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September 21, 2026

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

Dear Registrar:

Re: FortisBC Energy Inc. (FEI)

2027 Annual Review of Delivery Rates (Application)

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

On July 24, 2026, FEI filed the Application referenced above. In accordance with the regulatory timetable established in BCUC Order G-150-26 for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 1.[1]

FEI has filed a portion of the response to BCUC IR1 1.1 on a confidential basis as identified in that response and has provided a redacted version for the public record of this proceeding.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Registered Interveners

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

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A. OTHER REVENUE

1.0 Reference: OTHER REVENUE

Exhibit B-2 (Application), Section 5.2.4.3, p. 37; FortisBC Energy Inc. Discontinue Operation of the LNG Fueling Station at Vedder Transport Ltd and Cancel Tariff Supplements J-3, J-9, J-27 and J-54 proceeding, Order G-162-25 dated June 27, 2025

Vedder Abbotsford Fuelling Station

By Order G-162-25 dated June 27, 2025, the British Columbia Utilities Commission (BCUC) approved FortisBC Energy Inc. (FEI) to discontinue operation of the Vedder Abbotsford Fueling Station (Fuelling Station), among other things.

On page 37 of the Application, FEI states that the settlement agreement with Vedder Transport Ltd. (Vedder) for unrecovered capital costs for the Fuelling Station is expected to be finalized and executed at the end of 2026. FEI states:

> […] Upon executing the settlement agreement, the Vedder Abbotsford Fuelling station will be retired, and FEI will credit the book value of the station to FEI's plant in service, record the removal costs in the Net Salvage Provision/Cost deferral account, and record the remaining balance, including the excess capital credits to Vedder, in the CNG & LNG Recoveries deferral account.

1.1 Please complete the below table to illustrate FEI's proposed accounting treatment and refund/recovery mechanism for each item pertaining to the Fuelling Station, separately under the following scenarios:

a) Full recovery of the unrecovered capital costs for the Fuelling Station from Vedder; and

b) Partial or no recovery of the unrecovered capital costs for the Fuelling Station from Vedder.

For completing the table, please note the following:

- In the "FEI's Proposed Accounting Treatment" column, please identify the proposed accounting treatment for each component, including the use of any applicable deferral accounts; and
- In the "Recovery From/Refund To" column, please identify the party (e.g. Vedder, FEI's other customers, or FEI's shareholders) that will ultimately bear the cost or receive the benefit of each cost component.

Cost Component	FEI's Proposed Accounting Treatment	Recovery From/Refund To
Unrecovered Capital Costs		
Removal Costs		
Excess Capital Credits		

Response:

For a portion of this response, FEI has redacted certain information that FEI is filing on a confidential basis and requesting be held confidential by the BCUC in perpetuity, pursuant to Section 23 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-192-25.[1] The redacted information contains commercially sensitive and market competitive information which, if disclosed publicly, could prejudice or influence future negotiations of contracts between FEI and suppliers or counterparties, which could result in higher costs for customers.

FEI and Vedder have negotiated a settlement amount of [redacted] (excluding GST) for the Vedder Abbotsford Fueling Station. As of the date of this response, FEI is awaiting signature from Vedder and is expecting the settlement agreement to be executed before the end of 2026.

Table 1 below shows the actual unrecovered amount associated with the Vedder Abbotsford Fueling Station, which totals [redacted]. The station was decommissioned in 2024. The removal costs represent the actual costs to decommission the Vedder Abbotsford Fueling Station,

[1] As amended by Order G-228-25.

including disconnection, signage removal, and site restoration completed by contractors with support from FEI's internal labour.

[redacted]

[redacted]

Pursuant to section 3 of Direction No. 5 to the BCUC, CNG and LNG services and all related costs and revenues are treated as part of FEI's natural gas class of service, with all costs and revenues allocated to all applicable customers.[2] Therefore, any surplus or deficiency resulting from the settlement with Vedder will be returned to or recovered from FEI's other customers through delivery rates.

Upon the execution of the settlement agreement, the settlement amount will be recorded as an account receivable from Vedder, which will be cleared once the funds are received from Vedder. Table 2 below illustrates the accounting treatment of the negotiated settlement amount, which will result in full recovery of the unrecovered capital and removal costs from Vedder. As requested, FEI also included an example of partial recovery by assuming the settlement amount (excluding GST) is [redacted]. The accounting treatment is the same whether the settlement results in full recovery or partial/no recovery and is consistent with previous terminations or buyouts of CNG or LNG fueling stations.

[redacted]

The difference between the settlement amount and the total unrecovered capital and removal costs will be recorded in the CNG & LNG Recoveries deferral account, which will be recovered

[2] https://www.bclaws.gov.bc.ca/civix/document/id/lc/statreg/245_2013#section3.

from/returned to FEI's other customers through amortization into FEI's delivery rates. [redacted]

[redacted]

1.2 Please discuss the likelihood of a scenario wherein FEI receives a settlement amount from Vedder that is less than the amount of the total unrecovered capital costs for the Fuelling Station (i.e. no amounts or partial amounts recovered). If a partial amount is expected to be recovered from Vedder, please quantify this amount.

1.2.1 In the above scenario, and with consideration to FEI's response to BCUC IR 1.1 above (scenario b)), please clarify whether FEI intends to recover the portion that is not recovered from Vedder (Loss on Recovery) from ratepayers or its shareholders.

1.2.1.1 If FEI intends to recover the Loss on Recovery from ratepayers, please explain why this amount should be recovered from FEI's ratepayers and not its shareholders.

Response:

Please refer to the response to BCUC IR1 1.1.

1.3 Please quantify the estimated removal costs for the Fuelling Station and briefly explain the basis for this estimate.

Response:

Please refer to the response to BCUC IR1 1.1.

1.4 With consideration to FEI's response to BCUC IR 1.1 (scenarios a) and b)), as applicable, please explain why the removal costs associated with the Fuelling Station are recoverable from ratepayers.

Response:

Please refer to the response to BCUC IR1 1.1.

B. OPERATIONS AND MAINTENANCE EXPENSE

2.0 Reference: OPERATIONS AND MAINTENANCE (O&M) EXPENSE
Exhibit B-2, Section 6.3.3, pp. 43, 45
Integrity Digs

On page 43 of the Application, FEI states:

> [T]he 2026 Projected Integrity O&M is $12.9 million, which is $0.9 million higher than 2026 Approved. The main drivers of the increase in 2026 Projected integrity digs compared to 2026 Approved are:
>
> […]
>
> - Regulatory requirements associated with water management which are increasing costs at a dig site in the vicinity of Burns Bog in Delta. The projection for this dig site is approximately $1 million;
> - Helicopter-only access is required for a particular integrity dig site in a remote mountainous area on Vancouver Island, resulting in a projected cost for this site of approximately $1.4 million. […]

In Table 6-6 on page 45 of the Application, FEI shows that the average cost per integrity dig is $102,000 in the 2026 Approved, $121,000 for the 2026 Projected and $99,000 for the 2027 Forecast.

Further on page 45 of the Application, FEI states: "there continues to be significant uncertainty with respect to the number and complexity of integrity digs."

2.1 Please clarify whether FEI was aware of the need to complete integrity digs: a) in the vicinity of Burns Bog; and b) in "a remote mountainous area" on Vancouver Island, when it developed the 2026 Approved integrity O&M.

2.1.1 If yes, please explain why higher costs associated with: a) water management regulatory requirements in the vicinity of Burns Bog; and b) helicopter-only access on Vancouver Island, were not originally accounted for in the 2026 Approved integrity O&M.

Response:

When developing the 2026 Approved integrity O&M, FEI was aware of the need to complete integrity digs in the vicinity of Burns Bog and in a remote mountainous area on Vancouver Island; however, as discussed below, the issues related to water management regulatory requirements and helicopter-only access were not known at the time the forecasts were developed.

The integrity dig in the vicinity of Burns Bog was known and planned for 2025. The dig was located in the parking lot of an industrial area, and excavation began in late July 2025. However, FEI encountered unexpected conditions during excavation as the water table was found to be higher

than the depth of the pipeline and a natural aquifer was also encountered. This contributed to running water that made the excavation unstable.

Work was subsequently stopped and environmental permitting processes were initiated. Permitting took approximately one year, and involved the BC Energy Regulator (BCER), the City of Delta, and Metro Vancouver. The environmental permit set restrictions related to both quality and quantity of water, requiring on-site water treatment and controlled disposal. The work extended into 2026.

The integrity dig in a remote mountainous area on Vancouver Island was also known. At the time of preparing the forecast, FEI was in the process of investigating and developing options for site access but had not yet completed its plan. FEI investigated and considered a ground-access option, which was subsequently deemed infeasible due to its timing (i.e., beyond the engineering-driven dig timeframe) and which could also have resulted in higher overall costs. Schedule and complexity issues related to the ground-access option included:

- Distance to travel to the dig site was approximately 15 km, would have crossed 44 water crossings, and would have crossed approximately 5 km of archaeologically sensitive land;
- Plans for traversing steep mountainous terrain would have required advance geotechnical engineering and likely would have required mitigation;
- FEI considered it unlikely that environmental permits related to water crossings could be obtained within the available time; and
- FEI determined that the archaeological mitigation was infeasible within the available time. Consultation had identified that an archaeological dig would be needed every 10 m for the 5 km stretch (approximately 500 digs).

By the end of 2025, the above schedule and complexity issues necessitated a decision to proceed with helicopter access, enabling FEI to complete this dig in 2026 and avoid a reduction to the pipeline operating pressure. As discussed in the Application, FEI is avoiding future dig costs at this site by addressing four features.

2.2 Please explain, using supporting examples as necessary, how uncertainty with respect to the number and complexity of integrity digs is generally considered in developing FEI's integrity O&M forecasts.

Response:

In developing its integrity O&M forecasts, FEI considers uncertainty with respect to the number of integrity digs as follows:

- The number of digs determined from analysis completed prior to the filing of the Annual Review application is forecast with certainty. For the current Application, this applied to less than 25 percent of the forecast digs.
- To estimate the number of other digs where analysis is not complete prior to the filing of the Annual Review application, FEI relies on the engineering judgement of qualified staff. For example, in developing the dig numbers associated with ITS TIMC-related in-line inspections, which are scheduled later in 2026, FEI's engineering department considered the following information:
    - results from CTS TIMC-related EMAT runs and digs;
    - year of construction of the lines (1957);
    - pipe manufacturing methodology (low-frequency electric resistance welds); and
    - material properties (e.g., toughness values obtained through laboratory testing of actual cut-out pipe).

In consideration of the above information, FEI developed a projected dig rate of approximately twice the rate that had been previously used for CTS post-EMAT digs.

In developing its integrity O&M forecasts, FEI considers uncertainty with respect to the complexity of integrity digs as follows:

- When developing its integrity O&M forecasts, FEI typically has an expected operating region for each of the digs and utilizes this information when estimating a cost per dig. While FEI recognizes that each of its operating regions has the potential for digs with a wide range of complexity (as discussed on page 46 of the Application), FEI considers regional factors that broadly influence dig costs. For example, the Interior region tends to have a greater proportion of digs in rural areas, and sites are typically less congested and easier to access.
- For the 2027 Forecast, FEI recognized that a greater proportion of 2027 digs are anticipated to be in the Interior compared to 2026, and has estimated lower unit costs for those digs versus digs expected to occur in other regions. FEI considered its historical cost information, and also supplemented its estimates with operational inputs, resulting in a forecast blended Average Cost per Dig across all three regions and all five Reason for Dig categories that is lower in 2027 than in 2026.

FEI updates its integrity O&M forecasts monthly during each calendar year, reflecting new information as it becomes available.

2.3 Given the 2026 Projected average cost per integrity dig of $121,000, please explain whether a higher 2027 forecast average cost per dig closer to that amount (i.e. $121,000), is reasonable.

2.3.1 If the 2026 Projected average cost is not applicable when considering the 2027 forecast, please explain why not.

Response:

Based on the information available at this time, including the various uncertainties discussed on page 46 the Application and in the response to BCUC IR1 2.2, FEI considers the 2027 Forecast to be reasonable.

FEI's 2027 Forecast includes a greater proportion of digs in the Interior compared to 2026, for which FEI has assessed a greater likelihood of lower unit costs (as discussed on page 47 of the Application). Accordingly, the blended Average Cost per Dig across all three regions and all five Reason for Dig categories is forecast to be lower than in 2026. This is due to the Interior region tending to have a greater proportion of digs in rural areas, and sites are typically less congested and easier to access versus FEI's other operating regions.

3.0 Reference: O&M EXPENSE

Exhibit B-2, Section 6.3.3, p. 46

Non-In-line Inspection (Non-ILI) Digs

On page 46 of the Application, FEI states: "The increased number of digs forecast for 2027 is a result of FEI's ongoing response to six minor leaks since 2022 on the NPS 3 Fernie Lateral."

3.1 Please describe the nature of the minor leaks on the NPS 3 Fernie Lateral and discuss FEI's plans for future digs and investigations on this lateral.

Response:

Since the time of the Application filing, an additional 8 leaks have been identified, bringing the total number of leaks to 14. Each of these leaks has been reported to the BCER.

All leaks have been identified through monthly on-foot leak surveys conducted along the pipeline right-of-way. Excavations completed to date have confirmed that the leaks are minor, commonly referred to as "bubble leaks", with no evidence of significant gas release. This pipeline has an operating stress for which time-dependent failures are expected to occur as leaks, as opposed to ruptures, limiting the potential for safety-related consequences.

FEI is undertaking a comprehensive investigation to understand the cause and extent of these leaks and to support the continued operation of the pipeline to deliver gas to the community of Fernie. The investigation includes the following activities:

- **Above-ground inspection survey:** FEI will conduct an above-ground inspection survey in September 2026, employing multiple above-ground assessment techniques to evaluate the integrity of this small diameter pipeline and identify locations warranting further evaluation through integrity digs. In-line inspection tools of the appropriate diameter and capable of detecting the leak mechanism identified in prior leaks are not commercially available.
- **Metallurgical and laboratory analysis:** FEI is performing detailed laboratory testing and metallurgical examination of pipe samples collected from a leak location to support further understanding of the degradation mechanism(s) contributing to the leaks.

None of the failures on the NPS 3 Fernie Lateral qualify as material safety incidents, which are reported annually to the BCUC in accordance with Decision and Order G-52-24. FEI is maintaining ongoing communication with the BCER regarding its actions and findings.

3.2 Please discuss the likelihood that the minor leaks on the NPS 3 Fernie Lateral are indicative of a substantial integrity issue that could result in higher-than-anticipated integrity O&M in 2027.

Response:

There is insufficient information available at this time to conclude whether the leaks are indicative of a broader integrity concern affecting this pipeline or whether they are the result of a more localized issue. The NPS 3 Fernie Lateral was installed in the 1960s; however, FEI operates numerous pipelines of similar vintage that, to date, have not exhibited comparable leak activity.

As described in the response to BCUC IR1 3.1, FEI is undertaking a comprehensive investigation to understand the cause and extent of these leaks and to support the continued operation of the pipeline to deliver gas to the community of Fernie. The results of the above-ground inspection survey and any subsequent integrity digs, laboratory testing, and metallurgical analysis will inform FEI's assessment of the significance of the issue, including cost impacts, as well as the short- and long-term solutions necessary to address the issue while meeting gas load requirements in the Fernie area.

FEI expects continued additional O&M costs in future years, potentially to both operations and integrity, until a longer-term solution is developed and implemented for this lateral.

4.0 Reference: O&M EXPENSE

Exhibit B-2, Section 6.3.4, pp. 48–49, Table 6-7

Advanced Metering Infrastructure (AMI) O&M

On page 48 of the Application, FEI provides Table 6-7 outlining its 2026 Approved, 2026 Projected and 2026 Forecast AMI O&M expenses, including meter installation, meter reading, operations, customer service and new AMI activities costs.

On page 48 of the Application, FEI states that FEI Operations is on track to complete *more meter installations* for 2026 Projected than originally anticipated. Concurrently, on page 48 of the Application, FEI states that as of June 2026, *fewer meters than anticipated* have been transitioned to automatic reads, resulting in more manual meter reads.

4.1 Please briefly describe the process, and any conditions which must be met, for FEI to complete the transition from manual meter reads to automatic reads following the installation of an AMI meter.

Response:

FEI will transition from manual to automated reading once a meter reading route has reached the commissioning threshold of 95 percent of meters exchanged to an AMI meter and has met the following acceptance criteria:

- confirmation that the meters in a meter reading route are communicating reliably with the AMI network; and
- the collected automated reads have been demonstrated to be consistently received and validated for billing purposes.

4.2 Please explain why, as of June 2026, fewer than anticipated installed AMI meters have been transitioned to automatic reads, notwithstanding that FEI expects to complete more meter installations in 2026 than originally anticipated. As part of the response, please discuss whether there have been any issues with the adoption (e.g. uptake) and/or implementation of AMI meters in 2026 year-to-date.

Response:

The increased installation volume shown in Table 6-7 does not directly translate into a proportional increase in meters transitioned to automatic reads, because Table 6-7 includes only installations completed by FEI Operations. The majority of meter exchanges are being completed by deployment contractors that are assigned to specific areas of the province, while FEI

Operations is responsible for a small portion of meter exchanges spread throughout the service territory.

Deployment is being carried out concurrently across multiple areas and meter reading routes throughout FEI's service territory, rather than on a route-by-route or regional basis. As a result, meter reading routes initially transition at a slower pace, followed by an increase in pace as multiple routes simultaneously meet the commissioning threshold and acceptance criteria described in the response to BCUC IR1 4.1. The number of routes transitioned to automated reads is therefore primarily driven by the commissioning and acceptance requirements, rather than by customer uptake or implementation issues.

Overall, the adoption and implementation of AMI meters is progressing well, and no significant issues have been identified. FEI continues to transition meter reading routes as they satisfy the established commissioning threshold and acceptance criteria.

Additionally, on page 48 of the Application, FEI states that "in 2027, FEI expects to complete a similar level of meter installations as 2026 Projected […]."

On pages 48 and 49 of the Application, regarding AMI customer service O&M, FEI states that the 2026 Projected expense is higher than 2026 Approved due to a higher-than-expected volume of customer service activities experienced during the meter switching process. However, FEI forecasts a decrease in Customer Service O&M in 2027 compared to the 2026 Projected costs.

4.3 Please discuss the factor(s) that have led to a higher-than-expected volume of customer service activities to-date in 2026 as stated in the preamble above and whether these circumstances are expected to persist through the end of 2026. As part of the response, please discuss: (i) how any of these factor(s), if at all, have informed the development of the 2027 Forecast AMI Customer Service O&M; and (ii) whether FEI expects any of these factor(s) to impact the actual to forecast variances in 2027 AMI Customer Service O&M.

Response:

The higher-than-expected volume of customer service activities is driven by fewer-than-anticipated meters transitioned to automated billing as of June 2026. The impacts on customer service activities included billing investigation and exceptions, meter reading coordinator workload, and meter switching identification and validation. FEI expects these circumstances to continue through the remainder of 2026, although the impact is expected to gradually lessen as additional meter routes transition to billing based on automated reads.

This has informed the development of the 2027 Forecast AMI Customer Service O&M. The pace of transition of meter routes is expected to increase through 2027 as a greater proportion of meter routes reach the commissioning threshold and become available for billing based on automated reads, reducing the volume of customer service activities compared to what has been experienced in 2026. As a result, FEI is forecasting lower AMI Customer Service O&M in 2027 compared to 2026.

The AMI Project timeline for meter deployment completion and final Project close out remains on schedule, accordingly FEI does not expect significant actual to forecast variances in 2027 AMI Customer Service O&M if the schedule is maintained.

4.4 Notwithstanding that FEI expects to complete a similar level of meter installations in 2027 as 2026 Projected, please explain why FEI forecasts a decrease in Customer Service O&M in 2027.

Response:

Please refer to the response to BCUC IR1 4.3.

On page 49 of the Application, regarding New AMI Activities costs, FEI states that the 2026 Projected costs are lower than 2026 Approved primarily due to a shift in the deployment timing and ramp up period for the base stations from 2026 to 2027. For 2027, the increase from 2026 Projected is primarily due to the deferred base stations from 2026 being completed in 2027.

4.5 Please explain why the deployment of AMI base stations shifted from 2026 to 2027.

Response:

FEI clarifies that while a minor shift in base station deployment timing did occur between 2026 and 2027, the primary reason for the forecast increase in 2027 New AMI Activities costs is that Production Environment SaaS fees and Sensus Analytics licensing costs are expected to increase as FEI approaches functional acceptance of the AMI network and systems and as more AMI meters communicate over the network by the end of 2027. These costs are therefore forecast to be incurred later than originally anticipated, resulting in higher costs in 2027 relative to 2026.

The statement in the Application regarding a shift in base station deployment timing was intended to describe the timing of associated AMI operating costs rather than the physical deployment of base stations. Generally, the timing of the physical deployment of base stations is consistent with planned; however, the timing of when the actual operating costs are expected to occur has been slightly delayed due to administrative activities that need to occur subsequent to the installation of the stations.

C. RATE BASE

5.0 Reference: RATE BASE

Exhibit B-2, Section 7.6.1, Tables 7-8 and 7-9, pp. 68–69; FEI 2020 and 2021 Annual Review of Delivery Rates proceeding, Exhibit B-2, Section 7.5, Table 7-10, pp. 66–67

2026 Long Term Gas Resource Plan (LTGRP) Deferral Account

On page 69 of the Application, FEI states that it filed its 2026 LTGRP with the BCUC on March 27, 2026. FEI forecasts total regulatory costs associated with the development and regulatory review of the 2026 LTGRP of $2.900 million, including studies/analysis (such as for long-term demand forecast modelling and demand side management (DSM) analysis), multiple external consultants, engagement costs, and regulatory proceeding costs. FEI provides Table 7-9 in the Application showing a breakdown of the total costs for the 2026 LTGRP amounting to $2.900 million.

On pages 66 to 67 of Exhibit B-2 to the FEI 2020 and 2021 Annual Review of Delivery Rates proceeding, FEI estimated total costs of developing the 2022 LTGRP to be $0.850 million, plus $0.350 million for regulatory proceeding costs. FEI also provided Table 7-10 in Exhibit B-2 showing a breakdown of the total costs for the 2022 LTGRP amounting to $0.850 million.

5.1 Please provide a breakdown of the forecast $2.900 million total costs for the 2026 LTGRP by the year(s) in which they were or will be incurred (i.e. 2025, 2026, other).

Response:

Please refer to Table 1 below for the breakdown of the total forecast cost of $2.900 million by year, including the detailed breakdown of the costs associated with long-term demand forecasting scenario modelling and DSM analysis.

Table 1: 2026 LTGRP Cost Breakdown by Year

	2024 Actual	2025 Actual	2026 Projected	Total
Long-term demand forecasting, scenario modelling, and DSM analysis	$ 363	$ 1,079	$ 207	**$ 1,650**
Scenario Modelling and Sensitivity Analysis	259	594	132	**985**
DSM Analysis	-	127	8	**135**
Energy Supply & System Planning	-	118	21	**139**
Integrated Project Management	105	240	46	**391**
RPAG, interested parties, and Indigenous communities' engagement	$ 121	$ 125	$ 4	**$ 250**
Dual-Fuel Analysis	75	219	206	**500**
Regulatory Proceeding	-	17	483	**500**
Total	**$ 560**	**$ 1,440**	**$ 900**	**$ 2,900**

The individual activities related to long-term demand forecasting, scenario modelling, and DSM analysis are described below:

- **Scenario Modelling and Sensitivity Analysis** includes the development and evaluation of the planning scenarios used to assess potential future resource needs. This work incorporates feedback received through engagement activities, evaluates sensitivities for key variables such as customer growth, customer accounts and DSM, and integrates fuel-switching assumptions across FortisBC's gas and electric planning processes to support a coordinated assessment of future energy demand.
- **DSM Analysis** includes the incorporation of findings from the 2024 Conservation Potential Review (CPR), including the assessment of achievable energy savings and demand reduction potential under various DSM assumptions and planning scenarios.
- **Energy Supply and System Planning** includes load shape development and analysis of scenario impacts on energy supply requirements, system capacity needs, and infrastructure planning.
- **Integrated Project Management** includes overall project governance and coordination, engagement activities, management of planning inputs and outputs, development of data visualizations and reporting materials, and preparation and documentation of the methodologies, assumptions, and analytical approaches used throughout the Long-Term Resource Plans.

The actual expenditures incurred for the 2022 LTGRP were $2.338 million (approximately $1.707 million net of tax as discussed in the Annual Review for 2025-2026 Delivery Rates application[3]), not the estimated amount of $0.850 million referenced by the BCUC in the preamble. The forecast amount provided in the Annual Review for 2020-2021 Delivery Rates (i.e., $0.850 million) was the initial forecast and was developed prior to the establishment of the regulatory timetable for the proceeding. Of the $2.338 million total cost (or $1.707 million net of tax), the regulatory proceeding costs comprised approximately $1.494 million (or $1.090 million net of tax). The higher actual proceeding costs in the 2022 LTGRP compared to the forecast proceeding costs for the 2026 LTGRP are due to the 2022 LTGRP process including three rounds of IRs, intervener evidence and FEI's rebuttal evidence. Based on the regulatory timetable established in the 2026 LTGRP proceeding by Order G-84-26, which includes only one round of IRs and no intervener evidence, FEI has forecast $0.500 million (or $0.365 million net of tax), which is significantly less than the actual proceeding-related costs incurred for the 2022 LTGRP.

The 2026 LTGRP costs related to the preparation of the LTGRP (i.e., scenario modelling and analysis, studies, external consultants and engagement activities) are higher than the costs incurred for the 2022 LTGRP. The key drivers of these increased costs are discussed below:

- Increased complexity of the forecasting framework for the 2026 LTGRP, including expansion of scenario and sensitivity analysis.
- Additional work and costs required to enhance the End Use Annual Method in the 2026 LTGRP, which is described in Section 3.2 of the 2026 LTGRP. This work included:

[3] Exhibit B-2, Section 7.7.2.6, p. 77.

- Determining an appropriate set of alternative scenarios based on engagement and feedback;
- Adding sensitivity analysis for additional key variables, including customer accounts, DSM, and carbon capture, utilization, and storage;
- Adding renewable and lower-carbon gas to the transportation sector forecasts; and
- Integrating the key driver inputs and scenarios between FEI's LTGRP and FBC's LTERP, as well as increased consultation with BC Hydro to better understand differences in each utility's long-term demand scenarios.

- Additional work and costs associated with the Dual-Fuel Study which expands on the Kelowna Electrification Case Study that was presented in the 2022 LTGRP to understand the impact of fuel switching at a more granular level for the customers of both gas and electric utilities. As described in Section 4.7 of the 2026 LTGRP, the Dual-Fuel Study uses the billing data of residential customers within the shared service area of FEI and FBC to analyze the impact of demand shifting from gas to electricity.

5.1.1 If any of these costs were incurred or forecastable in 2025 or earlier, please explain why the 2026 LTGRP deferral account was not requested by FEI in the 2025 and 2026 Annual Review of Delivery Rates proceeding or other annual review proceeding.

Response:

FEI could have requested to establish the 2026 LTGRP deferral account in the Annual Review for 2025-2026 Delivery Rates. However, establishing the deferral account earlier would not have changed the timing of when the amortization of the deferral account would commence or the amount of the amortization itself. FEI decided to wait until the Annual Review for 2027 Delivery Rates application to request the deferral account because the forecast costs were better defined, particularly the regulatory proceeding costs, as the regulatory timetable for the 2026 LTGRP proceeding was established prior to FEI's filing of the Annual Review for 2027 Delivery Rates application.

With the benefit of more actual costs and the establishment of the regulatory timetable for the 2026 LTGRP, FEI was able to both seek approval of the deferral account and request an amortization period in the same application (i.e., the current Application). While not necessary, FEI determined that some regulatory efficiencies may be achieved with this approach, as the BCUC and interveners would be able to ask questions on the actual/forecast costs and the amortization period in the same proceeding, with more actual costs available to inform the forecast underpinning the request.

The cycles of long-term resource plan development are well established and understood. In the case of the 2026 LTGRP, FEI was directed by the BCUC to file the application by March 31, 2026.[4] In the 2022 LTGRP Decision, FEI was also directed to provide additional or new information on various topics in the next LTGRP. It was therefore established and known at the time that the 2022 LTGRP Decision was issued in March 2024 that FEI would be developing the next LTGRP and incurring costs related to this development. FEI has acted in a manner consistent with the directives in the 2022 LTGRP Decision and in a manner consistent with the development of previous LTGRPs. The timing of the request to establish the 2026 LTGRP deferral account does not have any impact on the activities that FEI was required to undertake in the preparation of the LTGRP, the actual costs that have been and will ultimately be incurred, or the timing of when these costs would actually be recovered in delivery rates. Accordingly, and consistent with the standard and well-established practice of developing the long-term resource plans and recording regulatory proceeding costs, the concept of retroactive ratemaking is not applicable.

FEI has relied on this established practice with the BCUC regarding the treatment of application costs in bringing forward the deferral account request for the 2026 LTGRP. The work to develop and prepare for the 2026 LTGRP is required and necessary. Had FEI not incurred costs to develop and prepare for the 2026 LTGRP in prior years, it would not be able to meet the BCUC's expectations for the LTGRP. Therefore, rejecting the establishment of the deferral account as well as the recovery of the costs incurred only based on the timing of the deferral account request relative to the timing of when the costs were incurred, without consideration of whether the costs were necessary or reasonable, would be inconsistent with the established treatment of application/regulatory proceeding costs, and would therefore be unfair and unreasonable.

In the proceeding regarding FortisBC's Application for Approval of Capital Expenditures for the Enterprise Resource Planning Modernization and Customer Information System Replacement Projects, the BCUC asked a similar question regarding retroactive ratemaking and FEI's and FBC's requests for approval of Application and Preliminary Stage Development Costs deferral accounts. FEI and FBC provided a comprehensive response to that question, which noted the BCUC's consistent practice of approving project development cost deferral accounts after project development costs have begun to be incurred.[5] The BCUC similarly approves proceeding cost deferral accounts after costs have begun to be incurred. In Orders G-125-26 and G-126-26, the BCUC approved FEI's and FBC's Application and Preliminary Stage Development Costs deferral accounts.[6]

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4 Directive 2 of Order G-78-24.

5 See Exhibit B-3, BCUC IR1 18.1: https://docs.bcuc.com/documents/proceedings/2026/doc_86251_b-3-fortisbc-response-bcuc-ir1-public.pdf.

6 https://docs.bcuc.com/documents/proceedings/2026/doc_87500_g-125-26-g-126-26-fortisbc-erp-cis-projects-final.pdf.

5.1.2 If any of these costs pertain to 2026 or earlier, for which delivery rates have already been set, please explain whether the recovery of these costs in rates beginning in 2027 constitutes retroactive ratemaking.

Response:

Please refer to the response to BCUC IR1 5.1.1.

5.2 Please provide a breakdown of the "long-term demand forecasting scenario modelling and DSM analysis" expenditures amounting to $1.650 million as shown in Table 7-9 of the Application.

Response:

Please refer to the response to BCUC IR1 5.1.

5.3 Please discuss the key drivers for the increase in the costs associated with the 2026 LTGRP compared to the 2022 LTGRP (e.g. number of consultants used, complexity of forecasting, etc.).

Response:

Please refer to the response to BCUC IR1 5.1.

On page 69 of the Application, FEI states:

> FEI is also seeking approval to amortize the 2026 LTGRP deferral account over three years, commencing January 1, 2027. 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., the 2022 LTGRP deferral account).

In Table 7-8 on page 68 of the Application, FEI states: "Generally, FEI amortizes the costs of regulatory proceedings over the period of time related to the application, which serves to match the timing of costs and benefits."

5.4 Please explain why FEI proposes a three-year amortization period for the 2026 LTGRP deferral account. As part of the response, please clarify whether FEI proposes: a) to match the amortization period of the 2022 LTGRP deferral account, or b) to match the period of time related to the application, or c) to match both, or d) another reason.

Response:

FEI's assessment of an appropriate amortization period for the 2026 LTGRP deferral account included the following factors:

- The forecast balance of the deferral account;
- The immediate rate impact on customers resulting from the amortization;
- The benefits of rate smoothing resulting from a longer amortization period versus the potential for intergenerational inequity;
- Whether the period matches the benefits or timeline of the project/application, or the expected period until the next application; and
- The amortization periods of previous similar deferral accounts, such as the 2022 LTGRP deferral account.

Based on the above considerations, FEI evaluated amortization periods ranging from 1 year to 5 years. Table 1 below provides the incremental delivery rate impact for each amortization period.

Table 1: Delivery Rate Impact due to the 2026 LTGRP Deferral Account based on an Amortization Period of One to Five Years

	Amortization Period				
	1 Year	2 Years	3 Years	4 Years	5 Years
Incremental Delivery Margin in 2027 ($000s)	2,957	1,568	1,105	873	734
Incremental Delivery Rate Impact compared to 2026 Approved (%)	0.22%	0.12%	0.08%	0.07%	0.05%
Incremental Delivery Rate Impact compared to 2026 Approved ($/GJ)	0.015	0.008	0.006	0.004	0.004

FEI rejected a 1-year amortization period due to the much greater and immediate impact on customer rates in 2027 when compared to a longer amortization period. FEI also considered there to be diminishing benefits in terms of rate smoothing for longer amortization periods such as four or five years (e.g., there is almost no change in the delivery rate impact in $/GJ from 3- to 5-year amortization periods). As such, FEI considered 2- or 3-year periods would provide some rate smoothing benefits without unnecessarily extending the recovery timeline for the deferred costs.

FEI then considered the approved amortization periods for the most recent LTGRP deferral accounts – the 2017 LTGRP deferral account and the 2022 LTGRP deferral account – both of which had approved amortization periods of three years. With regard to the timing of the next

LTGRP application, FEI stated in the 2026 LTGRP application that it anticipates submitting the next LTGRP approximately three to five years following the conclusion of the 2026 LTGRP proceeding.[7]

Based on all of the above factors, FEI considers the proposed 3-year amortization period for the 2026 LTGRP deferral account to be reasonable.

5.5 Please discuss whether FEI considered any alternate amortization period(s) for the 2026 LTGRP deferral account and explain why these alternatives were ultimately not chosen.

Response:

Please refer to the response to BCUC IR1 5.4.

[7] FEI 2026 LTGRP, Exhibit B-1, Section 10.2, p. 10-6.

6.0 Reference: RATE BASE

Exhibit B-2, Section 7.6.1, Table 7-8, pp. 68–69

2026 Mains Extension (MX) Policies Review Deferral Account

On page 69 of the Application, FEI states that it seeks approval to amortize the proposed 2026 MX Policies Review Deferral Account over a one-year period beginning January 1, 2027.

In Table 7-8 on page 68 of the Application, FEI states: "Generally, FEI amortizes the costs of regulatory proceedings over the period of time related to the application, which serves to match the timing of costs and benefits."

6.1 Please explain why FEI proposes a one-year amortization period for the 2026 MX Policies Review Deferral Account. As part of the response, please explain the consideration, if any, to the "period of time" related to the FEI 2026 Review of Mains Extension and Connection Policies proceeding and clarify what that time period is.

Response:

Consistent with the factors discussed in the response to BCUC IR1 5.4, FEI considered the following when assessing the appropriate amortization period for the 2026 MX Policies Review deferral account:

- The forecast balance of the deferral account;
- The immediate rate impact on customers resulting from the amortization;
- The benefits of rate smoothing resulting from a longer amortization period versus the potential for intergenerational inequity;
- Whether the period matches the benefits or timeline of the project/application, or the expected period until the next application; and
- The amortization periods of previous similar deferral accounts.

For the 2026 MX Policies Review deferral account, FEI evaluated amortization periods ranging from 1 year to 5 years. Table 1 below provides the incremental delivery rate impact for each amortization period.

Table 1: Delivery Rate Impact due to the 2026 MX Policies Review Deferral Account based on an Amortization Period of One to Five Years

	Amortization Period				
	1 Year	2 Years	3 Years	4 Years	5 Years
Incremental Delivery Margin in 2027 ($000s)	343	182	128	101	85
Incremental Delivery Rate Impact compared to 2026 Approved (%)	0.03%	0.01%	0.01%	0.01%	0.01%
Incremental Delivery Rate Impact compared to 2026 Approved ($/GJ)	0.002	0.001	0.001	0.001	0.000

As shown in the above table, due to the relatively small size of the expected balance of the deferral account, the impact on delivery rates is minimal even if the balance is amortized over 1 year.

As such, even though the benefits related to the 2026 MX Policies Review and the timing of the next MX Policies Review will be greater than 1 year, other factors such as the forecast size of the deferral account, the negligible rate smoothing benefits, and the minimal immediate impact on customer rates from amortizing the balance over 1 year, support FEI's proposed 1-year amortization period.

6.2 Please discuss whether FEI considered any alternate amortization period(s) for the 2026 MX Policies Review deferral account and explain why these alternatives were ultimately not chosen.

Response:

Please refer to the response to BCUC IR1 6.1.

D. EARNINGS SHARING AND RATE RIDERS

7.0 Reference: EARNINGS SHARING AND RATE RIDERS

Exhibit B-2, Section 10.3.3.1, Table 10-4, pp. 82–83

Approved Investments for Clean Growth Innovation Fund (CGIF)

On page 82 of the Application, FEI provides Table 10-4 showing its approved 2025 CGIF investments by application. On page 83 of the Application, FEI provides further details for these investments, which include:

a. a hydrogen pyrolysis pilot project;

b. two projects at existing RNG facilities in BC to improve methane production;

c. a project to advance preliminary development of a syngas demonstration project; and

d. four projects that will research and demonstrate utilization of solid carbon created from methane pyrolysis to produce low-cost hydrogen.

7.1 Please provide the current status of the above-mentioned CGIF projects. As part of the response, please indicate whether these projects are in pre-development, under construction, fully operational etc.

Response:

FEI provides the requested information below.

- The hydrogen pyrolysis project is a larger pilot with multiple funding partners. FEI has finalized its contribution agreement. The project team is still finalizing contribution agreements for some of the remaining funders. The project is expected to start the design phase by the end of 2026.
- The first RNG project is a demonstration of a wood-based catalyst that is being dosed into an anaerobic digester in BC. The demonstration began in September and is expected to last 120 days, which is the duration required for a statistically significant result. The second RNG project is to develop a metal organic framework (MOF) based biogas upgrader that can separate nitrogen as well as carbon dioxide to be effective for landfill gas upgrading. The demonstration unit is in fabrication and a BC landfill site has been selected. The first biogas throughput at the demonstration unit is expected by the end of 2026.
- The syngas feasibility study is proceeding in phases. The first two phases – a biomass supply study for the Prince George region and technology scouting – are complete. Technology scouting identified a shortlist of technology vendors that could work for this application. The project team is now negotiating with these vendors on cost and timeline to develop a cost estimate. In parallel to the development of a cost estimate, work will also include developing a carbon intensity model and procedure for wood-to-RNG projects, as well as a study into the market for byproduct biochar and the potential for harvesting wood

to support fire risk mitigation through forest thinning, fire breaks, and fire salvage. The cost estimate and carbon intensity studies are expected to start by November and be completed by the end of 2027. The first risk mitigation study will begin in the spring of 2027 to build off results of another project testing forest floor carbon contents across the province.

- The first of these projects has a signed contribution agreement and students have been hired by the university to investigate carbon black usage in industrial applications, including higher performance coatings and industrial rubber products. The second project is a multi-year carbon valorization research hub to debottleneck barriers in methane pyrolysis development and commercialization. This research hub is in pre-development, and does not yet have a contribution agreement. The third and fourth projects are demonstration projects with multiple funding partners that include demonstrating the use of solid carbon in hot asphalt mix and aluminum smelting anodes, respectively. Both of these projects are in pre-development, with demonstrations expected to occur in the 2027-2028 timeframe.