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July 20, 2026

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

Dear Registrar:

Re: FortisBC Energy Inc. (FEI)
2026 Long Term Gas Resource Plan (LTGRP)
Response to the British Columbia Utilities Commission (BCUC) Information Request (IR) No. 1

On March 27, 2026, FEI filed the 2026 LTGRP referenced above. In accordance with the regulatory timetable established in BCUC Order G-84-26 for the review of the 2026 LTGRP, FEI respectfully submits the attached response to BCUC IR No. 1.[1]

FEI has filed the response to BCUC IR1 16.1 on a confidential basis as identified in the 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

[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. ANNUAL DEMAND FORECAST

1.0 Reference: UNDERSTANDING OUR FUTURE ENERGY NEEDS

Exhibit B-1 (Application), Section 3, pp. 3-1, 3-6, Table 3-5, pp. 3-7, 3-11, Table 3-8, p. 3-12

Building Codes and Equipment Standards Setting in Diversified Approach Scenario

On pages 3-1 and 3-6 of the 2026 Long Term Gas Resource Plan (Application), FortisBC Energy Inc. (FEI) explains its five demand forecast scenarios which include Baseline Trends, Diversified Approach, Electrification Focus, Lower-Carbon Transportation and LNG Future, and Prolonged Transition.

On page 3-7 of the Application, FEI provides Table 3-5, which shows key drivers for all five scenarios, one of which is Building Codes and Equipment Standards. FEI sets a "Medium" setting for this key driver in the Diversified Approach scenario, and a "Medium-High" for the Baseline Trends.

On page 3-12 of the Application, FEI provides Table 3-8, which summarizes the different settings for the most impactful Building Codes and Equipment Standards settings for existing and new buildings, two of which are the Zero Carbon Step Code (ZCSC) and the Highest Efficiency Equipment Standards (HEES). The "Medium" setting shows "only known municipalities" for ZCSC and "not implemented" for HEES.

On page 3-11 of the Application, FEI explains that a "Medium" setting for ZCSC was developed for municipalities that had adopted a step above the mandatory province-wide standard as of November 2025, whereas a "Medium-High" setting illustrates a scenario in which ZCSC alongside HEES was adopted province-wide.

1.1 Please explain the basis for FEI's assumption in the Baseline Trends scenario that ZCSC will be adopted province wide by 2030 and HEES will be adopted province-wide in 2030.

Response:

FEI's assumptions for province-wide adoption of the ZCSC and HEES by 2030 in the Baseline Trends scenario were based on announced policy direction at the time the assumptions were finalized.

The Baseline Trends scenario was developed to reflect forward looking drivers, considering how known policies could evolve, not just what has already been implemented. At the time of scenario development, provincial direction pointed toward increasing electrification and lower-emissions buildings, including broader adoption of the ZCSC and HEES. This direction is reflected in the buildings pathway (Section 2.3) of the CleanBC Roadmap to 2030,[1] which includes a commitment to support the transition to zero-carbon new buildings by 2030 and to introduce highest-efficiency standards for new space and water heating equipment by 2030 (and earlier where feasible).

1.2 Please explain why FEI did not include province-wide ZCSC adoption by 2030 in the Diversified Approach scenario.

1.2.1 Please describe a high level or directional impact on FEI's annual and peak demand forecast if a province-wide ZCSC adoption by 2030 were included in the Diversified Approach scenario.

Response:

FEI did not include province-wide adoption of the ZCSC and HEES by 2030 in the Diversified Approach annual demand scenario because the scenario incorporates policies that have been implemented at the time of scenario development, unlike the Baseline Trends scenario which incorporates policies that have been announced, but not yet implemented. Further, the Diversified Approach scenario is intended to reflect a balanced policy trajectory, rather than an accelerated transition that prioritizes electrification.

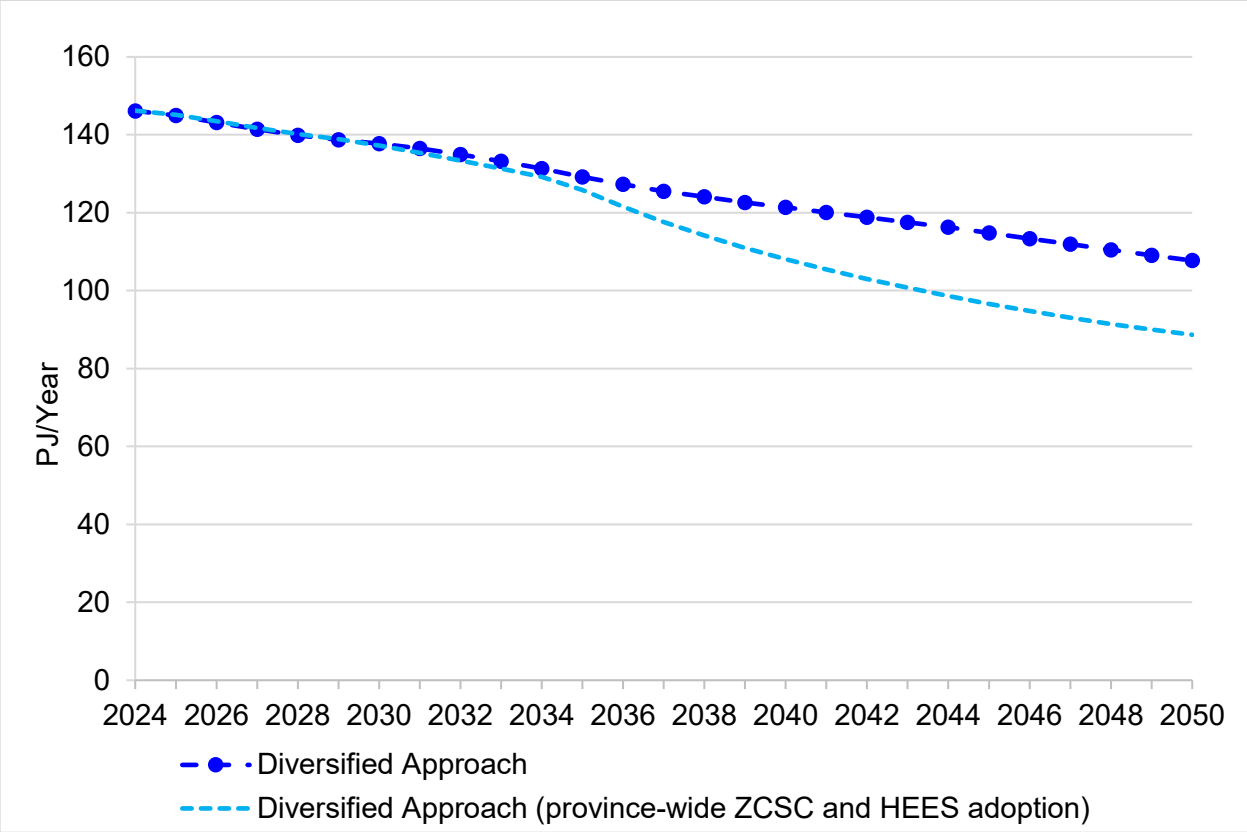
Under the Diversified Approach scenario, FEI applied a "Medium" setting for the Building Codes & Equipment Standards key driver, which assumes ZCSC adoption only occurs in municipalities that had adopted it as of November 2025, and does not assume implementation of the HEES. This reflects the current policy environment, as ZCSC adoption above the EL-1 step remains municipality-driven and uneven across the province, while the details of the HEES have not been finalized nor confirmed, including its implementation timeline.

[1] https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/cleanbc/cleanbc_roadmap_2030.pdf.

In contrast, province-wide ZCSC adoption by 2030 is represented in the "Medium-High" and "High" settings and is therefore captured in the Baseline Trends and Electrification Focus scenarios, respectively. These higher settings represent more policy-driven or accelerated pathways to electrification, including coordinated province-wide implementation of the ZCSC and HEES, which are subject to uncertainty in terms of timing, regulatory direction, and feasibility.

Please refer to Figure 1 below which shows the effect on annual residential and commercial demand based on a version of the Diversified Approach scenario that includes province-wide ZCSC and HEES adoption by 2030.

Figure 1: Annual Demand – Residential and Commercial Sectors



At a high level, FEI expects that, if the ZCSC and HEES were adopted and implemented province-wide by 2030, residential and commercial peak demand would be reduced relative to the System Peak Forecast by 2044, while industrial demand would be unaffected. FEI estimated the high-level peak demand impacts of fuel switching from the HEES by applying the proportional change in annual energy consumption to peak demand. As a high-level approximation, this estimate (using an energy-to-peak demand proxy) does not account for hourly load shapes or the coincidence of space and water heating loads during the system peak hour. Consequently, the estimated peak demand reductions are indicative and should not be interpreted as a detailed assessment of peak-hour impacts.

This estimate varies per transmission region for reasons including different growth rates, building stock, end-use penetration, and other factors. The relative impact of province-wide adoption of the ZCSC is less pronounced in regions that already have a higher number of municipalities that have adopted the highest level of the ZCSC (e.g., the Vancouver Island region), as was illustrated in Figure 7-1 of the 2026 LTGRP.

For the HEES, FEI included an estimated impact using the Medium market potential adoption for dual-fuel systems from the 2024 Conservation Potential Review (CPR), consistent with the approach described in Figure 1 of the response to CEC-COSCO-RCIA IR1 14.1, as dual-fuel systems are assumed to remain eligible under the HEES.

Table 1: Estimated Peak Demand Impacts of Province-Wide Adoption of the ZCSC and HEES Implemented by 2030

Transmission System	2044 SPF Peak Demand (TJ/Day)	ZCSC Impact in 2044 (TJ/day)	HEES Impact in 2044 (TJ/day)	2044 Peak Demand after ZCSC and HEES (TJ/Day)	% Change
VITS	505	(8)	(15)	483	-4%
CTS	2,186	(42)	(165)	1,979	-9%
ITS	369	(18)	(36)	315	-15%

When compared to the capacity of each transmission system, the VITS and CTS already had sufficient system capacity for the System Peak Forecast, and there is no impact on capacity requirements as a result of this estimation. For the ITS, the potential reduction in 2044 peak demand from 369 to 315 TJ/day potentially lowers peak demand below the existing system capacity and reduces reliance on short-term mitigation measures.

However, the magnitude and timing of reductions in peak demand remain uncertain and are dependent on future municipal adoption decisions, implementation timelines, building stock turnover, technology development, and the adoption rate of gas pathways such as dual-fuel heating systems and gas-fired heat pumps. Further, any reduction in annual energy or peak demand in the residential and commercial segments could be offset by increases in the industrial and transportation segments.

1.3 Please explain why FEI did not include province-wide HEES adoption in 2030 in the Diversified Approach scenario.

1.3.1 Please describe a high level or directional impact on FEI's annual and peak demand forecast if a province-wide HEES adoption in 2030 were included in the Diversified Approach scenario.

Response:

Please refer to the response to BCUC IR1 1.2.

2.0 Reference: UNDERSTANDING OUR FUTURE ENERGY NEEDS

Exhibit B-1, Section 3, p. 3-4; Metro Vancouver's Regional Growth Strategy 2050,[2] p. 19

Residential Demand Forecast

On page 3-4 of the Application, FEI states that it applies the same customer account forecast across all scenarios. FEI also states that its residential customer account forecasts are based on the Conference Board of Canada housing starts forecast for BC.

On page 19 of Metro Vancouver's Regional Growth Strategy 2050, it states:

> Strong population growth is an indicator of strong housing growth. To accommodate projected growth, the region will require an additional 500,000 dwelling units. Apartments are projected to make up over 50% of future growth, followed by multi-attached units.

2.1 Please explain whether and how FEI's residential demand forecast accounts for projected changes in housing mix toward apartments and multi-attached units, including any resulting impacts on average use per customer for new residential customers and annual residential demand.

Response:

The following response has been provided by FEI:

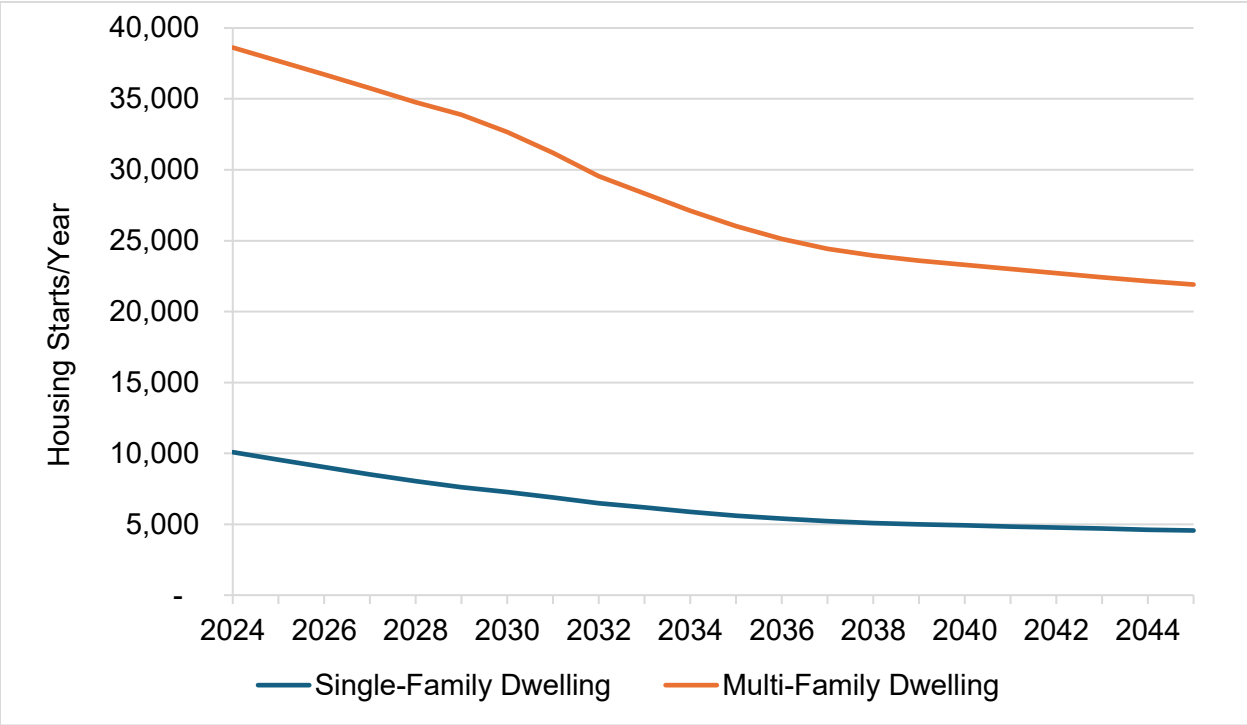
FEI's residential customer forecast accounts for changes in the housing mix towards multi-family dwellings.

The residential demand forecast is the product of the residential customer forecast and the residential use rate forecast. The residential customer forecast is based on discrete single and multi-family housing starts forecasts from the Signal49 (formerly the Conference Board of Canada, or CBOC).

The following figure shows the Signal49 housing starts forecasts for both single and multi-family dwellings. As shown in the figure, multi-family dwellings are expected to account for most of the housing starts in BC.

[2] metro-2050.pdf.

Figure 1: Signal49 Housing Starts Forecast by Dwelling Type (Single vs. Multi-Family)



The discrete Signal49 housing starts forecasts for single and multi-family dwellings are then compared to actual FEI single and multi-family customer additions and used to project single and multi-family customer additions 20 years into the future. These discrete customer forecasts, combined with the residential use rate forecast discussed below, appropriately account for changes in demand resulting from changes in the housing mix over time.

FEI has utilized this method for over 15 years.

The following response has been provided by Posterity Group:

The residential use rate forecast is based on forecasts of per-dwelling energy consumption characteristics across dwelling types and regions. As a result, the residential use rate forecast does account for the impacts of changing housing mix towards apartments and multi-attached units on average use-per-customer for new residential customers, as well as on annual residential demand.

Specifically, the per-dwelling energy consumption forecasts consider the following factors related to changes in the housing stock:

- Differences in energy consumption behavior between apartments and multi-attached units compared to other dwelling types (e.g., single-family dwellings), such as reduced space heating demand due to smaller dwelling size.

- Implementation of building codes and standards for new construction and how they impact energy consumption across dwelling types, such as in the timing and stringency of energy

requirements between multi-unit residential buildings (MURBs) and other dwelling types. This also reflects improved energy performance of new buildings over time, which has corresponding impacts on the forecasts of use-per-customer and annual residential demand.

3.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1, Section 2, p. 2-1, Section 3, pp. 3-24 – 3-25

Climate Change or Extreme Weather Impact on FEI's Annual and Peak Demand Forecast

On page 2-1 of the Application, FEI states that energy networks in British Columbia and across the Pacific Northwest are constrained under certain market conditions. FEI further explains that more frequent extreme weather events, combined with rising energy demand, are intensifying pressures on system reliability and resource adequacy, thereby straining existing infrastructure.

On pages 3-24 and 3-25 of the Application, FEI states that it modelled sensitivities for variables that did not align directly with the scenario narratives, including residential customer accounts, Demand Side Management (DSM), and carbon capture, utilization, and storage.

3.1 Please confirm, or explain otherwise, whether FEI considered climate change impacts or extreme weather events as part of its sensitivity analysis for its annual and peak demand forecasts.

3.1.1 If not confirmed, please explain why not. Please also describe the expected directional impact and any available quantitative impact on FEI's annual and peak demand forecasts if climate change or extreme weather events impacts were included in the sensitivity analysis.

Response:

FEI undertook preliminary, exploratory work to consider how climate change impacts could be reflected in the development of the annual demand forecast and indirectly in the peak demand (1-in-20 return period) forecast which incorporates observed extreme weather trends, as discussed below.

Annual Demand

For the annual demand forecast, FEI undertook initial exploratory work to assess how climate change impacts could be incorporated into modelling as a sensitivity analysis variable. This work was presented at the July 2025 RPAG session as a preliminary illustration of potential outcomes. The analysis considered two Intergovernmental Panel on Climate Change (IPCC)[3] climate pathways: Representative Concentration Pathway 4.5 (Shared Socioeconomic Pathway, SSP2-4.5), representing a "middle-of-the-road" global warming pathway, and Representative Concentration Pathway 8.5 (SSP5-8.5), representing a higher global warming pathway.

[3] The IPCC is the United Nations body for assessing the science related to climate change. See IPCC, Climate Change 2021: The Physical Science Basis, Working Group I Contribution to the Sixth Assessment Report (AR6), Chapter 4, Section 4.2.2, "Scenarios." Online at: https://www.ipcc.ch/report/ar6/wg1/chapter/chapter-4/

The sensitivity analysis was helpful to understand that there was not a material difference between the impacts of the two IPCC climate pathways. However, given its preliminary and exploratory nature, the analysis was not sufficiently developed to support robust quantification and was therefore not incorporated into the 2026 LTGRP. Notwithstanding, the analysis indicates that the directional impact of climate change is downward pressure on annual gas demand over time.

Peak Demand

While climate models are generally suited to projecting long-term average conditions, there remains limited reliability in their application to the frequency and severity of extreme weather events. As the application of a climate change sensitivity is more uncertain, FEI did not include climate change or extreme weather impacts as a formal sensitivity for peak demand in the 2026 LTGRP.

However, FEI's peak demand forecast is based on 1-in-20 design-day conditions, which incorporates statistically rare extreme weather events observed over the past 20 years, including the 2021 heat dome as well as three extreme cold weather events in December 2021, December 2022 and January 2024. These recent observed weather trends are incorporated through periodic updates to the design-day temperature assumptions used to estimate peak demand.

FEI will continue to advance its analytical approach in future planning cycles to further assess and, where appropriate, quantify the potential impacts of climate change and extreme weather on both annual and peak demand forecasts.

4.0 Reference: UNDERSTANDING OUR FUTURE ENERGY NEEDS

Exhibit B-1, Section 3, p. 3-13, Figure 3-1, p. 3-14; FEI 2022 Long Term Gas Resource Plan (LTGRP) proceeding, Decision and Order G-78-24 dated March 20, 2024 (2022 LTGRP Decision), p. 21

Marine Bunkering Demand Forecast

On page 3-14 of the Application, FEI provides Figure 3-1, which shows annual demand forecast for marine and ISO shipments.

On pages 3-13 to 3-14 of the Application, FEI describes forecast settings it developed for each of marine and ISO shipment market segments. FEI forecast increases in marine bunkering market to 31 petajoules (PJ) in 2032 under the "Low" setting, 39 PJ in 2032 with a gradual growth to 44 PJ by 2035 under the "Medium" setting, and 40 PJ by 2032 and 101 PJ by 2036 under the "High" setting.

On page 21 of FEI 2022 LTGRP Decision, the BCUC rejected FEI's planned investments in liquefied natural gas (LNG) for marine bunkering due to significant uncertainty and the lack of evidence around the demand forecast.

4.1 Please summarize the supporting evidence FEI relied on to develop LNG marine bunkering demand growth assumptions.

Response:

FEI clarifies that it was not seeking approval of specific investments in the 2022 LTGRP. The full context of the BCUC's commentary on page 21 of the 2022 LTGRP Decision regarding LNG marine bunkering is provided below for reference.

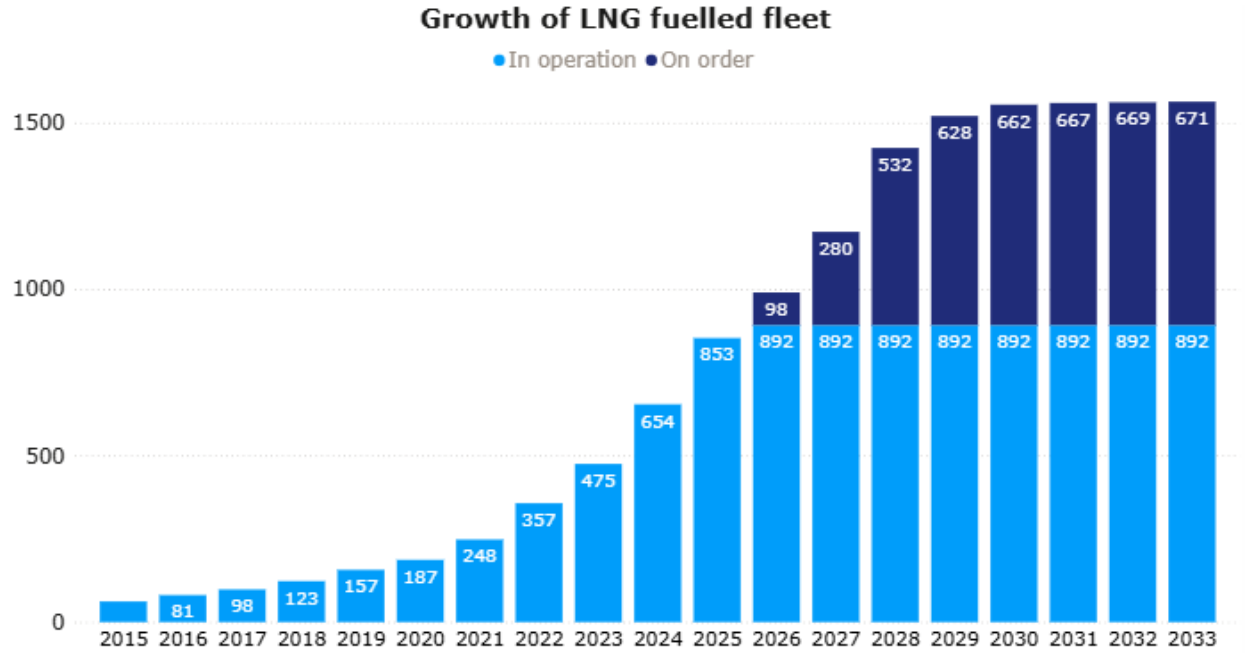
> The Panel accepts FEI's evidence that there is a significant potential sales market for LNG for bunkering and export, which could result in considerable benefits accruing to its ratepayers. Based on FEI's evidence, the Panel considers there is a possibility that such demand may materialize; therefore, **the Panel finds that the Planning LNG demand setting forecast that is included in the Diversified Energy Planning demand scenario is reasonable for the purposes of outlining FEI's potential demand in a long-term resource plan, and meets the requirements of section 44.1 (2)(a) of the UCA.** However, the Panel does not view the Planning LNG demand setting forecast alone to be sufficient justification for further investments in LNG. There is no evidence that FEI has entered into firm contracts for the sales of LNG for bunkering and export, nor is there evidence that such a prospect is imminent. Additionally, the Marine Jetty project, which is necessary for LNG bunkering and export, has not received the necessary permits, including an environmental assessment certificate, nor has a firm construction start date been set. Due to the significant uncertainty associated with this market currently, at this point in time the Panel is not in a position to determine that pursuit of sales, and related infrastructure investments in LNG for bunkering and export market will be beneficial to ratepayers and in the public interest, as discussed

further in section 3.4.2. Additionally, the Panel finds that it is reasonable for FEI to continue to evaluate the demand for LNG for bunkering and export and include such an evaluation in its next long-term gas resource plan.

Since the BCUC's 2022 LTGRP Decision (issued on March 20, 2024), the following developments have occurred which support FEI's LNG marine bunkering demand growth assumptions and evidence included in the 2026 LTGRP:

- The environmental assessment certificate for the Tilbury marine jetty project was issued in July 2024.
- Subsequent to issuance of the environmental assessment certificate, FEI commissioned a global specialized maritime brokerage firm, Affinity, to review previous demand forecasts including the Port of Vancouver's 2019 LNG demand forecasts. The study, which was received in January 2025, confirmed prior study projections, indicating that demand for LNG in the Port of Vancouver is expected to continue to rise, reaching between 0.6 and 1.1 million tonnes per annum (MTPA) by 2030 and between 3.8 to 5.8 MTPA by 2050.
- DNV, a world leading maritime classification society, shows LNG's strong leadership as an alternative marine fuel, with 892 LNG vessels in operation and 671 on order, for a total of 1,563 vessels in Q2 2026, almost three times the combined total of all other alternative fuels (methanol, hydrogen, and ammonia at 539 vessels),[4] as demonstrated in Figure 1 below.

Figure 1: Growth in LNG-Fueled Vessels



[4] DNV, Alternative Fuels Insight (AFI) platform (2026), online at (subscription required): https://www.dnv.com/services/alternative-fuels-insight-afi/.

- LNG accounted for 67 percent of alternative-fuel ship orders in 2025[5], and continues to show strong growth in 2026 with 60 orders by the end of May[6]. SEALNG, an industry coalition focused on LNG as a marine fuel, predicts upwards of 2,500 LNG dual fuel vessels in operation by 2030[7].

In addition to the developments noted above, FEI has seen exponential growth in marine bunkering demand since the installation of Seaspan's temporary manifold system in Q4 2024 that has enabled Seaspan to fill its marine bunkering vessels. In 2025, FEI sold over 4.3 PJ of LNG for marine bunkering, and in the first five months of 2026, FEI has already sold 3.6 PJ. The following table and figure show the rapid increase in LNG demand, which started at the end of 2024 and has continued to increase at a high rate.

Table 1: FEI Annual LNG Sales from 2022 to May 2026

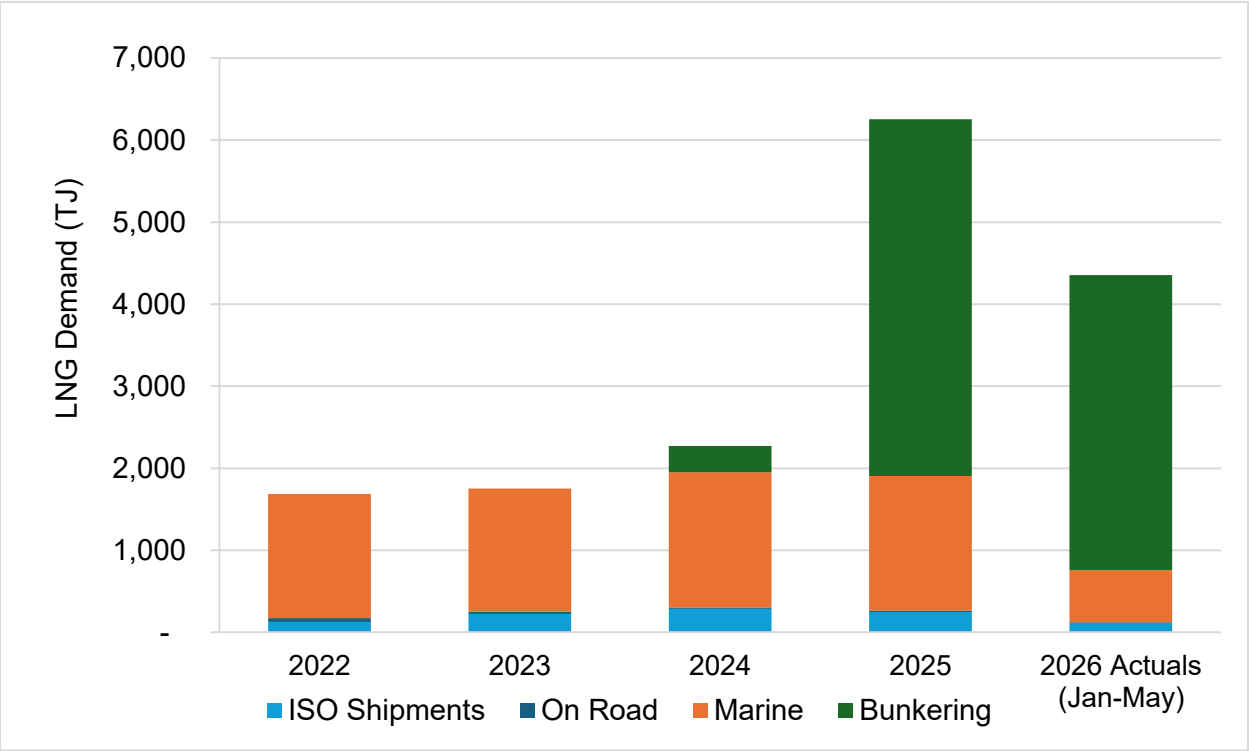
LNG Demand (TJ)	2022	2023	2024	2025	2026 Actuals (Jan-May)
On Road	48	26	13	15	5
Marine	1,512	1,502	1,651	1,643	637
Bunkering	-	-	323	4,353	3,597
ISO Shipments	125	223	286	245	115
Total	**1,686**	**1,752**	**2,273**	**6,257**	**4,354**

[5] Rivera, "LNG and methanol dominate nearly 90% of 'alternative' fuels in 2025 new ship orders" (December 2, 2025), online at: https://www.rivieramm.com/news-content-hub/news-content-hub/lng-and-methanol-dominate-nearly-90-of-alternative-fuels-in-2025-new-ship-orders-87003.

[6] MarineLink, "Alternative-Fuel Vessel Orders Reach 119 in First Five Months of 2026, DNV Finds" (June 4, 2026), online at: https://www.marinelink.com/news/alternativefuel-vessel-orders-reach-first-539957.

[7] SEA-LNG, The Journey: a Decade Moving Towards a Cleaner Future, "A View from the Bridge" (2025-2026), online at: https://sea-lng.org/wp-content/uploads/2026/01/A_View_From_The_Bridge_2026-1.pdf.

Figure 2: FEI Annual LNG Sales from 2022 to May 2026



4.2 Please explain whether new evidence and/or analysis support FEI's LNG marine bunkering demand growth assumptions in the 2026 LTGRP, in light of the BCUC's findings in the 2022 LTGRP decision regarding uncertainty associated with LNG marine bunkering.

Response:

Please refer to the response to BCUC IR1 4.1.

4.3 Please identify which LNG marine bunkering demand setting is relied on in FEI's assessment of future Coastal Transmission System (CTS) capacity needs and resource planning actions. If the LNG marine bunkering demand settings are not used for CTS infrastructure planning, please explain why not.

Response:

The CTS design assumes the Medium setting with a demand growth up to 136 TJ/day or 44 PJ annually from the marine (short-sea and bunkering) and ISO containerized shipments sectors.

As discussed in Section 7.3.2.2 of the 2026 LTGRP, additional LNG liquefaction demand beyond 136 TJ/day or 44 PJ annually from these sectors (i.e., beyond Tilbury 1B) may create system impacts and could trigger the need for system reinforcements of the CTS, including increased compression or pipeline looping additions (please refer to Table 7-3 on page 7-17 of the 2026 LTGRP).

B. DEMAND SIDE MANAGEMENT

5.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Section 4.2, p. 4-2; Appendix A, Table 6, pp. 23-24; Demand Side Measures Regulation (DSM Regulation) B.C. Reg. 167/2023

Adequacy

On page 4-2 of the Application, FEI states that it designs its Demand Side Measures (DSM) portfolio to meet the adequacy requirements of section 3 of the DSM Regulation, as set out in Table 6 of Appendix A.

Table 6 on pages 23 and 24 of Appendix A to the Application appears to refer to the previous version of the DSM Regulation, prior to BC Reg. 167/2023. See Section 3 (1) (a) (ii) (B), 3(1)(e) and 3(1)(g) in particular.

5.1 Please provide an updated version of Table 6 in Appendix A.

Response:

The table below provides an updated version of Table 6 in Appendix A.

Updated Table 6: Adequacy Requirements of the DSM Regulation

Section of the DSM Regulation	Adequacy Requirement	How FEI's DSM portfolio addresses adequacy
3(1)(a)	A demand-side measure intended specifically (i) To assist residents of low-income households to reduce their energy consumption, or (ii) To reduce energy consumption in housing owned or operated by (A) A housing provider that is a local government, a society as defined in section 1 of the *Societies Act*, other than a member-funded society as defined in section 190 of that Act, or an association as defined in section 1 (1) of the *Cooperative Association Act*, (B) Repealed. [B.C. Reg. 167/2023, s. 3 (b).] If the benefits of the reduction primarily accrue to (C) The low-income households occupying the housing, or (D) A housing provider referred to in clause (A), or (E) Repealed. [B.C. Reg. 167/2023, s. 3 (e).]	**Low Income Program Area:** includes measures intended specifically to serve individual Low Income customers, Indigenous housing, co-operative housing, non-profit housing, and charities that aid Low Income customers.
3(1)(b)	If the plan portfolio is submitted on or after June 1, 2009, a demand-side measure intended specifically to improve the energy efficiency of rental accommodations;	**Rental Apartment Efficiency Program:** incentives and energy saving measures intended specifically to support rental apartment buildings, targeting landlords, property managers, and in-suite upgrades for tenants in participating buildings.
3(1)(c)	An education program for students enrolled in schools in the public utility's service area;	**FEI's Conservation, Education and Outreach Program Area:** FEI's School Education Program supports school initiatives across FEI's service area.
3(1)(d)	If the plan portfolio is submitted on or after June 1, 2009, an education program for students enrolled in post-secondary institutions in the public utility's service area;	**FEI's Conservation, Education and Outreach Program Area:** FEI's School Education Program supports initiatives for post-secondary institutions across FEI's service area.

Section of the DSM Regulation	Adequacy Requirement	How FEI's DSM portfolio addresses adequacy
3(1)(e)	One or more demand-side measures to provide resources as set out in paragraph (g) of the definition of "class A demand-side measure", representing no less than (i) An average of 1% of the public utility's plan portfolio's expenditures per year over the portfolio's period of expenditures, or (ii) An average of $2 million per year over the portfolio's period of expenditures;	**FEI's Enabling Activities Program Area:** provides funding and support for developing codes and performance standards at the municipal, provincial and national level for energy efficient products and codes. FEI provides resources for and collaborates with other partners and municipalities on implementation and adoption of codes and standards and adoption of the BC Energy Step Code (ESC).[8] Included in the 1% planned adequacy funding are resources dedicated to standards making bodies which are advancing new testing and evaluation standards of gas fired equipment. Activities such as providing guidance and technical support for gas related energy efficiency initiatives are included to support the provincial government. On a federal level, planned funding is included to support the development of national building codes.
3(1)(f)	One or more demand-side measures intended to result in the adoption by local governments and first nations of a step;	**FEI's New Home and Commercial New Construction Programs:** provides tiered incentives for BC ESC including a customized offer for Indigenous groups.
3(1)(g)	A demand-side measure intended specifically to reduce energy consumption in any of the following: (i) Housing owned or operated by an Indigenous governing body or located on reserve land; (ii) A public building owned or operated by an Indigenous governing body.	**FEI's Indigenous Program Area:** The energy efficiency programming in this area focuses on improvements for existing homes and new construction, including measures intended specifically to reduce energy consumption in community buildings and community housing owned or operated by an Indigenous governing body.

1

8 BC ESC is an optional compliance path in the BC Building Code that local governments may use to incentivize or require a level of energy efficiency in new construction that goes beyond the BC Building Code requirements.

6.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Section 4.4.2, p. 4-14; FEI 2026 and 2027 Incremental DSM Expenditures proceeding, Exhibit B-1, Section 1.1, p. 1

Estimated Delivery Rate Impact

On page 4-14 of the Application, FEI states:

> This demonstrates that the average annual bill impact for residential customers under the Diversified Approach scenario is approximately 3.0 percent under the Medium setting and is 2.4 percent under the Low setting and 4.2 percent under the High setting. Further, for residential customers that have an annual consumption of approximately 55 GJ [gigajoule], the cumulative monthly bill impact in 2050 due to DSM programs would be $67 under the Medium setting, $50 under the Low setting and $113 under the High setting. FEI notes that the figures do not consider future rate design changes and are not indicative of a detailed bill forecast. They simply provide a directional view of the estimated 2050 bill impact due to DSM when compared to currently-approved rates in 2026.

In the ongoing 2026 and 2027 Incremental DSM Expenditures proceeding, FEI is requesting to increase the amortization period for its rate base DSM deferral account from 10 years to 20 years to better match the average measure life of its DSM portfolio and to provide immediate delivery rate mitigation benefits for customers.

6.1 Please clarify FEI's assumptions in the 2026 LTGRP, regarding the amortization period for its rate base DSM deferral account, in the estimated delivery rate impact provided in the Application. Depending on the assumption used, please provide the proportional impact of using either the alternative 10 or 20 year amortization period.

Response:

For all DSM expenditure settings and the associated rate impact analyses in the 2026 LTGRP, FEI used the currently approved amortization period of 10 years.

FEI notes that, on July 16, 2026, the BCUC issued Decision and Order G-153-26 regarding the FEI 2026 and 2027 Incremental DSM Expenditures Application. In the decision, the BCUC denied FEI's request to change the amortization period for its rate base DSM deferral account from 10 years to 20 years. Accordingly, the information contained in the 2026 LTGRP (i.e., the use of the 10-year amortization period for the DSM deferral account) reflects the approved amortization period for this deferral account.

7.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Section 4.6, pp. 4-20, 4-21

Kelowna Dual-Fuel Study

On pages 4-20 and 4-21 of the Application, FEI states that the Kelowna Dual-Fuel Study is an ongoing, collaborative study conducted by FEI and FortisBC Inc. (FBC) that analyses the impacts to both customers and utilities of dual-fuel heating systems compared to renewable natural gas (RNG) and electrification options in FortisBC's shared gas and electric service area in the Okanagan.

7.1 Please indicate who was appointed to conduct the study, and provide a copy of the terms of reference and the latest documentation of the reports' findings, if any.

Response:

The Kelowna Dual-Fuel Study was led by FortisBC, not a consultant; therefore, FEI did not develop any terms of reference for the study. Posterity Group supported FortisBC in the analysis through load modelling, as discussed on pages 4-24 and 4-27 of the 2026 LTGRP, and Energy and Environmental Economics (E3) supported the development of the Customer Affordability Model as discussed in Section 4.7.4 of the 2026 LTGRP.

FortisBC's analysis of dual-fuel systems has been ongoing and iterative since the Kelowna Electrification Case Study, and the findings to date have been included in Sections 4.6 and 4.7 of the 2026 LTGRP. FortisBC is continuing to advance dual-fuel analysis as part of FBC's 2026 LTERP to be filed later this year, to understand the implications on FBC's electric system.

8.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Section 4.1, p. 4-1; Section 4.6, p. 4-18; Dual-Fuel Heating Systems: FBC system capacity assumptions and peak mitigation

Kelowna Dual-Fuel Study

On page 4-1 of the Application, FEI states that current results from its ongoing Kelowna Dual-Fuel Study are used to analyze the impacts to both customers and utilities of dual-fuel heating systems compared to RNG and electrification options.

8.1 Please discuss the implications of the Kelowna Dual-Fuel study for the rest of FEI's service territory. In the response, please elaborate on what information FEI has about the need for dual -fuel systems to address electrical capacity in other areas of FEI's service territory.

Response:

While FEI does not have comprehensive information on electrical capacity constraints in other areas outside of FBC's service area, Table 1-1 of BC Hydro's 2025 IRP includes elements to prepare to initiate capacity upgrades to supply Vancouver Island, and to prepare to initiate a second step of Interior to Lower Mainland transmission upgrades, indicating a need for future capacity in these regions.

Publicly-available academic research from the University of Victoria's Institute for Integrated Energy Systems (IESVic) has illustrated the potential impacts of broader adoption of dual-fuel heating systems in British Columbia.[9] The IESVic study compared electric and hybrid (dual-fuel) residential heating pathways as described below, and found that dual-fuel heating systems can avoid electric peak demand across the province while supporting GHG emission reductions. The research is relevant to FEI's service area because it demonstrates the potential value of dual-fuel heating systems by region and is not confined to a single climate zone. For example, in the Lower Mainland and Vancouver Island, where temperatures are generally milder but residential load is more concentrated, dual-fuel systems can provide significant peak electric demand avoidance during cold-weather events that result in large system coincident electric heating demand.

This finding is directionally consistent with information presented in BC Hydro's 2025 IRP. BC Hydro reported that, in the Lower Mainland, dwellings with dual-fuel heating systems, including central heat pump systems with gas furnace backup, have approximately 75 percent lower peak demand than dwellings with single-fuel all-electric heat pump systems (Figure 2-7)[10]. This further

[9] Tamara Knittel et al, IESVic Study: *Charting Space Heating Futures: Toward a Blend of Electrification and Renewable Gas* (July 16, 2025). The IESVic study is currently under peer review prior to journal publication. However, the results of the study and the figures reproduced in this response are presented in the following link: https://www.youtube.com/watch?v=PypwghksnE0. The results of the study were presented to the RPAG by IESVic on July 10, 2025. Further, a study brief can be retrieved from: https://www.uvic.ca/research/centres/iesvic/news-events/energybriefs/current-briefs/charting-space-heating-futures.php.

[10] BC Hydro, 2025 Integrated Resource Plan (October 31, 2025) online at: https://docs.bcuc.com/documents/proceedings/2025/doc_84202_b-1-bch-2025-irp-application.pdf.

supports the conclusion that dual-fuel heating systems may provide material electric capacity value in coastal regions where peak weather conditions are less severe than in colder interior regions, but where the scale of residential load can be significant.

Specifically, the IESVic study evaluated the following two residential heating pathways:

- **Electric Heat:** in which most residential space heating demand is served by high-efficiency air-source heat pumps with remaining demand served by baseboard heating; and
- **Hybrid (Dual-Fuel) Heat:** in which a portion of residential space heating demand (under three adoption rate levels of 66, 60 and 33 percent) is served by dual-fuel systems that operate as electric heat pumps under moderate temperatures and switch to gas furnace operation during colder temperatures.

IESVic evaluated multiple switchover temperatures (SOTs) in 2°C increments, ranging from -6°C to +4°C, to assess how different operating strategies affect peak electricity demand, gas requirements, and GHG emissions.

IESVic found that the Electric Heat scenario substantially increases electric grid capacity requirements relative to Hybrid Heat scenarios, which incorporate dual-fuel systems that switch from electric to gas heat during colder weather to significantly reduce electric peak demand.

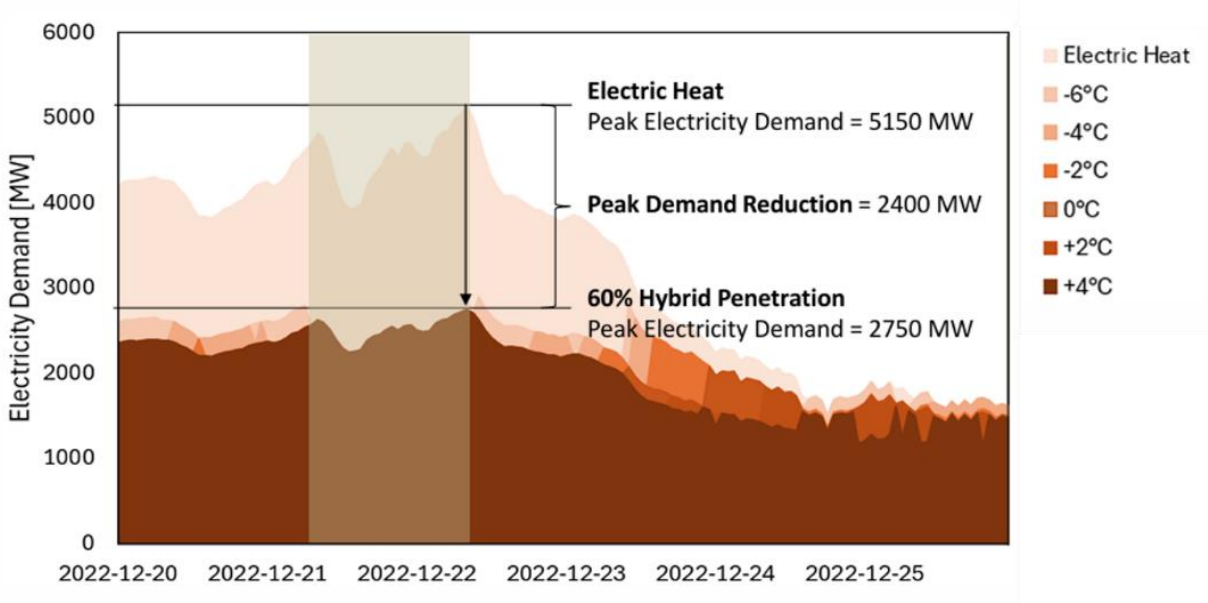
In Figure 1 below from the IESVic study, the potential electric peak demand in 2050 is presented using a temperature profile from December 2022.[11] This figure illustrates that in a dual-fuel scenario with 60 percent penetration, the electric peak demand for residential space heating could be 2,750 MW, which is 2,400 MW (or 47 percent) lower relative to the Electric Heat scenario.

This 2,400 MW peak demand reduction reflects the province-wide result for British Columbia in the illustrated 2022 weather year. Analysis from IESVic determined that a significant portion of this demand (a maximum of 1,400 MW or 1.4 GW) is attributable to the Lower Mainland and Vancouver Island, due to the combination of larger population density and periodic low-temperature events.[12] The remaining analysis presented is for results across FEI's service area and uses the 60 percent adoption rate level for dual-fuel systems.

[11] In this December 2022 temperature profile, daily temperatures at the Vancouver airport (Climate Zone 4) reached a minimum mean daily temperature of -10°C.

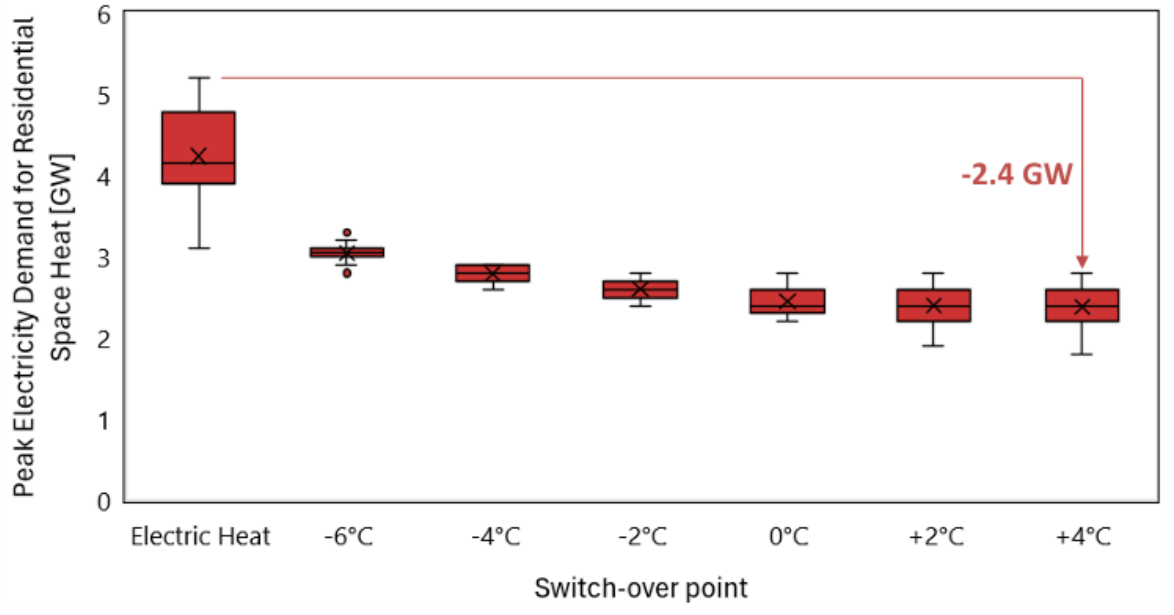
[12] For comparison, the avoided capacity in the Lower Mainland and Vancouver Island is greater than the peak generation available from the Site C hydroelectric facility (1,230 MW).

Figure 1: Peak Demand for Residential Space Heating in 2050 (2022 Weather Year)



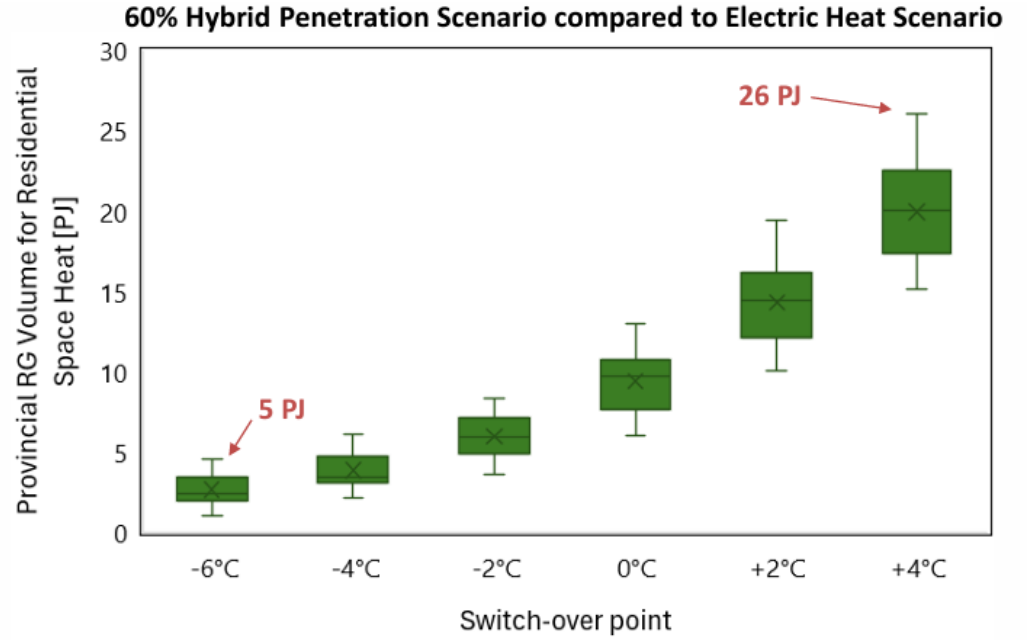
As shown in Figure 2 below, the IESVic study indicates that a 60 percent dual-fuel heating system penetration scenario could result in an average peak demand reduction (the difference between the "X" markers in the boxplots) between 1.2 GW and 1.9 GW, with a maximum peak demand reduction (the difference between the upper whiskers) of 2.4 GW, depending on the SOT.

Figure 2: Peak Demand for Residential Space Heating in 2050 Under Different Switchover Temperatures and Temperature Years



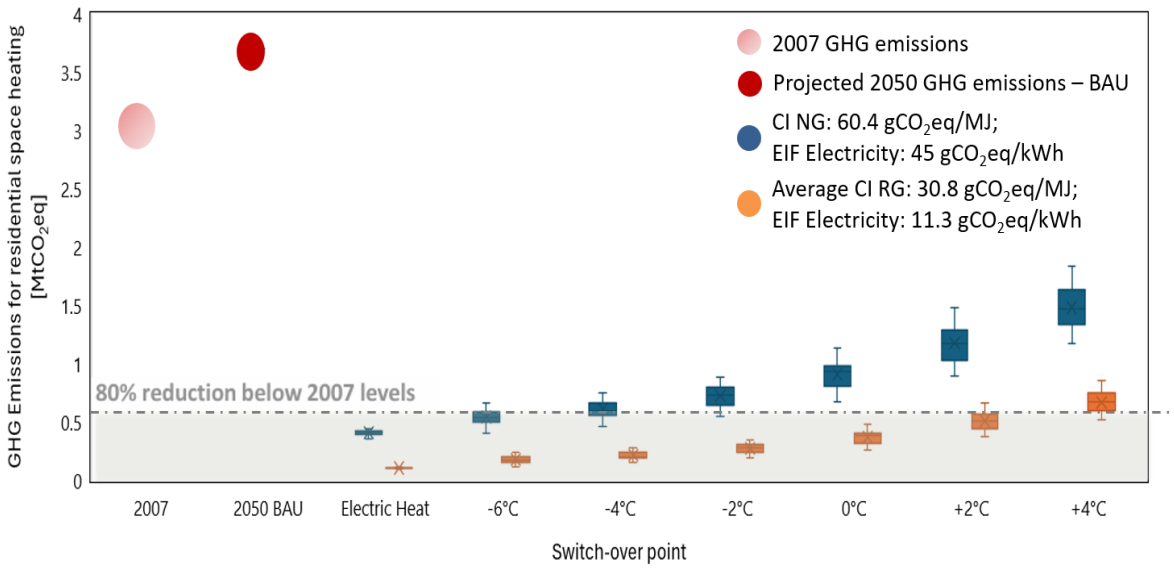
The IESVic study also evaluated the gas volumes required for residential dual-fuel heating systems. As illustrated in Figure 3 below, gas volumes for residential space heating varies from approximately 5 PJ at a -6°C SOT to approximately 26 PJ at a +4°C SOT.

Figure 3: Gas Requirements for Residential Space Heating in 2050 Under Different Switchover Temperatures



Lastly, the IESVic study illustrated how residential dual-fuel heating systems can support GHG emissions reductions. Figure 4 below illustrates that if residential dual-fuel heating systems are supplied with renewable gas, this can significantly reduce residential space-heating emissions and, depending on the SOT and the average carbon intensity of the gas supply, can be consistent with provincial GHG emissions reduction targets by 2050.

Figure 4: GHG Emissions for Residential Space Heat (Relative to 2007)[13] [14]



The IESVic study is responsive to LIEC-Saanich-Richmond IR1 8.4 because it evaluates how different switchover temperatures affect peak electricity demand, gas requirements and GHG emissions. However, the IESVic study does not provide FEI-specific region-by-region results for each degree of changeover temperature between FEI's program assumptions and a Québec-comparable changeover temperature. Rather, it provides province-wide evidence of the trade-off inherent in switchover temperature selection.

As shown in Figures 2 to 4 above, lower switchover temperatures reduce gas requirements (both renewable and non-renewable) and can support lower GHG emissions, while higher switchover temperatures provide additional electric peak mitigation during cold-weather periods. This demonstrates that the appropriate switchover temperature is not determined by peak demand alone, but requires balancing electric system capacity needs, annual gas consumption, GHG emissions, heat pump performance at colder temperatures, customer affordability and program participation.

In conclusion, the research from IESVic demonstrates that residential dual-fuel heating systems have the potential to provide significant system-wide benefits for residential space heating across BC. Relative to an Electric Heat scenario, residential dual-fuel heating systems can avoid electric winter peak demand and electricity consumption growth as compared to an electric heating baseline, while also achieving similar GHG emissions reductions. Consistent with the findings of the Kelowna Dual-Fuel Study, the most significant system benefit stems from avoided electric winter peak demand, which may defer or reduce investments in electric generation, transmission,

[13] Carbon Intensity (CI), Emission Intensity Factor (EIF), Business-as-usual (BAU), renewable gas (RG).

[14] The CI assumptions used in the IESVic academic research are independent of, and differ from, the emissions factors presented in Section 9.3 of the 2026 LTGRP and were developed independently for the purposes of the academic research.

and distribution infrastructure that may otherwise be required to support widespread electrification.

The IESVic research indicates that the benefits of dual-fuel heating systems are not confined to colder regions or areas experiencing localized electric infrastructure constraints. Instead, the research demonstrates that there is value across the province and different climate zones, especially in more populated and comparatively temperate regions, including the Lower Mainland and Vancouver Island.

These results from IESVic, and FortisBC's ongoing dual-fuel analysis, support the need for future analysis on the role that dual-fuel systems may play across the province in balancing the amount of electric demand growth which alleviates pressure to the electric grid, GHG emissions reductions, and efficient utilization of both gas and electric infrastructure across FEI's service area.

On page 4-18 of the Application, FEI states:

> Through joint utility planning, FEI and FBC identified dual-fuel heating systems as a key solution to balance system and customer needs across both gas and electric systems. Dual-fuel heating systems can avoid increasing electric demand during the highest periods of winter demand by using a gas furnace and the gas delivery system during these times, thereby deferring or avoiding electric infrastructure costs that would otherwise be required. A report from Ontario demonstrated that in cold climates dual-fuel heating systems can significantly reduce electricity system costs compared to ASHP [air source heat pump] with resistance back-up.

8.2 Please discuss the impact of dual-fuel heating systems on FEI's system peak demand.

Response:

FEI interprets this question as relating to the impact of dual-fuel heating systems on peak demand relative to existing gas furnaces in FortisBC's shared service area.

For dual-fuel heating systems, customers are required to install a new furnace with higher efficiency. This improved efficiency results in a modest reduction in peak gas demand, estimated at approximately 0.003 GJ in the peak hour per residential detached home in the ITS portion of FEI's gas system. Beyond the benefits of dual-fuel heating systems on reduced gas peak demand, they also provide benefits in improved efficiency, lower energy bills and GHG emissions, and avoided electric peak demand.

The system-level impact depends on the level of adoption. Within FEI's and FBC's shared service area, approximately 45,000 residential detached homes currently use gas furnaces for space

heating. Converting all these customers from existing gas furnaces to dual-fuel heating systems would result in an estimated total peak gas demand reduction of approximately 135 GJ per hour under maximum adoption. For the ITS, a peak hour factor of 5.5 percent is used to convert the peak daily gas demand to peak hourly demand by multiplying the daily gas demand by the peak hour factor. This results in a peak day impact of 2.5 TJ per day, as summarized in Table 1 below.

Table 1 presents both per-customer and system-wide impacts of dual-fuel heating systems in FEI's and FBC's shared service area. The avoided peak gas and reduced gas metrics represent reductions relative to a baseline gas furnace, while the avoided electric metrics represent changes relative to a ccASHP. The avoided GHG emissions are also expressed as reductions relative to the gas furnace baseline.

Table 1: Benefits of Dual-Fuel Heating Systems in FortisBC's Shared Service Area

Metric	Temperature Conditions	Baseline	Per Average Customer Amount	System-Wide Benefit (45,000 customers)
Avoided Peak Electric Demand	Design	Electric ccASHP	10.9 kW	490 MW
Avoided Electric Energy	Normal	Electric ccASHP	4,100 kWh	185 GWh
Avoided Peak Gas Demand	Design	Gas Furnace	0.003 GJ/h	2.5 TJ/day
Reduced Gas Energy	Normal	Gas Furnace	35 GJ	1.6 PJ
Net Lifetime Avoided GHG Emissions[15]	Normal	Gas Furnace	25.5 tCO_2e	1.2 $MtCO_2e$

8.3 Please discuss if FortisBC has undertaken an analysis to understand where the electrical system constraints are within Kelowna, and the broader FBC system, to enable better targeting of dual fuel systems where applicable.

Response:

FBC performs analysis as part of its regular system planning process to understand where electrical system constraints currently exist, as well as where system constraints are likely to emerge within the Kelowna area and across the broader FBC service area. FBC has been working to improve understanding of the locational aspects of various load drivers, including fuel switching and EV adoption, with the goal of better understanding where impacts on the system have the potential to be the greatest. FEI and FBC intend to use this load driver information to assess regionally targeted DSM activities, including dual-fuel systems, in future DSM planning. FBC expects to provide information about potential system constraints within the upcoming 2026 LTERP.

[15] Over the assumed useful measure life of 15 years for dual-fuel heating systems.

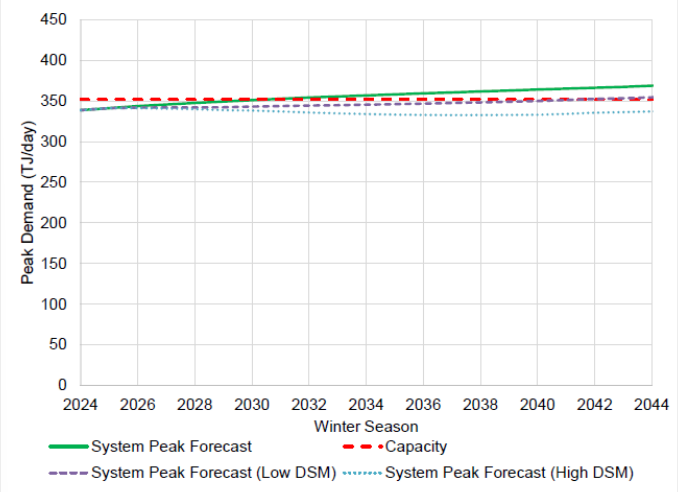
9.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Section 4.7.1, p. 4-24; Section 7.5.1.2, Figure 7-18, p. 7-32

ITS System Peak Forecast with DSM

In Figure 7-18 on page 7-32 of the Application, FEI provides the system peak forecast for the Inland Transmission System (ITS) with DSM. In the ITS, the High DSM setting suggests a decline in forecast peak demand that remains below the stated capacity of the system. However, FEI states there is no regulatory mechanism to ensure a certain amount of customer uptake of DSM measures to rely upon. FEI further states that annual updates to calculated UPC_{PEAK} values for FEI's customers have yet to show material changes in consumption as a result of DSM or changes to building practices and appliances, and the capacity shown (352 TJ/day) is predicated on the availability of the short-term mitigations which FEI is unable to rely on for long-term planning. As such, while DSM will help reduce annual energy use and reduce GHG [greenhouse gas] emissions, FEI needs to continue developing near term capacity expansions to ensure customer demands are met during peak conditions.

Figure 7-18: System Peak Forecast Method for the ITS with DSM



On page 4-24 of the Application, FEI states that "The Kelowna Electrification Case Study showed the significant costs, potentially more than $2 billion assuming 50 percent fuel switching from gas to electricity, associated with building out the electric system (excluding generation) to meet the peak demand currently served by the gas system."

9.1 Please clarify if FEI's forecast of the peak hour use per customer (UPCpeak) values take FEI's advanced DSM programs into account, and discuss any current DSM offerings that assist with lowering peak demand on FEI's system.

Response:

Confirmed. The System Peak Forecast with DSM takes advanced DSM measures, and other measures, into account as listed in Section 4.3.3 of the 2026 LTGRP. The amount of energy savings from advanced DSM for the Medium DSM setting is outlined in Table 4-2 in Section 4.4.1.1 of the 2026 LTGRP.

Any of FEI's current DSM programs that reduce energy during a peak day will contribute to a lower peak demand, and most current DSM programs contribute to system peak reductions. This includes HVAC equipment, including gas heat pumps, building envelope improvements, and industrial equipment, amongst others. In addition, FEI is currently piloting gas demand response to assess if that would further assist with reducing peak demand.

9.2 In the absence of meaningful reductions in peak demand through DSM to address peak demand on FEI's ITS system, please provide any analysis FEI has undertaken to estimate the cost of the long-term expansion of the ITS, compared to the costs of building out FBC's electrical system.

Response:

FEI continues to evaluate a number of potential alternatives to address the forecast capacity constraints on the ITS (please refer to the responses to BCUC IR1 21.1 and 21.2 for further details). As a result, FEI does not yet have new cost information for expanding the ITS on a long-term basis to compare with the cost of expanding FBC's electric system (excluding generation) to meet electrification load as discussed in the Kelowna Electrification Case Study. However, the Okanagan Capacity Upgrade (OCU) Project, as defined in the CPCN application and the subsequently approved Okanagan Capacity Mitigation Plan (OCMP) Project can provide an indicative range of costs for expanding the ITS.

The OCU Project was proposed to add approximately 63 TJ/day of capacity to the ITS at an estimated cost of approximately $327 million at the time of the application in 2023, which equates to approximately $360 million in 2026 dollars after adjusting for inflation.

The proposed incremental peak-day gas capacity of 63 TJ/day from the OCU Project is equivalent to approximately 730 MW of thermal load, or 580 to 630 MW of incremental electric peak demand, depending on the efficiency assumptions.[16] This would be most similar to the estimated incremental capacity of 522 MW under the 50 percent electrification scenario of the Kelowna Electrification Case Study (i.e., the total capacity of 950 MW as shown in Table 4-10 of the

[16] A 63 TJ/day of peak-day gas capacity is equivalent to approximately 730 MW of thermal load, which is equivalent to about 580 to 630 MW of electric peak power based on Posterity Group's end-use model depending on the conversion factor (i.e., electric efficiency over gas efficiency) used (i.e., page 8-12, Footnote 198 of the 2026 LTGRP).

Kelowna Electrification Case Study less FBC's planned capacity of 428 MW).[17] FEI provides Table 4-10 from the Kelowna Electrification Case Study below for ease of comparison.

In the response to BCUC IR2 120.1 in the 2022 LTGRP proceeding, FEI estimated the 50 percent electrification scenario would lead to a cumulative rate impact of 143 percent for FBC customers over a 20-year period, which is equivalent to a compound annual growth rate (CAGR) of approximately 5 percent. Further, on a per thermal load basis of 730 MW, the OCU Project would cost approximately $0.5 million per MW (i.e., $360 million / 730 MW), while the 50 percent electrification scenario from the Kelowna Electrification Case Study would cost approximately $3.4 million per MW (i.e., $2.5 billion / 730 MW).

Table 4-10 of Kelowna Electrification Case Study: Summary of System Impacts and Land Acquisition Costs Required for Electrification

	Project Costs ($ Millions)		
Peak Demand and Electrification Cases	711 MW (25%)	950 MW (50%)	1,429 MW (100%)
System Upgrades (Table 4-2)	930	1,550	1,890
Land Acquisition (Table 4-3)	345 – 776	605 – 1,361	680 – 1,531
Total	**1,275 - 1,706**	**2,155 - 2,911**	**2,570 - 3,421**

FEI provides below a further comparison from the customer's perspective which includes the incremental electric bill, avoided gas bill, incremental appliance upfront costs, ongoing maintenance costs, and any potential incentives between a long-term expansion of the ITS (contemplated as likely to occur in the Diversified Approach scenario) and the building out FBC's electric system (as would likely be necessary under the Electrification Focus scenario).

Using the Customer Affordability Tool discussed in Section 4.7.4 of the 2026 LTGRP, Table 1 below provides a comparison of the net lifecycle costs or benefits (in the same format as Table 4-10 of the 2026 LTGRP) for adopting different space heating technologies under the preferred Diversified Approach scenario compared to the Electrification Focus scenario. The comparison assumes:

- For the Diversified Approach scenario, an annual gas delivery rate escalator of 5 percent is applied, which is based on the 27-year directional annual delivery rate increase for the Diversified Approach scenario as shown in Table 9-8 of Section 9.4.4 of the 2026 LTGRP, while keeping the electric rate escalation to the average 4 percent annually. These assumptions are the same as the "High Gas Costs" scenario in Table 4-10 of the 2026 LTGRP and, as further discussed in the response to BCUC IR1 11.9, are representative of a customer's overall costs or benefits under a pathway that prioritizes leveraging both the gas and electric systems through dual-fuel systems.
- For the Electrification Focus scenario, an annual gas delivery rate escalator of 5.6 percent is applied, which is based on the 27-year directional annual delivery rate increase under the Electrification Focus scenario as shown in Table 9-8 of Section 9.4.4 of the 2026

[17] Section 4.1 of the Kelowna Electrification Case Study.

LTGRP, plus an annual electric rate escalator of 5 percent which is based on the 50 percent electrification scenario from the Kelowna Electrification Case Study. These assumptions represent the customer's overall costs or benefits under a pathway that prioritizes electrification through fuel-switching.

Table 1: Lifecycle Costs and Benefits from Customer's Perspective by Heating System Type Under the Diversified Approach Scenario and the Electrification Focus Scenario

Net Cost (+) or Net Benefit (-)	Customer in a Large Detached Home			Customer in a Medium Detached Home		
Scenario	**ASHP**	**ccASHP**	**Dual-Fuel**	**ASHP**	**ccASHP**	**Dual-Fuel**
Diversified Approach	$ (195)	$ 763	$ (1,566)	$ (1,484)	$ (450)	$ (733)
Electrification Focus	$ 352	$ 1,149	$ (1,457)	$ (1,036)	$ (130)	$ (637)

As shown in Table 1 above, customers under the Electrification Focus scenario would always have a higher overall total cost (or reduced net benefits) than customers under the Diversified Approach scenario. This is also true regardless of the type of space heating system adopted by the customer. For example, a customer with an ASHP or cold-climate ASHP is expected to have lower electric bills under the Diversified Approach scenario given the reduced need (and costs) of building out the electrical system. Ultimately, the Diversified Approach scenario would be more affordable to all customers in terms of the total energy bill.

10.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Section 4.6, footnote 105, p. 4-19; Section 4.7.2, p. 4-25; FEI 2026 and 2027 Incremental DSM Expenditures proceeding, Exhibit B-3, BCUC IR 5.5, 6.7;

Hydro-Quebec website "How Rate DT works"; DSM Regulation B.C. Reg. 326/2008, Section 1.1

Dual-Fuel Heating Systems – Switchover Temperatures and Performance

In footnote 105 on page 4-19 of the Application, FEI states that in a dual-fuel heating system, a switchover temperature determines whether the electric heat pump is running above that temperature, or a gas furnace is running below that temperature.

Section 1.1 of the DSM Regulation distinguishes between requirements for dual-fuel systems in climate zones 4 and 5, and climate zones 6 and above.

In response to BCUC Information Request (IR) 5.5 in the ongoing FEI 2026 and 2027 Incremental DSM Expenditures proceeding, FEI stated that Dual Fuel System Rebate Participants are required to have the system installed with prescribed switchover set-points, set to the following region-specific temperatures for the duration of the system's lifetime:

- Lower Mainland and Vancouver Island regions: 5°C or lower.
- Southern Interior and Northern BC regions: 2°C or lower.

In the FEI 2026 and 2027 Incremental DSM Expenditures proceeding, FEI stated in response to BCUC IR 6.7, that these switchover temperature values were initially selected based on alignment with provincial program guidance, including thresholds previously applied under the Province of British Columbia's CleanBC Better Homes program, where dual fuel systems were required to be installed with switchover set-points at or below 5°C in coastal climates and at or below 2°C in colder interior and northern regions.

On page 4-25 of the Application, FEI states that at temperatures below -22°C such as during the winter design peak day in Kelowna, the modelled heat pumps have a coefficient of performance (COP) of approximately 1.0.

10.1 Please clarify if the two separate regions identified by FEI in the Dual Fuel System Rebate are aligned with climate zones 4 and 5, and 6 upwards, or clarify otherwise.

Response:

The two separate regions in the Dual Fuel System Rebate align with climate zones 4 and 5, and 6 upwards as follows:

- **Lower Mainland and Vancouver Island:** this region is within climate zone 4[18] and, as such, the 5°C switchover temperature applies.
- **Columbia and Inland:** this region is within climate zones 5, 6, and 7A and, as such, the 2°C switchover temperature applies.[19]

10.2 Please discuss if FEI has considered applying the same 2°C switchover set-point in both regions, and if not, why not.

Response:

FEI initiated the dual-fuel heating system pilot and subsequent program rebate offer in alignment with provincial program guidance, including the CleanBC Better Homes program, which applied region-specific switchover temperature requirements.

FEI has collected measurement and verification data from dual-fuel heating system participants using a 5°C switchover temperature in the Lower Mainland and Vancouver Island, and a 2°C switchover temperature in the Southern Interior and Northern BC. The data for climate zones 4 and 5 indicate that systems operating under these region-specific switchover temperatures meet the performance expectations for climate zones 4 and 5 set out in the DSM Regulation.

Given the differing climatic conditions across service areas, FEI continues to apply region-specific switchover temperatures to support appropriate system operation and program performance outcomes and intends to maintain the current regional approach.

Hydro-Quebec's Rate DT Dual Energy[20] offer uses an external switchover temperature of -12°C or -15°C depending on the region.

10.3 Please discuss if FEI has considered applying a lower switchover temperature in any or all of the named regions, and expand on the rationale for its decision. Please address the consideration of the varying capacity of the gas or electric systems in the response.

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[18] The communities northwest of Nanaimo and Gibsons which are climate zone 5, not climate zone 4, use the switchover temperature of 5°C.

[19] Whistler is climate zone 6 (e.g., not Lower Mainland) and therefore aligns with the switchover temperature of 2°C for the Southern Interior and Northern BC regions.

[20] https://www.hydroquebec.com/residential/customer-space/rates/rate-dt-how-it-works.html#:~:text=Temperature%20sensor.

Response:

FEI has not yet considered applying a lower switchover temperature (SOT) in these regions. As discussed in the response to BCUC IR1 6.7 in the FEI 2026 and 2027 Incremental DSM Expenditures proceeding, these SOTs were initially selected based on alignment with provincial program guidance, including thresholds previously applied under the Province of British Columbia's CleanBC Better Homes program.

Additionally, applying these SOTs has resulted in positive customer feedback and an annual average seasonal coefficient of performance equal to or greater than 1.5 as required in the Demand-Side Measures Regulation.[21] Therefore, there has been no need to consider applying a lower SOT.

Further to the positive customer feedback, a customer survey from FEI's residential dual-fuel heating system pilot demonstrated that these initial SOTs of 2°C or 5°C, depending on the region, resulted in pilot participants being very satisfied and having positive impressions of it being comfortable, with 70 percent reporting thermal comfort either slightly or significantly improved. Per the survey results, lower SOTs would decrease comfort for customers and increase unease with perceptions of a heat pump's lukewarm air.

There are numerous considerations to be made in applying lower SOTs than currently established in FEI's dual-fuel programs. The summary of these considerations below demonstrates that slightly lower SOTs (i.e., down to -2°C in the Interior) offer additional GHG emissions reductions with limited cost implications to customers or utilities, but that under significantly lower SOTs (i.e., reducing to -12°C or -15°C) there are additional detrimental trade-offs in customer costs, abatement value, rate burden, and increases to electric system peaks.

- **Affordability Impacts to Participants:** Figure 4-22 in the 2026 LTGRP demonstrates how lower SOTs would increase bills for customers, given that the efficiency of electric heating does not outweigh the rate advantage for gas compared to electricity at colder temperatures either for residential or small commercial customers.[22] Please refer to the response to BCUC IR1 11.5 for the annual bill impact under different SOTs. Additionally, as was discussed in Section 4.7.4.3 of the 2026 LTGRP, the results of the dual-fuel heating system pilot demonstrated that the current SOTs are already providing bill savings relative to a gas furnace baseline for more than half of participating households.
- **GHG Emissions Reductions:** Lower SOTs result in lower gas usage and therefore higher GHG emissions reductions. The increase (e.g., an additional 15 percent after lowering of the SOT to -2°C in Kelowna) in avoided GHG emissions occurs at a faster pace during milder temperatures such as 2°C to -2°C as demonstrated in the Updated Figure 4-23 provided in the response to BCUC IR1 12.1, due to low distribution of temperatures colder than -2°C.

[21] As per 1.1(2)(i)(i) of the Demand-Side Measures Regulation.

[22] As of June 2026, FEI's RS 1 is 3.1 times less than FBC's RS 1 and 2.5 times less than BC Hydro's RS 1151. Comparatively, FEI's RS 2 is 2.3 times less than FBC's RS 20 and 2.5 times less than BC Hydro's RS 1300.

- **Marginal Abatement Value:** Figure 4-24 in the 2026 LTGRP demonstrates that lowering the SOT by a few degrees achieves marginal abatement values for participants, based on customer bills, of less than $200/tCO$_2$e. Lowering the SOT into colder temperatures (i.e., below -2°C in the Interior) does not achieve cost-effective marginal abatement values.
- **Impacts to Non-Participants:** Adoption of a material number of dual-fuel heating systems from participants with even lower SOTs, down to -12°C or -15°C, could significantly reduce gas consumption for FEI's residential class, which would create upward rate pressure for both adopting and non-adopting customers.
- **Electric Peak Load Impacts:** Through analysis of dual-fuel heating systems, FortisBC determined that a 2°C degree SOT does not materially impact the coincident system peak hour demand for FBC for the winter peak month, regardless of potential adoption. While FortisBC has not yet analyzed in detail the impacts of lower SOTs to FBC's electric system, eventually a "tipping point" will be reached where the SOT is not high enough to avoid peak electric demand increases to FBC's system peaks. Therefore, lower SOTs would cause increased winter peak demand for electric utilities. FBC cannot presently analyze the SOT implications to BC Hydro's system and BC Hydro's monthly coincident system peaks.

The varying capacity of the gas transmission and delivery system is not a relevant consideration, given that FEI's gas system was designed to accommodate the entire heating load of customers with gas furnaces, and a reduced heating load under a dual-fuel system is able to be served by FEI's delivery system.

11.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Section 4.6, p. 4-18; Section 4.7.2, p. 4-26; Section 4.7.3.1, p. 4-28, Table 4-8, p.4-29; Section 4.7.4, pp. 4-31, 4-37, 4-39, 4-40, Figure 4-18, p. 4-33

Dual-fuel Heating Systems and Customer's Energy bills

On page 4-18 of the Application, FEI states:

> A customer in British Columbia generally receives both a gas and electric bill. The gas utility bill includes the cost to purchase gas and to deliver the gas safely and reliably to their home. The electric utility bill includes the cost of electricity and the infrastructure and services needed to deliver the electricity safely and reliably; however, the infrastructure required to meet incremental electric heating demand – especially during peak times – can be costly.
>
> Dual-fuel heating systems help to moderate cost increases for both utilities and customers by using gas heating during peak times to avoid electric system costs, which also allows the electric heat pump to operate during the most efficient times.

On page 4-26 of the Application, FEI states: "In contrast, a dual-fuel heating system …with a switchover temperature of 2°C would result in little to no increase in electric demand on the peak day, as gas would be providing all the heating load on that day."

On page 4-28 of the Application, FEI states:

> Dual-fuel heating systems contribute meaningfully to the reduction of gas usage, and therefore GHG emissions, while also significantly avoiding the impact of peak electric demand increases. Table 4-8 provides the annual and peak demand (during 6 to 7 pm) for both gas and electricity for a Customer in a Large Detached Home. Table 4-8 illustrates that dual-fuel heating systems with a switchover temperature of 2°C can reduce gas demand in residential single-family dwellings by approximately 43 percent while also avoiding increases to peak electric demand.

Table 4-8: Design Peak Demand and Normalized Energy for a Customer in a Large Detached Home in Kelowna

Metric	Baseline Consumption	After installing a ccASHP	After installing a Dual-Fuel Heating System
Peak Electric Demand (Design) – kW	2.3	14.8 **(+537%)**	2.3 **(+0%)**
Peak Gas Demand (Design) – GJ/h	0.054	0[119] **(-100%)**	0.051 **(-6%)**[120]
Annual Electric Energy (Normalized) – kWh	9,956	17,613 **(+77%)**	13,115 **(+32%)**
Annual Gas Energy (Normalized) – GJ/h	96.1	15.2 **(-84%)**	54.8 **(-43%)**

FEI states in Table 4-8 on page 4-29 of the Application, that a Dual-Fuel heating system is expected to result in a 6 percent reduction in peak gas demand. Footnote 120 on the same page, states that if a customer adopts a dual-fuel system and upgrades from a low-

or mid-efficiency furnace to a high-efficiency furnace, they may also achieve some peak gas demand savings as well.

11.1 Please explain the current assumptions regarding the efficiency of gas equipment used in a dual-fuel system in FEI's Kelowna study.

Response:

In the Kelowna Dual-Fuel Study, and in the 2024 CPR, a residential dual-fuel heating system includes a new high-efficiency gas furnace with an Annual Fuel Utilization Efficiency (AFUE) of 95 percent.

FEI estimates that existing customers in the Interior that have a gas furnace have an average installed AFUE of approximately 90 percent; therefore, residential dual-fuel heating systems reflect a moderate improvement in gas equipment efficiency.

11.2 Please explain the requirements of FEI's various dual-fuel rebate offerings (current and prospective) regarding the efficiency of the gas components used in dual-fuel systems.

Response:

For FEI's Residential and Low Income dual-fuel rebate offerings, the gas furnace component of eligible systems is required to be a 95 percent AFUE or higher furnace. This threshold aligns with the minimum energy performance standard (MEPS) established by Natural Resources Canada (NRCan) for gas furnaces without an integrated cooling component, which specifies a minimum AFUE of 95 percent for applicable product categories.

The NRCan MEPS establishes the minimum allowable efficiency for products that can be sold and installed in Canada and, as such, represents the baseline efficiency level in the absence of DSM programming. The DSM Regulation does not prescribe a specific furnace efficiency requirement; instead, DSM program design is based on achieving cost-effective energy savings relative to this baseline. In this context, FEI's requirement to install furnaces meeting or exceeding 95 percent AFUE ensures that supported equipment is consistent with the prevailing regulatory baseline and supports the calculation of incremental savings.

For dual-fuel systems more broadly, the DSM Regulation requirements focus on the overall system performance, including the combined efficiency of both the electric heat pump and gas furnace components, requiring an average seasonal coefficient of performance (SCOP), which must be equal to or greater than 1.5 when considered in aggregate in climate zones 4 and 5. While the gas furnace efficiency is not part of the DSM Regulation, program eligibility is determined based on the combined system performance criteria to ensure the system delivers

measurable and cost-effective energy savings relative to baseline equipment assumptions and in compliance with the DSM Regulation.

11.3 If available, please provide an updated version of Table 4-8 showing the annual electric and gas energy consumption assuming a switchover temperature of 5°C, and -1°C. If such analysis is not available, please estimate the proportional and directional impact.

Response:

Please refer to Updated Table 4-8 below for the annual electric and gas energy consumption, as well as design peak electric and gas demand, for a dual-fuel (DF) heating system under the alternative SOT assumptions of 5°C and -1°C. The information in the table includes whole-home electric and gas consumption.

Updated Table 4-8: Design Peak Demand and Normalized Energy for a Customer in a Large Detached Home in Kelowna

Metric	Baseline Consumption	After Installing a ccASHP	After Installing a DF System (5°C SOT)	After Installing a DF System (2°C SOT)	After Installing a DF System (-1°C SOT)
Peak Electric Demand (Design) – kW	2.3	14.8 **(+537%)**	2.3 **(+0%)**	2.3 **(+0%)**	2.3 **(+0%)**
Peak Gas Demand (Design) – GJ/h	0.054	0[23] **(-100%)**	0.051 **(-6%)**	0.051 **(-6%)**	0.051 **(-6%)**
Annual Electric Energy (Normalized) – kWh	9,956	17,613 **(+77%)**	11,585 **(+16%)**	13,115 **(+32%)**	14,782 **(+48%)**
Annual Gas Energy (Normalized) – GJ	96.1	15.2 **(-84%)**	70.7 **(-26%)**	54.8 **(-43%)**	40.5 **(-58%)**

The Annual Gas Energy After Installing a ccASHP of 15.2 GJ shown in Updated Table 4-8 above includes gas use for domestic hot water heating, fireplaces, barbeques, cooking, pools, and other uses.

FEI also provides Table 1 below which includes only space heating. On the FBC coincident system peak day, dual-fuel heating systems are utilizing the gas furnace and therefore have no peak electric demand.

[23] Assuming no water heating, cooking, or other gas end-uses are used within the 6 to 7 pm hour, which may or may not be the case in reality.

Table 1: Design Peak Space Heating Demand and Normalized Space Heating Energy for a Customer in a Large Detached Home in Kelowna

Metric	Baseline Consumption	After Installing a ccASHP	After Installing a DF System (5°C SOT)	After Installing a DF System (2°C SOT)	After Installing a DF System (-1°C SOT)
Peak Electric Demand (Design) – kW	0	12.5	0	0	0
Peak Gas Demand (Design) – GJ/h	0.031	0	0.028	0.028	0.028
Annual Electric Energy (Normalized) – kWh	0[24]	7,657	1,629	3,159	4,826
Annual Gas Energy (Normalized) – GJ	80.9	0	55.5	39.6	25.3

On page 4-37 of the Application, FEI states that dual-fuel heating systems can lower household energy bills compared to either an electric heat pump or a gas furnace.

Further, on page 4-40 of the Application FEI states that it is still unknown to FEI at what point customers will find lower switch-over points unaffordable.

On page 4-39 of the Application, FEI states that on an overall annual heating bill basis, adopting a cold climate heat pump results in a customer paying approximately 15 percent more than if the same customer adopted a dual-fuel heating system.

11.4 Please confirm that the annual bill for the dual-fuel customer noted above used a switchover of 2°C, or explain otherwise.

Response:

Confirmed. A customer adopting a cold climate heat pump was estimated to pay approximately 15 percent more for heating in 2040 ($1,533), than if the same customer adopted a dual-fuel heating system, based on an SOT of 2°C, and had a 15 percent blend of RNG ($1,334).

This calculation was completed through the following steps:

1. For a customer in a Large Detached Home in Kelowna,[25] their demand for each hour in a normalized weather year was estimated for the following cases:

    a. Gas furnace (Baseline);

[24] The electricity consumption for space heating excludes auxiliary electricity use associated with gas furnace operation, such as blower fans and control systems, however, this impact is modest compared to the heating load.

[25] Customer types and household characteristics are set out in Table 4-7 of the 2026 LTGRP.

b. After dual-fuel heating system installation (with average efficiency heat pump);

c. After cold climate heat pump adoption; and

d. After average efficiency heat pump adoption.

2. The hourly demand was paired with a corresponding temperature and rounded to the nearest Celsius degree.

3. Each hourly gas and electric demand value was multiplied by $17.72/GJ (the residential gas service cost of 85 percent natural gas and 15 percent RNG blend for RS 1 after an annual rate escalator of 3 percent per year), and $0.2002/kWh (the residential electric rate after an annual rate escalator of 4 percent per year) for heating costs in 2040 (in $2023).

4. This resulted in the annual bills noted above.

5. To simplify the results from hourly heating cost to average daily heating bill:

   a. Hourly demand was aggregated into total daily demand for each of the 365 days.

   b. Each day's 24 hours of temperature was calculated as a Mean Daily Temperature (MDT) by the formula =(MAX+MIN)/2, and then rounded to the nearest degree.

   c. Daily demand value was multiplied by the above rates.

   d. The average cost of heating per day was averaged by temperature, to result in Figure 4-22.

11.5 If available, please provide a comparison of the impact on the annual heating bill for a dual-fuel customer using a switchover point of -1°C. If such analysis is not available, please estimate the proportional and directional impact.

Response:

Lowering the SOT increases the operating range of the heat pump and reduces use of the gas furnace. While this lowers gas consumption, it increases electricity use, especially during colder periods when heat pump efficiency declines and electricity rates are more expensive.

Table 1 below summarizes the impact on the annual household bill in 2040 at SOTs of -1°C and 5°C[26] under normalized weather conditions and different RNG blending assumptions. The 0 percent RNG blend excludes the influence of RNG, to isolate the impact on the annual heating bill when changing the dual-fuel system's SOT. The 15 percent RNG blend aligns with the Medium

[26] FEI included the SOT of 5°C for completeness, as the BCUC has requested an updated version of Figure 4-18 which includes an SOT of 5°C in IR1 11.7.

setting description in Section 5.3.1 of the 2026 LTGRP. The differences in bills in Table 1 are solely attributable to heating, and not as a result of any other gas or electric end-uses.

Table 1: Annual Household Heating Bill and Relative Heating Bill Change in 2040 (in $2023) Compared to a 2°C SOT

RNG Blend	-1°C	2°C	5°C
0%	$3,829 **+$129 (+3%)**	$3,700	$3,620 **-$80 (-2%)**
15%	$3,968 **+$80 (+2%)**	$3,888	$3,863 **-$25 (-1%)**

However, as discussed further in the response to BCUC IR1 10.3, lower SOTs for a material number of dual-fuel heating participants could significantly reduce gas consumption for FEI's residential class, which would create upward rate pressure for both adopting and non-adopting customers, and is not reflected in these baseline rate escalator assumptions.

Figure 4-18 on page 4-33 of the Application, provides the life-cycle costs and benefits of dual-fuel heating systems from the Participant Cost Test perspective.

11.6 Please confirm that Figure 4-18 used 2°C as the switchover temperature for the analysis, or explain otherwise.

Response:

Confirmed. Figure 4-18 is based on a switchover temperature of 2°C for the lifecycle cost and benefit analysis.

11.7 If available, please provide an updated version of Figure 4-18 showing the lifecycle costs and benefits for a dual-fuel heating system with a switchover temperature of 5°C, and -1°C. If such analysis is not available, please estimate the proportional and directional impact.

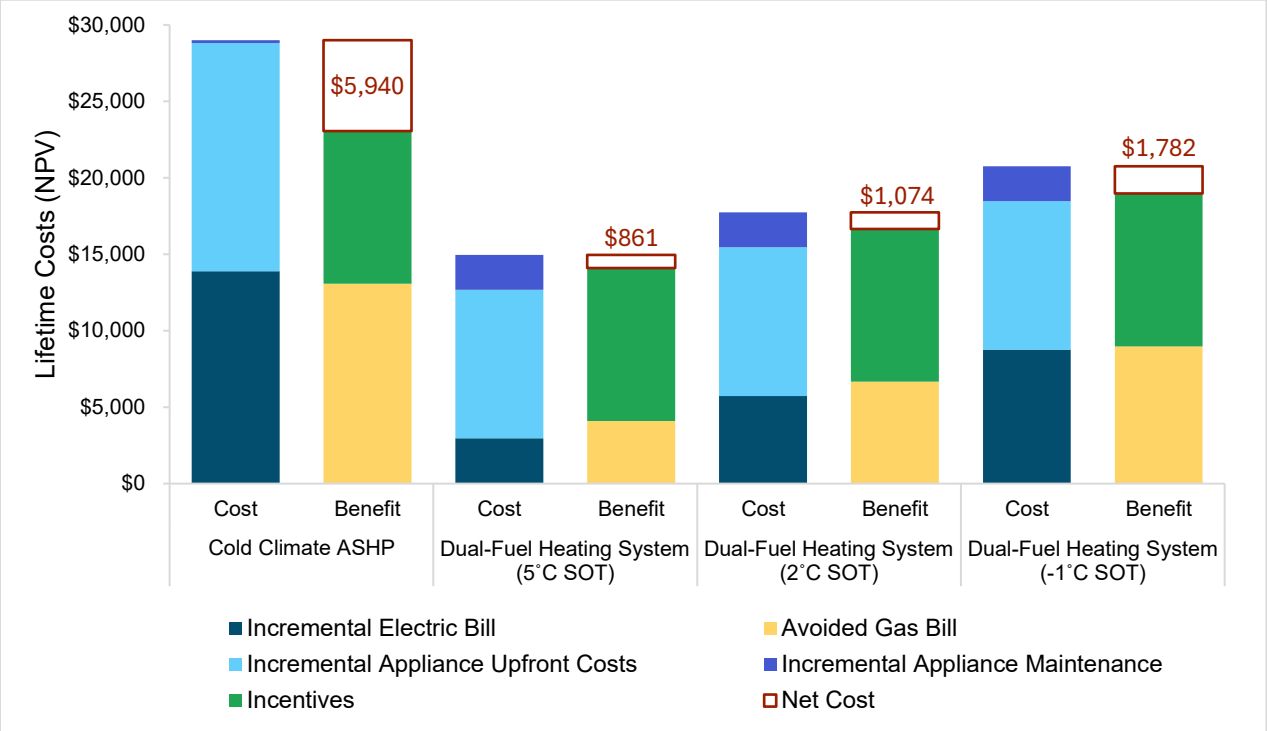
Response:

Please see the revised version of Figure 4-18 below which includes dual-fuel heating systems under the alternative SOTs of 5°C and -1°C.

The results indicate that higher SOTs (which utilize the gas furnace more) lower costs for customers due to gas heating being a lower cost option than heating with electricity during cold

temperatures. For example, the net benefit associated with changing the SOT from -1°C to +5°C is approximately $921 in savings (net cost of $11,782 for -1°C less $10,861 for 5°C, leaving aside incentives). This demonstrates that lowering SOTs in the Dual Fuel System Rebate would increase costs for customers.

Revised Figure 4-18: Lifecycle Costs and Benefits from Participant Cost Test Perspective



On page 4-31 of the Application, FEI states that the Customer Affordability Tool assumes nominal gas and electric rate escalators of 3 and 4 percent annually respectively.

11.8 Please provide the basis for the gas and electric rate escalators used in the Customer Affordability Tool.

Response:

The basis for the gas rate escalator of 3 percent used in the Customer Affordability Tool was an assessment of delivery rate increases over the past five years. To account for a higher gas rate escalator, Figure 4-19 and Table 4-10 of the 2026 LTGRP used 5 percent to align with the compound annual delivery rate change that landed generally in the middle of the range of the scenarios presented in Table 9-8 of the 2026 LTGRP.

In contrast, the rate impact analysis for the 2026 LTERP has not yet been completed. Therefore, the electric rate escalator was based on an historical cumulative average growth rate of FBC

electric rate increases over the last five years, which resulted in an approximate 4 percent rate increase as the base assumption. The cumulative average growth rate captures previous electric rate volatility, which provides a useful measure for evaluating future rate impacts that are uncertain.

11.9 Please discuss if FEI used the same rate escalator assumptions for the Participant Cost Test comparison, or explain otherwise. Please discuss if FEI has considered the impact on rates (and participant bills) of declining annual gas sales with the increasing use of dual-fuel systems, and if so, how this has been incorporated into the lifecycle costs and benefits for dual-fuel customers.

Response:

FEI confirms that it used the nominal gas rate escalator of 3 percent and the electric rate escalator of 4 percent annually for the Customer Affordability tool which presented the Participant Cost Test comparison in Section 4.7.4.1 of the 2026 LTGRP. The Participant Cost Test comparison is produced from the Customer Affordability tool. FEI notes that the 3 and 4 percent rate escalators are based on the 5-year compound annual growth rate (CAGR) of the total approved bill (i.e., includes cost of gas in the case of FEI) of an average residential customer of FEI and FBC, respectively, from January 1, 2022 to January 1, 2026.

FEI also considered the potential rate increase due to declining annual gas sales with the increasing use of dual-fuel systems when evaluating the lifecycle costs and benefits for dual-fuel customers. This is reflected in Table 4-10 of the 2026 LTGRP under the “High Gas Costs” sensitivity scenario. FEI assumed an annual delivery rate escalator of 5 percent as well as the “High” setting for natural gas and renewable gas prices (as shown in Table 5-4 of the 2026 LTGRP) for the commodity component in the Customer Affordability tool, while keeping the electric rate escalator unchanged. The 5 percent annual delivery rate escalator is based on the CAGR of the Diversified Approach scenario, shown in Table 9-8 of Section 9.4.4 of the 2026 LTGRP, which represents a future pathway that prioritizes dual-fuel systems with an overall decline in gas throughput on FEI’s system.

FEI notes that higher gas rates mean the benefits of avoided gas costs would be larger for dual-fuel system customers. This is illustrated in Table 4-10 of the 2026 LTGRP, where under the “High Gas Costs” scenario both customer types would expect an overall net benefit if dual-fuel systems are adopted instead of cold-climate ASHPs. In reality, there will likely be increases in rates for both gas and electricity instead of just increases in gas rates. As demonstrated in Table 4-10, any increase in gas and/or electric rates will generally favor the dual-fuel system in terms of lifecycle costs and benefits.

12.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Section 4.7.4, p. 4-35, Figure 4-21, p. 4-37, Figure 4-23, p. 4-39, footnote 126, p. 4-39

Dual-Fuel Heating Systems – Switchover temperatures and GHG emission reductions

On page 4-39 of the Application, FEI states, that switchover temperatures in a dual-fuel heating system are an additional lever that can be used to achieve greater GHG emission reductions in the building sector.

On page 4-35 of the Application, FEI states that at a switchover temperature of 2°C in the Southern Interior of BC, dual-fuel heating systems are estimated to reduce building emissions by 41 percent, after accounting for incremental electric emissions, and achieve further reductions through increased amounts of RNG.

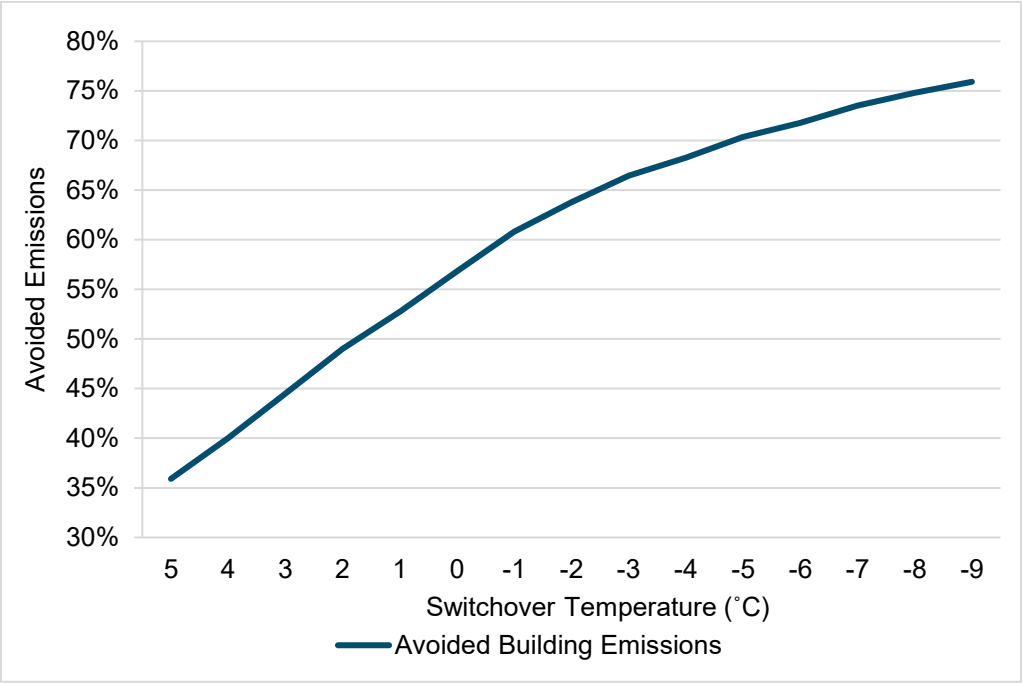
Figure 4-23 on page 4-39 of the Application shows the total avoided building emissions at lower switchover temperatures ranging from 2°C to -9°C.

12.1 Please provide an updated version of Figure 4-23 showing the avoided building emissions for an extended range of 5°C to -9°C, including any necessary explanations to account for differences in regional performance.

Response:

A revised version of Figure 4-23 has been provided below to show total avoided building GHG emissions over an expanded range of SOTs from 5°C to -9°C.

Revised Figure 4-23: Total Avoided Building Emissions at Lower Switchover Temperatures

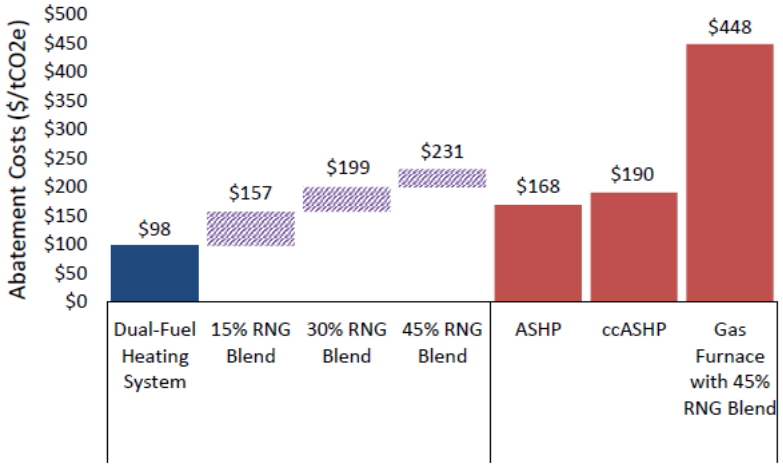


As shown in the above figure, lower SOTs result in increased avoided GHG emissions, as the dual-fuel heating system relies less on gas for heating and more on the electric heat pump. The relationship between SOT and avoided emissions is approximately linear down to -1°C. Below that temperature, the slope begins to flatten, indicating that further GHG emissions reductions due to lowering the SOT yield diminishing incremental benefits. This is mainly due to a low distribution of colder temperatures below -1°C, demonstrating that there is not much added value in reducing SOT further below to reduce minimal hours of gas furnace run-time and minimal GHG emissions savings.

Figure 4-21 on page 4-37 of the Application, illustrates how dual-fuel heating systems (with or without using RNG) have low GHG abatement costs, illustrating cost-effective emissions reductions for a customer when compared against both all-electric options (either average efficiency or ccASHP [cold climate Air Source Heat Pump]) and an increased RNG blend percentage up to 45 percent in an existing gas furnace. A uniform $10,000 incentive is applied to all equipment options, excluding a stand-alone gas furnace, to ensure a consistent comparison.

FEI notes in footnote 126 on the same page that lowering the incentive from $10,000 to $5,000 results in a marginal abatement cost of $331/tCO2e for installing only a dual-fuel system.

Figure 4-21: Household Abatement Values (PCT Perspective) from Heating Options[126] and RNG Blend Percentages



12.2 Please provide the emission factor used for RNG in the Kelowna study.

Response:

The end-use emission factor for RNG applied in the Kelowna Dual-Fuel Study is 0.0003 tCO_2e/GJ. This value is consistent with the emissions factor presented in Table 9-2 of the 2026 LTGRP.

12.3 Please provide the total GHG emissions for a dual-fuel heating system using a 45 percent RNG blend, compared to the ASHP options shown in Figure 4-21.

Response:

FEI interprets this question as asking about the avoided GHG emissions from these options as compared to a gas furnace, as opposed to the remaining GHG emissions in the heating system. However, to be responsive, please find the total GHG emissions remaining in the heating system, total avoided building GHG emissions, and avoided building emissions percentages for each measure option listed in the below table.

All values represent cumulative impacts over the measure life of 15 years. RNG blends also impact remaining non-heating gas load.

When responding to this IR, FEI discovered an error on page 4-35, line 18 of the 2026 LTGRP. The avoided lifetime total emissions for the two customer types should be 29 and 36 tCO_2e, not 21 and 27 tCO_2e. FEI has included the corrected value, where applicable, in the table below.

Customer in Large Detached Home – Large Single Detached Home (>3,000 square feet)			
Space Heating Option	**Total GHG Emissions - Heating System (tCO_2e)**	**Total Avoided Building Emissions (tCO_2e)**	**Avoided Building Emissions Percentages**
Dual-Fuel Heating System	30.7	30.0	41%
Dual-Fuel Heating System with 15% RNG Blend	26.2	36.2	49%
Dual-Fuel Heating System with 30% RNG Blend	21.8	42.3	57%
Dual-Fuel Heating System with 45% RNG Blend	17.3	48.5	65%
ASHP	2.7	58.0	79%
ccASHP	2.3	58.4	79%
Gas Furnace with 45% RNG Blend	33.4	32.4	44%

12.4 Please discuss why FEI did not provide a 100 percent RNG blend to compare against electric-only ASHPs.

Response:

FEI did not provide a 100 percent RNG blend to compare against electric-only ASHPs because there was no long-term supply scenario in the 2026 LTGRP that contemplated a system-wide 100

percent RNG blend by 2040 (the last year of the measure life of a dual-fuel heating system installed in 2026). FEI modeled RNG blends in 15 percent increments up to 45 percent to reflect progressively higher, yet still plausible, levels of RNG use, and to illustrate the directional impact on abatement costs as RNG blend levels increase. A 45 percent RNG blend for the comparison in Figure 4-21 of the 2026 LTGRP is a reasonable assumption as this reflects the highest RNG blend percentage achieved by 2040 in any scenario (i.e., in the Lower-Carbon Transportation and LNG Future).

13.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Section 4.6, p. 4-18, p. 4-19; Section 4.7.4, p. 4-31; Table 4-9, p. 4-32, p. 4-33

Dual Fuel Program Design

Page 19 of the Clean Prosperity study cited by FEI in footnote 103 on page 4-18 of the Application, states:

> The London pilot, and another similar study in Peel Region suggested two key areas for improvement in hybrid heating systems: (1) improving the ability of households to optimize between cost savings and emissions reductions through less default use of natural gas, via better optimization settings in the thermostat; and (2) increase the sizing of heat pumps to increase the electric heating capacity of the home at ambient temperatures below -5 °C. The larger the heat pump installed in a hybrid heating system, the more of the home's heating needs can be met through electric heating, and the greater the emissions reductions.

On page 4-33 of the Application, FEI states that the higher cost for a ccASHP is due in part to the higher cost of equipment for an electric heat pump sized to provide the home's entire heating load previously served by a gas furnace.

On page 4-31 of the Application, FEI states that another benefit of dual-fuel heating systems is that the heat pump does not need to be sized to meet the entire home's heating load and can utilize a smaller sized electric heat pump in the dual- fuel heating system. For example, in homes around 3,000 square feet, a smaller three-ton heat pump can be paired with a gas furnace, whereas if the same home were to fuel switch completely to electricity, it may require a more expensive and larger sized heat pump, such as a four to five ton unit.

Table 4-9 on page 4-32 of the Application shows the costs for space heating options:

Table 4-9: Costs for Space Heating Options[123]

Customer in a Large Detached Home				
Equipment ($2023)	**Baseline (Gas Furnace and A/C)**	**Average Efficiency ASHP**	**Cold Climate ASHP**	**Dual-Fuel Heating System with Average ASHP**
Upfront Cost	$6,277[124]	$17,800	$21,200	$16,000
Annual Maintenance	$195	$213	$213	$408
Customer in a Medium Detached Home				
Upfront Cost	$6,277	$16,000	$19,000	$16,000
Annual Maintenance	$195	$213	$213	$408

13.1 Please confirm that FEI's Dual Fuel Rebate offering requires the installation of an average efficiency ASHP as opposed to a cold climate ASHP, or explain otherwise.

Response:

FEI notes that, as discussed in its 2026-2027 Incremental DSM Expenditures Application, the Low Income Dual Fuel Rebate was removed from the market in May 2025 and the Residential Dual Fuel Rebate was removed from the market in December 2025 due to significantly higher than anticipated participation.

When in market, FEI's Residential and Low Income Dual Fuel rebates required a high efficiency air source heat pump, not a cold climate heat pump. The heat pump component of the dual-fuel system was required to meet the following criteria:

- Seasonal Energy Efficiency Ratio (SEER) ≥ 16; Heating Seasonal Performance Factor (HSPF) (Region IV) ≥ 10.00 or SEER2 ≥ 15.20; HSPF2 (Region IV) ≥ 8.50; and
- Minimum capacity of 12,000 BTU (1 tonne).

These criteria exceed the Canadian minimum efficiency performance standards for air source heat pumps, which require SEER2 ≥ 13.40; HSPF2 (Region IV) ≥ 6.70.

13.1.1 Please discuss the extent to which cold climate ASHPs could impact customers' energy savings and GHG emissions if included as part of dual fuel systems.

Response:

Cold climate ASHPs (ccASHP) are designed to maintain heating capacity and efficiency at lower outdoor temperatures relative to average efficiency units; however, there is a limited operational window when a ccASHP would provide incremental benefit over an average efficiency ASHP in a dual-fuel heating system. This is because the heat pump only operates above the SOT, where standard efficiency heat pumps perform comparably to ccASHPs.

FEI analyzed the costs and benefits of installing a dual-fuel heating system with an average efficiency ASHP, compared to a dual-fuel heating system with a ccASHP. Based on this analysis, the lifecycle net cost of a dual-fuel heating system with an average efficiency heat pump is lower and it achieves nearly identical GHG emissions reductions. This is because the limited bill savings due to efficiency gains and energy savings in a dual-fuel heating system with a ccASHP are not enough to outweigh the incremental upfront capital costs associated with a ccASHP.[27]

[27] The incremental upfront capital costs for a ccASHP compared to an average efficiency ASHP also may not outweigh the efficiency gains and bill savings for customers with a gas furnace fuel switching to stand-alone heat pump systems, as illustrated in Table 4-10 of the 2026 LTGRP.

Table 1 below illustrates, for a customer in a large detached home in Kelowna using an SOT of 2°C, some key metric differences between these two dual-fuel heating options.

Table 1: Dual-Fuel Heating Systems with an Average or Cold Climate Heat Pump

Customer in a Large Detached Home		
Metric ($2023)	**Dual-Fuel Heating System with Average ASHP**	**Dual-Fuel Heating System with ccASHP**
Equipment Upfront Cost	$16,000	$18,500
Decremental Gas Energy (Normalized) – GJ	-41.2	-41.2
Incremental Electric Energy (Normalized) – kWh	+3,159	+2,804
Incremental Electric Bill – NPV	$5,730	$5,086
Lifecycle Net Cost (PCT Perspective) – NPV	**$1,074**	**$2,931**

As demonstrated in the table above, a dual-fuel heating system with a ccASHP in Kelowna reduces the same amount of gas, uses 11 percent less incremental electricity, but results in a 173 percent higher lifecycle net cost, compared to a dual-fuel heating system with an average efficiency ASHP.

Given that the additional GHG emissions benefits of a dual-fuel system with a ccASHP are only due to using slightly less electricity, the incremental GHG emissions reductions are marginal, reducing the household avoided emissions from 49.02 percent (as shown in Figure 4-20 of the 2026 LTGRP), to 49.16 percent – i.e., an additional 0.14 percent, or 0.11 tCO_2e of lifecycle avoided heating emissions.

On page 4-18 of the Application, FEI states that in July 2024, FEI introduced a dual-fuel heating offer for existing residential homes, in addition to supporting dual-fuel systems for commercial businesses and new residential construction.

On page 4-19 of the Application, FEI states that it has also been pursuing cost-effective dual-fuel heating options for multi-unit residential buildings (MURBs) and commercial buildings. These measures target building segments where full electrification remains challenging today and represent early-to-mid adoption solutions that balance emissions reduction, grid readiness, and cost-effectiveness while enabling broader market transition.

13.2 Please clarify if FEI is offering dual-fuel options for new residential, MURB and commercial buildings, and if so, whether it intends to do so over the entire planning period.

Response:

FEI offers dual-fuel options across new residential, commercial, and multi-unit residential building (MURB) segments through its existing DSM programs.

For new residential construction, dual-fuel systems are embedded within FEI's New Home program as an eligibility requirement for participation.

For commercial and MURB segments, dual-fuel options are currently supported through the commercial dual-fuel RTU offering, which enables participation from applicable building types, including new construction MURBs.

FEI is also assessing segment-specific applications of dual-fuel systems through targeted pilot initiatives. Insights from these pilots are intended to inform ongoing program design and enhance program effectiveness over time, including considerations related to cost-effectiveness, market readiness, and alignment with regulatory and policy direction.

Currently, FEI intends to continue offering dual-fuel options across new residential, commercial, and MURB segments throughout the planning period, subject to approval of applicable DSM expenditure plans and applicable building codes and regulations. As dual-fuel options expand beyond residential heating into additional residential, commercial and MURB end-use applications, this integrated approach is expected to continue improving overall efficiency, reducing gas consumption and GHG emissions, and avoiding electric peak demand requirements.

13.3 If applicable, please explain how FEI ensures that new construction dual-fuel offers result in gas savings, as opposed to substituting for electrification options.

Response:

FEI ensures that new construction dual-fuel offers result in gas savings by targeting new construction buildings where the baseline is a natural gas heating system that would result in higher overall gas consumption compared to a dual-fuel system, as permitted under current building practices and the baseline BC Energy Step Code level. Further, dual fuel systems result in gas savings in these new construction projects because they are designed so that the electric heat pump serves as the primary heating source, with the gas-fired space heating equipment operating only under colder conditions based on defined switchover temperatures.

C. SUPPLY-SIDE RESOURCES

14.0 Reference: SUPPLY-SIDE RESOURCES

Exhibit B-1, Section 3.5.4, pp. 3-15, 3-16; Section 5.3.2, p. 5-8; Section 5.3.3, p. 5-10; Section 5.4, p. 5-18; FEI 2022 LTGRP proceeding, Exhibit B-1, Appendix D-2, Table 2, p. 22

Renewable Natural Gas

On page 5-8 of the Application, FEI states:

> Table 5-3 breaks out the RNG supply settings between supply located within or outside of BC. While in-province and out-of-province sources each account for about 50 percent of the number of operational projects, the volume outside of BC is significantly higher due to more abundant feedstock and a higher number of developed projects. This difference is consistently reflected across all scenarios whereby in-province projects contribute approximately 15 percent of the total RNG supply volume and out-of-province projects account for about 85 percent… Given the availability of biomass resources in BC compared to outside of BC, it is reasonable to assume that in the future, the amounts of RNG supplied from within and outside of BC will be relatively constant. [Emphasis added]

14.1 Please provide FEI's assessment of the differences in security of RNG supply from in-province projects as compared to RNG supply from out-of-province projects.

Response:

There is no material difference in the security of supply between in-province and out-of-province RNG.

Security of supply includes factors such as the reliability of production, contractual supply obligations, portfolio diversity, deliverability, and the ability to manage shortfalls across the broader RNG supply portfolio. There is a wide variety of inputs (e.g., feedstocks, facility types) to RNG production, which contribute to production variability regardless of geographic location. While any individual RNG facility may experience production variability, FEI manages this risk through a diversified supplier portfolio, minimum contractual supply obligations, and long-term agreements. A shortfall at one facility can therefore be mitigated through supply from other projects or other portfolio management measures. From a contractual perspective, FEI applies comparable expectations to both in-province and out-of-province suppliers, including minimum supply obligations and long-term agreement terms. In almost all cases, FEI has imposed minimum RNG supply volumes on suppliers, which supports both ongoing supply performance and long-term supply planning.

FEI notes that out-of-province RNG has more reliably met production expectations on a regular basis, which may reflect larger and more mature feedstock markets and a greater number of developed projects outside of BC.

FEI also notes that it has acquired natural gas from both within and outside of the province for many years, and considers both sources of supply to be secure and reliable.

14.2 Please discuss the likelihood and consequences of any sudden loss of RNG supplied by displacement from out-of-province projects, including the extent to which such impacts may change if FEI significantly increases its supply from out-of-province RNG. In the response, please include a comparison of the consequences of a sudden loss of RNG supplied by displacement from an out-of-province project to the sudden loss of supply from a different regional supply resource, such as a market area off-system gas storage resource or a peaking resource.

Response:

FEI considers the likelihood of a sudden loss of a material portion of its out-of-province RNG supply to be low. FEI acquires RNG through a diversified portfolio of biomethane purchase agreements (BPAs) with multiple suppliers, reducing reliance on any single project, counterparty or jurisdiction. FEI's out-of-province RNG is generally sourced from established developers operating multiple facilities, supporting stable supply performance. In addition, BPAs are typically long term, which limits exposure to abrupt supply disruptions.

The contractual terms of FEI's BPAs further enhance the security of supply. The BPAs typically include minimum and maximum delivery obligations, providing flexibility while maintaining a reliable level of supply and protection against non-performance. In the event of supplier underperformance or interruption, contractual provisions also enable procurement of replacement RNG from the market, subject to market conditions and with limited incremental cost exposure.

The primary consequence of a sudden loss of out-of-province RNG supply would be a reduction in RNG deliveries offset by an increase in natural gas deliveries. Therefore, a sudden loss or increase of out-of-province RNG supply would primarily affect emissions reduction outcomes and customer participation in RNG programs. However, FEI actively monitors its RNG supply portfolio and manages procurement to maintain sufficient supply and inventory to meet customer RNG requirements.

If FEI were to increase its reliance on out-of-province RNG, the likelihood and nature of the impact would not materially change due to the factors discussed above. Even at higher levels of out-of-province RNG procurement, any disruption would not affect the ability to meet the physical demand for gas on the FEI natural gas system as RNG can be replaced with natural gas.

In contrast, the sudden loss of supply from a different regional supply resource, such as a market area off-system gas storage resource or a peaking resource, could be more significant. FEI's gas supply is supported by market-area storage, peaking resources, and pipeline supply that are

specifically designed to respond to periods of elevated demand or system stress. These resources are critical to maintaining system reliability and ensuring that sufficient gas can be delivered to customers. A sudden loss of these resources could impair ability to meet demand, particularly during peak periods, and may result in reliability risks or service curtailment. Unlike RNG supply, these resources are not readily substitutable in real time.

On page 5-8 of the Application, FEI provides Table 5-3 as reproduced below:

Table 5-3: Potential RNG – Breakdown by Within Province and Out-of-Province Sources (PJ/Year)

	Low			Medium			High		
Milestone Years	Within BC	Outside BC	Total	Within BC	Outside BC	Total	Within BC	Outside BC	Total
2030	2.5	14.4	**16.8**	4.3	24.7	**29.0**	5.8	33.7	**39.5**
2040	2.5	14.4	**16.8**	7.1	41.4	**48.5**	10.5	60.6	**71.1**
2050	2.5	14.4	**16.8**	8.8	51.2	**60.0**	13.2	76.8	**90.1**

On page 22 of Appendix D-2 to FEI's 2022 LTGRP, FEI provided Table 2 as reproduced below:

Table 2 B.C. RNG Potential, in Petajoules (PJ) per Year

	Agricultural	Municipal	WWTP	LFG	Total
2021	2.4	3.1	0.48	2.9	**8.9**
2030	2.5	3.5	0.55	3.1	**9.5**
2050	2.8	4.6	0.69	3.1	**11.2**

14.3 Please discuss why FEI has reduced its outlook for potential RNG availability from within BC in 2030 from 9.5 PJ in the 2022 LTGRP, to a range of 2.5 – 5.8 PJ in the 2026 LTGRP.

Response:

The reduction in the outlook for RNG availability from within BC reflects FEI's updated assessment of supply potential, informed by evolving market conditions, and project development experience.

In recent years, RNG project economics have become more challenging. Increases in equipment, construction, and labour costs, together with higher borrowing costs, have impacted the ability of some RNG projects to meet the GGRR price cap. RNG project development also continues to involve relatively higher development and financing risks compared to more established investment opportunities, which can limit capital deployment and slow the pace of project advancement.

In addition, differences in policy support, including the availability of capital incentives in other jurisdictions, have contributed to a comparatively slower pace of RNG development within BC. Feedstock availability is also affected by competing uses for organic waste streams. Alternative applications, such as composting or other waste management pathways, may represent lower-risk or more established options, which can reduce the portion of feedstock ultimately directed toward RNG production.

As a result, the revised range of 2.5 to 5.8 PJ by 2030 represents a current estimate of RNG supply that can be achieved under prevailing economic, market, and regulatory conditions. The 2.5 PJ baseline reflects existing approved RNG agreements within BC at this time, while the 5.8 PJ upper end reflects a projection based on FEI's experience over the past decade developing its own projects and working with suppliers to develop their projects.

14.4 Please discuss whether FEI considers increasing the supply of RNG from within BC to be a strategic priority for FEI. If it does, please describe FEI-led projects or initiatives that will increase RNG supply from within BC.

Response:

FEI considers increasing the supply of RNG from within BC to be a strategic priority.

Increasing viable BC-based RNG supply projects supports supply diversity, local economic development, and aligns with provincial objectives. FEI is advancing BC-based RNG projects through three primary areas of activity:

1. FEI is evaluating and advancing RNG projects in partnership with local and regional governments at landfills, and continuing to assess RNG opportunities across available organic feedstock sources where those opportunities can support cost-effective RNG supply.

2. FEI is supporting the development and adoption of technologies that improve project viability. This includes small scale upgrading solutions suited to BC's relatively small RNG sites, such as municipal landfills in the Interior of BC. Next generation upgrading equipment can lower costs, unlocking additional opportunities at locations that were not previously economically viable. In addition, FEI is also playing an active role in supporting new technology trials at its own facilities, supplier facilities and at universities. Some of these technologies can help enhance RNG production and/or expand sources of potential feedstock for future projects.

3. FEI is seeking available grant funding to offset capital and operating costs, while also continuing to optimize project design and operations to improve cost-efficiency and meet regulatory requirements.

14.4.1 Please explain the extent to which proximity and access to a local gas grid currently limits the potential for RNG production within BC.

Response:

Proximity and access to the local gas grid is a key factor that can influence the development of RNG projects within BC and one of the two fundamental considerations for any project to proceed beyond initial assessment: (1) whether there is feedstock that can be used to create RNG; and (2) whether there is an end use or injection point for that RNG.

Close proximity to the gas system is a key enabler for an RNG project as it impacts project costs associated with interconnection to the system or costs associated with transporting RNG via virtual pipeline to an injection site. Greater distances require additional pipelines or injection facilities and related equipment, which generally increase project complexity, require additional capital, necessitate increased permitting and engagement, and increase development timelines. However, the extent to which proximity and access to the gas system affects project viability depends on the project's feedstock availability, production scale, interconnection requirements, local system capacity, and overall economics.

Further on page 5-10 of the Application, FEI states:

> Finally, the RNG supply forecast is reliant on the existence of supportive policy and regulatory frameworks, which also influence market activation. Policy direction, such as mandates requiring RNG procurement or enabling policy that promotes the use of RNG, could influence supply and demand factors in the market in alignment with provincial GHG emission reduction targets. For example, RNG from BC is in high demand amongst transportation sector uses due to its recognition as a compliance pathway within the *Low Carbon Fuel Act*. Conversely, due to the absence of compliance pathways in the ZCSC, RNG is not enabled as a solution for lowering emissions in new buildings.

14.5 Please discuss whether FEI considers there to be a need to increase the supply of RNG from within BC to meet the high demand for this fuel type within the transportation sector, as noted on page 5-10 of Exhibit B-1.

Response:

Demand for RNG, including from the transportation sector, has increased in recent years, supported by policies such as the *Low Carbon Fuel Act* that recognize RNG as a pathway for emissions reductions and as a compliance option for regulated fuel suppliers.

For the past few years, demand for RNG produced in BC has been higher than available production. This indicates that new RNG projects within BC would be beneficial in supporting continued market development and would help respond to demand from sectors that can use RNG to reduce emissions.

FEI has made significant progress over the past few years and has steadily increased its RNG supply from BC, growing from approximately 200 TJ annually to 1,300 TJ annually over the past five years. FEI continues to support the development of additional RNG supply in BC where projects are available on commercially reasonable terms and can be advanced in a manner consistent with applicable policy and regulatory requirements.

FEI continues to prioritize BC RNG projects and is working to bring several new domestic RNG facilities online.

On pages 3-15 and 3-16 of the Application, FEI provides its low, medium and high demand forecast settings for on-road vehicle fuel switching. FEI explains that for the renewable compressed natural gas (R-CNG) high demand forecast setting "demand decreases to 0.4 PJ by the mid-2030s, stabilizing at 0.3 PJ by 2050." FEI further explains that for the hydrogen high demand forecast setting demand increases to "5.0 PJ by 2050."

On page 5-18 of the Application, FEI provides Table 5-4: Outlook for Energy Prices for Fuel Types, as reproduced below.

Table 5-4: Outlook of Energy Prices for Fuel Types[143]

	Price Forecast (Real $2023)								
	Low ($/GJ)			Medium ($/GJ)			High ($/GJ)		
Milestone Years	NG[144]	RNG	H_2	NG	RNG	H_2	NG	RNG	H_2
2025	2.24	24.88	24.79	2.84	25.01	25.20	4.07	25.34	26.01
2030	2.29	24.88	21.89	3.08	25.69	23.22	4.81	27.79	29.25
2035	2.70	20.92	20.81	3.80	26.39	23.96	5.47	30.48	35.41
2040	2.71	17.49	19,79	4.25	27.11	24.26	5.70	33.42	42.88
2045	3.10	14.52	18.82	4.47	27.85	24.81	6.13	36.65	51.92
2050	3.48	11.95	17.90	4.60	28.61	25.09	6.46	40.20	62.86

14.6 Please explain FEI's basis for assuming demand for hydrogen as an on-road vehicle fuel will exceed demand for R-CNG tenfold by 2050. In FEI's response,

please discuss how future energy prices for these fuel types were considered in the forecast demand for R-CNG versus hydrogen as an on-road vehicle fuel.

Response:

The transportation fuel demand forecasts presented in the 2026 LTGRP reflect the combined effects of technology availability, vehicle suitability, policy and regulatory assumptions, infrastructure development, and fuel economics. The forecasts are not based solely on a comparison of projected fuel prices.

FEI's transportation demand outlook in the High setting assumes that hydrogen's primary opportunity is within heavy-duty transportation applications that are expected to require zero-emissions fuel pathways over the long term, particularly certain Class 7 and 8 vehicle segments. The forecast also reflects assumptions regarding the continued implementation of zero-emission vehicle policies increasing vehicle availability, improvements in hydrogen fueling infrastructure, and declining hydrogen costs over time.

By contrast, the demand outlook for R-CNG in the High setting assumes R-CNG continues serving transportation applications where gaseous fuel internal combustion technologies remain competitive. However, the demand outlook for the High setting reflects the assumption that over time an increasing portion of the medium- and heavy-duty transportation sector transitions towards technologies that qualify as zero-emission under prevailing policy frameworks. As a result, the forecast demand for hydrogen grows more rapidly than the forecast demand for R-CNG in the later years of the planning horizon.

Future fuel prices were considered as one input into the demand assessment. As shown in Table 5-4 of the 2026 LTGRP, the forecast assumes declining hydrogen costs over time while the forecast cost of RNG remains relatively stable or increases depending on the scenario. However, fuel price was not the sole determinant of adoption. The demand outlook also reflects assumptions regarding the total cost of vehicle ownership, vehicle availability, infrastructure deployment, policy support mechanisms, and technology suitability for specific duty cycles.

Accordingly, the forecast difference between hydrogen and R-CNG demand by 2050 should not be interpreted as a result of fuel price assumptions alone, but rather as the combined outcome of the broader market, technology, infrastructure, and policy assumptions incorporated into FEI's transportation demand assessment.

15.0 Reference: SUPPLY-SIDE RESOURCES

Exhibit B-1, Section 5.3.4, pp. 5-10, 5-14; Section 6.2, p. 6-6; BCUC Hydrogen Regulation Inquiry Final Report, p. 24[28]

Hydrogen

On page 5-10 of the Application, FEI states:

> To advance commercialization and help enable the scaling up of hydrogen supply, FEI is engaging in targeted activities such as piloting demonstration projects to validate technical and economic assumptions, leveraging the CGIF to support high-impact initiatives, and building internal expertise as the market develops.

15.1 Please briefly describe how costs to advance FEI's readiness to acquire hydrogen are expected to change over the next 5-10 years.

Response:

There is still a high degree of uncertainty regarding the timing and ability to achieve the readiness to acquire hydrogen. As such, in the near term, FEI's preliminary expectations are that the costs related to achieving readiness to acquire hydrogen and other related initiatives will remain relatively consistent with FEI's expenditures over the past few years.

FEI is unable to accurately predict the level of expenditures that may be required over the 5-to-10-year period and beyond, as these costs may be influenced by a range of external factors, including changes in policy and regulatory frameworks, market conditions, technology development, supply chain maturity, third-party funding availability, and the pace of broader hydrogen sector development.

On page 5-14 of the Application, FEI states:

> FEI has also engaged with vehicle manufacturers, fuel suppliers, and infrastructure developers to explore practical hydrogen fueling models, with a particular focus on depot-based and corridor-oriented approaches… Early insights from these activities are informing FEI's broader assessment of hydrogen demand within the transportation sector and helping refine assumptions used in long-term planning scenarios.

On page 24 of the BCUC's Inquiry into the Regulation of Hydrogen Energy Services Final Report, the BCUC stated:

[28] BCUC Hydrogen Regulation Inquiry Final Report.

At this time, hydrogen as a transportation fuel is being provided at a retail level in BC and the Inquiry participants stated that this end-use is currently the most active component of the Hydrogen Energy Service industry. Inquiry submissions suggest that the market is currently developing, with a limited customer base. Submissions also indicate that the sale of hydrogen as a transportation fuel occurs in a competitive market, in that fuel buyers have a choice of fuel (e.g. gas, diesel, electricity). It is anticipated that in the future, as the number of market entrants grows, providers of hydrogen as a transportation fuel will also compete amongst themselves, for example on the basis of price or customer satisfaction.

15.2 Please elaborate on FEI's current plans with respect to providing hydrogen as a transportation fuel. In the response, please discuss FEI's assessment of hydrogen as a transportation fuel market and how the competitiveness of this market affects FEI's approach to providing hydrogen energy services.

Response:

FEI is primarily focused on heavy-duty transportation applications, including Class 8 trucking and, potentially, rail freight transportation.

Through its existing compressed natural gas (CNG) transportation service, FEI currently provides CNG to more than 70 commercial fleets across BC, directly and indirectly. This experience has provided FEI with practical knowledge of fleet fueling requirements, fueling infrastructure development, station operations, and the operational considerations associated with gaseous transportation fuels.

As part of its long-term planning activities, FEI has assessed the potential role that hydrogen may play in the decarbonization of heavy-duty transportation. This work has included engagement with vehicle manufacturers, fuel suppliers, infrastructure developers, and fleet operators to better understand hydrogen supply chains, fueling models, infrastructure requirements, customer demand, and market development trends. FEI's current assessment is that hydrogen-fueled heavy transportation remains at an early stage of development in British Columbia and North America. While vehicle technologies and supporting infrastructure continue to advance, uncertainty remains regarding the pace of adoption, availability of hydrogen supply, infrastructure deployment, and overall economics.

FEI will continue to monitor market developments and evaluate potential opportunities and risks associated with hydrogen's potential future role in heavy transportation. FEI's current activities are focused on understanding potential future customer requirements, market developments, and infrastructure needs. FEI expects to support pilot activities in the near term to better understand the long-term role of regulated utilities in supporting the hydrogen transportation market.

On page 6-6 of the Application, FEI states:

> As other renewable and lower-carbon gas sources such as hydrogen are introduced in 2030 and beyond, FEI will assess their impact using a similar approach as outlined above with regard to RNG supply. FEI will continue to monitor the renewable and lower-carbon gas supply forecast on an annual basis and adjust its supply portfolio through the ACP process.

15.3 Please discuss how FEI's long-term planning may have to adjust if hydrogen supply does not materialize on the timelines, scale, or costs, as currently envisioned in the 2026 LTGRP.

Response:

FEI's long-term planning, as outlined in the 2026 LTGRP, already recognizes uncertainty regarding the timing, scale, and cost of hydrogen supply. Accordingly, hydrogen is treated as a potential and conditional resource rather than a foundational assumption, and FEI's planning framework is designed to adapt if hydrogen does not materialize as currently envisioned.

In circumstances where hydrogen supply is delayed, constrained, or uneconomic, FEI's long-term planning approach would adjust in the following ways:

- Rebalancing the supply portfolio toward RNG and natural gas resources;
- Leveraging flexible contracting and portfolio management strategies;
- Expanding DSM and other demand-side measures; and
- Utilizing existing and planned infrastructure to maintain system reliability.

This integrated and adaptive approach supports FEI's ability to continue balancing the energy priorities of affordability, reliability, and sustainability under a range of potential hydrogen outcomes.

D. SUPPLY PORTFOLIO PLANNING

16.0 Reference: SUPPLY PORTFOLIO PLANNING
Exhibit B-1, Section 6.5.3, p. 6-17
Northwest Pipeline Expansion

On page 6-17 of the Application, FEI states:

> Expanding the Northwest Pipeline Gorge capacity would allow gas to flow west into the Seattle and Portland region that would potentially decrease demand at Huntingdon (Sumas delivery shown in the figure). FEI is currently working with Northwest Pipeline to determine whether this expansion could physically flow gas north to Huntingdon. If feasible, FEI would be interested in placing a firm bid to support this expansion, as it would enhance FEI's diversity of supply and supply resiliency within the portfolio. The project is in the early stages of development, and FEI will be monitoring progress closely given the challenging permitting environment for pipeline projects.

16.1 Please provide an update on Northwest Pipeline's expansion of its Stanfield to Sumas pipeline system, including the timing of the pipeline expansion, the cost to bid to support this expansion, and the estimated volume of gas that could physically flow north to Huntingdon as a result.

Response:

FEI is requesting that this response be filed on a confidential basis, as requested by Northwest Pipeline, and 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.[29] As the information is commercially sensitive, Northwest Pipeline requests that the information only be accessible to the BCUC.

[redacted]

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

17.0 Reference: SUPPLY PORTFOLIO PLANNING

Exhibit B-1, Section 9.2.2, p. 9-4

Tilbury Phase 1B Expansion

On page 9-4 of the Application, FEI states:

> FEI will continue to target investment in infrastructure that promotes supply reliability and resilience, such as the North Mist expansion project. Additionally, if LNG demand growth beyond the capacity of the Tilbury 1B expansion continues in the Lower Mainland area, expansion of the CTS after 2035 and additional firm supply resources, including regional infrastructure as discussed in Section 6.5.3, may be required.

17.1 Please provide an update on FEI's current planning with respect to the Tilbury 1B expansion project including: timing of the expansion, volume of expanded liquefaction capacity, cost of the expansion project, and anticipated BCUC regulatory review process for the expansion.

Response:

As discussed in the response to BCUC IR1 4.1, FEI has experienced significant growth in demand for LNG for the marine bunkering sector. With a growing market for LNG, and LNG volume at Tilbury expected to be fully sold in 2026 and beyond, FEI is seeking to expand its Tilbury LNG facility.

FEI is currently authorized through Direction No. 5 to expand LNG facilities at Tilbury, up to $400 million (i.e., Phase 1B). However, to serve the growing market, amendments to Direction No. 5 would be required to enable an expansion of the Phase 1B facilities up to 0.65 MTPA, consistent with the Medium setting outlined in Section 3.5.3 of the 2026 LTGRP.

The capacity, timing, cost and regulatory review processes related to the Phase 1B expansion remain uncertain. However, if FEI proceeded with the scope currently enabled under Direction No. 5, FEI anticipates that the earliest date that the Phase 1B facilities could be in service is 2031.

E. SYSTEM RESOURCE NEEDS AND ALTERNATIVES

18.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES
Exhibit B-1, Section 7.2.3, p. 7-5
Smaller Transmission Laterals

On page 7-5 of the Application, FEI states:

> For capacity planning purposes, FEI divides its planning area into three main transmission systems and several smaller transmission laterals. The three main transmission systems are:
>
> - the VITS [Vancouver Island Transmission System], encompassing customers served on Vancouver Island, the Sunshine Coast, Squamish and Whistler;
> - the CTS, encompassing the Fraser Valley and surrounding cities, and Metro Vancouver; and
> - the ITS, encompassing the Southern Interior communities in the Kootenays, the Okanagan Valley, and the South Thompson Valley.
>
> FEI has developed peak demand forecasts using both the Traditional Peak Method and the System Peak Forecast Method for the VITS, CTS and ITS.

18.1 Please identify the smaller transmission laterals outside the VTS, CTS, and ITS, including the number of customers served by each lateral or service area.

Response:

FEI operates smaller transmission laterals that connect approximately 62,000 customers with Enbridge's T-South system and 23,000 customers with TC Energy's Foothills BC pipeline. The approximate number of customers and the corresponding service area of each lateral are listed in Tables 1 and 2 below.

Table 1: FEI Transmission Laterals Connected to T-South

Item #	Lateral name	Approx. # of customers	Service area
1	Fort Nelson	2,518	Fort Nelson
2	Hudson Hope	434	Hudson's Hope
3	Chetwynd	1,577	Chetwynd
4	Louisianna Pacific	1	East Pine (Tembec Industries)
5	Mackenzie	1,776	Mackenzie
6	Bear Lake	99	Bear Lake
7	Prince George	33,208	Prince George
8	Dunkley Lumber	1	Dunkley
9	Quesnel	8,191	Quesnel

Item #	Lateral name	Approx. # of customers	Service area
10	Gibraltar Mine	1	McLeese Lake
11	Williams Lake	7,014	Williams Lake
12	Clinton	386	Clinton
13	Ashcroft-Cache Creek	1,324	Cache Creek and Ashcroft
14	HVC & Logan Lake	1,011	Logan Lake
15	Merritt	4,072	Lower Nicola and Merritt

Table 2: FEI Transmission Laterals Connected to Foothills BC

Item #	Lateral name	Approx. # of customers	Service area
1	Cranbrook	15,073	Cranbrook and Kimberley
2	Galloway	458	Galloway
3	Elko	70	Elko
4	Fernie	3,911	Fernie
5	Byron Creek	1	Byron Creek Coal (Sparwood)
6	Sparwood	3,407	Sparwood and Elkford

18.2 Please discuss the methodology FEI uses to monitor and forecast peak demand for smaller transmission laterals and explain whether and how this information is incorporated into long term resource planning.

Response:

FEI applies a consistent methodology to monitor and forecast peak demand across all transmission systems, including the laterals identified in response to BCUC IR1 18.1. The smaller transmission laterals are designed to ensure sufficient inlet pressure is delivered to major gate stations serving downstream distribution systems during peak day operations. A lateral is considered capacity-constrained when the inlet pressure at its associated gate station drops below a specified threshold, signaling that the gate station is approaching its design capacity. When capacity constraints are identified on smaller transmission laterals, it will trigger a project to evaluate and possibly expand the capacity of the system. FEI would then either file for CPCN approval with the BCUC or include the expenditures in its sustainment capital forecast as part of a revenue requirement application.

FEI completed these assessments as part of the long-term resource planning process, and, with the exception of the Williams Lake Lateral as further discussed in the response to BCUC IR1 18.3, no changes to these laterals were identified in the planning horizon.

18.3 Please identify any smaller transmission laterals where FEI currently forecasts, or has recently identified, potential capacity constraints during the planning horizon. For each, provide the nature of the constraint, expected timing and planned mitigation measures.

Response:

As outlined in the 2022 LTGRP, the Cache Creek/Ashcroft lateral has been close to its maximum capacity for several years.[30] FEI conducted a comprehensive study on this system to evaluate available options for maintaining system capacity. Based on the findings of the study, FEI decided to implement operational safeguards and alarm systems instead of proceeding with a pipeline expansion project at that time. FEI will continue to monitor the capacity of the lateral to ensure that peak demand can be effectively managed through the existing operational measures. Should core load growth accelerate beyond current expectations, FEI will consider reinstating the project.

Since the 2022 LTGRP proceeding, the Williams Lake Lateral was identified as being capacity constrained. FEI has initiated a sustainment capital project to evaluate options to expand the capacity of this lateral with a currently targeted in-service date in 2028.

[30] Exhibit B-1, 2022 LTGRP Application, Section 7.3.4, pp. 7-31.

19.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Section 7.3, p. 7-9

Capacity Impacts from Urban Growth and Infrastructure Changes

On page 7-9 of the Application, FEI explains that it examines, among other things, existing and major system infrastructure to identify the expected timing of system constraints and the action plan needed to develop formal solutions that may require further expenditure applications to the BCUC. FEI states:

> Changes in the planning environment and new information may emerge that could impact the timing of the constraints, or the alternative solutions being considered. Such changes will be presented in future LTGRPs or in any required applications to the BCUC.

19.1 Please discuss whether FEI has assessed the potential impacts of urban population growth and resulting class location changes on the capacity and operability of its existing transmission pipeline system over the planning horizon. If so, provide a summary of the assessment and key findings.

Response:

FEI did not assess the potential impacts of urban population growth and its specific impact to class location changes and how this could result in changes to the capacity and operability of its transmission pipeline system over the planning horizon, as it is challenging to connect projected population growth at a municipal level over the planning horizon to a specific location along a specific transmission pipeline.

Class location changes are triggered by the addition of dwelling units within 400 metres of a transmission pipeline, not by general population increases. Further, once a change in dwelling unit count within 400 metres has been identified, not every change in dwelling unit count results in an intervention being required. Rather, further assessment is required to determine if the change requires a project to bring the pipeline's design parameters in line with the requirements of that class location, or whether remedial actions such as a pressure reduction could be put into effect instead. This assessment is required to be done on a site-specific basis as it is dependent on the specific parameters of that pipeline segment, such as wall thickness and grade of steel.

FEI's Asset Management team maintains a process for monitoring, assessing and addressing class locations throughout its system. FEI takes proactive measures to look for potential developments that could trigger a class location upgrade through municipal zoning processes; however, not all proposed developments end up being constructed as planned or in the timeline anticipated. Accordingly, FEI carefully monitors these developments and works to time any potential upgrades in an appropriate timeline.

The Maximum Operating Pressure of the CTS allows for Class 3 designations in nearly all locations, making this system relatively resilient to class location changes related to population

growth. As such, FEI does not anticipate future class location changes in the CTS during the planning horizon.

The ITS and VITS are more susceptible to class location changes than the CTS, and upgrades related to class location changes are continuously managed by FEI as part of its sustainment capital program. Based on past development patterns, FEI can anticipate future class location changes on the following transmission segments.

Pipeline System	Pipeline Segment
Interior Transmission System (ITS)	Southern Crossing NPS 24
	Trail to Salmo NPS 12
	Salmo to Yahk NPS 12
	Vernon to Penticton NPS 12
	Savona to Vernon NPS 12
	Princeton to Oliver NPS 12
	Oliver to Grand Forks NPS 10
	Grand Forks to Trail NPS 10
Vancouver Island Transmission System (VITS)	Vancouver Island Mainline NPS 10

19.2 Please identify any transmission pressure pipeline segments where FEI anticipates future class location changes may require pressure reductions, pipeline replacement, looping, re- routing, or other mitigation measures during the planning horizon.

Response:

Please refer to the response to BCUC IR1 19.1.

19.3 Please discuss whether FEI as part of the LTGRP assessed the potential impacts of major transportation or public infrastructure projects (e.g. bridge replacements, highway expansions, rapid transit projects, or road widenings), or other third party infrastructure projects, on existing gas transmission capacity during the planning horizon. If so, provide examples and associated planning assumptions.

Response:

FEI did not assess the impact of major transportation or public infrastructure projects on existing gas transmission capacity during the planning horizon as part of the 2026 LTGRP, as FEI does

not typically receive long-term infrastructure planning forecasts from third-party infrastructure owners. Third-party infrastructure needs and timelines can be uncertain and are often not available to FEI until the information is publicly available in a shorter-term planning horizon.

FEI maintains close relationships with third-party organizations, in particular the Ministry of Transportation and Transit, and works to identify any potential infrastructure projects that have the potential to impact FEI's infrastructure and come up with appropriate mitigation plans. Generally, replacements of bridges that have pipelines on them will require alternate routing as new bridge designs preclude having pipelines suspended from them. As such, alternate routing or watercourse crossings may be required which can have significant lead times so early identification and planning is essential. FEI's Asset Management team collaborates with other utilities, municipalities, and government agencies to gain visibility on upcoming work, and align work where practicable.

20.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Section 7.3.3.3, pp. 7-24 – 7-25

SCGT as a Potential Future Electric Supply Option

On page 7-24 of the Application, FEI states:

> FBC's previous two electric resource plans identified that the most cost-effective and reliable option to meet the generation needs for new firm peak demand is a simple-cycle gas turbine (SCGT) generating facility. While providing reliable and cost-effective electricity, accommodating an SCGT could require significant upgrades to both the gas (e.g., new pipeline capacity) and electric systems.

On page 7-25 of the Application, FEI states:

> The addition of an SCGT near Kelowna (i.e., within the heart of the OCCA [Okanagan Capacity Constrained Area]) would require an expansion for gas through either or both of the North and South paths described in Section 3 7.3.3.2. Alternatively, if incremental electric generation requirements were met from generation outside of the OCCA, an expansion of the electric system infrastructure would be required to transport the electricity to the Kelowna area. In advance of FBC's 2026 LTERP, FBC continues to evaluate requirements and infrastructure options, for both the gas and electric system, required to serve the capacity and energy needs of the Okanagan region.

20.1 Please discuss the potential advantages and disadvantages, if any, of reviewing FEI and FBC's gas and electric resource plans on a more coordinated timeline, for example from the perspective of understanding the potential impacts of FBC's potential plans for an addition of an SCGT upon FEI's planning for potential gas infrastructure.

Response:

FEI discusses the potential advantages and disadvantages of reviewing the FEI and FBC long-term resource plans on a more coordinated timeline below; however, it is important to note that FEI and FBC already work closely to coordinate their resource plans to the extent possible within their respective planning and regulatory frameworks. This coordinated internal planning includes consideration of potential impacts of an SCGT.

The primary advantages of reviewing FEI's and FBC's long-term resource plans on a coordinated timeline are that the assumptions and forecasts underpinning the resource plans could be reviewed and assessed at the same time. This would potentially enhance the comparability of the assumptions and forecasts and allow for improved consistency of information across both resource plan proceedings.

However, coordinating the filing of FEI's and FBC's resource plans would likely not improve the efficiency of the regulatory review processes because the utilities would still need to file separate

resource plans. While FEI's and FBC's service areas overlap, they are not identical and each of the utilities must make planning considerations based on their distinct service areas, energy services and resource planning considerations. As an example, FBC's electric generation supply planning is much different than FEI's gas supply planning, which relies primarily on purchasing supply in competitive markets.

A further disadvantage of coordinating the resource planning review processes is the burden that it would place on FEI's and FBC's staffing resources. Many of the same individuals and departments are involved in the development of the resource plans for FEI and FBC. Combining the filing and regulatory reviews of the resource plans would increase the work required to develop these applications. Further, while there is overlap in the engagement on FEI's and FBC's resource plans, not all of the interested parties (or interveners) are the same. Fully combining the review timelines would mean that FEI/FBC would have to conduct all engagement activities at essentially the same time, which might negatively impact interested parties' level of engagement, as many of the topics covered at each engagement session would be irrelevant to the particular party's interests.

Ultimately, while broad alignment of resource plan timelines can support comparability across plans, differences in utility-specific requirements and system needs may require advancing plans on distinct timelines. More rigid synchronization may limit each utility's ability to respond independently and efficiently to emerging planning requirements, as well as to coordinate appropriately with other regulatory filings and decision-making processes. FEI and FBC therefore consider it important to have some flexibility in terms of when each utility is required to file their respective resource plans.

20.2 In a scenario in which FBC decides to advance with a SCGT plant in the Okanagan area, please elaborate on the potential impact of such a decision on FEI's transmission system and the timelines required for FEI's decision making processes, including the time required to engage in BCUC regulatory processes.

Response:

As noted in Table 7-4 of the 2026 LTGRP, peak day natural gas demand requirements for an SCGT load will depend on the installed generation capacity and would range from 23 to 90 TJ/day for a range of power generation capacities of 90 to 360 MW.

A load of this nature would influence the supply-demand balance within the ITS. The ITS serves a broad geographic area, and certain segments can experience higher pressure drops during periods of peak demand. As a result, the impact of an SCGT load would depend on its location within the system:

- If installed within the Okanagan Capacity Constrained Area (OCCA) near Kelowna, the additional demand would further influence existing capacity constraints by contributing to an incremental pressure drop between the supply points (Savona Tap in the north and Oliver in the south) and the stations serving Vernon and Kelowna. These impacts could be managed through system reinforcements, such as pipeline looping, similar to that described in the OCU Project CPCN application, or through the addition of facilities such as compression or peak shaving.
- If installed outside of the OCCA (e.g., at or upstream of the Oliver control station), an SCGT load addition may not have any impact on delivery pressures near Kelowna and Vernon and therefore may not necessitate a gas system expansion within the OCCA.

Any increased load within the ITS would be expected to increase flows along the 24-inch Southern Crossing Pipeline (SCP) which connects the East Kootenay Exchange with Oliver. Should higher demand levels materialize, capacity expansion options for this pipeline segment may be considered.

Overall, the potential impact of an SCGT load on the FEI transmission system is highly dependent on project-specific factors, including location, timing, and magnitude, and therefore requires further assessment as these parameters become more defined. The need for such a resource would be driven by FBC resource and system requirements, and any associated gas system implications would be evaluated accordingly. Depending on the nature and scope of any required gas system reinforcements, implementation timelines could also be influenced by FEI's planning and decision-making processes, including any applicable regulatory review and approval requirements. FEI expects to provide additional details following the FBC 2026 LTERP proceeding.

In line with Action Item 6 of the 2026 LTGRP Action Plan, FEI will continue to monitor peak demand forecasts and assess system resource requirements, including the need for potential expansions or upgrades across its service areas.

21.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Section 7.3.3.2, p. 7-24

Timing of Potential Future CPCN Application

On page 7-24 of the Application, FEI states:

> To ensure OCCA customer needs continue to be met and to reduce the system's reliance on short-term mitigations, some of which remain outside of FEI's control, FEI continues to develop project alternatives in preparation for the likely submission of a CPCN [Certificate of Public Convenience and Necessity] application.

21.1 Please provide FEI's current expectations regarding the timing of any future CPCN should FEI determine that a CPCN application is required in the future, and the circumstances that may affect the need or timing for a future project.

Response:

FEI continues to advance the development of potential system reinforcement alternatives to address forecast capacity constraints on the ITS to maintain safe and reliable service to customers in the OCCA. Based on FEI's current planning analysis, demand growth on the ITS is forecast to exceed available system capacity, including with the OCMP Project in place, by winter 2031/2032. Absent implementation of a long-term solution, this capacity shortfall would increase the risk of gas service disruption and requires continued reliance on short-term mitigation measures, some of which are not fully within FEI's control, including operation at elevated, non-contractual system supply pressures.

FEI considers it likely that a CPCN application will be required to address the identified capacity shortfall. Based on current assumptions and the status of project development activities, FEI's expectation is to file a CPCN application at the end of 2027 or early 2028. This timing reflects the need to further develop and assess project alternatives, advance a preferred option to an appropriate level of definition, and align regulatory review and approval timelines with the requirement to have infrastructure in service prior to the forecast shortfall in winter 2031/2032.

The appropriate planning horizon for system expansions (for example, whether infrastructure should be sized for shorter-term or longer-term needs) remains an important consideration, as it can materially impact project design, cost, and staging. Further, the results of the ongoing alternatives analysis, including technical feasibility, cost, and overall system performance, will inform both the need for a CPCN application and its timing. External factors, such as permitting requirements, engagement with Indigenous communities and interested parties, and procurement timelines for critical equipment, may also affect project development schedules and the timing of a filing.

21.2 Please provide a high-level summary of the potential alternatives currently being assessed by FEI, including any mitigation activities and lead time considerations.

Response:

FEI is evaluating three broad categories of alternatives to address the identified system need: (1) pipeline reinforcement; (2) compression-based solutions; and (3) additional LNG peak-shaving capacity.

Pipeline reinforcement alternatives include looping portions of the existing transmission system to increase deliverability into the OCCA, including concepts aligned with elements of the previously proposed OCU project, such as adding capacity to move additional gas north from the Penticton area. FEI is also considering alternate routing options that could bring additional supply from other parts of the system. While these alternatives could provide meaningful capacity increases, they may involve longer development timelines and higher costs due to routing requirements, environmental review, land access, and engagement with Indigenous communities and other stakeholders.

Compression-based alternatives would increase throughput on the existing system through new compressor installations at strategic locations, including configurations that improve flow along key corridors into the OCCA and address system pressure limitations. These options may reduce the need for new pipeline construction and could offer a smaller environmental footprint or shorter permitting timeline, but they require consideration of electrical power supply for electric-drive units, fuel requirements and emissions limitations for gas-driven units, and long-lead procurement for major equipment.

FEI is also assessing additional peak shaving capacity, including a facility similar to the OCMP Project, as well as traditional LNG peak shaving facilities. A facility similar to the OCMP Project may provide incremental capacity support over shorter time horizons, but such a facility is limited by storage duration and generally cannot support longer-term planning horizons, such as a 10- or 15-year load forecast. To meet those longer-term requirements, a traditional LNG peak shaving facility would likely be required.

Lead time considerations are a critical factor across all alternatives, given the expected requirement to have a solution in place before the forecast shortfall in winter 2031/2032. FEI anticipates that the procurement of critical equipment for compression-based alternatives may extend to approximately three years, presenting challenges to those alternatives. Pipeline-based alternatives may not face the same equipment constraints, but can involve longer timelines for routing, land acquisition, permitting, and Indigenous and stakeholder engagement.

There have been no new physical mitigation activities identified that support the OCCA, and FEI remains reliant on short-term mitigations in the ITS with the principal benefit coming from the increased tap pressure at Savona. The System Peak Forecast, however, indicates the capacity shortfall in the ITS is two years later relative to the Traditional Peak Method, allowing for additional planning and alternative analysis.

22.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Appendix D, Section 5.2, p. 24

Early Use of AMI Data for Interim Peak Demand Forecasting in the Okanagan

On page 24 of Appendix D to the Application, FEI states:

> As shown in Table 5-1, the deployment of AMI [Advanced Metering Infrastructure] meters is happening concurrently throughout FEI's service territory by four deployment vendors and FEI Operations throughout 2025 to 2028; therefore, no single region of FEI's service territory is anticipated to be fully complete in advance of the first quarter of 2028. FEI does not anticipate that it will have complete AMI meter data from the Okanagan region before the expected project close out in the second quarter of 2028. Accordingly, in the short term, the AMI Project will not provide any benefits towards enabling peak demand reduction activities as the project is not estimated to be complete until 2028. Further, FEI expects that at least a full year of detailed customer consumption information collected from AMI meters would be required before the information could effectively inform peak demand-related initiatives on its distribution system.

22.1 Please identify the approximate number and percentage of Okanagan region customers expected to have AMI meters installed by the end of each year from 2025 through 2028.

Response:

The total number of AMI meters expected to be installed for residential and small commercial customers in the Okanagan region by the end of the AMI Project is 124,708. Please refer to the following table for the cumulative number and percentage of AMI meters expected to be installed each year between 2025 and 2028 for residential and small commercial customers in the Okanagan region.

2025		2026		2027		2028	
#	%	#	%	#	%	#	%
23,369	19%	66,142	54%	111,851	90%	124,708	100%

By the end of 2027, FEI expects that AMI meter deployment for residential and small commercial customers will be substantially complete in the following communities in the Okanagan region: Coldstream, Enderby, Cawston, Hedley, Kaleden, Kelowna, Keremeos, Lake Country, Lumby, Naramata, Okanagan Falls, Oliver, Oyama, Peachland, Princeton, Summerland, and Winfield.

22.2 Please explain whether FEI expects AMI deployment to be substantially complete in any individual Okanagan communities or operating areas prior to the overall project completion date.

Response:

Please refer to the response to BCUC IR1 22.1.

22.3 Please discuss whether FEI has considered any pilot, staged, or interim analytical approaches that would allow AMI data from partially deployed areas to inform regional peak demand forecasting prior to full AMI deployment. Please include, but do not limit your response to, a discussion of the Okanagan region.

22.3.1 Please discuss whether such approaches could assist with accelerating FEI's refinement of its peak demand forecasts ahead of anticipated capacity driven infrastructure projects.

Response:

As discussed in Section 5 of FEI's OCMP Peak Demand Mitigation Report (see Appendix D-1 of the 2026 LTGRP), FEI expects that once the AMI Project is complete, it will be able to use the more granular consumption information to enhance its understanding of the real-time behavior of gas consumers and the direct response of the distribution system. Data from the AMI Project will support gas demand response and distribution system planning. However, the AMI Project itself will not avoid the need for capacity expansion in the Okanagan region or contribute measurably to regional peak demand forecasting as FEI already has metering data at its stations (i.e., regional level) that provide granular flow and pressure information to monitor actual peak and transmission system capacity requirements.

FEI has started working with the limited AMI data available based on AMI deployment to date, but FEI does not anticipate that any refinements to its distribution system planning forecasts can be accelerated until more data becomes available and FEI's analysis of the broader datasets can be completed.

FEI has begun analyzing the AMI data format and preparing tools and interfaces with which the data can be analyzed to inform FEI's processes. However, the AMI data set is currently small and is not concentrated on any single region or dwelling type. Due to the limited set of data from available premises, there is not yet adequate data available to draw any statistically relevant conclusions.

FEI is also working with available AMI data on possible analytical methods to allow for premise-level forecasting. The methods use the same segmented spline regression analytical techniques that have worked well in the past. However, FEI will need more data over three or more years to be able to predict whether the methods using AMI data will improve forecast results.

F. GHG EMISSIONS

23.0 Reference: BALANCING AFFORDABILITY, RELIABILITY AND SUSTAINABILITY
Exhibit B-1, Section 9.3.3, Figure 9-4, p. 9-9, p. 9-10
GHG Emissions – End Use

On page 9-9 of the Application, in Figure 9-4 GHG Emissions (End Use) – Residential, Commercial and Industrial Sector, FEI compares the end use GHG emissions of different scenarios and the province of BC climate targets during the planning horizon. The figure shows that the Diversified Approach scenario, FEI's preferred one, would meet provincial climate targets towards the end of the planning horizon.

On page 9-10 of the Application, FEI "acknowledges that meaningful progress towards GHG emissions reductions is dependent on FEI's ability to promote the development of renewable and lower-carbon gas supply and continued investment and customer uptake in DSM programs. FEI's ability to meet provincial targets is also linked to external conditions and this needs to be considered rationally when evaluating the ability to meet provincially legislated emissions reductions objectives."

23.1 Please elaborate on the relative uncertainty of the GHG forecasts in the Diversified Approach and Electrification Focus scenarios.

Response:

As introduced in Section 2 of the 2026 LTGRP, long-term planning to 2050 is undertaken in the context of significant uncertainty, including evolving policy direction, constraints within regional energy systems, and the pace of technological development. These uncertainties require FEI to continually adapt its planning approach and consider a range of plausible demand and supply pathways to ensure the continued delivery of safe, reliable, resilient, and affordable service.

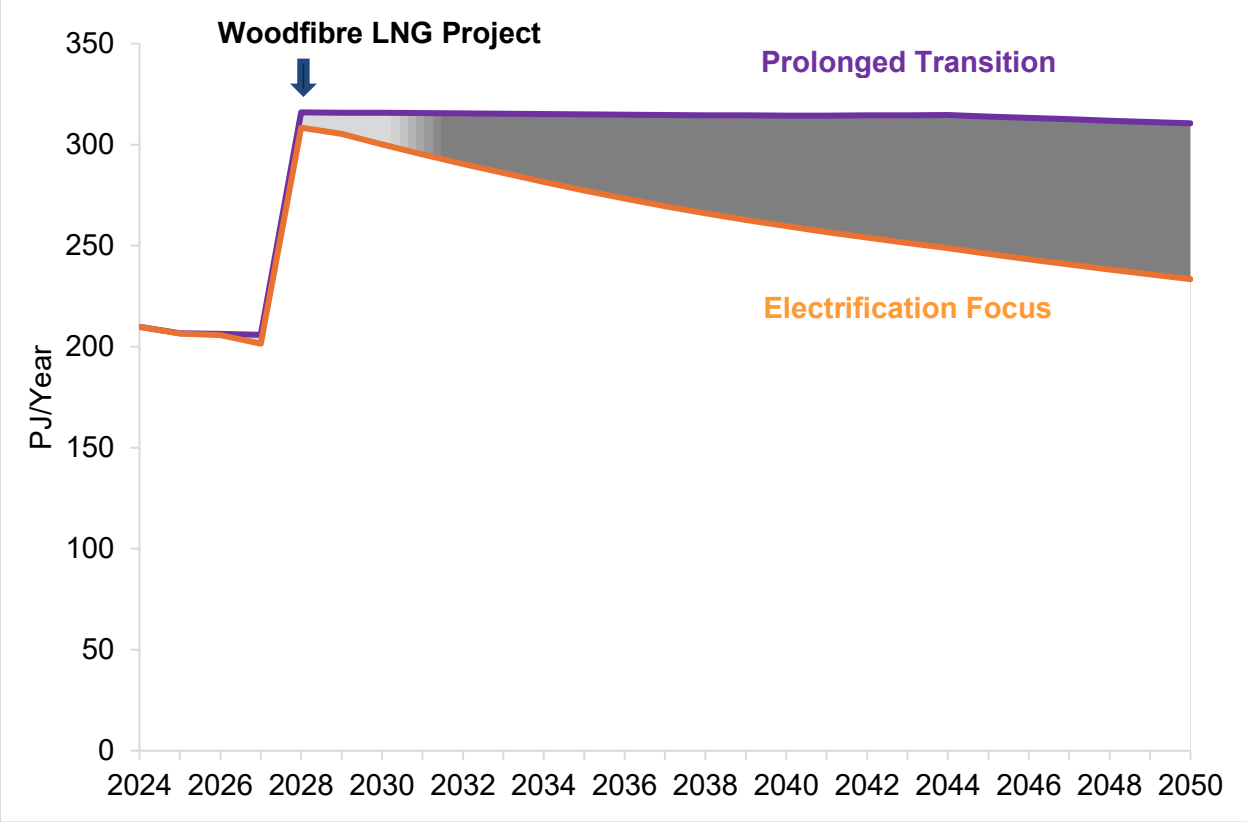
In this context, uncertainty is inherent not only in the development of the Diversified Approach and Electrification Focus scenarios, but also in the associated GHG emissions results. Emissions outcomes are directly dependent on underlying assumptions related to demand, technology adoption, supply portfolio, and policy evolution embedded within each scenario. As such, differences in scenario drivers translate directly into variability in projected GHG outcomes.

As described in Section 3, scenario outcomes are similar in the near term (to 2030), but uncertainty increases over the longer term (to 2050), leading to a wider range of potential demand, supply, and emissions outcomes. This highlights the value of scenario analysis in assessing trade-offs and risks across potential futures.

To address this uncertainty, the 2026 LTGRP applies a scenario-based framework, as described in Section 3.8, rather than relying on a single forecast. FEI provides Figure 3-11 below from the 2026 LTGRP which illustrates this approach, with the shaded range representing the span of potential outcomes, bounded by the Prolonged Transition scenario (upper bound) and the

Electrification Focus scenario (lower bound). This framework enables FEI to evaluate system impacts and GHG implications across a spectrum of possible future states.

Figure 3-11: Total Annual Demand – Planning Range for Residential, Commercial, and Industrial Sector, including the Woodfibre LNG Project



The relative uncertainty associated with GHG emissions forecasts under both the Diversified Approach and Electrification Focus scenarios reflects broader uncertainty in underlying policy, market, and technology trajectories. As noted in the *Climate Change Accountability Report 2025*, British Columbia is not currently on track to meet its 2030 emissions targets,[31] underscoring the gap between policy objectives and realized outcomes and reinforcing the inherent uncertainty in long-term GHG emissions projections.

Thus, while FEI continues to identify the Diversified Approach as the preferred planning scenario, the breadth of uncertainty affecting both scenario development and associated GHG emissions outcomes necessitates maintaining flexibility and preparing for a range of potential futures.

[31] Province of British Columbia, Climate Change Accountability Report 2025, pp. 4, 16, online at https://www2.gov.bc.ca/assets/gov/environment/climate-change/action/cleanbc/2025_climate_change_accountability_report.pdf.

23.2 Please further discuss the additional available opportunities to enhance GHG emission reductions to meet the BC provincial targets for the Diversified Approach and Electrification Focus scenarios.

23.2.1 Please estimate the magnitude and direction of the impact of these opportunities on future rates.

Response:

FEI discusses each of the Diversified Approach and Electrification Focus scenarios below regarding potential additional GHG emissions reduction opportunities and the magnitude and direction of the impact of these opportunities on future rates.

Diversified Approach Scenario

In Figure 9-5 of the 2026 LTGRP, FEI identified three primary drivers of GHG emissions reductions in the Residential, Commercial and Industrial sector within the Diversified Approach scenario: (1) fuel switching from gas to electricity; (2) improving energy efficiency through DSM programs; and (3) renewable and lower carbon gases. Any opportunities for further GHG emissions reductions from the Diversified Approach scenario in the Residential, Commercial and Industrial sector would generally continue to fall within these three primary areas. FEI elaborates on the three primary areas/drivers as follows:

- **Fuel switching from gas to electricity:** Electrification of end uses, particularly in the residential and commercial sectors and select industrial applications, contributes to GHG emissions reductions. As outlined in Section 3 of the 2026 LTGRP, the extent of this contribution is influenced by the evolution of building codes, equipment standards, and broader policy direction. While more stringent policies could increase the pace and scale of electrification, the 2026 LTGRP identifies an ongoing role for the gas system in supporting system reliability and customer choice, including through hybrid approaches such as dual-fuel systems.

- **Improving Energy Efficiency through DSM programs:** DSM measures play a significant role in reducing overall energy demand and associated emissions. The Diversified Approach scenario is modelled using a Medium DSM setting; however, there is potential to further expand DSM contributions under more favourable policy, market, and participation conditions. Increased adoption of advanced measures – such as dual-fuel systems, deep energy retrofits, and emerging technologies including gas-fired heat pumps – could enhance emissions reductions while maintaining cost-effectiveness for customers. Sections 4.6 and 4.7 of the 2026 LTGRP further highlight the system and customer benefits of dual-fuel technologies, and FEI will continue to monitor their development and collaborate with utilities.

- **Renewable and lower-carbon gas:** Section 5 of the 2026 LTGRP outlines the role of RNG and hydrogen in reducing the carbon intensity of delivered energy. The extent and timing of their contribution are dependent on supply availability, infrastructure development, and the broader regulatory and market environment, as further discussed

in the responses to BCUC IR1 14.1 through 14.6 and 15.1 through 15.3. These factors collectively inform the pace at which lower-carbon gas solutions can be integrated to support emissions reductions.

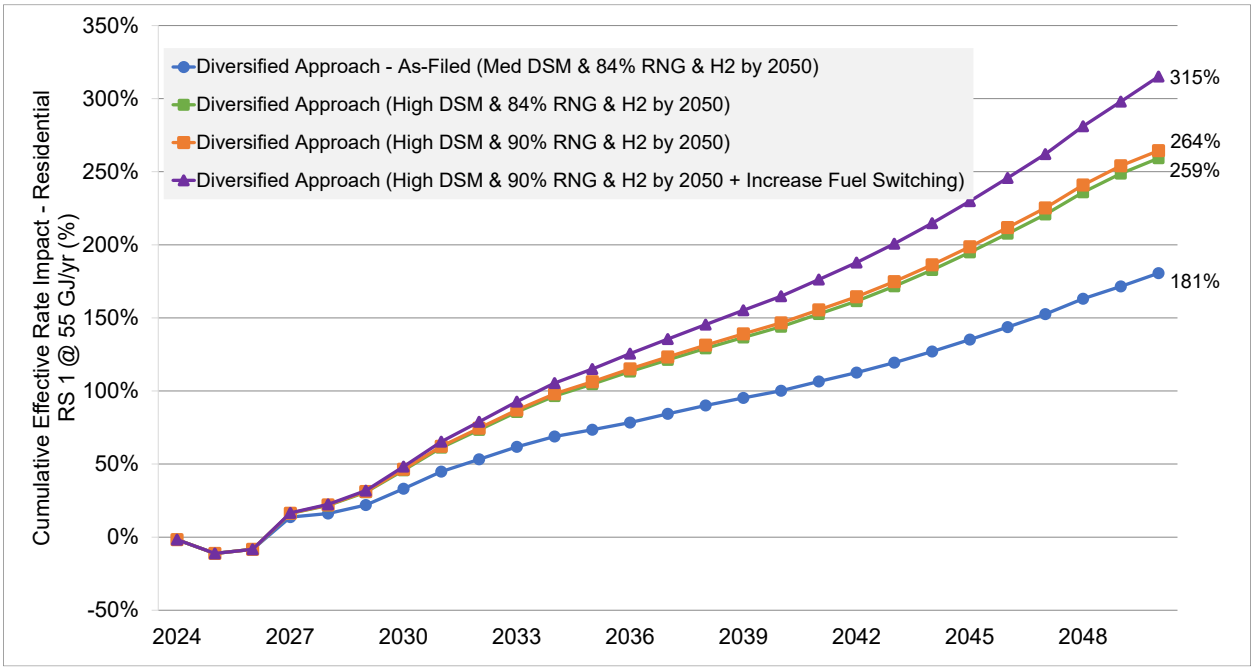
FEI also has opportunities to reduce emissions in the transportation and marine sectors. As discussed in Section 9.3.4 of the 2026 LTGRP, the use of lower-carbon gas in these sectors offers an additional avenue for reducing emissions beyond the residential, commercial, and industrial sectors, particularly in applications where electrification may be more challenging. In these cases, lower-carbon gas can help reduce emissions relative to higher-emitting fuels such as marine gas oil and diesel.

FEI has also identified additional opportunities to contribute to emissions reductions through Carbon Capture, Utilization, and Storage (CCUS). As discussed in Section 9.3.5 of the 2026 LTGRP, CCUS provides additional emissions reduction opportunities. However, CCUS is expected to be primarily applicable to certain industrial applications, and its broader deployment remains uncertain. Accordingly, the 2026 LTGRP does not assume a material contribution from CCUS until approximately 2035, reflecting current technology maturity and commercial considerations.

FEI has not identified and completed a detailed analysis on any specific opportunities beyond those already discussed in the 2026 LTGRP. However, for illustrative purposes, FEI provides a sensitivity analysis on the directional impact to customer rates if there are further enhancements in the three primary areas beyond the level assumed in the Diversified Approach scenario. This is shown in Figure 1 by assuming:

- DSM expenditures are increased from the Medium setting under the Diversified Approach scenario to the High setting. This will potentially increase the adoption of energy efficiency, and therefore further reduce gas demand as well as GHG emissions.
- The percentage of renewable and lower-carbon gas is increased from 84 percent by 2050 to approximately 90 percent by 2050.
- The level of fuel switching is increased by assuming the overall gas demand from residential, commercial, and industrial customers under the Diversified Approach scenario will resemble the Electrification Focus scenario, which prioritized electrification through fuel switching. However, fuel switching is largely dependent on future policy and regulation that is outside of FEI's direct control.

Figure 1: Sensitivity Analysis of Customer Rate Impacts Due to Further Increase in DSM Expenditures, Renewable and Lower-Carbon Gas, and Fuel Switching from the Diversified Approach



FEI notes that the Diversified Approach scenario presented in the 2026 LTGRP is expected to meet provincial climate targets towards the end of the planning horizon to 2050; thus, as discussed in Section 9.1.1, it is important to consider the balance between affordability and sustainability in the context of additional rate impacts for achieving GHG emissions reductions beyond the provincial climate targets. Given that the percentage of renewable and lower-carbon gas in FEI's system under the Diversified Approach scenario is already approximately 84 percent by 2050, the majority of the additional opportunities for further GHG emissions reductions would likely come from increasing DSM expenditures or increasing the level of fuel switching (which is outside of FEI's direct control). As shown in Figure 1 above, further increases in DSM expenditures and fuel switching beyond the levels assumed in the Diversified Approach scenario would materially increase customer rates, highlighting the trade-off between achieving additional GHG emissions reductions and maintaining affordability for customers.

Electrification Focus Scenario

Unlike the Diversified Approach scenario, the Electrification Focus scenario does not include a significant role for renewable and lower-carbon gases. This reflects an assumed policy environment that prioritizes electricity-based solutions for end-use energy needs and limits the role of gas-based GHG emissions reduction options.

FEI acknowledges that the actions represented in the Electrification Focus and Diversified Approach scenarios are not mutually exclusive, and that elements of each – such as DSM, fuel switching, and increased supply of renewable and lower-carbon gas – could collectively contribute to GHG emissions reductions. However, the scenarios were structured as distinct and internally

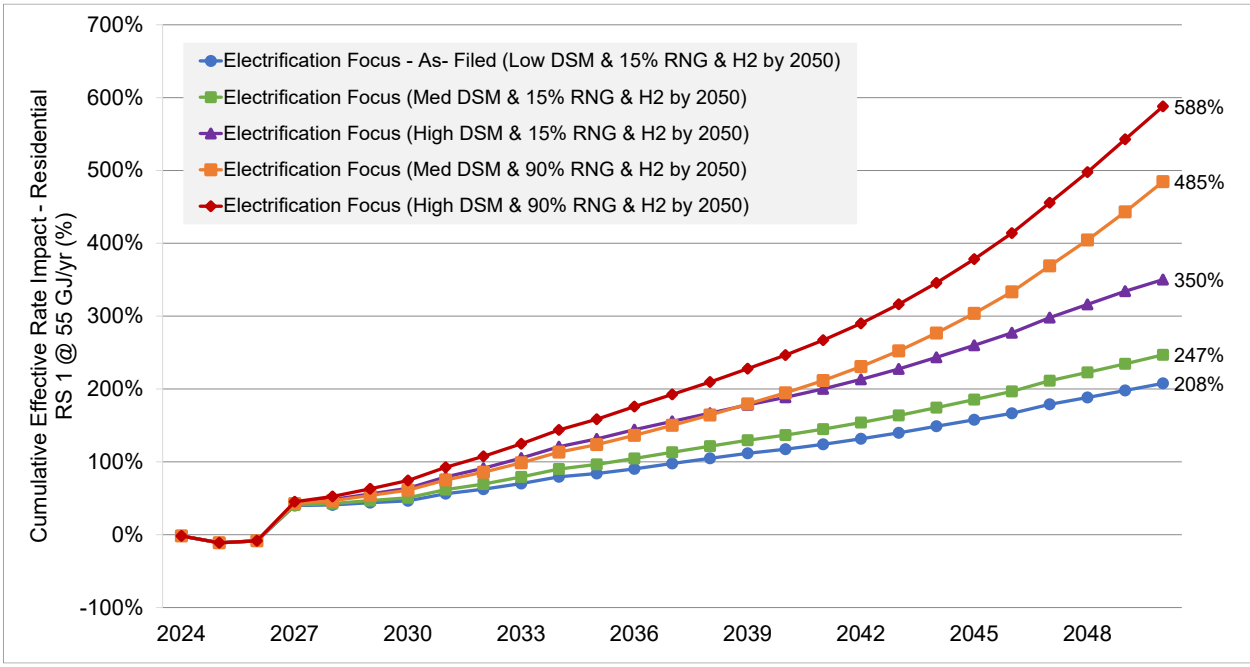
consistent pathways to enable a clear assessment of trade-offs across different policy directions and system evolution trajectories. In this context, the Diversified Approach scenario specifically examines a pathway with a greater role for renewable and lower-carbon gas, while also demonstrating the continued role and viability of the gas system within a lower-emissions future.

For illustrative purposes only, FEI has undertaken a sensitivity analysis on the directional impact to customer rates of increased lower-carbon gas supply or enhanced DSM uptake on emissions outcomes. However, such sensitivities are not reflective of the intended design of the Electrification Focus scenario and would reduce its effectiveness in illustrating the implications, trade-offs, and system impacts of a pathway primarily driven by electrification.

Figure 2 below provides a sensitivity analysis on the directional impact to customer rates for the Electrification Focus scenario if:

- DSM expenditures are increased from the Low setting under the Electrification Focus scenario to the Medium and High settings. This will potentially increase the adoption of energy efficiency, and therefore further reduce gas demand as well as GHG emissions compared to the Electrification Focus scenario presented in the 2026 LTGRP.
- The percentage of renewable and lower-carbon gas in FEI's system under the Electrification Focus scenario is maximized by increasing the percentage blending from 15 percent by 2050 to approximately 90 percent by 2050 (a level comparable to the Diversified Approach scenario). However, FEI does not consider including a larger proportion of renewable and lower-carbon gas in its supply mix beyond the level already included in the Electrification Focus scenario to be appropriate. The Electrification Focus scenario was intentionally developed to reflect a policy environment centered on electrification, resulting in significant fuel switching from natural gas to electricity. Introducing higher levels of renewable and lower-carbon gas into this scenario would not be consistent with its underlying design or analytical purpose.
- FEI made no changes to the level of fuel switching under the Electrification Focus scenario as this scenario already prioritizes fuel switching through government policies and incentives.

Figure 2: Sensitivity Analysis of Customer Rate Impacts Due to Further Increase in DSM Expenditures and Renewable and Lower-Carbon Gas from the Electrification Focus Scenario



As shown in Figure 2 above, further increases in DSM expenditures and renewable and lower-carbon gas (to a level comparable to the Diversified Approach scenario) result in customer rate impacts that are materially higher than those associated with the Diversified Approach scenario, even beyond the enhanced DSM expenditures and renewable and lower-carbon gas blending levels modelled in Figure 1. Given the Electrification Focus scenario is expected to achieve less GHG emission reductions than the Diversified Approach scenario (as shown in Figure 9-4 of the 2026 LTGRP), the sensitivity analysis shows that the Diversified Approach scenario provides a more cost-effective pathway and achieves a better balance between affordability and sustainability.

23.3 Please explain whether FEI considered an Electrification Focus scenario that includes a larger proportion of low-carbon gasses in its supply mix, and discuss whether such a scenario would allow for a more like-for-like comparison with the Diversified Approach scenario.

Response:

Please refer to the response to BCUC IR1 23.2.