Sarah Walsh
Director, Regulatory Affairs

Gas Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

Electric Regulatory Affairs Correspondence
Email: electricity.regulatory.affairs@fortisbc.com

FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (778) 578-3861
Cell: (604) 230-7874
www.fortisbc.com

July 20, 2026

City of Richmond (Richmond), Lulu Island Energy Company (LIEC)
Brendan Burns, Staff Solicitor

Corporation of the District of Saanich (Saanich)
Rebecca Newlove, Manager of Sustainability

Dear LIEC-Saanich-Richmond:

Re: FortisBC Energy Inc. (FEI)
2026 Long Term Gas Resource Plan (LTGRP)
Response to LIEC-Saanich-Richmond Joint Information Request (IR) No. 1

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

FEI notes that LIEC-Saanich-Richmond have submitted IRs that, while presented as a single numbered IR, contain multiple distinct requests for information. For example, LIEC-Saanich-Richmond IRs 4.5, 8.5 and 8.7 are examples of IRs that contain multiple IRs in one.

FEI considers that this approach is inconsistent with the wording and purpose of Order G-111-26. In that Order, the Panel consolidated parties into intervener groups, directed them to file information requests jointly, and limited intervener groups to "a maximum of 30 questions each, inclusive of sub-questions, for Intervener Information Request (IR) No. 1." The intent of these directions was to promote a focused and efficient review process. Submitting compound IRs, or requests including sub-questions that exceed the 30-question limit undermines the efficiency objectives underlying Order G-111-26. Further, incorporating multiple IRs into a single IR has decreased the understandability of the questions, which has increased the amount of time and effort required by FEI to respond to the questions and thus has undermined the intended regulatory efficiencies from limiting the number of IRs.

Notwithstanding its concerns regarding compliance with the Panel's direction, FEI has provided responses to these IRs by addressing the central inquiry raised by each request, with a view to assisting the Panel's review of the Application and ensuring that interveners receive responsive information on the key issues they seek to examine. FEI advises that, in future

[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.

processes, it may object to multiple discrete requests for information being combined into a single question.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Registrar
Registered Interveners

Table of Contents **Page No.**

A. Scope and effect of acceptance

1.0 Topic: Effect of acceptance on later proceedings

Reference: Application, Exhibit B-1, Section 1.1 (Application and Order Sought) and Appendix G-2 (draft order). UCA ss. 44.1(6), 44.1(9), 44.2(6), 45, 46 and 71.

FEI seeks acceptance of the 2026 LTGRP as being in the public interest under section 44.1(6), and does not seek any conclusive determination or CPCN exemption under section 44.1(9), or any specific approval folded into the order.

1.1 Confirm that FEI does not contend that acceptance of the 2026 LTGRP under section 44.1(6) constitutes a determination that any specific resource (e.g., resources to meet peak loads), demand-side measure or programs (including the residential dual-fuel heating program), any expenditure, or the Diversified Approach scenario itself is in the public interest; and that FEI does not intend to rely on acceptance of the 2026 LTGRP, or on any finding made by the Panel in this proceeding, as a public-interest determination or mandatory consideration in any later application under section 44.2, 45, 46 or 71, including the deemed acceptance in section 44.2(6). If not confirmed, please explain.

Response:

FEI is requesting that the BCUC accept the 2026 LTGRP as being in the public interest pursuant to section 44.1(6) of the *Utilities Commission Act* (UCA) and therefore intends to rely on that acceptance to the extent relevant in future proceedings.

FEI has not requested, and therefore does not have any plan to rely on, approval or acceptance of any specific resource, expenditure, DSM measure or program, or long-term scenario, or any exemptions or conclusive determinations under section 44.1(9).

B. Demand forecast and scenario framing

2.0 Topic: Regional load forecasts

Reference: Application, Exhibit B-1, Appendix A, Table 4, items 11 and 20 (pp. 16, 18); Sections 4, 7 and 8.6; p. 8-13 and Table 8-4. Order G-78-24, pp. 25 and 38.

In Order G-78-24 the Panel directed that future LTGRPs include a deeper analysis of regional load forecasts (p. 25) and regional-level analysis of demand and supply resources, including infrastructure requirements (p. 38). FEI's compliance entries map these directions to sectoral annual demand in Section 4, transmission-system capacity in Section 7, and customer growth rates in Section 8.6.

2.1 Provide, disaggregated to FEI's billing regions (Lower Mainland, Vancouver Island, Inland, Columbia, Whistler and Revelstoke) and for each of the five demand scenarios, the residential, commercial and industrial annual demand, the forecast DSM savings, and the forecast peak demand. Please provide this as an extension of Tables 3-2 and 3-3, adding annual demand and average per-customer demand for each region and scenario.

Response:

As a result of using the end-use model for scenario planning, FEI is unable to provide annual demand and DSM savings disaggregated by billing region. The end-use methodology in the 2026 LTGRP applies Business As Usual (BAU) customer account growth rates to base-year customer accounts by sector (residential, commercial, and industrial) at the parent-region level used in the 2026 LTGRP and the 2024 Conservation Potential Review (CPR): Lower Mainland, Northern BC, Southern Interior, and Vancouver Island, Sunshine Coast, and Whistler. Therefore, annual demand (including average per-customer values) and DSM savings are developed at the parent-region level rather than the FEI billing-region level.

To provide the requested regional information to the extent available, FEI has prepared a breakdown of annual demand and DSM savings by parent region for each demand scenario, as presented in Tables 1 through 8 below. The Use Per Customer (UPC) results should be interpreted as directional values, given that FEI utilized the same customer account forecast for each scenario, before the key drivers impacted the consumption.

In addition, FEI is not able to provide forecast peak demand disaggregated by FEI billing region. As discussed in Section 7 of the 2026 LTGRP, peak demand forecasts are developed at the level of FEI's major transmission systems (CTS, ITS and VITS), rather than by billing region.

Table 1: Annual Energy and Average UPC in Lower Mainland[1]

	Residential Sector		Commercial Sector		Industrial Sector	
Scenario / Year	Annual Demand (GJ)	Average UPC (GJ)	Annual Demand (GJ)	Average UPC (GJ)	Annual Demand (GJ)	Average UPC (GJ)
Baseline Trends						
2024	52,907,765	91	44,489,603	801	30,454,111	3,980
2030	47,078,816	77	41,190,275	721	31,461,441	3,994
2040	30,328,107	48	31,878,038	536	31,409,435	3,829
2044	26,912,306	42	29,113,623	483	31,523,757	3,794
Diversified Approach						
2024	52,877,531	91	44,489,602	801	30,454,109	3,980
2030	48,607,237	80	41,420,218	725	31,461,428	3,994
2040	41,461,863	65	35,616,961	599	31,396,789	3,828
2044	39,384,282	61	33,635,576	558	31,481,705	3,789
Electrification Focus						
2024	52,907,765	91	44,489,603	801	30,454,110	3,980
2030	44,847,391	74	38,733,103	678	31,367,839	3,982
2040	28,680,494	45	27,550,833	463	30,469,616	3,715
2044	25,308,412	39	23,720,757	394	30,001,384	3,610
Lower-Carbon Transportation and LNG Future						
2024	52,907,765	91	44,489,603	801	30,454,110	3,980
2030	46,971,847	77	41,242,291	722	31,418,707	3,989
2040	30,167,357	47	31,545,454	530	30,729,424	3,746
2044	26,650,649	41	28,322,714	470	30,464,067	3,666
Prolonged Transition						
2024	52,907,765	91	44,489,603	801	30,454,110	3,980
2030	50,396,824	83	43,572,583	762	31,975,418	4,059
2040	46,873,050	73	43,625,099	733	33,035,689	4,028
2044	45,843,707	70	43,509,933	722	33,443,124	4,025

Table 2: Annual Energy and Average UPC in Northern British Columbia

	Residential Sector		Commercial Sector		Industrial Sector	
Scenario / Year	Annual Demand (GJ)	Average UPC (GJ)	Annual Demand (GJ)	Average UPC (GJ)	Annual Demand (GJ)	Average UPC (GJ)
Baseline Trends						
2024	4,917,636	82	2,980,880	515	16,712,271	30,728
2030	4,631,994	74	2,910,795	480	14,368,096	25,247
2040	3,107,957	47	2,560,293	389	14,488,489	23,517

[1] Tables 1 to 4 are presented in GJ because it is a more suitable unit for expressing residential customer UPC values.

	Residential Sector		Commercial Sector		Industrial Sector	
Scenario / Year	Annual Demand (GJ)	Average UPC (GJ)	Annual Demand (GJ)	Average UPC (GJ)	Annual Demand (GJ)	Average UPC (GJ)
2044	2,775,239	41	2,484,138	363	14,791,204	23,136
Diversified Approach						
2024	4,916,069	82	2,980,880	515	16,712,271	30,728
2030	4,807,720	77	2,937,534	484	14,368,102	25,247
2040	4,463,546	67	2,901,317	440	14,494,509	23,527
2044	4,355,678	64	2,927,692	428	14,811,515	23,168
Electrification Focus						
2024	4,917,636	82	2,980,880	515	16,712,270	30,728
2030	4,393,392	70	2,768,665	456	14,359,729	25,232
2040	2,922,989	44	2,240,004	340	14,424,084	23,413
2044	2,582,714	38	2,033,143	298	14,682,433	22,966
Lower-Carbon Transportation and LNG Future						
2024	4,917,636	82	2,980,880	515	16,712,270	30,728
2030	4,631,131	74	2,913,646	480	14,362,998	25,238
2040	3,102,766	47	2,538,056	385	14,440,854	23,440
2044	2,749,798	41	2,418,585	354	14,714,587	23,017
Prolonged Transition						
2024	4,917,636	82	2,980,880	515	16,712,271	30,728
2030	4,891,446	78	3,006,757	495	14,380,720	25,269
2040	4,843,541	73	3,300,795	501	14,538,260	23,598
2044	4,854,226	72	3,543,680	519	14,855,611	23,237

Table 3: Annual Energy and Average UPC in Southern Interior

	Residential Sector		Commercial Sector		Industrial Sector	
Scenario / Year	Annual Demand (GJ)	Average UPC (GJ)	Annual Demand (GJ)	Average UPC (GJ)	Annual Demand (GJ)	Average UPC (GJ)
Baseline Trends						
2024	15,079,971	71	11,497,898	588	15,705,633	9,345
2030	14,002,854	63	11,265,779	546	15,613,390	8,818
2040	9,053,267	38	9,824,298	437	15,596,542	8,100
2044	7,989,429	33	9,396,386	406	15,586,445	7,858
Diversified Approach						
2024	15,072,392	71	11,497,898	588	15,705,631	9,345
2030	14,528,171	65	11,343,611	550	15,613,446	8,818
2040	13,082,469	55	10,826,674	482	15,602,484	8,103
2044	12,635,359	52	10,657,171	460	15,605,544	7,867

	Residential Sector		Commercial Sector		Industrial Sector	
Scenario / Year	Annual Demand (GJ)	Average UPC (GJ)	Annual Demand (GJ)	Average UPC (GJ)	Annual Demand (GJ)	Average UPC (GJ)
Electrification Focus						
2024	15,079,971	71	11,497,898	588	15,705,631	9,345
2030	13,258,010	59	10,750,725	521	15,597,301	8,809
2040	8,503,358	36	8,633,524	384	15,472,342	8,035
2044	7,441,044	31	7,779,253	336	15,385,803	7,756
Lower-Carbon Transportation and LNG Future						
2024	15,079,971	71	11,497,898	588	15,705,631	9,345
2030	13,992,754	63	11,281,204	547	15,603,739	8,813
2040	9,028,917	38	9,732,800	433	15,505,039	8,052
2044	7,923,767	33	9,157,268	396	15,445,342	7,786
Prolonged Transition						
2024	15,079,971	71	11,497,898	588	15,705,632	9,345
2030	14,859,142	66	11,649,223	565	15,640,545	8,833
2040	14,392,026	61	12,316,551	548	15,691,965	8,149
2044	14,277,918	59	12,568,360	543	15,702,291	7,916

Table 4: Annual Energy and Average UPC in Vancouver Island, Sunshine Coast and Whistler

	Residential Sector		Commercial Sector		Industrial Sector	
Scenario / Year	Annual Demand (GJ)	Average UPC (GJ)	Annual Demand (GJ)	Average UPC (GJ)	Annual Demand (GJ)	Average UPC (GJ)
Baseline Trends						
2024	6,729,055	48	7,595,139	653	714,557	2,255
2030	6,417,593	42	7,426,311	592	774,006	2,272
2040	4,490,337	27	6,532,376	465	752,050	1,976
2044	4,097,839	24	6,263,556	428	741,745	1,876
Diversified Approach						
2024	6,725,792	48	7,595,139	653	714,557	2,255
2030	6,644,077	44	7,460,286	595	774,007	2,272
2040	6,099,980	37	6,929,810	493	752,370	1,977
2044	5,938,081	35	6,768,590	463	742,763	1,878
Electrification Focus						
2024	6,729,055	48	7,595,139	653	714,557	2,255
2030	6,112,509	40	7,146,772	570	773,209	2,270
2040	4,262,479	26	5,765,703	410	745,561	1,959
2044	3,871,202	23	5,196,912	355	731,153	1,849
Lower-Carbon Transportation and LNG Future						
2024	6,729,055	48	7,595,139	653	714,557	2,255

	Residential Sector		Commercial Sector		Industrial Sector	
Scenario / Year	Annual Demand (GJ)	Average UPC (GJ)	Annual Demand (GJ)	Average UPC (GJ)	Annual Demand (GJ)	Average UPC (GJ)
2030	6,409,245	42	7,442,677	594	773,555	2,271
2040	4,474,734	27	6,446,593	459	747,297	1,963
2044	4,071,093	24	6,047,921	414	734,349	1,857
Prolonged Transition						
2024	6,729,055	48	7,595,139	653	714,557	2,255
2030	6,845,489	45	7,706,719	615	776,059	2,279
2040	6,889,305	41	8,159,900	581	758,866	1,994
2044	6,931,783	40	8,328,063	570	749,824	1,896

The DSM settings associated with each scenario are described in Table 4-1 in the 2026 LTGRP. Tables 5 through 8 below present the DSM savings potential for the four parent regions under the five scenarios. The Baseline Trends, Electrification Focus, Lower-Carbon Transportation and LNG Future, and Prolonged Transition scenarios are evaluated using the Low DSM setting, while the Diversified Approach scenario is evaluated using the Medium DSM setting.

Table 5: DSM Savings Potential (PJ) by Sectors in Lower Mainland

Scenarios / Year	Residential (PJ)	Commercial (PJ)	Industrial (PJ)
Baseline Trends			
2024	0.0	0.0	0.0
2030	2.3	0.4	0.8
2040	4.0	1.3	1.8
2044	4.3	1.5	2.1
Diversified Approach			
2024	0.0	0.0	0.0
2030	3.0	1.1	1.0
2040	8.0	3.7	2.2
2044	9.4	4.0	2.5
Electrification Focus			
2024	0.0	0.0	0.0
2030	2.2	0.4	0.8
2040	3.8	1.2	1.7
2044	4.1	1.3	2.0
Lower-Carbon Transportation and LNG Future			
2024	0.0	0.0	0.0
2030	2.3	0.4	0.8
2040	4.0	1.3	1.8

Scenarios / Year	Residential (PJ)	Commercial (PJ)	Industrial (PJ)
2044	4.1	1.4	2.0
Prolonged Transition			
2024	0.0	0.0	0.0
2030	2.5	0.4	0.8
2040	6.6	1.7	1.9
2044	7.8	2.0	2.3

Table 6: DSM Savings Potential (PJ) by Sectors in Northern British Columbia

Scenarios / Year	Residential (PJ)	Commercial (PJ)	Industrial (PJ)
Baseline Trends			
2024	0.0	0.0	0.0
2030	0.2	0.1	0.3
2040	0.4	0.2	0.6
2044	0.5	0.3	0.7
Diversified Approach			
2024	0.0	0.0	0.0
2030	0.3	0.1	0.4
2040	0.9	0.6	0.7
2044	1.1	0.6	0.9
Electrification Focus			
2024	0.0	0.0	0.0
2030	0.2	0.1	0.3
2040	0.4	0.2	0.6
2044	0.5	0.2	0.7
Lower-Carbon Transportation and LNG Future			
2024	0.0	0.0	0.0
2030	0.2	0.1	0.3
2040	0.4	0.2	0.6
2044	0.5	0.3	0.7
Prolonged Transition			
2024	0.0	0.0	0.0
2030	0.2	0.1	0.3
2040	0.7	0.3	0.6
2044	0.9	0.3	0.7

Table 7: DSM Savings Potential (PJ) by Sectors in Southern Interior

Scenarios / Year	Residential (PJ)	Commercial (PJ)	Industrial (PJ)
Baseline Trends			
2024	0.0	0.0	0.0
2030	0.7	0.1	0.5
2040	1.3	0.4	0.9
2044	1.4	0.5	1.0
Diversified Approach			
2024	0.0	0.0	0.0
2030	0.9	0.3	0.6
2040	2.6	1.3	1.1
2044	3.2	1.5	1.2
Electrification Focus			
2024	0.0	0.0	0.0
2030	0.7	0.1	0.5
2040	1.2	0.4	0.9
2044	1.3	0.4	1.0
Lower-Carbon Transportation and LNG Future			
2024	0.0	0.0	0.0
2030	0.7	0.1	0.5
2040	1.3	0.4	0.9
2044	1.3	0.5	1.0
Prolonged Transition			
2024	0.0	0.0	0.0
2030	0.7	0.1	0.5
2040	2.1	0.5	0.9
2044	2.5	0.6	1.1

Table 8: DSM Savings Potential (PJ) by Sectors in Vancouver Island, Sunshine Coast and Whistler

Scenarios / Year	Residential (PJ)	Commercial (PJ)	Industrial (PJ)
Baseline Trends			
2024	0.0	0.0	0.0
2030	0.2	0.1	0.0
2040	0.5	0.4	0.0
2044	0.6	0.4	0.0

Scenarios / Year	Residential (PJ)	Commercial (PJ)	Industrial (PJ)
Diversified Approach			
2024	0.0	0.0	0.0
2030	0.3	0.2	0.0
2040	1.0	0.9	0.0
2044	1.2	1.0	0.0
Electrification Focus			
2024	0.0	0.0	0.0
2030	0.2	0.1	0.0
2040	0.5	0.3	0.0
2044	0.5	0.4	0.0
Lower-Carbon Transportation and LNG Future			
2024	0.0	0.0	0.0
2030	0.2	0.1	0.0
2040	0.5	0.4	0.0
2044	0.5	0.4	0.0
Prolonged Transition			
2024	0.0	0.0	0.0
2030	0.3	0.1	0.0
2040	0.8	0.4	0.0
2044	1.0	0.6	0.0

1

3.0 Topic: Basis of the plan - continued growth versus managed transition

Reference: Application, Exhibit B-1, Appendix D-1 (OCMP Peak Demand Mitigation Report), Section 1 (p. 3) and Section 2 (p. 7); Appendix A, Table 4, item 23 (p. 18); Section 2; Section 3 (Customer Account Forecast, p. 3-4); Section 9 (Table 9-1, Tables 9-8, 9-9 and 9-11, Figure 9-12, p. 9-25), and the long-term financial analysis (Growth, Sustainment and Other, 2027 to 2050). Order G-78-24, p.49.

FEI states it has developed the plan using the Diversified Approach scenario as its foundation, and that lower-demand outcomes can be accommodated within FEI's portfolio flexibility while planning effort focuses on higher-demand pathways. In Order G-78-24 (p. 49) the Panel directed FEI to address whether continued growth in the gas network best serves ratepayer and public interest.

3.1 Provide a structured comparison of cumulative ratepayer cost and GHG outcomes through 2050 under (a) the Diversified Approach and (b) the Electrification Focus scenario, with reference to Table 9-1 and the rate changes in Tables 9-8, 9-9 and 9-11, on a per-Core-Customer basis. Given that FEI applies the same customer-account forecast across all scenarios (p. 3-4), confirm whether FEI also applies the same new-connection and Growth-related capital expenditure forecast under the Electrification Focus scenario as under the Diversified Approach. If so, explain how a scenario intended to reflect significant building electrification is consistent with unchanged gas-network growth.

Response:

Please refer to the response to CEC-COSCO-RCIA IR1 10.1 for a detailed and structured comparison of the cumulative rate and total bill impacts between the Diversified Approach and Electrification Focus scenarios, including a breakdown of various drivers of the impacts attributable to declining throughput of residential, commercial, and industrial customers, DSM, renewable and lower-carbon gas, and new LNG demand as referenced in Table 9-1 of the 2026 LTGRP.

Please refer to Figures 1 and 2 below comparing the total bill, separately for the delivery-related and commodity and renewable gas-related components, between the Diversified Approach and Electrification Focus scenarios on a per-residential (Rate Schedule (RS) 1) customer basis with an average consumption of 55 GJ. FEI notes that the directional rate increases over the 27-year analysis period (from 2024 to 2050) shown in Tables 9-8, 9-9, and 9-11 of the 2026 LTGRP also assume an average annual residential customer consumption of 55 GJ.

Figure 1: Diversified Approach – Total RS 1 Bill per Average Customers (2024 to 2050)

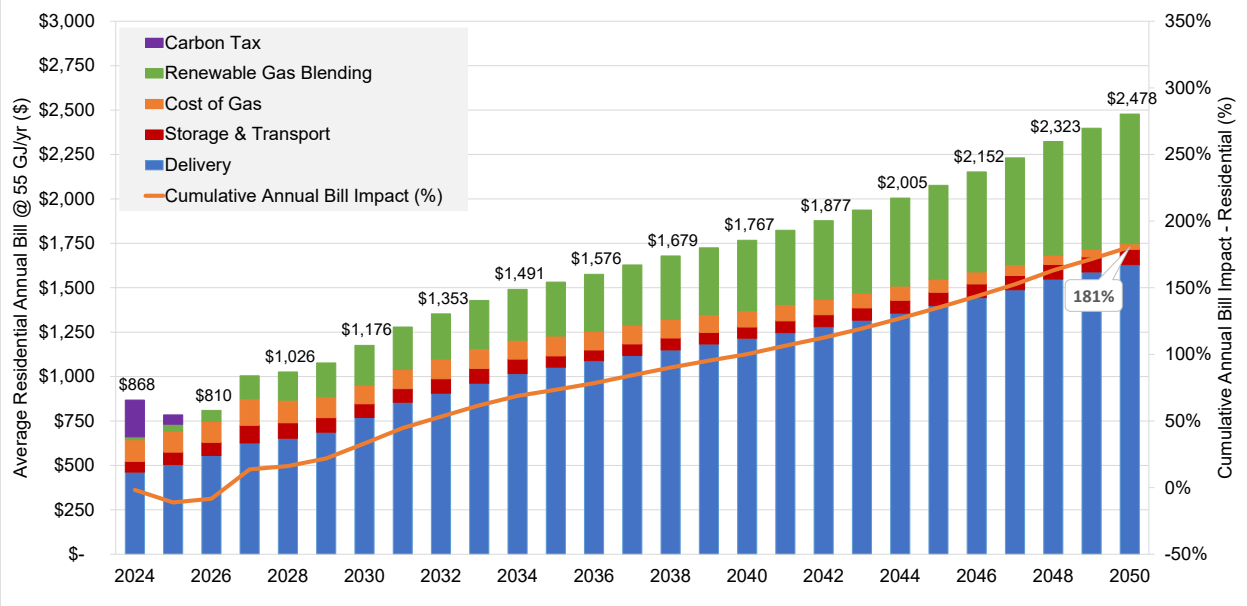
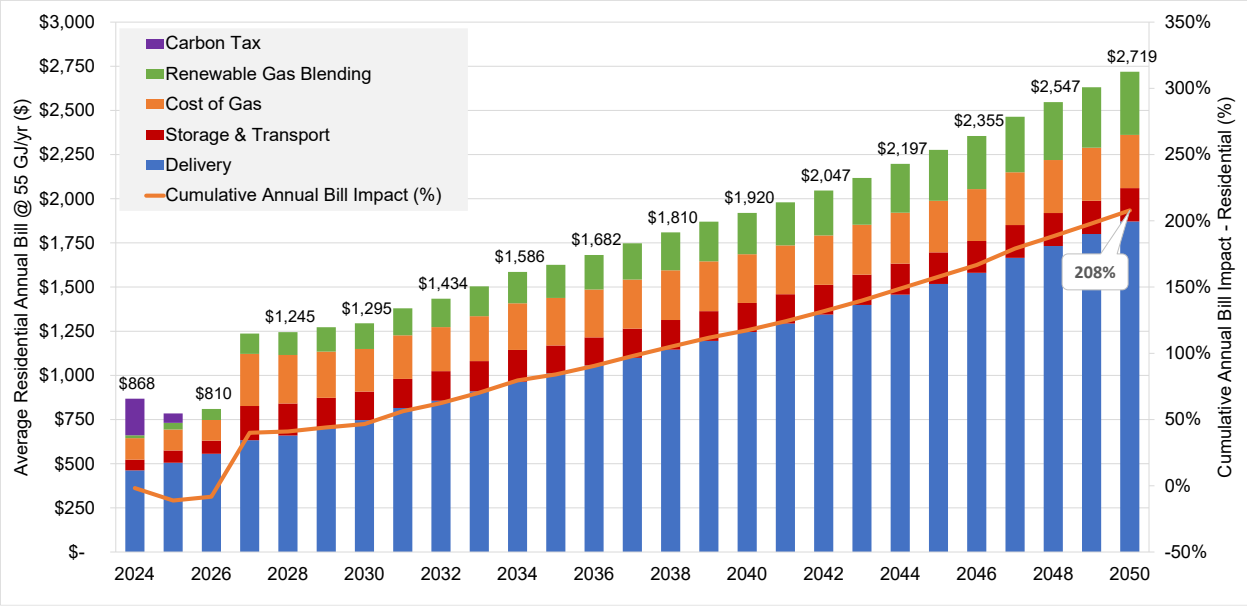


Figure 2: Electrification Focus – Total RS 1 Bill per Average Customers (2024 to 2050)



Please also refer to Table 1 below for the GHG emissions on a per customer basis in 2050 for the Diversified Approach and Electrification Focus scenarios. As shown in Figure 9-4 of the 2026 LTGRP, the Diversified Approach scenario would achieve more GHG emissions reductions than the Electrification Focus scenario while also meeting the climate targets by 2050.

Table 1: Comparison of GHG Emissions per Customer in 2050 between Diversified Approach and Electrification Focus Scenarios

	Reference	Diversified Approach	Electrification Focus
GHG Emissions (End Use), 2050 ($MtCO_2e$)	Figure 9-4 of LTGRP	1.1	4.7
Total number of customer forecast (2050)	Appendix B of LTGRP	1,251,202	1,251,202
GHG Emissions per Customer (tCO_2e)		0.9	3.8

Regarding the assumption of capital expenditures for new connections under the Electrification Focus scenario, FEI confirms that the same amount is applied to both the Electrification Focus and Diversified Approach scenarios. This is because the two scenarios assumed the same number of customers forecast over the planning period from 2024 to 2050, as discussed in Section 3.3 of the 2026 LTGRP. FEI notes that the work required and the associated cost to connect a new customer (i.e., growth-related capital which includes service lines and meters, and new mains if needed) would be the same in each of the Diversified Approach and Electrification Focus scenarios.

The difference in terms of capital expenditures between the Diversified Approach and Electrification Focus scenarios is not associated with growth-related capital given that the same number of customers were forecast for both scenarios. Instead, the difference is reflected in the different level of capital expenditures needed for future capacity, resiliency, and reliability upgrades, given that the Electrification Focus scenario would have significantly less demand throughput (i.e., the same number of customers but a significant decline in use per customer) than the Diversified Approach scenario.

For the purposes of the directional rate and bill impact analysis performed in the 2026 LTGRP, FEI reduced the level of future capital expenditures through to 2050 under the Electrification Focus scenario for capacity, resiliency, and reliability upgrades by approximately 75 percent from the level assumed for the Diversified Approach scenario in order to reflect the significant building electrification under the Electrification Focus scenario. However, as shown in Section 9.4 of the 2026 LTGRP, even with a significant reduction in future capital expenditures under the Electrification Focus scenario, customers who remain connected to the gas system will experience a higher rate impact than the same customers under the preferred pathway of the Diversified Approach scenario.

3.2 FEI states (p. 9-25) that the Electrification Focus scenario is expected to have a high delivery-rate impact due to the aggressive reduction in demand, and that the total bill impacts of the Diversified Approach and Electrification Focus scenarios appear closer than their delivery-rate impacts because of the differing renewable-gas blend. For the Electrification Focus scenario, isolate the delivery-rate component of the per-Core-Customer bill, separately from the commodity and

renewable-gas-blend components, and provide its trajectory to 2050, together with the resulting delivery-related bill for a residential Core Customer who remains connected to gas throughout. State the extent to which the rising per-Core-Customer delivery rate is attributable to declining throughput and a shrinking customer base rather than to the renewable-gas blend, with reference to Tables 9-8 and 9-9 and Figure 9-12.

Response:

Please refer to the response to LIEC-Saanich-Richmond IR1 3.1.

3.3 Building on BCUC IR 11.9 (impact on rates of declining annual gas sales) and the delivery-rate dynamics addressed in 3.2, state whether FEI has modelled the feedback by which the rising per-customer cost of remaining on the gas system accelerates customer switching to electricity even in the absence of any policy driver (a death-spiral dynamic). In particular, confirm whether FEI models the cross-price elasticity between gas and electricity prices, given that Order G-78-24 (Directive 4, pp. 20-21) recommended FEI investigate cross-price elasticity effects with renewable electricity, and that FEI states it does not incorporate such an assumption (Appendix A). Provide any such analysis, or confirm none was performed.

Response:

Please refer to the response to BCSEA-MS2S IR1 7.1.

3.4 To inform the Panel's assessment of whether continued growth in the gas network best serves the ratepayer and public interest (Order G-78-24, p. 49), identify the portion of FEI's forecast Growth-related capital expenditure (system extensions, new service connections and associated system reinforcement) over the 2027 to 2050 period, and of its projected 2050 rate base, that would be exposed to under-recovery or stranding under the Electrification Focus scenario relative to the Diversified Approach. If FEI has not assessed this exposure, confirm so.

Response:

While the demand forecasts for its residential and commercial customers (i.e., Figures 3-5 and 3-6 of the 2026 LTGRP, respectively) show a significant decline in the throughput on FEI's system

under the Electrification Focus scenario, FEI expects there will still be customers remaining on the system as well as new customers requiring gas service over the planning horizon to 2050. Further, as shown in Figure 3-7 of the 2026 LTGRP, FEI expects industrial demand to remain relatively consistent under all scenarios. Similarly, FEI expects LNG demand related to marine bunkering and ISO shipments to grow under all scenarios, as shown in Figure 3-1 of the 2026 LTGRP, contributing to continued utilization of FEI's system over the planning horizon.

As such, FEI's assets will still be used and useful and fully recoverable under the Electrification Focus scenario. Instead, the risk under the Electrification Focus scenario would be the higher rate increase and bill impact for customers remaining on the gas system, as demonstrated in Section 9.4 of the 2026 LTGRP, relative to the preferred Diversified Approach scenario, which leverages the use of both the gas and electric systems (e.g., through technologies like dual-fuel systems) to provide reliable service.

Additionally, as discussed in the response to LIEC-Saanich-Richmond IR1 3.1, the 2026 LTGRP assumed the same amount of growth-related capital (i.e., cost to install new mains, service lines, and meters for new connections) between the Diversified Approach and Electrification Focus scenarios given both scenarios used the same customer account forecast. For the purposes of the directional rate and total bill impact projection included in Section 9.4 of the 2026 LTGRP, FEI assumed the 2027 estimate of growth-related capital (i.e., new mains, service lines, meters) provided in FortisBC's 2025-2027 Rate-Setting Framework (RSF) Application[2] of approximately $59.9 million, plus annual inflation of two percent over the period from 2027 to 2050. This is equivalent to approximately $1.3 billion of projected rate base for assets related to new mains, service lines, and meters over the period from 2027 to 2050.

[2] FortisBC 2025-2027 Rate Setting Framework Application (April 8, 2024), Table C3-4, Section C3.3.1.2, p. C-79. Online at: https://docs.bcuc.com/documents/proceedings/2024/doc_76751_b-1-fei-fbc-2025-2027-ratesettingframework-application.pdf.

4.0 Topic: Depth of the Electrification Focus scenario and consistency with BC Hydro

Reference: Application, Exhibit B-1, Sections 3.4 to 3.5, Table 3-5 (pp. 3-1, 3-6); Figure 3-4; Section 8.6 and p. 8-13. Order G-78-24, p. 20. Exhibit B-1, BC Hydro 2025 IRP Proceeding (Section 2.3.4.3, p. 2-37); Exhibit B-5, BC Hydro 2025 IRP Proceeding (BCUC IRs 1.4.1 and 1.4.3); Exhibit B-6, BC Hydro 2025 IRP Proceeding (CEBC IR 1.1.4).

Order G-78-24 (p. 20) directed FEI to include a deep electrification scenario. FEI's Electrification Focus scenario sets Building Codes and Equipment Standards and Price Impact to Customer to High, but Marine and ISO Shipments and On-Road Fuel Switching to Low (Table 3-5). FEI states (p. 8-13) that the Electrification Focus scenario is comparable to BC Hydro's total fuel-switching estimate of 11,900 GWh. In its 2025 IRP information-request responses, BC Hydro filed a GHG-aligned load projection developed with Navius Research Inc. and an updated February 2026 Reference Load Forecast materially higher than the 2025 Reference Scenario.

4.1 FEI states (p. 8-13) that its Electrification Focus scenario is comparable to BC Hydro's total fuel-switching estimate of 11,900 GWh. Identify the specific BC Hydro source document for that figure, and confirm whether the 11,900 GWh is included within a BC Hydro 2025 IRP load scenario or contingency plan, or instead sits outside all of them as additional load (for example, the province-wide Zero Carbon Step Code and HEES load that BC Hydro describes as beyond its Reference and High Load Scenarios: Exhibit B-1, BC Hydro 2025 IRP Proceeding, Section 2.3.4.3, p. 2-37). Reconcile this with FEI's characterization of that load at p. 8-13 as comparable to a BC Hydro estimate.

Response:

In Section 8.6.3 of the 2026 LTGRP, page 8-13, FEI states the following:

> Comparatively, in Section 2.3.4.3 of BC Hydro's 2025 IRP, BC Hydro's fuel switching volumes, for residential and commercial sectors in F2050 were presented as follows:
>
> 1. 1,600 GWh – Zero Carbon Building Code (for municipalities that have adopted the codes);
> 2. 2,400 GWh – Zero Carbon Building Code (additional load for province wide adoption); and
> 3. 7,900 GWh – Highest Equipment Efficiency Standard.
>
> In BC Hydro's Reference Load Scenario, only the first fuel switching item was included, for a total of 1,600 GWh for their planning scenario. As a sensitivity, BC Hydro presented the second and third components, which sum to a total of 11,900

GWh of incremental electricity load in fiscal 2050 due to residential and commercial fuel switching.

Exhibit B-9 of BC Hydro's 2025 IRP proceeding (Sections 3 and 5) contains additional information on BC Hydro's load forecasting and resource planning for the GHG targets scenario.

4.2 For the Electrification Focus scenario, disaggregated to FEI's billing regions, state the assumed proportion of converting gas-heated dwellings that adopt full electric heating versus dual-fuel (hybrid) heating, and explain the assumptions underlying those proportions, including the share of gas heating systems assumed to switch to a heat pump at end-of-life replacement and any reverse switching from electric back to gas.

Response:

As a result of using the end-use model for scenario planning (described further in the response to LIEC-Saanich-Richmond IR1 2.1), FEI is not able to disaggregate dual-fuel adoption to FEI's billing regions. However, please refer to the response to CEC-COSCO-RCIA IR1 14.1, which illustrates market adoption potential for existing residential gas-heated buildings that are converted to dual-fuel heating systems.

FEI is unable to provide a trajectory for the number of dwellings converted from gas heating to fully electric heating as this was modelled through the Key Drivers outlined in Section 3.5 (e.g., Building Codes & Equipment Standards and Price Impact to Customer), and not through DSM potential from the 2024 CPR. FEI did not have a DSM measure for full electric heating in the CPR.

Finally, FEI has not modeled any reverse switching from all-electric heating back to gas heating.

4.3 Explain why forecast gas consumption under the Electrification Focus scenario is only modestly below the Baseline Trends scenario. Please support the response with a comparison of the Electrification Focus and Baseline scenarios on a residential and commercial Core Customer basis (for example, a revised Figure 3-4 excluding the industrial sector, or Figures 3-5 and 3-6 combined).

Response:

Please refer to Table 3-5 of the 2026 LTGRP which illustrates the differences in the key demand drivers between the Electrification Focus and Baseline Trends scenarios. As shown in the table and described in Section 3.5.1 of the 2026 LTGRP, both scenarios have declining gas

consumption due to the impact of the Building Codes & Equipment Standards key driver on gas demand. Then, for gas consumption that is not already impacted by policy-driven drivers, the Price Impact to Customer driver also contributes to additional declining gas consumption.

To compare the annual demand for the residential and commercial sectors, please refer to the tables in Section 1.2 of Appendix B of the 2026 LTGRP.

4.4 Compare FEI's Electrification Focus scenario to the greenhouse-gas-aligned load projection BC Hydro developed with Navius Research and filed in its 2025 IRP proceeding, which reaches approximately 114,000 GWh and 20,500 MW by F2050 (about 25 percent above BC Hydro's High Load Scenario) (Exhibit B-5, BC Hydro 2025 IRP Proceeding, BCUC IRs 1.4.1 and 1.4.3). State whether FEI considers its Electrification Focus scenario to represent a pathway aligned with provincial greenhouse gas targets or only a building-code-driven sensitivity, and explain the basis for that characterization.

Response:

Comparison to BC Hydro Scenario

As illustrated in Table 8-5 of the 2026 LTGRP, FEI's Electrification Focus scenario is estimated to contain approximately 9,800 to 12,500 GWh of residential and commercial fuel switching load by 2050. In BC Hydro's "2040 and 2050 GHG Targets Load Projection" scenario, the residential and commercial fuel switching volumes are approximately 12,500 GWh by 2050.

GHG Emissions Reductions

FEI does not consider the Electrification Focus scenario to be a comprehensive pathway aligned with provincial GHG reduction targets. Rather, it is a scenario designed to examine the impact of increased electrification resulting from specific demand drivers, including higher levels of building fuel switching, electrification policies, and price impacts.

The Electrification Focus scenario was developed by modifying selected demand drivers within the model, as described in more detail in Section 3.5 of the 2026 LTGRP. The model does not optimize for achieving a specific provincial greenhouse gas reduction target nor does it treat the Electrification Focus as a building code-driven sensitivity. Instead, the Electrification Focus scenario is one of multiple scenarios that evaluates the implications of alternative plausible assumptions relating to building codes and equipment standards, DSM-driven fuel switching, lower-carbon transportation adoption, industrial activity and other demand drivers. The resulting greenhouse gas emissions impacts are then assessed as an output of the scenario.

FEI considers the Diversified Approach scenario to be more representative of a pathway consistent with achieving provincial greenhouse gas reduction objectives. While the Diversified Approach scenario includes significant electrification, it also recognizes the importance of renewable and lower-carbon gaseous fuels in sectors, including where electrification may be technically, economically or operationally challenging. This includes certain industrial processes, transportation applications and other end uses where electricity may not currently provide practical solutions.

4.5 Building on BCUC IRs 3.1 and 3.1.1 (climate change and extreme-weather demand sensitivity), state whether, and how, FEI's demand scenarios capture market-driven adoption of electric heating and cooling independent of greenhouse gas policy, including: heat pumps adopted primarily for space cooling, including where rising cooling demand reflects warming summers and increasing wildfire smoke; single-system replacement economics at furnace end-of-life; electrical-service or panel upgrades prompted by electric-vehicle adoption that reduce the friction and marginal cost of subsequent heat pump adoption; all-electric new-construction economics, including avoided gas-connection costs on declining use; and the rising cost of staying connected to gas as core throughput declines, through both the per-GJ delivery and commodity rates (as the largely fixed network costs and FEI's own renewable-gas blending are spread over fewer units) and the fixed monthly basic charge (as fixed costs are spread over fewer customers), which together can make a low-use gas connection uneconomic and prompt partially-electrified customers to disconnect entirely. For each, state the extent to which it is assumed to displace gas space heating as a by-product, and confirm whether any disproportionate effect in the coastal regions, where existing cooling penetration is lower than in the Interior, is reflected. BC Hydro confirms that its load forecast includes the space-cooling contribution of new residential and commercial heat pumps, estimated at approximately 3 percent of residential and of commercial sector load (Exhibit B-6, BC Hydro 2025 IRP Proceeding, CEBC IR 1.1.4).

Response:

The scenarios that are presented in the 2026 LTGRP are not intended to represent every possible market-led electrification driver individually; rather, they are directional scenarios based on a coherent set of assumptions and cover a broad range of potential future outcomes. As such, FEI's demand scenarios primarily capture electrification trends through the key demand drivers that are described in Section 3.5 of the 2026 LTGRP, including Building Codes & Equipment Standards and Price Impact to Customer. These two key drivers consider how different levels of policy and price can result in a range of residential and commercial customers fuel switching to electricity.

5.0 Topic: Consistency of FEI's scenarios with provincial GHG targets

Reference: Application, Exhibit B-1, Section 9.2, Tables 9-2, 9-3 and 9-4 and Figure 9-4 (pp. 9-6 to 9-10).

In Table 9-4 FEI presents the percentage emission reductions of the Diversified Approach scenario at milestone years against the provincial economy-wide GHG reduction targets of 40 percent by 2030, 60 percent by 2040 and 80 percent by 2050, and states the targets are provided for reference and contextual comparison. British Columbia has also established legislated 2030 sectoral targets, including 59 to 64 percent for the buildings and communities sector and 38 to 43 percent for the industry sector, relative to 2007. FEI applies the end-use emission factors in Table 9-2 to residential, commercial and industrial gas, RNG and hydrogen, and the life-cycle emission factors in Table 9-3 to the transportation, marine and ISO shipments sectors.

5.1 Provide the milestone-year percentage emission reductions presented in Table 9-4 for each of the five demand scenarios, rather than the Diversified Approach alone, disaggregated so that the residential and commercial result can be compared against the legislated 2030 buildings and communities sectoral target and the industrial result against the legislated 2030 industry sectoral target.

Response:

Table 1 below presents the estimated end-use GHG emissions reductions for the residential, commercial, and industrial sectors at each milestone year, relative to 2007 levels, across the five demand scenarios evaluated in the 2026 LTGRP.

Table 1: GHG Emissions Reductions (End Use) – Residential, Commercial and Industrial Sectors for All Scenarios

Milestone Year	Energy Demand (Post-DSM) (PJ/Yr)	Total Emissions ($MtCO_2e$/Yr)	Emissions Reductions Relative to 2007 ($MtCO_2e$ /Yr)	FEI Percentage Decrease from 2007 (%)
Diversified Approach				
2030	193	8.240	2.607	24%
2035	176	6.658	4.188	39%
2040	162	5.093	5.754	53%
2045	151	3.344	7.502	69%
2050	140	1.126	9.721	90%
Electrification Focus				
2030	186	8.539	2.308	21%
2035	160	7.198	3.648	34%
2040	140	6.192	4.654	43%
2045	125	5.425	5.422	50%
2050	111	4.713	6.133	57%

Milestone Year	Energy Demand (Post-DSM) (PJ/Yr)	Total Emissions ($MtCO_2e$/Yr)	Emissions Reductions Relative to 2007 ($MtCO_2e$ /Yr)	FEI Percentage Decrease from 2007 (%)
Baseline Trends				
2030	193	8.880	1.966	18%
2035	167	7.576	3.271	30%
2040	150	6.684	4.162	38%
2045	137	6.070	4.776	44%
2050	127	5.539	5.307	49%
Prolonged Transition				
2030	201	9.296	1.551	14%
2035	195	8.968	1.879	17%
2040	189	8.686	2.160	20%
2045	185	8.458	2.388	22%
2050	177	8.088	2.758	25%
Lower-Carbon Transportation and LNG Future				
2030	193	7.532	3.315	31%
2035	167	5.092	5.755	53%
2040	148	2.833	8.013	74%
2045	135	0.649	10.198	94%
2050	132	0.212	10.634	98%

The GHG emissions reductions presented in Table 9-4 and in Table 1 above reflect an integrated system-wide assessment across FEI's customer base, incorporating the combined impact of multiple measures and fuels. These results are not structured to align with, or be directly comparable to, the legislated sectoral targets, which are established at a province-wide level and are not attributable to individual entities or specific energy suppliers.

FEI does not consider the requested disaggregation of GHG emissions reductions by sector to be consistent with the context of the *Climate Change Accountability Act* sectoral targets. The Act does not assign responsibility for achieving the emissions reduction targets, nor does it prescribe the methods by which such targets are to be achieved. Accordingly, FEI is not directly accountable for any individual sectoral target, and the 2026 LTGRP scenarios are not designed to meet or be assessed against sector-specific targets.

Nonetheless, FEI recognizes that its gas supply is a source of GHG emissions for its customers in the buildings and communities (residential and commercial) and industrial sectors. FEI's role is therefore to enable GHG emissions reductions across multiple sectors, rather than to achieve or be assessed against a specific sectoral target.

Consistent with this framework, FEI's planning supports GHG emissions reductions across the residential, commercial, and industrial sectors through a combination of renewable and

lower-carbon gas supply, DSM, fuel switching, and other initiatives, as described in the 2026 LTGRP.

5.2 Confirm whether any of FEI's five scenarios achieve the legislated 2030 buildings and communities sectoral target of 59 to 64 percent for FEI's residential and commercial customers, and if none do, identify the incremental measures and their approximate scale that would be required for FEI's residential and commercial throughput to be consistent with that sectoral target by 2030.

Response:

Please refer to the response to LIEC–Saanich–Richmond IR1 5.1.

C. Renewable and lower-carbon gas

6.0 Topic: Status and realism of the RNG supply forecast

Reference: Application, Exhibit B-1, Section 5.3, Tables 5-1 and 5-3 (pp. 5-7 to 5-8); Table 5-4 (p. 5-17); Section 6.2; Section 9.2, Tables 9-2 and 9-4; Executive Summary, Figure ES-9 (p. ES-20). Order G-78-24 (low-carbon-gas infrastructure directives).

FEI describes the Low supply setting as relying exclusively on the current portfolio of RNG contracts, held at approximately 16.8 PJ per year. FEI states that meeting provincial GHG targets will require it to incorporate a significant portion of renewable and lower-carbon gas, with significant bill impacts. Table 5-3 indicates that out-of-province sources account for approximately 85 percent of FEI's forecast RNG supply across all scenarios, and Section 6 describes Off-System RNG as supply injected into natural gas systems typically outside BC, with FEI taking delivery of an equivalent volume of gas at the Station 2 and AECO/NIT hubs. In Table 9-2 FEI applies an end-use emission factor of 0.0003 tCO2e per GJ to all RNG. In Order G-78-24 the Panel directed FEI to provide more detail on, and to expedite planning of, low-carbon-gas (RNG, hydrogen) infrastructure investments.

6.1 Provide a project-by-project list of FEI's current RNG supply contracts, stating for each: counterparty or project name; location (within BC, elsewhere in Canada, or the United States); contracted annual volume; contract start date and term; current or expected commercial operation date; volume actually delivered in the most recent contract year; and whether the contract depends on a facility not yet in commercial operation (with the current expected commercial operation date, and including any BC woodwaste-to-RNG projects such as the Fruitvale project).

Response:

Please refer to Table 1 below. FEI has not provided the contract term for the individual projects, as this information is commercially sensitive, the public disclosure of which can be reasonably expected to impair FEI's ability to obtain favourable commercial terms in future RNG contracting strategies.

Table 1: Summary of RNG Projects

Project Name	Project Location	Expected Volume when RNG facility reaches its full capacity (TJ/Yr)	Anticipated Delivery Start Date	2025 Actual Volume (TJ/Yr)	Technology Type
Columbia Shuswap Regional District	BC	12	1/1/2013	5	Landfill
Fraser Valley Biogas Ltd.	BC	128	1/15/2026	140	Ag Digester
City of Kelowna	BC	56	6/1/2014	50	Landfill
Seabreeze Farm Ltd.	BC	51	2/1/2015	37	Ag Digester
GVSDD (Metro Vancouver)	BC	46	6/1/2021	33	WWTP
City of Surrey	BC	46	6/1/2018	61	Mun Digester
City of Vancouver	BC	225	1/1/2025	5	Landfill
Tidal Energy Marketing Inc.(Niagara BPA)	Canada	173	3/1/2024	283	Landfill
REN Energy International Corp. - Fruitvale	BC	855	8/1/2028	Not in Service	Wood/Biomass
Tidal Energy Marketing Inc.(London BPA)	Canada	58	10/1/2020	73	Mun Digester
Faromor CNG Corp.	Canada	99	10/1/2021	79	Ag Digester
Regional District of Fraser-Fort George	BC	73	6/1/2028	Not in Service	Landfill
Bradam Canada Inc.(Hamilton)	Canada	1,125	9/1/2027	Not in Service	Mun Digester
Lethbridge Biogas LP	Canada	265	8/1/2021	275	Ag Digester
Dicklands Farms Partnership	BC	109	4/24/2023	78	Ag Digester
Walker RNG Inc.	Canada	152	9/1/2023	173	Ag Digester
Assai Energy LLC(Archaea)	USA	1,001	3/1/2022	988	Landfill
Grow the Energy Circle Ltd.	Canada	45	9/1/2024	32	Ag Digester
Capital Regional District	BC	189	4/1/2025	186	Landfill
Shell Energy North America Canada Inc.	USA	590	8/1/2021	534	WWTP
Evergreen (Oshawa)Environmental Inc.	Canada	202	3/1/2027	Not in Service	Ag Digester
Tidal-Winnebago	USA	788	7/1/2024	888	Landfill
Delta RNG	BC	773	4/1/2024	785	Landfill
Archaea(Portfolio)	USA	7,665	7/1/2022	3,866	Landfill
RNG Energy Solutions(Linden)	USA	1,200	3/1/2027	Not in Service	Ag Digester
BioRefinex	Canada	172	4/1/2028	Not in Service	Mun Digester
Rimrock	Canada	415	6/1/2029	Not in Service	Ag Digester
American Organic Energy LLC	USA	400	1/1/2028	Not in Service	Ag Digester

6.2 Provide a revised Table 9-4 that disaggregates the forecast GHG emission reductions under the Diversified Approach by source, separately identifying (a) RNG produced and combusted within British Columbia (On-System RNG), (b) RNG sourced outside BC, and (c) hydrogen; and, on that basis, restate the total emission reductions counting only On-System RNG.

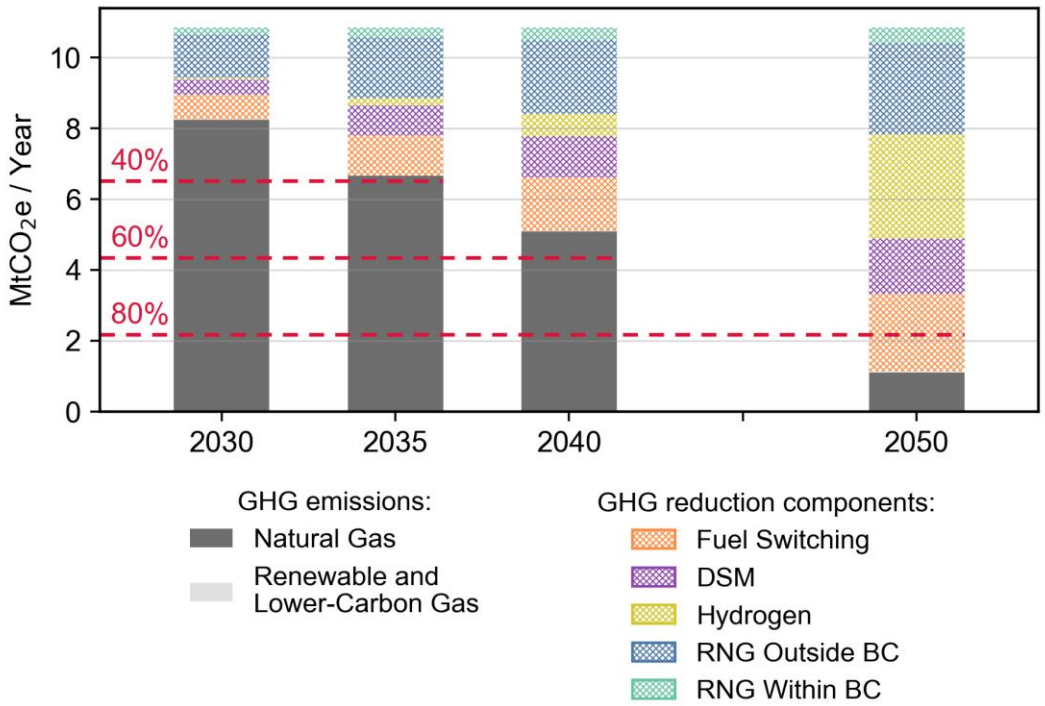
Response:

GHG emissions reductions under the Diversified Approach scenario arise from the combination of multiple measures, including fuel switching, DSM, and renewable and lower-carbon gas supply (including RNG sourced within and outside BC), as described in Sections 9.3.4 and 9.3.5 of the 2026 LTGRP.

Table 9-4 presents the combined impact of these GHG emissions reduction drivers. The reductions are not attributable to a single source in isolation but rather result from coordinated system-level changes across the portfolio of measures.

To provide additional insight, a revised version of Figure 9-5 is provided below, which disaggregates the renewable and lower-carbon gas component into hydrogen, RNG sourced within BC, and RNG sourced from outside of BC.

Revised Figure 9-5: GHG Emissions (End Use) Components – Residential, Commercial and Industrial Sectors for the Diversified Approach Scenario (Disaggregated by Source)



As shown in the above figure, the relative contribution of RNG outside BC is consistent with the supply assumptions presented in the 2026 LTGRP (Table 5-3), which indicate that approximately 85 percent of forecast RNG supply is sourced from outside BC, thereby demonstrating alignment between the disaggregated results and the underlying planning assumptions.

6.3 Explain the basis on which FEI considers the emission attributes of out-of-province, Off-System RNG to be creditable against British Columbia's territorial greenhouse gas reduction targets.

Response:

The RNG that FEI acquires from outside of BC and delivers to BC by displacement reduces GHG emissions in British Columbia because the GHG emissions from RNG are biogenic and, therefore, do not result in incremental emissions of carbon dioxide to the atmosphere. The transfer of the environmental attributes (EAs) of RNG to FEI and the sale of those attributes to FEI's customers

gives British Columbia the sole right to claim that it is using the RNG that FEI acquires and the sole right to recognize the biogenic nature of the RNG emissions within British Columbia.

The reduction in GHG emissions resulting from RNG is consistent with the Intergovernmental Panel on Climate Change (IPCC) guidelines for jurisdictional inventory reporting, which recognize that the GHG emissions resulting from the consumption of RNG should be recorded in the jurisdiction where that RNG is used. The carbon dioxide (CO_2) component of the RNG used within BC does not contribute to BC's overall GHG emissions because RNG is methane produced from biogenic feedstocks, which means the CO_2 that is released when the RNG combusted is balanced by the carbon drawn out of the atmosphere to create its raw materials.

The reduction in GHG emissions within British Columbia due to RNG acquired from outside the province is recognized by the BC Government. For example, the BC's Climate Action Secretariat's Carbon Neutral Government program recognizes GHG emissions reductions through the blend of RNG into FEI's gas supply by adjusting its natural gas emissions factors for anthropogenic CO_2 and biogenic CO_2 proportional to the RNG blend. Commencing in July 2024, the emissions factors for use of natural gas from FEI were adjusted to reflect the fact that a percentage of the gaseous energy received from FEI was RNG, thereby lowering the anthropogenic CO_2 emissions of the gaseous energy stream.

The GHG reductions in BC are supported by FEI's robust accounting and verification practices, which include:[3]

- **Allocation of EAs to FEI:** FEI's Biomethane Purchase Agreements (BPAs) include provisions allocating all EAs to FEI for any RNG volumes it purchases. FEI's contractual provisions are comprehensive in their approach, such that the EAs related to the production of RNG are exclusively transferred to FEI. FEI's BPAs also require the RNG to be below a certain carbon intensity level, which is determined annually. If the supplier did not meet these requirements, then FEI would have the contractual right to terminate the contract and no longer purchase the RNG.
- **Ongoing Warrants and Assurances:** FEI's RNG suppliers must warrant and assure to FEI that they are meeting their contractual obligations under the BPAs to allocate EAs to FEI. Pursuant to these contractual provisions, FEI procures the attestation letters that are filed with the BCUC in FEI's annual RNG reporting. In the attestation letters, RNG suppliers provide a written attestation of the exclusive transfer of the EAs associated with the volume of RNG that is sold to FEI.
- **Regular Audits:** In all of its BPAs, FEI has the contractual right to perform production audits at the supplier's RNG plant on a regular basis. This includes the right to review records related to feedstock and emissions specific to the supplier facilities used to determine the overall lifecycle carbon intensity of the RNG produced by the facility. These audits are performed by a third party, with the first performed after the first year of regular

[3] Exhibit C1-9, Review of Renewable Natural Gas Definition and Accounting, FEI Reply Submission (January 12, 2026), pp. 33-35. Online at: https://docs.bcuc.com/documents/proceedings/2026/doc_85227_c1-9-fei-replysubmissions.pdf.

operation and then every three years thereafter. The audits performed to date for out-of-province RNG suppliers have not identified any issues or double counting.

- **Chain of Custody Framework:** FEI has developed and uses a robust chain of custody framework for out-of-province RNG purchases that provides a thorough and rigorous compliance process to ensure proper gas accounting for delivery of RNG. RNG suppliers provide the documentation for the chain of custody on a monthly basis to FEI. FEI only settles invoices for RNG purchases when the appropriate documentation is provided and passes a review. FEI has the most rigorous, transparent and executable processes for the chain of custody tracking amongst its peers.

- **Scan of Carbon Credit Markets:** To provide further assurance of the absence of double counting of EAs, FEI retained consultants to conduct scans of carbon credit markets in North America to identify registration of FEI's RNG suppliers in these markets and any potential issues. The scans have not detected any double counting. FEI has been involved in the North American RNG market for over 10 years and has no indication of any registry in any out-of-province jurisdiction that is counting EAs associated with the RNG FEI acquires. CleanCounts is similarly not aware of any instance of double-counting.

- **Consequences of Breach of Contract:** FEI's processes are enforceable through contractual obligations. If an RNG supplier were to sell the EAs associated with a volume of RNG sold to FEI to a third party, use such EAs to generate carbon credits or other tradable environmental certificates, or report the benefits associated with the EAs for its own voluntary or compliance purposes (e.g., reporting against its own GHG emissions reduction targets), this would contravene the contractual provisions in its BPA with FEI. Contravening the contractual terms of the BPA would create a contractual breach, which could result in FEI suing that party for damages or terminating the BPA, or both. The consequences of a breach of contract and enforcement by FEI would be significant for suppliers.

- **FEI Tracks and Retires EAs:** To track the sale and retirement of EAs of the RNG that it acquires pursuant to the GGRR, FEI has been using a cost and volume continuity report for more than 10 years. The continuity of the cost and volume of RNG is included in FEI's RNG Account (formerly Biomethane Variance Account). FEI's RNG Account Status Report reconciles the opening inventory, acquisition, sales and closing inventory both in quantity and costs/revenues. FEI reconciles its books monthly, supporting the accurate management of RNG inventory over time. Through these activities, FEI maintains the integrity of RNG inventory data and effectively manages customer sales, avoiding double counting of RNG supply volume and associated EAs.

- **BCUC Oversight:** In addition to the practice above, the BCUC also retains considerable oversight over FEI's acquisition and sale of RNG to customers. For example, the BCUC reviews and approves all the terms of FEI's tariff. FEI also files all BPAs with the BCUC for acceptance, including the 25 BPAs between FEI and out-of-province suppliers accepted since 2020. Moreover, on April 30 each year, FEI files its Annual BPA Compliance Report with the BCUC which, in particular, includes written attestation letters from RNG suppliers providing a written attestation of the exclusive transfer of the EAs

associated with the volume of RNG that is sold to FEI. In addition to these BCUC oversight mechanisms, FEI also reports annually to the BC Government on its prescribed undertakings.

6.4 With reference to the Order G-78-24 directive to provide more detail on, and to expedite planning of, low-carbon-gas (RNG and hydrogen) infrastructure investments, and building on BCUC IRs 14.3 and 15.3, confirm that FEI is not proposing to advance hydrogen-related infrastructure at this time and has reduced its assumed hydrogen delivery volumes. Explain how those decisions are consistent with that directive, given that the plan's forecast GHG reductions depend on a rising share of renewable and lower-carbon gas. If FEI considers it has complied with the directive, identify the specific infrastructure-planning steps relied on.

Response:

While FEI is not proposing to advance hydrogen-related infrastructure investments at this time and has reduced assumed hydrogen delivery volume, FEI's approach in the 2026 LTGRP is not inconsistent with the Panel's commentary in the 2022 LTGRP Decision and Order G-78-24.

FEI provides the Panel's commentary regarding hydrogen investments from page 37 of the decision below for context:

> The Panel recognizes that FEI is not requesting approval of any infrastructure investments related to the supply of RNG, hydrogen or other low-carbon gases. However, the Panel finds that the pursuit of infrastructure investments for the production and delivery of low-carbon gases for sales to its customers as outlined in the LTGRP, to be prudent and reasonable. Such infrastructure investments would require FEI to bring forward an application for review and approval by the BCUC under the appropriate section of the UCA.

Accordingly, the Panel requested that FEI provide more detail on, and expedite planning for, lower-carbon gas infrastructure; it did not require FEI to proceed with hydrogen infrastructure before the necessary conditions are in place.

Regarding the Panel's request on page 38 of the decision for more detail on specific lower-carbon gas related infrastructure investments in the next LTGRP, Section 5 of the 2026 LTGRP responds to the request by setting out a staged hydrogen pathway: feasibility and pilots in the 2020s, demonstration and scale-up in the 2030s, and potential commercial roll-out in the 2040s and beyond. FEI's plan recognizes hydrogen as a potential long-term GHG emissions reduction pathway, but large-scale deployment depends on policy, market, technology, regulatory, cost, and demand signposts that are not yet sufficiently developed.

As discussed in Section 5.3.4 of the 2026 LTGRP, 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 Clean Growth Innovation Fund to support high-impact initiatives, and building internal expertise as the market develops.

Please also refer to the responses to BCUC IR1 14.3, 14.6, 15.2 and 15.3.

D. Dual-fuel (hybrid) heating and district-scale alternatives

7.0 Topic: Transferability of the Kelowna dual-fuel study

Reference: Application, Exhibit B-1, Section 4.7 (pp. 4-21, 4-25) and footnote 106; Table 7-1; Figures 4-14 and 4-16; Table ES-1 (p. ES-8). Order G-78-24, p. 20.

FEI presents Part 1 of the Kelowna Dual-Fuel Study, geographically scoped to FBC's North Okanagan region, and defers Part 2 to FBC's 2026 LTERP. Footnote 106 states the analysis cannot currently be completed by FEI for the remainder of the province because the corresponding electric billed-consumption data is managed by other utilities. The 490 MW peak-avoidance figure derived from that dataset is presented as a Key Takeaway in the Executive Summary.

7.1 Building on BCUC IRs 10.1 and 11.7, provide the sensitivity of the 490 MW peak-avoidance figure to assumptions about climate zone, outdoor design temperature, building stock, customer demographics and rate design, and include within that sensitivity the figure recalculated for representative coastal Climate Zone 4 conditions (for example, an outdoor design temperature of −7 to −13 degrees Celsius). Please present the results with reference to Table 7-1 and Figures 4-14 and 4-16.

Response:

Please refer to the response to BCUC IR1 8.1.

7.2 Please provide an energy model for the house used in the Kelowna dual-fuel heat pump (DFHP) pilot that accurately characterizes the energy performance of this home, including its dimensions, specifications and energy performance indicators (Thermal Energy Demand Intensity, Mechanical Energy Usage Intensity, Air Changes per Hour).

Response:

FEI did not use a discrete energy model (such as OpenStudio or EnergyPlus) to model the various customer types and their homes in the Kelowna Dual-Fuel Study.

FEI grouped together customers with similar energy consumption patterns, using aggregated historical hourly AMI electric data and monthly gas billed consumption to create these customer types. These customer types were then paired with segmentation research to provide different representative typical building types.

8.0 Topic: Cost-effectiveness methodology for dual-fuel heating

Reference: Application, Exhibit B-1, Section 4, Section 4.4.1 and Table 4-2 (p. 4-7), and Section 4.8; Tables 4-8 and 4-9 (pp. 4-29, 4-32); Figures 4-12 (p. 4-20); Figures 4-15 to 4-18 (pp. 4-25 to 4-33); Figure 4-21 and footnote 126 (p. 4-39); Figure 4-24; footnote 124; pp. 4-19 and 4-26; Appendix A, Table 4, item 3; Section 8, Table 8-5 (p. 8-12). UCA s. 44.1(8)(c).

FEI finds residential dual-fuel heating cost-effective under the Utility Cost Test. The baseline in Table 4-9 is a gas furnace with air-conditioning, and footnote 124 states that 84 percent of FEI's shared-service-area residential customers already have air-conditioning. FEI's dual-fuel modelling applies regional switchover set-points in the order of 2 degrees Celsius. Since launching the residential dual-fuel incentive in July 2024, FEI reports approximately 2,300 participants and credits the program with avoiding 25 MW on FBC's peak winter day (pp. 4-19, 4-26), applying a CAD 5,000 incentive in the Utility Cost Test (Figure 4-12) and a uniform CAD 10,000 incentive in the marginal abatement cost comparison (Figure 4-21, footnote 126). FEI also relies on the dual-fuel program in addressing demand-side measure adequacy under section 44.1(8)(c).

8.1 Building on BCUC IR 11.8 (basis for the rate escalators in the Customer Affordability Tool), provide all inputs to the Utility Cost Test for the dual-fuel program, including the avoided-cost benefit and the RNG price, RNG volume and carbon-intensity assumptions within it.

Response:

FEI disagrees with the statement in the preamble that "FEI also relies on the dual-fuel program in addressing demand-side measure adequacy under section 44.1(8)(c)". FEI has not stated this in its evidence, nor has LIEC-Saanich-Richmond provided a supporting reference to where FEI has made this statement.

In Section 4.6.1 of the 2026 LTGRP, FEI presented a Utility Cost Test perspective of residential dual-fuel heating systems for its shared service area. Through analysis with Posterity Group for the Kelowna Dual-Fuel Study, FEI estimated that residential dual-fuel heating systems reduce gas consumption by 35 GJ per average customer within FortisBC's shared service area. Reduced gas consumption from dual-fuel heating systems varies in different parts of the province, and therefore this Utility Cost Test analysis does not use the exact same reduced gas consumption as what is applicable to FEI's in-market dual-fuel offers, and was intended to provide an example for the shared service area. FEI's in-market dual-fuel offers currently apply an FEI system-wide measure savings average.

The Utility Cost Test calculation was performed in accordance with the requirements for calculating avoided natural gas cost set out in section 4(1.1)(a) of the DSM Regulation, which does not require any carbon-intensity assumption to determine cost-benefit results. The calculation was completed as follows:

A. Avoided Gas Commodity Costs – RNG (Benefit) =

- The avoided gas consumption of 35 GJ per an average customer in the shared service area;
- The avoided gas cost for the current year (aligned with Section 4(1.1)(a)(i) of the DSM Regulation), is $35.69 in 2025;
- FEI's real utility discount rate is 4.0 percent per the 2025 and 2026 Annual Review of Delivery Rates Application;[4] and
- Therefore, the Net Present Value of 35 GJ * $35.69/GJ, using the discount rate of 4.0 percent over the 15 year measure life = $14,444.

B. FEI Contribution to Incentive (Cost) = $5,000 incentive that FEI last provided in its offer.

C. Non-Incentive Admin Costs (Cost) = Estimated at 15 percent of the corresponding incentive costs as per Step 4 in Section 4.3.1 of the 2026 LTGRP ($5,000 x 0.15 = $750).

The FEI Net Benefit was then calculated as Benefits minus Costs = A - B - C.

8.2 Provide the cost-effectiveness result for the dual-fuel program if the avoided-cost benefit is calculated using conventional natural gas rather than 100 percent RNG.

Response:

Please refer to the response to LIEC-Saanich-Richmond IR1 8.1.

8.3 Building on BCUC IRs 10.3, 11.3 and 12.1, confirm whether the switchover set-points used in the DFHP modelling are chosen to minimize total energy costs to the ratepayer. If they are not, identify the minimum-operating-cost (economic-optimum) set-point and calculate the effect of using that set-point, rather than FEI's prescribed regional set-points, on gas consumption, GHG emission reductions, and the value of the avoided electrical peak load. The economic-optimum set-point and its effects are distinct from the fixed-temperature switchover sensitivities (for example, 5 and −1 degrees Celsius) requested in BCUC IRs 11.3, 11.5 and 11.7.

[4] Exhibit B-2, FBC 2025 and 2026 Annual Review of Delivery Rates (July 24, 2025), online at: https://docs.bcuc.com/documents/proceedings/2025/doc_82987_b-2-fbc-annual-review-2025-2026-rates-application.pdf.

Response:

Please refer to the response to BCUC IR1 10.2 for an explanation of how the switchover temperatures were selected for FEI's dual-fuel heating program.

FEI interprets "minimum operating cost" as the switchover temperature (SOT) that minimizes the customer's total annual energy bill. Table 1 below presents the annual energy bill, lifetime total avoided building GHG emissions (relative to a gas furnace), annual building gas consumption, and peak demand savings (relative to a ccASHP) across a range of SOTs from 5°C to −1°C for a representative customer in a large detached home in Kelowna. Given that FEI does not have electric billing consumption for every FEI region, this cannot be completed for every single customer in FortisBC's service area, but provides a good indication of the directional impacts of different SOTs.

As discussed in the response to BCUC IR1 12.3, FEI discovered an error on page 4-35, line 18 of the 2026 LTGRP. The avoided lifetime total GHG emissions, under a 2°C SOT, should be approximately 29 and 36 tCO_2e, not 21 and 27 tCO_2e for Medium and Large Detached Homes, respectively.

Table 1: Annual Energy Bill, Lifetime Avoided Emissions, Annual Gas Building Consumption, and Electric Peak Savings for a Large Detached Home in Kelowna with a 15 percent RNG Blend in 2040

SOT	Annual Energy Bill in 2040	Lifetime Avoided Building GHG Emissions (tCO_2e)	Annual Building Gas Consumption (GJ)	Annual Electric Peak Savings (kW)
5	$3,863	26.5	70.7	-12.5
4	$3,867	29.5	65.8	-12.5
3	$3,876	32.9	60.3	-12.5
2	$3,888	36.2	54.8	-12.5
1	$3,906	39.0	50.3	-12.5
0	$3,934	41.9	45.3	-12.5
-1	$3,967	44.9	40.5	-12.5

This demonstrates that 5°C is the SOT within the range shown that minimizes customer energy bills in the shared service area, as even with a 15 percent RNG blend, gas is more cost-effective for heating, especially during cold temperatures. However, there are multiple considerations to be made under different SOTs (including a diminishing avoided electric peak benefit), and these are described further in the response to BCUC IR1 10.3.

Annual system coincident electric peak demand savings remain constant across all SOT scenarios shown; there is no incremental avoided peak "per degree of changeover". This is because the electric system coincident peak in Kelowna occurs at the outdoor design temperature of approximately −26°C, at which point the dual-fuel system operates in gas mode regardless of the selected SOT.

8.4 Énergir, the principal natural gas distribution utility in Québec, jointly offers a residential bi-energy program with Hydro-Québec. The changeover from heat pump to gas is set to approximately minus 12 degrees Celsius (minus 15 degrees Celsius in colder regions). Under this design and Quebec's colder climate, the heat pump supplies approximately 70 percent of annual heating and gas serves only the coldest periods. (See Hydro-Québec, "Dual-energy offer," hydroquebec.com; Énergir, "Biénergie avec thermopompe," energir.com).

FEI's modelling adopts a materially higher changeover, in the order of 2 degrees Celsius.

For each FEI region, state the outdoor design (peak) temperature and provide the avoided electrical peak load, the incremental avoided peak per degree of changeover, the gas consumption and the GHG emissions of the dual-fuel program as a function of changeover temperature from approximately 2 degrees Celsius down to a Québec-comparable changeover. In doing so, identify the changeover temperature beyond which each additional degree yields diminishing avoided-peak benefit relative to the additional gas consumption and forgone GHG reductions, and explain how FEI selected its changeover in light of that trade-off. This is particularly relevant to coastal Climate Zone 4, where the design temperature is approximately minus 7 to minus 13 degrees Celsius.

Response:

The metrics associated with dual-fuel heating system switchover temperatures in Kelowna are provided in the response to LIEC-Saanich-Richmond IR1 8.3.

Further details regarding the impacts of dual-fuel systems relative to electric heat pumps in the Lower Mainland (climate zone 4) are provided in the response to BCUC IR1 8.1.

8.5 FEI reports that since it began incentivizing residential dual-fuel heating systems in July 2024, approximately 2,300 shared-service-area customers have taken the offer, and credits this with avoiding 25 MW on FBC's peak winter day (p. 4-26), presenting strong participation as evidence of market interest and readiness (p. 4-19). FEI applies a CAD 5,000 incentive in the Utility Cost Test (Figure 4-12, p. 4-20) and a uniform CAD 10,000 incentive in the marginal abatement cost comparison (Figure 4-21 and footnote 126, p. 4-39). (a) Confirm the residential dual-fuel incentive amounts and their effective dates since the July 2024 launch, including any reduction in the standard incentive and any income-qualified tier

offered and subsequently withdrawn. (b) Disaggregate the approximately 2,300 figure by the incentive amount in effect at enrolment, with monthly enrolment counts. (c) State the incentive amount FEI considers representative for forward-looking program planning, and confirm whether the cost-effectiveness and uptake evidence relied on in the LTGRP reflects that amount.

Response:

FEI provides the following responses to parts (a), (b), and (c) of this question.

a) The residential dual-fuel amounts and their effective dates are as follows:

Rebate Type	Rebate Value	Effective Dates
Standard	$10,000	July 1st 2024 – April 30th 2025[5]
Standard	$5,000	May 1st 2024 – December 18th 2025
Income-Qualified	$15,000	July 1st 2024 – April 30th 2025[6]

b) Please refer to the following table showing annual enrollment counts for each rebate value, and a monthly average of participants across each year.

Enrollment Year[7]	Standard $10,000	Standard $5,000	Income-Qualified $15,000	Monthly Average
2024	707	N/A	133	140
2025	926	293[8]	192	118

c) The incentive amounts FEI is currently using for forward-looking program planning are $4,000 for the standard residential rebate and $8,000 for the income-qualified rebate. In Section 4.6.1 of the 2026 LTGRP, Figure 4-12 illustrates residential dual-fuel heating cost-effectiveness results using the previous standard residential rebate of $5,000. Additionally, in the 2024 CPR, FEI and Posterity Group modelled the market potential for dual-fuel heating systems at the Low, Medium, and High settings representing an incentive of 25 percent, 50 percent and 100 percent of the incremental cost. The Medium market potential scenario aligns with a standard rebate amount of $4,000. The potential uptake trajectories from the 2024 CPR are provided in the response to CEC-COSCO-RCIA IR1 14.1.

---

5 Following the effective end date, customers were able to apply for the rebate up to six months after the invoice date provided all criteria for the applicable rebate amount were fulfilled. This included documentation demonstrating that the installation deadline had been met. Applications were no longer accepted after December 18, 2025.

6 Ibid.

7 Enrollment year refers to the year that customer submitted the rebate application.

8 The standard $5,000 rebate was available from May 2025 through December 2025.

8.6 Explain how FEI defines and measures DSM adequacy for the purpose of section 44.1(8)(c). Confirm whether the dual-fuel heating program (and any other gas-fired peak-electricity-support measure) is counted as demand-side management in FEI's DSM plans, and if so, identify the provision of the DSM Regulation or other authority relied on to characterize as DSM a measure that maintains or increases gas throughput while shifting peak load from the electric system to the gas system.

Response:

As discussed in the response to LIEC-Saanich-Richmond IR1 8.1, FEI disagrees with the statement in the preamble that "FEI also relies on the dual-fuel program in addressing demand-side measure adequacy under section 44.1(8)(c)". FEI has not stated this in its evidence, nor has LIEC-Saanich-Richmond provided a supporting reference to where FEI has made this statement. FEI defines DSM adequacy in line with Section 3 of the Demand-Side Measures Regulation.

FEI has not yet determined what measures will be included in future DSM plans. FEI confirms that its dual-fuel heating measures, as included in FEI's currently accepted 2024-2027 DSM Plan, conserve energy, promote energy efficiency, and reduce the energy demand FEI must serve, and are therefore DSM as defined in the *Clean Energy Act*.

Further, these measures are explicitly permitted under the Demand-Side Measures Regulation as an "integrated dual-energy space heating system". The baseline for these measures is a lower efficiency gas-fired space heating equipment which is compared to the higher efficiency of the adopted dual-fuel measure. As the baseline is a gas fired space heating system, the measures shift demand from the gas system to the electric system. However, should BC's Highest Efficiency Equipment Standards (HEES) be implemented, the baseline would shift from gas to electric space heating where electricity peak demand support would come into consideration.

8.7 FEI models dual-fuel systems as an advanced DSM measure (Appendix A, Table 4, item 3) and reports 10.8 PJ of "Advanced DSM" savings in 2050 under the Diversified Approach (Medium DSM setting), a category combining dual-fuel systems with deep energy retrofits and gas-fired heat pumps (Table 4-2, p. 4-7). A dual-fuel system both reduces a retained customer's gas use, through the heat pump above the switchover temperature, and retains gas throughput, through the gas furnace below it. For 2030, 2040 and 2050 under the Diversified Approach (Medium DSM setting): (a) provide the dual-fuel portion of the Advanced DSM savings in Table 4-2, separately from deep energy retrofits and gas-fired heat pumps; (b) provide the residential, commercial and industrial annual gas

throughput retained by customers assumed to adopt dual-fuel systems, and the corresponding contribution to FEI's forecast peak day demand; and (c) state the number of dual-fuel installations, by sector, assumed in the forecast in those years, with the assumed switchover temperature and per-customer gas use. If FEI cannot provide (a) to (c) because dual-fuel adoption is not modelled at the measure or program level, explain how dual-fuel is represented in the demand and DSM modelling, including in the fuel-switching volumes in Table 8-5 (p. 8-12) that FEI states cannot be attributed to individual drivers, and how both the retained throughput and the avoided gas use are reflected in the Diversified Approach annual and peak demand forecasts.

Response:

Please refer to the response to CEC-COSCO-RCIA IR1 14.1.

9.0 Topic: District-scale alternatives and program-access fairness

Reference: Application, Exhibit B-1, Section 4 (dual-fuel program design and DSM offerings), Sections 4.6 to 4.8.

FEI's dual-fuel program supports building-scale systems that pair an air-source heat pump with a gas furnace. A thermal energy network can perform the equivalent function at district scale, pairing central heat pumps (including sewer-heat-recovery or geo-exchange sources) with gas peaking, while benefiting from load diversity and higher central-plant efficiency.

9.1 As a matter of integrated resource planning: (a) confirm whether FEI's dual-fuel incentive and related DSM offerings are available to thermal energy networks or central heating plants that combine heat pumps with gas peaking, and if not, explain why a district-scale system performing the same peak-management function is not eligible or assessed; and (b) provide any analysis FEI has performed comparing building-scale dual-fuel heating with district-scale hybrid heating (a thermal energy network served by more efficient central heat pumps with gas peaking and possibly thermal storage or waste heat recovery), including relative coefficient of performance, peak-electricity avoidance and GHG outcomes, or if no such analysis exists, confirm so.

Response:

FEI does not agree with the statement in the preamble that "A thermal energy network can perform the equivalent function" as building-scale dual-fuel systems. Thermal energy networks are materially different from individual dual-fuel customer level applications in the following ways:

- Both upfront customer expenditures and utility capital expenditures can be significant for a thermal energy network whereas individual dual fuel systems involve a much smaller equipment investment.
- Due to dependence on site-specific detail, thermal energy networks present scaling challenges, especially in retrofit applications as they require full participation from the district or neighborhood with appropriate density to be effective. Individual dual-fuel systems allow adoption over time and without density requirements and future flexibility.
- Waste heat recovery would be considered a critical sensitivity to make this type of thermal energy network project viable, eliminating some locations without access to a reliable consistent waste heat source. Individual dual-fuel systems do not require a waste heat source.

To answer the two questions posed:

a) FEI's current commercial prescriptive dual-fuel offer is not applicable to thermal energy networks or central heating plants, but thermal energy networks and central heating plants could be considered through FEI's Custom Efficiency Program:

- FEI's commercial prescriptive dual-fuel offer is designed for building-scale equipment, specifically dual-fuel rooftop units (RTUs). These systems are standardized, commercially available products that can be readily specified, verified, and rebated within FEI's commercial prescriptive program. As such, the offer would not be applicable to thermal energy networks or central heating plants, which are not building-scale packaged dual-fuel RTU systems.
- Thermal energy networks and central heating plants could be considered through FEI's Custom Efficiency Program, where eligibility is assessed case-by-case based on demonstrated incremental, attributable, and cost-effective natural gas savings. This analysis is supported by an engineering study and review. For example, a central heating plant could implement a thermal gradient header system at an existing gas boiler plant, where the boilers provide base heating and are supplemented by electric heat pumps and heat recovery.

b) FEI has not completed any analysis comparing building-scale dual-fuel heating with district-scale hybrid heating that includes relative coefficient of performance, peak-electricity avoidance and GHG outcomes.

9.2 As a matter of integrated planning, describe whether and how FEI assessed the interaction of a province-wide dual-fuel program with municipal district energy service areas, municipal fuel-switching incentive programs and Zero Carbon Step Code requirements.

Response:

FEI did not assess the interaction of a province-wide dual-fuel program with municipal district energy service areas, municipal fuel-switching incentive programs, and Zero Carbon Step Code requirements.

For the demand scenarios presented in Section 3 of the 2026 LTGRP, gas demand associated with district energy systems is captured within the industrial sector, where district energy providers are represented as a distinct segment.

In addition, steam-to-hot water conversion (district energy) is included as a DSM measure within the DSM analysis. However, the potential for this measure was not evaluated in combination with municipal fuel-switching incentive programs or Zero Carbon Step Code requirements.

E. Integrated planning and non-pipe alternatives

10.0 Topic: Coordination with BC Hydro

Reference: Application, Exhibit B-1, Section 1; Section 8.6.

FEI states that the 2026 LTGRP reflects enhanced coordination of scenario planning between FEI, FBC and BC Hydro, including participation in technical advisory committees and meetings between resource-planning teams.

10.1 Building on BCUC IR 20.1 (coordinated FEI and FBC gas and electric resource planning), describe any joint or coordinated resource-planning product developed with BC Hydro for the 2026 LTGRP, as distinct from data-sharing or the alignment of input assumptions, including whether the utilities jointly assessed gas-to-electric transition pathways or coordinated infrastructure investment and decommissioning, and confirm whether the avoided electric infrastructure costs relied on anywhere in the Application, including in the dual-fuel cost-effectiveness analysis, have been reviewed or confirmed by BC Hydro, and at what spatial resolution (feeder, substation or region).

Response:

FortisBC and BC Hydro have a long-standing history of collaboration and joint coordination on aspects of resource planning. As BC Hydro noted in their submission in the Energy Supply to the Okanagan Region proceeding,[9] BC Hydro and FortisBC have coordinated on areas such as integrated utility planning workshops, load forecasting and planning assumptions, technical engagement and information sharing, supply-side resource considerations, Mandatory Reliability Standards (MRS), and more recently, the West Kelowna Transmission Project. In addition, FortisBC and BC Hydro have collaborated on demand-side management and joint energy efficiency programs for decades.

In FortisBC's submission in the same proceeding, FortisBC outlined areas of coordinated resource planning with BC Hydro since the 2026 LTGRP was filed, distinct from data-sharing or alignment of input assumptions. A key area of coordinated resource planning is the potential for a joint dual-fuel heating system incentive program, which can lower gas demand and associated emissions without increasing electric peak demand. FortisBC has met, discussed, and continues to engage with BC Hydro on this initiative, as well as other opportunities for continued collaboration in support of resource planning objectives.

[9] British Columbia Utilities Commission, "British Columbia Hydro and Power Authority (BC Hydro) Review of the Okanagan Region Energy Supply BC Hydro Initial Submission" (April 27, 2026) online at: https://docs.bcuc.com/documents/other/2026/doc_87043_2026-04-27-bc-hydro-submission.pdf.

11.0 Topic: Non-pipe alternatives, thermal networks and waste heat

Reference: Application, Exhibit B-1, Section 7 (including Section 7.5, p. 7-33) and Appendix D-1. Order G-78-24, p. 25.

FEI describes the development of a BC-specific non-pipe-solution framework in Section 7 and Appendix D-1, and states at Section 7.5 (p. 7-33, under the sub-heading "Updates on the Development of a BC-Specific NPS Framework") that, at this time, it is not proposing to develop a formal BC-specific NPS framework.

11.1 Confirm whether FEI is proposing to develop a formal BC-specific non-pipe-solution (NPS) framework in response to Directive 10 of Order G-78-24 (p. 25); if not (as indicated at Section 7.5, p. 7-33: "At this time, FEI is not proposing to develop a formal BC-specific NPS framework"), explain the basis on which FEI has decided not to develop a formal framework; and provide the current status of any non-pipe process FEI does intend to apply, confirming whether that process considers zonal electrification, thermal energy networks, waste heat recovery and thermal energy storage as alternatives to gas-system extension, capacity expansion or main replacement, and if not, why not.

Response:

As discussed in Section 7.5.2 of the 2026 LTGRP, FEI continues to consider a formal BC-specific NPS framework, but it has decided not to develop it at this time for the following reasons:

- AMI meters are required to determine the potential magnitude of demand savings that a pilot program could achieve. The data from AMI meters will help determine the efficacy of a demand response program.
- FEI considers that it is not feasible for interruptible rates for commercial customers to avoid the need to expand gas infrastructure in the future.
- FEI is already undertaking all the available NPS within its service area without a formal framework in place.
- FEI is currently undertaking the Kelowna Dual-Fuel study to further understand the impacts of fuel switching at a more granular level for the customers of both the gas and electric utilities. This work is ongoing.

In the meantime, FEI will continue to implement NPS solutions on a project-by-project basis and will continue to monitor developments across North America in regard to NPS frameworks.