The 2025 Projected property taxes are estimated based on actual tax rates and assessed values for 2025.

For 2026, FEI is forecasting property taxes to increase by approximately 1.9 percent from the 2025 Projected level. The most significant drivers of the forecast changes from 2025 Projected to 2026 Forecast are as follows:

1. ***Changes in Tax Rates*.** Mill rates are expected to change for 2026 as follows:
   a) Municipal general mill rates are expected to increase on average by approximately 5.0 percent in 2026 across FEI's operating municipalities; however, since many municipalities are already at the legislated rate cap of $40 per $1,000 of assessment value on utility properties, the increases due to changes in tax rates will be tempered;
   b) Rural general mill rates are expected to decrease in 2026 by approximately 4.0 percent based on the actual legislated utility rate change in 2025 of $3.47 per $1,000 of assessment value from the 2024 rate of $3.62 per $1,000 of assessment value;
   c) School mill rates are expected to decrease in 2026 by approximately 3.0 percent based on the actual legislated utility rate change in 2025 of $11.74 per $1,000 of assessment value from the 2024 rate of $12.11 per $1,000 of assessment value; and
   d) Other mill rates are expected to increase by approximately 4.5 percent in 2026, primarily from Regional District and Transit Authority taxes.
2. ***Changes in Revenues to Calculate Grants In-lieu of Taxes.*** Grants in-lieu to municipalities are anticipated to decline by 10 percent compared to 2025 Projected. As In-lieu taxes are calculated as a fixed percentage of revenues, any fluctuations in overall revenues reported to municipalities will directly impact the amount of In-Lieu taxes owed.
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 2026, land and improvements have been included together:
   a) A 7.2 percent increase in assessed values of distribution lines and services plus additional new construction;
   b) A 7.2 percent increase in assessed values of transmission lines;
   c) A 6.5 percent increase in assessed values for LNG improvements;
   d) A 5.0 percent increase in office improvements; and
   e) Land values are expected to decrease by 1 percent except for the legislated Right-of-Way rate which is expected to increase by 2.65 percent.

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

9.3 *INCOME TAX*

FEI is subject to corporate income taxes imposed by the Federal and BC governments. Current income taxes have been calculated using the flow-through (taxes payable) method, consistent with BCUC-approved past practice, at the corporate tax rate of 27 percent for 2025 and 2026, which is unchanged from 2024. 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.

For 2025, FEI is projecting income taxes to be $77.321 million, which is approximately $10.079 million or 11.5 percent less than the 2024 Approved level. The decrease is due to higher income tax deductible in 2025 through CCA by approximately $51.562 million, which is mostly by higher undepreciated capital cost (UCC) additions when compared to 2024 Approved, especially for RNG related assets with high CCA rates. The decrease resulting from the higher income tax deductible is partially offset by an increase in rate base return due to the increase in 2025 Projected rate base compared to 2024 Approved, as discussed in Section 7.1 of the Application.

For 2026, FEI is forecasting income taxes to be $112.260 million, which is approximately $34.939 million or 45.2 percent higher than the 2025 Projected level. The increase is primarily due to the following:

- higher amortization of deferral accounts in 2026 compared to 2025, as discussed in Section 7.7 of the Application;
- higher rate base return as well as higher depreciation expense resulting from the forecast increase in rate base in 2026 compared to 2025, as discussed in Section 7.1 of the Application; and
- reduced income tax deductible through CCA resulting from lower UCC additions in asset classes with higher CCA rates.

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

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

9.4 *SUMMARY*

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

10. 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 $12.460 million pre-tax credit ($9.095 million after-tax) earnings sharing amount to customers as part of the 2025 delivery rates. FEI has also set out the RSAM, Fort Nelson Residential Common Rate Phase-in, and Clean Growth Innovation Fund (CGIF) rate riders for 2025 and 2026 and provides details on the CGIF, which is funded through the collection of the CGIF rate rider.

10.2 *EARNINGS SHARING*

In the RSF Decision (at page 18), the BCUC approved the continuation of the same earnings sharing mechanism utilized during the 2020-2024 MRP term, whereby 50 percent of the achieved ROE above or below the allowed ROE is 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 formula Growth capital, where the true-up of the formula inputs happens only once actuals are known. Thus, for 2025 delivery rates, it is the 2024 formula O&M, 2024 Growth capital, and 2024 earnings sharing amounts that are calculated and impact rates in 2025.

For 2025, FEI proposes to distribute a $12.460 million pre-tax credit ($9.095 million after-tax) to customers, comprised of:

- The $5.314 million credit difference between the projected 2023 deferral account after-tax credit addition of zero embedded in 2024 delivery rates, and the actual 2023 deferral account after-tax credit addition of $5.314 million;
- The $2.898 million credit difference between the forecast 2024 deferral account after-tax credit addition of zero embedded in 2024 delivery rates, and the actual 2024 deferral account after-tax credit addition of $2.898 million;
- The $0.209 million credit difference between the projected 2023 financing addition of $0.303 million credit[72] and the actual 2023 financing addition of $0.512 million credit;

[72] Annual Review for 2024 Delivery Rates, Section 10.2. FEI notes that the amount shown in Section 10.2 of the Annual Review for 2024 Delivery Rates was a credit of $0.264 million. The financing amount was updated in the Compliance Filing to Order G-334-23 to reflect the Stage 1 GCOC Decision received after the Annual Review for 2024 Delivery Rates application was filed.

- The $0.409 million credit difference between the forecast 2024 financing addition of $0.151 million credit[73] embedded in 2024 delivery rates, and the actual 2024 financing addition of $0.560 million credit embedded in this Application; and

- 2025 forecast financing of $0.265 million (credit).[74]

FEI proposes to distribute $12.460 million to customers in 2025 as a reduction in 2025 revenue requirements through amortization of the projected 2025 opening after-tax balance as well as 2025 Projected financing of $9.095 million in the Earnings Sharing deferral account.

For 2026, FEI is not projecting any earnings sharing from 2025 to be included in the 2026 delivery rates. As FEI has included actual amounts up until May 31, 2025 within its 2025 Projected revenue requirement throughout this Application, FEI is not projecting any further variances for the remainder of the year from the amounts included in this Application.

As part of future rate filings, the actual earnings sharing for 2025 and 2026 will be distributed to or collected from customers in a similar manner as described above, which will account for the actual 2025 and 2026 ROE variances from approved.

10.3 *RATE RIDERS*

There are two delivery rate riders that are set through the Annual Review process. These are the RSAM Rate Riders and the Fort Nelson Residential Common Rate Phase-in Rate Rider. Additionally, pursuant to the RSF 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 RSF to support FEI's CGIF activities.

Pursuant to Order G-313-24, FEI was approved to the set the RSAM Rate Rider, Fort Nelson Residential Common Rate Phase-in Rate Rider, and the CGIF rider on an interim basis, effective January 1, 2025. In Section 1.2 of the Application, FEI seeks approval to set these rate riders on a permanent basis, effective January 1, 2025.

10.3.1 RSAM Rate Rider

The RSAM rate rider collects or refunds the previous year's projected RSAM balance from RS 1, 2, 3 and 23 customers over two years.

Pursuant to Order G-313-24, FEI was approved to set the 2025 RSAM rate rider at $0.149 per GJ on an interim basis, effective January 1, 2025. The 2025 RSAM rate rider was determined based on the 2024 Projected closing balance in the RSAM account at the time of the 2025 Interim Rate Application filed with the BCUC on November 27, 2024. Consistent with past treatment, any difference between the actual RSAM ending balance and the projected ending balance used to

[73] Annual Review for 2024 Delivery Rates, Compliance Filing dated February 9, 2024, Schedule 12, Line 26, Column 4.
[74] Section 11 - 2025, Schedule 12, Line 25, Column 4.

set the RSAM rate rider will be included in the calculation of the following year's rate rider. As such, as explained above, FEI seeks approval in this Application to set the 2025 RSAM rate rider of $0.149 per GJ on a permanent basis, effective January 1, 2025.

For the 2026 RSAM rate rider, the projected 2025 ending balance of the RSAM account, including interest, is a debit of $44.487 million. Based on the 2026 Forecast demand from RS 1, 2, 3, and 23 customers, the 2026 RSAM rider is calculated to be $0.212 per GJ shown in Table 10-1.

Table 10-1: 2026 RSAM Rate Rider

2025 RSAM + Interest Closing Balance ($000)	44,487
Amortization Period (Years)	2
2026 Amortization Post-Tax ($000)	22,243
Tax Rate	27%
2026 Amortization Pre-Tax ($000)	30,471

RSAM (Rider 5) Calculation

Rate Class	RSAM Amortization (S000)	2026 Volume (TJ)	Rider ($/GJ)
Rate 1/1BU/1U/1X		81,390.1	0.212
Rate 2/2BU/2U/2X		29,419.1	0.212
Rate 3/3BU/3U/3X		30,668.2	0.212
Rate 23		2,498.9	0.212
	30,471	143,976.3	0.212

The differences that result from the actual 2025 ending RSAM balance varying from the projection, and the actual 2026 volumes varying from the forecast set out in this filing, will be included in the calculation of the 2027 RSAM rate rider and, in this way, refunded to or collected from customers.

10.3.2 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 10-2 below provides the calculation of the 2025 and 2026 Fort Nelson Residential Customer Common Rate Phase-in Rate Rider, which is a credit $0.609 per GJ for 2025 and a credit of $0.355 per GJ for 2026. FEI notes that the 2025 Fort Nelson Residential Customer Common Rate Phase-in Rate Rider of $0.609 per GJ (credit) was approved on an interim basis by Order G-313-24. As shown in Table 10-2 below, there is no change to the 2025 permanent rate rider compared to the interim rate rider (after rounding to three decimal places) based on the updated demand forecast for FEFN's residential customers.

Table 10-2: 2025 and 2026 Fort Nelson Residential Customer Common Rate Phase-in Rider

Line	Particular	Reference	2025	2026
1	FEFN (RS 1) Delivery Margin @ Existing Rate w/o Rider ($000s)		1,724.6	1,937.7
2	FEFN (RS 1) Delivery Margin (RS 1) @ Existing Rate w/ Rider ($000s)		1,558.0	1,822.5
3	Incremental Delivery Margin from FEFN RS 1 ($000s)	Line 1 - Line 2	166.6	115.2
4				
5	Effective Incremental Delivery Rate ($/GJ)	Line 3 / Line 12	0.762	0.508
6	Annual Incremental of Phase-In ($/GJ)	Line 5 / 3 Years (Remaining) for 2025, /2 Years (Remaining) for 2026	0.254	0.254
7				
8	FEFN Residential Common Rate Phase-in ($/GJ)	-(Line 5 - Line 6)	(0.508)	(0.254)
9	2021 FEFN Surplus Revenue ($/GJ)	2023 Annual Review - Evid Update; Table A-6; Line 9	(0.101)	(0.101)
10	**Total FEFN Residential Common Rate Phase-in Rider ($/GJ)**	**Line 8 + Line 9**	**(0.609)**	**(0.355)**
11				
12	2025 & 2026 FEFN Residential Demand Forecast (TJ)		218.7	226.8

10.3.3 Clean Growth Innovation Fund (CGIF)

The CGIF is an important and effective mechanism that supports provincial decarbonization goals by advancing innovative technologies that help FEI and its customers lower GHG emissions while maintaining the use of its gaseous energy delivery system. In addition, the CGIF provides FEI staff with direct exposure to the start-up companies and academic institutions developing the technologies. This direct exposure facilitates the development of internal FEI knowledge through CGIF learnings and supports FEI's advancement of the energy transition in the interests of its customers.

The CGIF was established as part of the 2020-2024 MRP (2020 CGIF), with FEI collecting $0.40 per month per customer through the CGIF rider. In the RSF Decision, the BCUC approved the continuation of the CGIF for the term of the RSF (2025 CGIF), including the $0.40 per month per CGIF rate rider. FEI was directed to return the ending balance of the 2020 CGIF to customers through amortization of the balance over one year in 2025. FEI was further directed to return any residual balance in the 2025 CGIF to customers at the end of the RSF term.[75]

10.3.3.1 2020 CGIF Ending Balance

The ending balance in the 2020 CGIF is $5.224 million, as shown in Table 10-3 below.

[75] RSF Decision and Order G-69-25, pp. 82-83.

Table 10-3: 2020 CGIF Closing Balance ($ millions)

	2020	2021	2022	2023	2024	Total
Portfolio Approvals	**$ 1.450**	**$ 4.002**	**$ 1.524**	**$ 4.165**	**$ 9.458**	**$ 20.599**
Cancelled/Adjusted Projects	**$ 0.067**	**$ 1.975**	**$ 0.364**	**$ 0.062**	**$ 0.059**	**$ 2.527**
Net Approvals	**$ 1.383**	**$ 2.027**	**$ 1.160**	**$ 4.103**	**$ 9.399**	**$ 18.072**
Opening Balance	**$ -**	**$ (0.791)**	**$ (3.816)**	**$ (7.186)**	**$ (10.508)**	**$ -**
Funding collected	(2.099)	(5.093)	(5.176)	(5.230)	(5.299)	(22.898)
Expenditures	1.022	1.127	0.972	1.431	2.754	7.306
Accrued committed	-	-	-	-	10.765	10.765
Tax	0.291	1.071	1.135	1.026	(2.219)	1.303
Financing	(0.005)	(0.130)	(0.301)	(0.549)	(0.715)	(1.700)
Closing Balance	**$ (0.791)**	**$ (3.816)**	**$ (7.186)**	**$ (10.508)**	**$ (5.224)**	**(5.224)**

As shown in the above table, the total net portfolio approvals over the 2020 CGIF term were $18.072 million. Included in this total is $10.765 million of accrued committed funding for projects which will be spent over the next three to four years as the projects are completed. After the inclusion of taxes and financing, FEI will be returning $7.156 million ($5.224 million after-tax) to customers in 2025.

However, due to the 2020 CGIF being a non-rate base deferral account (attracting AFUDC), if unaddressed, there would be a circular issue for regulatory accounting purposes whereby new AFUDC amounts will continue to accumulate in the account each year and must be factored into the amortization schedule.

To address this circular AFUDC issue, FEI proposes to transfer the $5.224 million after-tax balance accumulated in the 2020 CGIF deferral account at the end of 2024 to the existing rate base Residual Delivery Rate Riders deferral account effective January 1, 2025, and to return the $7.156 million ($5.224 million after-tax) to customers in 2025 via amortization of the Residual Delivery Rate Riders deferral account. This account, which was approved by Order G-44-12 and has been historically used for similar purposes, has an approved amortization period of one year. Thus, transfer of the balance from the 2020 CGIF to the Residual Delivery Rate Riders deferral account at the end of 2024 will enable FEI to return the unused 2020 CGIF funds to customers as directed in the RSF Decision.

FEI also notes that it is possible that some of the accrued committed funds (i.e., some of the $10.765 million) may ultimately be unspent if, for example, a project is cancelled or some of the funds committed to the project are not spent. If such a situation occurs, FEI proposes to also capture these unspent amounts in the Residual Delivery Rate Riders deferral account and return the amounts to customers in the subsequent year through amortization.

FEI has included this request in Section 1.2 (Approvals Sought) of the Application and in the draft order attached as Appendix C.

10.3.3.2 2025 CGIF

In the RSF Decision, the BCUC approved the continuation of the CGIF, which enables clean energy innovation by helping advance emerging technologies that benefit FEI's customers by providing cost effective, safe and reliable energy solutions. As approved in the RSF Decision, FEI has continued to collect the CGIF rate rider of $0.40 per month per customer. FEI is projecting to collect $5.295 million in 2025 and is forecasting to collect $5.349 million in 2026.

Table 10-4 below shows the projected/forecast amounts to be collected and expended in 2025 and 2026.

Table 10-4: Clean Growth Innovation Fund 2025-2026 Deferral Account Continuity ($ millions)

	Actual Jan - Jun 2025	Projected Jul - Dec 2025	Forecast 2026
Portfolio Approvals	**$ 1.076**	**$ 2.924**	**$ 5.000**
Opening Balance	**$ -**	**$ (1.945)**	**$ (1.823)**
Funding collected	(2.616)	(2.678)	(5.349)
Expenditures	-	3.000	4.000
Accrued committed	-	-	-
Tax	0.706	(0.086)	0.364
Financing	(0.035)	(0.113)	(0.144)
Closing Balance	**$ (1.945)**	**$ (1.823)**	**$ (2.951)**

As of the end of June 2025, the 2025 CGIF has had one portfolio review, and $1.1 million in new projects have been approved. FEI expects to review at least one more portfolio of projects before the end of 2025.

10.3.3.2.1 GOVERNANCE

FEI has continued to maintain the governance structure that was established under the 2020 CGIF.

CGIF portfolios are first reviewed by FEI subject matter experts. The recommendations of the Company's subject matter experts are reviewed by the CGIF Steering Team (CGIF-ST) and are either approved or rejected. Some proposals are approved by the CGIF-ST with conditions. The CGIF-ST is comprised of FEI senior managers that provide leadership to a variety of departments that are key to assessing the technical and business aspects of the portfolio proposals.

Proposals recommended by the Company's subject matter experts are presented to the External Advisory Council (EAC) for input and comment that will support final portfolio approvals. The input and comments from the EAC are considered throughout the decision process. The EAC for the 2025 CGIF includes the following stakeholders:

- BCSEA;

- BC Ministry of Energy, Mines and Low-Carbon Innovation;
- Foresight Cleantech Accelerator Centre;
- Simon Frasier University;
- University of British Columbia;
- Malahat Nation;
- NorthX Climate (formerly BC Center for Innovation and Clean Energy);
- BC Bioenergy Network; and
- University of Victoria.

The CGIF Executive Steering Committee (ESC) is the final stage of portfolio review and is responsible for: (1) making a final decision regarding which projects, if any, within a given portfolio are approved; and (2) providing overall strategic direction over CGIF expenditures. The ESC reviews each portfolio with the benefit of recommendations and summaries of the commentary received from FEI subject matter experts, the CGIF-ST and the EAC to determine whether a project should be approved.

10.3.3.2.2 INVESTMENT PROFILE

Consistent with the 2020 CGIF, grants from the 2025 CGIF will be focused on several application areas critical for decarbonizing FEI's gas system: production; distribution; end-use; carbon capture, utilization and storage (CCUS); and generalized low-carbon initiatives.

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. 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 CCUS.

While it is still early in the 2025 CGIF term, the total approved investment in these application categories, and subcategories, is shown in Table 10-5.

Table 10-5: CGIF Approved Investment by Application ($ millions)

Application	Sub-Application	Approved Grant
Production	Renewable Hydrogen	0.000
	Renewable Natural Gas	0.222
	Renewable Syngas	0.000
	Subtotal	**0.222**
Distribution	Renewable Hydrogen	0.000
	Subtotal	**0.000**
End-Use	Energy Efficiency	0.000
	Hybrid Systems	0.000
	Renewable Hydrogen	0.000
	Renewable Natural Gas	0.000
	Transportation	0.030
	Subtotal	**0.030**
Carbon Capture	Carbon capture	0.124
	End-Use	0.000
	Storage	0.000
	Subtotal	**0.124**
General Low-Carbon	General Initiatives	0.700
	Subtotal	**0.700**
Total		**1.076**

The majority of the approved funding is related to FEI's continued participation in the Natural Gas Innovation Fund (NGIF). Additionally, two projects related to improving RNG feedstock and one project related to carbon capture using a metal-organic framework have been approved. The 2025 CGIF also approved a project to support a demonstration of a heavy-duty hydrogen vehicle in the Lower Mainland.

10.4 *SUMMARY*

As discussed in Section 10.2 above, FEI proposes to distribute a $12.460 million pre-tax credit ($9.095 million after-tax) earnings sharing amount to customers as part of 2025 delivery rates.

In Section 10.3, FEI provides information on its 2025 and 2026 delivery rate riders. For the RSAM rate rider, FEI is proposing to set the currently approved interim 2025 rider of $0.149 per GJ on a permanent basis and to set the 2026 RSAM rate rider at $0.212 per GJ. For the Fort Nelson Residential Common Rate Phase-in Rate Rider, FEI is proposing to set the currently approved interim 2025 credit rider of $0.609 per GJ on a permanent basis, and to set the 2026 rider at a credit of $0.355 per GJ. FEI has also provided details on the CGIF in Section 10.3.3, which is funded through the collection of the basic charge CGIF rider.

11. FINANCIAL SCHEDULES

11.1 *2025 Financial Schedules*

Description	Schedule Reference
Summary Of Rate Change	1
Rate Base	
Utility Rate Base	2
Formula Inflation Factors	3
Capital Expenditures	4
Capital Expenditures To Plant Reconciliation	5
Plant In Service Continuity Schedule	6
Accumulated Depreciation Continuity Schedule	7
Non-Reg Plant Continuity Schedule	8
Contributions In Aid Of Construction Continuity Schedule	9
Net Salvage Continuity Schedule	10
Unamortized Deferred Charges And Amortization - Rate Base	11
Unamortized Deferred Charges And Amortization - Non-Rate Base	12
Working Capital Allowance	13
Cash Working Capital	14
Deferred Income Tax Liability / Asset	15
Revenue Requirement	
Utility Income And Earned Return	16
Volume And Revenue	17
Cost Of Energy	18
Margin And Revenue At Existing And Revised Rates	19
Operating And Maintenance Expense	20
Depreciation And Amortization Expense	21
Property And Sundry Taxes	22
Other Revenue	23
Income Taxes	24
Capital Cost Allowance	25
Return On Capital	26
Embedded Cost Of Long Term Debt	27

SUMMARY OF RATE CHANGE
FOR THE YEAR ENDING DECEMBER 31, 2025
($millions)

Schedule 1

Line No.	Particulars	2025 Projected		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	$ 5.267		
3	Change in Other Revenue	10.170	15.437	
4				
5	**O&M CHANGES**			
6	Resetting Base O&M	(11.285)		
7	Capitalized Overhead Study	6.012		
8	Gross O&M Change	42.552		
9	Capitalized Overhead Change	(7.042)	30.237	
10				
11	**DEPRECIATION EXPENSE**			
12	Depreciation Rate Change (Depreciation Study)	(3.900)		
13	Depreciation from Net Additions	1.426	(2.474)	
14				
15	**AMORTIZATION EXPENSE**			
16	CIAC Rate Change (Depreciation Study)	0.000		
17	CIAC from Net Additions	0.952		
18	Net Salvage Rate Change (Depreciation Study)	5.900		
19	Deferrals	3.323	10.175	
20				
21	**FINANCING AND RETURN ON EQUITY**			
22	Financing Rate Changes	0.674		
23	Financing Ratio Changes	(3.683)		
24	Resetting Rate Base	14.758		
25	Cash Working Capital - Lead/Lag Study	0.000		
26	Rate Base Growth	28.872	40.621	
27				
28	**TAX EXPENSE**			
29	Property and Other Taxes	3.568		
30	Other Income Taxes Changes	(10.079)	(6.511)	
31				
32	**2024 Revenue Deficiency**		15.915	
33	**2025 Revenue Deficiency**		(15.352)	
34				
35	**REVENUE DEFICIENCY (SURPLUS)**		**$ 88.048**	Schedule 16, Line 11, Column 4
36				
37	Non-Bypass Margin at 2024 Approved Rates		1,136.106	Schedule 19, Line 17, Column 3
38	Rate Change		7.75%	

Schedule 2

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Line No.	Particulars	2024 Approved	2025 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 8,723,480	$ 9,197,357	$ 473,877	Schedule 6.2, Line 33, Column 3
2	Opening Balance Adjustment	-	-	-	Schedule 6.2, Line 33, Column 4
3	Net Additions	369,743	420,371	50,628	Schedule 6.2, Line 33, Columns 5+6+7
4	Plant in Service, Ending	9,093,223	9,617,728	524,505	
5					
6	Accumulated Depreciation Beginning	$ (2,726,314)	$ (2,890,246)	$ (163,932)	Schedule 7.2, Line 33, Column 5
7	Opening Balance Adjustment	-	-	-	Schedule 7.2, Line 33, Column 6
8	Net Additions	(164,985)	(108,098)	56,887	Schedule 7.2, Line 33, Columns 7+8
9	Accumulated Depreciation Ending	(2,891,299)	(2,998,344)	(107,045)	
10					
11	CIAC, Beginning	$ (464,929)	$ (472,866)	$ (7,937)	Schedule 9, Line 6, Column 2
12	Opening Balance Adjustment	-	-	-	
13	Net Additions	(14,932)	(7,950)	6,982	Schedule 9, Line 6, Columns 5+6
14	CIAC, Ending	(479,861)	(480,816)	(955)	
15					
16	Accumulated Amortization Beginning - CIAC	$ 205,638	$ 209,580	$ 3,942	Schedule 9, Line 13, Column 2
17	Opening Balance Adjustment	-	-	-	
18	Net Additions	8,851	7,899	(952)	Schedule 9, Line 13, Columns 5+6
19	Accumulated Amortization Ending - CIAC	214,489	217,479	2,990	
20					
21	Net Plant in Service, Mid-Year	$ 5,837,214	$ 6,199,936	$ 362,722	
22					
23	Adjustment for timing of Capital additions	$ 31,093	$ 75,650	$ 44,557	
24	Capital Work in Progress, No AFUDC	33,914	36,755	2,841	
25	Unamortized Deferred Charges	(160,899)	85,905	246,804	Schedule 11.1, Line 26, Column 10
26	Working Capital	76,166	53,869	(22,297)	Schedule 13, Line 14, Column 3
27	Deferred Income Taxes Regulatory Asset	738,348	927,015	188,667	Schedule 15, Line 6, Column 3
28	Deferred Income Taxes Regulatory Liability	(738,348)	(927,015)	(188,667)	Schedule 15, Line 6, Column 3
29					
30	Mid-Year Utility Rate Base	$ 5,817,488	$ 6,452,115	$ 634,627	

FORMULA INFLATION FACTORS
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Schedule 3

Line No.	Particulars	Reference	2025	Total for 2025 Rate Setting	Cross Ref
	(1)	(2)	(3)	(4)	(5)
1	**Formula Cost Drivers**				
2	CPI		3.012%		
3	AWE		5.384%		
4	Labour Split				
5	Non Labour		50.000%		
6	Labour		50.000%		
7	CPI/AWE	(Line 2 x Line 5) + (Line 3 x Line 6)	4.198%		
8	Productivity Factor		-0.550%		
9	Net Inflation Factor	Line 7 + Line 8	3.648%		
10					
11					
12	**Growth in Average Customer Calculation**				
13	Actual Prior Year Average Customers		1,093,663		
14	Average Customers for the Year	Schedule 19, Line 29, Column 9	1,102,958		
15	Average Customer Projected - Rate Setting Purposes	Line 14		1,102,958	

Schedule 4

CAPITAL EXPENDITURES
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Line No.	Particulars	Growth CapEx	Other CapEx	Projected CapEx	Total CapEx	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Inflation Indexed Capital Growth**					
2	2024 Unit Cost Growth Capital - Adjusted for 2025 Annual Review	$ 9,300				
3	2025 Net Inflation Factor	3.648%				Schedule 3, Line 9, Column 3
4	2025 Unit Cost Growth Capital	$ 9,639				
5	2025 Gross Customer Additions	10,000				
6	2025 Inflation Indexed Growth Capital	$ 96,390			$ 96,390	
7	2023 Growth Capital Customer True-Up				(1,640)	
8	2025 System Extension Fund				1,000	
9	2025 Growth CIAC				3,514	
10	2025 Inflation Indexed Gross Growth Capital				$ 99,264	
11						
12	**Capital Tracked Outside of Formula**					
13	Pension & OPEB (Growth Capital Portion)			$ 1,176		
14	RNG Assets			19,181		
15	NGT Assets			6,323		
16	Sustainment Capital			125,599		
17	Other Capital			67,904		
18	Sub-total			$ 220,183	220,183	
19						
20	**Total Capital Expenditures Before CIAC**				$ 319,447	

CAPITAL EXPENDITURES TO PLANT RECONCILIATION
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Schedule 5

Line No.	Particulars		2025 Projected	Cross Reference
	(1)		(2)	(3)
1	**CAPEX**			
2	Growth Capital Expenditures	$	99,264	Schedule 4, Line 10, Column 5
3	Forecast Capital Expenditures		220,183	Schedule 4, Line 18, Column 5
4	Total Capital Expenditures	$	319,447	
5				
6	**Special Projects and CPCN's**			
7	Inland Gas Upgrade	$	7,194	
8	Pattullo Gasline Replacement		33	
9	Transmission Integrity Program - CTS		25,598	
10	Gibsons Capacity Upgrade		581	
11	Transmission Integrity Program - ITS		41,992	
12	FEI Advance Metering Infrastructure (AMI) CPCN		194,157	
13	Okanagan Capacity Mitigation Plan (OCMP)		11,160	
14	Tilbury Expansion Project		23,108	
15	CTS Expansion Project		6,000	
16	Total Capital Expenditures	$	309,823	
17				
18	**Total Capital Expenditures**	$	629,270	
19				
20				
21	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**			
22				
23	Regular Capital Expenditures	$	319,447	Line 4
24	Add - Capitalized Overheads		58,114	Schedule 20, Line 28, Column 4
25	Add - AFUDC		9,005	
26	Gross Capital Expenditures		386,566	
27	Change in Work in Progress		40,619	
28	**Total Regular Additions to Plant**	$	427,185	
29				
30	Special Projects and CPCN's Capital Expenditures	$	309,823	Line 16
31	Add - AFUDC		39,300	
32	Gross Capital Expenditures		349,123	
33	Change in Work in Progress		(197,823)	
34	**Total Special Projects and CPCN Additions to Plant**	$	151,300	
35				
36	**Grand Total Additions to Plant**	$	578,485	

PLANT IN SERVICE CONTINUITY SCHEDULE Schedule 6
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Line No.	Account	Particulars	12/31/2024	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2025	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	52,708	-	1,671	-	-	54,379	
8	461-02	Transmission Land Rights - Mt. Hayes	643	-	-	-	-	643	
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	7,180	-	-	-	-	7,180	
12	471-11	Distribution Land Rights - Byron Creek	1	-	-	-	-	1	
13	402-01	Application Software - 12.5%	82,670	-	312	11,384	(9,630)	84,736	
14	402-02	Application Software - 20%	32,254	-	-	11,202	(5,221)	38,235	
15			$ 182,736	$ -	$ 1,983	$ 22,586	$ (14,851)	$ 192,454	
16									
17		**MANUFACTURED GAS / LOCAL STORAGE**							
18	430-00	Manufact'd Gas - Land	$ 31	$ -	$ -	$ -	$ -	$ 31	
19	432-00	Manufact'd Gas - Struct. & Improvements	1,312	-	-	-	-	1,312	
20	433-00	Manufact'd Gas - Equipment	2,122	-	-	-	-	2,122	
21	434-00	Manufact'd Gas - Gas Holders	2,948	-	-	-	-	2,948	
22	436-00	Manufact'd Gas - Compressor Equipment	367	-	-	-	-	367	
23	437-00	Manufact'd Gas - Measuring & Regulating Equipment	2,518	-	-	-	-	2,518	
24	440-00	Land in Fee Simple and Land Rights (Tilbury)	15,164	-	-	-	-	15,164	
25	442-00	Structures & Improvements (Tilbury)	101,354	-	-	-	-	101,354	
26	443-00	Gas Holders - Storage (Tilbury)	184,971	-	-	-	-	184,971	
27	448-11	Piping (Tilbury)	53,015	-	-	-	-	53,015	
28	448-21	Pre-treatment (Tilbury)	34,307	-	-	-	-	34,307	
29	448-31	Liquefaction Equipment (Tilbury)	90,421	-	-	-	-	90,421	
30	449-00	Local Storage Equipment (Tilbury)	23,905	-	-	-	-	23,905	
31	440-01	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	-	-	-	-	1,083	
32	442-01	Structures & Improvements (Mount Hayes)	19,355	-	-	-	-	19,355	
33	443-05	Gas Holders - Storage (Mount Hayes)	61,907	-	-	-	-	61,907	
34	448-41	Send out Equipment(Tilbury)	10,919	-	-	-	-	10,919	
35	448-51	Sub-station and Electric (Tilbury)	38,505	-	-	-	-	38,505	
36	448-61	Control Room (Tilbury)	5,034	-	-	-	-	5,034	
37	448-10	Piping (Mount Hayes)	12,714	-	-	-	-	12,714	
38	448-20	Pre-treatment (Mount Hayes)	29,462	-	-	-	-	29,462	
39	448-30	Liquefaction Equipment (Mount Hayes)	28,940	-	-	-	-	28,940	
40	448-40	Send out Equipment (Mount Hayes)	23,743	-	-	-	-	23,743	
41	448-50	Sub-station and Electric (Mount Hayes)	21,788	-	-	-	-	21,788	
42	448-60	Control Room (Mount Hayes)	6,674	-	-	-	-	6,674	
43	448-65	MH Inspection (Mount Hayes)	1,572	-	-	-	(1,416)	156	
44	448-66	Tilbury LNG - Inspection	5,476	-	-	-	-	5,476	
45	449-01	Local Storage Equipment (Mount Hayes)	6,133	-	-	-	-	6,133	
46			$ 785,740	$ -	$ -	$ -	$ (1,416)	$ 784,324	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Schedule 6.1

Line No.	Account	Particulars	12/31/2024	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2025	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**TRANSMISSION PLANT**							
2	460-00	Land in Fee Simple	$ 11,086	$ -	$ -	$ -	$ -	$ 11,086	
3	462-00	Compressor Structures	49,585	-	-	2,629	(417)	51,797	
4	463-00	Measuring Structures	28,691	-	543	-	-	29,234	
5	464-00	Other Structures & Improvements	6,871	-	6,428	2,172	(3)	15,468	
6	465-00	Mains	1,781,171	-	95,687	37,495	(3,510)	1,910,843	
7	465-20	Mains - INSPECTION	49,186	-	-	21,081	(8,145)	62,122	
8	465-11	IP Transmission Pipeline - Whistler	60,674	-	-	-	-	60,674	
9	465-30	Mt Hayes - Mains	6,307	-	-	-	-	6,307	
10	465-10	Mains - Byron Creek	1,371	-	-	-	-	1,371	
11	466-00	Compressor Equipment	209,089	-	-	4,080	(1,073)	212,096	
12	466-10	Compressor Equipment - OVERHAUL	2,590	-	-	5	(1,408)	1,187	
13	467-00	Mt. Hayes - Measuring and Regulating Equipment	5,925	-	-	1,449	-	7,374	
14	467-10	Measuring & Regulating Equipment	140,213	-	33,041	9,344	(361)	182,237	
15	467-20	Telemetering	35,000	-	-	-	-	35,000	
16	467-31	IP Intermediate Pressure Whistler	313	-	-	45	-	358	
17	467-30	Measuring & Regulating Equipment - Byron Creek	291	-	-	-	-	291	
18	468-00	Communication Structures & Equipment	3,358	-	-	3,592	-	6,950	
19			$ 2,391,721	$ -	$ 135,699	$ 81,892	$ (14,917)	$ 2,594,395	
20									
21		**DISTRIBUTION PLANT**							
22	470-00	Land in Fee Simple	$ 6,349	$ -	$ -	$ -	$ -	$ 6,349	
23	472-00	Structures & Improvements	57,377	-	10,598	2,058	(72)	69,961	
24	472-10	Structures & Improvements - Byron Creek	124	-	-	-	-	124	
25	473-00	Services	1,698,782	-	-	82,933	(3,656)	1,778,059	
26	474-00	House Regulators & Meter Installations	156,284	-	-	-	(26,607)	129,677	
27	474-02	Meters/Regulators Installations	279,613	-	2	24,675	(39,271)	265,019	
28	475-00	Mains	2,468,010	-	80	67,901	(4,127)	2,531,864	
29	476-00	Compressor Equipment	614	-	-	-	-	614	
30	477-10	Measuring & Regulating Equipment	254,742	-	2,161	15,578	(939)	271,542	
31	477-20	Telemetering	35,403	-	777	875	(53)	37,002	
32	477-30	Measuring & Regulating Equipment - Byron Creek	153	-	-	-	-	153	
33	478-10	Meters	338,715	-	-	20,430	(34,756)	324,389	
34	478-20	Instruments	17,936	-	-	842	-	18,778	
35	479-00	Other Distribution Equipment	-	-	-	-	-	-	
36			$ 5,314,102	$ -	$ 13,618	$ 215,292	$ (109,481)	$ 5,433,531	
37									
38		**BIO GAS**							
39	472-20	Bio Gas Struct. & Improvements	$ 2,017	$ -	$ -	$ 6,227	$ -	$ 8,244	
40	475-10	Bio Gas Mains – Municipal Land	10,974	-	-	5,229	-	16,203	
41	475-20	Bio Gas Mains – Private Land	1,175	-	-	-	-	1,175	
42	418-10	Bio Gas Purification Overhaul	20	-	-	2	-	22	
43	418-20	Bio Gas Purification Upgrader	11,827	-	-	50,436	-	62,263	
44	477-40	Bio Gas Reg & Meter Equipment	5,836	-	-	1,415	-	7,251	
45	478-30	Bio Gas Meters	295	-	-	76	-	371	
46	474-10	Bio Gas Reg & Meter Installations	1,497	-	-	2,619	-	4,116	
47	483-25	RNG Comp S/W	-	-	-	-	-	-	
48	465-40	Bio Gas Transmission Pipe	-	-	-	1,561	-	1,561	
49	466-40	Bio Gas Compressor Equipment	-	-	-	3,295	-	3,295	
50			$ 33,641	$ -	$ -	$ 70,860	$ -	$ 104,501	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Schedule 6.2

Line No.	Account	Particulars	12/31/2024	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2025	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Natural Gas for Transportation**							
2	476-10	NG Transportation CNG Dispensing Equipment	$ 17,138	$ -	$ -	$ -	$ -	$ 17,138	
3	476-20	NG Transportation LNG Dispensing Equipment	13,208	-	-	-	-	13,208	
4	476-30	NG Transportation CNG Foundations	3,163	-	-	-	-	3,163	
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	805	-	-	-	-	805	
8			$ 35,440	$ -	$ -	$ -	$ -	$ 35,440	
9									
10		**GENERAL PLANT & EQUIPMENT**							
11	480-00	Land in Fee Simple	$ 31,944	$ -	$ -	$ -	$ -	$ 31,944	
12	482-10	Frame Buildings	28,430	-	-	-	-	28,430	
13	482-20	Masonry Buildings	147,688	-	-	3,802	(96)	151,394	
14	482-30	Leasehold Improvement	5,509	-	-	-	(867)	4,642	
15	483-30	GP Office Equipment	2,399	-	-	489	(110)	2,778	
16	483-40	GP Furniture	21,175	-	-	3,742	(166)	24,751	
17	483-10	GP Computer Hardware	38,897	-	-	11,178	(9,356)	40,719	
18	483-20	GP Computer Software	10,294	-	-	-	(1,038)	9,256	
19	484-00	Vehicles	67,318	-	-	9,609	-	76,927	
20	484-10	Vehicles - Leased	5,781	-	-	-	(2,844)	2,937	
21	485-10	Heavy Work Equipment	735	-	-	-	-	735	
22	485-20	Heavy Mobile Equipment	15,124	-	-	-	-	15,124	
23	486-00	Small Tools & Equipment	60,797	-	-	5,832	(2,573)	64,056	
24	487-20	Equipment on Customer's Premises	-	-	-	-	-	-	
25	488-10	Telephone	317	-	-	-	(173)	144	
26	488-20	Radio	17,569	-	-	1,903	(226)	19,246	
27			$ 453,977	$ -	$ -	$ 36,555	$ (17,449)	$ 473,083	
28									
29		**UNCLASSIFIED PLANT**							
30	499-00	Plant Suspense	-	-	-	-	-	-	
31			$ -	$ -	$ -	$ -	$ -	$ -	
32									
33		**Total Plant in Service**	$ 9,197,357	$ -	$ 151,300	$ 427,185	$ (158,114)	$ 9,617,728	
34									
35		Cross Reference			Schedule 5, Line 34, Column 2	Schedule 5, Line 28, Column 2			

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Schedule 7

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2024	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2025	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%	$ 68	$ -	$ 1	$ -	$ -	$ -	$ 69	
3	178-00	Organization Expense	728	1.00%	479	-	7	-	-	-	486	
4	401-01	Franchise and Consents	197	2.50%	144	-	5	-	-	-	149	
5	402-03	Other Intangible Plant	1,907	2.50%	1,389	-	48	-	-	-	1,437	
6	440-02	Water/Land Rights Tilbury	4,299	0.00%	-	-	-	-	-	-	-	
7	461-01	Transmission Land Rights	54,379	0.00%	1,766	-	-	-	-	-	1,766	
8	461-02	Transmission Land Rights - Mt. Hayes	643	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	7,180	0.00%	248	-	-	-	-	-	248	
12	471-11	Distribution Land Rights - Byron Creek	1	0.00%	1	-	-	-	-	-	1	
13	402-01	Application Software - 12.5%	82,982	12.50%	34,137	-	10,334	(9,630)	-	-	34,841	
14	402-02	Application Software - 20%	32,254	20.00%	11,714	-	6,451	(5,221)	-	-	12,944	
15			$ 184,719		$ 49,965	$ -	$ 16,846	$ (14,851)	$ -	$ -	$ 51,960	
16												
17		**MANUFACTURED GAS / LOCAL STORAGE**										
18	430-00	Manufact'd Gas - Land	$ 31	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
19	432-00	Manufact'd Gas - Struct. & Improvements	1,312	2.50%	524	-	33	-	-	-	557	
20	433-00	Manufact'd Gas - Equipment	2,122	5.00%	478	-	106	-	-	-	584	
21	434-00	Manufact'd Gas - Gas Holders	2,948	2.50%	1,092	-	74	-	-	-	1,166	
22	436-00	Manufact'd Gas - Compressor Equipment	367	4.00%	227	-	15	-	-	-	242	
23	437-00	Manufact'd Gas - Measuring & Regulating Equipment	2,518	5.00%	1,454	-	126	-	-	-	1,580	
24	440-00	Land in Fee Simple and Land Rights (Tilbury)	15,164	0.00%	1	-	-	-	-	-	1	
25	442-00	Structures & Improvements (Tilbury)	101,354	3.70%	16,982	-	3,750	-	-	-	20,732	
26	443-00	Gas Holders - Storage (Tilbury)	184,971	1.71%	27,163	-	3,163	-	-	-	30,326	
27	448-11	Piping (Tilbury)	53,015	2.50%	7,081	-	1,325	-	-	-	8,406	
28	448-21	Pre-treatment (Tilbury)	34,307	4.01%	7,652	-	1,376	-	-	-	9,028	
29	448-31	Liquefaction Equipment (Tilbury)	90,421	2.50%	12,892	-	2,261	-	-	-	15,153	
30	449-00	Local Storage Equipment (Tilbury)	23,905	2.10%	14,023	-	502	-	-	-	14,525	
31	440-01	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	0.00%	-	-	-	-	-	-	-	
32	442-01	Structures & Improvements (Mount Hayes)	19,355	3.06%	9,775	-	592	-	-	-	10,367	
33	443-05	Gas Holders - Storage (Mount Hayes)	61,907	1.65%	13,698	-	1,021	-	-	-	14,719	
34	448-41	Send out Equipment(Tilbury)	10,919	2.50%	1,214	-	273	-	-	-	1,487	
35	448-51	Sub-station and Electric (Tilbury)	38,505	2.50%	5,354	-	963	-	-	-	6,317	
36	448-61	Control Room (Tilbury)	5,034	6.75%	1,512	-	340	-	-	-	1,852	
37	448-10	Piping (Mount Hayes)	12,714	2.43%	4,047	-	309	-	-	-	4,356	
38	448-20	Pre-treatment (Mount Hayes)	29,462	3.71%	15,451	-	1,093	-	-	-	16,544	
39	448-30	Liquefaction Equipment (Mount Hayes)	28,940	2.42%	9,681	-	700	-	-	-	10,381	
40	448-40	Send out Equipment (Mount Hayes)	23,743	2.43%	7,783	-	577	-	-	-	8,360	
41	448-50	Sub-station and Electric (Mount Hayes)	21,788	2.43%	7,242	-	529	-	-	-	7,771	
42	448-60	Control Room (Mount Hayes)	6,674	5.01%	5,421	-	334	-	-	-	5,755	
43	448-65	MH Inspection (Mount Hayes)	1,572	20.00%	1,226	-	314	(1,416)	-	-	124	
44	448-66	Tilbury LNG - Inspection	5,476	20.00%	1,095	-	1,095	-	-	-	2,190	
45	449-01	Local Storage Equipment (Mount Hayes)	6,133	3.47%	1,563	-	213	-	-	-	1,776	
46			$ 785,740		$ 174,631	$ -	$ 21,084	$ (1,416)	$ -	$ -	$ 194,299	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Schedule 7.1

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2024	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2025	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**TRANSMISSION PLANT**										
2	460-00	Land in Fee Simple	$ 11,086	0.00%	$ 503	$ -	$ -	$ -	$ -	$ -	$ 503	
3	462-00	Compressor Structures	49,585	2.97%	25,304	-	1,473	(417)	-	-	26,360	
4	463-00	Measuring Structures	29,234	2.19%	9,735	-	640	-	-	-	10,375	
5	464-00	Other Structures & Improvements	13,299	3.31%	4,633	-	440	(3)	-	-	5,070	
6	465-00	Mains	1,876,858	1.48%	544,314	-	27,778	(3,510)	-	-	568,582	
7	465-20	Mains - INSPECTION	49,186	15.20%	16,499	-	7,476	(8,145)	-	-	15,830	
8	465-11	IP Transmission Pipeline - Whistler	60,674	1.53%	10,979	-	928	-	-	-	11,907	
9	465-30	Mt Hayes - Mains	6,307	1.54%	1,369	-	97	-	-	-	1,466	
10	465-10	Mains - Byron Creek	1,371	5.03%	1,773	-	69	-	-	-	1,842	
11	466-00	Compressor Equipment	209,089	2.31%	119,434	-	4,830	(1,073)	-	-	123,191	
12	466-10	Compressor Equipment - OVERHAUL	2,590	10.19%	2,066	-	264	(1,408)	-	-	922	
13	467-00	Mt. Hayes - Measuring and Regulating Equipment	5,925	2.28%	2,255	-	135	-	-	-	2,390	
14	467-10	Measuring & Regulating Equipment	173,254	2.27%	35,773	-	3,933	(361)	-	-	39,345	
15	467-20	Telemetering	35,000	6.01%	15,223	-	2,104	-	-	-	17,327	
16	467-31	IP Intermediate Pressure Whistler	313	2.14%	148	-	7	-	-	-	155	
17	467-30	Measuring & Regulating Equipment - Byron Creek	291	2.41%	66	-	7	-	-	-	73	
18	468-00	Communication Structures & Equipment	3,358	0.00%	3,691	-	-	-	-	-	3,691	
19			$ 2,527,420		$ 793,765	$ -	$ 50,181	$ (14,917)	$ -	$ -	$ 829,029	
20												
21		**DISTRIBUTION PLANT**										
22	470-00	Land in Fee Simple	$ 6,349	0.00%	$ (13)	$ -	$ -	$ -	$ -	$ -	$ (13)	
23	472-00	Structures & Improvements	67,975	2.01%	15,540	-	1,366	(72)	-	-	16,834	
24	472-10	Structures & Improvements - Byron Creek	124	4.67%	100	-	6	-	-	-	106	
25	473-00	Services	1,698,782	2.11%	481,692	-	35,845	(3,656)	-	-	513,881	
26	474-00	House Regulators & Meter Installations	156,284	4.35%	135,333	-	6,798	(22,888)	-	-	119,243	
27	474-02	Meters/Regulators Installations	279,615	4.55%	78,198	-	12,723	(11,541)	-	-	79,380	
28	475-00	Mains	2,468,090	1.42%	649,990	-	35,047	(4,127)	-	-	680,910	
29	476-00	Compressor Equipment	614	0.00%	1,444	-	-	-	-	-	1,444	
30	477-10	Measuring & Regulating Equipment	256,903	2.66%	78,300	-	6,834	(939)	-	-	84,195	
31	477-20	Telemetering	36,180	4.97%	10,152	-	1,798	(53)	-	-	11,897	
32	477-30	Measuring & Regulating Equipment - Byron Creek	153	0.00%	210	-	-	-	-	-	210	
33	478-10	Meters	338,715	3.38%	225,919	-	11,449	(28,829)	-	-	208,539	
34	478-20	Instruments	17,936	2.86%	9,043	-	513	-	-	-	9,556	
35	479-00	Other Distribution Equipment	-	0.00%	-	-	-	-	-	-	-	
36			$ 5,327,720		$ 1,685,908	$ -	$ 112,379	$ (72,105)	$ -	$ -	$ 1,726,182	
37												
38		**BIO GAS**										
39	472-20	Bio Gas Struct. & Improvements	$ 2,017	2.69%	253	$ -	$ 54	$ -	$ -	$ -	$ 307	
40	475-10	Bio Gas Mains – Municipal Land	10,974	1.54%	385	-	169	-	-	-	554	
41	475-20	Bio Gas Mains – Private Land	1,175	1.53%	43	-	18	-	-	-	61	
42	418-10	Bio Gas Purification Overhaul	20	5.00%	11	-	1	-	-	-	12	
43	418-20	Bio Gas Purification Upgrader	11,827	5.00%	4,917	-	591	-	-	-	5,508	
44	477-40	Bio Gas Reg & Meter Equipment	5,836	3.24%	1,028	-	189	-	-	-	1,217	
45	478-30	Bio Gas Meters	295	5.19%	30	-	15	-	-	-	45	
46	474-10	Bio Gas Reg & Meter Installations	1,497	5.08%	209	-	76	-	-	-	285	
47	483-25	RNG Comp S/W	-	20.00%	-	-	-	-	-	-	-	
48	465-40	Bio Gas Transmission Pipe	-	1.53%	-	-	-	-	-	-	-	
49	466-40	Bio Gas Compressor Equipment	-	2.42%	-	-	-	-	-	-	-	
50			$ 33,641		$ 6,876	$ -	$ 1,113	$ -	$ -	$ -	$ 7,989	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Schedule 7.2

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2024	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2025	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	17,138	5.00%	$ 5,935	-	857	-	-	-	$ 6,792	
3	476-20	NG Transportation LNG Dispensing Equipment	13,208	5.00%	6,071	-	660	-	-	-	6,731	
4	476-30	NG Transportation CNG Foundations	3,163	5.00%	1,170	-	158	-	-	-	1,328	
5	476-40	NG Transportation LNG Foundations	1,049	5.00%	550	-	52	-	-	-	602	
6	476-50	NG Transportation LNG Pumps (Pumps only apply to LNG)	77	10.00%	75	-	1	-	-	-	76	
7	476-60	NG Transportation CNG Dehydrator	805	5.00%	266	-	40	-	-	-	306	
8			$ 35,440		$ 14,067	$ -	$ 1,768	$ -	$ -	$ -	$ 15,835	
9												
10		**GENERAL PLANT & EQUIPMENT**										
11	480-00	Land in Fee Simple	$ 31,944	0.00%	$ 17	$ -	$ -	$ -	$ -	$ -	$ 17	
12	482-10	Frame Buildings	28,430	2.75%	15,722	-	782	-	-	-	16,504	
13	482-20	Masonry Buildings	147,688	1.36%	40,808	-	2,009	(96)	-	-	42,721	
14	482-30	Leasehold Improvement	5,509	9.49%	946	-	198	(867)	-	-	277	
15	483-30	GP Office Equipment	2,399	6.67%	1,329	-	160	(110)	-	-	1,379	
16	483-40	GP Furniture	21,175	5.00%	7,188	-	1,058	(166)	-	-	8,080	
17	483-10	GP Computer Hardware	38,897	25.00%	13,837	-	9,724	(9,356)	-	-	14,205	
18	483-20	GP Computer Software	10,294	12.50%	3,875	-	1,183	(1,038)	-	-	4,020	
19	484-00	Vehicles	67,318	7.15%	34,168	-	4,813	-	-	-	38,981	
20	484-10	Vehicles - Leased	5,781	9.44%	5,781	-	-	(2,844)	-	-	2,937	
21	485-10	Heavy Work Equipment	735	4.04%	507	-	30	-	-	-	537	
22	485-20	Heavy Mobile Equipment	15,124	8.51%	6,106	-	1,287	-	-	-	7,393	
23	486-00	Small Tools & Equipment	60,797	5.00%	26,194	-	3,040	(2,573)	-	-	26,661	
24	487-20	Equipment on Customer's Premises	-	6.67%	-	-	-	-	-	-	-	
25	488-10	Telephone	317	6.67%	294	-	9	(173)	-	-	130	
26	488-20	Radio	17,569	6.67%	8,262	-	1,172	(226)	-	-	9,208	
27			$ 453,977		$ 165,034	$ -	$ 25,465	$ (17,449)	$ -	$ -	$ 173,050	
28												
29		**UNCLASSIFIED PLANT**										
30	499-00	Plant Suspense	-	0.00%	-	-	-	-	-	-	-	
31			$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	
32												
33		**Total**	$ 9,348,657		$ 2,890,246	$ -	$ 228,836	$ (120,738)	$ -	$ -	$ 2,998,344	
34		Less: Depreciation & Amortization Transferred to RNG Account					(1,113)					
35		Less: Vehicle Depreciation Allocated To Capital Projects					(1,781)					
36		**Net Depreciation Expense**					$ 225,942					
37												
38		Cross Reference	Schedule 6.2, Line 33, Columns 3+4+5									

NON-REG PLANT CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Line No.	Particulars			12/31/2024	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2025	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, 2025**									
11	**($000s)**									
12										
13										
14		Gross Plant for	Depreciation		Opening Bal	Depreciation	Depreciation	Cost of		
15	Particulars	Depreciation	Rate	12/31/2024	Adjustment	Expense	Retirements	Removal	12/31/2025	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%	151,129	-	4,238	-	-	155,367	
21									-	
22	**Total**	$ 177,648		$ 151,129	$ -	$ 4,238	$ -	$ -	$ 155,367	

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Line No.	Particulars	12/31/2024	CPCN / Open Bal Adjt	Adjustment	Additions	Retirements	12/31/2025	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CIAC**							
2	Distribution Contributions	$ 315,782	$ -	$ -	$ 3,514	$ -	$ 319,296	
3	Transmission Contributions	152,997	-	-	4,436	-	157,433	
4	Others	3,521	-	-	-	-	3,521	
5	RNG	566	-	-	-	-	566	
6	**Total**	$ 472,866	$ -	$ -	$ 7,950	$ -	$ 480,816	
7								
8	**Amortization**							
9	Distribution Contributions	$ (142,573)	$ -	$ -	$ (5,431)	$ -	$ (148,004)	
10	Transmission Contributions	(65,384)	-	-	(2,264)	-	(67,648)	
11	Others	(1,265)	-	-	(176)	-	(1,441)	
12	RNG	(358)	-	-	(28)	-	(386)	
13	**Total**	$ (209,580)	$ -	$ -	$ (7,899)	$ -	$ (217,479)	
14								
15	**Net CIAC**	$ 263,286	$ -	$ -	$ 51	$ -	$ 263,337	
16								
17								
18	Total CIAC Amortization Expense per Line 13, Column 5				$ (7,899)			
19	Less: CIAC Amortization Transferred to RNG Account				28			
20	**Net CIAC Amortization Expense**				$ (7,871)			

NET SALVAGE CONTINUITY SCHEDULE Schedule 10
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2024	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2025	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**INTANGIBLE PLANT**							
2	461-01	Transmission Land Rights	$ 54,379	0.00%	$ 146	$ -	$ -	$ 146	
3	471-01	Distribution Land Rights	7,180	0.00%	5	-	-	5	
4			$ 61,559		$ 151	$ -	$ -	$ 151	
5									
6		**MANUFACTURED GAS / LOCAL STORAGE**							
7	437-00	Manufact'd Gas - Measuring & Regulating Equipment	$ 2,518	0.00%	$ (22)	$ -	$ -	$ (22)	
8	442-00	Structures & Improvements (Tilbury)	101,354	0.30%	4,232	304	-	4,536	
9	443-00	Gas Holders - Storage (Tilbury)	184,971	0.30%	11,654	555	-	12,209	
10	448-11	Piping (Tilbury)	53,015	0.24%	978	127	-	1,105	
11	448-21	Pre-treatment (Tilbury)	34,307	0.34%	1,083	117	-	1,200	
12	448-31	Liquefaction Equipment (Tilbury)	90,421	0.46%	3,497	416	-	3,913	
13	449-00	Local Storage Equipment (Tilbury)	23,905	-0.17%	2,035	(41)	-	1,994	
14	442-01	Structures & Improvements (Mount Hayes)	19,355	0.40%	700	77	-	777	
15	443-05	Gas Holders - Storage (Mount Hayes)	61,907	0.36%	1,742	223	-	1,965	
16	448-41	Send out Equipment(Tilbury)	10,919	0.25%	129	27	-	156	
17	448-51	Sub-station and Electric (Tilbury)	38,505	0.48%	1,229	185	-	1,414	
18	448-10	Piping (Mount Hayes)	12,714	0.28%	268	36	-	304	
19	448-20	Pre-treatment (Mount Hayes)	29,462	0.48%	1,127	140	-	1,267	
20	448-30	Liquefaction Equipment (Mount Hayes)	28,940	0.57%	1,288	165	-	1,453	
21	448-40	Send out Equipment (Mount Hayes)	23,743	0.28%	516	66	-	582	
22	448-50	Sub-station and Electric (Mount Hayes)	21,788	0.57%	961	124	-	1,085	
23	449-01	Local Storage Equipment (Mount Hayes)	6,133	0.14%	145	9	-	154	
24			$ 743,957		$ 31,562	$ 2,530	$ -	$ 34,092	

NET SALVAGE CONTINUITY SCHEDULE Schedule 10.1
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2024	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2025	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**TRANSMISSION PLANT**							
2	462-00	Compressor Structures	$ 49,585	0.12%	$ 650	$ 60	$ -	$ 710	
3	463-00	Measuring Structures	29,234	0.46%	1,008	134	-	1,142	
4	464-00	Other Structures & Improvements	13,299	0.25%	228	33	-	261	
5	465-00	Mains	1,876,858	0.47%	52,334	8,821	-	61,155	
6	465-11	IP Transmission Pipeline - Whistler	60,674	0.33%	1,429	199	-	1,628	
7	465-30	Mt Hayes - Mains	6,307	0.31%	155	20	-	175	
8	466-00	Compressor Equipment	209,089	0.10%	2,863	209	-	3,072	
9	467-00	Mt. Hayes - Measuring and Regulating Equipment	5,925	0.13%	110	8	-	118	
10	467-10	Measuring & Regulating Equipment	173,254	0.14%	1,522	243	-	1,765	
11	467-20	Telemetering	35,000	0.02%	(28)	7	-	(21)	
12	467-31	IP Intermediate Pressure Whistler	313	0.19%	9	1	-	10	
13	468-00	Communication Structures & Equipment	3,358	0.00%	401	-	-	401	
14			$ 2,462,896		$ 60,681	$ 9,735	$ -	$ 70,416	
15									
16		**DISTRIBUTION PLANT**							
17	470-00	Land in Fee Simple	$ 6,349	0.00%	$ (2,099)	$ -	$ -	$ (2,099)	
18	472-00	Structures & Improvements	67,975	0.53%	1,498	360	-	1,858	
19	473-00	Services	1,698,782	2.47%	123,292	41,949	(21,565)	143,676	
20	474-00	House Regulators & Meter Installations	156,284	0.87%	4,945	1,360	-	6,305	
21	474-02	Meters/Regulators Installations	279,615	0.00%	749	-	-	749	
22	475-00	Mains	2,468,090	0.56%	75,935	13,821	-	89,756	
23	476-00	Compressor Equipment	614	0.00%	706	-	-	706	
24	477-10	Measuring & Regulating Equipment	256,903	0.40%	6,788	1,028	-	7,816	
25	477-20	Telemetering	36,180	0.31%	542	112	-	654	
26	478-10	Meters	338,715	-0.17%	2,671	(576)	-	2,095	
27			$ 5,309,507		$ 215,027	$ 58,054	$ (21,565)	$ 251,516	
28									
29		**BIO GAS**							
30	472-20	Bio Gas Struct. & Improvements	$ 2,017	0.28%	$ 19	$ 7	$ -	$ 26	
31	475-10	Bio Gas Mains – Municipal Land	10,974	0.38%	73	62	-	135	
32	475-20	Bio Gas Mains – Private Land	1,175	0.39%	7	5	-	12	
33	418-20	Bio Gas Purification Upgrader	11,827	0.25%	201	32	-	233	
34	477-40	Bio Gas Reg & Meter Equipment	5,836	0.01%	(6)	1	-	(5)	
35	474-10	Bio Gas Reg & Meter Installations	1,497	1.29%	50	23	-	73	
36			$ 33,326		$ 344	$ 130	$ -	$ 474	

NET SALVAGE CONTINUITY SCHEDULE Schedule 10.2
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2024	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2025	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Natural Gas for Transportation**							
2	476-10	NG Transportation CNG Dispensing Equipment	$ 17,138	0.00%	$ (1)	$ -	$ -	$ (1)	
3	476-20	NG Transportation LNG Dispensing Equipment	13,208	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			$ 31,472		$ 34	$ -	$ -	$ 34	
7									
8		**GENERAL PLANT & EQUIPMENT**							
9	482-10	Frame Buildings	$ 28,430	0.38%	$ 11	$ 108	$ -	$ 119	
10	482-20	Masonry Buildings	147,688	0.18%	783	265	-	1,048	
11	482-30	Leasehold Improvement	5,509	0.00%	(116)	-	-	(116)	
12	483-30	GP Office Equipment	2,399	0.00%	1	-	-	1	
13	483-40	GP Furniture	21,175	0.00%	(94)	-	-	(94)	
14	484-00	Vehicles	67,318	-1.55%	(5,574)	(1,044)	-	(6,618)	
15	485-10	Heavy Work Equipment	735	-0.18%	(36)	(1)	-	(37)	
16	485-20	Heavy Mobile Equipment	15,124	1.72%	(1,336)	260	-	(1,076)	
17	486-00	Small Tools & Equipment	60,797	0.00%	70	-	-	70	
18	487-20	Equipment on Customer's Premises	-	0.00%	(2)	-	-	(2)	
19	488-20	Radio	17,569	0.00%	(7)	-	-	(7)	
20			$ 366,744		$ (6,300)	$ (412)	$ -	$ (6,712)	
21									
22		**Total**	$ 9,009,461		$ 301,499	$ 70,037	$ (21,565)	$ 349,971	
23		Less: Depreciation & Amortization Transferred to RNG Account				(130)			
24		**Net Salvage Depreciation Expense**				$ 69,907			
25		Cross Reference	Schedule 6.2, Columns 3+4+5				Schedule 11.1, Line 4, Column 4		

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE Schedule 11
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Line No.	Particulars	12/31/2024	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2025	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)	$ (19,378)	$ -	$ 6,712	$ (1,812)	$ -	$ 25,119	$ (6,782)	$ 3,859	$ (7,760)	
3	Commodity Cost Reconciliation Account (CCRA)	(18,739)	-	(19,877)	5,367	-	-	-	(33,249)	(25,994)	
4	Revenue Stabilization Adjustment Mechanism (RSAM)	65,716	-	(9,604)	2,593	-	(21,189)	5,721	43,237	54,477	
5	Interest on CCRA / MCRA / RSAM / Gas Storage	(1,624)	-	2,262	(611)	181	2,052	(554)	1,706	41	
6	SCP Mitigation Revenues Variance Account	-	-	-	-	-	-	-	-	-	
7	Pension & OPEB Variance	(596)	-	(1,938)	-	(991)	-	-	(3,525)	(2,061)	
8	BCUC Levies Variance	(360)	-	-	-	360	-	-	-	(180)	
9		$ 25,019	$ -	$ (22,445)	$ 5,537	$ (450)	$ 5,982	$ (1,615)	$ 12,028	$ 18,524	
10											
11	**2. Rate Smoothing Accounts**										
12											
13	**3. Benefits Matching Accounts**										
14	Demand-Side Management (DSM)	$ 342,779	$ 72,839	$ 60,000	$ (16,200)	$ (62,031)	$ -	$ -	$ 397,387	$ 406,503	
15	NGV Conversion Grants	6	-	-	-	(3)	-	-	3	5	
16	Emissions Regulations	(333)	-	93	(25)	333	-	-	68	(133)	
17	Greenhouse Gas Reduction Regulation Incentives	39,304	-	151	(41)	(6,432)	-	-	32,982	36,143	
18	CNG and LNG Recoveries	(204)	-	(1,120)	302	371	-	-	(651)	(428)	
19	2025-2027 RSF Application	575	-	163	(43)	(192)	-	-	503	539	
20	BCUC Initiated Inquiry Costs	142	-	200	(54)	(142)	-	-	146	144	
21	PGR Application and Preliminary Stage Development Costs	(41)	-	-	-	41	-	-	-	(21)	
22	2021 Generic Cost of Capital Proceeding	874	-	5	(1)	(175)	-	-	703	789	
23	2023 DSM Expenditures Schedule Application	(10)	-	-	-	10	-	-	-	(5)	
24	City of Coquitlam Application Proceeding	(2)	-	-	-	2	-	-	-	(1)	
25	2024-2027 DSM Expenditures Schedule Application	124	-	-	-	(41)	-	-	83	104	
26	2023 Cost of Service Allocation Study	117	-	51	(14)	(117)	-	-	37	77	
27	AMI Application and Feasibility Costs	6,155	-	-	-	(3,078)	-	-	3,077	4,616	
28	OCMP Application and Preliminary Stage Development Costs	452	22,892	122	(33)	(5,932)	-	-	17,501	20,423	
29		$ 389,938	$ 95,731	$ 59,665	$ (16,109)	$ (77,386)	$ -	$ -	$ 451,839	$ 468,754	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE Schedule 11.1
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Line No.	Particulars	12/31/2024	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2025	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	$ 3,500	$ -	$ -	$ -	$ (737)	$ -	$ -	$ 2,763	$ 3,132	
3	Gas Asset Records Project	161	-	-	-	(161)	-	-	-	81	
4	Net Salvage Provision/Cost	(301,495)	-	21,565	-	(70,037)	-	-	(349,967)	(325,731)	
5	PCEC Start Up Costs	480	-	-	-	(44)	-	-	436	458	
6	2022 Long Term Gas Resource Plan Application	1,707	-	-	-	(569)	-	-	1,138	1,423	
7	2021 Renewable Gas Program Comprehensive Review	1,972	-	-	-	(657)	-	-	1,315	1,644	
8	GCU Preliminary Stage Development Costs	258	-	-	-	(258)	-	-	-	129	
9	Transmission Integrity Management Capabilities	6,501	-	-	-	(2,255)	-	-	4,246	5,374	
10	Annual Review Proceeding Costs	46	-	150	(40)	(46)	-	-	110	78	
11	Prince George Customer Service Centre Disposition	17	-	1,341	(12)	-	-	-	1,346	682	
12		$ (286,853)	$ -	$ 23,056	$ (52)	$ (74,764)	$ -	$ -	$ (338,613)	$ (312,733)	
13											
14	**4. Retroactive Expense Accounts**										
15											
16	**5. Other Accounts**										
17	Pension & OPEB Funding	$ (97,157)	$ -	$ 8,843	$ -	$ -	$ -	$ -	$ (88,314)	$ (92,736)	
18	US GAAP Pension & OPEB Funded Status	(12,023)	-	-	-	-	-	-	(12,023)	(12,023)	
19	COVID-19 Customer Recovery Fund	287	-	-	-	(287)	-	-	-	144	
20	Existing Meter Cost Recovery	-	-	23,095	-	-	-	-	23,095	11,548	
21	Previously Retired Meter Cost Recovery	-	-	14,281	-	-	-	-	14,281	7,141	
22	PST Rebate on Select Machinery and Equipment	(202)	-	-	-	202	-	-	-	(101)	
23	Residual Delivery Rate Riders	(5,224)	-	-	-	5,224	-	-	-	(2,612)	
24		$ (114,319)	$ -	$ 46,219	$ -	$ 5,139	$ -	$ -	$ (62,961)	$ (88,640)	
25											
26	**Total**	$ 13,785	$ 95,731	$ 106,495	$ (10,624)	$ (147,461)	$ 5,982	$ (1,615)	$ 62,293	$ 85,905	
27	Less: Net Salvage Amortization Transferred to RNG Account					130					
28	**Net Rate Base Deferred Amortization Expense**					$ (147,331)					

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE Schedule 12
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Line No.	Particulars	12/31/2024	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2025	Mid-Year Average	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**1. Forecasting Variance Accounts**										
2	RNG Account	$ 58,407	$ (40,696)	$ 84,353	$ (21,090)	$ -	$ (82,992)	$ 22,408	$ 20,390	$ 19,051	
3	Flowthrough	370	-	11	-	(381)	-	-	-	185	
4	RNG Mitigation Revenue	(23,667)	40,696	(23,031)	6,002	-	-	-	-	8,515	
5	Marketer Cost Variance	13	-	1	-	-	-	-	14	14	
6		$ 35,123	$ -	$ 61,334	$ (15,088)	$ (381)	$ (82,992)	$ 22,408	$ 20,404	$ 27,764	
7	**2. Rate Smoothing Accounts**										
8	City of Vancouver Biomethane Purchase Agreement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
9	Fort Nelson Residential Customer Common Rate Phase-in Rate Rider	129	-	7	-	(129)	133	(36)	104	117	
10	2023-2025 Revenue Deficiency	63,303	-	19,623	(4,145)	-	-	-	78,781	71,042	
11		$ 63,432	$ -	$ 19,630	$ (4,145)	$ (129)	$ 133	$ (36)	$ 78,885	$ 71,159	
12											
13	**3. Benefits Matching Accounts**										
14	Demand-Side Management (DSM) - Non Rate Base	$ 72,839	$ (72,839)	$ 127,828	$ (33,750)	$ -	$ -	$ -	$ 94,078	$ 47,039	
15	PEC Pipeline Development Costs and Commitment Fees	(2,398)	-	-	-	-	-	-	(2,398)	(2,398)	
16	Regional Gas Supply Diversity Project Development Costs	3,529	-	225	-	-	-	-	3,754	3,642	
17	Clean Growth Innovation Fund (2025-2027)	-	-	2,948	(810)	-	(5,295)	1,430	(1,727)	(864)	
18	OCMP Application and Preliminary Stage Development Costs	22,892	(22,892)	-	-	-	-	-	-	-	
19		$ 96,862	$ (95,731)	$ 131,001	$ (34,560)	$ -	$ (5,295)	$ 1,430	$ 93,707	$ 47,419	
20											
21	**4. Retroactive Expense Accounts**										
22											
23	**5. Other Accounts**										
24	Mark to Market - Hedging Transactions	$ 100,154	$ -	$ -	$ -	$ -	$ -	$ -	$ 100,154	$ 100,154	
25	Earnings Sharing Account	(8,830)	-	(265)	-	9,095	-	-	-	(4,415)	
26	US GAAP Uncertain Tax Positions	-	-	-	-	-	-	-	-	-	
27	FEFN - Right-Of-Way Agreement	185	-	11	-	-	-	-	196	191	
28	Flotation Costs	-	-	18,558	-	-	-	-	18,558	9,279	
29	AMI Foreign Exchange (FX) Mark to Market Valuation	-	-	-	-	-	-	-	-	-	
30		$ 91,509	$ -	$ 18,304	$ -	$ 9,095	$ -	$ -	$ 118,908	$ 105,209	
31											
32											
33	**Total Non Rate Base Deferral Accounts**	$ 286,926	$ (95,731)	$ 230,269	$ (53,793)	$ 8,585	$ (88,154)	$ 23,802	$ 311,904	$ 251,550	

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Line No.	Particulars	2024 Approved	2025 Projected	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 27,161	$ 15,944	$ (11,217)	Schedule 14, Line 30, Column 5
3					
4	Add/Less: Funds Unavailable/(Funds Available)				
5	Employee Loans	1,802	1,753	(49)	
6	Employee Withholdings	(7,688)	(7,755)	(67)	
7					
8	**Other Working Capital Items**				
9	Transmission Line Pack Gas	2,703	1,825	(878)	
10	Gas In Storage	49,854	38,852	(11,002)	
11	Inventories - Materials and Supplies	2,616	3,286	670	
12	Refundable Contributions	(282)	(36)	246	
13					
14	Total	$ 76,166	$ 53,869	$ (22,297)	

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Schedule 14

Line No.	Particulars	2025 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	$ 1,016,139	38.5	$ 39,121,352		
4	Commercial Tariff Revenue	555,124	37.6	20,872,662		
5	Industrial Tariff Revenue	203,367	45.3	9,212,526		
6	Bypass and Special Rates	39,677	40.0	1,587,080		
7						
8	**Other Revenue**					
9	Late Payment Charges	3,628	52.9	191,921		
10	Application Charges	1,569	38.1	59,779		
11	Other Utility Income	27,112	38.1	1,032,967		
12						
13	Total	$ 1,846,616		$ 72,078,287	39.0	
14						
15	**EXPENSES**					
16	Energy Purchases	$ 561,240	(40.1)	$ (22,505,724)		
17	Operating and Maintenance	335,394	(29.9)	(10,028,281)		
18	Property Taxes	86,927	(0.6)	(52,156)		
19	Operating Fees	12,151	(343.9)	(4,178,833)		
20	Carbon Tax	168,393	(28.9)	(4,866,558)		
21	GST	39,971	(33.3)	(1,331,047)		
22	PST	41,191	(40.9)	(1,684,717)		
23	Income Tax	77,321	(15.2)	(1,175,279)		
24						
25	Total	$ 1,322,589		$ (45,822,595)	(34.6)	
26						
27	Net Lag (Lead) Days				4.4	
28	Total Expenses				$ 1,322,589	
29						
30	Cash Working Capital				$ 15,944	

DEFERRED INCOME TAX LIABILITY / ASSET Schedule 15
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Line No.	Particulars	2024 Approved	2025 Projected	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Total DIT Liability- After Tax	$ (556,041)	$ (702,600)	$ (146,559)	
2	Tax Gross Up	(205,659)	(259,866)	(54,207)	
3	DIT Liability/Asset - End of Year	$ (761,700)	$ (962,466)	$ (200,766)	
4	DIT Liability/Asset - Opening Balance	(714,996)	(891,563)	(176,567)	
5					
6	DIT Liability/Asset - Mid Year	$ (738,348)	$ (927,015)	$ (188,667)	

UTILITY INCOME AND EARNED RETURN Schedule 16
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Line No.	Particulars	2024 Approved	2025 Projected at 2024 Approved Rates	2025 Projected Revised Revenue	2025 Projected at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (TJ)	161,958	168,989		168,989	7,031	
3	Transportation Volume (TJ)	58,206	51,052		51,052	(7,154)	
4		220,165	220,041	-	220,041	(123)	Schedule 17, Line 23, Column 3
5							
6	**REVENUE AT EXISTING RATES**						
7	Sales	$ 1,827,890	$ 1,657,074	$ -	$ 1,657,074	$ (170,816)	
8	Deficiency (Surplus)	-	-	84,650	84,650	84,650	
9	Transportation	86,545	69,185	-	69,185	(17,360)	
10	Deficiency (Surplus)	-		3,398	3,398	3,398	
11	Total	1,914,435	1,726,259	88,048	1,814,307	(100,128)	Schedule 19, Line 29, Column 8
12				-			
13	**COST OF ENERGY**	744,149	561,240	-	561,240	(182,909)	Schedule 18, Line 23, Column 3
14							
15	**MARGIN**	1,170,286	1,165,019	88,048	1,253,067	82,781	
16							
17	**EXPENSES**						
18	O&M Expense (net)	305,157	335,394	-	335,394	30,237	Schedule 20, Line 29, Column 4
19	Depreciation & Amortization	349,116	356,817	-	356,817	7,701	Schedule 21, Line 15, Column 3
20	Property Taxes	83,359	86,927	-	86,927	3,568	Schedule 22, Line 8, Column 3
21	Other Revenue	(42,479)	(32,309)	-	(32,309)	10,170	Schedule 23, Line 12, Column 3
22	Deferred Revenue Deficiency	(15,915)	(15,352)	-	(15,352)	563	Schedule 1, Line 33, Column 3
23	Utility Income Before Income Taxes	491,048	433,542	88,048	521,590	30,542	
24							
25	Income Taxes	87,400	53,551	23,770	77,321	(10,079)	Schedule 24, Line 13, Column 3
26							
27	**EARNED RETURN**	$ 403,648	$ 379,991	$ 64,278	$ 444,269	$ 40,621	Schedule 26, Line 5, Column 7
28							
29	**UTILITY RATE BASE**	$ 5,817,488	$ 6,451,465		$ 6,452,115	$ 634,627	Schedule 2, Line 30, Column 3
30	**RATE OF RETURN ON UTILITY RATE BASE**	6.94%	5.89%		6.89%	-0.05%	Schedule 26, Line 5, Column 6

VOLUME AND REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Schedule 17

Line No.	Particulars	2024 Approved	2025 Projected	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (TJ)**				
2	Residential				
3	Rate Schedule 1	83,378.5	80,535.0	(2,843.5)	
4	Commercial				
5	Rate Schedule 2	29,678.8	29,428.2	(250.6)	
6	Rate Schedule 3	27,002.0	29,619.0	2,617.0	
7	Rate Schedule 23	3,637.1	2,271.4	(1,365.7)	
8	Industrial				
9	Rate Schedule 4	177.7	175.1	(2.6)	
10	Rate Schedule 5	11,870.1	15,987.0	4,116.9	
11	Rate Schedule 6	18.1	20.4	2.3	
12	Rate Schedule 7	6,799.4	9,588.2	2,788.8	
13	Rate Schedule 22 - Firm Service	13,874.6	14,334.1	459.5	
14	Rate Schedule 22 - Interruptible Service	12,943.7	9,708.3	(3,235.4)	
15	Rate Schedule 25	7,777.0	6,193.1	(1,583.9)	
16	Rate Schedule 27	3,876.7	3,056.9	(819.8)	
17	Bypass and Special Rates				
18	Rate Schedule 22 - Firm Service	10,421.1	9,998.4	(422.7)	
19	Rate Schedule 25	905.5	735.8	(169.7)	
20	Rate Schedule 46	3,033.6	3,636.2	602.6	
21	Byron Creek	12.6	9.3	(3.3)	
22	VIGJV	4,758.0	4,745.0	(13.0)	
23	Total	220,164.5	220,041.4	(123.1)	
24					
25	**REVENUE AT EXISTING RATES**				
26	Residential				
27	Rate Schedule 1	$ 1,092,727	$ 959,845	$ (132,882)	
28	Commercial				
29	Rate Schedule 2	321,102	281,434	(39,668)	
30	Rate Schedule 3	248,578	236,696	(11,882)	
31	Rate Schedule 23	16,781	10,483	(6,298)	
32	Industrial				
33	Rate Schedule 4	1,198	1,025	(173)	
34	Rate Schedule 5	87,901	98,194	10,293	
35	Rate Schedule 6	138	125	(13)	
36	Rate Schedule 7	41,130	46,734	5,604	
37	Rate Schedule 22 - Firm Service	15,381	15,120	(261)	
38	Rate Schedule 22 - Interruptible Service	15,540	11,848	(3,692)	
39	Rate Schedule 25	24,291	18,764	(5,527)	
40	Rate Schedule 27	8,099	6,314	(1,785)	
41	Bypass and Special Rates				
42	Rate Schedule 22 - Firm Service	799	865	66	
43	Rate Schedule 25	421	424	3	
44	Rate Schedule 46	35,116	33,021	(2,095)	
45	Byron Creek	134	136	2	
46	VIGJV	5,099	5,231	132	
47	Total	$ 1,914,435	$ 1,726,259	$ (188,176)	

COST OF ENERGY Schedule 18
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Line No.	Particulars	2024 Approved	2025 Projected	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**COST OF GAS**				
2	Residential				
3	Rate Schedule 1	$ 391,703	$ 276,423	$ (115,280)	
4	Commercial				
5	Rate Schedule 2	140,732	101,773	(38,959)	
6	Rate Schedule 3	121,353	96,919	(24,434)	
7	Rate Schedule 23	72	37	(35)	
8	Industrial				
9	Rate Schedule 4	725	509	(216)	
10	Rate Schedule 5	48,358	46,355	(2,003)	
11	Rate Schedule 6	60	43	(17)	
12	Rate Schedule 7	27,769	27,881	112	
13	Rate Schedule 22 - Firm Service	276	231	(45)	
14	Rate Schedule 22 - Interruptible Service	257	156	(101)	
15	Rate Schedule 25	155	100	(55)	
16	Rate Schedule 27	77	49	(28)	
17	Bypass and Special Rates				
18	Rate Schedule 22 - Firm Service	207	161	(46)	
19	Rate Schedule 25	18	12	(6)	
20	Rate Schedule 46	12,387	10,591	(1,796)	
21	Byron Creek	-	-	-	
22	VIGJV	-	-	-	
23	Total	$ 744,149	$ 561,240	$ (182,909)	

MARGIN AND REVENUE AT EXISTING AND REVISED RATES Schedule 19

FOR THE YEAR ENDING DECEMBER 31, 2025

($000s)

Line No.	Particulars	2024 Approved Margin	2025 Projected Margin at 2024 Approved Rates	2025 Projected Effective Increase	2025 Projected Margin at Revised Rates	2025 Projected Revenue at 2024 Approved Rates	2025 Projected Effective Increase	2025 Projected 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	$ 701,024	$ 683,422	$ 56,294	$ 739,716	$ 959,845	$ 56,294	$ 1,016,139	1,000,880	80,535.0	
4	Commercial										
5	Rate Schedule 2	180,370	179,661	14,868	194,529	281,434	14,868	296,302	92,411	29,428.2	
6	Rate Schedule 3	127,225	139,777	10,833	150,610	236,696	10,833	247,529	8,102	29,619.0	
7	Rate Schedule 23	16,709	10,446	810	11,256	10,483	810	11,293	383	2,271.4	
8	Industrial										
9	Rate Schedule 4	473	516	(21)	495	1,025	(21)	1,004	26	175.1	
10	Rate Schedule 5	39,543	51,839	1,702	53,541	98,194	1,702	99,896	792	15,987.0	
11	Rate Schedule 6	78	82	6	88	125	6	131	19	20.4	
12	Rate Schedule 7	13,361	18,853	968	19,821	46,734	968	47,702	64	9,588.2	
13	Rate Schedule 22 - Firm Service	15,105	14,889	1,003	15,892	15,120	1,003	16,123	23	14,334.1	
14	Rate Schedule 22 - Interruptible Service	15,283	11,692	906	12,598	11,848	906	12,754	6	9,708.3	
15	Rate Schedule 25	24,136	18,664	418	19,082	18,764	418	19,182	179	6,193.1	
16	Rate Schedule 27	8,022	6,265	261	6,526	6,314	261	6,575	47	3,056.9	
17	Total Non-Bypass	$ 1,141,329	$ 1,136,106	$ 88,048	$ 1,224,154	$ 1,686,582	$ 88,048	$ 1,774,630	1,102,932	200,916.7	
18											
19											
20	**Bypass and Special Rates**										
21	Rate Schedule 22 - Firm Service	$ 592	$ 704		$ 704	$ 865		$ 865	6	9,998.4	
22	Rate Schedule 25	403	412		412	424		424	3	735.8	
23	Rate Schedule 46	22,729	22,430		22,430	33,021		33,021	15	3,636.2	
24	Byron Creek	134	136		136	136		136	1	9.3	
25	VIGJV	5,099	5,231		5,231	5,231		5,231	1	4,745.0	
26	Total Bypass & Special	$ 28,957	$ 28,913	$ -	$ 28,913	$ 39,677	$ -	$ 39,677	26	19,124.7	
27											
28											
29	Total	$ 1,170,286	$ 1,165,019	$ 88,048	$ 1,253,067	$ 1,726,259	$ 88,048	$ 1,814,307	1,102,958	220,041.4	
30											
31	**Effective Increase**			7.75%			5.22%				

OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Schedule 20

Line No.	Particulars	Inflation Indexed O&M	Projected O&M	Total O&M	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Inflation Indexed O&M**				
2	2024 Base Unit Cost O&M	$ 274			G-69-25
3	2025 Net Inflation Factor	3.648%			Schedule 3, Line 9, Column 3
4	2025 Base Unit Cost O&M	$ 283			Line 2 x (1 + Line 3)
5					
6	2025 Average Customer Projected - Rate Setting Purpose	1,102,958			Schedule 3, Line 15, Column 4
7					
8	2025 Inflation Indexed O&M before prior year True-up	$ 312,137			Line 4 x Line 6 / 1000
9					
10	2023 Average Customer True-up	709			
11					
12	2025 Inflation Indexed O&M	$ 312,846		$ 312,846	Sum of Lines 8 and 10
13					
14	**O&M Tracked Outside of Formula**				
15	Pension & OPEB (O&M Portion)		$ 6,790		
16	Insurance		12,623		
17	Integrity O&M		9,700		
18	AMI Flowthrough O&M		24,721		
19	BCUC fees		8,481		
20	RNG O&M		7,278		
21	Renewable Gas Development		4,584		
22	NGT O&M		3,075		
23	Variable LNG Production		10,688		
24	Sub-total		$ 87,940	87,940	Sum of Lines 15 through 23
25					
26	**Total Gross O&M**			$ 400,786	Line 12 + Line 24
27	O&M Transferred to RNG Account			(7,278)	
28	Capitalized Overhead			(58,114)	-14.5 % x Line 26
29	**Net O&M Expense**			$ 335,394	Sum of Lines 26 through 28

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Schedule 21

Line No.	Particulars	2024 Approved	2025 Projected	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 232,095	$ 228,836	$ (3,259)	Schedule 7.2, Line 33, Column 7
3	Depreciation & Amortization Transferred to RNG Account	(793)	(1,113)	(320)	Schedule 7.2, Line 34, Column 7
4	Vehicle Depreciation Allocated To Capital Projects	(2,886)	(1,781)	1,105	Schedule 7.2, Line 35, Column 7
5		228,416	225,942	(2,474)	
6					
7	**Amortization**				
8	Rate Base Deferrals	$ 125,309	$ 147,461	$ 22,152	Schedule 11.1, Line 26, Column 6
9	Rate Base Deferrals - Net Salvage Amortization Transferred to RNG Account	(54)	(130)	(76)	Schedule 11.1, Line 27, Column 6
10	Non-Rate Base Deferrals	4,268	(8,585)	(12,853)	Schedule 12, Line 33, Column 6
11	CIAC	(8,851)	(7,899)	952	Schedule 9, Line 13, Column 5
12	CIAC Amortization Transferred to RNG Account	28	28	-	Schedule 9, Line 19, Column 5
13		120,700	130,875	10,175	
14					
15	Total	$ 349,116	$ 356,817	$ 7,701	

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Schedule 22

Line No.	Particulars	2024 Approved	2025 Projected	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	General School and Other	$ 66,926	$ 69,054	$ 2,128	
2	1% In-Lieu of Municipal Taxes	16,510	17,999	1,489	
3					
4	Total	$ 83,436	$ 87,053	$ 3,617	
5					
6	Total Property Tax Expense per Line 4	$ 83,436	$ 87,053	$ 3,617	
7	Less: Property Tax Transferred to RNG Account	(77)	(126)	(49)	
8	**Net Property Tax Expense**	$ 83,359	$ 86,927	$ 3,568	

OTHER REVENUE
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Schedule 23

Line No.	Particulars	2024 Approved	2025 Projected	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Late Payment Charge	$ 3,607	$ 3,628	$ 21	
2	Application Charge	1,797	1,569	(228)	
3	NSF Returned Cheque Charges	28	28	-	
4	Other Recoveries	288	288	-	
5	SCP Third Party Revenue	13,320	13,284	(36)	
6	NGT Tanker Rental Revenue	1,021	971	(50)	
7	NGT Overhead and Marketing Recovery	341	227	(114)	
8	RNG Other Revenue	762	(8,122)	(8,884)	
9	LNG Capacity Assignment	18,039	18,039	-	
10	CNG & LNG Service Revenues	3,276	2,397	(879)	
11					
12	Total	$ 42,479	$ 32,309	$ (10,170)	

Schedule 24

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Line No.	Particulars		2024 Approved		2025 Projected		Change	Cross Reference
	(1)		(2)		(3)		(4)	(5)
1	**EARNED RETURN**	$	403,648	$	444,269	$	40,621	Schedule 16, Line 27, Column 5
2	Deduct: Interest on Debt		(151,024)		(164,086)		(13,062)	Schedule 26, Lines 1+2, Column 7
3	Adjustments to Taxable Income		(16,320)		(71,131)		(54,811)	Line 36
4	Accounting Income After Tax	$	236,304	$	209,052	$	(27,252)	
5								
6	1 - Current Income Tax Rate		73.00%		73.00%		0.00%	
7	Taxable Income	$	323,704	$	286,373	$	(37,331)	
8								
9	Current Income Tax Rate		27.00%		27.00%		0.00%	
10	Income Tax - Current	$	87,400	$	77,321	$	(10,079)	
11								
12	Previous Year Adjustment		-		-		-	
13	**Total Income Tax**	$	87,400	$	77,321	$	(10,079)	
14								
15								
16	**ADJUSTMENTS TO TAXABLE INCOME**							
17	Addbacks:							
18	Non-tax Deductible Expenses	$	1,200	$	1,200	$	-	
19	Depreciation		228,416		225,942		(2,474)	Schedule 21, Line 5, Column 3
20	Amortization of Deferred Charges		129,523		138,746		9,223	Schedule 21, Lines 8+9+10, Column 3
21	Amortization of Debt Issue Expenses		1,076		1,491		415	
22	Vehicles: Interest & Capitalized Depreciation		2,886		1,781		(1,105)	
23	Pension Expense		3,088		6,962		3,874	
24	OPEB Expense		4,222		6,248		2,026	
25								
26	Deductions:							
27	Capital Cost Allowance		(297,127)		(348,689)		(51,562)	Schedule 25, Line 24, Column 6
28	CIAC Amortization		(8,823)		(7,871)		952	Schedule 21, Lines 11+12, Column 3
29	Debt Issue Costs		(2,087)		(1,086)		1,001	
30	Vehicle Lease Payment		-		-		-	
31	Pension Contributions		(15,233)		(16,413)		(1,180)	
32	OPEB Contributions		(3,433)		(3,702)		(269)	
33	Overheads Capitalized Expensed for Tax Purposes		(29,617)		(38,075)		(8,458)	
34	Removal Costs		(22,644)		(21,565)		1,079	Schedule 11.1, Line 4, Column 4
35	Major Inspection Costs		(7,767)		(16,100)		(8,333)	
36	Total	$	(16,320)	$	(71,131)	$	(54,811)	

CAPITAL COST ALLOWANCE Schedule 25
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Line No.	Class	CCA Rate	12/31/2024 UCC Balance	2025 Additions	Adjustments	2025 CCA	Projected 12/31/2025 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 845,240	$ -	$ -	$ (33,810)	$ 811,430
2	1(b)	6%	143,561	16,806	-	(9,622)	150,745
3	2	6%	67,955	-	-	(4,077)	63,878
4	3	5%	1,383	-	-	(69)	1,314
5	6	10%	175	-	-	(17)	158
6	7	15%	19,594	3,386	-	(3,447)	19,533
7	8	20%	24,159	11,921	-	(7,216)	28,864
8	10	30%	13,906	9,609	-	(7,055)	16,460
9	10.1	30%	203	-	-	(61)	142
10	12	100%	-	22,222	-	(22,222)	-
11	13	manual	4,186	-	-	(1,358)	2,828
12	14.1 (pre 2017)	7%	12,283	-	-	(860)	11,423
13	14.1 (post 2016)	5%	14,997	-	-	(750)	14,247
14	17	8%	749	-	-	(60)	689
15	38	30%	3,054	-	-	(916)	2,138
16	43.1 (post 2024)	30%	-	46,785	-	(35,088)	11,697
17	43.2	50%	107	-	-	(54)	53
18	47	8%	119,854	-	-	(9,588)	110,266
19	47 (LNG Plant - post Feb 2015)	8%	148,570	-	-	(11,885)	136,685
20	49	8%	629,924	113,305	-	(59,458)	683,771
21	50	55%	7,570	11,111	-	(10,275)	8,406
22	51	6%	1,896,538	283,477	-	(130,801)	2,049,214
23							
24	Total		$ 3,954,008	$ 518,622	$ -	$ (348,689)	$ 4,123,941

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2025
($000s)

Line No.	Particulars	2024 Approved Earned Return	Amount	Ratio	2025 Average Embedded Cost	Cost Component	Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 153,587	$ 3,366,381	52.17%	4.68%	2.44%	$ 157,560	$ 3,973	Schedule 27, Lines 24&26, Columns 5&6&7
2	Short Term Debt	(2,563)	182,282	2.83%	3.58%	0.10%	6,526	9,089	
3	Common Equity	252,624	2,903,452	45.00%	9.65%	4.34%	280,183	27,559	
4									
5	Total	$ 403,648	$ 6,452,115	100.00%		6.89%	$ 444,269	$ 40,621	
6									
7	Cross Reference		Schedule 2, Line 30, Column 3						

Schedule 27

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2025
($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	136,978	137,819	2.644%	3,644	
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	148,697	150,000	4.724%	7,086	
19	2025 Medium Term Debt Issue	September 1, 2025	September 1, 2055	247,500	83,562	4.662%	3,896	
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				$ 3,366,381		$ 157,560	
25								
26	Average Embedded Cost					4.68%		
27								
28	* Interest Rate is Effective Interest Rate as it includes amortization of debt issue costs							

11.2 *2026 FINANCIAL SCHEDULES*

Description	Schedule Reference
Summary Of Rate Change	1
Rate Base	
Utility Rate Base	2
Formula Inflation Factors	3
Capital Expenditures	4
Capital Expenditures To Plant Reconciliation	5
Plant In Service Continuity Schedule	6
Accumulated Depreciation Continuity Schedule	7
Non-Reg Plant Continuity Schedule	8
Contributions In Aid Of Construction Continuity Schedule	9
Net Salvage Continuity Schedule	10
Unamortized Deferred Charges And Amortization - Rate Base	11
Unamortized Deferred Charges And Amortization - Non-Rate Base	12
Working Capital Allowance	13
Cash Working Capital	14
Deferred Income Tax Liability / Asset	15
Revenue Requirement	
Utility Income And Earned Return	16
Volume And Revenue	17
Cost Of Energy	18
Margin And Revenue At Existing And Revised Rates	19
Operating And Maintenance Expense	20
Depreciation And Amortization Expense	21
Property And Sundry Taxes	22
Other Revenue	23
Income Taxes	24
Capital Cost Allowance	25
Return On Capital	26
Embedded Cost Of Long Term Debt	27

SUMMARY OF RATE CHANGE
FOR THE YEAR ENDING DECEMBER 31, 2026
($millions)

Schedule 1

Line No.	Particulars	2026 Forecast		Cross Reference
	(1)	(2)	(3)	(4)
1	**VOLUME/REVENUE RELATED**			
2	Customer Growth and Volume	$ (9.520)		
3	Change in Other Revenue	(15.704)	(25.224)	
4				
5	**O&M CHANGES**			
6	Gross O&M Change	15.087		
7	Capitalized Overhead Change	(2.284)	12.803	
8				
9	**DEPRECIATION EXPENSE**			
10	Depreciation from Net Additions	15.824	15.824	
11				
12	**AMORTIZATION EXPENSE**			
13	CIAC from Net Additions	(0.127)		
14	Deferrals	40.085	39.958	
15				
16	**FINANCING AND RETURN ON EQUITY**			
17	Financing Rate Changes	1.615		
18	Financing Ratio Changes	1.062		
19	Rate Base Growth	26.443	29.120	
20				
21	**TAX EXPENSE**			
22	Property and Other Taxes	1.649		
23	Other Income Taxes Changes	34.939	36.588	
24				
25	**2025 Revenue Deficiency**		15.352	
26				
27	**REVENUE DEFICIENCY (SURPLUS)**		**$ 124.421**	Schedule 16, Line 11, Column 4
28				
29	Non-Bypass Margin at 2025 Approved Interim Rates		1,235.266	Schedule 19, Line 17, Column 3
30	Rate Change		10.07%	

Schedule 2

UTILITY RATE BASE
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Line No.	Particulars	2025 Projected	2026 at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Plant in Service, Beginning	$ 9,197,357	$ 9,617,728	$ 420,371	Schedule 6.2, Line 34, Column 3
2	Opening Balance Adjustment	-	-	-	Schedule 6.2, Line 34, Column 4
3	Net Additions	420,371	294,865	(125,506)	Schedule 6.2, Line 34, Columns 5+6+7
4	Plant in Service, Ending	9,617,728	9,912,593	294,865	
5					
6	Accumulated Depreciation Beginning	$ (2,890,246)	$ (2,998,344)	$ (108,098)	Schedule 7.2, Line 34, Column 5
7	Opening Balance Adjustment	-	-	-	Schedule 7.2, Line 34, Column 6
8	Net Additions	(108,098)	(47,069)	61,029	Schedule 7.2, Line 34, Columns 7+8
9	Accumulated Depreciation Ending	(2,998,344)	(3,045,413)	(47,069)	
10					
11	CIAC, Beginning	$ (472,866)	$ (480,816)	$ (7,950)	Schedule 9, Line 6, Column 2
12	Opening Balance Adjustment	-	-	-	
13	Net Additions	(7,950)	(11,331)	(3,381)	Schedule 9, Line 6, Columns 5+6
14	CIAC, Ending	(480,816)	(492,147)	(11,331)	
15					
16	Accumulated Amortization Beginning - CIAC	$ 209,580	$ 217,479	$ 7,899	Schedule 9, Line 13, Column 2
17	Opening Balance Adjustment	-	-	-	
18	Net Additions	7,899	8,026	127	Schedule 9, Line 13, Columns 5+6
19	Accumulated Amortization Ending - CIAC	217,479	225,505	8,026	
20					
21	Net Plant in Service, Mid-Year	$ 6,199,936	$ 6,478,293	$ 278,357	
22					
23	Adjustment for timing of Capital additions	$ 75,650	$ 108,607	$ 32,957	
24	Capital Work in Progress, No AFUDC	36,755	42,350	5,595	
25	Unamortized Deferred Charges	85,905	143,152	57,247	Schedule 11.1, Line 23, Column 10
26	Working Capital	53,869	62,977	9,108	Schedule 13, Line 14, Column 3
27	Deferred Income Taxes Regulatory Asset	927,015	990,694	63,679	Schedule 15, Line 6, Column 3
28	Deferred Income Taxes Regulatory Liability	(927,015)	(990,694)	(63,679)	Schedule 15, Line 6, Column 3
29					
30	Mid-Year Utility Rate Base	$ 6,452,115	$ 6,835,379	$ 383,264	

FORMULA INFLATION FACTORS
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Line No.	Particulars	Reference	2025	2026	Total for 2026 Rate Setting	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Formula Cost Drivers**					
2	CPI		3.012%	2.397%		
3	AWE		5.384%	4.154%		
4	Labour Split					
5	Non Labour		50.000%	50.000%		
6	Labour		50.000%	50.000%		
7	CPI/AWE	(Line 2 x Line 5) + (Line 3 x Line 6)	4.198%	3.276%		
8	Productivity Factor		-0.550%	-0.550%		
9	Net Inflation Factor	Line 7 + Line 8	3.648%	2.726%		
10						
11						
12	**Growth in Average Customer Calculation**					
13	Actual/Projected Prior Year Average Customers		1,093,663	1,102,958		
14	Average Customers for the Year	Schedule 19, Line 29, Column 9	1,102,958	1,114,373		
15	Change in Average Customers	Line 14 - Line 13	9,295	11,415	20,710	
16	Customer Growth Factor Multiplier				100%	
17	Change in Customers - Rate Setting Purposes	Line 15 x Line 16			20,710	
18						
19						
20	**Average Customer Forecast - Rate Setting Purposes**	Line 14			1,114,373	

CAPITAL EXPENDITURES Schedule 4
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Line No.	Particulars	Growth CapEx	Other CapEx	Forecast CapEx	Total CapEx	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)
1	**Inflation Indexed Capital Growth**					
2	2025 Unit Cost Growth Capital	$ 9,639				
3	2026 Net Inflation Factor	2.726%				Schedule 3, Line 9, Column 4
4	2026 Unit Cost Growth Capital	$ 9,902				
5	2026 Gross Customer Additions	8,000				
6	2026 Inflation Indexed Growth Capital	$ 79,216			$ 79,216	
7	2024 Growth Capital Customer True-Up				(11,524)	
8	2026 System Extension Fund				1,000	
9	2026 Growth CIAC				2,888	
10	2026 Inflation Indexed Gross Growth Capital				$ 71,580	
11						
12	**Capital Tracked Outside of Formula**					
13	Pension & OPEB (Growth Capital Portion)			$ 1,095		
14	RNG Assets			4,800		
15	NGT Assets			-		
16	Sustainment Capital			131,733		
17	Other Capital			62,696		
18	Sub-total			$ 200,324	200,324	
19						
20	**Total Capital Expenditures Before CIAC**				$ 271,904	

CAPITAL EXPENDITURES TO PLANT RECONCILIATION
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Schedule 5

Line No.	Particulars	2025 Projected	2026 Forecast	Cross Reference
	(1)	(2)	(3)	(4)
1	**CAPEX**			
2	Growth Capital Expenditures	$ 99,264	$ 71,580	Schedule 4, Line 10, Column 5
3	Forecast Capital Expenditures	220,183	200,324	Schedule 4, Line 18, Column 5
4	Total Capital Expenditures	$ 319,447	$ 271,904	
5				
6	**Special Projects and CPCN's**			
7	Inland Gas Upgrade	$ 7,194	$ -	
8	Pattullo Gasline Replacement	33	-	
9	Transmission Integrity Program - CTS	25,598	1,023	
10	Gibsons Capacity Upgrade	581	-	
11	Transmission Integrity Program - ITS	41,992	29,164	
12	FEI Advance Metering Infrastructure (AMI) CPCN	194,157	306,634	
13	Okanagan Capacity Mitigation Plan (OCMP)	11,160	19,800	
14	Tilbury Expansion Project	23,108	22,700	
15	CTS Expansion Project	6,000	12,000	
16	Total Capital Expenditures	$ 309,823	$ 391,321	
17				
18	**Total Capital Expenditures**	$ 629,270	$ 663,225	
19				
20				
21	**RECONCILIATION OF CAPITAL EXPENDITURES TO PLANT**			
22				
23	Regular Capital Expenditures	$ 319,447	$ 271,904	Line 4
24	Add - Capitalized Overheads	58,114	60,398	Schedule 20, Line 28, Column 4
25	Add - AFUDC	9,005	7,645	
26	Gross Capital Expenditures	386,566	339,947	
27	Change in Work in Progress	40,619	(4,000)	
28	**Total Regular Additions to Plant**	$ 427,185	$ 335,947	
29				
30	Special Projects and CPCN's Capital Expenditures	$ 309,823	$ 391,321	Line 16
31	Add - AFUDC	39,300	48,105	
32	Gross Capital Expenditures	349,123	439,426	
33	Change in Work in Progress	(197,823)	(222,211)	
34	**Total Special Projects and CPCN Additions to Plant**	$ 151,300	$ 217,215	
35				
36	**Grand Total Additions to Plant**	$ 578,485	$ 553,162	

PLANT IN SERVICE CONTINUITY SCHEDULE Schedule 6
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Line No.	Account	Particulars	12/31/2025	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2026	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	54,379	-	-	-	-	54,379	
8	461-02	Transmission Land Rights - Mt. Hayes	643	-	-	-	-	643	
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	7,180	-	-	-	-	7,180	
12	471-11	Distribution Land Rights - Byron Creek	1	-	-	-	-	1	
13	402-06	AMI Software	-	-	10,001	-	-	10,001	
14	402-01	Application Software - 12.5%	84,736	-	-	9,803	(7,339)	87,200	
15	402-02	Application Software - 20%	38,235	-	-	9,646	(5,873)	42,008	
16			$ 192,454	$ -	$ 10,001	$ 19,449	$ (13,212)	$ 208,692	
17									
18		**MANUFACTURED GAS / LOCAL STORAGE**							
19	430-00	Manufact'd Gas - Land	$ 31	$ -	$ -	$ -	$ -	$ 31	
20	432-00	Manufact'd Gas - Struct. & Improvements	1,312	-	-	-	-	1,312	
21	433-00	Manufact'd Gas - Equipment	2,122	-	-	-	-	2,122	
22	434-00	Manufact'd Gas - Gas Holders	2,948	-	-	-	-	2,948	
23	436-00	Manufact'd Gas - Compressor Equipment	367	-	-	-	-	367	
24	437-00	Manufact'd Gas - Measuring & Regulating Equipment	2,518	-	-	-	-	2,518	
25	440-00	Land in Fee Simple and Land Rights (Tilbury)	15,164	-	-	-	-	15,164	
26	442-00	Structures & Improvements (Tilbury)	101,354	-	-	-	-	101,354	
27	443-00	Gas Holders - Storage (Tilbury)	184,971	-	-	-	-	184,971	
28	448-11	Piping (Tilbury)	53,015	-	-	-	-	53,015	
29	448-21	Pre-treatment (Tilbury)	34,307	-	-	-	-	34,307	
30	448-31	Liquefaction Equipment (Tilbury)	90,421	-	-	-	-	90,421	
31	449-00	Local Storage Equipment (Tilbury)	23,905	-	-	-	-	23,905	
32	440-01	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	-	-	-	-	1,083	
33	442-01	Structures & Improvements (Mount Hayes)	19,355	-	-	-	-	19,355	
34	443-05	Gas Holders - Storage (Mount Hayes)	61,907	-	-	-	-	61,907	
35	448-41	Send out Equipment(Tilbury)	10,919	-	-	24,197	-	35,116	
36	448-51	Sub-station and Electric (Tilbury)	38,505	-	-	-	-	38,505	
37	448-61	Control Room (Tilbury)	5,034	-	-	-	-	5,034	
38	448-10	Piping (Mount Hayes)	12,714	-	-	-	-	12,714	
39	448-20	Pre-treatment (Mount Hayes)	29,462	-	-	-	-	29,462	
40	448-30	Liquefaction Equipment (Mount Hayes)	28,940	-	-	-	-	28,940	
41	448-40	Send out Equipment (Mount Hayes)	23,743	-	-	-	-	23,743	
42	448-50	Sub-station and Electric (Mount Hayes)	21,788	-	-	-	-	21,788	
43	448-60	Control Room (Mount Hayes)	6,674	-	-	-	-	6,674	
44	448-65	MH Inspection (Mount Hayes)	156	-	-	-	(156)	-	
45	448-66	Tilbury LNG - Inspection	5,476	-	-	-	-	5,476	
46	449-01	Local Storage Equipment (Mount Hayes)	6,133	-	-	-	-	6,133	
47			$ 784,324	$ -	$ -	$ 24,197	$ (156)	$ 808,365	

PLANT IN SERVICE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Schedule 6.1

Line No.	Account	Particulars	12/31/2025	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2026	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**TRANSMISSION PLANT**							
2	460-00	Land in Fee Simple	$ 11,086	$ -	$ -	$ -	$ -	$ 11,086	
3	462-00	Compressor Structures	51,797	-	-	2,400	(359)	53,838	
4	463-00	Measuring Structures	29,234	-	-	-	(244)	28,990	
5	464-00	Other Structures & Improvements	15,468	-	2,826	1,983	(3)	20,274	
6	465-00	Mains	1,910,843	-	16,494	34,194	(3,023)	1,958,508	
7	465-20	Mains - INSPECTION	62,122	-	-	5,444	(2,939)	64,627	
8	465-11	IP Transmission Pipeline - Whistler	60,674	-	-	-	-	60,674	
9	465-30	Mt Hayes - Mains	6,307	-	-	-	-	6,307	
10	465-10	Mains - Byron Creek	1,371	-	-	-	-	1,371	
11	466-00	Compressor Equipment	212,096	-	41,976	3,721	(924)	256,869	
12	466-10	Compressor Equipment - OVERHAUL	1,187	-	-	4	-	1,191	
13	467-00	Mt. Hayes - Measuring and Regulating Equipment	7,374	-	-	981	-	8,355	
14	467-10	Measuring & Regulating Equipment	182,237	-	10,937	8,514	(1,076)	200,612	
15	467-20	Telemetering	35,000	-	-	-	(57)	34,943	
16	467-31	IP Intermediate Pressure Whistler	358	-	-	30	-	388	
17	467-30	Measuring & Regulating Equipment - Byron Creek	291	-	-	-	-	291	
18	468-00	Communication Structures & Equipment	6,950	-	-	3,279	-	10,229	
19			$ 2,594,395	$ -	$ 72,233	$ 60,550	$ (8,625)	$ 2,718,553	
20									
21		**DISTRIBUTION PLANT**							
22	470-00	Land in Fee Simple	$ 6,349	$ -	$ -	$ -	$ -	$ 6,349	
23	472-00	Structures & Improvements	69,961	-	-	1,877	(143)	71,695	
24	472-10	Structures & Improvements - Byron Creek	124	-	-	-	-	124	
25	473-00	Services	1,778,059	-	-	75,726	(3,656)	1,850,129	
26	474-00	House Regulators & Meter Installations	129,677	-	57,586	-	(54,559)	132,704	
27	474-02	Meters/Regulators Installations	265,019	-	-	22,528	(83,899)	203,648	
28	475-00	Mains	2,531,864	-	-	61,955	(3,554)	2,590,265	
29	476-00	Compressor Equipment	614	-	-	-	-	614	
30	477-10	Measuring & Regulating Equipment	271,542	-	-	14,199	(2,645)	283,096	
31	477-20	Telemetering	37,002	-	-	797	(125)	37,674	
32	477-30	Measuring & Regulating Equipment - Byron Creek	153	-	-	-	-	153	
33	478-10	Meters	324,389	-	66,074	17,592	(72,130)	335,925	
34	478-20	Instruments	18,778	-	-	725	-	19,503	
35	479-00	Other Distribution Equipment	-	-	-	-	-	-	
36			$ 5,433,531	$ -	$ 123,660	$ 195,399	$ (220,711)	$ 5,531,879	
37									
38		**BIO GAS**							
39	472-20	Bio Gas Struct. & Improvements	$ 8,244	$ -	$ -	$ 145	$ -	$ 8,389	
40	475-10	Bio Gas Mains – Municipal Land	16,203	-	-	136	-	16,339	
41	475-20	Bio Gas Mains – Private Land	1,175	-	-	-	-	1,175	
42	418-10	Bio Gas Purification Overhaul	22	-	-	-	-	22	
43	418-20	Bio Gas Purification Upgrader	62,263	-	-	-	-	62,263	
44	477-40	Bio Gas Reg & Meter Equipment	7,251	-	-	477	-	7,728	
45	478-30	Bio Gas Meters	371	-	-	9	-	380	
46	474-10	Bio Gas Reg & Meter Installations	4,116	-	-	62	-	4,178	
47	483-25	RNG Comp S/W	-	-	-	-	-	-	
48	465-40	Bio Gas Transmission Pipe	1,561	-	-	-	-	1,561	
49	466-40	Bio Gas Compressor Equipment	3,295	-	-	-	-	3,295	
50			$ 104,501	$ -	$ -	$ 829	$ -	$ 105,330	

PLANT IN SERVICE CONTINUITY SCHEDULE Schedule 6.2
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Line No.	Account	Particulars	12/31/2025	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2026	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Natural Gas for Transportation**							
2	476-10	NG Transportation CNG Dispensing Equipment	$ 17,138	$ -	$ -	$ 4,046	$ -	$ 21,184	
3	476-20	NG Transportation LNG Dispensing Equipment	13,208	-	-	-	-	13,208	
4	476-30	NG Transportation CNG Foundations	3,163	-	-	-	-	3,163	
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	805	-	-	-	-	805	
8			$ 35,440	$ -	$ -	$ 4,046	$ -	$ 39,486	
9									
10		**GENERAL PLANT & EQUIPMENT**							
11	480-00	Land in Fee Simple	$ 31,944	$ -	$ -	$ -	$ -	$ 31,944	
12	482-10	Frame Buildings	28,430	-	-	-	(406)	28,024	
13	482-20	Masonry Buildings	151,394	-	-	3,273	(82)	154,585	
14	482-30	Leasehold Improvement	4,642	-	-	-	(130)	4,512	
15	483-30	GP Office Equipment	2,778	-	-	422	(175)	3,025	
16	483-40	GP Furniture	24,751	-	-	3,222	(111)	27,862	
17	483-10	GP Computer Hardware	40,719	-	-	9,625	(9,638)	40,706	
18	483-20	GP Computer Software	9,256	-	-	-	(662)	8,594	
19	484-00	Vehicles	76,927	-	-	8,274	-	85,201	
20	484-10	Vehicles - Leased	2,937	-	-	-	(2,089)	848	
21	485-10	Heavy Work Equipment	735	-	-	-	-	735	
22	485-20	Heavy Mobile Equipment	15,124	-	-	-	-	15,124	
23	486-00	Small Tools & Equipment	64,056	-	-	5,022	(2,002)	67,076	
24	487-20	Equipment on Customer's Premises	-	-	-	-	-	-	
25	488-30	AMI Communication and Equipment	-	-	11,321	-	-	11,321	
26	488-10	Telephone	144	-	-	-	(51)	93	
27	488-20	Radio	19,246	-	-	1,639	(247)	20,638	
28			$ 473,083	$ -	$ 11,321	$ 31,477	$ (15,593)	$ 500,288	
29									
30		**UNCLASSIFIED PLANT**							
31	499-00	Plant Suspense	-	-	-	-	-	-	
32			$ -	$ -	$ -	$ -	$ -	$ -	
33									
34		**Total Plant in Service**	$ 9,617,728	$ -	$ 217,215	$ 335,947	$ (258,297)	$ 9,912,593	
35									
36		Cross Reference			Schedule 5, Line 34, Column 3	Schedule 5, Line 28, Column 3			

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Schedule 7

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2025	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2026	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%	$ 69	$ -	$ 1	$ -	$ -	$ -	$ 70	
3	178-00	Organization Expense	728	1.00%	486	-	7	-	-	-	493	
4	401-01	Franchise and Consents	197	2.50%	149	-	5	-	-	-	154	
5	402-03	Other Intangible Plant	1,907	2.50%	1,437	-	48	-	-	-	1,485	
6	440-02	Water/Land Rights Tilbury	4,299	0.00%	-	-	-	-	-	-	-	
7	461-01	Transmission Land Rights	54,379	0.00%	1,766	-	-	-	-	-	1,766	
8	461-02	Transmission Land Rights - Mt. Hayes	643	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	7,180	0.00%	248	-	-	-	-	-	248	
12	471-11	Distribution Land Rights - Byron Creek	1	0.00%	1	-	-	-	-	-	1	
13	402-06	AMI Software	10,001	10.00%	-	-	1,000	-	-	-	1,000	
14	402-01	Application Software - 12.5%	84,736	12.50%	34,841	-	10,592	(7,339)	-	-	38,094	
15	402-02	Application Software - 20%	38,235	20.00%	12,944	-	7,647	(5,873)	-	-	14,718	
16			$ 202,455		$ 51,960	$ -	$ 19,300	$ (13,212)	$ -	$ -	$ 58,048	
17												
18		**MANUFACTURED GAS / LOCAL STORAGE**										
19	430-00	Manufact'd Gas - Land	$ 31	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
20	432-00	Manufact'd Gas - Struct. & Improvements	1,312	2.50%	557	-	33	-	-	-	590	
21	433-00	Manufact'd Gas - Equipment	2,122	5.00%	584	-	106	-	-	-	690	
22	434-00	Manufact'd Gas - Gas Holders	2,948	2.50%	1,166	-	74	-	-	-	1,240	
23	436-00	Manufact'd Gas - Compressor Equipment	367	4.00%	242	-	15	-	-	-	257	
24	437-00	Manufact'd Gas - Measuring & Regulating Equipment	2,518	5.00%	1,580	-	126	-	-	-	1,706	
25	440-00	Land in Fee Simple and Land Rights (Tilbury)	15,164	0.00%	1	-	-	-	-	-	1	
26	442-00	Structures & Improvements (Tilbury)	101,354	3.70%	20,732	-	3,750	-	-	-	24,482	
27	443-00	Gas Holders - Storage (Tilbury)	184,971	1.71%	30,326	-	3,163	-	-	-	33,489	
28	448-11	Piping (Tilbury)	53,015	2.50%	8,406	-	1,325	-	-	-	9,731	
29	448-21	Pre-treatment (Tilbury)	34,307	4.01%	9,028	-	1,376	-	-	-	10,404	
30	448-31	Liquefaction Equipment (Tilbury)	90,421	2.50%	15,153	-	2,261	-	-	-	17,414	
31	449-00	Local Storage Equipment (Tilbury)	23,905	2.10%	14,525	-	502	-	-	-	15,027	
32	440-01	Land in Fee Simple and Land Rights (Mount Hayes)	1,083	0.00%	-	-	-	-	-	-	-	
33	442-01	Structures & Improvements (Mount Hayes)	19,355	3.06%	10,367	-	592	-	-	-	10,959	
34	443-05	Gas Holders - Storage (Mount Hayes)	61,907	1.65%	14,719	-	1,021	-	-	-	15,740	
35	448-41	Send out Equipment(Tilbury)	10,919	2.50%	1,487	-	273	-	-	-	1,760	
36	448-51	Sub-station and Electric (Tilbury)	38,505	2.50%	6,317	-	963	-	-	-	7,280	
37	448-61	Control Room (Tilbury)	5,034	6.75%	1,852	-	340	-	-	-	2,192	
38	448-10	Piping (Mount Hayes)	12,714	2.43%	4,356	-	309	-	-	-	4,665	
39	448-20	Pre-treatment (Mount Hayes)	29,462	3.71%	16,544	-	1,093	-	-	-	17,637	
40	448-30	Liquefaction Equipment (Mount Hayes)	28,940	2.42%	10,381	-	700	-	-	-	11,081	
41	448-40	Send out Equipment (Mount Hayes)	23,743	2.43%	8,360	-	577	-	-	-	8,937	
42	448-50	Sub-station and Electric (Mount Hayes)	21,788	2.43%	7,771	-	529	-	-	-	8,300	
43	448-60	Control Room (Mount Hayes)	6,674	5.01%	5,755	-	334	-	-	-	6,089	
44	448-65	MH Inspection (Mount Hayes)	156	20.00%	124	-	31	(156)	-	-	(1)	
45	448-66	Tilbury LNG - Inspection	5,476	20.00%	2,190	-	1,095	-	-	-	3,285	
46	449-01	Local Storage Equipment (Mount Hayes)	6,133	3.47%	1,776	-	213	-	-	-	1,989	
47			$ 784,324		$ 194,299	$ -	$ 20,801	$ (156)	$ -	$ -	$ 214,944	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE Schedule 7.1
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2025	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2026	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1		**TRANSMISSION PLANT**										
2	460-00	Land in Fee Simple	$ 11,086	0.00%	$ 503	$ -	$ -	$ -	$ -	$ -	$ 503	
3	462-00	Compressor Structures	51,797	2.97%	26,360	-	1,538	(359)	-	-	27,539	
4	463-00	Measuring Structures	29,234	2.19%	10,375	-	640	(244)	-	-	10,771	
5	464-00	Other Structures & Improvements	18,294	3.31%	5,070	-	606	(3)	-	-	5,673	
6	465-00	Mains	1,927,337	1.48%	568,582	-	28,525	(3,023)	-	-	594,084	
7	465-20	Mains - INSPECTION	62,122	15.20%	15,830	-	9,442	(2,939)	-	-	22,333	
8	465-11	IP Transmission Pipeline - Whistler	60,674	1.53%	11,907	-	928	-	-	-	12,835	
9	465-30	Mt Hayes - Mains	6,307	1.54%	1,466	-	97	-	-	-	1,563	
10	465-10	Mains - Byron Creek	1,371	5.03%	1,842	-	69	-	-	-	1,911	
11	466-00	Compressor Equipment	254,072	2.31%	123,191	-	5,869	(924)	-	-	128,136	
12	466-10	Compressor Equipment - OVERHAUL	1,187	10.19%	922	-	121	-	-	-	1,043	
13	467-00	Mt. Hayes - Measuring and Regulating Equipment	7,374	2.28%	2,390	-	168	-	-	-	2,558	
14	467-10	Measuring & Regulating Equipment	193,174	2.27%	39,345	-	4,385	(1,076)	-	-	42,654	
15	467-20	Telemetering	35,000	6.01%	17,327	-	2,104	(57)	-	-	19,374	
16	467-31	IP Intermediate Pressure Whistler	358	2.14%	155	-	8	-	-	-	163	
17	467-30	Measuring & Regulating Equipment - Byron Creek	291	2.41%	73	-	7	-	-	-	80	
18	468-00	Communication Structures & Equipment	6,950	0.00%	3,691	-	-	-	-	-	3,691	
19			$ 2,666,628		$ 829,029	$ -	$ 54,507	$ (8,625)	$ -	$ -	$ 874,911	
20												
21		**DISTRIBUTION PLANT**										
22	470-00	Land in Fee Simple	$ 6,349	0.00%	$ (13)	$ -	$ -	$ -	$ -	$ -	$ (13)	
23	472-00	Structures & Improvements	69,961	2.01%	16,834	-	1,406	(143)	-	-	18,097	
24	472-10	Structures & Improvements - Byron Creek	124	4.67%	106	-	6	-	-	-	112	
25	473-00	Services	1,778,059	2.11%	513,881	-	37,517	(3,656)	-	-	547,742	
26	474-00	House Regulators & Meter Installations	187,263	4.35%	119,243	-	8,520	(45,988)	-	-	81,775	
27	474-02	Meters/Regulators Installations	265,019	4.55%	79,380	-	12,058	(38,551)	-	-	52,887	
28	475-00	Mains	2,531,864	1.42%	680,910	-	35,952	(3,554)	-	-	713,308	
29	476-00	Compressor Equipment	614	0.00%	1,444	-	-	-	-	-	1,444	
30	477-10	Measuring & Regulating Equipment	271,542	2.66%	84,195	-	7,223	(2,645)	-	-	88,773	
31	477-20	Telemetering	37,002	4.97%	11,897	-	1,839	(125)	-	-	13,611	
32	477-30	Measuring & Regulating Equipment - Byron Creek	153	0.00%	210	-	-	-	-	-	210	
33	478-10	Meters	390,463	3.38%	208,539	-	14,268	(68,655)	-	-	154,152	
34	478-20	Instruments	18,778	2.86%	9,556	-	537	-	-	-	10,093	
35	479-00	Other Distribution Equipment	-	0.00%	-	-	-	-	-	-	-	
36			$ 5,557,191		$ 1,726,182	$ -	$ 119,326	$ (163,317)	$ -	$ -	$ 1,682,191	
37												
38		**BIO GAS**										
39	472-20	Bio Gas Struct. & Improvements	$ 8,244	2.69%	$ 307	$ -	$ 222	$ -	$ -	$ -	$ 529	
40	475-10	Bio Gas Mains – Municipal Land	16,203	1.54%	554	-	250	-	-	-	804	
41	475-20	Bio Gas Mains – Private Land	1,175	1.53%	61	-	18	-	-	-	79	
42	418-10	Bio Gas Purification Overhaul	22	5.00%	12	-	1	-	-	-	13	
43	418-20	Bio Gas Purification Upgrader	62,263	5.00%	5,508	-	3,113	-	-	-	8,621	
44	477-40	Bio Gas Reg & Meter Equipment	7,251	3.24%	1,217	-	235	-	-	-	1,452	
45	478-30	Bio Gas Meters	371	5.19%	45	-	19	-	-	-	64	
46	474-10	Bio Gas Reg & Meter Installations	4,116	5.08%	285	-	209	-	-	-	494	
47	483-25	RNG Comp S/W	-	20.00%	-	-	-	-	-	-	-	
48	465-40	Bio Gas Transmission Pipe	1,561	1.53%	-	-	24	-	-	-	24	
49	466-40	Bio Gas Compressor Equipment	3,295	2.42%	-	-	80	-	-	-	80	
50			$ 104,501		$ 7,989	$ -	$ 4,171	$ -	$ -	$ -	$ 12,160	

ACCUMULATED DEPRECIATION CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Schedule 7.2

Line No.	Account	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2025	Opening Bal Adjustment	Depreciation Expense	Retirements	Cost of Removal	Adjustments	12/31/2026	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	17,138	5.00%	$ 6,792	-	857	-	-	-	$ 7,649	
3	476-20	NG Transportation LNG Dispensing Equipment	13,208	5.00%	6,731	-	660	-	-	-	7,391	
4	476-30	NG Transportation CNG Foundations	3,163	5.00%	1,328	-	158	-	-	-	1,486	
5	476-40	NG Transportation LNG Foundations	1,049	5.00%	602	-	52	-	-	-	654	
6	476-50	NG Transportation LNG Pumps (Pumps only apply to LNG)	77	10.00%	76	-	1	-	-	-	77	
7	476-60	NG Transportation CNG Dehydrator	805	5.00%	306	-	40	-	-	-	346	
8			$ 35,440		$ 15,835	$ -	$ 1,768	$ -	$ -	$ -	$ 17,603	
9												
10		**GENERAL PLANT & EQUIPMENT**										
11	480-00	Land in Fee Simple	$ 31,944	0.00%	$ 17	$ -	$ -	$ -	$ -	$ -	$ 17	
12	482-10	Frame Buildings	28,430	2.75%	16,504	-	782	(406)	-	-	16,880	
13	482-20	Masonry Buildings	151,394	1.36%	42,721	-	2,059	(82)	-	-	44,698	
14	482-30	Leasehold Improvement	4,642	9.49%	277	-	441	(130)	-	-	588	
15	483-30	GP Office Equipment	2,778	6.67%	1,379	-	185	(175)	-	-	1,389	
16	483-40	GP Furniture	24,751	5.00%	8,080	-	1,238	(111)	-	-	9,207	
17	483-10	GP Computer Hardware	40,719	25.00%	14,205	-	10,180	(9,638)	-	-	14,747	
18	483-20	GP Computer Software	9,256	12.50%	4,020	-	1,157	(662)	-	-	4,515	
19	484-00	Vehicles	76,927	7.15%	38,981	-	5,500	-	-	-	44,481	
20	484-10	Vehicles - Leased	2,937	9.44%	2,937	-	-	(2,089)	-	-	848	
21	485-10	Heavy Work Equipment	735	4.04%	537	-	30	-	-	-	567	
22	485-20	Heavy Mobile Equipment	15,124	8.51%	7,393	-	1,287	-	-	-	8,680	
23	486-00	Small Tools & Equipment	64,056	5.00%	26,661	-	3,203	(2,002)	-	-	27,862	
24	487-20	Equipment on Customer's Premises	-	6.67%	-	-	-	-	-	-	-	
25	488-30	AMI Communication and Equipment	11,321	6.67%	-	-	755	-	-	-	755	
26	488-10	Telephone	144	6.67%	130	-	(2)	(51)	-	-	77	
27	488-20	Radio	19,246	6.67%	9,208	-	1,284	(247)	-	-	10,245	
28			$ 484,404		$ 173,050	$ -	$ 28,099	$ (15,593)	$ -	$ -	$ 185,556	
29												
30		**UNCLASSIFIED PLANT**										
31	499-00	Plant Suspense	-	0.00%	-	-	-	-	-	-	-	
32			$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	
33												
34		**Total**	$ 9,834,943		$ 2,998,344	$ -	$ 247,972	$ (200,903)	$ -	$ -	$ 3,045,413	
35		Less: Depreciation & Amortization Transferred to RNG Account					(4,171)					
36		Less: Vehicle Depreciation Allocated To Capital Projects					(2,035)					
37		**Net Depreciation Expense**					$ 241,766					
38												
39		Cross Reference	Schedule 6.2, Line 34, Columns 3+4+5									

NON-REG PLANT CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Schedule 8

Line No.	Particulars			12/31/2025	Opening Bal Adjustment	CPCN's	Additions	Retirements	12/31/2026	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, 2026**
11 **($000s)**
12
13

Line No.	Particulars	Gross Plant for Depreciation	Depreciation Rate	12/31/2025	Opening Bal Adjustment	Depreciation Expense	Depreciation Retirements	Cost of Removal	12/31/2026	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%	155,367	-	4,238	-	-	159,605	
21									-	
22	**Total**	$ 177,648		$ 155,367	$ -	$ 4,238	$ -	$ -	$ 159,605	

CONTRIBUTIONS IN AID OF CONSTRUCTION CONTINUITY SCHEDULE Schedule 9
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Line No.	Particulars	12/31/2025	CPCN / Open Bal Adjt	Adjustment	Additions	Retirements	12/31/2026	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
1	**CIAC**							
2	Distribution Contributions	$ 319,296	$ -	$ -	$ 2,888	$ -	$ 322,184	
3	Transmission Contributions	157,433	-	-	8,443	-	165,876	
4	Others	3,521	-	-	-	-	3,521	
5	RNG	566	-	-	-	-	566	
6	**Total**	$ 480,816	$ -	$ -	$ 11,331	$ -	$ 492,147	
7								
8	**Amortization**							
9	Distribution Contributions	$ (148,071)	$ -	$ -	$ (5,492)	$ -	$ (153,563)	
10	Transmission Contributions	(67,651)	-	-	(2,330)	-	(69,981)	
11	Others	(1,372)	-	-	(176)	-	(1,548)	
12	RNG	(385)	-	-	(28)	-	(413)	
13	**Total**	$ (217,479)	$ -	$ -	$ (8,026)	$ -	$ (225,505)	
14								
15	**Net CIAC**	$ 263,337	$ -	$ -	$ 3,305	$ -	$ 266,642	
16								
17								
18	Total CIAC Amortization Expense per Line 13, Column 5				$ (8,026)			
19	Less: CIAC Amortization Transferred to RNG Account				28			
20	**Net CIAC Amortization Expense**				$ (7,998)			

NET SALVAGE CONTINUITY SCHEDULE
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2025	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2026	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**INTANGIBLE PLANT**							
2	461-01	Transmission Land Rights	$ 54,379	0.00%	$ 146	$ -	$ -	$ 146	
3	471-01	Distribution Land Rights	7,180	0.00%	5	-	-	5	
4			$ 61,559		$ 151	$ -	$ -	$ 151	
5									
6		**MANUFACTURED GAS / LOCAL STORAGE**							
7	437-00	Manufact'd Gas - Measuring & Regulating Equipment	$ 2,518	0.00%	$ (22)	$ -	$ -	$ (22)	
8	442-00	Structures & Improvements (Tilbury)	101,354	0.30%	4,536	304	-	4,840	
9	443-00	Gas Holders - Storage (Tilbury)	184,971	0.30%	12,209	555	-	12,764	
10	448-11	Piping (Tilbury)	53,015	0.24%	1,105	127	-	1,232	
11	448-21	Pre-treatment (Tilbury)	34,307	0.34%	1,200	117	-	1,317	
12	448-31	Liquefaction Equipment (Tilbury)	90,421	0.46%	3,913	416	-	4,329	
13	449-00	Local Storage Equipment (Tilbury)	23,905	-0.17%	1,994	(41)	-	1,953	
14	442-01	Structures & Improvements (Mount Hayes)	19,355	0.40%	777	77	-	854	
15	443-05	Gas Holders - Storage (Mount Hayes)	61,907	0.36%	1,965	223	-	2,188	
16	448-41	Send out Equipment(Tilbury)	10,919	0.25%	156	27	-	183	
17	448-51	Sub-station and Electric (Tilbury)	38,505	0.48%	1,414	185	-	1,599	
18	448-10	Piping (Mount Hayes)	12,714	0.28%	304	36	-	340	
19	448-20	Pre-treatment (Mount Hayes)	29,462	0.48%	1,267	141	-	1,408	
20	448-30	Liquefaction Equipment (Mount Hayes)	28,940	0.57%	1,453	165	-	1,618	
21	448-40	Send out Equipment (Mount Hayes)	23,743	0.28%	582	66	-	648	
22	448-50	Sub-station and Electric (Mount Hayes)	21,788	0.57%	1,085	124	-	1,209	
23	449-01	Local Storage Equipment (Mount Hayes)	6,133	0.14%	154	9	-	163	
24			$ 743,957		$ 34,092	$ 2,531	$ -	$ 36,623	

NET SALVAGE CONTINUITY SCHEDULE Schedule 10.1
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2025	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2026	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**TRANSMISSION PLANT**							
2	462-00	Compressor Structures	$ 51,797	0.12%	$ 710	$ 62	$ -	$ 772	
3	463-00	Measuring Structures	29,234	0.46%	1,142	134	-	1,276	
4	464-00	Other Structures & Improvements	18,294	0.25%	261	46	-	307	
5	465-00	Mains	1,927,337	0.47%	61,155	9,059	-	70,214	
6	465-11	IP Transmission Pipeline - Whistler	60,674	0.33%	1,628	200	-	1,828	
7	465-30	Mt Hayes - Mains	6,307	0.31%	175	20	-	195	
8	466-00	Compressor Equipment	254,072	0.10%	3,072	254	-	3,326	
9	467-00	Mt. Hayes - Measuring and Regulating Equipment	7,374	0.13%	118	10	-	128	
10	467-10	Measuring & Regulating Equipment	193,174	0.14%	1,765	270	-	2,035	
11	467-20	Telemetering	35,000	0.02%	(21)	7	-	(14)	
12	467-31	IP Intermediate Pressure Whistler	358	0.19%	10	1	-	11	
13	468-00	Communication Structures & Equipment	6,950	0.00%	401	-	-	401	
14			$ 2,590,571		$ 70,416	$ 10,063	$ -	$ 80,479	
15									
16		**DISTRIBUTION PLANT**							
17	470-00	Land in Fee Simple	$ 6,349	0.00%	$ (2,099)	$ -	$ -	$ (2,099)	
18	472-00	Structures & Improvements	69,961	0.53%	1,858	371	-	2,229	
19	473-00	Services	1,778,059	2.47%	143,676	43,918	(22,644)	164,950	
20	474-00	House Regulators & Meter Installations	187,263	0.87%	6,305	2,038	-	8,343	
21	474-02	Meters/Regulators Installations	265,019	0.00%	749	-	-	749	
22	475-00	Mains	2,531,864	0.56%	89,756	14,179	-	103,935	
23	476-00	Compressor Equipment	614	0.00%	706	-	-	706	
24	477-10	Measuring & Regulating Equipment	271,542	0.40%	7,816	1,085	-	8,901	
25	477-20	Telemetering	37,002	0.31%	654	115	-	769	
26	478-10	Meters	390,463	-0.17%	2,095	(551)	-	1,544	
27			$ 5,538,136		$ 251,516	$ 61,155	$ (22,644)	$ 290,027	
28									
29		**BIO GAS**							
30	472-20	Bio Gas Struct. & Improvements	$ 8,244	0.28%	$ 26	$ 23	$ -	$ 49	
31	475-10	Bio Gas Mains – Municipal Land	16,203	0.38%	135	61	-	196	
32	475-20	Bio Gas Mains – Private Land	1,175	0.39%	12	5	-	17	
33	418-20	Bio Gas Purification Upgrader	62,263	0.25%	233	155	-	388	
34	477-40	Bio Gas Reg & Meter Equipment	7,251	0.01%	(5)	1	-	(4)	
35	474-10	Bio Gas Reg & Meter Installations	4,116	1.29%	73	53	-	126	
36	465-40	Bio Gas Transmission Pipe	1,561	0.33%	-	5	-	5	
37	466-40	Bio Gas Compressor Equipment	3,295	0.07%	-	2	-	2	
38			$ 104,108		$ 474	$ 305	$ -	$ 779	

NET SALVAGE CONTINUITY SCHEDULE Schedule 10.2
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Line No.	Account	Particulars	Gross Plant for Depreciation	Salvage Rate	12/31/2025	Net Salv Provision	Retirement Costs / Proceeds on Disp.	12/31/2026	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1		**Natural Gas for Transportation**							
2	476-10	NG Transportation CNG Dispensing Equipment	$ 17,138	0.00%	$ (1)	$ -	$ -	$ (1)	
3	476-20	NG Transportation LNG Dispensing Equipment	13,208	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			$ 31,472		$ 34	$ -	$ -	$ 34	
7									
8		**GENERAL PLANT & EQUIPMENT**							
9	482-10	Frame Buildings	$ 28,430	0.38%	$ 119	$ 108	$ -	$ 227	
10	482-20	Masonry Buildings	151,394	0.18%	1,048	273	-	1,321	
11	482-30	Leasehold Improvement	4,642	0.00%	(116)	-	-	(116)	
12	483-30	GP Office Equipment	2,778	0.00%	1	-	-	1	
13	483-40	GP Furniture	24,751	0.00%	(94)	-	-	(94)	
14	484-00	Vehicles	76,927	-1.55%	(6,618)	(1,192)	-	(7,810)	
15	485-10	Heavy Work Equipment	735	-0.18%	(37)	(1)	-	(38)	
16	485-20	Heavy Mobile Equipment	15,124	1.72%	(1,076)	260	-	(816)	
17	486-00	Small Tools & Equipment	64,056	0.00%	70	-	-	70	
18	487-20	Equipment on Customer's Premises	-	0.00%	(2)	-	-	(2)	
19	488-30	AMI Communication and Equipment	-	0.00%	-	-	-	-	
20	488-20	Radio	19,246	0.00%	(7)	-	-	(7)	
21			$ 388,083		$ (6,712)	$ (552)	$ -	$ (7,264)	
22									
23		**Total**	$ 9,457,886		$ 349,971	$ 73,502	$ (22,644)	$ 400,829	
24		Less: Depreciation & Amortization Transferred to RNG Account				(305)			
25		**Net Salvage Depreciation Expense**				$ 73,197			
26		Cross Reference	Schedule 6.2, Columns 3+4+5				Schedule 11.1, Line 3, Column 4		

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE | Schedule 11
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Line No.	Particulars	12/31/2025	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2026	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)	$ 3,859	$ -	$ -	$ -	$ -	$ (2,643)	$ 714	$ 1,930	$ 2,895	
3	Commodity Cost Reconciliation Account (CCRA)	(33,249)	-	45,547	(12,298)	-	-	-	-	(16,625)	
4	Revenue Stabilization Adjustment Mechanism (RSAM)	43,237	-	-	-	-	(29,614)	7,996	21,619	32,428	
5	Interest on CCRA / MCRA / RSAM / Gas Storage	1,706	-	(2,053)	554	189	(416)	113	93	900	
6	SCP Net Mitigation Revenues Variance Account	-	-	-	-	-	-	-	-	-	
7	Pension & OPEB Variance	(3,525)	-	-	-	3,364	-	-	(161)	(1,843)	
8	BCUC Levies Variance	-	-	-	-	-	-	-	-	-	
9		$ 12,028	$ -	$ 43,494	$ (11,744)	$ 3,553	$ (32,673)	$ 8,823	$ 23,481	$ 17,755	
10											
11	**2. Rate Smoothing Accounts**										
12											
13	**3. Benefits Matching Accounts**										
14	Demand-Side Management (DSM)	$ 397,387	$ 94,078	$ 60,000	$ (16,200)	$ (75,822)	$ -	$ -	$ 459,443	$ 475,454	
15	NGV Conversion Grants	3	-	-	-	(3)	-	-	-	2	
16	Emissions Regulations	68	-	-	-	(68)	-	-	-	34	
17	Greenhouse Gas Reduction Regulation Incentives	32,982	-	-	-	(6,013)	-	-	26,969	29,976	
18	CNG and LNG Recoveries	(651)	-	(1,301)	351	650	-	-	(951)	(801)	
19	2025-2027 RSF Application	503	-	-	-	(232)	-	-	271	387	
20	BCUC Initiated Inquiry Costs	146	-	51	(14)	(146)	-	-	37	92	
21	2021 Generic Cost of Capital Proceeding	703	-	-	-	(176)	-	-	527	615	
22	2024-2027 DSM Expenditures Schedule Application	83	-	-	-	(41)	-	-	42	63	
23	2023 Cost of Service Allocation Study	37	-	100	(27)	(37)	-	-	73	55	
24	AMI Application and Feasibility Costs	3,077	-	-	-	(3,077)	-	-	-	1,539	
25	OCMP Application and Preliminary Stage Development Costs	17,501	-	-	-	(5,962)	-	-	11,539	14,520	
26		$ 451,839	$ 94,078	$ 58,850	$ (15,890)	$ (90,927)	$ -	$ -	$ 497,950	$ 521,934	

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - RATE BASE Schedule 11.1
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Line No.	Particulars	12/31/2025	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2026	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	$ 2,763	$ -	$ -	$ -	$ (737)	$ -	$ -	$ 2,026	$ 2,395	
3	Net Salvage Provision/Cost	(349,967)	-	22,644	-	(73,502)	-	-	(400,825)	(375,396)	
4	PCEC Start Up Costs	436	-	-	-	(44)	-	-	392	414	
5	2022 Long Term Gas Resource Plan Application	1,138	-	-	-	(569)	-	-	569	854	
6	2021 Renewable Gas Program Comprehensive Review	1,315	-	-	-	(657)	-	-	658	987	
7	Transmission Integrity Management Capabilities	4,246	-	-	-	(2,255)	-	-	1,991	3,119	
8	Annual Review Proceeding Costs	110	-	150	(40)	(110)	-	-	110	110	
9	Prince George Customer Service Centre Disposition	1,346	-	-	-	(1,346)	-	-	-	673	
10	Regional Gas Supply Diversity Project Development Costs	-	3,754	-	-	(1,251)	-	-	2,503	3,129	
11		$ (338,613)	$ 3,754	$ 22,794	$ (40)	$ (80,471)	$ -	$ -	$ (392,576)	$ (363,718)	
12											
13	**4. Retroactive Expense Accounts**										
14											
15	**5. Other Accounts**										
16	Pension & OPEB Funding	$ (88,314)	$ -	$ 10,366	$ -	$ -	$ -	$ -	$ (77,948)	$ (83,131)	
17	US GAAP Pension & OPEB Funded Status	(12,023)	-	-	-	-	-	-	(12,023)	(12,023)	
18	Existing Meter Cost Recovery	23,095	-	27,330	-	(4,619)	-	-	45,806	34,451	
19	Previously Retired Meter Cost Recovery	14,281	-	30,064	-	(2,856)	-	-	41,489	27,885	
20	Residual Delivery Rate Riders	-	-	-	-	-	-	-	-	-	
21		$ (62,961)	$ -	$ 67,760	$ -	$ (7,475)	$ -	$ -	$ (2,676)	$ (32,819)	
22											
23	**Total**	$ 62,293	$ 97,832	$ 192,898	$ (27,674)	$ (175,320)	$ (32,673)	$ 8,823	$ 126,179	$ 143,152	
24	Less: Net Salvage Amortization Transferred to RNG Account					305					
25	**Net Rate Base Deferred Amortization Expense**					$ (175,015)					

UNAMORTIZED DEFERRED CHARGES AND AMORTIZATION - NON-RATE BASE Schedule 12
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Line No.	Particulars	12/31/2025	Opening Bal./ Transfer/Adj.	Gross Additions	Less Taxes	Amortization Expense	Rider	Tax on Rider	12/31/2026	Mid-Year Average	Cross Ref
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
1	**1. Forecasting Variance Accounts**										
2	RNG Account	$ 20,390	$ (9,046)	$ 189,687	$ (49,728)	$ -	$ (154,255)	$ 41,649	$ 38,697	$ 25,021	
3	Flowthrough	-	-	-	-	-	-	-	-	-	
4	RNG Mitigation Revenue	-	9,046	(12,392)	3,346	-	-	-	-	4,523	
5	Marketer Cost Variance	14	-	(19)	5	-	-	-	-	7	
6		$ 20,404	$ -	$ 177,276	$ (46,377)	$ -	$ (154,255)	$ 41,649	$ 38,697	$ 29,551	
7	**2. Rate Smoothing Accounts**										
8	City of Vancouver Biomethane Purchase Agreement	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	
9	Fort Nelson Residential Customer Common Rate Phase-in Rate Rider	104	-	5	-	(104)	81	(22)	64	84	
8	2023-2025 Revenue Deficiency	78,781	-	4,905	-	-	-	-	83,686	81,234	
10		$ 78,885	$ -	$ 4,910	$ -	$ (104)	$ 81	$ (22)	$ 83,750	$ 81,318	
11											
12	**3. Benefits Matching Accounts**										
13	Demand-Side Management (DSM) - Non Rate Base	$ 94,078	$ (94,078)	$ 58,704	$ (15,498)	$ -	$ -	$ -	$ 43,206	$ 21,603	
14	PEC Pipeline Development Costs and Commitment Fees	(2,398)	-	-	-	-	-	-	(2,398)	(2,398)	
15	Regional Gas Supply Diversity Project Development Costs	3,754	(3,754)	-	-	-	-	-	-	-	
16	Clean Growth Innovation Fund 2025-2027	(1,727)	-	3,862	(1,080)	-	(5,349)	1,444	(2,850)	(2,289)	
17		$ 93,707	$ (97,832)	$ 62,566	$ (16,578)	$ -	$ (5,349)	$ 1,444	$ 37,958	$ 16,917	
18											
19	**4. Retroactive Expense Accounts**										
20											
21	**5. Other Accounts**										
22	Mark to Market - Hedging Transactions	$ 100,154	$ -	$ -	$ -	$ -	$ -	$ -	$ 100,154	$ 100,154	
23	Earnings Sharing Account	-	-	-	-	-	-	-	-	-	
24	US GAAP Uncertain Tax Positions	-	-	-	-	-	-	-	-	-	
25	FEFN - Right-Of-Way Agreement	196	-	12	-	-	-	-	208	202	
26	Flotation Costs	18,558	-	1,040	-	(3,712)	-	-	15,886	17,222	
27	AMI Foreign Exchange (FX) Mark to Market Valuation	-	-	-	-	-	-	-	-	-	
28		$ 118,908	$ -	$ 1,052	$ -	$ (3,712)	$ -	$ -	$ 116,248	$ 117,578	
29											
30											
31	**Total Non Rate Base Deferral Accounts**	$ 311,904	$ (97,832)	$ 245,804	$ (62,955)	$ (3,816)	$ (159,523)	$ 43,071	$ 276,653	$ 245,363	

Schedule 13

WORKING CAPITAL ALLOWANCE
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Line No.	Particulars	2025 Projected	2026 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Cash Working Capital**				
2	Cash Working Capital	$ 15,944	$ 13,556	$ (2,388)	Schedule 14, Line 30, Column 5
3					
4	Add/Less: Funds Unavailable/(Funds Available)				
5	Employee Loans	1,753	1,753	-	
6	Employee Withholdings	(7,755)	(7,755)	-	
7					
8	**Other Working Capital Items**				
9	Transmission Line Pack Gas	1,825	1,796	(29)	
10	Gas In Storage	38,852	50,377	11,525	
11	Inventories - Materials and Supplies	3,286	3,286	-	
12	Refundable Contributions	(36)	(36)	-	
13					
14	Total	$ 53,869	$ 62,977	$ 9,108	

CASH WORKING CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Schedule 14

Line No.	Particulars	2026 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	$ 1,100,713	38.5	$ 42,377,451		
4	Commercial Tariff Revenue	601,570	37.6	22,619,032		
5	Industrial Tariff Revenue	211,382	45.3	9,575,604		
6	Bypass and Special Rates	37,602	40.0	1,504,080		
7						
8	**Other Revenue**					
9	Late Payment Charges	3,511	52.9	185,732		
10	Application Charges	1,533	38.1	58,407		
11	Other Utility Income	42,969	38.1	1,637,119		
12						
13	Total	$ 1,999,280		$ 77,957,425	39.0	
14						
15	**EXPENSES**					
16	Energy Purchases	$ 564,259	(40.1)	$ (22,626,786)		
17	Operating and Maintenance	348,197	(29.9)	(10,411,090)		
18	Property Taxes	88,576	(0.6)	(53,146)		
19	Operating Fees	12,341	(343.9)	(4,244,217)		
20	Carbon Tax	-	(28.9)	-		
21	GST	39,971	(33.3)	(1,331,047)		
22	PST	41,191	(40.9)	(1,684,717)		
23	Income Tax	112,260	(15.2)	(1,706,352)		
24						
25	Total	$ 1,206,796		$ (42,057,355)	(34.9)	
26						
27	Net Lag (Lead) Days				4.1	
28	Total Expenses				$ 1,206,796	
29						
30	Cash Working Capital				$ 13,556	

Schedule 15

DEFERRED INCOME TAX LIABILITY / ASSET
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Line No.	Particulars	2025 Projected	2026 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Total DIT Liability- After Tax	$ (702,600)	$ (743,813)	$ (41,213)	
2	Tax Gross Up	(259,866)	(275,109)	(15,243)	
3	DIT Liability/Asset - End of Year	$ (962,466)	$ (1,018,922)	$ (56,456)	
4	DIT Liability/Asset - Opening Balance	(891,563)	(962,466)	(70,903)	
5					
6	DIT Liability/Asset - Mid Year	$ (927,015)	$ (990,694)	$ (63,679)	

UTILITY INCOME AND EARNED RETURN
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Schedule 16

Line No.	Particulars	2025 Projected	2026 Forecast at 2025 Interim Rates	2026 Forecast Revised Revenue	2026 Forecast at Revised Rates	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	**ENERGY VOLUMES**						
2	Sales Volume (TJ)	168,989	170,371		170,371	1,382	
3	Transportation Volume (TJ)	51,052	51,829		51,829	777	
4		220,041	222,200	-	222,200	2,158	Schedule 17, Line 23, Column 3
5							
6	**REVENUE AT EXISTING RATES**						
7	Sales	$ 1,741,724	$ 1,755,435	$ -	$ 1,755,435	$ 13,711	
8	Deficiency (Surplus)	-	-	117,981	117,981	117,981	
9	Transportation	72,583	71,411	-	71,411	(1,172)	
10	Deficiency (Surplus)	-		6,440	6,440	6,440	
11	Total	1,814,307	1,826,846	124,421	1,951,267	136,960	Schedule 19, Line 29, Column 8
12				-			
13	**COST OF ENERGY**	561,240	564,259	-	564,259	3,019	Schedule 18, Line 23, Column 3
14							
15	**MARGIN**	1,253,067	1,262,587	124,421	1,387,008	133,941	
16							
17	**EXPENSES**						
18	O&M Expense (net)	335,394	348,197	-	348,197	12,803	Schedule 20, Line 29, Column 4
19	Depreciation & Amortization	356,817	412,599	-	412,599	55,782	Schedule 21, Line 15, Column 3
20	Property Taxes	86,927	88,576	-	88,576	1,649	Schedule 22, Line 8, Column 3
21	Other Revenue	(32,309)	(48,013)	-	(48,013)	(15,704)	Schedule 23, Line 12, Column 3
22	Deferred Revenue Deficiency	(15,352)	-	-	-	15,352	
23	Utility Income Before Income Taxes	521,590	461,228	124,421	585,649	64,059	
24							
25	Income Taxes	77,321	78,673	33,587	112,260	34,939	Schedule 24, Line 13, Column 3
26							
27	**EARNED RETURN**	$ 444,269	$ 382,555	$ 90,834	$ 473,389	$ 29,120	Schedule 26, Line 5, Column 7
28							
29	**UTILITY RATE BASE**	$ 6,452,115	$ 6,834,029		$ 6,835,379	$ 383,264	Schedule 2, Line 30, Column 3
30	**RATE OF RETURN ON UTILITY RATE BASE**	6.89%	5.60%		6.93%	0.04%	Schedule 26, Line 5, Column 6

VOLUME AND REVENUE Schedule 17
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Line No.	Particulars	2025 Projected	2026 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**ENERGY VOLUME SOLD (TJ)**				
2	Residential				
3	Rate Schedule 1	80,535.0	81,390.1	855.1	
4	Commercial				
5	Rate Schedule 2	29,428.2	29,419.1	(9.1)	
6	Rate Schedule 3	29,619.0	30,668.2	1,049.2	
7	Rate Schedule 23	2,271.4	2,498.9	227.5	
8	Industrial				
9	Rate Schedule 4	175.1	175.1	-	
10	Rate Schedule 5	15,987.0	16,034.9	47.9	
11	Rate Schedule 6	20.4	19.9	(0.5)	
12	Rate Schedule 7	9,588.2	9,204.4	(383.8)	
13	Rate Schedule 22 - Firm Service	14,334.1	14,183.6	(150.5)	
14	Rate Schedule 22 - Interruptible Service	9,708.3	9,938.8	230.5	
15	Rate Schedule 25	6,193.1	6,232.4	39.3	
16	Rate Schedule 27	3,056.9	2,819.4	(237.5)	
17	Bypass and Special Rates				
18	Rate Schedule 22 - Firm Service	9,998.4	10,641.2	642.8	
19	Rate Schedule 25	735.8	758.2	22.4	
20	Rate Schedule 46	3,636.2	3,459.2	(177.0)	
21	Byron Creek	9.3	11.4	2.1	
22	VIGJV	4,745.0	4,745.0	-	
23	Total	220,041.4	222,199.8	2,158.4	
24					
25	**REVENUE AT EXISTING RATES**				
26	Residential				
27	Rate Schedule 1	$ 1,016,139	$ 1,025,459	$ 9,320	
28	Commercial				
29	Rate Schedule 2	296,302	296,397	95	
30	Rate Schedule 3	247,529	256,105	8,576	
31	Rate Schedule 23	11,293	12,448	1,155	
32	Industrial				
33	Rate Schedule 4	1,004	999	(5)	
34	Rate Schedule 5	99,896	99,763	(133)	
35	Rate Schedule 6	131	135	4	
36	Rate Schedule 7	47,702	45,632	(2,070)	
37	Rate Schedule 22 - Firm Service	16,123	15,627	(496)	
38	Rate Schedule 22 - Interruptible Service	12,754	11,158	(1,596)	
39	Rate Schedule 25	19,182	19,397	215	
40	Rate Schedule 27	6,575	6,124	(451)	
41	Bypass and Special Rates				
42	Rate Schedule 22 - Firm Service	865	865	-	
43	Rate Schedule 25	424	425	1	
44	Rate Schedule 46	33,021	30,945	(2,076)	
45	Byron Creek	136	136	-	
46	VIGJV	5,231	5,231	-	
47	Total	$ 1,814,307	$ 1,826,846	$ 12,539	

COST OF ENERGY Schedule 18
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Line No.	Particulars	2025 Projected	2026 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**COST OF GAS**				
2	Residential				
3	Rate Schedule 1	$ 276,423	$ 278,334	$ 1,911	
4	Commercial				
5	Rate Schedule 2	101,773	101,356	(417)	
6	Rate Schedule 3	96,919	99,963	3,044	
7	Rate Schedule 23	37	57	20	
8	Industrial				
9	Rate Schedule 4	509	507	(2)	
10	Rate Schedule 5	46,355	46,296	(59)	
11	Rate Schedule 6	43	44	1	
12	Rate Schedule 7	27,881	26,657	(1,224)	
13	Rate Schedule 22 - Firm Service	231	327	96	
14	Rate Schedule 22 - Interruptible Service	156	229	73	
15	Rate Schedule 25	100	143	43	
16	Rate Schedule 27	49	65	16	
17	Bypass and Special Rates				
18	Rate Schedule 22 - Firm Service	161	245	84	
19	Rate Schedule 25	12	17	5	
20	Rate Schedule 46	10,591	10,019	(572)	
21	Byron Creek	-	-	-	
22	VIGJV	-	-	-	
23	Total	$ 561,240	$ 564,259	$ 3,019	

MARGIN AND REVENUE AT EXISTING AND REVISED RATES
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Schedule 19

Line No.	Particulars	2025 Projected Margin	2026 Forecast: Margin at 2025 Interim Rates	2026 Forecast: Effective Increase	2026 Forecast: Margin at Revised Rates	2026 Forecast: Revenue at 2025 Interim Rates	2026 Forecast: Effective Increase	2026 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	$ 739,716	$ 747,125	$ 75,254	$ 822,379	$ 1,025,459	$ 75,254	$ 1,100,713	1,011,248	81,390.1	
4	Commercial										
5	Rate Schedule 2	194,529	195,041	19,645	214,686	296,397	19,645	316,042	92,994	29,419.1	
6	Rate Schedule 3	150,610	156,142	15,727	171,869	256,105	15,727	271,832	8,545	30,668.2	
7	Rate Schedule 23	11,256	12,391	1,248	13,639	12,448	1,248	13,696	404	2,498.9	
8	Industrial										
9	Rate Schedule 4	495	492	50	542	999	50	1,049	26	175.1	
10	Rate Schedule 5	53,541	53,467	5,385	58,852	99,763	5,385	105,148	792	16,034.9	
11	Rate Schedule 6	88	91	9	100	135	9	144	19	19.9	
12	Rate Schedule 7	19,821	18,975	1,911	20,886	45,632	1,911	47,543	64	9,204.4	
13	Rate Schedule 22 - Firm Service	15,892	15,300	1,542	16,842	15,627	1,542	17,169	23	14,183.6	
14	Rate Schedule 22 - Interruptible Service	12,598	10,929	1,101	12,030	11,158	1,101	12,259	6	9,938.8	
15	Rate Schedule 25	19,082	19,254	1,939	21,193	19,397	1,939	21,336	179	6,232.4	
16	Rate Schedule 27	6,526	6,059	610	6,669	6,124	610	6,734	47	2,819.4	
17	Total Non-Bypass	$ 1,224,154	$ 1,235,266	$ 124,421	$ 1,359,687	$ 1,789,244	$ 124,421	$ 1,913,665	1,114,347	202,584.8	
18											
19											
20	**Bypass and Special Rates**										
21	Rate Schedule 22 - Firm Service	$ 704	$ 620		$ 620	$ 865		$ 865	6	10,641.2	
22	Rate Schedule 25	412	408		408	425		425	3	758.2	
23	Rate Schedule 46	22,430	20,926		20,926	30,945		30,945	15	3,459.2	
24	Byron Creek	136	136		136	136		136	1	11.4	
25	VIGJV	5,231	5,231		5,231	5,231		5,231	1	4,745.0	
26	Total Bypass & Special	$ 28,913	$ 27,321	$ -	$ 27,321	$ 37,602	$ -	$ 37,602	26	19,615.0	
27											
28											
29	Total	$ 1,253,067	$ 1,262,587	$ 124,421	$ 1,387,008	$ 1,826,846	$ 124,421	$ 1,951,267	1,114,373	222,199.8	
30											
31	**Effective Increase**			10.07%			6.95%				

OPERATING AND MAINTENANCE EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Schedule 20

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	2025 Base Unit Cost O&M	$ 283			
3	2026 Net Inflation Factor	2.726%			Schedule 3, Line 9, Column 4
4	2026 Base Unit Cost O&M	$ 291			Line 2 x (1 + Line 3)
5					
6	2026 Average Customer Forecast - Rate Setting Purpose	1,114,373			Schedule 3, Line 20, Column 5
7					
8	2026 Inflation Indexed O&M before prior year True-up	$ 324,283			Line 4 x Line 6 / 1000
9					
10	2024 Average Customer True-up	937			
11					
12	2026 Inflation Indexed O&M	$ 325,220		$ 325,220	Sum of Lines 8 and 10
13					
14	**O&M Tracked Outside of Formula**				
15	Pension & OPEB (O&M Portion)		$ 5,725		
16	Insurance		12,748		
17	Integrity O&M		12,000		
18	AMI Flowthrough O&M		25,578		
19	BCUC fees		8,208		
20	RNG O&M		7,946		
21	Renewable Gas Development		5,084		
22	NGT O&M		2,994		
23	Variable LNG Production		11,038		
24	Sub-total		$ 91,321	91,321	Sum of Lines 15 through 23
25					
26	**Total Gross O&M**			$ 416,541	Line 12 + Line 24
27	O&M Transferred to RNG Account			(7,946)	
28	Capitalized Overhead			(60,398)	-14.5 % x Line 26
29	**Net O&M Expense**			$ 348,197	Sum of Lines 26 through 28

DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Line No.	Particulars	2025 Projected	2026 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**Depreciation**				
2	Depreciation Expense	$ 228,836	$ 247,972	$ 19,136	Schedule 7.2, Line 34, Column 7
3	Depreciation & Amortization Transferred to RNG Account	(1,113)	(4,171)	(3,058)	Schedule 7.2, Line 35, Column 7
4	Vehicle Depreciation Allocated To Capital Projects	(1,781)	(2,035)	(254)	Schedule 7.2, Line 36, Column 7
5		225,942	241,766	15,824	
6					
7	**Amortization**				
8	Rate Base Deferrals	$ 147,461	$ 175,320	$ 27,859	Schedule 11.1, Line 23, Column 6
9	Rate Base Deferrals - Net Salvage Amortization Transferred to RNG Account	(130)	(305)	(175)	Schedule 11.1, Line 24, Column 6
10	Non-Rate Base Deferrals	(8,585)	3,816	12,401	Schedule 12, Line 31, Column 6
11	CIAC	(7,899)	(8,026)	(127)	Schedule 9, Line 13, Column 5
12	CIAC Amortization Transferred to RNG Account	28	28	-	Schedule 9, Line 19, Column 5
13		130,875	170,833	39,958	
14					
15	Total	$ 356,817	$ 412,599	$ 55,782	

PROPERTY AND SUNDRY TAXES
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Schedule 22

Line No.	Particulars	2025 Projected	2026 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	General School and Other	$ 69,054	$ 72,563	$ 3,509	
2	1% In-Lieu of Municipal Taxes	17,999	16,203	(1,796)	
3					
4	Total	$ 87,053	$ 88,766	$ 1,713	
5					
6	Total Property Tax Expense per Line 4	$ 87,053	$ 88,766	$ 1,713	
7	Less: Property Tax Transferred to RNG Account	(126)	(190)	(64)	
8	**Net Property Tax Expense**	$ 86,927	$ 88,576	$ 1,649	

OTHER REVENUE Schedule 23
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Line No.	Particulars	2025 Projected	2026 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	Late Payment Charge	$ 3,628	$ 3,511	$ (117)	
2	Application Charge	1,569	1,533	(36)	
3	NSF Returned Cheque Charges	28	28	-	
4	Other Recoveries	288	288	-	
5	SCP Third Party Revenue	13,284	13,284	-	
6	NGT Tanker Rental Revenue	971	1,067	96	
7	NGT Overhead and Marketing Recovery	227	228	1	
8	RNG Other Revenue	(8,122)	7,592	15,714	
9	LNG Capacity Assignment	18,039	18,039	-	
10	CNG & LNG Service Revenues	2,397	2,443	46	
11					
12	Total	$ 32,309	$ 48,013	$ 15,704	

INCOME TAXES
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Schedule 24

Line No.	Particulars	2025 Projected	2026 Forecast	Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)
1	**EARNED RETURN**	$ 444,269	$ 473,389	$ 29,120	Schedule 16, Line 27, Column 5
2	Deduct: Interest on Debt	(164,086)	(176,563)	(12,477)	Schedule 26, Lines 1+2, Column 7
3	Adjustments to Taxable Income	(71,131)	6,691	77,822	Line 36
4	Accounting Income After Tax	$ 209,052	$ 303,517	$ 94,465	
5					
6	1 - Current Income Tax Rate	73.00%	73.00%	0.00%	
7	Taxable Income	$ 286,373	$ 415,777	$ 129,404	
8					
9	Current Income Tax Rate	27.00%	27.00%	0.00%	
10	Income Tax - Current	$ 77,321	$ 112,260	$ 34,939	
11					
12	Previous Year Adjustment	-	-	-	
13	**Total Income Tax**	$ 77,321	$ 112,260	$ 34,939	
14					
15					
16	**ADJUSTMENTS TO TAXABLE INCOME**				
17	Addbacks:				
18	Non-tax Deductible Expenses	$ 1,200	$ 1,200	$ -	
19	Depreciation	225,942	241,766	15,824	Schedule 21, Line 5, Column 3
20	Amortization of Deferred Charges	138,746	178,831	40,085	Schedule 21, Lines 8+9+10, Column 3
21	Amortization of Debt Issue Expenses	1,491	1,602	111	
22	Vehicles: Interest & Capitalized Depreciation	1,781	2,035	254	
23	Pension Expense	6,962	8,798	1,836	
24	OPEB Expense	6,248	2,903	(3,345)	
25					
26	Deductions:				
27	Capital Cost Allowance	(348,689)	(332,547)	16,142	Schedule 25, Line 24, Column 6
28	CIAC Amortization	(7,871)	(7,998)	(127)	Schedule 21, Lines 11+12, Column 3
29	Debt Issue Costs	(1,086)	(1,690)	(604)	
30	Vehicle Lease Payment	-	-	-	
31	Pension Contributions	(16,413)	(18,317)	(1,904)	
32	OPEB Contributions	(3,702)	(3,750)	(48)	
33	Overheads Capitalized Expensed for Tax Purposes	(38,075)	(39,571)	(1,496)	
34	Removal Costs	(21,565)	(22,644)	(1,079)	Schedule 11.1, Line 3, Column 4
35	Major Inspection Costs	(16,100)	(3,927)	12,173	
36	Total	$ (71,131)	$ 6,691	$ 77,822	

CAPITAL COST ALLOWANCE Schedule 25
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Line No.	Class	CCA Rate	12/31/2025 UCC Balance	2026 Additions	Adjustments	2026 CCA	Forecast 12/31/2026 UCC Balance
	(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	1	4%	$ 811,430	$ 4,325	$ -	$ (32,630)	$ 783,125
2	1(b)	6%	150,745	8,752	-	(9,570)	149,927
3	2	6%	63,878	-	-	(3,833)	60,045
4	3	5%	1,314	-	-	(66)	1,248
5	6	10%	158	-	-	(16)	142
6	7	15%	19,533	2,958	-	(3,374)	19,117
7	8	20%	28,864	10,265	-	(7,826)	31,303
8	10	30%	16,460	8,274	-	(7,420)	17,314
9	10.1	30%	142	-	-	(43)	99
10	12	100%	-	19,135	-	(19,135)	-
11	13	manual	2,828	-	-	(1,078)	1,750
12	14.1 (pre 2017)	7%	11,423	-	-	(800)	10,623
13	14.1 (post 2016)	5%	14,247	-	-	(712)	13,535
14	17	8%	689	-	-	(55)	634
15	38	30%	2,138	-	-	(641)	1,497
16	43.1 (post 2024)	30%	11,697	-	-	(3,509)	8,188
17	43.2	50%	53	-	-	(27)	26
18	47	8%	110,266	-	-	(8,821)	101,445
19	47 (LNG Plant - post Feb 2015)	8%	136,685	22,028	-	(12,697)	146,016
20	49	8%	683,771	73,576	-	(60,588)	696,759
21	50	55%	8,406	9,568	-	(9,886)	8,088
22	51	6%	2,049,214	447,791	-	(149,820)	2,347,185
23							
24	Total		$ 4,123,941	$ 606,672	$ -	$ (332,547)	$ 4,398,066

RETURN ON CAPITAL
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Schedule 26

Line No.	Particulars	2025 Projected Earned Return	Amount	Ratio	2026 Average Embedded Cost	Cost Component	Earned Return	Earned Return Change	Cross Reference
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	Long Term Debt	$ 157,560	$ 3,653,664	53.45%	4.73%	2.53%	$ 172,987	$ 15,427	Schedule 27, Lines 25&27, Columns 5&6&7
2	Short Term Debt	6,526	105,794	1.55%	3.38%	0.05%	3,576	(2,950)	
3	Common Equity	280,183	3,075,921	45.00%	9.65%	4.34%	296,826	16,643	
4									
5	Total	$ 444,269	$ 6,835,379	100.00%		6.93%	$ 473,389	$ 29,120	
6									
7	Cross Reference		Schedule 2, Line 30, Column 3						

EMBEDDED COST OF LONG TERM DEBT
FOR THE YEAR ENDING DECEMBER 31, 2026
($000s)

Schedule 27

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	138,705	37,085	2.644%	981	
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	148,697	150,000	4.724%	7,086	
19	2025 Medium Term Debt Issue	September 1, 2025	September 1, 2055	247,500	250,000	4.662%	11,655	
20	2026 Medium Term Debt Issue (Series B Renewal)	July 1, 2026	July 1, 2056	435,151	221,579	4.662%	10,331	
21								
22	FEVI L/T Debt Issue - 2008	February 16, 2008	February 15, 2038	247,999	250,000	6.109%	15,273	
23	FEVI L/T Debt Issue - 2010	December 6, 2010	December 6, 2040	98,836	100,000	5.278%	5,278	
24								
25	Total				$ 3,653,664		$ 172,987	
26								
27	Average Embedded Cost					4.73%		
28								
29	* 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 the RSF, emerging accounting guidance, and the status of its non-rate base deferral accounts. With respect to its non-rate base deferral accounts, FEI proposes an amortization period for the Flotation Costs deferral account, proposes changes to the RNG Account, and seeks approval to capture the revenue deficiency resulting from setting permanent 2025 delivery rates at the interim approved level in the existing 2023-2024 Revenue Deficiency deferral account and to commence amortizing the deferral account in 2027. FEI also provides information on the Flow-through deferral account.

12.2 *EXOGENOUS (Z) FACTORS*

FEI is permitted to adjust the cost of service for "Exogenous Factors" under the RSF. 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 RSF Decision.

For 2025 and 2026, FEI has not identified any items that merit exogenous factor treatment.

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." Although this directive was not included as part of the 2020-2024 MRP Decision, FEI continued to provide accounting policy changes and updates as part of the Annual Reviews during the MRP term.

Consistent with the Annual Reviews during the PBR Plan and MRP terms, FEI will continue to provide accounting policy changes and updates as part of the Annual Reviews during the RSF term.

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 2025 or 2026.

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).

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 sub-sections below, FEI seeks the following approvals regarding existing non-rate base deferral accounts:

- Record the difference between 2025 interim and permanent delivery rates in the existing 2023-2024 Revenue Deficiency deferral account, rename this account the 2023-2025 Revenue Deficiency deferral account, and amortize the deferral account over five years commencing January 1, 2027;
- Amortize the Flotation Costs deferral account over five years, commencing January 1, 2026; and
- Modify the RNG Account.

FEI also provides updated information on the Flow-through deferral account.

12.4.2.1 2023-2024 Revenue Deficiency Deferral Account

The 2023-2024 Revenue Deficiency deferral account was first established by Order G-275-23 to record the incremental revenue deficiency between 2023 interim and permanent delivery rates resulting from the BCUC's decision in the GCOC Stage 1 proceeding (GCOC Stage 1 Decision). In the BCUC's decision on the FEI Annual Review for 2024 Delivery Rates[76], FEI was further

[76] Annual Review for 2024 Delivery Rates Decision and Order G-334-23, pp. 20-21.

approved to set its 2024 delivery rate increase at 8 percent and to record the remaining revenue deficiency from 2024 in the 2023-2024 Revenue Deficiency deferral account. FEI was also directed to seek approval of an amortization period for the 2023-2024 Revenue Deficiency deferral account in the next rate-setting application.

FEI's currently approved interim delivery rate increase for 2025 is 7.75 percent.[77] As explained in Section 1, based on the updated projections and forecasts for 2025, FEI's projected 2025 revenue deficiency is $103.400 million, which would result in a delivery rate increase of 9.10 percent. If the permanent 2025 delivery rates were adjusted to incorporate the full incremental deficiency, an additional 1.35 percent would need to be applied to the entire year's delivery rates in 2025. As discussed in Section 1 of the Application, given that FEI does not expect a decision on the Annual Review for 2025-2026 Delivery Rates until November or December 2025, it is not practical or feasible to adjust the 2025 delivery rates in 2025. While FEI could apply a one-time bill adjustment in 2026 to collect the incremental revenue deficiency, as explained in Section 1, this would further increase customers' bills in January 2026 when gas consumption is typically highest (i.e., in winter).

Accordingly, FEI proposes to defer the revenue deficiency resulting from the difference between 2025 interim and permanent delivery rates in the existing 2023-2024 Revenue Deficiency deferral account and to rename the deferral account the 2023-2025 Revenue Deficiency deferral account. As further discussed below, FEI proposes to amortize the 2023-2025 Revenue Deficiency deferral account over five years, commencing January 1, 2027.

Including the difference between the 2025 interim and permanent revenue deficiency, the projected ending balance as of December 31, 2025 in the 2023-2025 Revenue Deficiency deferral account is approximately $78.781 million. FEI considered various options for recovering the balance in the deferral account, including commencing amortization in either 2026 or 2027, and amortizing the deferral account over a range of years.

Amortization Periods

Given the projected 2025 ending balance of the deferral account of $78.781 million, FEI ruled out amortization periods less than three years due to the annual incremental rate impact. Accordingly, FEI considered amortization periods ranging from 3 years to 10 years, as shown in Table 12-1 below.

Table 12-1: Amortization Periods for the 2023-2025 Revenue Deficiency Deferral Account

	Amortization Period							
	3 Years	4 Years	5 Years	6 Years	7 Years	8 Years	9 Years	10 Years
Incremental Revenue in 2027 ($ millions)	38.213	28.660	22.928	19.107	16.377	14.330	12.738	11.464
Delivery Rate Impact, compared to 2026 (%)	2.81%	2.11%	1.69%	1.41%	1.20%	1.05%	0.94%	0.84%
Year 1 Delivery Rate Impact - RS 1 ($)	$ 25.56	$ 19.17	$ 15.33	$ 12.78	$ 10.95	$ 9.58	$ 8.52	$ 7.67

[77] Approved by Order G-313-24.

An amortization period of three years would align with the number of years of deficiencies recorded in the deferral account; however, as shown in the above table, a 3-year amortization period would result in an incremental annual rate impact of 2.81 percent.

Regarding amortization periods of 8 to 10 years, the rate smoothing benefits begin to taper off and considerations of intergenerational inequity begin to outweigh the limited smoothing benefits. Amortization periods of 6 or 7 years provide more rate smoothing than a 5-year period, but the extended recovery timeframe creates more potential for intergenerational inequity.

Based on the analysis above, FEI proposes a 5-year amortization period for the deferral account. Five years achieves some rate smoothing, as the incremental annual rate impact due to the amortization of the deferral account is less than 2 percent (i.e., 1.69 percent), while also ensuring that the balance in the deferral account is recovered over a reasonably short time frame (thus mitigating potential issues of intergenerational inequity). FEI discusses options for commencing recovery of the deferral account below.

Commencement of Amortization

Typically, FEI would propose to commence amortizing a deferral account in the upcoming test year (i.e., 2026); however, in consideration of the delivery rate increase in 2026, FEI also evaluated the reasonableness of delaying amortization of the deferral account until 2027.

The impact on 2026 delivery rates of commencing amortization of the deferral account is approximately 1.75 percent (i.e., if the amortization of the deferral account is included in 2026 delivery rates, the delivery rate increase in 2026 would be 11.82 percent instead of the proposed 10.07 percent). In Section 1 of the Application, FEI explained that the potential range of delivery rate increases in 2027 based on what is known at this time is 6 to 8 percent.

When comparing the 2026 delivery rate increase with and without the inclusion of the deferral account amortization to the potential 2027 delivery rate increase, FEI considers it more reasonable to delay amortization to 2027. Delaying the amortization not only mitigates the 2026 delivery rate impact but it smooths the expected 2026 and 2027 delivery rate increases. For instance, in a scenario where the delivery rate increase in 2027 is 8 percent, adding the deferral account amortization would increase the 2027 delivery rate to close to 10 percent, which would result in the 2026 and 2027 delivery rate increases being relatively consistent. This compares to commencing amortization in 2026, where the resulting 2026 delivery rate increase would be 11.82 percent, followed by a potential 2027 delivery rate increase of 8 percent.

While FEI is ultimately proposing to commence amortization of the deferral account in 2027, FEI notes that this approach results in further delaying the recovery of the deferral account and thus has a greater potential for intergenerational inequity (i.e., the first deficiency extends back to 2023 and the deferral account balance will not be fully recovered until 2031). If not for the timing of the RSF Decision and therefore the timing of applying for permanent 2025 delivery rates, FEI would likely have proposed to commence amortizing the deferral account in 2025.

However, when considering such factors as the immediate rate impact to customers in 2026, rate smoothing, and that the delay in recovery is only one additional year, FEI recommends commencing amortization of the 2023-2025 Revenue Deficiency deferral account in 2027. Accordingly, FEI seeks approval of the following:

- Capture the revenue deficiency resulting from the difference between the 2025 interim and permanent revenue requirement in the existing 2023-2024 Revenue Deficiency deferral account;
- Rename the deferral account the 2023-2025 Revenue Deficiency deferral account; and
- Amortize the 2023-2025 Revenue Deficiency deferral account over five years, commencing January 1, 2027.

12.4.2.2 Flotation Costs Deferral Account

On June 9, 2025, the BCUC issued Order G-138-25 granting approval to FEI to establish a new non-rate base deferral account, titled the Flotation Costs deferral account, attracting interest at FEI's WACC, to record its actual flotation costs attributable to the equity injections by its parent company, Fortis Inc. FEI was further approved to capture the actual 2023 and 2024 flotation costs of $18.5 million (before-tax) in the Flotation Costs deferral account and was directed to propose an amortization period for the deferral account in the Annual Review for 2025-2026 Delivery Rates application.

In accordance with Order G-138-25, and as further discussed below, FEI proposes a 5-year amortization period for the Flotation Costs deferral account. FEI also provides the necessary supporting information to record and recover the actual incurred flotation costs attributable to the equity injections received thus far in 2025 from Fortis Inc.

12.4.2.2.1 ACTUAL 2025 EQUITY INJECTIONS AND THE ASSOCIATED FLOTATION COSTS

In the first quarter of 2025, FEI issued common equity shares in the amount of $225 million.[78] FEI accordingly seeks approval to record the associated actual flotation costs for this equity issuance, calculated based on Fortis Inc.'s actual incurred issuance costs, in the Flotation Costs deferral account.

FEI proposes to continue to compute its flotation costs based on Fortis Inc.'s Dividend Reinvestment Plan ("DRIP") discount of 2 percent after-tax (2.74 percent before-tax). FEI considers this approach reasonable because, similar to the equity injections completed in 2023 and 2024, Fortis Inc. relied on its DRIP program to fund FEI's equity injection in March 2025. Using the 2.74 percent DRIP discount, FEI calculates the actual 2025 flotation costs to be $6.165 million, as shown in the following table.

[78] As approved by Order G-56-25.

Table 12-2: 2025 Actual Equity Injection and Flotation Costs Calculation

FortisBC Energy Inc.	2025
Equity Injection	$ 225,000,000
Benchmark Flotation Cost Requested (before-tax)	2.74%
Total Amount for Recovery in Customer Rates (before-tax)	**$ 6,165,000**

FEI accordingly requests approval to record $6.165 million of actual flotations costs incurred for the 2025 equity issuance in the Flotation Costs deferral account. The after-tax costs will be captured in the Flotation Costs deferral account and will be amortized into rates based on the proposed amortization period discussed below.

12.4.2.2.2 PROPOSED AMORTIZATION PERIOD FOR THE FLOTATION COSTS DEFERRAL ACCOUNT

FEI seeks approval of a 5-year amortization period for the Flotation Costs deferral account, commencing January 1, 2026.

FEI evaluated amortization periods from 3 to 10 years but ultimately determined that 5 years is the most reasonable based on the nature of the costs recorded in the deferral account and customer rate impacts.

Nature of the Costs

Different types of costs have different benefit periods. For instance, the 10-year amortization period for DSM deferral accounts approved by the BCUC reflects the longer-term benefit of these costs. Flotation costs similarly have a longer benefit period.

In the GCOC Stage 1 proceeding, FortisBC's expert, Mr. Coyne of Concentric Energy Advisors, explained the long-term nature of flotation costs as follows:[79]

> Flotation costs are part of the invested costs of the utility, which are properly reflected on the balance sheet under "paid in capital." They are not current expenses, and, therefore, are not reflected on the income statement. Like investments in rate base or the issuance costs of long-term debt, flotation costs are incurred over time. As a result, the majority of a utility's flotation cost is incurred prior to the test year but remains part of the cost structure that exists during the test year and beyond.

As Mr. Coyne noted, debt issuance costs are passed on to customers over time through the effective interest method embedded in long-term debt instruments and amortized over the life of the debt. In other words, debt issuance costs are amortized based on their benefit period which is defined by their term. Similarly, an equity issuance cost amortization period should, in principle, align with its benefit period. However, unlike debt, equity has an indefinite life and does not mature. Therefore, it would not be possible to amortize issuance cost over the life of the equity.

[79] Exhibit B1-21, Rebuttal Testimony of James Coyne, p. 22.

Nevertheless, the long-term nature and benefit period of equity issuances and their associated costs warrant a longer amortization period, irrespective of other factors.

Another factor that supports a longer amortization period relates to the lumpy nature of equity issuances and their associated costs. As shown in the table below, the average size of equity issuances between 2023 to the first quarter of 2025 is more than 2.5 times greater than the average issuances between 2013 to 2025 period, which clearly indicates the lumpy nature of equity issuances and their associated flotation costs.

Table 12-3: FEI's Equity Issuances Since 2013

Fiscal Year	FEI's Equity Issuances ($million)
2013	0
2014	0
2015	85
2016	30
2017	0
2018	40
2019	140
2020	40
2021	100
2022	150
2023	400
2024	275
2025	225
Avg (2013-2025)	114
Avg (2023-2025)	300

Apart from the size of the equity issuance, the flotation cost itself can also be lumpy as the issuance costs for certain equity issuance methods such as bought deal offerings are considerably higher than others (such as the DRIP discounts). Amortizing the Flotation Cost deferral account balance over a longer period would therefore better spread the flotation costs amongst the current and future ratepayers that benefit from them.

Rate Impact Analysis

FEI considered amortization periods ranging from 3 to 10 years. As shown in the table below, a 3-year amortization has the largest rate impact (0.69 percent), a 5-year amortization period results in a 0.41 percent rate impact, and amortization periods of 8 to 10 years have similar, smaller rate impacts (either slightly above or below 0.25 percent).

Table 12-4: Delivery Rate Impact Analysis for Various Amortization Periods

	Amortization Period			
	3 Years	5 Years	8 Years	10 Years
Incremental Revenue in 2026 ($ millions)	8.474	5.084	3.178	2.542
Delivery Rate Impact in 2026, compared to 2025 (%)	0.69%	0.41%	0.26%	0.21%
Year 1 Delivery Rate Impact - RS 1 ($)	$ 5.67	$ 3.40	$ 2.13	$ 1.70

In 2026, for an average FEI residential customer consuming 90 GJ per year, the 3, 5, 8 and 10-year amortization periods would be equal to a total annual bill impact of approximately $5.67, $3.40, $2.13, and $1.70, respectively.

In conclusion, and given the above-mentioned considerations, FEI proposes a 5-year amortization period for the following reasons:

- A 3-year amortization period is too short to reflect the long-term and lumpy nature of the equity issuance costs and their benefit period, while 8- or 10-year amortization periods are unnecessarily long considering the size of the deferral account balance and the rate impact analysis.
- A 5-year amortization period sufficiently reflects the long-term nature of the issuance costs and their benefit period. The rate impact resulting from a 5-year amortization period (i.e., 0.41 percent) approximately equals to the average rate impacts of the four amortization scenarios discussed above and adequately smooths out any lumpiness in equity issuances and their associated costs.

FEI therefore considers that a 5-year amortization period appropriately reflects the nature of the costs and provides a reasonable balance between mitigating the immediate delivery rate impact and creating an overly long amortization period.

12.4.2.2.3 APPROVALS SOUGHT

FEI seeks approval of the following (as summarized in Section 1.2):

- Capture the actual after-tax costs of the 2025 equity issuance in the Flotation Costs deferral account; and
- Amortize the balance in the Flotation Costs deferral account over five years, commencing January 1, 2026.

12.4.2.3 RNG Account

As discussed below, FEI is seeking approval to modify the existing non-rate base RNG Account to attract WACC financing, effective January 1, 2025, in alignment with the treatment of similar types of costs and non-rate base deferral accounts.

12.4.2.3.1 BACKGROUND AND CURRENT TREATMENT OF THE RNG ACCOUNT

FEI currently records the value of its RNG inventory in the RNG Account, formerly referred to as the Biomethane Variance Account (BVA).

The RNG Account (at that time, the BVA), was established pursuant to Order G-194-10 as a rate base deferral account to capture the costs to procure and process consumable biomethane (RNG) as well as RNG Charge (formerly referred to as Biomethane Energy Recovery Charge (BERC)) revenues. In the FortisBC Energy Utilities (FEU) 2012-2013 Revenue Requirement

Application, FEI proposed to change the treatment of the RNG Account to a non-rate base deferral account. FEI requested this change for two reasons:

1. To enable FEI to stream the net of RNG related costs and revenues more easily to future RNG customers; and
2. To eliminate the potential to double-count the earnings on some costs which were already earning a rate base return.[80]

Since the inception of the RNG Program, the use of the RNG Account has changed to predominantly contain the costs of RNG acquired from third party producers, with only a small proportion of the costs now related to FEI's own infrastructure. The proportion of costs attributable to RNG acquired from third party producers has continued to grow as FEI has been able to contract for greater RNG supply volumes (pursuant to the GGRR) and as RNG production projects have started to come into service.

12.4.2.3.2 ADDRESSING THE BALANCE IN THE RNG ACCOUNT

On December 17, 2021, FEI filed its BERC Rate Assessment Report Stage 2 Comprehensive Review and Application for a Revised Renewable Gas Program, proposing three programs to provide RNG to customers. These included the Mandatory New Connections program, the Voluntary program, and the Blend program, whereby FEI would designate a percentage of all sales customers gaseous energy as RNG. The BCUC approved the Voluntary and Blend programs but denied the Mandatory New Connections program.[81]

As a result of the denial of the Mandatory New Connections program, one avenue for the use of RNG was eliminated, resulting in higher levels of inventory and greater levels of unrecovered costs remaining in the RNG Account at any given time. FEI must therefore manage its RNG inventory levels (and unrecovered costs) by delivering RNG to Voluntary customers (which currently has a small impact on inventory levels), delivering an increasing percentage of the RNG Blend to sales customers, and redirecting RNG, where appropriate, to alternative markets.

With regard to the Blend program, as of July 1, 2024, FEI commenced introducing the RNG Blend service to all sales customers, and the blend is currently set at 3 percent.[82] FEI is cognizant that increasing the Blend and associated rider causes customer bill impacts. For each 1 percent increase in the Blend percent there is an approximate 3 percent increase in a customer's bill. FEI therefore recognizes the need to balance the increase in the Blend percentage with other rate changes that affect customers.

[80] The rate base return already embedded in the RNG Account is the return on biomethane upgrading and interconnection assets that are included in FEI's rate base and are reclassed to the RNG Account.

[81] Decision and Order G-77-24.

[82] Approved by Order G-181-25.

12.4.2.3.3 REQUEST TO MODIFY THE ACCOUNTING TREATMENT OF THE RNG ACCOUNT

The RNG Account is now carrying a significant balance, primarily due to the build-up of RNG inventory, and FEI expects that this balance will continue to be significant in the upcoming years. This is demonstrated in Table 12-5 below, which sets out FEI's mid-year average actual and forecast balance in the RNG Account. In consideration of the balance that FEI is now carrying in the RNG Account and the treatment approved for other costs (and deferral accounts) of a similar nature, FEI seeks approval to commence earning WACC on the account effective January 1, 2025.

Table 12-5: Mid-Year Average Balance of RNG Account (Actual and Forecast)

Year	$000	Type
2015	1,320	Actual
2016	252	Actual
2017	(349)	Actual
2018	1,176	Actual
2019	959	Actual
2020	1,831	Actual
2021	5,484	Actual
2022	17,602	Actual
2023	31,168	Actual
2024	41,104	Actual
2025	36,922	Forecast
2026	29,314	Forecast

As discussed above, in the FEU 2012-2013 Revenue Requirement Application, FEI proposed that the RNG Account be treated as a non-rate base deferral account with no financing given the majority of the activity in the RNG Account, at that time, related to the cost of service, including the earned return on assets in FEI's rate base. Currently, the majority of the activity and balance in the RNG Account relates to transactions around the commodity itself (i.e., purchases, sales and the remaining inventory balance). FEI incurs actual financing costs to carry these transactions, irrespective of the source of those costs (own costs or cash paid to third party producers). They are dollars expended and earned in the current period, without recovery, thereby requiring financing. Consistent with other deferral accounts, including FEI's RNG Mitigation Revenue deferral account,[83] MCRA and CCRA, FEI should be allowed to earn WACC on the RNG Account. This is approach is consistent with the Fair Return Standard.

The increase in uncollected RNG costs is material enough to negatively impact FEI's overall return in a manner that is inconsistent with the Fair Return Standard. Comparable investment and capital attraction requirements of the Fair Return Standard require that the overall return is sufficient to enable the utility to compete for capital by offering a comparable risk adjusted return and for the utility to attract capital on reasonable terms and conditions. As previously recognized by the BCUC, deferral account financing impacts a utility's risk profile since the financing has a

[83] Approved by Order G-242-24.

direct impact on a utility's earnings. Currently, the balance in the RNG Account earns no return, which is clearly inconsistent with the Fair Return Standard. Therefore, as the amount of the uncollected RNG costs increase, FEI's risk increases commensurately, and the overall return will further deviate from the Fair Return Standard.

Accordingly, FEI seeks approval to modify the RNG Account to earn a WACC return. The RNG Account will continue to be a non-rate base deferral account, and there will be no impact to delivery rates as a result of this change. The WACC financing costs will accrue to the RNG Account and will be recovered from all sales service customers through the S&T RNG Blend rider.

12.4.2.4 Flow-Through Deferral Account

As approved by the RSF Decision, 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 C4-7 of the RSF Application, reproduced below.

Table 12-6: 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	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
Depreciation on CPCNs/Exogenous items	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
Revenues from CPCNs/Exogenous items	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/timing variances	Flow-through deferral	Flow-through deferral
Interest on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Interest on CPCNs/Exogenous items	Flow-through deferral	Flow-through deferral
Other interest variances	Subject to earnings sharing	Subject to earnings sharing
Income Tax:		
Income tax variances due to changes in tax rates/laws	Flow-through deferral	Flow-through deferral
Income tax on Clean Growth Projects [2,3]	Flow-through deferral	Flow-through deferral
Income tax on CPCNs/Exogenous items	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, renewable and low carbon gas initiatives (biomethane service and renewable gas development), variable LNG production, integrity digs, AMI project, EV charging stations, MRS triennial audits, and MRS assessment reports.

2: Cost of service for NGT fueling stations and tankers, variable LNG production, Methane Emission Mitigation, and EV DCFC 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.

Similar to the discussion in Section 10.1 on FEI's 2025 Projected earnings sharing amount, FEI is not projecting a Flow-through balance for 2025. This is because FEI has included actual amounts up until May 31, 2025 within its Projected 2025 revenue requirement throughout this Application and is not projecting any further variances for the remainder of the year from the amounts included in this Application. Therefore, there are no amounts to include within the 2025 Flow-through projection.

An adjustment to include the difference between the projected amount of zero and final actual amounts for 2025 subject to flow-through will be recorded in the deferral account in 2025 and amortized in 2027 rates.

In accordance with the method set out in the table above, the calculation of the 2024 Actual Flow-through amount (credit of $6.593 million) is shown in Table 12-7 below. To calculate the overall combined amount to be collected from customers (debit of $0.381 million), FEI has also included the following adjustments:

- The $7.672 million debit difference between the projected ending 2023 deferral account debit balance of $9.052 million[84] embedded in 2024 delivery rates, and the actual ending 2023 deferral account debit balance of $16.724 million. A more detailed breakout of the 2023 variance is provided in Table 12-8 below;
- The $0.709 million credit difference between the forecast 2024 financing addition of $0.274 million debit[85] embedded in 2024 delivery rates, and the actual 2024 financing addition of $0.435 million credit embedded in this Application; and
- 2025 forecast financing of a $0.011 million debit.[86]

[84] Annual Review for 2024 Delivery Rates, Compliance Filing, Appendix A, Schedule 12, Line 3, Column 2.
[85] Annual Review for 2024 Delivery Rates, Compliance Filing, Appendix A, Schedule 12, Line 3, Column 4.
[86] Section 11 - 2025, Schedule 12, Line 3, Column 4.

Table 12-7: 2024 Actual Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	2024 Approved	2024 Actual	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Delivery Margin**			
2	Residential (Rate 1)	$ (701.024)	$ (703.852)	$ (2.828)
3	Commercial (Rate 2, 3, 23)	(324.304)	(342.796)	(18.492)
4	Industrial (All Others)	(144.958)	(149.749)	(4.791)
5				
6	**Net O&M Expense**			
7	Pension & OPEB	2.555	2.555	-
8	Insurance	13.328	12.871	(0.457)
9	Biomethane	5.817	6.540	0.723
10	NGT	2.604	3.170	0.566
11	Variable LNG Production Costs	8.135	8.234	0.099
12	Integrity O&M	11.200	12.401	1.201
13	Renewable Gas Development	4.052	2.250	(1.802)
14	BCUC Levies	9.955	9.955	-
15	2021 Flooding Damage and Remediation	-	1.065	1.065
16	Biomethane O&M transferred to BVA	(5.817)	(6.540)	(0.723)
17	Capitalized Overhead	(59.233)	(59.233)	-
18				
19	**Depreciation and Amortization**			
20	Amortization of Deferrals	129.523	129.523	-
21	Depreciation variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	1.027	1.027
22	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	0.065	0.065
23				
24	**Total Property Taxes**	83.359	88.719	5.360
25				
26	**Other Revenues**			
27	SCP Third Party Revenue	(13.320)	(13.320)	-
28	NGT Tanker Rental Revenue	(1.021)	(0.869)	0.152
29	Biomethane Other Revenue	(0.762)	(1.957)	(1.195)
30	LNG Capacity Assignment	(18.039)	(18.039)	-
31	CNG & LNG Service Revenues	(3.276)	(2.792)	0.484
32				
33	**Interest Expense**			
34	Long-term debt interest expense variance	153.587	153.575	(0.012)
35	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	0.253	0.253
36	Short-term debt rate variance	-	2.708	2.708
37	Short-term debt volume variance from long-term debt issue variance	-	-	-
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	-	5.159	5.159
42	Income tax/CCA rate changes	-	-	-
43	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	-	4.844	4.844
44				
45	**2024 After-Tax Flow-Through Addition to Deferral Account (excluding Financing)**			**(6.593)**
46				
47	2023 Ending Deferral Account Balance True-up			7.672
48	2024 Financing True-up			(0.709)
49	2025 Financing Addition to Deferral Account			0.011
50				
51	**2025 After-Tax Amortization**			**0.381**

12.4.2.4.1 2024 ACTUAL FLOW-THROUGH VARIANCES

As shown in Table 12-7 above, the 2024 Actual flow-through variance is a credit of $6.593 million. The variances in each flow-through category are described below.

The variances in delivery margin are primarily due to favourable commercial margin as a result of an increase in large commercial customers switching from small commercial, along with a favourable industrial margin from higher firm demand, partially offset by lower LNG demand.

The flow-through components of O&M expense were $0.672 million higher than approved, with the main variance related to integrity O&M, which was $1.201 million higher than approved. The variance was mainly due to site-specific integrity dig scope factors (e.g., site access, site management during the dig, site restoration, pipeline outside diameter, and pipeline repairs). Please also refer to Section 6.3.3 of the Application.

Actual property tax expense was $5.360 million higher than approved mainly due to higher actual in-lieu taxes than forecast.

The flow-through components of Other Revenue were $0.559 million higher than approved, with the main variance related to Biomethane Other Revenues, which were $1.195 million higher than approved. The variance in Biomethane Other Revenues is explained in Section 5.

The variance between the actual (-7.73 percent) and approved (3.21 percent) short-term debt interest rates results in an amount to be recovered from customers of $2.708 million, shown on Line 36 of Table 12-7 above.

The unfavourable income tax variance of $4.844 million is calculated as 27 percent of the aforementioned variances.

The combined unfavourable variance of $6.504 million related to depreciation/CIAC amortization, interest and tax variances on Clean Growth/CPCN/exogenous capital amounts, shown on Lines 21, 22, 35 and 41, respectively, in Table 12-7 above, were derived for 2024 by comparing the actual 2024 cost of service impacts of Clean Growth Initiative assets and the IGU, Tilbury 1A Expansion, LMIPSU and CTS TIMC projects to the amounts forecast for those same projects.

12.4.2.4.2 2023 FLOW-THROUGH DEFERRAL ACCOUNT TRUE-UP

As mentioned above, FEI provides a breakout of the 2023 true-up amount of $7.672 million debit in Table 12-8 below, along with an explanation of the variances.

Table 12-8: 2023 Actual vs. Projected Flow-through Deferral Account Additions ($ millions)

Line No.	Particulars	2023 Projected	2023 Actual	After-Tax Flow-Through Variance
	(1)	(2)	(3)	(4)
1	**Delivery Margin**			
2	Residential (Rate 1)	$ (645.472)	$ (647.027)	$ (1.555)
3	Commercial (Rate 2, 3, 23)	(301.191)	(312.420)	(11.230)
4	Industrial (All Others)	(133.738)	(124.540)	9.198
5				
6	**Net O&M Expense**			
7	Pension & OPEB	9.577	9.577	-
8	Insurance	12.406	12.371	(0.035)
9	Biomethane	5.075	6.196	1.121
10	NGT	2.412	2.376	(0.036)
11	Variable LNG Production Costs	7.899	8.348	0.449
12	Integrity Digs	9.000	9.812	0.812
13	Renewable Gas Development	3.069	3.301	0.232
14	BCUC Levies	8.493	8.493	-
15	Biomethane O&M transferred to BVA	(5.075)	(6.196)	(1.121)
16	Capitalized Overhead	(56.744)	(56.744)	-
17				
18	**Depreciation and Amortization**			
19	Amortization of Deferrals	115.131	115.131	-
20	Depreciation variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.151)	(0.151)
21	CIAC Amortization variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.028)	(0.028)
22				
23	**Total Property Taxes**	81.293	80.552	(0.741)
24				
25	**Other Revenues**			
26	Tilbury insurance proceeds	(6.135)	(6.135)	-
27	Flood Claim Insurance Proceeds - Bill Credits	-	(0.174)	(0.174)
28	SCP Third Party Revenue	(13.286)	(13.286)	-
29	NGT Tanker Rental Revenue	(1.008)	(0.754)	0.254
30	Biomethane Other Revenue	(1.069)	(1.069)	-
31	LNG Capacity Assignment	(18.039)	(18.039)	-
32	CNG & LNG Service Revenues	(3.215)	(2.926)	0.289
33				
34	**Interest Expense**			
35	Long-term debt interest expense variance	153.500	153.517	0.017
36	Interest variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	(0.852)	(0.852)
37	Short-term debt rate variance	(1.512)	5.579	7.091
38	Short-term debt volume variance from long-term debt issue variance	3.290	(2.877)	(6.167)
39	Short-term debt timing variance from long-term debt issue timing	-	-	-
40				
41	**Income Tax Expense**			
42	Income tax variance on Clean Growth Projects/CPCNs/Exogenous Capital	-	10.441	10.441
43	Income tax/CCA rate changes	-	-	-
44	Income tax on taxable flowthrough variances above (excl. Clean Growth Projects/CPCNs/Exogenous Capital)	1.289	1.719	0.431
45				
46	**2023 After-Tax Flow-Through Addition to Deferral Account (excluding Financing)**			**8.245**
47				
48	2023 Financing True-up			(0.573)
49				
50	**2023 Ending Deferral Account Balance True-up**			**7.672**

The variances in delivery margin are primarily due to favourable commercial margin as a result of an increase in large commercial customers switching from small commercial, partially offset by an unfavourable industrial margin due to reduced LNG demand.

The flow-through components of O&M expense were $1.422 million higher than projected, with the main variance related to integrity O&M, which was $0.812 million higher than projected. The variance was mainly due to site-specific integrity dig scope factors (e.g., site access, site management during the dig, site restoration, pipeline outside diameter, and pipeline repairs).

Actual property tax expense was $0.741 million lower than projected due to differences in tax rates. The 2023 Projected amounts were calculated using actual 2023 assessment values but estimated 2023 tax rates.

The flow-through components of Other Revenue were $0.369 million lower than projected, with the main variance related to CNG & LNG Service Revenues, which were $0.289 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 (-5.75 percent) and projected (6.58 percent) short-term debt interest rates results in an amount to be recovered from customers of $7.091 million, shown on Line 37 of Table 12-8 above. The net variance of $6.167 million refundable to customers on Lines 38 and 39 of Table 12-8 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 multiplied by a negative short-term debt rate. Overall, the interest variances were mainly offset and resulted in a combined amount to be recovered from customers of $0.089 million.

The unfavourable income tax variance of $0.431 million is calculated as 27 percent of the aforementioned variances.

The combined unfavourable variance of $9.410 million related to depreciation/CIAC amortization, interest and tax variances on Clean Growth/CPCN/exogenous capital amounts, shown on Lines 20, 21, 36 and 42, respectively, in Table 12-8 above, were derived for 2023 by comparing the actual 2023 cost of service impacts of the Clean Growth Initiative assets and the IGU, Tilbury 1A Expansion, LMIPSU, Patullo Gas Replacement and CTS TIMC projects to the amounts forecast for those same projects.

12.5 *SUMMARY*

FEI has proposed an amortization period for the Flotation Costs deferral account, proposes changes to the RNG Account, and seeks approval to capture the revenue deficiency resulting from setting permanent 2025 delivery rates at the interim approved level in the existing 2023-2024 Revenue Deficiency deferral account and to commence amortization of the deferral account. FEI also provided information on the Flow-through deferral account.

13. SERVICE QUALITY INDICATORS

13.1 *INTRODUCTION AND OVERVIEW*

Under the RSF, SQIs are used to monitor the Company'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 RSF Decision and Order G-69-25, the BCUC approved a balanced set of SQIs for FEI, covering safety, responsiveness to customer needs, and reliability. The BCUC also approved the introduction of five energy transition informational indicators to the suite of SQIs. Eight of the SQIs have benchmarks and performance ranges set by a threshold level. Ten of the SQIs are for information only and as such do not have benchmarks or performance ranges.

In this section, FEI reports on its 2024 and June 2025 year-to-date (YTD) performance as measured against the SQI benchmarks and thresholds. For 2024, FEI reports on the SQI performance based on the suite of SQIs (and, where applicable, their respective benchmarks and thresholds) approved for the 2020-2024 MRP term. For 2025, FEI reports on the YTD SQI performance based on the suite of SQIs (and, where applicable, their respective benchmarks and thresholds) approved in the RSF Decision.

In 2024, for the nine SQIs with benchmarks, eight performed at or better than the approved benchmarks, with one SQI (Emergency Response Time) only slightly below the benchmark but well above the threshold. Regarding the informational indicators, the performance generally remains at a level consistent with prior years. In 2025 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 2020-2024 MRP term, FEI has provided 2024 and year-to-date 2025 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 2024 and June YTD performance for 2025 to the approved benchmarks and thresholds. As the 2024 SQI results are measured against the benchmarks and thresholds approved in the 2020-2024 MRP Decision, FEI provides the benchmarks and thresholds approved in both the 2020-2024 MRP Decision and the 2025-2027 RSF Decision in Table 13-1 below (where there have been changes). The Actual 2024 and June 2025 YTD results are also provided for the informational SQIs.

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

Performance Measure	Description	Benchmark	Threshold	2024 Results	2025 June YTD Results
Safety SQIs					
Emergency Response Time	Percent of calls responded to within one hour	>= 97.7%	96.2%	97.5%	96.9%
Telephone Service Factor (Emergency)	Percent of emergency calls answered within 30 seconds or less	>= 95%	92.8%	97.4%	97.8%
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	1.41	N/A
		<= 1.64	2.21	N/A	1.43
Public Contacts with Gas Lines	Current year average of number of line damages per 1,000 BC One calls received	<= 8	12	5	N/A
		<= 6	10	N/A	4
Responsiveness to the Customer Needs SQIs					
First Contact Resolution	Percent of customers who achieved call resolution in one call	>= 78%	74%	80%	75%
Billing Index	Measure of customer bills produced meeting performance criteria	<= 3.0	5.0	2.43	2.27
Meter Reading Completion	Informational indicator – number of scheduled meters that were read	>= 95%	92%	95%	N/A
		-	-	N/A	96%
Telephone Service Factor (Non-Emergency)	Percent of non-emergency calls answered within 30 seconds or less	>= 70%	68%	70%	63%
Meter Exchange Appointment	Percent of appointments met for meter exchanges	>= 95%	93.8%	97.5%	97.9%
Customer Satisfaction Index	Informational indicator - measures overall customer satisfaction	-	-	8.6	8.6
Average Speed of Answer	Informational indicator – amount of time it takes to answer a call (seconds)	-	-	50	77
Reliability SQIs					
Transmission Reportable Incidents	Informational indicator – number of reportable incidents to outside agencies	-	-	0	0
Leaks per KM of Distribution System Mains	Informational indicator - measures the number of leaks on the distribution system per KM of distribution system mains	-	-	0.0040	0.0022

Performance Measure	Description	Benchmark	Threshold	2024 Results	2025 June YTD Results
Energy Transition SQIs					
Scope 1 Emissions	Informational indicator – total direct GHG emissions from FEI owned or controlled sources ($MtCO_2e$)	-	-	0.16	Not available
Scope 3 Emissions	Informational indicator – total annual BC emissions resulting from customers' combustion gas delivered by FEI sources ($MtCO_2e$)	-	-	10.9	6.1
Renewable and Lower Carbon Energy Supply Volume	Informational indicator – acquired annual Renewable Gas and Lower Carbon Energy supply (TJ)	-	-	2,776	1,871
	Informational indicator – Renewable and Lower Carbon Energy supply as % of total gas consumed by customers			1.26%	1.52%
Natural Gas for Transportation Volume	Informational indicator – total gas consumed by CNG and LNG customers (TJ)	-	-	3,716	2,810
Demand Side Management Energy Savings	Informational indicator – measure of lifetime gas savings from conservation and energy management programs (TJ)	-	-	14,159	Not available

In the following sections, FEI reviews each SQI's year-to-date performance in 2024 and 2025. 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 2024 result was 97.5 percent, which is slightly below the benchmark but well above the threshold. The 2024 performance was consistent with the performance in 2023. The June 2025 YTD performance is 96.9 percent, which is below the benchmark but above the threshold.

For comparison, the Company's annual results under the 2020 to 2024 MRP and June 2025 year to date performance are provided below.

Table 13-2: Historical Emergency Response Time

Description	2020	2021	2022	2023	2024	June 2025 YTD
Results	97.7%	97.7%	97.7%	97.5%	97.5%	96.9%
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 2024 result was 97.4 percent which was better than the benchmark of 95 percent. The June 2025 YTD performance is 97.8 percent which is also better than the benchmark.

For comparison, the Company's annual results under the 2020 to 2024 MRP and June 2025 year to date performance are provided below.

Table 13-3: Historical TSF (Emergency) Results

Description	2020	2021	2022	2023	2024	June 2025 YTD
Results	96.9%	96.9%	97.1%	97.8%	97.4%	97.8%
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 2024 (three-year rolling average) result was 1.41 which was better than the benchmark. The 2024 annual AIFR was 1.51 which reflected 7 Medical Treatments and 20 Lost Time Injuries.

The June 2025 YTD performance (three-year rolling average) result is 1.43 which is better than the benchmark. The June 2025 YTD performance (annual) is 1.39 and reflects 6 Medical Treatments and 7 Lost Time Injuries.

Strengthening the safety culture continues to be a key driver for FEI, building on the commitment to learn from safety events, proactively 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.

FEI continues to seek opportunities to improve the AIFR through its ongoing commitment to proactive hazard mitigation, particularly in regard to manual labour tasks, safe handling procedures, and slip/trip/fall prevention. FEI has adopted multiple mitigation measures, including enhanced 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 programs/assessments, injury prevention strategies, and a range of technology solutions.

For comparison, the Company's annual results under the 2020 to 2024 MRP and June 2025 year to date performance are provided below.

Table 13-4: Historical All Injury Frequency Rate Results

Description	2020	2021	2022	2023	2024	June 2025 YTD
Annual Results	1.43	1.99	1.36	1.35	1.51	1.39
Three year rolling average	1.66	1.75	1.59	1.58	1.41	1.43
Benchmark	2.08					1.64
Threshold	2.95					2.21

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.

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 2024 result was 5, which is better than the benchmark. The June 2025 YTD 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 1 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.

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. The 2025 YTD volume of BC One Call tickets (86,461) is reasonably consistent with the most recent three years (i.e., 84,880 for 2024 YTD, 83,923 for 2023 YTD, and 82,699 for 2022 YTD). The hits per 1,000 ticket metric continues to trend in the right direction, indicating the effectiveness of the additional steps FEI is taking to address line damages.

For comparison, the Company's annual results under the 2020 to 2024 MRP and June 2025 year to date performance are provided below.

Table 13-5: Historical Public Contact with Gas Lines Results

<table>
<tr><th>Description</th><th>2020</th><th>2021</th><th>2022</th><th>2023</th><th>2024</th><th>June 2025 YTD</th></tr>
<tr><td>Annual Results</td><td>7</td><td>6</td><td>6</td><td>5</td><td>5</td><td>4</td></tr>
<tr><td>Benchmark</td><td colspan="5">8</td><td>6</td></tr>
<tr><td>Threshold</td><td colspan="5">12</td><td>10</td></tr>
<tr><td>BC One Call Ticket Volume</td><td>141,262</td><td>163,584</td><td>157,174</td><td>158,478</td><td>169,425</td><td>86,461</td></tr>
<tr><td>Line Damages</td><td>973</td><td>1,034</td><td>896</td><td>844</td><td>779</td><td>338</td></tr>
</table>

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 2024 result was 80 percent which is better than the benchmark. The June 2025 YTD performance is 75 percent, which is below the benchmark but above the threshold. The 2025 YTD was largely impacted early in 2025 by the Canada Post job action and high bill inquiries creating challenging and unprecedented volumes in the first quarter. As a result of the job action, customers were calling the contact centre multiple times to get account balances, confirm account balances due to invoices being delivered out of sequence, to seek clarity on payment amounts and methods, and request assistance with signing up for paperless billing.

FEI supports customers in a variety of ways, including flexible payment options, energy efficiency tips, rebates and programs, and providing customers the necessary agency resources that may be available to them. FEI expects to remain above the threshold and move closer to the benchmark by the end of 2025. FEI continues to maintain a high Customer Satisfaction Index as noted below.

For comparison, the Company's annual results under the 2020 to 2024 MRP and June 2025 year to date performance are provided below.

Table 13-6: Historical First Contact Resolution Levels

Description	2020	2021	2022	2023	2024	June 2025 YTD
Annual Results	81%	79%	78%	77%	80%	75%
Benchmark	78%					
Threshold	74%					

13.2.2.2 Billing Index

The Billing Index indicator tracks the effectiveness of the Company's billing system by measuring the percentage of customer bills produced meeting performance criteria. The Billing Index is a composite index with three components:

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

- Billing timeliness (percent of invoices delivered to Canada Post within two days of file creation); and
- Billing accuracy (percent of bills without a production issue based on input data).

The objective is to achieve a score of three 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 2024 result was 2.43 which was better than the benchmark of 3.0. The June 2025 YTD result is 2.27 which is also better than the benchmark. No significant issues have arisen in 2024 and 2025.

The 2024 Billing Index sub-measures calculation is as follows.

Table 13-7: Calculation of 2024 Billing Index

Billing sub-measure	Percent Achieved (PA)	Formula		Result
Billing Accuracy (Percent of bills without a Production Issue, based on input data); Target - 99.9%	99.51%	If (PA≥99.9%,5000*(1 - PA),100*(1.05-PA))	=100*(1.05-99.51%)	5.49
Billing Timeliness (Percent of invoices delivered to Canada Post within 2 days of file creation); Target - 95%	100%	(100%-PA)*100	=(100%-100%)*100	0.00
Billing Completion (Percent of accounts billed within 2 days of the billing due date); Target - 95%	98.2	(100%-PA)*100	=(100%-98.2%)*100	1.80
Billing Service Quality Indicator; Target < 3		(Accuracy PA+Timeliness PA+Completion PA)/3	=(5.49+0.00+1.80) / 3	2.43

For comparison, the Company's annual results under the 2020 to 2024 MRP and June 2025 year to date performance are provided below.

Table 13-8: Historical Billing Index Results

Description	2020	2021	2022	2023	2024	June 2025 YTD
Annual Results	0.62	0.94	1.02	1.38	2.43	2.27
Benchmark	3.0					
Threshold	5.0					

13.2.2.3 Meter Reading Completion

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.

In the RSF Decision[87], the BCUC approved FEI's proposal to rename this SQI from "Meter Reading Accuracy" to "Meter Reading Completion", and the BCUC approved FEI's request to change this metric to an informational indicator. As such, commencing in 2025, the Meter Reading Completion indicator will no longer be reported against a benchmark and threshold.

The 2024 result was 95 percent, which met the benchmark established for the 2020-2024 MRP term. The June 2025 YTD performance is 96 percent.

For comparison, the Company's annual results under the 2020 to 2024 MRP and June 2025 year to date performance are provided below.

Table 13-9: Historical Meter Reading Completion Results

Description	2020	2021	2022	2023	2024	June 2025 YTD
Annual Results	89%	88%	88%	95%	95%	96%
Benchmark	95%					N/A
Threshold	92%					N/A

[87] Decision and Order G-69-25, p. 60.

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 within 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 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 2024 result was 70 percent which meets the benchmark. The June 2025 YTD performance is 63 percent which is below the threshold.

The June 2025 YTD TSF (Non-Emergency) was largely impacted early in 2025 by the Canada Post job action and high bill inquiries creating challenging and unprecedented volumes in the first quarter. The job action resulted in increased call volumes in January as customers were calling the contact centre to get account balances, confirm account balances due to invoices being delivered out of sequence, seek clarity on payment amounts and methods, and request assistance with signing up for paperless billing. FEI supported customers in a variety of ways during the job action, including making changes to the Interactive Voice Response (IVR) and website to ensure that self-serve options were easily accessible to customers, such as the ability to retrieve account balances and sign up for paperless billing. Due to the unexpected large volume experienced in the first quarter of 2025, the year-to-date performance as of the end of June remains below threshold; however, FEI expects to meet the annual performance threshold if current performance levels continue as expected.

For comparison, the Company's annual results under the 2020 to 2024 MRP and June 2025 year to date performance are provided below.

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

Description	2020	2021	2022	2023	2024	June 2025 YTD
Annual Results	70%	70%	62%	71%	70%	63%
Benchmark	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 to better meet the needs of customers and match resources to appointments while maintaining emergency response capabilities.

The 2024 result was 97.5 percent which was better than the benchmark. The June 2025 YTD performance is 97.9 percent, which is also better than the benchmark.

For comparison, the Company's annual results under the 2020 to 2024 MRP and June 2025 year to date performance are provided below.

Table 13-11: Historical Meter Exchange Appointment Results

Description	2020	2021	2022	2023	2024	June 2025 YTD
Annual Results	98.1%	98.3%	98.5%	99.1%	97.5%	97.9%
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 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 2024 was 8.6, which was slightly higher than the 8.5 score received in 2023. The score for June 2025 YTD is 8.6. Of the five measures that make up the overall customer satisfaction score, the results for 2024 were static in two areas and higher in three areas compared to the annual 2023 scores. The score for Energy Conservation Information increased from 7.5 to 7.6, the score for the Contact Centre increased from 8.5 to 8.7, and the score for Field Services increased from 9.1 to 9.2. The scores for Overall Satisfaction and Accuracy of Meter Reading remained static at 8.5 and 8.3, respectively.

For comparison, the Company's annual results under the 2020 to 2024 MRP and June 2025 year to date performance are provided below.

Table 13-12: Historical Customer Satisfaction Results

Description	2020	2021	2022	2023	2024	June 2025 YTD
Annual Results	8.7	8.7	8.6	8.5	8.6	8.6
Benchmark	N/A					
Threshold	N/A					

13.2.2.7 Average Speed of Answer

The Average Speed of Answer (ASA) is an informational indicator that measures the amount of time it takes for a customer service representative to answer a customer's call (seconds).

The 2024 result was 50 seconds, which was better than each of the previous year's results during the 2020-2024 MRP term. The June 2025 YTD performance is 77 seconds. The challenges in the contact centre due to the Canada Post job action, as described above, had a negative impact on the ASA in the early months of 2025. Consistent with the TSF (Non-Emergency) returning to threshold levels, the monthly ASA also returned to levels of under one minute starting in March. FEI expects this metric to continue to improve throughout the remainder of the year.

For comparison, the Company's annual results under the 2020 to 2024 MRP and June 2025 year to date performance are provided below.

Table 13-13: Average Speed of Answer

Description	2020	2021	2022	2023	2024	June 2025 YTD
Annual Results	72	65	106	65	50	77
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.

As of October 1, 2014, the Company reports Transmission Reportable Incidents based on the new BCER reporting criteria, including Level 1 (moderate), Level 2 (major), and Level 3 (serious) reportable incidents for both transmission and intermediate pressure assets that operate at a pressure exceeding 100 psi. This includes pipelines, mains, services, stations, LNG plants and compressor stations, but excludes distribution assets that operate below 100 psi.

There were no reportable incidents in 2024 and there have been no reportable incidents thus far in 2025 (June 2025 YTD).

For comparison, the Company's annual results under the 2020 to 2024 MRP and June 2025 year to date results are provided below.

Table 13-14: Historical Transmission Reportable Incidents

Description	2020	2021	2022	2023	2024	June 2025 YTD
Annual Results – Level 1	1	0	0	0	0	0
Annual Results – Level 2	0	0	3	0	0	0
Annual Results – Level 3	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 for 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 2025 YTD five-year rolling average result of 0.0046 calculated using data from January 2021 to June 2025.

Table 13-15: May 2025 Year-to-Date Five-Year Rolling Average

Period	Metric
January – December 2021	0.0055
January – December 2022	0.0058
January – December 2023	0.0055
January – December 2024	0.0040
January – June 2025	0.0022
Five Year Rolling Average	0.0046

The Company's annual results under the 2020 to 2024 MRP and June 2025 year to date 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 2025 five-year average is calculated using 2021 to 2025 annual data). The June 2025 YTD result is 0.0022 and is based on 53 leaks detected year-to-date, which is consistent with the 2024 year-to-date leaks detected (50) and lower than the 2023 year-to-date leaks detected (82) for the similar 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	2020	2021	2022	2023	2024	June 2025 YTD
Leaks	152	131	138	131	98	53
Total km	23,460	23,707	23,734	23,913	24,045	24,171
Leaks per km	0.0065	0.0055	0.0058	0.0055	0.0041	0.0022
5 year rolling average	0.0056	0.0058	0.0060	0.0059	0.0055	0.0046

13.2.4 Energy Transition Informational Indicators

In accordance with the RSF Decision[88], FEI is reporting on five new informational indicators related to the energy transition during the term of the RSF. These informational indicators, and their definitions, are as follows:

[88] RSF Decision and Order G-169-25, pp. 65-66.

- **Scope 1 Emissions:** Total direct GHG emissions from FEI owned or controlled sources (MtCO2e).
- **Scope 3 Emissions:** Total annual BC emissions resulting from customers' combustion gas delivered by FEI sources (MtCO2e).
- **Renewable and Lower Carbon Energy Supply:** Acquired annual renewable and lower carbon energy supply (TJ) and the percentage of renewable and lower carbon energy supply in FEI's total gas supply mix, as well as the mix of renewable and lower carbon gas sources.
- **Natural Gas for Transportation Volume:** Total gas consumed by CNG and LNG customers (TJ).
- **Demand Side Management Energy Savings:** Measure lifetime gas savings from conservation and energy management programs (TJ).

FEI provides further discussion and the annual results of each indicator in the subsections below.

13.2.4.1 Scope 1 Emissions

Scope 1 emissions, as defined under the Greenhouse Gas Protocol Corporate Accounting and Reporting Standards, are direct emissions from owned or controlled sources. This includes externally verified Scope 1 GHG emissions as reported to the BC Ministry of Environment for FEI and its LNG operations.

FEI reports on direct GHG emissions (Scope 1) from its gas operations, third-party gas line damage incidents, RNG processing facilities, FEI fleet vehicles, and gas for comfort heating for FEI facilities. Annual variations are linked to the overall gas delivered to customers due to variations in weather and other factors, including planned and unplanned methane releases.

In 2024, FEI's direct emissions were 0.16 $MtCO_2e$, which included an unplanned release of gas from a compressor station. This release did not pose a public safety risk, and the BCER was notified of this event.

For comparison, the Company's annual results from 2020 through 2024 are provided below.

Table 13-17: Historical Scope 1 Emissions

Description	2020	2021	2022	2023	2024	June 2025 YTD
Scope 1 Emissions ($MtCO_2e$)	0.14	0.15	0.24	0.15	0.16	Not available

13.2.4.2 Scope 3 Emissions

In this section, FEI provides the Category 11 Scope 3 emissions, which are the total annual BC GHG emissions resulting from customers' combustion of gas delivered by FEI sources. These are a category of emissions that FEI does not directly control but are related to the energy the Company delivers to customers.

In 2024, the total annual Category 11 Scope 3 emissions were 10.9 MtCO2e.

For comparison, the Company's annual results from 2020 through 2024 and June 2025 year-to-date results are provided below.

Table 13-18: Historical Scope 3 Emissions

Description	2020	2021	2022	2023	2024	June 2025 YTD
Scope 3 Emissions ($MtCO_2e$)	11.0	11.5	11.6	10.6	10.9	6.1

13.2.4.3 Renewable and Lower Carbon Energy Supply

The Renewable and Lower Carbon Energy Supply indicator tracks the total volume of renewable and lower carbon energy supply acquired in the calendar year in terajoules (TJ).

In the RSF Decision, the BCUC also directed FEI to include specific reporting on the mix of renewable and lower carbon gas sources, as well as the percentage of these sources in its total gas supply.[89]

In 2024, FEI acquired 2,776 TJ of renewable and lower carbon energy, which is 1.26 percent of FEI's total gas consumed by customers in 2024. The 2,776 TJ was comprised entirely of renewable natural gas.

For comparison, the Company's annual results from 2020 through 2024 and June 2025 year-to-date results are provided below.

[89] RSF Decision and Order G-169-25, p. 65.

Table 13-19: Historical Renewable and Lower Carbon Energy Supply

Description	2020	2021	2022	2023	2024	June 2025 YTD
Renewable and Lower Carbon Energy Supply Volume (TJ)	252	715	2,295	2,778	2,776	1,871
Total Volume of Gas Consumed by Customers (PJ)	219	228	231	213	220	123
Renewable and Lower Carbon Energy Supply as Percentage of Total Gas Consumed by Customers (%)	0.12	0.31	0.99	1.31	1.26	1.52

13.2.4.4 Natural Gas for Transportation Volumes

FEI is advancing lower- and zero-carbon transportation, including CNG and LNG as replacement fuel for heavy-carbon transport fuels. For this informational indicator, FEI has combined the CNG and LNG volume delivered to the transportation and marine sector into one overall supply metric. This includes the CNG delivered to CNG stations, LNG stations and the LNG used in marine bunkering.

In 2024, FEI delivered 3,716 TJ of Natural Gas for Transportation volume.

For comparison, the Company's annual results from 2020 through 2024 and June 2025 year-to-date results are provided below.

Table 13-20: Natural Gas for Transportation Volumes

Description	2020	2021	2022	2023	2024	June 2025 YTD
Total Gas Consumed by CNG and LNG Customers (TJ)	2,413	2,652	3,077	3,117	3,716	2,810

13.2.4.5 Demand Side Management Energy Savings

The Demand Side Management Energy Savings informational indicator measures the lifetime gas savings from FEI's conservation and energy management (C&EM) programs. These savings are the total reductions that occur over the life of all measures implemented (based on the Net Present Value of gas savings). Lifetime in this context refers to the entire stream of savings from measures supported in each of the years listed and annualizing that to present time to show the total value of the stream of savings. This view of the energy savings most accurately reflects the overall eventual impact of the savings incurred as a result of the measures incented by FEI's DSM programming.

In 2024, the total measure of lifetime gas savings from FEI's C&EM programs was 14,159 TJ.

For comparison, the Company's annual results from 2020 through 2024 are provided below.

Table 13-21: Demand Side Management Energy Savings

Description	2020	2021	2022	2023	2024	June 2025 YTD
Lifetime gas savings from conservation and energy management programs (TJ)	7,937	12,304	10,811	10,104	14,159	Not Available

13.3 SUMMARY

In summary, FEI's 2024 results and June 2025 year-to-date SQI performance indicate that the Company's overall performance is representative of a high level of service quality. In 2024, for the nine SQIs with benchmarks, eight performed at or better than the approved benchmarks, with one SQI (Emergency Response Time) only slightly below the benchmark but well above the threshold. Regarding the informational indicators, the performance generally remains at a level consistent with prior years.

Appendix A

DEMAND FORECAST SUPPLEMENTARY INFORMATION

Appendix A-1

STATISTICS CANADA AND CONFERENCE BOARD OF CANADA REPORTS

Table A1-1: Consumer Price Index (CPI)

Reference period	
	2002=100
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
July 2023	152.1
August 2023	152.6
September 2023	152.7
October 2023	152.6
November 2023	152.8
December 2023	152.1
January 2024	152.6
February 2024	153.0
March 2024	153.8
April 2024	154.7
May 2024	155.4
June 2024	155.5
July 2024	156.4
August 2024	156.2
September 2024	155.8
October 2024	156.2

Table A1-1: Consumer Price Index (CPI) (Continued)

November 2024	156.3
December 2024	156.1
January 2025	156.0
February 2025	157.6
March 2025	157.8
April 2025	157.8
May 2025	159.0
June 2025	158.8

Table A1-2: Average Weekly Earnings (AWE)

Reference period	Dollars
July 2022	1,156.22 B
August 2022	1,168.36 B
September 2022	1,168.27 B
October 2022	1,173.63 B
November 2022	1,177.91 B
December 2022	1,159.28 B
January 2023	1,181.92 B
February 2023	1,176.30 B
March 2023	1,192.57 B
April 2023	1,204.70 B
May 2023	1,209.06 B
June 2023	1,207.69 B
July 2023	1,221.78 B
August 2023	1,222.39 B
September 2023	1,234.00 B
October 2023	1,232.42 B
November 2023	1,235.47 B
December 2023	1,239.48 B
January 2024	1,248.60 B
February 2024	1,253.16 B
March 2024	1,256.76 B
April 2024	1,256.94 B
May 2024	1,266.79 B
June 2024	1,271.37 B
July 2024	1,279.27 B
August 2024	1,283.58 B
September 2024	1,286.76 B
October 2024	1,288.42 B
November 2024	1,292.63 B

Table A1-2: Average Weekly Earnings (AWE) (Continued)

December 2024	1,290.29 B
January 2025	1,302.22 B
February 2025	1,300.75 B
March 2025	1,304.48 B
April 2025	1,310.45 B

Table A1-3: Provincial Outlook Long-Term Economic Forecast 2025 and 2026

BRITISH COLUMBIA	2023	2024	2025	2026
Housing Starts Units, Singles, British Columbia (Thousands ('000s))	6,965	5,577	5,503	5,492
Percent Change		**-19.9%**	**-1.3%**	**-0.2%**
Housing Starts Units, Multiples, British Columbia (Thousands ('000s))	43,525	39,019	37,131	37,198
Percent Change		**-10.4%**	**-4.8%**	**0.2%**
Total (Thousands ('000s))	50,490	44,597	42,634	42,690

Source: e-Data
Conference Board of Canada
Table 156: Housing Starts, SINGLE
Table 157: Housing Starts, MULTIPLE
February 3, 2025
Provincial Medium Term
Forecast: 25 Run: 2025

Appendix A-2

HISTORICAL FORECAST AND CONSOLIDATED TABLES

Appendix A-2

Historical Forecast and Consolidated Tables

Table of Contents

List of Appendices

1. INTRODUCTION

This appendix presents two data sets as follows:

1. Historical and Forecast Data
    a. 2015 – 2024 Actual data
    b. 2025 Projected data
    c. 2026 Forecast data
2. Percent Error
    a. 2015 - 2024 Forecast, Actual and percent error

2. HISTORICAL AND FORECAST DATA TABLES

Table A2-1: FEI Customer Counts, Customer Additions, Use per Customer, and Energy[1]

FEI Customer Counts

Rate	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025-P	2026-F
RS 1	886,169	897,528	910,885	930,142	940,751	953,746	963,987	974,334	985,844	996,178	1,006,183	1,016,189
RS 2	85,076	86,074	86,973	88,244	88,686	89,363	89,683	89,976	90,185	92,708	93,380	94,051
RS 3	5,301	5,189	5,441	6,028	6,973	6,805	7,013	7,224	8,849	7,941	8,310	8,677
RS 23	1,724	1,803	1,712	1,648	871	746	697	620	453	376	394	412
Industrial	976	955	976	989	1,020	1,023	1,026	1,050	1,067	1,069	1,065	1,065
NGT	31	42	56	41	53	69	74	98	101	101	101	101
Total	979,277	991,591	1,006,043	1,027,092	1,038,354	1,051,752	1,062,480	1,073,302	1,086,499	1,098,373	1,109,432	1,120,495

FEI Customer Additions

Rate	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025-P	2026-F
RS 1	12508	11359	13357	19257	10609	12995	10241	10347	9674	10334	10005	10006
RS 2	1450	998	899	1271	442	677	320	293	(236)	2523	672	672
RS 3	132	(112)	252	587	945	(168)	208	211	1609	(908)	369	367
RS 23	202	79	(91)	(64)	(777)	(125)	(49)	(77)	(167)	(77)	18	18
Industrial	(1)	(21)	21	13	31	3	3	24	17	2	(4)	0
NGT	13	11	14	(15)	12	16	5	24	3	0	0	0
Total	14305	12314	14452	21049	11262	13398	10728	10728	10900	11874	11059	11063

FEI Normalized Use Per Customer (GJ)

Rate	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025-P	2026-F
RS 1	84.4	87.5	85.8	85.1	82.4	86.2	85.7	83.0	81.8	80.4	80.4	80.5
RS 2	332.6	339.1	336.8	332.5	318.1	322.2	328.1	334.9	326.5	313.5	317.3	315.0
RS 3	3,587.2	3,720.9	3,692.5	3,549.8	3,516.7	3,660.3	3,702.5	3,737.6	3,513.9	3,558.1	3,662.8	3,595.8
RS 23	5,173.7	5,279.0	5,360.5	5,344.9	5,051.3	5,440.7	5,724.3	5,818.1	5,764.4	6,236.1	5,946.1	6,202.8

FEI Energy (PJ)[(1)]

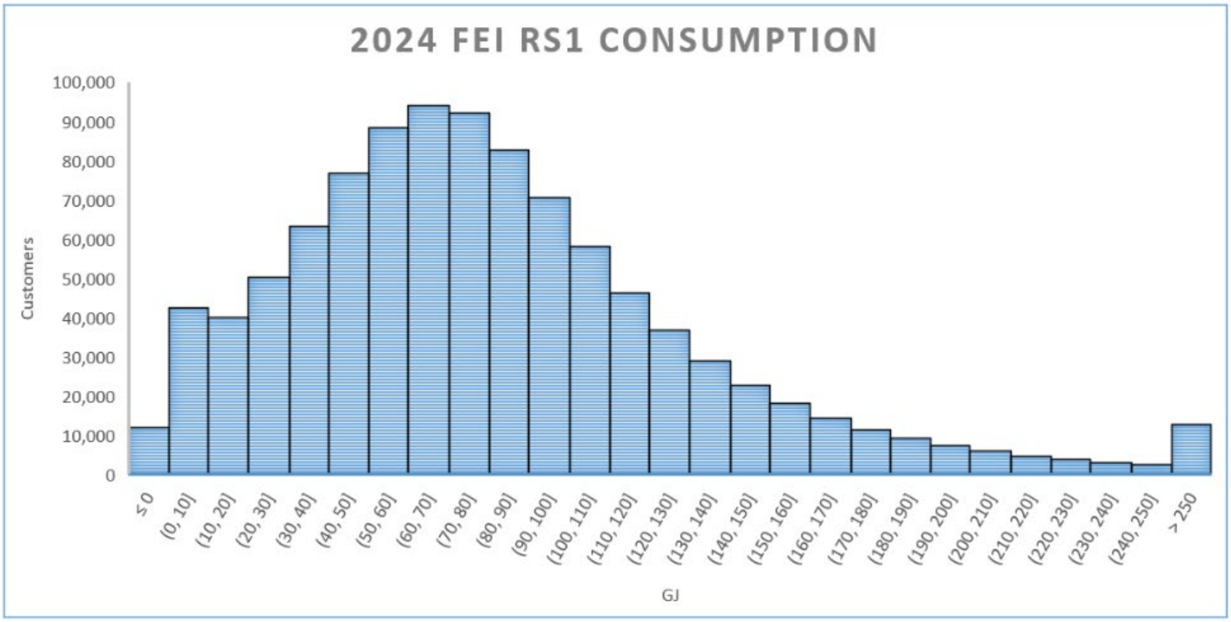
Rate	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025-P	2026-F
RS 1	74.1	77.9	77.5	78.3	77.0	81.6	82.2	80.4	80.3	79.8	80.5	81.4
RS 2	28.0	29.0	29.1	29.1	28.1	28.7	29.3	30.0	29.3	28.7	29.4	29.4
RS 3	19.2	19.4	19.7	20.9	22.5	24.6	25.7	26.7	29.2	29.6	29.6	30.7
RS 23	8.6	9.3	9.5	9.0	7.3	4.6	4.2	3.9	3.4	2.7	2.3	2.5
Industrial	79.6	83.7	87.4	88.4	91.5	89.5	90.8	77.6	72.5	75.6	72.9	73.1
NGT	1.1	1.3	1.8	1.6	2.6	2.6	3.0	3.2	3.3	3.9	5.3	5.2
Total	210.6	220.6	225.0	227.3	229.0	231.7	235.2	221.8	218.0	220.3	220.0	222.2

Table A2-2: FEI 2026F Industrial Forecast Demand by Region[2]

Region Group	2026 Forecast Demand by Region (PJ)
Mainland	66.1
Vancouver Island	6.9
Whistler	0.1
Total Industrial Demand	**73.1**

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 2025



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.

3.1 *AMALGAMATED NET CUSTOMERS*

FEI Customers	2015	2016	2017	2018	2019	2020	2021	2022	2023*	2024*
Rate Schedule 1										
Forecast	883,371	892,830	909,727	916,365	934,804	950,330	958,899	974,625	981,299	994,950
Actual	886,169	897,528	910,885	930,142	940,751	953,746	963,987	974,334	985,844	996,178
Error = (ACT-FCST)	2,798	4,698	1,158	13,777	5,947	3,416	5,088	(291)	4,545	1,228
Percent Error = (Error/ACT)	0.3%	0.5%	0.1%	1.5%	0.6%	0.4%	0.5%	0.0%	0.5%	0.1%

FEI Customers	2015	2016	2017	2018	2019	2020	2021	2022	2023*	2024*
Rate Schedule 2										
Forecast	84,651	85,667	87,712	88,494	89,203	89,558	90,430	90,956	91,112	91,271
Actual	85,076	86,074	86,973	88,244	88,686	89,363	89,683	89,976	90,185	92,708
Error = (ACT-FCST)	425	407	(739)	(250)	(517)	(195)	(747)	(980)	(927)	1,437
Percent Error = (Error/ACT)	0.5%	0.5%	-0.8%	-0.3%	-0.6%	-0.2%	-0.8%	-1.1%	-1.0%	1.6%

FEI Customers	2015	2016	2017	2018	2019	2020	2021	2022	2023*	2024*
Rate Schedule 3										
Forecast	5,117	5,035	5,354	5,223	5,623	7,221	7,469	7,034	7,055	7,237
Actual	5,301	5,189	5,441	6,028	6,973	6,805	7,013	7,224	8,849	7,941
Error = (ACT-FCST)	184	154	87	805	1,350	(416)	(456)	190	1,794	704
Percent Error = (Error/ACT)	3.5%	3.0%	1.6%	13.4%	19.4%	-6.1%	-6.5%	2.6%	20.3%	8.9%

FEI Customers	2015	2016	2017	2018	2019	2020	2021	2022	2023*	2024*
Rate Schedule 23										
Forecast	1,552	1,670	1,760	1,934	1,744	906	941	782	703	624
Actual	1,724	1,803	1,712	1,648	871	746	697	620	453	376
Error = (ACT-FCST)	172	133	(48)	(286)	(873)	(160)	(244)	(162)	(250)	(248)
Percent Error = (Error/ACT)	10.0%	7.4%	-2.8%	-17.4%	-100.2%	-21.4%	-35.0%	-26.1%	-55.2%	-66.1%

FEI Customers	2015	2016	2017	2018	2019	2020	2021	2022	2023*	2024*
Large Commercial										
Forecast	6,669	6,705	7,114	7,157	7,367	8,127	8,410	7,816	7,758	7,861
Actual	7,025	6,992	7,153	7,676	7,844	7,551	7,710	7,844	9,302	8,317
Error = (ACT-FCST)	356	287	39	519	477	(576)	(700)	28	1,544	456
Percent Error = (Error/ACT)	5.1%	4.1%	0.5%	6.8%	6.1%	-7.6%	-9.1%	0.4%	16.6%	5.5%

*2023 and beyond includes FTN for both Actual and Forecast

1 ## 3.2 AMALGAMATED NET CUSTOMER ADDITIONS

FEI Customer Additions	2015	2016	2017	2018	2019	2020	2021	2022	2023*	2024*
Rate Schedule 1										
Forecast	9,710	9,461	11,522	9,141	10,724	9,579	8,569	10,096	7,171	9,903
Actual	12,508	11,359	13,357	19,257	10,609	12,995	10,241	10,347	9,674	10,334
Error = (ACT-FCST)	2,798	1,898	1,835	10,116	(115)	3,416	1,672	251	2,503	431
Percent Error = (Error/ACT)	22.4%	16.7%	13.7%	52.5%	-1.1%	26.3%	16.3%	2.4%	25.9%	4.2%

FEI Customer Additions	2015	2016	2017	2018	2019	2020	2021	2022	2023*	2024*
Rate Schedule 2										
Forecast	1,026	1,026	1,318	1,210	1,115	872	872	797	472	425
Actual	1,450	998	899	1,271	442	677	320	293	(236)	2,523
Error = (ACT-FCST)	424	(28)	(419)	61	(673)	(195)	(552)	(504)	(708)	2,098
Percent Error = (Error/ACT)	29.2%	-2.8%	-46.6%	4.8%	-152.3%	-28.8%	-172.5%	-171.9%	300.1%	83.2%

FEI Customer Additions	2015	2016	2017	2018	2019	2020	2021	2022	2023*	2024*
Rate Schedule 3										
Forecast	(52)	(51)	26	19	91	248	248	115	10	(2)
Actual	132	(112)	252	587	945	(168)	208	211	1,609	(908)
Error = (ACT-FCST)	184	(61)	226	568	854	(416)	(40)	96	1,599	(906)
Percent Error = (Error/ACT)	139.4%	54.5%	89.7%	96.8%	90.4%	247.6%	-19.2%	45.6%	99.4%	99.8%

FEI Customer Additions	2015	2016	2017	2018	2019	2020	2021	2022	2023*	2024*
Rate Schedule 23										
Forecast	30	30	18	66	16	35	35	18	3	2
Actual	202	79	(91)	(64)	(777)	(125)	(49)	(77)	(167)	(77)
Error = (ACT-FCST)	172	49	(109)	(130)	(793)	(160)	(84)	(95)	(170)	(79)
Percent Error = (Error/ACT)	85.1%	62.0%	119.8%	203.1%	102.1%	128.0%	171.4%	123.3%	101.8%	102.9%

2 *2023 and beyond includes FTN for both Actual and Forecast

3.3 AMALGAMATED NORMALIZED USE PER CUSTOMER

FEI UPC, GJ	2015	2016	2017	2018	2019	2020	2021	2022	2023*	2024*
Rate Schedule 1										
Forecast	83.1	81.6	82.2	89.1	87.0	85.7	83.1	84.1	84.8	84.2
Actual	84.4	87.5	85.8	85.1	82.4	86.2	85.7	83.0	81.8	80.4
Error = (ACT-FCST)	1.3	5.9	3.7	(4.0)	(4.6)	0.4	2.6	(1.1)	(2.9)	(3.8)
Percent Error = (Error/ACT)	1.5%	6.7%	4.3%	-4.7%	-5.6%	0.5%	3.1%	-1.3%	-3.6%	-4.8%

FEI UPC, GJ	2015	2016	2017	2018	2019	2020	2021	2022	2023*	2024*
Rate Schedule 2										
Forecast	333.7	329.5	328.4	345.2	341.3	324.9	321.8	320.4	321.7	326.8
Actual	332.6	339.1	336.8	332.5	318.1	322.2	328.1	334.9	326.5	313.5
Error = (ACT-FCST)	(1.1)	9.6	8.3	(12.7)	(23.2)	(2.7)	6.3	14.6	4.7	(13.3)
Percent Error = (Error/ACT)	-0.3%	2.8%	2.5%	-3.8%	-7.3%	-0.8%	1.9%	4.3%	1.4%	-4.2%

FEI UPC, GJ	2015	2016	2017	2018	2019	2020	2021	2022	2023*	2024*
Rate Schedule 3										
Forecast	3,754	3,593	3,488	3,842	3,831	3,648	3,551	3,557	3,652.0	3,728.0
Actual	3,587	3,721	3,692	3,550	3,517	3,660	3,703	3,737.6	3,513.9	3,558.1
Error = (ACT-FCST)	(167)	128	205	(292)	(314)	12	151	181	(138)	(169.9)
Percent Error = (Error/ACT)	-4.7%	3.4%	5.5%	-8.2%	-8.9%	0.3%	4.1%	4.8%	-3.9%	-4.8%

FEI UPC, GJ	2015	2016	2017	2018	2019	2020	2021	2022	2023*	2024*
Rate Schedule 23										
Forecast	5,309	5,382	5,227	5,399	5,492	5,480	5,278	5,365	5,570	5,835.5
Actual	5,174	5,279	5,361	5,345	5,051	5,441	5,724	5,818	5,764	6,236.1
Error = (ACT-FCST)	(135)	(103)	133	(54)	(440)	(39)	447	453	194	400.6
Percent Error = (Error/ACT)	-2.6%	-2.0%	2.5%	-1.0%	-8.7%	-0.7%	7.8%	7.8%	3.4%	6.4%

*2023 and beyound includes FTN for both Actual and Forecast

3.4 AMALGAMATED DEMAND

FEI Demand,PJ	2015	2016	2017	2018	2019	2020	2021	2022	2023*	2024*
Rate Schedule 1										
Forecast	73.1	72.5	74.3	81.2	80.8	81.1	79.3	81.5	82.9	83.4
Actual	74.1	77.9	77.5	78.3	77.0	81.6	82.2	80.4	80.3	79.8
Error = (ACT-FCST)	1.0	5.4	3.3	(2.9)	(3.7)	0.5	2.9	(1.1)	(2.6)	(3.6)
Percent Error = (Error/ACT)	1.3%	7.0%	4.2%	-3.7%	-4.9%	0.6%	3.5%	-1.3%	-3.2%	-4.5%
Abs. Percent Error	1.3%	7.0%	4.2%	3.7%	4.9%	0.6%	3.5%	1.3%	3.2%	4.5%

FEI Demand,PJ	2015	2016	2017	2018	2019	2020	2021	2022	2023*	2024*
Rate Schedule 2										
Forecast	28.1	28.0	28.5	30.3	30.2	28.9	28.9	29.0	29.2	29.7
Actual	28.0	29.0	29.1	29.1	28.1	28.7	29.3	30.0	29.3	28.7
Error = (ACT-FCST)	(0.1)	1.0	0.6	(1.2)	(2.1)	(0.2)	0.4	1.0	0.1	(1.0)
Percent Error = (Error/ACT)	-0.4%	3.4%	2.0%	-4.3%	-7.4%	-0.8%	1.2%	3.5%	0.5%	-3.3%

FEI Demand,PJ	2015	2016	2017	2018	2019	2020	2021	2022	2023*	2024*
Rate Schedule 3										
Forecast	19.2	18.1	18.7	20.1	21.5	25.2	26.2	24.9	25.7	27.0
Actual	19.2	19.4	19.7	20.9	22.5	24.6	25.7	26.7	29.2	29.6
Error = (ACT-FCST)	(0.0)	1.3	1.0	0.9	1.0	(0.6)	(0.5)	1.8	3.4	2.6
Percent Error = (Error/ACT)	-0.2%	6.7%	5.2%	4.1%	4.3%	-2.4%	-1.8%	6.8%	11.8%	8.9%

FEI Demand,PJ	2015	2016	2017	2018	2019	2020	2021	2022	2023*	2024*
Rate Schedule 23										
Forecast	8.3	9.0	9.2	10.3	9.6	4.8	4.9	4.1	3.9	3.6
Actual	8.6	9.3	9.5	9.0	7.3	4.6	4.2000	3.9	3.4	2.7
Error = (ACT-FCST)	0.3	0.3	0.4	(1.3)	(2.3)	(0.2)	(0.7)	(0.2)	(0.5)	(0.9)
Percent Error = (Error/ACT)	3.5%	3.2%	3.9%	-13.9%	-31.3%	-5.2%	-16.1%	-4.5%	-16.4%	-34.3%

FEI Demand,PJ	2015	2016	2017	2018	2019	2020	2021	2022	2023*	2024*
Commercial										
Forecast	55.6	55.1	56.4	60.7	61.3	59.0	60.0	58.0	58.8	60.3
Actual	55.8	57.7	58.3	59.0	57.9	57.9	59.200	60.6	61.9	61.0
Error = (ACT-FCST)	0.2	2.6	2.0	(1.6)	(3.4)	(1.1)	(0.8)	2.7	3.0	0.8
Percent Error = (Error/ACT)	0.3%	4.5%	3.4%	-2.8%	-5.9%	-1.9%	-1.3%	4.4%	4.9%	1.2%
Abs. Percent Error	0.3%	4.5%	3.4%	2.8%	5.9%	1.9%	1.3%	4.4%	4.9%	1.2%

FEI Demand,PJ	2015	2016	2017	2018	2019	2020	2021	2022	2023*	2024*
Rate 5										
Forecast	3.5	2.2	2.2	2.5	2.9	7.6	7.6	8.7	9.4	10.2
Actual	2.3	2.4	2.8	3.8	4.8	8.1	9.1	9.8	10.3	13.3
Error = (ACT-FCST)	(1.2)	0.3	0.7	1.3	1.9	0.5	1.6	1.1	0.9	3.1
Percent Error = (Error/ACT)	-52%	11%	23%	34%	40%	6%	17%	11%	9%	24%

FEI Demand,PJ	2015	2016	2017	2018	2019	2020	2021	2022	2023*	2024*
Rate 25										
Forecast	13.9	13.8	13.8	14.4	14.8	10.3	10.8	9.9	9.2	8.7
Actual	13.7	13.9	14.5	13.9	13.2	9.9	9.324	9.1	7.9	7.3
Error = (ACT-FCST)	(0.2)	0.1	0.7	(0.5)	(1.7)	(0.4)	(1.5)	(0.8)	(1.3)	(1.3)
Percent Error = (Error/ACT)	-1%	1%	5%	-3%	-13%	-4%	-16%	-9%	-17%	-18%

FEI Demand,PJ	2015	2016	2017	2018	2019	2020	2021	2022	2023*	2024*
Rate 22										
Forecast	33.2	36.3	38.2	38.5	43.3	41.0	37.4	37.8	39.5	37.3
Actual	37.0	40.5	40.9	42.0	43.3	39.0	40.070	38.6	38.8	38.1
Error = (ACT-FCST)	3.8	4.2	2.6	3.5	0.1	(2.0)	2.7	0.8	(0.7)	0.8
Percent Error = (Error/ACT)	10%	10%	6%	8%	0%	-5%	7%	2%	-2%	2%

FEI Demand,PJ	2015	2016	2017	2018	2019	2020	2021	2022	2023*	2024*
Rate 27										
Forecast	6.6	6.5	6.4	7.3	7.9	4.7	4.8	4.5	4.3	3.9
Actual	7.2	6.8	7.5	6.2	5.9	4.6	4.4365	4.3	3.9	3.4
Error = (ACT-FCST)	0.5	0.3	1.1	(1.1)	(2.0)	(0.1)	(0.4)	(0.2)	(0.4)	(0.5)
Percent Error = (Error/ACT)	7%	4%	14%	-17%	-34%	-1%	-8%	-4%	-10%	-14%

FEI Demand,PJ	2015	2016	2017	2018	2019	2020	2021	2022	2023*	2024*
Industrial* *										
Forecast	76.4	78.1	82.1	84.3	90.6	91.9	87.8	88.9	73.3	71.7
Actual	79.6	83.7	87.4	88.4	91.5	89.5	90.8	77.6	72.5	75.6
Error = (ACT-FCST)	3.2	5.6	5.3	4.2	0.9	(2.4)	2.9	(11.3)	(0.9)	3.9
Percent Error = (Error/ACT)	4.0%	6.7%	6.0%	4.7%	1.0%	-2.7%	3.2%	-14.6%	-1.2%	5.1%
Abs. Percent Error	4.0%	6.7%	6.0%	4.7%	1.0%	2.7%	3.2%	14.6%	1.2%	5.1%

FEI Demand,PJ**	2015	2016	2017	2018	2019	2020	2021	2022	2023*	2024*
FEI										
Forecast	205.2	205.7	212.8	226.2	232.6	232.0	227.1	228.4	215.1	215.4
Actual	209.5	219.3	223.3	225.8	226.4	229.0	232.2	218.6	214.6	216.4
Error = (ACT-FCST)	4.3	13.6	10.5	(0.4)	(6.2)	(2.9)	5.1	(9.7)	(0.5)	1.0
Percent Error = (Error/ACT)	2.1%	6.2%	4.7%	-0.2%	-2.7%	-1.3%	2.2%	-4.5%	-0.2%	0.5%
Abs. Percent Error	2.1%	6.2%	4.7%	0.2%	2.7%	1.3%	2.2%	4.5%	0.2%	0.5%

*2023 and beyound includes FTN for both Actual and Forecast
**Excld NGT and Burrard

*Excld NGT and Burrard

1 ## 3.5 MAINLAND NET CUSTOMERS

Mainland Customers	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 1										
Forecast	780,972	787,836	799,732	803,319	813,959	823,255	828,146	839,746	838,999	851,599
Actual	782,914	790,562	798,917	811,696	817,817	826,142	831,178	838,403	845,895	853,935
Error = (ACT-FCST)	1,942	2,726	(815)	8,377	3,858	2,887	3,032	(1,343)	6,896	2,336
Percent Error = (Error/ACT)	0.2%	0.3%	-0.1%	1.0%	0.5%	0.3%	0.4%	-0.2%	0.8%	0.3%

Mainland Customers	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 2										
Forecast	75,315	76,166	77,597	78,228	78,767	79,027	79,703	80,203	79,856	80,029
Actual	75,451	76,326	77,047	78,044	78,351	78,941	79,108	79,358	79,003	81,253
Error = (ACT-FCST)	136	160	(550)	(184)	(416)	(86)	(595)	(845)	(853)	1,224
Percent Error = (Error/ACT)	0.2%	0.2%	-0.7%	-0.2%	-0.5%	-0.1%	-0.8%	-1.1%	-1.1%	1.5%

Mainland Customers	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 3										
Forecast	4,560	4,497	4,667	4,608	5,029	6,545	6,799	6,239	6,224	6,400
Actual	4,671	4,605	4,867	5,478	6,291	6,046	6,243	6,443	7,895	7,091
Error = (ACT-FCST)	111	108	200	870	1,262	(499)	(556)	204	1,671	691
Percent Error = (Error/ACT)	2.4%	2.3%	4.1%	15.9%	20.1%	-8.3%	-8.9%	3.2%	21.2%	9.7%

Mainland Customers	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 23										
Forecast	1,552	1,582	1,609	1,669	1,562	836	872	742	664	590
Actual	1,573	1,614	1,546	1,458	800	708	661	587	438	364
Error = (ACT-FCST)	21	32	(63)	(211)	(762)	(128)	(211)	(155)	(226)	(226)
Percent Error = (Error/ACT)	1.3%	2.0%	-4.1%	-14.5%	-95.3%	-18.1%	-31.9%	-26.4%	-51.6%	-62.0%

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3.6 *MAINLAND NET CUSTOMER ADDITIONS*

Mainland Customer Additions	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 1										
Forecast	6,889	6,863	8,250	6,203	6,756	5,438	4,891	6,622	3,574	6,968
Actual	8,831	7,648	8,355	12,779	6,121	8,325	5,036	7,225	7,492	8,040
Error = (ACT-FCST)	1,942	785	105	6,576	(635)	2,887	145	603	3,918	1,072
Percent Error = (Error/ACT)	22.0%	10.3%	1.3%	51.5%	-10.4%	34.7%	2.9%	8.3%	52.3%	13.3%

Mainland Customer Additions	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 2										
Forecast	851	851	1,072	951	860	676	676	631	355	336
Actual	987	875	721	997	307	590	167	250	(355)	2,250
Error = (ACT-FCST)	136	24	(351)	46	(553)	(86)	(509)	(381)	(710)	1,914
Percent Error = (Error/ACT)	13.7%	2.7%	-48.7%	4.6%	-180.1%	-14.6%	-304.8%	-152.5%	199.9%	85.1%

Mainland Customer Additions	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 3										
Forecast	(65)	(64)	(1)	2	81	254	254	97	(13)	(22)
Actual	46	(66)	262	611	813	(245)	197	200	1,452	(804)
Error = (ACT-FCST)	111	(2)	263	609	732	(499)	(57)	103	1,465	(782)
Percent Error = (Error/ACT)	241.3%	3.0%	100.4%	99.7%	90.0%	203.7%	-28.9%	51.7%	100.9%	97.3%

Mainland Customer Additions	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 23										
Forecast	30	30	18	28	8	36	36	17	2	1
Actual	51	41	(68)	(88)	(658)	(92)	(47)	(74)	(149)	(74)
Error = (ACT-FCST)	21	11	(86)	(116)	(666)	(128)	(83)	(91)	(151)	(75)
Percent Error = (Error/ACT)	41.2%	26.8%	126.5%	131.8%	101.2%	139.1%	176.6%	123.0%	101.0%	101.8%

3.7 *MAINLAND NORMALIZED USE PER CUSTOMER*

Mainland UPC GJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 1										
Forecast	88.1	86.3	86.2	93.5	91.5	90.8	88.2	89.2	89.9	89.4
Actual	88.7	92.0	90.4	89.7	87.1	91.1	90.8	88.1	87.1	85.5
Error = (ACT-FCST)	0.6	5.7	4.2	(3.8)	(4.5)	0.3	2.6	(1.0)	(2.8)	(3.9)
Percent Error = (Error/ACT)	0.7%	6.2%	4.6%	-4.2%	-5.1%	0.4%	2.8%	-1.1%	-3.3%	-4.6%

Mainland UPC GJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 2										
Forecast	329	329	327	345	339	324	320	320	322	326.3
Actual	330	338	335	329	316	322	327	334	326	311.9
Error = (ACT-FCST)	1	10	8	(15)	(23)	(2)	7	13	4	(14)
Percent Error = (Error/ACT)	0.2%	2.8%	2.4%	-4.6%	-7.3%	-0.6%	2.2%	4.0%	1.3%	-4.6%

Mainland UPC GJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 3										
Forecast	3,599	3,537	3,517	3,770	3,746	3,640	3,501	3,591	3,671	3,739
Actual	3,524	3,658	3,625	3,477	3,468	3,682	3,704	3,728	3,504	3,547
Error = (ACT-FCST)	(75)	121	108	(293)	(278)	42	202	137	(167)	(192)
Percent Error = (Error/ACT)	-2.1%	3.3%	3.0%	-8.4%	-8.0%	1.1%	5.5%	3.7%	-4.8%	-5.4%

Mainland UPC GJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 23										
Forecast	5,309	5,348	5,197	5,416	5,521	5,537	5,362	5,418	5,579	5,831
Actual	5,157	5,304	5,388	5,357	5,127	5,497	5,699	5,811	5,751	6,216
Error = (ACT-FCST)	(152)	(44)	191	(59)	(394)	(41)	336	393	172	386
Percent Error = (Error/ACT)	-2.9%	-0.8%	3.5%	-1.1%	-7.7%	-0.7%	5.9%	6.8%	3.0%	6.2%

3.8 *MAINLAND NORMALIZED DEMAND*

Mainland Demand, PJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 1										
Forecast	68.5	67.7	68.6	74.8	74.2	74.5	72.8	74.6	75.3	75.9
Actual	68.9	72.3	71.8	72.2	70.9	74.9	75.2	73.6	73.3	72.8
Error = (ACT-FCST)	0.4	4.6	3.2	(2.6)	(3.2)	0.4	2.4	(1.0)	(2.0)	(3.1)
Percent Error = (Error/ACT)	0.5%	6.4%	4.5%	-3.6%	-4.6%	0.5%	3.2%	-1.4%	-2.7%	-4.2%
Abs. Percent Error	0.5%	6.4%	4.5%	3.6%	4.6%	0.5%	3.2%	1.4%	2.7%	4.2%

Mainland Demand, PJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 2										
Forecast	24.7	24.9	25.2	26.7	26.5	25.5	25.4	25.6	25.6	26.0
Actual	24.6	25.6	25.7	25.5	24.7	25.3	25.8	26.4	25.7	25.0
Error = (ACT-FCST)	(0.0)	0.7	0.5	(1.3)	(1.8)	(0.1)	0.5	0.8	0.1	(0.9)
Percent Error = (Error/ACT)	-0.2%	2.7%	2.0%	-5.0%	-7.3%	-0.5%	1.7%	3.1%	0.4%	-3.8%

Mainland Demand, PJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 3										
Forecast	16.4	16.0	16.4	17.4	18.8	22.6	23.5	22.3	22.9	23.9
Actual	16.5	16.8	17.3	18.5	20.1	22.1	22.9	23.7	25.9	26.3
Error = (ACT-FCST)	0.0	0.8	0.9	1.2	1.3	(0.5)	(0.5)	1.4	3.1	2.4
Percent Error = (Error/ACT)	0.3%	5.0%	5.4%	6.3%	6.4%	-2.4%	-2.3%	6.0%	11.9%	9.1%

Mainland Demand, PJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 23										
Forecast	8.3	8.4	8.3	9.0	8.6	4.5	4.6	4.0	3.7	3.4
Actual	8.0	8.4	8.6	8.1	6.6	4.3	4.0	3.7	3.2	2.6
Error = (ACT-FCST)	(0.3)	-	0.3	(0.8)	(2.0)	(0.2)	(0.6)	(0.2)	(0.5)	(0.8)
Percent Error = (Error/ACT)	-3.3%	0.0%	3.1%	-10.4%	-30.8%	-4.8%	-15.9%	-5.8%	-16.3%	-31.6%

Mainland Demand, PJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Commercial										
Forecast	49.3	49.3	49.9	53.1	53.9	52.6	53.4	51.8	52.2	53.4
Actual	49.1	50.8	51.6	52.2	51.3	51.7	52.7	53.8	54.8	54.0
Error = (ACT-FCST)	(0.3)	1.5	1.7	(0.9)	(2.5)	(0.9)	(0.7)	2.0	2.7	0.6
Percent Error = (Error/ACT)	-0.5%	3.0%	3.3%	-1.8%	-5.0%	-1.6%	-1.4%	3.8%	4.9%	1.2%
Abs. Percent Error	0.5%	3.0%	3.3%	1.8%	5.0%	1.6%	1.4%	3.8%	4.9%	1.2%

3.9 VANCOUVER ISLAND NET CUSTOMERS

FEVI Customers	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 1										
Forecast	99,921	102,458	107,314	110,270	117,957	124,041	127,631	131,838	137,323	138,443
Actual	100,747	104,358	109,259	115,618	119,998	124,627	129,764	132,861	135,000	137,236
Error = (ACT-FCST)	826	1,900	1,945	5,348	2,041	586	2,133	1,023	(2,323)	(1,207)
Percent Error = (Error/ACT)	0.8%	1.8%	1.8%	4.6%	1.7%	0.5%	1.6%	0.8%	-1.7%	-0.9%

FEVI Customers	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 2										
Forecast	9,047	9,209	9,808	9,971	10,131	10,218	10,408	10,443	10,523	10,501
Actual	9,330	9,459	9,629	9,891	10,028	10,117	10,270	10,312	10,444	10,704
Error = (ACT-FCST)	283	250	(179)	(80)	(103)	(101)	(138)	(131)	(79)	203
Percent Error = (Error/ACT)	3.0%	2.6%	-1.9%	-0.8%	-1.0%	-1.0%	-1.3%	-1.3%	-0.8%	1.9%

FEVI Customers	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 3										
Forecast	497	479	647	567	539	605	597	720	736	751
Actual	582	531	517	492	613	686	697	711	844	753
Error = (ACT-FCST)	85	52	(130)	(75)	74	81	100	(9)	108	2
Percent Error = (Error/ACT)	14.6%	9.8%	-25.1%	-15.2%	12.1%	11.8%	14.3%	-1.3%	12.8%	0.2%

FEVI Customers	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 23										
Forecast		83	141	243	164	66	65	39	37	34
Actual	141	175	152	179	67	37	35	32	14	11
Error = (ACT-FCST)	141	92	11	(64)	(97)	(29)	(30)	(7)	(23)	(23)
Percent Error = (Error/ACT)		52.6%	7.2%	-35.8%	-144.8%	-78.4%	-85.7%	-21.4%	-163.9%	-207.4%

3.10 *VANCOUVER ISLAND NET CUSTOMER ADDITIONS*

FEVI Customer Additions	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 1										
Forecast	2,759	2,537	3,188	2,857	3,888	4,043	3,590	3,443	3,564	2,933
Actual	3,583	3,611	4,901	6,359	4,380	4,629	5,137	3,097	2,139	2,236
Error = (ACT-FCST)	824	1074	1713	3502	492	586	1547	(346)	(1425)	(697)
Percent Error = (Error/ACT)	23.0%	29.8%	35.0%	55.1%	11.2%	12.7%	30.1%	-11.2%	-66.6%	-31.2%

FEVI Customer Additions	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 2										
Forecast	171	171	239	256	251	190	190	163	126	95
Actual	453	129	170	262	137	89	153	42	132	260
Error = (ACT-FCST)	282	(42)	(69)	6	(114)	(101)	(37)	(121)	6	165
Percent Error = (Error/ACT)	62.2%	-32.6%	-40.6%	2.3%	-83.2%	-113.5%	-24.2%	-287.3%	4.3%	63.6%

FEVI Customer Additions	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 3										
Forecast	13	13	32	19	11	(8)	(8)	17	19	20
Actual	98	(51)	(14)	(25)	121	73	11	14	133	-91
Error = (ACT-FCST)	85	(64)	(46)	(44)	110	81	19	(3)	114	(111)
Percent Error = (Error/ACT)	86.6%	125.5%	328.6%	176.0%	90.9%	111.0%	172.7%	-22.0%	85.4%	122.1%

FEVI Customer Additions	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 23										
Forecast		-	-	34	6	(1)	(1)	1	1	1
Actual	141	34	(23)	27	(112)	(30)	(2)	(3)	(18)	-3
Error = (ACT-FCST)	141	34	(23)	(7)	(118)	(29)	(1)	(4)	(19)	(4)
Percent Error = (Error/ACT)		100.0%	100.0%	-25.9%	105.4%	96.7%	50.0%	130.7%	105.4%	130.1%

3.11 *VANCOUVER ISLAND NORMALIZED USE PER CUSTOMER*

FEVI UPC, GJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 1										
Forecast	44.0	45.1	51.3	56.3	54.7	51.2	49.6	50.9	52.0	50.9
Actual	50.5	52.6	51.5	51.6	49.7	52.3	52.7	49.7	47.8	47.2
Error = (ACT-FCST)	6.5	7.5	0.3	(4.7)	(5.0)	1.1	3.1	(1.2)	(4.2)	(3.7)
Percent Error = (Error/ACT)	12.9%	14.3%	0.5%	-9.1%	-10.1%	2.1%	5.8%	-2.3%	-8.8%	-7.8%

FEVI UPC, GJs	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 2										
Forecast	372.0	334.0	322.8	342.5	357.0	331.9	333.4	318.6	318.4	325.1
Actual	346.0	343.0	344.8	351.2	332.7	322.2	331.2	338.4	322.1	319.5
Error = (ACT-FCST)	(26.0)	9.0	22.0	8.7	(24.3)	(9.7)	(2.2)	19.8	3.7	(5.6)
Percent Error = (Error/ACT)	-7.5%	2.6%	6.4%	2.5%	-7.3%	-3.0%	-0.7%	5.9%	1.1%	-1.7%

FEVI UPC, GJs	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 3										
Forecast	5,187.0	4,030.8	3,068.6	4,171.0	4,411.0	3,628.7	3,882.2	3,197.0	3,397.6	3,541.9
Actual	3,894.0	4,060.0	4,180.7	4,074.2	3,826.5	3,403.8	3,603.9	3,708.0	3,457.5	3,551.6
Error = (ACT-FCST)	(1,293.0)	29.2	1,112.1	(96.9)	(584.4)	(224.9)	(278.3)	511.0	59.9	9.7
Percent Error = (Error/ACT)	-33.2%	0.7%	26.6%	-2.4%	-15.3%	-6.6%	-7.7%	13.8%	1.7%	0.3%

FEVI UPC, GJs	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
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	5,221.1	5,695.2
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	5,858.6	6,302.6
Error = (ACT-FCST)	5636.0	(944.2)	(478.2)	(83.3)	(913.1)	(73.1)	1853.3	1,413.4	637.6	607.4
Percent Error = (Error/ACT)	100.0%	-18.7%	-9.3%	-1.6%	-20.9%	-1.5%	30.8%	24.6%	10.9%	9.6%

3.12 *VANCOUVER ISLAND NORMALIZED DEMAND*

FEVI Demand, PJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 1										
Forecast	4.3	4.6	5.4	6.1	6.3	6.2	6.2	6.6	7.0	7.0
Actual	5.0	5.4	5.5	5.8	5.9	6.4	6.7	6.5	6.4	6.4
Error = (ACT-FCST)	0.6	0.8	0.1	(0.3)	(0.5)	0.1	0.5	(0.1)	(0.6)	(0.5)
Percent Error = (Error/ACT)	12.9%	15.6%	1.5%	-5.6%	-8.3%	2.3%	6.9%	-1.4%	-10.1%	-8.3%
Abs. Percent Error	12.9%	15.6%	1.5%	5.6%	8.3%	2.3%	6.9%	1.4%	10.1%	8.3%

FEVI Demand, PJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 2										
Forecast	3.3	3.0	3.1	3.4	3.6	3.4	3.4	3.3	3.3	3.4
Actual	3.2	3.2	3.3	3.4	3.3	3.2	3.4	3.5	3.3	3.4
Error = (ACT-FCST)	(0.2)	0.2	0.2	0.0	(0.3)	(0.1)	(0.1)	0.2	(0.0)	(0.0)
Percent Error = (Error/ACT)	-4.7%	6.3%	5.4%	1.4%	-8.0%	-3.4%	-1.8%	5.1%	0.0%	-0.3%

FEVI Demand, PJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 3										
Forecast	2.5	1.9	2.0	2.4	2.4	2.3	2.3	2.3	2.5	2.6
Actual	2.4	2.2	2.1	2.1	2.0	2.2	2.5	2.6	2.8	2.8
Error = (ACT-FCST)	(0.1)	0.3	0.1	(0.3)	(0.3)	(0.0)	0.2	0.3	0.3	0.2
Percent Error = (Error/ACT)	-5.0%	13.6%	6.5%	-14.6%	-16.8%	-1.9%	6.9%	13.2%	10.6%	6.5%

FEVI Demand, PJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 23										
Forecast		0.5	0.8	1.2	0.8	0.3	0.2740	0.16556	0.19041	0.1900
Actual	0.5	0.8	0.9	0.8	0.6	0.3	0.2199	0.19726	0.15867	0.0839
Error = (ACT-FCST)	0.5	0.3	0.1	(0.4)	(0.2)	(0.0)	(0.0541)	0.0	(0.0317)	(0.1061)
Percent Error = (Error/ACT)	100.0%	37.5%	9.2%	-44.9%	-32.2%	-11.0%	(0.2459)	16.1%	-20.0%	-126.3%

FEVI Demand, PJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Commercial										
Forecast	5.9	5.4	5.9	7.0	6.8	5.9	6.0	5.7	6.0	6.2
Actual	6.2	6.2	6.3	6.3	6.0	5.8	6.1	6.3	6.2	6.3
Error = (ACT-FCST)	0.3	0.8	0.4	(0.6)	(0.8)	(0.2)	0.1	0.6	0.3	0.1
Percent Error = (Error/ACT)	4.4%	12.9%	6.3%	-10.0%	-13.6%	-3.2%	1.0%	8.8%	4.2%	1.1%
Abs. Percent Error	4.4%	12.9%	6.3%	10.0%	13.6%	3.2%	1.0%	8.8%	4.2%	1.1%

3.13 WHISTLER NET CUSTOMERS

WH Customers	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 1										
Forecast	2,478	2,536	2,681	2,775	2,889	3,034	3,122	3,041	3,145	3,115
Actual	2,508	2,608	2,709	2,828	2,936	2,977	3,045	3,070	3,119	3,169
Error = (ACT-FCST)	30	72	28	53	47	(57)	(77)	29	(26)	54
Percent Error = (Error/ACT)	1.2%	2.8%	1.0%	1.9%	1.6%	-1.9%	-2.5%	0.9%	-0.8%	1.7%

WH Customers	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 2										
Forecast	289	292	309	294	305	313	319	310	302	305
Actual	295	289	297	309	307	305	305	306	292	300
Error = (ACT-FCST)	6	(3)	(12)	15	2	(8)	(14)	(4)	(10)	(5)
Percent Error = (Error/ACT)	2.0%	-1.0%	-4.0%	4.7%	0.7%	-2.6%	-4.6%	-1.4%	-3.5%	-1.8%

WH Customers	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 3										
Forecast	60	59	39	48	55	71	74	75	76	69
Actual	48	53	57	58	69	73	73	70	88	82
Error = (ACT-FCST)	(12)	(6)	18	10	14	2	(1)	(5)	12	13
Percent Error = (Error/ACT)	-25.0%	-11.3%	31.6%	16.9%	20.2%	2.7%	-1.4%	-7.1%	13.3%	16.2%

WH Customers	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 23										
Forecast		5	10	22	18	4	4	1	1	1
Actual	10	14	14	11	4	1	1	1	1	1
Error = (ACT-FCST)	10	9	4	(11)	(14)	(3)	(3)	(0)	(0)	0
Percent Error = (Error/ACT)		64.3%	28.6%	-100.0%	-350.0%	-300.0%	-300.0%	-2.0%	-4.0%	1.9%

3.14 *WHISTLER NET CUSTOMER ADDITIONS*

WH Customer Additions	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 1										
Forecast	62	61	84	81	81	98	88	31	47	24
Actual	92	100	101	119	108	41	68	25	49	50
Error = (ACT-FCST)	30	39	17	38	27	(57)	(20)	(6)	2	26
Percent Error = (Error/ACT)	32.6%	39.0%	16.8%	31.8%	25.4%	-139.5%	-28.9%	-23.5%	3.1%	52.5%

WH Customer Additions	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 2										
Forecast	4	4	7	3	4	6	6	3	(1)	(0.3)
Actual	10	(6)	8	12	(2)	(2)	-	1	(14)	8
Error = (ACT-FCST)	6	(10)	1	9	(6)	(8)	(6)	(2)	(13)	8
Percent Error = (Error/ACT)	60.0%	166.7%	11.9%	77.4%	300.0%	400.0%		-167.0%	90.5%	104.2%

WH Customer Additions	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 3										
Forecast	-	-	(5)	(2)	(1)	2	1	1	2	(0.7)
Actual	(12)	5	4	1	11	4	-	(3)	18	(6)
Error = (ACT-FCST)	(12)	5	9	3	12	2	(1)	(4)	16	(5)
Percent Error = (Error/ACT)		100.0%	225.0%	339.0%	109.1%	50.0%	#DIV/0!	133.0%	90.9%	89.0%

WH Customer Additions	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 23										
Forecast		-	-	4	2	-	-	0	0	(1)
Actual	10	4	-	(3)	(7)	(3)	-	-	-	-
Error = (ACT-FCST)	10	4	0	(7)	(9)	(3)	0	(0)	(0)	1
Percent Error = (Error/ACT)	100.0%	100.0%		233.3%	128.6%	100.0%				

3.15 *WHISTLER NORMALIZED USE PER CUSTOMER*

WH UPC, GJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 1										
Forecast	79.7	85.1	97.9	102.1	99.5	99.0	95.8	101.8	102.1	104.4
Actual	91.3	97.7	93.5	96.3	94.2	101.5	100.3	103.6	100.6	99.7
Error = (ACT-FCST)	12	13	(4)	(6)	(5)	2	4	2	(2)	(5)
Percent Error = (Error/ACT)	12.7%	12.9%	-4.7%	-6.1%	-5.6%	2.4%	4.5%	1.8%	-1.5%	-4.7%

WH UPC, GJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 2										
Forecast	408.0	465.0	792.9	592.7	515.5	419.5	384.7	356.2	363.4	449.2
Actual	660.0	520.2	479.4	511.8	465.8	417.5	438.7	499.8	467.4	449.1
Error = (ACT-FCST)	252	55	(314)	(81)	(50)	(2)	54	144	104	(0)
Percent Error = (Error/ACT)	38.2%	10.6%	-65.4%	-15.8%	-10.7%	-0.5%	12.3%	28.7%	22.2%	0.0%

WH UPC, GJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 3										
Forecast	3,822.0	4,326.0	6,706.9	6,824.3	5,886.5	4,737.2	5,475.7	4,179.4	4,077.7	4161.1
Actual	5,618.0	5,638.0	5,107.9	5,747.4	5,392.0	4,220.8	4,558.7	4,869.8	4,608.8	4427.7
Error = (ACT-FCST)	1,796	1,312	(1,599)	(1,077)	(495)	(516)	(917)	690	531	267
Percent Error = (Error/ACT)	32.0%	23.3%	-31.3%	-18.7%	-9.2%	-12.2%	-20.1%	14.2%	11.5%	6.0%

WH UPC, GJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
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	12,413.7	13,465.3
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	12,020.7	13,660.9
Error = (ACT-FCST)		(810)	229	157	391	808	7,113	6,967	(393)	195.6
Percent Error = (Error/ACT)		-16.0%	5.0%	3.2%	7.7%	13.6%	56.9%	54.0%	-3.3%	0.0

1 ## 3.16 *WHISTLER NORMALIZED DEMAND*

WH Demand, PJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 1										
Forecast	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
Actual	0.2	0.2	0.2	0.3	0.3	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)	0.0%	14.6%	-4.1%	-5.3%	-4.6%	1.8%	2.4%	2.8%	-2.4%	-3.2%
Abs. Percent Error	0.0%	14.6%	4.1%	5.3%	4.6%	1.8%	2.4%	2.8%	2.4%	3.2%

WH Demand, PJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 2										
Forecast	0.1	0.1	0.2	0.2	0.2	0.1	0.1	0.1	0.1	0.1
Actual	0.2	0.2	0.1	0.2	0.1	0.1	0.1	0.2	0.1	0.1
Error = (ACT-FCST)	0.1	0.0	(0.1)	(0.0)	(0.0)	(0.0)	0.0	0.0	0.0	(0.0)
Percent Error = (Error/ACT)	36.8%	10.0%	-75.0%	-12.1%	-9.6%	-1.6%	8.3%	27.9%	20.1%	-3.0%

WH Demand, PJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 3										
Forecast	0.2	0.3	0.3	0.3	0.3	0.3	0.4	0.3	0.3	0.3
Actual	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4
Error = (ACT-FCST)	0.1	0.0	0.0	(0.0)	0.0	(0.0)	(0.1)	0.0	0.1	0.1
Percent Error = (Error/ACT)	17.9%	13.3%	3.5%	-3.8%	5.5%	-11.5%	-18.4%	11.2%	18.9%	23.3%

WH Demand, PJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Rate Schedule 23										
Forecast		0.03	0.04	0.09	0.08	0.02	0.02	0.01	0.01	0.01
Actual	0.03	0.06	0.06	0.06	0.05	0.02	0.01	0.01	0.01	0.01
Error = (ACT-FCST)		0.03	0.02	-0.03	-0.03	0.00	-0.01	0.01	0.00	0.00
Percent Error = (Error/ACT)		50.9%	32.2%	-44.7%	-73.7%	-7.7%	-72.6%	53.4%	-6.5%	2.9%

WH Demand, PJ	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Commercial										
Forecast	0.4	0.4	0.6	0.6	0.6	0.5	0.5	0.4	0.4	0.4
Actual	0.5	0.5	0.5	0.5	0.5	0.4	0.5	0.5	0.5	0.5
Error = (ACT-FCST)	0.2	0.1	(0.1)	(0.1)	(0.0)	(0.0)	(0.1)	0.1	0.1	0.1
Percent Error = (Error/ACT)	30.0%	16.8%	-15.0%	-11.1%	-5.4%	-8.5%	-12.4%	17.2%	18.7%	16.0%
Abs. Percent Error	30.0%	16.8%	15.0%	11.1%	5.4%	8.5%	12.4%	17.2%	18.7%	16.0%

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3.17 FORT NELSON NET CUSTOMER

FTN Rate Schedule 1 - Residential Customers	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Forecast	1,984	1,997	1,965	1,966	1,941	1,918	1,864	1,853	1,830	1,793
Actual	1,963	1,945	1,927	1,919	1,898	1,880	1,860	1,836	1,830	1,838
Error = (ACT-FCST)	(21)	(52)	(38)	(47)	(43)	(38)	(4)	(17)	0	45
Percent Error = (Error/ACT)	-1.1%	-2.7%	-2.0%	-2.4%	-2.3%	-2.0%	-0.2%	-0.9%	0.0%	2.5%

FTN Rate Schedule 2 - Small Commercial Customers	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Forecast Rate Schedule 2.1	468	479	478	480						
Forecast Rate Schedule 2					465	468	450	445	430	435
Actual Rate Schedule 2.1	474	478	476	473						
Actual Rate Schedule 2					460	452	445	445	446	451
Error = (ACT-FCST)	6	(1)	(2)	(7)	(5)	(16)	(5)	(0)	16	16
Percent Error = (Error/ACT)	1.3%	-0.2%	-0.4%	-1.5%	-1.1%	-3.5%	-1.1%	-0.1%	3.6%	3.5%

FTN Rate Schedule 3- Large Commercial Customers	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Forecast Rate Schedule 2.2	33	34	7	7						
Forecast Rate Schedule 3					19	19	17	13	20	17
Actual Rate Schedule 2.2	7	7	6	4						
Actual Rate Schedule 3					14	17	17	16	22	15
Error = (ACT-FCST)	(26)	(27)	(1)	(3)	(5)	(2)	-	3	2	(2)
Percent Error = (Error/ACT)	-371.4%	-385.7%	-16.7%	-75.0%	-35.7%	-11.8%	0.0%	16.7%	9.1%	-15.6%

3.18 FORT NELSON NET CUSTOMER ADDITIONS

FTN Customer Additions Rate Schedule 1 - Residential	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Forecast	13	13	1	1	32	(23)	(16)	(13)	(14)	(23)
Actual	1	(18)	(18)	(8)	(21)	(18)	(20)	(24)	(6)	8
Error = (ACT-FCST)	(12)	(31)	(19)	(9)	(53)	5	(4)	(11)	8	31
Percent Error = (Error/ACT)	-1200.0%	172.2%	105.6%	112.5%	252.4%	-27.8%	20.0%	45.8%	-139.3%	385.0%

FTN Customer Addition Rate Schedule 2.1/2 - Small Commercial	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Forecast Rate Schedule 2.1	11	11	2	2						
Forecast Rate Schedule 2					9	3	(1)	(3)	(8)	(5)
Actual Rate Schedule 2.1	28	4	(2)	(3)						
Actual Rate Schedule 2					3	(8)	(7)	-	1	5
Error = (ACT-FCST)	17	(7)	(4)	(5)	(6)	(11)	(6)	3	9	10
Percent Error = (Error/ACT)	60.7%	-175.0%	200.0%	166.7%	-200.0%	137.5%	85.7%		850.0%	200.0%

FTN Customer Additions Rate Schedule 2.2/3 - Large Commercial	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Forecast Rate Schedule 2.2	1	1	-	-						
Forecast Rate Schedule 3					(1)	-		(1)	2	1
Actual Rate Schedule 2.2	(24)	-	(1)	(2)						
Actual Rate Schedule 3					(6)	3	-	(1)	6	(7)
Error = (ACT-FCST)	(25)	(1)	(1)	(2)	(5)	3	-	-	5	(8)
Percent Error = (Error/ACT)	104.2%		100.0%	100.0%	83.3%	100.0%		0.0%	75.0%	109.5%

3.19 *FORT NELSON USE PER CUSTOMER*

FTN UPC Rate Schedule 1 - Residential	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Forecast	136.1	134.8	133.4	132.3	125.2	122.9	125.7	125.8	125.6	129.9
Actual	135.5	134.2	129.9	127.6	128.1	128.9	128.5	129.3	126.2	124.2
Error = (ACT-FCST)	(0.6)	(0.6)	(3.4)	(4.7)	2.9	6.0	2.8	3.5	0.6	(5.7)
Percent Error = (Error/ACT)	-0.5%	-0.4%	-2.6%	-3.7%	2.2%	4.6%	2.2%	2.7%	0.5%	-4.6%

FTN UPC Rate Schedule 2.1/2 - Small Commercial	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Forecast Rate Schedule 2.1	453	443	444	425						
Forecast Rate Schedule 2					349.3	322.7	370.3	336.9	355.8	368.3
Actual Rate Schedule 2.1	482.0	465.8	447.8	434.8						
Actual Rate Schedule 2					402.2	382.6	382.0	389.6	384.8	368.2
Error = (ACT-FCST)	29.2	22.8	3.5	9.5	52.9	59.9	11.8	52.7	29.0	(0.1)
Percent Error = (Error/ACT)	6.1%	4.9%	0.8%	2.2%	13.2%	15.7%	3.1%	13.5%	7.5%	0.0%

FTN UPC Rate Schedule 2.2/3 - Small Commercial	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Forecast Rate Schedule 2.2	3,534.8	3,583.8	8,081.4	8,103.2						
Forecast Rate Schedule 3					3,164.0	2,801.7	5,306.8	6,377.9	5,605.2	6,038
Actual Rate Schedule 2.2	6,616.0	7,868.6	8,085.8	9,169.2						
Actual Rate Schedule 3					4,910.0	4,643.2	5,327.6	7,048.7	5,195.3	4,358
Error = (ACT-FCST)	3,081.2	4,284.8	4.4	1,066.0	1,746.0	1,841.5	20.7	670.7	(409.9)	(1,681)
Percent Error = (Error/ACT)	46.6%	54.5%	0.1%	11.6%	35.6%	39.7%	0.4%	9.5%	-7.9%	-38.6%

3.20 *FORT NELSON NORMALIZED DEMAND*

FTN Demand GJ Rate Schedule 1 - Residential	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Forecast	268,635	267,546	261,825	259,874	244,160	236,900	235,314	233,889	230,713	234,300
Actual	265,419	262,275	251,350	245,434	244,434	243,175	239,912	238,860	231,474	228,839
Error = (ACT-FCST)	(3,216)	(5,271)	(10,475)	(14,440)	274	6,275	4,598	4,971	761	(5,461)
Percent Error = (Error/ACT)	-1.2%	-2.0%	-4.2%	-5.9%	0.1%	2.6%	1.9%	2.1%	0.3%	-2.4%

FTN Demand GJ Rate Schedule 2.1/2- Small Commercial	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Forecast Rate Schedule 2.1	208,315	208,642	211,897	203,742						
Forecast Rate Schedule 2					160,160	150,377	166,828	150,115	154,312	161,126
Actual Rate Schedule 2.1	222,697	221,733	214,211	205,955						
Actual Rate Schedule 2					185,202	173,841	171,131	173,378	170,787	164,944
Error = (ACT-FCST)	14,382	13,091	2,314	2,213	25,042	23,464	4,302	23,263	16,475	3,818
Percent Error = (Error/ACT)	6.5%	5.9%	1.1%	1.1%	13.5%	13.5%	2.5%	13.4%	9.6%	2.3%

FTN Demand GJ Rate Schedule 2.2/3 - Small Commercial	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Forecast Rate Schedule 2.2	115,656	120,843	56,570	56,722						
Forecast Rate Schedule 3					61,061	53,232	90,216	87,068	107,587	102,472
Actual Rate Schedule 2.2	64,924	55,081	48,357	41,919						
Actual Rate Schedule 3					70,419	71,320	90,569	115,562	101,553	82,789
Error = (ACT-FCST)	(50,732)	(65,762)	(8,213)	(14,804)	9,358	18,088	353	28,494	(6,034)	(19,682)
Percent Error = (Error/ACT)	-78.1%	-119.4%	-17.0%	-35.3%	13.3%	25.4%	0.4%	24.7%	-5.9%	-23.8%

FTN Demand GJ Commercial	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Forecast	323,972	329,485	268,467	260,464						
Forecast					221,221	203,609	257,044	237,183	261,900	263,598
Actual	287,621	276,814	262,568	247,874						
Actual					255,621	245,161	261,699	288,940	272,340	247,734
Error = (ACT-FCST)	(36,351)	(52,672)	(5,899)	(12,591)	34,400	41,552	4,655	51,757	10,441	(15,864)
Percent Error = (Error/ACT)	-12.6%	-19.0%	-2.2%	-5.1%	13.5%	16.9%	1.8%	17.9%	3.8%	-6.4%

FTN Demand GJ Rate Schedule 25* - General Firm Transportation	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Forecast	55,832	55,832	39,685	39,684	41,500	41,500				
Actual	49,790	41,110	41,847	43,197	37,105	29,541				
Error = (ACT-FCST)	(6,042)	(14,722)	2,162	3,513	(4,395)	(11,959)				
Percent Error = (Error/ACT)	-12.1%	-35.8%	5.2%	8.1%	-11.8%	-40.5%				

Note: Single remaining customer switched to RS 3 in 2020

FTN Demand GJ Total Demand	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Forecast	648,439	652,863	569,978	560,023	506,881	482,009	492,358	471,072	492,613	497,898
Actual	602,830	580,199	555,765	536,505	537,160	517,877	501,611	527,801	503,815	476,573
Error = (ACT-FCST)	(45,609)	(72,664)	(14,212)	(23,517)	30,279	35,868	9,253	56,729	11,202	(21,325)
Percent Error = (Error/ACT)	-7.6%	-12.5%	-2.6%	-4.4%	5.6%	6.9%	1.8%	10.7%	2.2%	-4.5%

Appendix B
PRIOR YEAR DIRECTIVES

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
G-278-22 – FEI Application for Common Rates and 2022 Revenue Requirements for the Fort Nelson Service Area						
1.	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 to January 1, 2027 for final year of five-year phase-in.	Section 10.3.2
G-69-25 and Decision – FEI Rate Setting Framework for 2025 to 2027						
2.	21 and 29		O&M Costs impacts by the AMI project	To properly track and report on the annual costs and savings, FEI proposes to forecast O&M costs impacted by the AMI project in each Annual Review and provide a discussion of its expectations for the costs for the coming year, with variances between forecast and actual costs recorded in the flow-through deferral account and returned to or recovered from customers in subsequent years. …FEI is approved to do the following: …Remove $19.783 million of O&M costs from its 2024 Base O&M that will be impacted by its AMI project and reclassify the related costs to Forecast (flow-through) O&M.	Ongoing during the Rate Framework term.	Section 6.3.4
3.	49		Hydrogen Integration	The Panel directs FEI to address hydrogen integration in its next rates application after the conclusion of the Rate Framework.	Will be addressed in FEI's 2028+ Rates Application.	n/a
4.	65-66		SQIs – FEI's Energy Transition Informational Indicators	***Renewable and Low Carbon Energy Supply Volume Indicator:*** The Panel directs FEI to also include specific reporting on the mix of renewable and low-carbon gas sources, as well as the percentage of these sources in its total gas supply, in each Annual Review. ***Scope 3 Emissions:*** The Panel directs FEI to include an informational indicator for Scope 3 emissions as part of its energy transition informational indicators.	Ongoing during the Rate Framework term.	Section 13.2.4

No.	Decision Page No.	Directive No.	Reference	Description / Details	Status	Section in this Application
5.	78		Next Rates Application	In its next rates application for the period beginning January 1, 2028, the Panel provides the following directions to FortisBC: • For FEI and FBC, evaluate the merits of a price cap model that takes a top-down approach to rate-setting, such that the customers' rate is the starting point as opposed to the end product; • For FEI, evaluate alternate rate frameworks based on a jurisdictional review of other research that begin with an optimal gas delivery price as the starting point; • Evaluate whether such a new common rates plan could reasonably be implemented for both FEI and FBC given potentially different impacts of the energy transition on their operations, or whether the next rates plan would merit separate rate frameworks for each of the two utilities; and • For FEI and FBC, evalue targeted incentives that may be appropriate to introduce to further incent FEI's and FBC's energy transition work.	Will be addressed in FEI's 2028+ Rates Application.	n/a
6.	82		Clean Growth Innovation Fund (CGIF)	The Panel directs FEI in its next rates application to (i) provide a comprehensive report of the utility of the CGIF in regard to its stated objectives; (ii) evaluate the need for continuation of the CGIF; and (iii) evaluate alternate mechanisms that might address these objectives including a review of any relevant mechanics in other Canadian jurisdictions.	Will be addressed in FEI's 2028+ Rates Application.	n/a
G-138-25 - FEI AND FBC ESTABLISHMENT OF AN EQUITY ISSUANCE COST DEFERRAL ACCOUNT AND RECOVERY OF EQUITY ISSUANCE COSTS						
7.	6	4	Equity Issuance Costs deferral accounts	FEI and FBC are each directed to propose an amortization period for their Flotation Costs deferral accounts in their next annual review or rate-setting process.		Section 12.4.2.2
G-162-25 - FEI DISCONTINUE OPERATION OF THE LNG FUELING STATION AT VEDDER TRANSPORT LTD.						
8.		3	Recovery of Amounts	FEI is directed to provide an update regarding the recovery of amounts associated with the decommissioning of the Vedder Abbotsford Fueling Station in its next Annual Review of Delivery Rates application to the BCUC.		Section 5.2.4.3

Appendix C

DRAFT ORDER

British Columbia Utilities Commission

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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 2025 and 2026 Delivery Rates

BEFORE:
[X. X. Last Name, Panel Chair]
[X. X. Last Name, Commissioner]
[X. X. Last Name, Commissioner]

on [Month Day, Year]

ORDER

WHEREAS:

A. On March 18, 2025, the British Columbia Utilities Commission (BCUC) issued its Decision and Order G-69-25 for FortisBC Energy Inc. (FEI) and G-70-25 for FortisBC Inc., approving a Rate Setting Framework (Rate Framework) for 2025 through 2027 (Rate Framework Decision). In accordance with the Rate Framework Decision, FEI is to conduct an annual review (Annual Review) process to set rates for each year;

B. By Order G-313-24 dated November 27, 2024, the BCUC approved a 7.75 percent delivery rate increase, on an interim and refundable basis, effective January 1, 2025;

C. By letter dated June 20, 2025, FEI proposed a regulatory timetable for the Annual Review for 2025 and 2026 Delivery Rates;

D. By Order G-179-25 dated July 22, 2025, the BCUC established the regulatory timetable for the FEI Annual Review for 2025 and 2026 Delivery Rates, which includes FEI filing its Annual Review materials, intervener registration, one round of information requests, letters of comment, FEI and intervener final arguments, and FEI reply argument;

E. On July 24, 2025, FEI submitted its materials for the Annual Review for 2025 and 2026 Delivery Rates (Application). In the Application, FEI requests approval to make the existing 2025 interim delivery rates permanent, effective January 1, 2025, and approval of a 10.07 percent permanent delivery rate increase, effective January 1, 2026, among other things; and

F. 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 make the existing 2025 interim delivery rates and rate riders permanent, effective January 1, 2025.

2. FEI is approved to capture the revenue deficiency resulting from the difference between the 2025 interim and permanent revenue requirement in the existing 2023-2024 Revenue Deficiency deferral account, rename the deferral account the 2023-2025 Revenue Deficiency deferral account, and amortize the deferral account over a five-year period starting January 1, 2027.

3. FEI is approved to recover the 2026 revenue requirement and resultant delivery rate change on a permanent basis, effective January 1, 2026.

4. Effective January 1, 2025 and for the duration of the Rate Framework term, FEI is approved to continue debiting the Midstream Cost Reconciliation Account (MCRA) and crediting Other Revenue in the amount of $346.617 per MMcfd.

5. FEI is approved the following regarding its deferral accounts:

    a. Approval to rename the Annual Review of 2020-2024 Rates deferral account the Annual Review Proceeding Costs deferral account, and to use this deferral account to capture actual regulatory proceeding costs related to the Annual Reviews during the Rate Framework term, and to continue to amortize the deferral account over a one-year period;

    b. Approval to rename the 2025 MRP Application deferral account the 2025-2027 RSF Application deferral account, and to amortize the deferral account over three years, commencing January 1, 2025;

    c. The 2021 Generic Cost of Capital Proceeding deferral account is approved to be amortized over a five-year period, commencing January 1, 2025;

    d. The 2021 Renewable Gas Program Comprehensive Review deferral account is approved to be amortized over a three-year period, commencing January 1, 2025;

    e. The 20203 Cost of Service Allocation (COSA) Study deferral account is approved to be amortized over a one-year period, commencing January 1, 2025;

    f. The 2022 Long-Term Gas Resource Plan (LTGRP) deferral account is approved to be amortized over a three-year period, commencing January 1, 2025;

    g. FEI is approved to capture the actual after-tax costs of the 2025 equity issuance in the Flotation Costs deferral account and to amortize the balance in the Flotation Costs deferral account over five years, commencing January 1, 2026; and

    h. FEI is approved to modify the existing RNG Account to attract financing costs at FEI's weighted-average cost of capital (WACC), effective January 1, 2025.

6. FEI is approved to set the 2026 Revenue Stabilization Adjustment Mechanism (RSAM) rate rider at $0.212 per GJ.

7. FEI is approved to set the Fort Nelson Residential Customer Common Rate Phase-in Rate Rider for 2026 to be a credit of $0.355 per GJ.

8. FEI is approved to transfer the 2024 ending balance of the 2020 Clean Growth Innovation Fund (CGIF) deferral account to the existing approved Residual Delivery Rate Riders deferral account, effective January 1, 2025, and to record any unspent accrued committed amounts in the Residual Delivery Rate Riders deferral account.

9. FEI is directed to file as a compliance filing amended tariff pages in accordance with the terms of this order for the BCUC's endorsement within 30 days from the date of the issuance of this order.

DATED at the City of Vancouver, in the Province of British Columbia, this [XXth] day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner