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December 22, 2022

B.C. Sustainable Energy Association
c/o William J. Andrews, Barrister & Solicitor
70 Talbot Street
Guelph, ON
N1G 2E9

Attention: Mr. William J. Andrews

Dear Mr. Andrews:

Re: FortisBC Energy Inc. (FEI)

2022 Long Term Gas Resource Plan (LTGRP) – Project No. 1599324

Response to the B.C. Sustainable Energy Association (BCSEA) Information Request (IR) No. 1

On May 9, 2022, FEI filed the LTGRP referenced above. In accordance with the amended regulatory timetable established in British Columbia Utilities Commission Order G-287-22 for the review of the LTGRP, FEI respectfully submits the attached response to BCSEA IR No. 1.

In its responses, FEI has identified responses which were provided by, contributed to, or developed with its consultants, the Posterity Group and Guidehouse.

For convenience and efficiency, FEI has occasionally provided an internet address for referenced reports instead of attaching lengthy 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.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

A. Planning Environment

1.0 Topic: GHG Reduction Standard

Reference: Application, Exhibit B-1, page 2-9, pdf p.75

On page 2-9 of the Application, FEI states:

> "The move from a voluntary renewable gas target to a mandated GHG [Greenhouse Gas] emissions cap is a substantial change in direction for provincial policy. While details on the GHGRS [Greenhouse Gas Reduction Standard] remain under development, FEI expects that it will place a stringent emissions reduction obligation on gas utilities. Compliance pathways to achieve the cap have not yet been developed; however, these pathways will be highly consequential for the overall role of gas utilities and for customers that rely on the energy that natural gas utilities deliver." [pdf p.75]

1.1 What is FEI's current estimate of the timing of the anticipated Greenhouse Gas Reduction Standard?

Response:

FEI is unable to provide an estimate of the timing as the Province has not announced a timeline for implementing the GHGRS.

1.2 What is FEI's current understanding of the options for compliance pathways for FEI to achieve the GHGRS cap as it will apply to FEI?

Response:

The Province has not announced options for compliance pathways for FEI to achieve the GHGRS cap. FEI holds the view that renewable and low-carbon gases, energy efficiency improvements through expanded DSM programs, carbon capture, utilization and storage for upstream gas and downstream end-users, GHG mitigation on FEI system operations, and potentially expanded provision of alternative energy services should be options that will be enabled for compliance with the GHGRS.

1.2.1 Are these options identified in the 2022 LTGRP? If so, please identify the location. If not, please explain why not.

Response:

Yes, FEI has captured the options it believes should be applicable. Section 9.2.1 of the Application outlines the options described in the response to BCSEA IR1 1.2. Further, Figure 9-1 illustrates the GHG emission reductions allocated to FEI's decarbonization initiatives that will be undertaken to meet the GHGRS for the DEP Scenario for 2030 and 2042. Please refer to the response to BCUC IR1 74 series for further discussion on FEI's emission reduction initiatives to meet the proposed GHGRS.

2.0 Topic: Low-Carbon Transportation

Reference: Application, Exhibit B-1, section 2.2.2.3.2 Low-Carbon Transportation (LCT), p.2-13, pdf p.79

FEI states on page 2-13:

> "The GGRR also authorizes a utility to invest up to $331.5 million in low-carbon transportation (LCT) programs, with commitments for funding to be made by March 31, 2022. The Province's plans to continue to support LCT through the GGRR are not yet known."

2.1 Please describe at a high level the extent to which FEI has invested in low-carbon transportation programs as prescribed undertakings under the GGRR.

Response:

To date, FEI has committed and issued approximately $71.7 million of the $224.0 million available for vehicle incentives, shop upgrades, and administration, marketing and training, and $56.5 million of the $107.5 million in allowable infrastructure investment, as prescribed undertakings under the GGRR. This includes incentivizing over one thousand CNG and LNG medium- and heavy-duty vehicles since 2011 and investing $19.2 million in the construction of CNG and LNG fueling stations. Fueling stations have been constructed throughout the province at customer locations and along strategic transportation corridors.

2.2 Please discuss at a high level the extent to which the Low-Carbon Transportation programs compete with electricity as substitute for diesel, oil or gasoline.

Response:

FEI does not currently view electric solutions as competition for FEI's low carbon transportation programs. FEI's LCT program targets medium- and heavy-duty vehicles and there are currently no commercially-proven, widely-available battery electric offerings for the medium- and heavy-duty transportation sectors in BC, with the exception of technology demonstration projects for battery electric transit buses operated by BC Transit and TransLink. Economic and technical challenges continue to hinder the emergence of these low carbon solutions for the non-transit medium- and heavy-duty transportations sectors. A portfolio of technologies will be needed for specific applications. FEI is starting to integrate RNG as a transportation fuel, as it allows companies to operate with very low emissions and requires no additional capital investment for customers, as RNG is a drop-in fuel that can be used directly in any CNG or LNG engine. As companies transition to alternative fuels, it is likely that a diversified approach will be used and RNG will be a key factor in the transition as technologies develop. FEI will continue to monitor the development of these new technologies. Notably, natural gas vehicles using RNG will be a key solution for the BC Low Carbon Fuel Standard to achieve the 30 percent carbon intensity reduction goal, as natural gas vehicles using RNG achieve a carbon intensity reduction greater than the requirement.

3.0 Topic: Gas v Electricity

Reference: Application, Exhibit B-1, Table 2-2: Difference in Costs for Space and Water Heating over Measure Life, p.2-33, pdf p.99

3.1 Please further explain Table 2-2, including the meaning of the positive and negative figures.

Response:

FEI provides the following explanations for each item in Table 2-2:

- **Difference in capital costs**: This is the difference between the estimated upfront capital and installation costs of a gas appliance and an electric appliance. For instance, the $3,000 difference indicates that the capital cost of an electric heat pump is $3,000 more than a gas furnace, as shown in Table 2-1 (i.e., $21,000 for an electric heat pump vs. $18,000 for a gas furnace). For water heating (an example of a positive amount), the capital costs of an electric water heater are $1,250 less than the gas water heating alternative (i.e., as shown in Table 2-1, an electric water heater's capital cost is $1,550 whereas a gas water heater's capital cost is $2,800).
- **Annual Payments for recovery of capital costs and total costs per year to pay off difference in capital cost**: As explained in footnote 97 of the Application, this is calculated based on the present value of an annuity formula and indicates the annual payments needed to recover the difference in capital costs discussed above. The $257 differential indicates that compared to an electric heat pump, the owner of a gas furnace will have to pay $257 less per year over the measure life of the appliance. On the other hand, for water heating (an example of a positive amount), the annual payments for a gas water heater system are $137 more than the electric alternative. The total costs per year to pay off the difference in the capital cost are calculated by adding the annual payment for recovery of capital costs to the difference in maintenance costs per year. Assuming that the annual maintenance costs for both gas and electric appliances are equal, there is no change in the total cost amounts.
- **Difference in capital and maintenance costs between gas and electric equipment ($/GJ)**: This is calculated by dividing the total costs per year to pay off the difference in capital cost by the assumed energy consumption. The difference in capital and maintenance costs between gas and electric appliances can then be compared with the difference between FEI's and BC Hydro's operating costs adjusted for higher efficiency of electric appliances. For instance, the negative $6.8 per GJ means that due to an electric heat pump's higher capital cost, BC Hydro's efficiency-adjusted rates should be $6.8 per GJ lower than FEI's burner tip rate for a heat pump to be economic. On the other hand, the positive $6.2 per GJ difference between a gas water heater and an electric water heater means that FEI's burner tip rates should be on average $6.2 per GJ lower over the measure life of the appliance, for a gas water heater to be competitive with an electric water heater on a total cost basis.

4.0 Topic: Gas Furnace v Electric Heat Pump

Reference: Application, Exhibit B-1, Gas Furnace as Compared to Electric Heat Pump, p.2-34, pdf p.100

FEI states on page 2-34:

> "Gas Furnace as Compared to Electric Heat Pump
>
> The analysis above shows that a gas furnace is less costly than a heat pump, with the difference estimated at $6.80 per GJ over the measure life. BC Hydro's efficiency adjusted Step 2 rate is $2.90 per GJ higher than FEI's burner tip rate and its Step 1 rate is $3.30 per GJ lower; therefore, without a means of reducing the heat pump's high capital costs, the gas furnace option will be more economic. Currently, both provincial and local governments as well as BC Hydro provide generous rebates to households who install heat pumps or convert their fossil fuel heating systems to central heat pumps. As such, when the heat pump's higher rebates are considered, the gas furnace's cost advantage can be reduced or eliminated in favour of the electric heat pump, depending on the rebate amount available at the time of installation." [page 2-34, pdf p.100]

4.1 Does the analysis of a Gas Furnace as Compared to an Electric Heat Pump take into account the forecast natural gas rate and bill increases discussed in section 9.4 of the LTGRP?

Response:

No, FEI's price competitiveness analysis between a gas furnace and an electric heat pump in Section 2.4.2 of the Application is based on natural gas and electricity rates effective as of April 1, 2022. Therefore, it does not take into account the forecasted bill impacts in Section 9.4 of the Application. FEI would require a 20-year forecast of electricity rates from BC Hydro in order to compare the two options on a long-term forecast basis.

5.0 Topic: Obligation to Serve New Customer Additions

Reference: Exhibit B-1, Figure ES-8. GHG Emission Reductions for Residential, Commercial and Industrial Customers Meets the GHGRS for the Diversified Energy (Planning) Scenario, p.ES-17, pdf p.38; OCUP CPCN Application, Exhibit B-1-2, p.29, pdf p.41

The *CleanBC Roadmap to 2030* states that the GHG Reduction Standard emissions cap on gas utilities will be approximately 6 MT CO_2e in 2030, of which FEI estimates approximately 5.7 Mt CO_2e would apply to FEI in 2030. [Exhibit B-1, p.ES-16, pdf p.37]

In the 2021 CPCN application for the Okanagan Capacity Upgrade Project, FEI indicates that its 'obligation to serve' under section 28 of the UCA is one of the drivers of the Project. FEI states:

> "FEI must also maintain adequate system capacity such that customer additions can be accommodated. Section 28 of the UCA states that a utility must provide service upon request, should the supply line be near the property requesting service.[14] Without an increase in ITS capacity, FEI will be unable to satisfy future growth in gas demand caused by new customer additions."
>
> [14] Section 28 of the UCA provides in part: "On being requested by the owner or occupier of the premises to do so, a public utility must supply its service to premises that are located within 200 metres of its supply line or any lesser distance that the commission prescribes suitable for that purpose". [OCUP CPCN Application, Exhibit B-1-2, p.29, pdf p.41]

5.1 Would FEI's ability to cost-effectively comply with the anticipated GHG Reduction Standard be enhanced if the BCUC could exempt FEI from the 'obligation to serve' new natural gas customer additions that would require large capital expenditures to serve adequately and where the new energy needs could be met with electricity?

<u>Response:</u>

FEI notes the key details of the GHGRS are not yet finalized by the Province; as such, FEI is unable to determine whether the anticipated enhancement to the GHGRS would have any implication on the cost-effectiveness of connecting new customers. However, FEI does not believe an exemption from the obligation to serve in the UCA would lead to otherwise more cost-effective customer additions regardless of the GHGRS. Although FEI has an obligation to serve under Section 28 of the UCA, there are also policies and practices in place, such as the BCUC-approved Main Extension (MX) Test, that ensure uneconomic customers are not added to FEI's system without an appropriate and reasonable level of contribution. For instance, the aggregate profitability index (PI) from the 2021 annual MX Test report is 2.09, meaning the aggregate net revenue would exceed the aggregate net cost to connect the new customers.

FEI further notes that a key finding in the Pathways Report was that the system-wide impacts and costs must be considered from aggregated individual actions. As discussed in the Pathways

Report and outlined in the Application, a diversified pathway that maintains a long-term role for the gas system is a lower cost abatement pathway for BC compared to an approach that is focused on widespread electrification. As such, exempting FEI from the “obligation to serve” new natural gas customer additions and replace the energy needs with electricity would not necessarily be more cost-effective when considering both natural gas and electric systems.

B. Clean Growth Pathway

6.0 Topic: GHG intensities of fuel types and decarbonization technologies

Reference: Application, Exhibit B-1, Table ES-2, Fuel Types and Decarbonization Technologies Used in the 2022 LTGRP, pdf 23

6.1 Please identify and discuss the sources for the carbon intensity figures (tCO_2e/GJ) in Table ES-2.

<u>Response:</u>

Please refer to the response to BCUC IR1 71.4.

6.2 Please explain why there is a single Life Cycle Emission Factor and End Use Emission Factor for each fuel type even though the underlying value is presumably a range.

<u>Response:</u>

FEI has adopted a deterministic model approach in estimating customer-related GHG emissions that assumes, while some renewable and low-carbon gas production projects may result in a higher emission factor than that used in modelling for the Application, so too will some projects result in a lower emission factor than that used to model. FEI considers that the emission factors used are somewhat conservative given that technology improvements made over the 20-year planning horizon will be aimed at improving emission factors since the primary motivation for developing renewable and low-carbon gases is to produce low carbon energy.

6.2.1 Regarding CCUS (Carbon Capture, Utilization and Storage) in particular, isn't there a wide range of GHG Emissions Factors involved, depending on the technology and the application of it?

<u>Response:</u>

Yes, actual CCUS lifecycle emission intensity must be quantified on an individual supply basis. The basis of the lifecycle emission factor for CCUS in Table ES-2 is the IEA GHG Technical Report (March 2019) entitled, *Towards Zero Emissions CCS in Power Plants Using Higher Capture Rates or Biomass*,[1] which estimates a CCUS efficiency of 90 percent. FEI has used this

[1] Available online at: https://ieaghg.org/publications/technical-reports/reports-list/9-technical-reports/951-2019-02-towards-zero-emissions.

value to represent emissions associated with using CCUS at an industrial facility. FEI will update the emission factor for CCUS if needed as development of the technology proceeds and more information is made available.

6.3 Please explain why renewable natural gas is listed as a single fuel type, rather than differentiating RNG from landfill gas, from manure, etc.?

Response:

For expediency, the RNG emission factors listed in Table ES-2 of the Application were calculated using an average emissions factor based on FEI's expectation of its mix of sources. With respect to the life cycle emission factor, a conservative estimate was adopted for the purposes of forecasting emissions. Actual life cycle emission intensity will be quantified on an individual supply basis. Please refer to the response to BCUC IR1 71.4 for further discussion.

6.4 For the Emission Factors for RNG, please explain how the avoidance of released methane is considered?

Response:

The life cycle emission factor for RNG provided in Table ES-2 is an estimate for the purposes of accounting for methane and other GHG emissions modeled in the Application. Actual life cycle emission factors will be determined on an individual supply basis using provincially- or federally-accepted life cycle assessment models such as GHGenius and the Clean Fuel Regulation's OpenLCA. As such, life cycle emission factors for modelling purposes are assumed to include all life cycle emissions, including methane releases which, in FEI's experience of delivering natural gas, have been shown to be a very small part of total emissions. To summarize, emission factors for RNG include all emissions and each project will be assessed on an individual supply basis based upon applicable regulation.

6.5 Turquoise hydrogen is mentioned elsewhere in the 2022 LTGRP. Why is it not included in Table ES-2? If suitable, please add a row for Turquoise Hydrogen.

Response:

Turquoise hydrogen, although discussed as a potential alternative in FEI's fuel mix in the Application, was not included in Table ES-2 because the Application did not assume or model any turquoise hydrogen within the renewable and low carbon portfolio. Therefore, FEI did not try to establish a carbon emissions factor value. Any such projects that would be brought into the portfolio would have a full emission production profile developed based on its specific design, which FEI would then use for ongoing reporting purposes. The long-term forecast for low-carbon gases is an assumption based on FEI's best understanding of the market outlook for renewable and low-carbon gas over the planning horizon. FEI will refine its analysis of emission reduction potential from hydrogen as it gains more insights into the individual component types of hydrogen, with assigned specific carbon intensity, as these technologies and pathways evolve.

7.0 Topic: Diversified Energy (Planning) Scenario

Reference: Application, Exhibit B-1, 4.5.1 Identifying FEI's Planning Scenario – The Diversified Energy (Planning) Scenario, p.4-17, pdf p.153

FEI states on page 4-17:

> FEI believes that a diversified pathway in which both the existing gas and electricity systems within BC have an important role to play in decarbonizing energy use in the province, is critical to a successful, reliable, resilient and cost-effective energy future, and that the Clean Growth Pathway plays a critical role. As such, <u>FEI is designating the Diversified Energy (Planning) Scenario as its planning scenario for the 2022 LTGRP</u>." [pdf p.153, underline added]

7.1 What does it mean that FEI is designating the Diversified Energy (Planning) Scenario as its planning scenario for the 2022 LTGRP?

<u>Response:</u>

FEI considers that the DEP Scenario best represents the future that will unfold over the next 20 years. Accordingly, FEI has developed plans to implement its Clean Growth Pathway based on this scenario, including the Action Plan in Section 10 of the Application.

7.2 Does the 2022 LTGRP plan for the other alternative scenarios, in addition to the DEP Scenario?

<u>Response:</u>

The Application has examined a broad range of other possible future scenarios that could unfold and identified contingency actions to be taken should FEI's demand unfold in a substantially different way than projected in the DEP Scenario. Section 6.2.4.3 of the Application discusses the actions to be undertaken in planning for the gas supply resources needed to serve FEI's customers and includes a discussion of contingency plans to address higher or lower than forecast demand uncertainty. Action Item 9 contains the monitoring activities that will help to identify if a scenario other than the DEP Scenario is unfolding and if contingency actions need to be implemented. Section 7.2 of the Application discusses the actions to be undertaken to design and extend the gas transmission and delivery system and includes a discussion of contingencies for either faster or slower demand growth. Action Item 10 describes the activities to monitor and implement contingency actions related to system planning. Overall, Action Item 8 will also help FEI to identify if a scenario other than the DEP scenario is emerging and understand what best next steps to take under such circumstances.

8.0 Topic: Pillar Four

Reference: Application, Exhibit B-1, 3.6 Pillar Four: Investing in LNG to Lower GHG Emissions In Marine Fueling And Global Markets, p.3-21, pdf p.126

8.1 Does FEI expect that the GHG Reduction Standard will include the GHG emissions of FEI's low-carbon transportation customers and its LNG marine fueling and global markets customers?

Response:

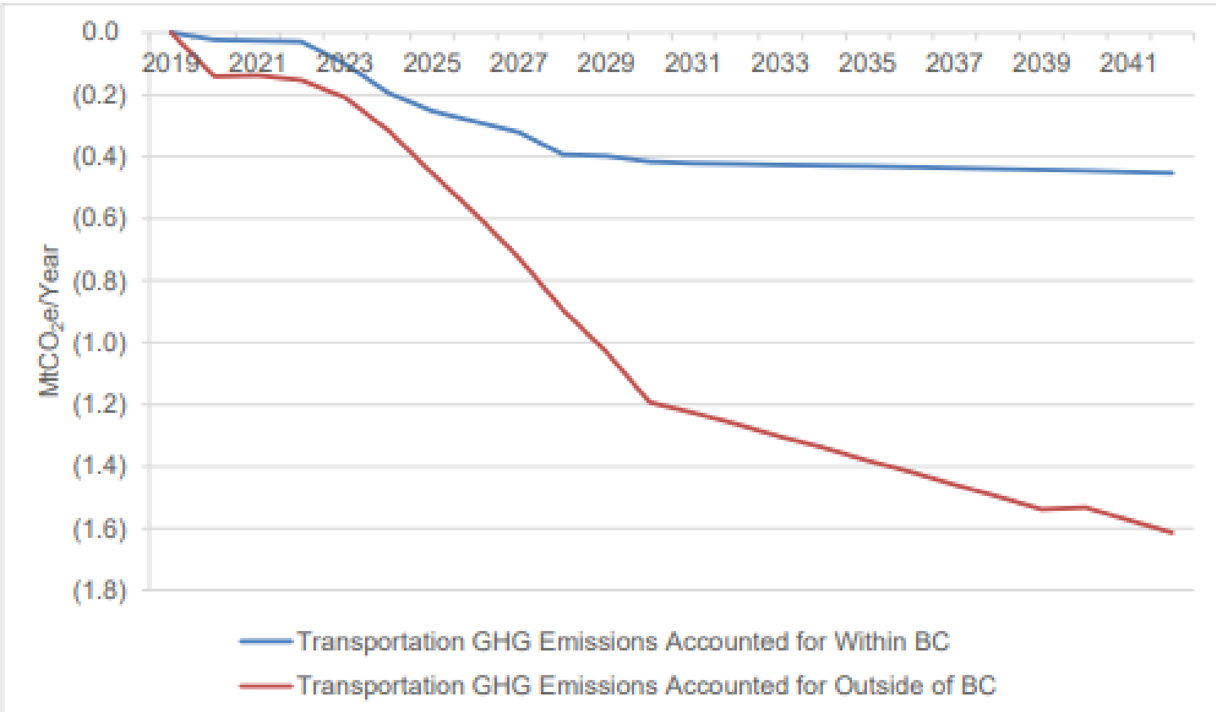
Please refer to the response to RCIA IR1 8.1.

8.2 To what extent does FEI's Pillar Four result in GHG emissions reductions accounted for in BC, as compared to GHG emissions reductions not accounted for in BC?

Response:

The information requested is provided in Figure 9-3, Section 9.2.2 on page 9-6 of the Application, and reproduced below. The emission reductions that are shown in the lower, red line in this figure, and which are accounted for outside of BC, can be viewed as the reductions resulting from Pillar 4 of FEI's Clean Growth Pathway. This is a conservative estimate of the global emissions reductions that can be achieved as part of Pillar 4 activities. The emissions shown by the upper blue line, and indicated as occurring within BC, can be viewed as resulting from Pillar 3 activities.

Figure 9-3: BC and Global Emission Reductions (Life Cycle) in the Diversified Energy (Planning) Scenario from Serving the Transportation and Global LNG Markets



8.3 Given that FEI's customers will soon have to substantially reduce their collective GHG emissions from the combustion of gas from FEI due to the requirements of the GHG Reduction Standard as anticipated in the CleanBC Roadmap to 2030, would FEI's 2022 LTGRP be improved by increasing the focus on reductions of customers' GHG emissions and reducing the focus on GHG reductions in Marine Fueling and Global Markets?

Response:

No, the Application would not be improved by changing focus. FEI has undertaken detailed and wide-ranging analysis of reducing GHG emissions associated with its customers in BC in line with the goals of the CleanBC Roadmap and is implementing actions to address these emissions. In other words, reducing content in the Application on emissions reductions from international customers would not lead to more action on reducing GHG emissions for domestic customers.

Further, while the GHGRS identified in the CleanBC Roadmap aims to reduce GHG emissions associated with domestic buildings and industrial customers, GHG abatement outside of BC's borders is also critical for addressing climate change and is an area where FEI can make important contributions as well. FEI considers that, irrespective of the GHGRS, reducing global emissions as can be accomplished through FEI serving marine fueling and global LNG markets is a critical action in addressing climate change.

8.4 Would it be more appropriate for FortisBC Holdings Inc., rather than FEI, to invest in the LNG for marine use and for export? If not, why not?

Response:

Both FEI and FortisBC Holdings Inc. (FHI) are expecting to play a role in providing LNG for marine use and export at Tilbury. FEI's marine customers today, BC Ferries and Seaspan Ferries, are being served with FEI assets, namely the existing base plant and T1A expansion at Tilbury, the plant at Mt. Hayes, the truck loading bays at both plants, and the marine tankers that FEI owns. Further, FEI currently provides service to small-scale LNG export customers who are delivering LNG from the existing FEI Tilbury facilities by customer-owned ISO containers using the truck loading bays. Both the existing domestic marine customers and the ISO export customers described above are served by FEI under the BCUC-approved Rate Schedule 46. In addition, FEI will invest further in LNG as approved through Order in Council (OIC) No. 557/2013 Direction No. 5 to the BCUC. The OIC supports the appropriateness of FEI's investments in LNG.

FHI's investments at Tilbury include the potential Tilbury Marine Jetty Project and a potential large-scale dedicated liquefaction facility at the Tilbury site.

8.5 Regarding "Marine Fueling Opportunities in BC," to what extent does FEI's LNG marine bunkering service enable existing and future customers to report reduced quantities of GHG emissions to the Province of BC?

Response:

FEI is currently providing LNG to BC Ferries and Seaspan Ferries, which reduces GHG emissions and local air contaminant emissions by displacing marine diesel. Fuels consumed for domestic marine transport, i.e. for shipping routes both originating and ending in BC, are included in BC's GHG emissions inventory. LNG that displaces higher carbon intensity marine diesel in domestic marine vessel traffic enables the reduction of GHG emissions in BC's domestic shipping sector, and the use of LNG to displace marine diesel by domestic BC customers is eligible for credit generation under the BC-LCFS.

With respect to whether existing and future customers are able to report reduced quantities of GHG emissions to the province of BC, GHG emissions from marine shipping are not subject to reporting requirements under the *Greenhouse Gas Industrial Reporting and Controls Act* and FEI is otherwise unaware of any other reporting requirements individual marine customers may have to the BC government.

C. Annual Energy Demand Forecasting

9.0 Topic: Customer Forecast

Reference: Application, Exhibit B-1, S. 4.3.1, Residential, Commercial and Industrial Customers, page 4-4; section 9.4, Rate Impact Implications of the Diversified Energy (Planning) Scenario, Figure 9-7, p. 9-13 and Table 9-2, page 9-15

FEI's introduction to the 2022 LTERP says it is a plan for a profound change away from providing conventional natural gas and toward providing renewable and low-carbon gas.

In section 9.4, FEI depicts substantial rate and bill increase projections over the planning period.

FEI describes its method for forecasting the numbers of its customers as:

> "… a well established method that remains consistent with previous LTGRP filings. The forecast of residential customers is based on the Conference Board of Canada housing starts forecast for BC, while commercial customers are forecast based on recent trends in growth for the commercial customer group. The forecast of industrial customers includes existing customers at the end of the base year (2019 year-end) along with any known commitments from customers to either join or leave the system."

9.1 Please confirm or otherwise explain that FEI's forecast of customer numbers does not take into account forecast or projected increases in FEI's delivery, storage & transport, and commodity rates. Does this differ between the Reference Case and BAU forecasts, or in any of FEI's alternative future scenarios?

<u>Response:</u>

Please refer to the response to BCUC IR1 27.8.

9.2 Given the profound changes FEI is planning for its service and the potentially large price implications for customers, does FEI consider that its customer numbers could in future be significantly affected by the level and speed of change of FEI's rates?

<u>Response:</u>

Please refer to the response to BCUC IR1 27.8.

10.0 Topic: Load forecasts, load projections and price elasticity

Reference: Application, Exhibit B-1, section 4.4.1, Residential, Commercial and Industrial Demand, pp. 4-8 to 4-14; section 4.4.2, End Use Annual Method of Demand Forecasting for the Low-Carbon Transportation and Global LNG Category, pp. 4-14 to 4-14; section 4.4.3, End Use Annual Method of Demand Forecasting for the New Large Industrial Demand Category, page 4-16; section 4.5, Alternate Future Scenarios and Critical Uncertainty Settings, pages 4-16 to 4-27; section 9.4, Rate Impact Implications of the Diversified Energy (Planning) Scenario, Figure 9-7, p. 9-13 and Table 9-2, page 9-15.pp.

In section 4.4.1, FEI describes its method for preparing its End Use Reference Case and Traditional BAU Annual Demand Method energy demand forecasts for its Residential, Commercial and Industrial customers.

In section 4.4.2, FEI describes its forecast methodology for conventional natural gas annual energy for Low-Carbon Transportation and Global LNG.

In section 4.4.3, FEI describes its forecast methodology for conventional natural gas annual energy for the New Large Industrial Demand category.

In section 4.5, FEI describes methodology to forecast or project annual energy loads for its six alternative future scenarios, including Diversified Energy (Planning) and Deep Electrification.

In section 9.4, FEI depicts substantial rate and bill increase projections over the planning period (Table 9-2).

10.1 What near-term and long-term price elasticities are used in FEI's load forecasts and scenarios?

Response:

The following response has been provided by Posterity Group in consultation with FEI.

Please refer to the following responses regarding near-term and long-term price elasticities used in FEI's load forecasts and scenarios:

- BCUC IR 27.2 through 27.4 discuss the levers impacting critical uncertainties including price elasticity of demand for natural gas with the change of natural gas price, the ranking of the critical uncertainties on demand, the percentage fuel share change in response to these uncertainties and FEI's confidence in the modelling approach.
- BCUC IR 27.6 discusses how the model accounts for the impacts of natural gas price elasticity.

- BCUC IR 27.7 discusses how the model accounts for the impact of fuel switching due to increasing natural gas prices, renewable or low carbon fuel prices, and overall rate increases.
- BCUC IR 27.8 discusses how the model accounts for the impact of rate increases upon customers (residential, commercial and industrial).
- BCUC IR 69.2 discusses the role of price elasticity in calculating emission reductions from natural efficiency and electrification and their impact on end use demand. This response includes Attachment 69.2 containing the report "Price Elasticity of Demand for Natural Gas: Considerations for Load Forecasting", February 14, 2019. This attachment is a literature review on price elasticity for natural gas demand conducted by Posterity Group (PG) on behalf of FEI as part of the end use demand forecast modelling work.

Below FEI provides a summary of the information described above.

The scenarios modelled for the Application use long-run price elasticity of demand for natural gas values to estimate changes in demand for gas based on changes in natural gas prices and carbon prices. Price elasticity is used to estimate the demand in a scenario when there is a change in Reference Case prices for natural gas and/or carbon. Therefore, the price elasticity value is the 'mechanism' to cause a change in gas demand from a price change.

The following table provides the values by sector.

	Residential	Commercial	Industrial
Long Run Price Elasticity Value	-0.38	-0.35	-0.70

Price elasticities vary over time as consumers shift demand in response to prices. It can take time for consumers to change behavior and switch capital in response to prices.

Economic theory provides two time periods: "short run" and "long run". In the context of natural gas demand, operations could vary in the short run (i.e., a homeowner changing the thermostat setting) while capital is fixed (i.e., the natural gas furnace remains the main heating source). Short run responses tend to be temporary in nature. In the long run, operations and capital can both vary. When a furnace reaches its end of life, for example, the consumer could respond to pricing signals by replacing it with a more efficient furnace or another type of heating equipment that does not use natural gas. Long run responses tend to be more permanent changes, compared to short run responses.

In the long run, more inputs and behaviour are susceptible to change in response to prices, therefore price elasticity of demand tends to be more elastic in the long run compared to the short run (i.e., long run elasticities are larger absolute values). Since the Application forecast period is relatively long (20 years) and the model produces annual values, long run elasticity values are used to analyze the longer-term impact of changes in prices, rather than shorter-term impacts.

The main takeaways from the literature review conducted by PG that there is a significant amount of literature on price elasticity of demand for energy. From the literature review, there were more studies on the residential sector, with fewer studies on the industrial sector, and a large range of values. The conclusion from this exercise is that it is unrealistic to have "correct" values from the literature specifically applicable to the modelling. Rather, it is important that the elasticity values reflect the theory on price elasticity of demand for energy. Therefore, elasticity values were selected that meet the following conditions that are provided by economic theory on elasticities and research on changes in demand for energy:

- Inelastic (<1), as the general assumption is that natural gas is an "essential" good for most customers, therefore customers tend to not change their consumption very much when prices change.
- Negative (>0), as an increase in price tends to cause a decrease in demand, all else being equal.

To find appropriate values without conducting an exhaustive literature review, PG used the price elasticity values provided by the Washington State Energy Office Carbon Tax Assessment Model.[2] To support their model, Washington State Energy Office conducted a literature review of price elasticities for demand of several fuels from various regions of the world and used statistical tests to determine appropriate values by sector and fuel. Elasticity values were selected for the residential, commercial and industrial sectors for natural gas, which are provided in the table above.

10.2 What are the price elasticities used in FEI's load forecasts and scenarios based on?

Response:

Please refer to the response to BCSEA IR1 10.1.

10.3 Does FEI consider that the elasticities used in its load forecasts and scenarios are realistic over the range of possible rate and bill increases arising from the outcomes of the 2022 LTERP?

[2] "CTAM Price Elasticity 2015.xlsx" online at: https://www.commerce.wa.gov/growing-the-economy/energy/washington-state-energy-office/carbon-tax/.

Response:

The following response has been provided by FEI in consultation with Posterity Group.

FEI assumes the question is referring to FEI's 2022 LTGRP, not LTERP.

Yes. FEI considers the elasticities used in the analysis are reasonable because they were obtained from a credible source and were applicable to FEI's context. While there is a range of price elasticities of demand for gas in the literature and they are estimated based on historical data, the values selected for the Application were based on a literature review and were considered appropriate for the modelling.

The scenarios use carbon price and natural gas (commodity) price as critical uncertainties to influence demand forecasts. Carbon price and commodity price influence FEI's rates and ultimately, customer bills. For further discussion on the modeling of retail rates, please refer to BCUC IR1 27.7.

Natural gas price was selected as a critical uncertainty instead of rate/customer bill impact, for the following key reasons:

- The literature review on price elasticity of demand suggests that a change in commodity price drives changes in demand;
- Forecasted long-run retail rate changes are outputs from the LTGRP analysis, therefore including them as inputs to the LTGRP would create a feedback loop in the analysis; and
- A customer's bill is made of several components[3] which would make modelling potential future rate changes for customers very difficult.

[3] A customer's bill is a combination of the commodity price, delivery charges, storage and transportation, and taxes, including the BC carbon tax. The commodity rates FEI charges to customers must be approved by the BCUC and are reviewed on a quarterly basis. Commodity rates for the upcoming 12 months are based on forecasted commodity prices among other things. Storage and Transport rates are approved annually by the BCUC with the Q4 gas cost report application and delivery rates are determined via an annual rate setting application to the BCUC.

11.0 Topic: Scenario Outcomes

Reference: Application, Exhibit B-1, section 4.6, End Use Annual Method Demand Forecast Results by Scenario, pages 4-27 to 4-38.

In section 4.6, among other things, FEI provides its rationale for rejecting the Deep Electrification scenario. For example, FEI states:

> "While the Lower Bound and Deep Electrification scenarios are useful for examining a full range of possible future actions and testing the boundaries of the critical uncertainties that can change the way energy is used in the future, there are significant implications for electricity demand, particularly with regard to peak capacity requirements, system resiliency and economic implications, that cannot be reconciled for these scenarios. Both of these scenarios assume that 100 percent of residential and commercial demand for gas is switched to electricity by 2050, and that 30 percent of industrial demand is switched to electricity in the Lower Bound scenario and 20 percent in the Deep Electrification scenario over that time period."

> "A number of studies have shown that an electrification pathway to decarbonization is more costly and riskier than a diversified pathway, in which the existing gas infrastructure is optimized and utilized to deliver low-carbon energy to customers in combination with a strong and resilient electricity system. system …" [page 4-28, underline added]

11.1 In what ways is the Diversified Energy (Planning) scenario optimized?

Response:

The DEP Scenario optimizes the use of BC's gas and electric delivery systems to achieve BC's GHG emissions reduction targets. This optimization utilizes the ability of the gas system to quickly ramp up to meet demand and leverages BC's investment in existing gas and electric infrastructure. The outcome of optimizing the use of both systems to achieve GHG reduction goals is lower overall energy rates for customers, higher system resiliency and greater practicality.

FEI's existing gas infrastructure provides safe, cost-effective and reliable energy service to British Columbians. The DEP Scenario would optimize the use of existing gas infrastructure by integrating renewable and low-carbon gases into the supply mix and engaging in other GHG abatement opportunities within FEI's current system. The DEP Scenario would also optimize electrification by streaming this solution to the optimal sectors and applications such as transportations sector's extensive use of electrification of light duty vehicles. The DEP Scenario itself is optimized because it leverages all available opportunities for GHG abatement, including energy efficiency technologies, DSM, renewable and low-carbon fuel, in addition to electrification, while also not compromising energy affordability and reliability. In this way, the DEP Scenario optimizes the attributes of both the gas and electric systems, as it envisions both systems working together to manage peak energy demand and the expense of the energy transition by leveraging systems that are already in place.

11.2 What amounts of electrification of existing gas loads or reduction of future gas loads due to electrification are assumed for the residential, commercial and industrial sectors in the Diversified Energy (Planning) scenario?

Response:

Please refer to the response to BCUC IR1 25.2. The "moderate electrification" row contained in the table included in the aforementioned IR response is aligned with the DEP Scenario.

11.3 Did FEI model different amounts of electrification of existing gas loads or reduction of future gas loads due to electrification for its Diversified Energy (Planning) scenario in order to find an optimum split between electricity and gas?

Response:

In the Application and supported by the Pathways Report, FEI modelled alternative future scenarios with different levels of electrification and determined that the DEP Scenario was optimal. The DEP Scenario effectively utilizes both the gas and electric systems, maximizing all available energy resources, to meet BC's GHG reduction targets at a lower cost than the Deep Electrification Scenario.

The DEP Scenario was influenced by the Pathways Report, which developed and evaluated scenarios for decarbonization in BC to meet the 2030 and 2050 provincial GHG reduction targets. The analysis in the Pathways Report was conducted using a 'what-if' model to allow for input into the broad pathways employed to achieve the 80 percent reduction target in order to understand trade-offs and synergies between different pathways.

In contrast, an optimization model typically generates a central optimized scenario based on assumptions for key input variables. An optimization model with a goal as ambitious as an 80 percent reduction in GHG emissions and a 30-year time horizon (as with the Pathways Report) with uncertain pathways on technology costs and innovation was not well suited to the task and consequently was not used.

D. Demand-Side Measures

12.0 Topic: DSM

Reference: Application, Exhibit B-1, section 5 Demand-Side Resources, p.5-1, pdf p.180

FEI states on page 5-1:

> "Under the Diversified Energy (Planning) Scenario with the High DSM Setting, FEI's savings from DSM activities are forecast to be significant, at approximately 25 PJ or 13 percent of annual load in 2042." [pdf p.180]

12.1 Does FEI consider that DSM energy savings of 13 percent of annual load in 2042 will be sufficient, in combination with reductions in the carbon intensity of gas delivered to customers, for FEI to meet the requirements of the anticipated Greenhouse Gas Reduction Standard described in the *CleanBC Roadmap to 2030*?

<u>Response:</u>

Yes. As discussed in Sections 4.5.1 and 9.2.1, as well as illustrated in Figure 9-1, of the Application, FEI's modelling of GHG emission reductions for the DEP Scenario meets the Province's planned GHGRS cap. As described in Section 9.2.1, FEI expects to reduce residential, commercial and industrial customer group emissions through changes in demand (before DSM), reductions in demand as a result of DSM, the transition to a renewable and low-carbon gas supply, and additional actions that are currently underway.

13.0 Topic: DSM

Reference: Exhibit B-1, Section 5, Demand Side Resources, pdf 181

On page 5-2 of the Application, FEI states:

> "As FEI does not construct its own energy generation resources, FEI's DSM analysis does not weigh the cost of DSM against the need for procuring or constructing upstream energy generation resources to meet demand growth. Instead, FEI's DSM analysis primarily seeks to establish an adequate and cost-effective level of DSM activity and explore the extent to which the peak demand implications of such DSM activity may defer FEI's requirements for downstream infrastructure. <u>To the extent that decarbonization initiatives lead FEI to produce renewable and low-carbon gas, such as for RNG and hydrogen, the benefits of DSM activities in reducing the need for additional upstream energy generation may be considered in upcoming LTGRP filings."</u> [B-1, pdf 181, underline added]

13.1 Please further explain the underlined sentence.

<u>Response:</u>

Currently, the benefits of DSM are calculated based on the avoided cost of energy and carbon from acquiring conventional gas from existing upstream market sources and avoided distribution costs. As larger components of FEI's gas supply transition from conventional gas to renewable and low-carbon energy sources, the incremental acquisition of gas switches from existing conventional sources to new low-carbon energy production. Thus, DSM may begin to offset the costs to acquire new renewable and low-carbon energy production, which is valued differently than conventional gas. This shift will be more akin to the way that DSM is measured against the need to build or buy electricity generation in electric integrated resource planning. As with electricity, the cost of infrastructure to transport these new gas supplies will also need to be included. While this transition has not yet advanced sufficiently to include in the time frame of the Application, it may need to be considered as a part of future LTGRPs.

13.2 Please confirm, or otherwise explain, that when FEI says "FEI to <u>produce</u> renewable and low-carbon gas, such as for RNG and hydrogen" this means FEI's <u>acquisition</u> of renewable and low-carbon gas, i.e., including purchases.

<u>Response:</u>

Not confirmed. Acquisition of renewable and low-carbon gas includes production and purchases. Producing renewable and low-carbon gas means FEI is generating these gases, likely within a partnership, through an on-system facility. In the same way that electric utilities currently have the option to buy or build electricity generation resources, FEI anticipates it will have the option to buy or build renewable and low-carbon gas generation resources, and that there would be different considerations for building resources as discussed in the response to BCSEA IR1 13.1.

13.3 When FEI says “additional upstream energy generation,” does this mean the upstream production and transportation of conventional natural gas, or of all types of pipeline gases?

Response:

In the referenced underlined section, the wording “additional upstream energy generation” refers to the upstream production and transportation of renewable and low-carbon gases. Please also refer to the response to BCSEA IR1 13.2.

13.4 Does FEI anticipate that the avoided cost of energy for DSM cost-effectiveness assessment will be based on the marginal cost of Renewable Gas under the requirements of the anticipated Greenhouse Gas Reduction Standard described in the *CleanBC Roadmap to 2030*?

Response:

FEI considers that the avoided cost of energy for DSM cost-effectiveness could be based on the marginal cost of renewable and low-carbon gas but is unable to comment at this time on future provincial regulation changes that may impact DSM cost-effectiveness, including changes to the Demand-Side Measures Regulation and the expected GHGRS described in the CleanBC Roadmap to 2030.

FEI continues on page 5-2:

> “In prior LTGRP submissions and in more traditional DSM modelling approaches, the savings of each additional unit of energy saved would be treated equally. However, in this LTGRP, where FEI is transitioning to renewable and low-carbon gas, the software model was designed to prioritize reducing conventional natural gas. Although the ability to apply DSM savings equally to all fuel types is discussed in the 2022 LTGRP, the analysis could not be completed in time for the 2022 LTGRP submission date since such analysis will require reconfiguring the software. The decision was made early in the LTGRP planning process, that the

priority for DSM in this model was to focus on energy savings to reduce GHG emissions. As an artifact of the logic in these models, the analysis may show curtailed DSM expenditures after 2030 as the proportion of renewable and low-carbon gas increases and natural gas declines. This is not demonstrated in the Reference Case due to the higher proportion of natural gas. FEI will assess updating the model for the next LTGRP, which will result in DSM savings being applied proportionally to all fuel types including renewable and low-carbon gas, so that savings will not be curtailed as the conventional gas share decreases." [pdf p.181, underline added]

13.5 Please explain more fully the function of the software model referred to in the quoted paragraph. What are the outputs of the model?

Response:

The following response has been provided by Posterity Group.

About the End Use Model used for the LTGRP Demand Forecasting

The load forecasts and analysis are conducted using Posterity Group's Navigator™ Energy and Emissions Simulation Suite ("Navigator"). Navigator is an end-use model that uses a "bottom up" approach to forecasting. It starts with granular information about how energy is used at the end-use level (e.g., how natural gas is used to heat a home) and builds on this data to describe how energy is used at the segment (e.g. detached homes), sector (e.g. residential), regional (e.g. Vancouver Island) and provincial level (e.g. BC). Navigator models are sector-based to reflect the unique way energy is used and regulated. Within each sector-model, the data (inputs and outputs) are divided up by rate class, region, segment (i.e., sub-sector), vintage, and end-use. Please see section 4.4.1.2 of the Application for more information as to why FEI uses an end use model to conduct demand forecasting.

The DSM Modelling Method for the LTGRP Scenarios

The amount of energy conservation potential estimated for each LTGRP scenario varies based on:

- The policy and economic conditions assumed in each scenario (reflected by the settings used for the Critical Uncertainties in each scenario); and,
- The DSM setting applied to the scenario.

The policy and economic conditions in a scenario affect the estimate of energy savings potential in the following ways:

- The number of building units to which a measure is applicable vary from one scenario to another because of differences in the number of new building units being constructed and differences in the fuel share for the end use(s) to which the measure applies. More new construction means more potential for measures applicable to new buildings. Decreased gas fuel share for an end use means less potential for measures applicable to that end use.

- The savings potential for a measure may change because the unit energy consumption (pre-DSM) may be different from one scenario to another. For example, more aggressive improvements in insulation or furnace efficiency as part of an advanced carbon policy scenario will mean less energy savings potential for advanced thermostats in the DSM estimate.
- The avoided cost of fossil-based natural gas varies from one scenario to another. Higher avoided costs for natural gas, due to commodity cost increases or higher carbon price, results in more measures passing the TRC and UCT tests. Note that this mechanism does not affect the MTRC results, as MTRC uses the zero-emissions energy alternative avoided cost, rather than the natural gas avoided cost.
- Reference adoption may vary between scenarios for specific measures that are affected by more advanced codes or standards.
- Avoided cost tends to drive retail rates in the long run.[4] Therefore, in the scenarios where avoided costs change, the retail rates are assumed to change in proportion. Higher retail rates make measures more attractive to the end user, because the simple payback after incentive will be shorter. This is assumed to increase program uptake.

For the Application, the energy conservation measures from the 2021 CPR are used as follows:

- For 2022, the bundle of measures that pass/fail the economic screening tests specified in the scenario, using the scenario-specific avoided costs for the tests, are applied.
- Adoption rates are adjusted to reflect the economic condition in each scenario (i.e., carbon price, gas price, retail rates, etc.)
- Energy savings potential is estimated for the built-environment sectors (residential, commercial and industrial).[5]
- The energy savings potential calculated for each scenario results in a change in previously modelled annual demand and GHG emissions for each scenario.

For each scenario, the following steps were taken to calculate energy savings potential:

1. **Create a DSM baseline** based on the scenario input assumptions including customer account growth, the level of fuel switching (price and policy drive), the stringency of codes and standards, etc. by closely matching the assumptions in the CPR's reference case.[6]

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[4] Avoided costs and retail rates do not move in lockstep, but we assume that, on average, any regulated utility will be permitted to recover the cost of energy in the rates they charge.

[5] DSM potential is not applied to the natural gas transportation or LNG export sectors, as DSM programs do not apply to those customers.

[6] The LTGRP reference case includes all currently expected step code advancements in the residential and commercial building codes, and so has slightly lower reference case consumption than the CPR reference case in the residential and commercial sectors. The *Demand-Side Measures Regulation* under the BC *Utilities Commission Act* allows the benefit of demand-side measures to be assessed as "what it would have been had no step code

2. **Apply all CPR measures** to the DSM baseline.
3. **Calculate technical potential** using applicability and reference case adoption rates which are adjusted for prices of energy in the scenario.
4. **Calculate economic potential** based on the economic screen used in the DSM Setting applied to the scenario and the avoided costs in the scenario.
5. **Calculate market potential** based on the participation rate (i.e., measure uptake).
6. **Incorporate program costs** using the same assumptions as the 2021 CPR. These assumptions include three incentive levels (25%, 50%, and 100% of measure incremental costs, as specified in the applicable DSM Budget Setting) and non-incentive program costs that are assumed to be 15% of the corresponding incentive costs.
    a. ***For the Deep Electrification scenario only: Iterate to find the optimal solutions of measures that meet the program budget**:* The model solves for an economic screening threshold in each year that allows just enough measures to pass the screen so that the program spending is below a specified limit for that year. This approach was required for the "Taper Off" DSM setting which was applied only to the Deep Electrification scenario. All other scenarios use the spending value that is calculated from implementing all the measures that pass the screening with no budget limit imposed.
7. **Apply the energy savings potential to annual demand. The savings are subtracted from the DSM baseline to get the resulting annual demand, and associated GHG emissions.**

<u>Calculating Participation in DSM Programming based on Fuel</u>

For the Application, the DSM-module of the model was designed to calculated participation in DSM programs based only on the volume of conventional natural gas each year. This means that scenarios with higher volumes of low-carbon and renewable gas supply have lower DSM savings because there are lower levels of participation. This is the approach used in the 2021 CPR

As stated in section 5.1 of the Application, FEI is aware that the DSM modelling method may need to be revised as FEI transitions to have more renewable and low-carbon gas on the system. However, the method described above was used as it continues to focus on energy savings that reduce GHG emissions and there was not enough time to revise the modelling software.

Model Outputs

The Navigator model outputs files in CSV format. There is one file per sector and fuel (e.g., Residential-Electricity, Industrial-RNG, etc.). Output is provided in annual values for the forecast period. The following outputs were provided by the model for each sector (residential,

been adopted in the Province." For this reason, step code levels were included as measures in the CPR, rather than included in the CPR reference case.

commercial, industrial, and LCT/LNG Export Demand) and fuel (natural gas, hydrogen, RNG, CCUS, and syngas and lignin):

- Consumption by rate class, region, segment, and end use.
- Greenhouse gas emissions (CO2e) by rate class, region, segment and end use.
- Number of customer accounts by rate class, region and segment.
- DSM Potential Savings by measure, rate class, region, segment and end use. DSM savings are provided for technical, economic and market potential.
- DSM Potential Consumption (i.e., resulting annual consumption after the DSM savings are applied) by rate class, region, segment and end-use. DSM potential consumption are provided for technical, economic and market potential.
- DSM screening results by test including TRC, mTRC, UCT, CCE, and customer payback.
- Energy costs including:
    - Avoided Energy cost of energy for a given rate class, region, segment, and fuel.
    - MTRC Avoided Energy Cost for a given rate class, region, segment, and fuel.
    - Retail Energy Cost for a given rate class, region, segment, and fuel.
- Program costs including:
    - Incentive Cost: spending required to achieve the savings for the measure, for a given rate class, region, segment and potential group (technical, economic and market).
    - Non-Incentive Cost: non-incentive spending required to achieve the savings for the measure, for a given rate class, region, segment and potential group (technical, economic and market).

13.6 How was the software model designed to prioritize reducing conventional natural gas? Does the model pick different DSM measures according to the GHG emissions reductions on a per GJ basis? Is the model able to choose between DSM measures according to the carbon intensity of the saved energy?

Response:

The following response has been provided by Posterity Group.

How was the software model designed to prioritize reducing conventional natural gas?

The response to this question begins with some background on how DSM potential is calculated in the model and the steps taken to generate the potential saving estimates for each scenario.

The amount of energy conservation potential estimated for each scenario varies based on:

- The policy and economic conditions assumed in each scenario (reflected by the settings used for the Critical Uncertainties in each scenario); and,
- The DSM setting applied to the scenario.

The policy and economic conditions in a scenario affect the estimate of energy savings potential in the following ways:

- The number of building units to which a measure is applicable vary from one scenario to another because of differences in the number of new building units being constructed and differences in the fuel share for the end use(s) to which the measure applies. More new construction means more potential for measures applicable to new buildings. Decreased gas fuel share for an end use means less potential for measures applicable to that end use.
- The savings potential for a measure may change because the unit energy consumption (pre-DSM) may be different from one scenario to another. For example, more aggressive improvements in insulation or furnace efficiency as part of an advanced carbon policy scenario will mean less energy savings potential for advanced thermostats in the DSM estimate.
- The avoided cost of conventional natural gas varies from one scenario to another. Higher avoided costs for natural gas, due to commodity cost increases or higher carbon price, result in more measures passing the Total Resource Cost (TRC) and Utility Cost (UCT) tests. Note that this mechanism does not affect the Modified Total Resource Cost (MTRC) results, as MTRC uses the zero-emissions energy alternative avoided cost, rather than the natural gas avoided cost.
- Reference adoption may vary between scenarios for specific measures that are affected by more advanced codes or standards.
- Avoided cost tends to drive retail rates in the long run.[7] Therefore, in the scenarios where avoided costs change, the retail rates are assumed to change in proportion. Higher retail rates make measures more attractive to the end user, because the simple payback after incentive will be shorter. This is assumed to increase program uptake.

Incentive levels and economic screening criteria also affect the savings potential in each scenario. DSM 'settings' were developed using combinations of three variables:

- Measure incentive levels (50 or 100 percent of each measure's incremental cost). In general, higher incentives drive higher participation in DSM.
- The economic screens (MTRC, UCT or TRC) that determine which measures are included in the analysis.

[7] Avoided costs and retail rates do not move in lockstep, but we assume that, on average, any regulated utility will be permitted to recover the cost of energy in the rates they charge.

- Overall budget limitations (including both incentive spending and non-incentive program spending).

Various combinations of these variables were used to create five DSM settings, which were then applied to the individual scenarios.

Exhibit 1: DSM Settings

DSM Setting	"Taper Off"	"Low"	"Medium UCT"	"Medium"	"High"
Description	Assumes DSM spending tapers off as the province electrifies	Constrained to include only the most cost-effective measures. Only 50% incentive level is used, and measures must pass TRC > 1 (no MTRC).	Any incentive level is permitted, but measures must pass UCT > 2 and MTRC or TRC >1. This represents more efficient budget spending.	Similar to the 2021 CPR's medium market potential scenario where adoption of measures is based on incentives covering 50% of a measure's incremental cost	Similar to the 2021 CPR's high market potential scenario where adoption of measures is based on incentives covering 100% of a measure's incremental cost
Incentive Level Setting	Any incentive level is permitted	50% of measure incremental cost	Any incentive level is permitted	50% of measure incremental cost	100% of measure incremental cost
Economic Screen Setting	Passes either TRC>1 or MTRC>1	Passes TRC>1	Passes TRC>1 or MTRC>1 and UCT>2	Passes TRC>1 or MTRC>1	Passes TRC>1 or MTRC>1
Budget Setting	Budget limited to 50% of 2022 spending in 2023, declining to 25% of 2022 spending by 2042	No budget limit applied	No budget limit applied	No budget limit applied	No budget limit applied

One of the five DSM settings was prescribed for each scenario, as per Exhibit 37, below.

Exhibit 2: DSM Settings in Each Scenario

Scenario	DSM Setting
Reference Case	Medium
Diversified Energy Planning	High (sensitivity conducted with Low, Medium, and Medium UCT settings)
Deep Electrification	Taper Off
Price-Based Regulation	Medium UCT
Economic Stagnation	Medium
Lower Bound	High DSM
Upper Bound	NA – no DSM

For the Application, the energy conservation measures from the 2021 Conservation Potential Review (CPR) are used as follows:

- For 2022, the bundle of measures that pass/fail the economic screening tests specified in the scenario, using the scenario-specific avoided costs for the tests, are applied.
- Adoption rates are adjusted to reflect the economic condition in each scenario (i.e., carbon price, gas price, retail rates, etc.)
- Energy savings potential is estimated for the built-environment sectors (residential, commercial and industrial).[8]
- The energy savings potential calculated for each scenario results in a change in previously modelled annual demand and GHG emissions for each scenario.

For each scenario, the following steps were taken to calculate energy savings potential:

1. **Create a DSM baseline** based on the scenario input assumptions including customer account growth, the level of fuel switching (price and policy drive), the stringency of codes and standards, etc. by closely matching the assumptions in the CPR's reference case.[9]
2. **Apply all CPR measures** to the DSM baseline.
3. **Calculate technical potential** using applicability and reference case adoption rates which are adjusted for prices of energy in the scenario.
4. **Calculate economic potential** based on the economic screen used in the DSM Setting applied to the scenario and the avoided costs in the scenario.

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[8] DSM potential is not applied to the natural gas transportation or LNG export sectors, as DSM programs do not apply to those customers.

[9] The LTGRP Reference Case includes all currently expected step code advancements in the residential and commercial building codes, and so has slightly lower reference case consumption than the CPR reference case in the residential and commercial sectors. The *Demand-Side Measures Regulation* under the BC *Utilities Commission Act* allows the benefit of demand-side measures to be assessed as "what it would have been had no step code been adopted in the Province." For this reason, step code levels were included as measures in the CPR, rather than included in the CPR reference case.

5. **Calculate market potential** based on the participation rate (i.e., measure uptake).
6. **Incorporate program costs** using the same assumptions as the 2021 CPR. These assumptions include three incentive levels (25, 50, and 100 percent of measure incremental costs, as specified in the applicable DSM Budget Setting) and non-incentive program costs that are assumed to be 15 percent of the corresponding incentive costs.
   a. ***For the Deep Electrification scenario only: Iterate to find the optimal solutions of measures that meet the program budget**:* The model solves for an economic screening threshold in each year that allows just enough measures to pass the screen so that the program spending is below a specified limit for that year. This approach was required for the "Taper Off" DSM setting which was applied only to the Deep Electrification scenario. All other scenarios use the spending value that is calculated from implementing all the measures that pass the screening with no budget limit imposed.
7. **Apply the energy savings potential to annual demand. The savings are subtracted from the DSM baseline to get the resulting annual demand, and associated GHG emissions.**

With that background, to address this question, the Application used the measure input data developed for the 2021 CPR, which were based around savings of conventional natural gas and did not contemplate significant replacement of that fuel with other gaseous fuels. Because the software version used for the LTGRP model did not include the capability to save a blend of fuels, the input data would have had to be completely reworked to approximate the savings of the other gaseous fuels. Rather than undertaking that rework, the modelers compensated for the fuel mixture by inflating the measure participation rates by the ratio of (all gaseous fuels) / (conventional natural gas). The intent was for each measure to save an amount of gas based on the total gaseous fuels supplied, but to have all the savings applied to the conventional natural gas.

This was partially effective. DSM did successfully target the conventional natural gas, and to some extent the savings were increased to compensate for the fuel blend. Unfortunately, in scenarios with higher volumes of low-carbon and renewable gas supply, the DSM savings were somewhat lower because the ratios applied to participation rates were not sufficient to compensate fully for the fuel blend effect.

As stated in Section 5.1 of the Application, FEI is aware that the DSM modelling method may need to be revised as FEI transitions to have more renewable and low-carbon gas on the system. However, for this Application the method described above was used as it does focus on energy savings that reduce GHG emissions and was the best option given the limitations of the software. Since the completion of the Application, the Navigator software has undergone some revisions and now includes a feature to apply DSM measures to a blend of fuels. The next LTGRP will be able to use this new feature.

Does the model pick different DSM measures according to the GHG emissions reductions on a per GJ basis?

No. The bundles of DSM measures applied to each scenario are based on A) the policy and economic conditions in each scenario (dictated by the settings for each Critical Uncertainties applied to the scenario); and B) the DSM setting applied to the scenario. The details of how measures included in the DSM analysis were incorporated into the scenarios is provided above.

In most scenarios, the two economic screens used to determine whether a measure was chosen for inclusion were the TRC and MTRC tests. In the TRC test, the carbon costs are embedded in the avoided costs of each fuel, so certainly measures that save more of a high carbon fuel will be more likely to pass the test. The MTRC test used an avoided cost based on a Zero-Emissions Energy Alternative (ZEEA) fuel, which was a higher cost than the costs used in the TRC test, even with carbon costs embedded. This had the effect of prioritizing the reduction of conventional natural gas even more than the carbon pricing embedded in the fuel cost.

Future versions of the software will allow DSM measures to be evaluated based on their cost of carbon reduction, in dollars per tonne of CO_2e, but this capability was not yet available for the Application. It is expected to be available for the next LTGRP.

Is the model able to choose between DSM measures according to the carbon intensity of the saved energy?

No. The bundles of DSM measures applied to each scenario are based on A) the policy and economic conditions in each scenario (dictated by the settings for each Critical Uncertainties applied to the scenario); and B) the DSM setting applied to the scenario. The details of how measures included in the DSM analysis were incorporated into the scenarios is provided above. As discussed in the response to the previous question, the use of the MTRC test with a ZEEA-based avoided cost for the conventional natural gas saved does have the effect of prioritizing savings of natural gas. Since conventional natural gas is the highest-carbon fuel being saved by the measures, the model is effectively prioritizing savings of that fuel, because of the cost assigned to it in the MTRC test.

13.7 What DSM measures did the model de-prioritize because of limited GHG emissions reductions associated with the energy savings?

<u>Response:</u>

The following response has been provided by Posterity Group.

No measures were specifically de-prioritized. There are three main modeling choices that cause certain types of DSM to be lower priority than others:

- Any measure that can save (i.e., reduce) conventional natural gas could also save any of the other gaseous fuels delivered through the same pipe. Because the software version used for the modeling could not save a blend of fuels, and the effort to reconfigure the measure inputs to save the other gaseous fuels would be very large and challenging to do accurately, the measures were not applied to these other fuels. Instead, it was assumed that DSM that could save any gaseous fuels would only reduce the acquisition of conventional natural gas. Instead of reducing the use of all gaseous fuels, the measures would have the effect of decreasing the proportion of conventional natural gas in the blend, and the acquisition of the lower-carbon fuels would be unchanged from FEI's plans.
- The use of the MTRC test, with an avoided cost based on a ZEEA for the natural gas saved, has the effect of placing a very high value on gas savings. Measures that save natural gas will be much more likely to pass the economic screen than they would have been with only the TRC test.
- The economic screening tests account for the savings of electricity in cases where a measure saves both electricity and gaseous fuels. Most building envelope measures, for example, save both space heating and space cooling, so electricity savings are a factor. Because the avoided cost of electricity tends to be higher than that of natural gas (even with the currently planned carbon pricing), normally the TRC test would prioritize measures that save a lot of electricity relative to their gas savings. The MTRC, with the ZEEA avoided costs, reduces the disparity between the avoided cost of electricity and that of natural gas. This has the effect of reducing the priority placed on measures that save electricity and increasing the priority placed on those that save natural gas. That said, there are no measures that failed the economic screen because of the use of the ZEEA. Electricity's avoided costs were not reduced, so nothing that passed before would suddenly fail the test. Measures saving a lot of natural gas are more likely to pass, but measures saving a lot of electricity still pass the screen if they did before.

13.7.1 In particular, did the model avoid picking DSM measures that would reduce energy use by new customers who would receive 100% RNG under the proposed (but not yet approved) Connecting Customers program?

Response:

The following response has been provided by Posterity Group.

No, the model did not do that. The model did not separate out these customers from the other customers, but instead treated the portfolio of fuels as a blend for all customers. Measure savings were applied only to conventional natural gas, but participation was inflated by multiplying by the ratio of total gaseous fuels to conventional natural gas. Any reductions in gas use were assumed to cause a reduction in conventional natural gas acquisition and leave the acquisition of low-carbon gaseous fuels unchanged from the plan.

In practice, no assumptions were made about who would be eligible for DSM programs. It was assumed that any DSM achievements, no matter what gases that customer used, would have the effect of reducing the amount of conventional gas in the portfolio and increasing the proportion of low-carbon gaseous fuels.

13.8 Is the prioritization of reducing conventional natural gas considered a substantive element of the 2022 LT DSM Plan?

Response:

The following response has been provided by Posterity Group.

No, the prioritization of natural gas over other fuel types in the DSM analysis was not a substantive element of the Application, but rather indicative of the rapidly changing policy environment that occurred over the 2019 to 2022 timeframe when the Application was developed. Early in the development stage, the decision was made to prioritize natural gas in DSM scenarios as the expectation at that time was a DSM focus on GHG reductions. However, as the magnitude of the supply of renewable and low-carbon gases in the DEP Scenario was more fully realized in the later development stages, the analysis resulted in some curtailed DSM expenditures after 2030 as an artifact of the logic in the models. Posterity Group made some adjustments to the model outputs to try to minimize the effects.

Please refer to the response to BCUC IR1 44.1 for information on upgrades to the modelling software such that DSM will be enabled for a blend of fuel types for the next LTGRP.

14.0 Topic: DSM – avoided cost

Reference: Exhibit B-1, s. 5.3.4, paragraph number, second bullet, pdf 191; Demand-Side Management Regulation, s. 4(1.1)(a)

FEI states:

> "The avoided cost of conventional natural gas varies from one scenario to another. Higher avoided costs for natural gas, due to commodity cost increases or higher carbon price, results in more measures passing the TRC and UCT tests. Note that this mechanism does not affect the MTRC results, as MTRC uses the Zero-Emission Energy Supply Alternative avoided cost, rather than the natural gas avoided cost"

The Demand-Side Measures Regulation, s.4(1.1)(a), states:

> "subject to subsections (1.2) and (1.3), the avoided natural gas cost, if any, respecting a demand-side measure, in addition to the avoided capacity cost, is the amount that the commission is satisfied represents the authority's long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia;"

The DSM Regulation, s.4(1.2), states:

> "Subsection (1.1)(a) does not apply to a demand-side measure that reduces the use of natural gas but does not reduce greenhouse gas emissions associated with that use of natural gas."

The DSM Regulation, s.4(1.3), states:

> "Subsection (1.1)(a) and (b) does not apply to a demand-side measure that encourages a switch from the use of oil or propane to the use of natural gas or electricity such that the switch would decrease greenhouse gas emissions in British Columbia."

14.1 Please identify the DSM measures for which FEI uses the Zero-Emission Energy Supply Alternative avoided cost and the DSM measures for which FEI uses avoided gas cost.

Response:

The following response has been provided by Posterity Group.

The DSM measures that are included in the Application's DSM analysis are illustrated in Tables 1 and 2 below for the DEP Scenario with the High DSM Setting. Table 1 provides the list of measures that were included based on passing the TRC. In the Application, this test is based on using the avoided cost of the next GJ of renewable or low-carbon gas, including applicable carbon price. Table 2 provides the list of additional measures that pass the MTRC using ZEEA as the avoided cost. The combined list would be used in the DEP Scenario High DSM Setting.

Under the current DSM Regulation, there is a 40 percent limit on the proportion of expenditures that can be contributed by measures or programs that require the MTRC to be cost-effective. In the DEP Scenario DSM analysis with the High DSM Setting beginning in 2030, expenditures are for measures with TRC greater than 1 and therefore require the MTRC to be cost-effective and exceed 40 percent of the DSM portfolio. As a result of the proposed GHGRS, for the purposes of this long-term forecasting exercise, and due to the modeling complexity of having to impose an MTRC cap for each year, sector and applicable scenario as an iterative process, FEI considered that allowing a scenario where there is no MTRC cap imposed was the best approach. If, in developing future detailed DSM Expenditures Plans, portfolio results exceed the 40 percent MTRC limit, FEI would require a change in the MTRC cap limit to achieve these savings.

In most scenarios, both tests were conducted, so both costs were used for every measure. Measure lists will vary for different scenarios, based on the assumptions in the applied DSM setting. In scenarios in which the DSM settings were based on measures only passing the TRC test, such as the Low DSM Setting, the measure list would resemble Table 1. In scenarios in which the DSM settings were based on measures passing either the TRC or the MTRC test, the measure list would resemble the combined set of Tables 1 and 2.

Table 1*:* Measures Included Based on TRC Using Gas as the Avoided Cost

1a. Residential Measures

Measures Passing the TRC
Residential
Attic Duct Insulation
Attic Insulation (R-12.6 Baseline)
Basement or Crawlspace Insulation
Combination System - Type 1 and 2
Communicating Thermostat
ENERGY STAR Dishwasher
Faucet Aerator
Fireplace Timer
High Efficiency (EnerChoice) Gas Fireplace or Vertically Direct Vented Fireplace
High Efficiency (ENERGY STAR) Clothes Washer
High Efficiency (ENERGY STAR) Gas Clothes Dryer
Home Energy Report
Low Flow Showerhead
Pipe Wrap
Wall Insulation - Cavity (R-3 baseline)

1b. Commercial Measures

Measures Passing the TRC
Commercial
Advanced Thermostat
Air Curtain
Air Sealing
Building Energy Report
Boiler or Furnace Tune-Up
Boiler Combination Controls
Boiler Cycling Controls
Boiler Zoning Controls
Comprehensive Recommissioning
Condensing Boiler (Early Replacement)
Condensing Boiler (Replace On Burnout)
Condensing On-Demand Direct Contact Hot Water Heater
Condensing Storage Direct Contact Hot Water Heater
Condensing Supply Boiler
Condensing Unit Heater
Condensing Make-up Air Unit (Replace On Burnout)
Direct Control Kitchen Vent
Hot Water Tank Insulation
Dock Door Seal
Direct Vent Fireplace
Efficient Pre-Rinse Spray Valve
Efficient Cooking Equipment
Energy Recovery Ventilator
ESTAR Dishwasher
Faucet Aerators
Gas Heat Pump - Combination System
Hotel Controls
Heat Recovery Chiller
Heat Recovery Ventilation
Infrared Heaters
Low Flow Showerhead
New Construction Step 2 - Commercial Building
New Construction Step 2 - Non Step Code Building
New Construction Step 2 - Multi-Unit Residential Building
New Construction Step 3 - Commercial Building
New Construction Step 3 - Non-Step Code Building
New Construction Step 3 - Multi-Unit Residential Building
Occupant Behaviour
Passive Domestic Water Heater Recovery
Recirculation Demand Control
Refrigeration Heat Recovery
Reverse Flow Energy Recovery Ventilator
Rooftop Unit Controls
Solar Preheat
Steam to Hot Water
Steam Trap
Strip Curtains
Window Film

1c. Industrial Measures

Measures Passing the TRC
Industrial
Advanced Thermostats
Advanced Veneer Dryer
Air Compressor Heat Recovery (Process Heating)
Air Compressor Heat Recovery (Space Heating)
Air Curtain
Boiler Right-Sizing
Boiler Tune-Up
Combustion Testing
Condensing Boiler
Condensing Mke-Up Air Unit
Condensing Unit Heaters
Direct Contact Hot Water Heater
Economizer
Energy Management
Furnace Retrofit
Greenhouse Curtains
Greenhouse Envelope
Heat Recovery Systems
High Efficiency Burners
High Efficiency Dryers
High Efficiency Kilns
High Efficiency Ovens
High Efficiency Roof Top Unit Controls
HVAC Boiler Tune Up
HVAC Ventilation Optimization
Improved Condensate Return (Retrofit)
Integrated Greenhouse Environmental Controls
Loading Dock Seals
Pipe Insulation
Process Boiler Load Control
Process Control
Regenerative Catalytic Oxidizer
Replace Steam Traps
Solar Wall
Tank Insulation
Venturi Steam Trap

Table 2: Additional Measures Included Based on MTRC Using ZEAA as the Avoided Cost

2a. Residential Measures

Additional Measures Passing the MTRC
Residential
Air Source Heat Pump (Central) - New Gas Furnace
Air Source Heat Pump (Central) - Retrofit Existing Gas Furnace
Attic Insulation (R-20 Baseline)
Boiler (Early Retirement)
Boiler Reset Controls
Combination System - Type 1 and 2 (Early Retirement)
Combination System - Type 3
Comprehensive Air Sealing
Comprehensive Draft Proofing
Drain Water Heat Recovery
Exposed Floor Insulation
Furnace Early Retirement
Gas Heat Pump - Domestic Hot Water - (Mature Market Costs)
Gas Heat Pump - Space Heating
Gas Heat Pump Combination System - Type 1 and 2
High Efficiency Boiler
High Efficiency Boiler Dual Fuel-Gas Primary
High Efficiency Furnace
High Efficiency Furnace Dual Fuel-Gas Primary
High Quality Furnace Installation - ENERGY STAR Verified
High-Efficiency (ENERGY STAR) Condensing Gas Tankless Water Heater - Mature Market Costs
High-Efficiency Heat Recovery Ventilator
High-Efficiency Storage Gas Water Heater
HVAC Zoning (HVAC Zone Control)
Manufactured Homes - Duct Sealing
Manufactured Homes - Floor Insulation
New Construction - Step 3 Homes
New Construction - Step 3 Homes - Electric Water Heating
New Construction - Step 4 Homes
New Construction - Step 4 Homes - Electric Water Heating
New Construction - Step 5 Homes
New Construction - Step 5 Homes - Electric Water Heating
New Construction - Step 5 Homes - Mature Market Costs
Outdoor Pool Cover
Solar Pool Heater
Thermostatic Restrictor Shower Valve
Wall Insulation - Cavity (R-10 baseline)
Wall Insulation - Sheathing (R-7 baseline)

2b. Commercial Measures

Additional Measures Passing the MTRC
Commercial
Advanced Buiding Automation System (BAS)
Condensing Make-Up Air Unit (Early Replacement)
Destratification Fan
Destratification Fan (Early Replacement)
Destratification Fan (Replace on Burnout)
ESTAR Clothes Washer
Heat Transfer Technology
Indoor Pool Cover
New Construction Step 4 - Non-Step Code Buildings
New Construction Step 4 - MURB
Residential Furnace (Early Replacement) in Small Commercial Buildings
Residential Furnace (Replace on Burnout) in Small Commercial Buildings
Roof Insulation
Solar Hot Water Pool Heater
Sterilizer Heat Recovery
Submetering
Thermostat Shower Valve
Vortex De-Aerators
Wall Insulation
Window Upgrade

2c. Industrial Measures

Additional Measures Passing the MTRC
Industrial
Destratification Fan
Steam to Hot Water Conversion (District Energy)

14.2 What avoided cost of energy and avoided cost of capacity do the 2021 CPR and FEI use?

Response:

The following response has been provided by FEI with contribution from Posterity Group.

For the avoided cost used to calculate the TRC, please refer to Table 2 in FEI's response to BCUC IR1 35.1. For the avoided cost (ZEEA) used to calculate the modified TRC, please refer to Table 3 in FEI's response to BCUC IR1 35.1.

14.3 In analyzing the benefit-cost ratios for the 2022 LT DSM Plan, how does the forecast cost of gas commodity change over the planning horizon as more RNG is mixed into FEI's system?

Response:

The following response has been provided by Posterity Group in consultation with FEI.

In all scenarios, the avoided cost used in the TRC test is the marginal cost of additional renewable or low-carbon gas supply. The avoided cost varies according to the forecast marginal cost of renewable or low-carbon gases, but does not vary based on their share of the gas supply, because it is a marginal cost, not an average cost. The majority of scenarios, however, use a DSM setting in which a measure is included if it passes either the TRC or the MTRC test. The only scenario in which measures were required to only pass the more stringent TRC test was the Low DSM Setting used in the DEP Scenario.

There were no scenarios in which the marginal cost of renewable or low-carbon gases rose to the point where their avoided cost was greater than the ZEEA. In summary, the MTRC was the dominant determination of whether a measure was cost-effective. In the scenarios considered, therefore, the RNG cost did not affect the cost-effectiveness of individual measures. Even in scenarios that only used the TRC test, it was the marginal cost of RNG that affected cost-effectiveness, not its proportion in the blend of fuels. Therefore, there were no changes to the list of measures included in the economic screening process as the proportion of renewable and low-carbon gas increased over the planning period.

14.4 Does the 2021 CPR's analysis address potential changes in energy prices during the 2022 LTGRP's planning horizon? If not, how does FEI factor this into its DSM analysis?

Response:

The following response has been provided by Posterity Group in consultation with FEI.

The 2021 CPR used an assumed trajectory for changes in energy prices over time, including a gradual rise in the commodity cost of natural gas. There was no assumed change in the cost of electricity.

14.5 Topic: DSM

Reference: Application, Exhibit B-1, Table 5-3: DSM Settings, p.5-11, pdf p.190

Please explain how the different DSM Settings were matched to the different scenarios.

Response:

The following response has been provided by FEI in consultation with Posterity Group.

Please refer to Table 2 in the response to BCUC IR1 70.1 that illustrates the choice of DSM setting applied to each scenario and the assumptions regarding the choice of the setting. DSM settings are described in Table 5-3 in the Application and were applied to each scenario according to alignment with the scenario narrative described in Table 4-1 in the Application. The DSM analysis then estimates the potential impact of DSM programs by tailoring the results of the 2021 CPR to the economic and policy considerations reflected in each scenario.

14.6 Does the Taper Off DSM Setting as applied to the Deep Electrification scenario result in the same amount of DSM spending and savings per unit of gas throughput on FEI's system as the High DSM Setting as applied to the Diversified Energy (Planning) scenario? If not, please discuss the reasons for this.

Response:

The following response has been provided by Posterity Group in consultation with FEI.

No. The Taper Off DSM Setting as applied to the Deep Electrification Scenario results in a lower amount of DSM expenditures and savings per unit of gas throughput than the High DSM Setting in the DEP Scenario. The data extracts in Table 1 and the calculations in Table 2 below support this conclusion. The calculations illustrated for the year 2030 follows:

- In terms of energy savings: the Deep Electrification Scenario resulted in energy savings of 0.048 PJ per PJ of throughput while the DEP Scenario resulted in energy savings of 0.057 PJ per PJ of throughput; and

- In terms of DSM expenditures: the Deep Electrification Scenario resulted in expenditures of $0.17 million per PJ of throughput while the DEP Scenario resulted in expenditures of $0.58 million per PJ of throughput.

The main reasons for the higher level of DSM activity per PJ of piped fuel throughput for the DEP Scenario are the following:

- The Deep Electrification Scenario reduces DSM potential because the pre-DSM consumption of gas available for DSM is much lower;
- The High DSM Setting used in the DEP Scenario applies incentives equal to 100 percent of each measure's incremental costs, causing relatively high program participation, and places no limit on DSM program budgets. The Taper Off DSM Setting used in the Deep Electrification Scenario allows any incentive, but places limits on the DSM budgets, tapering the budgets off towards the end of the forecast period since In this scenario, electrification is the chosen pathway to decarbonization and, with costs to maintain the gas system rising due to decreasing demand, the scenario reasons that placing additional cost burdens of DSM activities on remaining customers will also diminish over the planning horizon. A limit on DSM spending results in a reduction in the savings that can be achieved;
- Customer growth in the Deep Electrification Scenario is set to the low setting, whereas the DEP Scenario uses the reference customer growth setting. Fewer customers reduces the scope for DSM;
- The Deep Electrification Scenario uses the accelerated settings for codes and standards, whereas the DEP Scenario uses the reference settings. More aggressive codes and standards eliminate the potential for certain measures that are superseded by a code or standard, further reducing the DSM potential in the Deep Electrification Scenario; and
- The Deep Electrification Scenario uses the low setting for natural gas price, whereas the DEP Scenario uses the reference setting. The DSM model adjusts measure uptake using a payback model. Lower gas prices lengthen the after-incentive payback of the measures, reducing measure uptake.

Furthermore, it is important to note that the DEP Scenario exhibited more DSM savings and expenditures even though, due to significantly higher renewable and low-carbon gas supply than the Deep Electrification Scenario, DSM savings potential is underestimated by the current model. The modelling approach calculates participation in DSM programs based only on the volume of conventional natural gas each year. The modelers compensated for this by increasing measure participations by the ratio of (all gaseous fuels)/(traditional natural gas), but this compensation was imperfect and left some DSM underestimated.

FEI provides the details of the analysis below. In Table 1, FEI presents the data extracts required for the analysis and in Table 2, the calculations required for the analysis.

Step 1 – Data Extracts for the Residential, Commercial and Industrial Customer Groups[10]

Table 1 below provides data comparing the Deep Electrification Scenario with the DEP Scenario High DSM Setting for the following outputs for buildings and industry sectors (i.e., residential, commercial and industrial customer types). The data includes:

- Pre-DSM demand for gas throughput of all fuel types (natural gas, RNG, hydrogen, syngas and lignin) (PJ);
- DSM savings (PJ per year); and
- DSM expenditures (incentive + non-incentive costs in millions of $CAD per year).

Table 1: Data extract of Pre-DSM Demand, DSM Savings (PJ) and DSM Expenditures (million CAD)

	Pre-DSM Demand (PJ)		DSM Savings (PJ)		DSM Expenditures (millions)	
Year	Deep Electrification	DEP High DSM	Deep Electrification	DEP High DSM	Deep Electrification	DEP High DSM
2020	213	219	1.6	2.4	$ 48	$ 249
2021	206	214	3.1	4.7	$ 57	$ 250
2022	202	214	4.5	6.7	$ 59	$ 242
2023	198	213	5.7	8.4	$ 56	$ 236
2024	194	213	6.9	10.0	$ 55	$ 229
2025	285	309	8.0	11.5	$ 53	$ 217
2026	279	310	9.0	12.9	$ 51	$ 222
2027	275	311	10.0	14.3	$ 49	$ 222
2028	271	313	10.9	15.8	$ 46	$ 227
2029	267	315	11.8	17.1	$ 43	$ 208
2030	262	317	12.6	18.2	$ 44	$ 183
2031	256	317	13.1	19.5	$ 41	$ 197
2032	252	318	13.8	20.6	$ 39	$ 192
2033	248	319	14.3	21.6	$ 37	$ 177
2034	240	320	14.7	22.5	$ 34	$ 170
2035	236	320	15.1	23.4	$ 32	$ 157
2036	233	321	15.3	24.1	$ 29	$ 145
2037	229	321	15.3	24.7	$ 27	$ 134
2038	225	322	15.3	25.2	$ 25	$ 123
2039	222	322	15.3	25.6	$ 23	$ 113
2040	218	323	15.1	25.8	$ 17	$ 105
2041	213	323	14.7	26.0	$ 16	$ 100
2042	211	324	14.4	26.0	$ 12	$ 71

[10] Although FEI provides CNG and LNG, currently those are mainly provided for Low-Carbon Transportation and LNG export. These customers are not covered by DSM programming modelled for this LTGRP.

Step 2 – Outcomes from Calculations Produced the Data for Table 2

The data extracted in Table 1 is used to calculate post-DSM savings and expenditures per unit of gas throughput on FEI's system as provided in Table 2 below.

Table 2: Comparison of DSM Energy Savings and DSM Expenditures per PJ of Piped Fuel between the Deep Electrification Scenario and the DEP – High DSM Scenario

	Energy Savings per PJ of Piped Fuel (PJ/PJ)		DSM Expenditures per PJ of Piped Fuel ($million/PJ)	
Year	Deep Electrification	DEP High DSM	Deep Electrification	DEP High DSM
2020	0.007	0.011	$ 0.22	$ 1.14
2021	0.015	0.022	$ 0.28	$ 1.17
2022	0.022	0.031	$ 0.29	$ 1.13
2023	0.029	0.039	$ 0.28	$ 1.11
2024	0.035	0.047	$ 0.28	$ 1.08
2025	0.028	0.037	$ 0.19	$ 0.70
2026	0.032	0.042	$ 0.18	$ 0.72
2027	0.036	0.046	$ 0.18	$ 0.71
2028	0.040	0.050	$ 0.17	$ 0.72
2029	0.044	0.054	$ 0.16	$ 0.66
2030	0.048	0.057	$ 0.17	$ 0.58
2031	0.051	0.061	$ 0.16	$ 0.62
2032	0.055	0.065	$ 0.16	$ 0.60
2033	0.058	0.068	$ 0.15	$ 0.56
2034	0.061	0.070	$ 0.14	$ 0.53
2035	0.064	0.073	$ 0.13	$ 0.49
2036	0.066	0.075	$ 0.13	$ 0.45
2037	0.067	0.077	$ 0.12	$ 0.42
2038	0.068	0.078	$ 0.11	$ 0.38
2039	0.069	0.079	$ 0.10	$ 0.35
2040	0.069	0.080	$ 0.08	$ 0.32
2041	0.069	0.080	$ 0.07	$ 0.31
2042	0.069	0.080	$ 0.06	$ 0.22

In summary, Table 2 illustrates that the energy savings and DSM expenditures per PJ of throughput are higher in the DEP Scenario than the Deep Electrification Scenario.

14.7 For the Medium UCT, why was the UCT screen set at > 2?

Response:

Please refer to the response to BCUC IR1 38.5.

15.0 Topic: DSM – Deep Energy Retrofits

Reference: Exhibit B-1

FEI mentions deep energy retrofits at various places in the Application.

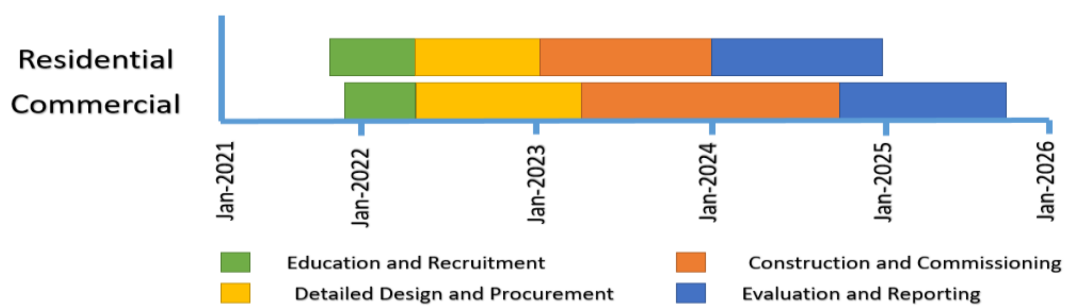
15.1 Please give an update on FEI's deep energy retrofit pilot work. When does FEI expect to be able to provide results and findings?

<u>Response:</u>

Please refer to the responses to BCUC IR1 46 series in which FEI provides background regarding its Advanced DSM initiatives including deep energy retrofits. The series provides information regarding emissions reductions modeled in the Application, timelines for implementing pilots, realization of increased savings in the future, and the barriers and remedial actions that can be taken to increase the likelihood of a successful outcome.

The following discussion provides an update on FEI's current deep energy retrofit pilot projects with two main streams of activities targeting Residential Part 9 and Commercial Part 3 buildings. The B.C. Building Code regulates buildings in two main categories commonly called Part 9 and Part 3 buildings. In general, a single-family home is a good example of a Part 9 building while a Multi-Unit Residential Building is an example of a Part 3 building. Part 9 Buildings are 3 stories or less and have a building area less than 600 m^2. Buildings that are not in Part 9 are categorized as Part 3.

Both pilots started in late 2021, with four distinctive phases summarized in the graphic below:



The four phases are described as follows:

1. <u>Education and recruitment:</u> Raising awareness about deep energy retrofits, promoting the available pilot project opportunities, receiving applications, assessment and analysis of all applicants, ranking and selection of final participants.
2. <u>Detailed design and procurement:</u> Evaluating different potential bundles, selection and detailing the most efficient design scenario, preparing for construction, and procuring equipment and services.

3. Construction and commissioning: Installation of all designed measures, construction of the new envelope and energy system, commissioning of the retrofitted building.
4. Evaluation and reporting: Measurement and verification of the retrofitted systems, reporting the process, results and all learnings, transitioning to the program team to design a full-scale rebate program.

The two pilots have completed phase one and are currently in the second phase. Phase Three, construction and commissioning of the residential pilots, will be completed by the end of 2023 with results available in 2024. The construction and commissioning phase of commercial pilots will be completed towards end of 2024 with results available in 2025.

During Phase One, FEI finalized the selection of 20 single family dwellings (Residential Part 9) and four multi unit residential buildings (Commercial Part 3) as the final participants of the deep energy retrofit pilot program. All of the homes and buildings are spread across BC climate zones 4, 5 and 6.[11]

The results of Phase One for Residential Part 9 buildings demonstrated that 51 to 68 percent reductions in natural gas usage were achievable by undergoing deep energy retrofit upgrades, while an estimation of 76 to 82 percent reductions were shown for Commercial Part 3 buildings. Those early results also showed an achievable 57 to 77 percent of GHG emission reductions in both Single Family Dwellings and Multi Unit Residential Buildings. Another interesting takeaway from the initial modelling analysis of Part 9 homes was that in addition to reducing their heating demand, there is potential to reduce the cooling demand in summer as well.

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[11] CleanBC, "What is my climate zone?" (2022) online at: https://betterhomesbc.ca/faqs/climate-zone/.

E. Gas Supply Portfolio Planning

16.0 Topic: Forecast Renewable and Low-Carbon Gas Supply

Reference: Application, Exhibit B-1, s. 6.2.3, Portfolio Integration of Renewable and Low-Carbon Gas Supply, Figure 6-3: Forecast Renewable and Low-Carbon Gas Supply, pdf 235; s. 7.4, Integration of Renewable and Low-Carbon Gas, pdf 288

FEI states on page 6-11:

> "FEI has targeted its long-term acquisition of renewable and low-carbon gas supply to meet BC provincial targets for carbon emission reductions in 2030 and 2050. Figure 6-3 below shows the forecast increase in supplies of renewable and low-carbon gas that FEI expects to acquire annually over the planning horizon. <u>The majority of these supplies will be made up of RNG and hydrogen, with smaller amounts of syngas and lignin, and potentially conventional natural gas or RNG combined with CCUS later in the planning horizon. The amount of each of these types of renewable and low-carbon gas supplies is more difficult to forecast</u>, although FEI expects its forecasts to evolve and be refined in future LTGRPs. Additional discussion of the renewable and low-carbon gas supply mix is provided in Section 7.4, along with a discussion of the implications for FEI's infrastructure needs." [pdf p.234, underline added]

Regarding the quantity and timing of resource availability, FEI states on page 7-34 that the amounts of each fuel type may vary:

> "Although FEI has modelled the mix of renewable and low-carbon gas in certain proportions over time in the LTGRP planning scenario, <u>the actual amount of each component that is acquired and delivered to customers could vary from the forecast amounts over the planning horizon based on a number of important factors, including resource costs and supply project opportunities and development.</u> Renewable and low-carbon gases with the highest volume potential over the planning horizon are RNG and hydrogen." [pdf p.288, underline added]

16.1 Please provide in graphic and tabular form the forecasts of each type of renewable and/or low-carbon gas and lignin that contributes to the total Forecast Renewable and Low-Carbon Gas Supply shown in Figure 6-3 for the Diversified Energy (Planning) scenario with High DSM. Please distinguish between blue, green, turquoise and waste hydrogen. If FEI does not have precise forecast figures, please provide forecast ranges.

<u>Response:</u>

FEI has not developed a forecast of the individual components of the renewable and low-carbon gas portfolio. Please refer to the response to BCUC IR1 52.6 for a modelled example of what the breakdown might look like and an associated discussion. FEI cannot provide a forecast of separate hydrogen types within the supply portfolio since hydrogen supply development is still in early stages and insufficient information exists with which to forecast the volume of individual hydrogen type supply.

16.2 Please provide a version of Figure 6-3 breaking down the Forecast Renewable and Low-Carbon Gas Supply between generated within BC and generated outside of BC.

Response:

Please refer to the response to BCUC IR1 52.8, which explains why FEI only forecasts on-system versus off-system RNG supplies in the shorter term (1-5 years).

16.3 Please provide a version of Figure 6-3 breaking down the Forecast Renewable and Low-Carbon Gas Supply between supply from prescribed undertakings under the GGRR and supply not from prescribed undertakings under the GGRR.

Response:

Please refer to the response to BCUC IR1 52.6 for a modelled breakdown of the components of the renewable and low-carbon gas supplies. The only renewable and low-carbon component supply identified in that response that is currently not named under the GGRR is carbon capture, utilization and storage.

FEI will acquire renewable and low-carbon gas supplies as prescribed undertakings under the GGRR until FEI has reached the maximum allowed, which is approximately 30 PJ. After the GGRR maximum has been reached, and if FEI determines that it needs greater supply, then FEI anticipates it would file for acceptance/approval of supply with the BCUC pursuant to a suitable section of the UCA.

16.4 Please explain in detail how FEI derived its forecasts of the fuels that contribute to the curve in Figure 6-3, including an explanation of any price or price elasticity assumptions, and an explanation of any uncertainty about the availability of supply.

Response:

Please refer to the responses to BCUC IR1 52.4, 52.5, and 52.6 for further discussion related to the availability of supply and BCUC IR1 69.2 regarding how price elasticity of demand values were incorporated into the models.

16.5 For fuel types that are not prescribed under the GGRR, please discuss the regulatory framework under which FEI would acquire the fuel and recover the cost in rates.

Response:

For fuel types not prescribed under the GGRR, and assuming the current regulatory framework is in place at the time that FEI applies to acquire the fuel, FEI would likely apply to the BCUC pursuant to section 44.2(1)(c) of the UCA for approval of a schedule of its anticipated expenditures.

Section 44.2(1)(c) of the UCA gives public utilities the option to apply for acceptance of an expenditure schedule for energy acquisitions, as follows:

> 44.2 (1) <u>A public utility may file with the commission an expenditure schedule containing one or more of the following:</u>
>
> (a) a statement of the expenditures on demand-side measures the public utility has made or anticipates making during the period addressed by the schedule;
>
> (b) a statement of capital expenditures the public utility has made or anticipates making during the period addressed by the schedule;
>
> (c) <u>a statement of expenditures the public utility has made or anticipates making during the period addressed by the schedule to acquire energy from other persons.</u>
>
> [Emphasis added.]

Section 44.2(3) of the UCA states that the BCUC must accept the schedule, if the BCUC considers that making the expenditures referred to in the schedule would be in the public interest. Energy, in section 44.2 of the UCA, is not restricted in the same way as it is in Part 5 of the UCA.

FEI anticipates that it would set out in its application the need for the expenditure and a mechanism for cost recovery.

17.0 Topic: Natural Gas Supply

Reference: Application, Exhibit B-1, Appendix D-1, Figure D1-4, pdf 1485, and Figure D1-5, pdf 1486

In Figure D1-4, US Natural Gas Production, sourced from S&P Global, there is a "Fast Transition Scenario" curve that starts in 2022 and declines to roughly 60% of indicated production by 2050.

In Figure D1-5, Marketable Natural Gas Production by Province, from Canada's Energy Future 2021, there is an "Evolving Policy Scenario" curve starting in 2022 and declining to roughly 60% of indicated production by 2050.

17.1 Are the "Fast Transition Scenario" and "Evolving Policy Scenario" curves by FEI?

Response:

No. As noted in Footnote 1 of Appendix D-1, on page 1, the Canada Energy Regulator (CER) provided net zero modelling for the first time in its "Evolving Policies" scenario, as part of its Canada's Energy Future 2021, released in December 2021. Additionally, IHS Markit provided a "Fast Transition" scenario as a pathway to net-zero carbon emissions in North America in May 2021.

17.2 What conclusions has FEI drawn about the price and availability of fossil natural gas if the "Fast Transition Scenario" and "Evolving Policy Scenario" are realized?

Response:

FEI has not drawn any conclusions from the "Fast Transition Scenario" and "Evolving Policy Scenario", as these long-term outlooks are for informational purposes only, and energy markets as well as price and gas production forecasts are constantly changing. These scenarios were prepared in May 2021 and December 2021, respectively. Since the release of these scenarios, global gas and energy markets have undergone a significant transition, entering into a new paradigm, both as a result of market tightness and due to the Russian invasion of Ukraine in February 2022.

If IHS Markit provides an updated "Fast Transition Scenario" as part of its bi-annual long-term market outlook, this could be more comparable to their "Base Case" scenario released in the same vintage, resulting in an appropriate and direct assessment that is not affected by a lengthy period of time during a rapidly-evolving energy transition. However, FEI would still not use this outlook to draw any conclusions about the price and availability of natural gas that affect its own strategies.

18.0 Topic: Renewable and Low-Carbon Gas Supply Potential

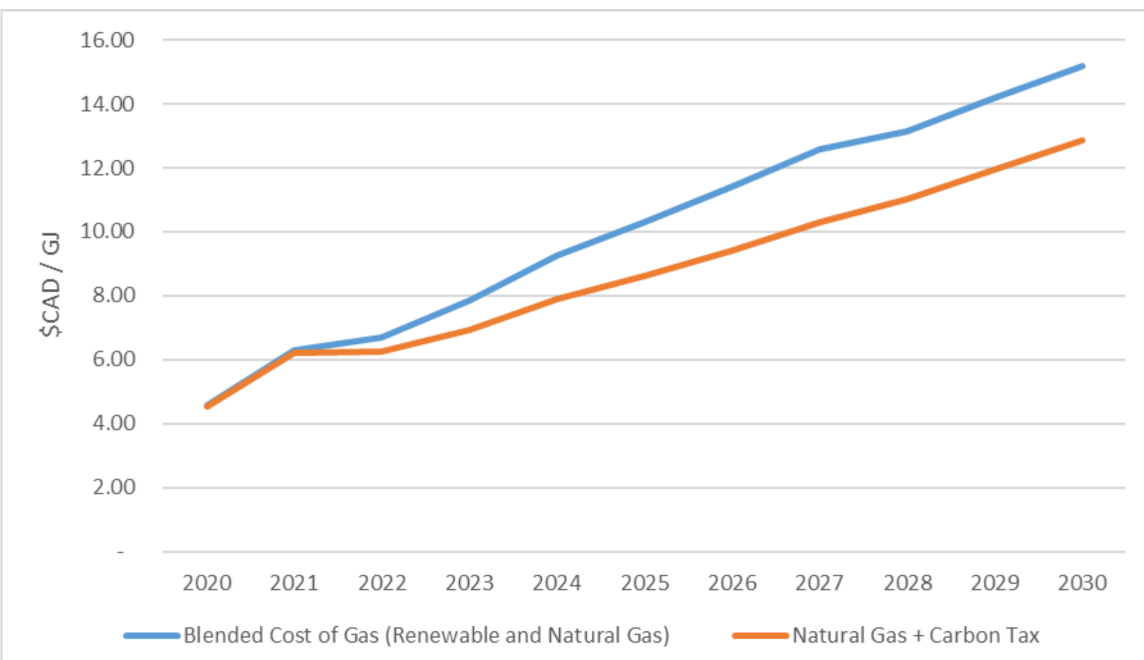
Reference: Application, Exhibit B-1, Appendix D-2, BC Renewable and Low-Carbon Gas Supply Potential Study, Figures 2 & 3, pdf 1498; section 4.3.2 BC Potential for Blue Hydrogen Production, pdf 1568; section 4.3.3, BC Potential for Turquoise Hydrogen Production, pdf 1569

18.1 Please provide versions of Figures 2 and 3 with superimposed curves of: the conventional natural gas price forecast that FEI uses, and a curve of the price for a blended conventional gas and RG commodity that FEI believes it could realistically charge its customers while achieving the decarbonization of FEI's gas system needed to achieve the goals of the Roadmap to 2030.

<u>Response:</u>

FEI is unable to alter Figures 2 and 3 from British Columbia Renewable and Low-Carbon Gas Supply Potential Study[12] as requested. However, FEI has provided a figure below showing the conventional natural gas price forecast (including the carbon tax) and a blended (or weighted average) cost of gas for conventional natural gas and renewable gas price out to 2030. The conventional natural gas and the renewable gas prices were used in modeling individual scenarios; however the blended cost was only used in Section 9 of the Application where FEI calculated cumulative rate (bill) impacts for residential (RS 1) customers under the DEP Scenario.

Figure 1: Natural Gas Price Forecast and the Blended Cost of Gas for Natural and Renewable Gas (Includes Carbon Tax)



[12] Exhibit B-1, 2022 LTGRP Application, Appendix D-2.

18.2 Please describe how the production costs were derived for blue hydrogen and turquoise hydrogen, or point out where in the application this information is.

Response:

Production cost inputs were adopted from the British Columbia Renewable and Low-Carbon Gas Supply Potential Study.[13] Notable cost drivers from the study analysis for 2030 and 2050 include production cost decreases based on the authors' assumption that capital cost and sequestration costs decline. For example, by 2030, the study results assumed a decline of 9 percent and 10 percent in capital and sequestration costs, respectively. By 2050, the study assumed a decline of 20 percent and 25 percent reduction in capital and sequestration costs, respectively. The following tables summarize the main inputs used to derive the production costs for low-carbon hydrogen produced from natural gas with carbon sequestration in the form of gaseous carbon dioxide (blue hydrogen) and low-carbon hydrogen produced from natural gas with carbon sequestration in the form of solid carbon (turquoise hydrogen).[14]

Table 1: 2021 Blue Hydrogen Production Cost Assumptions

Production Cost Input	Assumptions
Capital Cost	▪ Capital Cost for facility was a function of the cost to produce 100 tonnes of blue hydrogen per day based on estimate from ZEN Report 2019[15] ▪ Assumed 9 percent cost of capital
Labour Cost	▪ Author assumptions based on average labour costs in industry and number of workers needed to run a facility on average. ▪ Based on BC large-scale hydrogen production.
Utility Cost	▪ Electricity cost (1 kWh per kg H_2) per Timmberg et al. 2020[16] ▪ Methane Conversion efficiency 75 percent from ZEN Report 2019 ▪ Electricity and gas feedstock costs were a function of average market price at time of research in late 2021
Sequestration Cost	▪ 10 Kg of CO_2 produced from 1 Kg H_2 produced. ZEN Report 2019[1] ▪ Cost of CCS equals $75 per tonne CO_2 ▪ 90 percent capture efficiency
Other	▪ Insurance, administration, and other costs equal 5 percent of CAPEX, authors own assumption regarding industry averages

13 Exhibit B-1, 2022 LTGRP Application, Appendix D-2.

14 Note: Assumptions in both Table 1 and Table 2 were supplied by Envint Consultants outside of BC Renewable Gas Supply Potential Study

15 British Columbia Hydrogen Study ZEN and the art of Clean Energy Solutions: https://acrobat.adobe.com/link/track?uri=urn%3Aaaid%3Ascds%3AUS%3A971d4088-cc84-4437-a3fe-ee0b9a8f517d&viewer%21megaVerb=group-discover.

16 Hydrogen and hydrogen-derived fuels through methane decomposition of natural gas – GHG emissions and costs: https://www.sciencedirect.com/science/article/pii/S2590174520300155.

Table 2: 2021 Turquoise Hydrogen Assumptions

Production Cost Input (Plasma Pyrolysis)	Assumptions
Capital Cost	▪ Capital Cost for facility was a function of the cost to produce 100 tonnes of turquoise hydrogen per day. ▪ Assumed 9 percent cost of capital
Labour Cost	▪ Author assumptions based on average labour costs in industry and number of workers needed to run a facility on average. ▪ Based on BC large scale hydrogen production
Utility Cost	▪ Electricity cost (10 kWh per kg H2) per ZEN Report 2019[2] ▪ Methane Conversion efficiency 57 percent ▪ Electricity and Gas feedstock costs were a function of price at time of research in late 2021
Carbon Black Revenue	▪ Revenue from Carbon Black sales comes from market price of carbon black ($800 per tonne) multiplied by the assumed production 3.2 kg of Carbon Black per tonne H2 ▪ Carbon black revenue declines in 2030 and 2050 due to increasing amounts of hydrogen in gas pipelines, therefore less carbon black and more feed-through hydrogen
Other	▪ Insurance, administration, and other costs equal 5 percent of CAPEX, authors' own assumption

18.3 In the case of turquoise hydrogen, does the cost calculation factor in possible revenues from the sale of carbon black?

Response:

Confirmed, the cost calculation does include the revenues from a potential sale of the captured byproduct carbon in the form of carbon black powder or graphite powder to secondary markets. Please refer to the response to BCSEA IR1 18.2 for assumptions around carbon black revenues.

18.4 Why is almost 15 PJ of turquoise hydrogen shown as being available at virtually no cost in 2030? Why is the production cost of turquoise hydrogen shown as approximately $7/GJ in 2050?

Response:

The BC Renewable and Low-Carbon Gas Potential Study analyzes the net cost of turquoise hydrogen after accounting for byproduct carbon sales in the form of carbon black that reduces the production cost below $1 per GJ by 2030. Turquoise hydrogen presents a unique opportunity due to the co-production of byproduct carbon and no capture or sequestration is required, making the process easier to locate and operate. Depending on its exact texture and quality, carbon black can have considerable value in the market. The Study has conservatively assumed that a value of $800 CAD per tonne is attainable, with international carbon black prices currently over $600 USD per tonne.[17] This is shown in the Study analysis as sufficient to cancel out almost all the capital and operating cost of a new production facility, leading to very low hydrogen production costs. Natural gas is the main cost parameter, but somewhat higher pricing could be absorbed. In 2050, the cost of turquoise hydrogen increases because the Study analysis assumes more costs associated with feedstock supply, which would increase the operating costs associated with production. Should demand for byproduct carbon increase due to the global energy transition, then that will improve the cost competitiveness of this production process of hydrogen. Without a robust market for byproduct carbon, turquoise hydrogen costs would be higher and generally align with green hydrogen, given the technology is not currently commercially deployed. Turquoise hydrogen production technological progress will ultimately determine its overall cost trajectory into the planning period.

18.5 How does FEI assess the maturity of the technology to capture and store CO2 in order to create blue hydrogen?

Response:

FEI uses several means to assess the maturity of carbon capture and storage (CCS) to create low-carbon intensity (blue) hydrogen from natural gas. FEI refers to organizations such as the International Energy Agency (IEA), which states that the application of CCS for hydrogen production from natural gas has been demonstrated at scale over the last decades, but is still at the early adoption stage.[18] FEI is also supporting industry efforts in Canada such as the Hydrogen Strategy for Canada,[19] the BC Hydrogen Strategy,[20] and the BC Renewable and Low-Carbon Gas Supply Potential Study,[21] among others, to model the cost, technical uncertainty in terms of technology-readiness level, and carbon intensity of these technologies, if they were to be deployed in British Columbia. FEI is also evaluating the technical, economic and low-carbon gas supply production potential for a number of hydrogen production project concepts that would seek to use emerging best-in-class CCS technologies.

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17 https://fred.stlouisfed.org/series/WPU06790918.
18 IEA, "CCUS in Clean Energy Transitions Flagship Report: CCUS technology innovation" (September 2020) online at: https://www.iea.org/reports/ccus-in-clean-energy-transitions, License: CC BY 4.0.
19 Exhibit B-1, Appendix A-3.
20 Exhibit B-1, Appendix A-4.
21 Exhibit B-1, Appendix D-2.

18.5.1 How does FEI portray the cost and availability uncertainties of blue hydrogen, given the technological and cost uncertainties of commercialized CCUS?

Response:

CCUS is not an uncertain technology — there are multiple CCUS facilities that currently operate around the world. The maturity of CCUS depends on the technology type being applied and their use cases. Commercially viable applications of CCUS can and should be scaled up rapidly across multiple applications, including blue hydrogen.

As discussed in the BC Renewable and Low-Carbon Gas Supply Potential Study,[22] significant potential for blue hydrogen exists in the province at low cost. Further, leading organizations, such as the IEA, have observed that the project pipeline for blue hydrogen is expanding significantly. In the IEA's latest report, the Global Hydrogen Review 2022,[23] the IEA states:

> Low-emission hydrogen and ammonia production has been a key driver of CCUS development in recent years, along with an improved investment environment and strengthened climate goals. Around a third of the global CCUS project pipeline plans to capture CO2 from hydrogen production. Since January 2021, over 50 new hydrogen projects with CCUS were announced. If all projects under development go ahead, around 80 Mt CO2 could be captured from hydrogen production by 2030, including around 50 Mt CO2 in dedicated facilities for merchant hydrogen or ammonia production, around 5 Mt CO2 in methanol and just over 15 Mt CO2 in refineries. Low-emissions H2 production from CCUS-equipped facilities could reach around 7 Mt H2 in 2030. While promising in terms of the deployment pipeline, very few of these projects had reached final investment decisions as of August 2022. Further, it remains unclear whether current natural gas price hikes might delay FIDs planned for the coming year, especially in Europe.[24]

This is to say that blue hydrogen development has experienced significant interest around the world, and while uncertainties are not fully addressed, FEI's interest in the technology is aligned with the global market.

Any new technology adoption has some level of risk (including cost and availability) associated with it. FEI uses a portfolio approach for GHG abatement, long-term resource planning and utility-scale project engineering and execution, contracting and regulatory approvals to mitigate those risks to the best of its ability. This approach is in line with leading risk management practices.

[22] Exhibit B-1, Appendix D-2.
[23] IEA, Global Hydrogen Review 2022, online at: https://iea.blob.core.windows.net/assets/c5bc75b1-9e4d-460d-9056-6e8e626a11c4/GlobalHydrogenReview2022.pdf.
[24] Global Hydrogen Review 2022, p. 87.

18.6 How does FEI assess the maturity of the technology to produce turquoise hydrogen and create marketable carbon black?

18.6.1 How does FEI portray the cost and availability uncertainties of turquoise hydrogen, given the technological and cost uncertainties of its production?

Response:

FEI refers to the BC Renewable and Low-Carbon Gas Supply Potential Study that presents an overview of the different emerging pyrolysis technologies to produce "turquoise" hydrogen and classifies the maturity of the different technologies, ranging as mostly low maturity with some high maturity. FEI recently announced its memorandum of understanding (MOU) with Hazer Technologies and Suncor to develop a pilot turquoise hydrogen project in the Lower Mainland at the Suncor facility in Burnaby. By participating in the project, FEI will be assessing the performance and applicability of this technology in the BC context and will evaluate the full business case of turquoise hydrogen production, including the potential to economically scale-up the technology and commercialize the byproduct carbon in the form of graphite sales.

19.0 Topic: Regional Gas Supply Diversity Project

Reference: Application, Exhibit B-1, section 6.3.3, Regional Gas Supply Diversity (RGSD) Project, pages 6-26 to 6-28

FEI states on page 6-28 that

> "Recommended actions that FEI will take to manage FEI's gas supply portfolio include:
>
> … Evaluate opportunities within FEI's own operating region to improve infrastructure resiliency and supply diversity such as the RGSD project, which will support diversity, reliability, and decarbonization over the long term; …" [pdf p.251]

19.1 Please explain why FEI situates the RGDS Project within gas supply portfolio management as distinct from system resource needs and alternatives.

Response:

The RGSD Project is situated within Section 6 of the Application (Gas Supply Portfolio Planning) because it will become a Pacific Northwest regional asset that FEI will contract for to bring gas supply to FEI's pipeline system. The main driver of the RGSD project is not to address system capacity needs discussed in Section 7 of the Application.

The RGSD project would provide multiple benefits to FEI's gas supply portfolio through adding long-term resiliency, decarbonization benefits, and diverse supply to the region that is sourced from one of the largest natural gas trading hubs in North America (i.e. AECO/NIT). The RGSD pipeline would greatly mitigate the risk of outage conditions through providing long-duration daily gas supply to meet winter loads by an alternative route to the existing T-South pipeline. FEI's customers would significantly benefit from having two sources of piped gas supply – RGSD and T-South.

19.2 What is FEI's understanding of the status of Enbridge's plans to expand the capacity of the T-South system?

Response:

On July 29, 2022, Enbridge formally commenced the process to garner shipper support to expand the T-South pipeline by conducting a binding open season. This process was intended to provide interested parties with the opportunity to make a firm commitment for the expansion with a minimum term of twenty years. This expansion was anticipated to increase the capacity of the T-South pipeline by 300 MMcf/day.

On November 4, 2022, Enbridge confirmed that the open season was fully subscribed for 300 MMcf/day, with a weighted average term of 65 years.[25] Enbridge does not publicly disclose the names of the successful bidders who were awarded the capacity until the expansion in-service date. The cost of the expansion, originally estimated at $2.5 billion earlier in 2022 by Enbridge, has since been revised to up to $3.6 billion in November 2022, which would lead to an even higher toll increase for all T-South shippers than originally anticipated. Enbridge expects to file a regulatory application to the Canada Energy Regulator (CER) in Q1 2024, and anticipates that the expansion capacity could be in-service no earlier than Q4 2028, contingent upon CER approval.[26]

19.3 How would it affect FEI's plans for RGSD if Enbridge's T-South expansion plans were implemented?

Response:

As stated in Section 6.3.3 of the Application, the RGSD Project is needed along with other infrastructure to address resiliency requirements, future demand forecasts in light of regional supply constraints and the transition to renewable and low-carbon gas. Stated another way, the significant additional cost that FEI customers will pay for any expansion(s) of T-South, including Enbridge's proposed T-South Expansion, comes with little, if any, upside for FEI and its customers in terms of access to supply, supply cost, resiliency, or progress towards a renewable and low-carbon energy future. Therefore, Enbridge's T-South Expansion would not negate the need to continue developing and assessing the RGSD Project. Further, if the RGSD Project is successfully developed, it will allow FEI to reduce its current exposure on the T-South pipeline by optimizing its amount of pipeline holdings between two pipelines. In this scenario, FEI anticipates it would release excess T-South capacity to existing or new parties that may be interested or relinquish T-South capacity back to Westcoast. This action by FEI may have some impact to the Enbridge project.

[25] Enbridge, "Enbridge Announces Expansion of T-South Pipeline Segment of B.C. Pipeline System" (November 4, 2022) online at: https://www.newswire.ca/news-releases/enbridge-announces-expansion-of-t-south-pipeline-segment-of-b-c-pipeline-system-812344338.html.

[26] Ibid.

F. System Resource Needs and Alternatives

20.0 Topic: System Resource Alternatives

Reference: Application, Exhibit B-1, 7, System Resource Needs and Alternatives

FEI states on page 7-1:

> "Planning for system resource needs includes system sustainment and renewal, integrity upgrades, and system expansion projects that together contribute to overall system resiliency. FEI's system sustainment planning process identifies important near-term and long-term system renewal requirements and projects to improve system integrity. <u>There are traditionally three resource options to evaluate when planning system expansions: pipelines, compression and storage</u>. As FEI continues to develop renewable and low-carbon resources, reliable on-system production will soon become a fourth alternative for consideration." [pdf p.255, underline added]

20.1 Does FEI ever consider demand-side measures as an option for responding to capacity constraints? If so, please elaborate. If not, why not?

<u>Response:</u>

FEI is studying demand-side measures to respond to capacity constraints but is not currently employing them. FEI currently does not have hourly or daily metering in place for the vast majority of its customers. Without it, FEI cannot assess the magnitude of change in peak hour or peak day demand resulting from demand-side measures. Without this consumption information, FEI cannot validate to what extent peak demand could be reduced reliably. FEI's AMI Project, if approved, will allow FEI to begin installing meters that can provide more precise consumption information that would aid in validation of the peak demand reductions from demand-side measures. In addition, some demand-side measures rely on behavioral changes in customers to comply with measures aimed at reducing consumption at peak times. While behavioral changes will produce reliable results under most conditions experienced throughout a year, FEI is not confident that the approach will be reliable and effective under extreme peak winter conditions when the possibility of exceeding the available system capacity would be present in the absence of traditional capacity upgrade infrastructure.

20.2 Does FEI ever consider avoiding a system expansion by coordinating with an electric utility to use electricity to meet the thermal energy needs of new customers that would otherwise be new gas customers?

Response:

FEI has not coordinated with local electrical utilities to avoid system expansion. FEI allows customers to make their own choice regarding their energy needs, and has an obligation to provide service to customers that request it. The natural gas system currently supplies a much greater portion of British Columbia's energy needs in peak winter conditions than the electrical system. A shift in peak demand from the gas to the electrical system over time will create some very significant generation, transmission and distribution expansion requirements to the electrical system, as discussed in the response to BCUC IR1 30.3.

21.0 Topic: Okanagan Capacity Upgrade Project

Reference: Application, Exhibit B-1, 7.3.3 FEI Interior Transmission System, p.7-25, pdf p.279

FEI states on page 7-26:

> "FEI currently has a CPCN Application for the Okanagan Capacity Upgrades (OCU) project in the regulatory review progress. The preferred alternative is an approximately 30-kilometre NPS 16 pipeline loop between Penticton and Kelowna reinforcing the existing NPS 12 pipeline currently in service." [page 7-26, pdf p.280]

21.1 Why has the BCUC proceeding for FEI's CPCN Application for the Okanagan Capacity Upgrade Project been adjourned?

Response:

FEI's Application for a CPCN for the Okanagan Capacity Upgrade (OCU) Project was adjourned pursuant to Order G-48-22. In the reasons for decision attached as Appendix A to Order G-48-22, the BCUC Panel determined that an adjournment of the OCU proceeding was warranted at that time, stating that there had been numerous delays and extension requests to the regulatory process to facilitate further engagement between FEI and the Penticton Indian Band (PIB), and there was a lack of clarity with respect to the precise timing and content of FEI's proposed evidentiary update, which may depend on the outcome of further engagement with the PIB. Therefore, given the multiple extensions that had already occurred and further uncertainty regarding the next steps, the Panel determined it was appropriate to adjourn the proceeding until FEI has filed its proposed evidentiary update.

21.2 When does FEI intend to re-initiate its CPCN Application for the OCUP?

Response:

FEI continues to engage with PIB and have further discussions regarding the OCU project. FEI plans to include a proposal for a further regulatory timetable in its evidentiary update. The timing of FEI's evidentiary update is currently uncertain.

21.3 Please confirm, or otherwise explain, that the 2022 LTGRP assumes the OCUP will be completed.

Response:

Confirmed. The need for the OCU Project is required to support current levels of peak demand, not a future forecast level of peak demand. Until the OCU Project can be completed, FEI is employing a series of short-term mitigation measures that are not sustainable in the longer term.

21.4 Is it correct that the 2022 LTGRP does not explicitly address the planning need for the OCUP?

Response:

The planning need for the OCU Project was explicitly addressed in FEI's 2017 LTGRP and in the OCU CPCN Application. In this Application, FEI is examining the planning need where forecast peak demand may exceed the capacity of the proposed OCU Project.

21.5 Does FEI rely on the 2017 LTGRP to establish the need for the OCUP on a long-term planning basis?

Response:

Please refer to the response to BCSEA IR1 21.4.

21.6 Please identify and explain the differences between the 2017 LTGRP and the 2022 LTGRP in terms of ITS capacity and the need for the Okanagan Capacity Upgrade Project.

Response:

The 2017 LTGRP identified the need to address the capacity of the Interior Transmission System (ITS) in 2022 and identified a project identified as "Option 1 Okanagan Reinforcement- South Loop" as a preferred alternative. This project formed the basis for the OCU Project. Based on the 2016 peak demand forecast used in the 2017 LTGRP, the upgrade would support the forecast peak demand until 2035, at which time additional upgrades would be required to meet peak demand beyond the end of the forecast period (2036).

In the Application, the OCU Project, once operational, is projected to support the peak demand growth in the Traditional forecast until 2038, at which time additional upgrades would be required.

As discussed in the response to BCSEA IR1 21.3, the current peak demand forecast continues to show a deficit in capacity occurring in 2022 and beyond which requires short-term mitigation to support the forecast peak demand until the OCU Project is approved and constructed.

21.7 Please confirm, or otherwise explain, that the Okanagan Capacity Upgrade Project was developed prior to the BC Government's issuance of the *CleanBC Roadmap to 2030.*

Response:

Confirmed.

21.8 Has, or will, FEI reevaluate whether there is a need for the OCUP given the 2022 LTGRP's dramatically different planning environment compared to that of the 2017 LTGRP?

Response:

FEI is continually re-evaluating capacity upgrade requirements. The peak demand of existing customers on the ITS indicates a need for the OCU Project as the current short-term mitigation measures in place until the OCU Project is completed are not sustainable over the longer term.

The 2017 LTGRP says "The current peak day system capacity for the ITS is <u>approximately 315 TJ/d.</u>" [2017 LTGRP, p.176, pdf p.201] The 2021 OCUP CPCN application indicates that the current ITS capacity is <u>approximately 330 TJ/d</u> [OCUP CPCN, Exhibit B-1-2, Figure 3-7, p.19, pdf p.31]

In the OCUP CPCN application, the ITS Capacity after Completion of OCUP is <u>about 370 TJ/d</u> [Exhibit B-1-2, OCUP CPCN Application, Figure 3-8, p.20, pdf p.32] In apparent contrast, the 2022 LTGRP shows ITS Existing Capacity With OCU as <u>400 TJ/day</u> [Exhibit B-1, Figures 7-14 and 7-15].

21.9 What is the current peak day system capacity for the ITS without the OCUP?

Response:

The current ITS capacity to support peak demand without the OCU Project is 333 TJ per day which is consistent with the OCU CPCN Application.

With regard to the apparent differences in capacity values noted in the preamble to this IR, FEI provides the following clarification.

In response to BCSEA IR1 3.8, in the OCU CPCN proceeding, FEI provided the following explanation for the differences in the capacity presented:

> …With respect to the representation of capacity between the two forecasts, the 2017 LTGRP forecast reflected capacity at the traditional design minimum inlet pressure and is represented as a capacity of 315 TJ per day in the figure against the 2017 LTGRP peak demand forecast.
>
> The "Current ITS Capacity" reflects that the existing Kelowna #1 and Polson Gate Stations had some capacity to accept inlet pressures below the minimum design criteria of 350 psig without requiring mitigation measures. This raises the available capacity reflected in that capacity line. FEI also re-examined the historical maximum Industrial demand and revised it downward in the capacity shortfall region where reasonable to do so. This also has the effect in these plots of raising the capacity line relative to the peak demand curve. The combined effect provided a capacity of 333 TJ per day against the 2019 peak demand forecast….

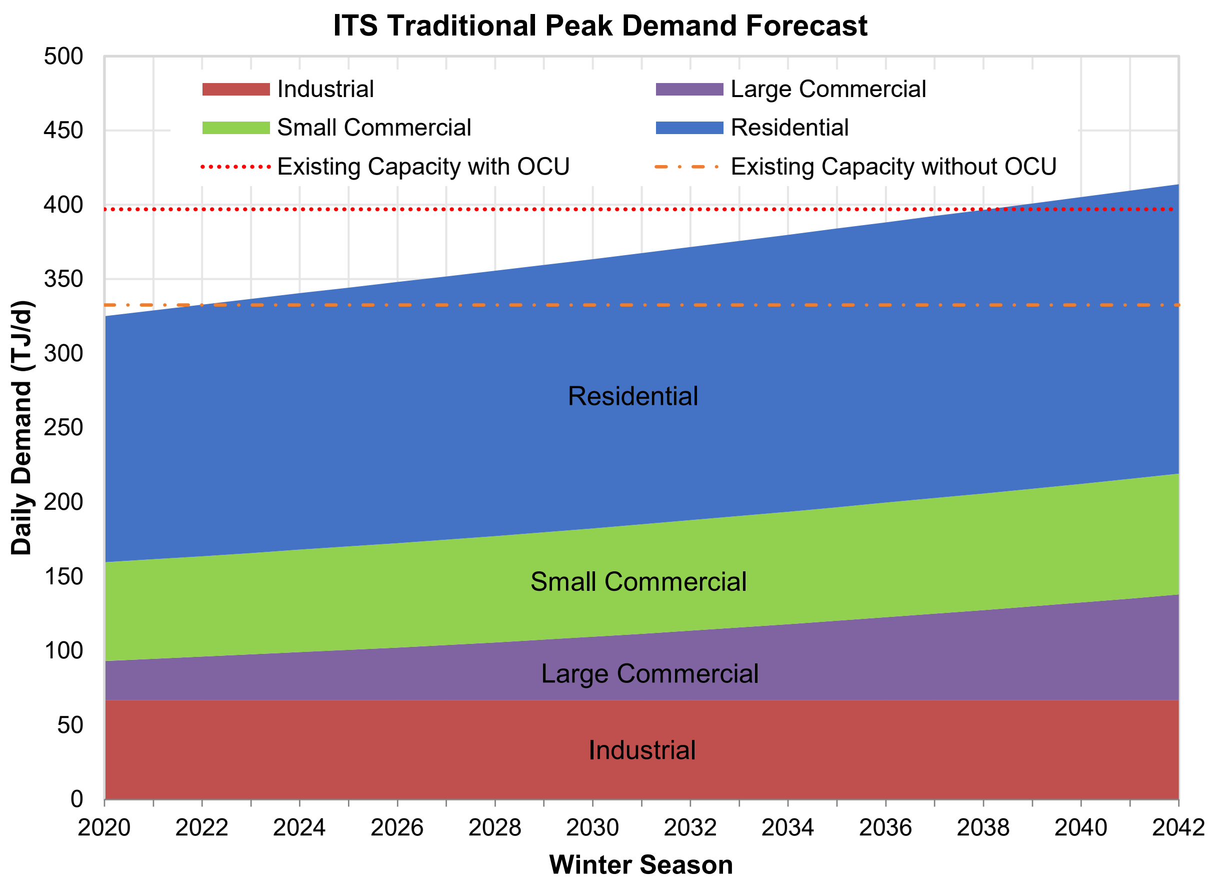
With regard to FEI's representation of capacity upon completion of the OCU Project, the OCU CPCN presented a capacity of 370 TJ per day for the project and in the rounds of information requests indicated that the capacity of the OCU pipeline could be increased to 397 TJ per day by addressing an upstream constraint in the Kootenays with compression upgrades at FEI's Kitchener compressor station or resolving delivery pressure commitments in the Kootenays provided by TC Energy. Please refer to the response to BCUC IR1 13.1 from the OCU CPCN Application where FEI provides the OCU capacity with this constraint addressed.

Since filing the OCU CPCN Application and associated IR responses, FEI has resolved the delivery pressure constraint with TC Energy and, as a result, is representing the OCU capacity at the higher value of 397 TJ per day in the Application.

21.10 Figure 7-14: ITS Traditional Peak Demand Forecast shows Existing Capacity with OCU as a dotted red line. Please provide a version of Figure 7-14 showing Existing Capacity without OCU, as well as Existing Capacity with OCU.

Response:

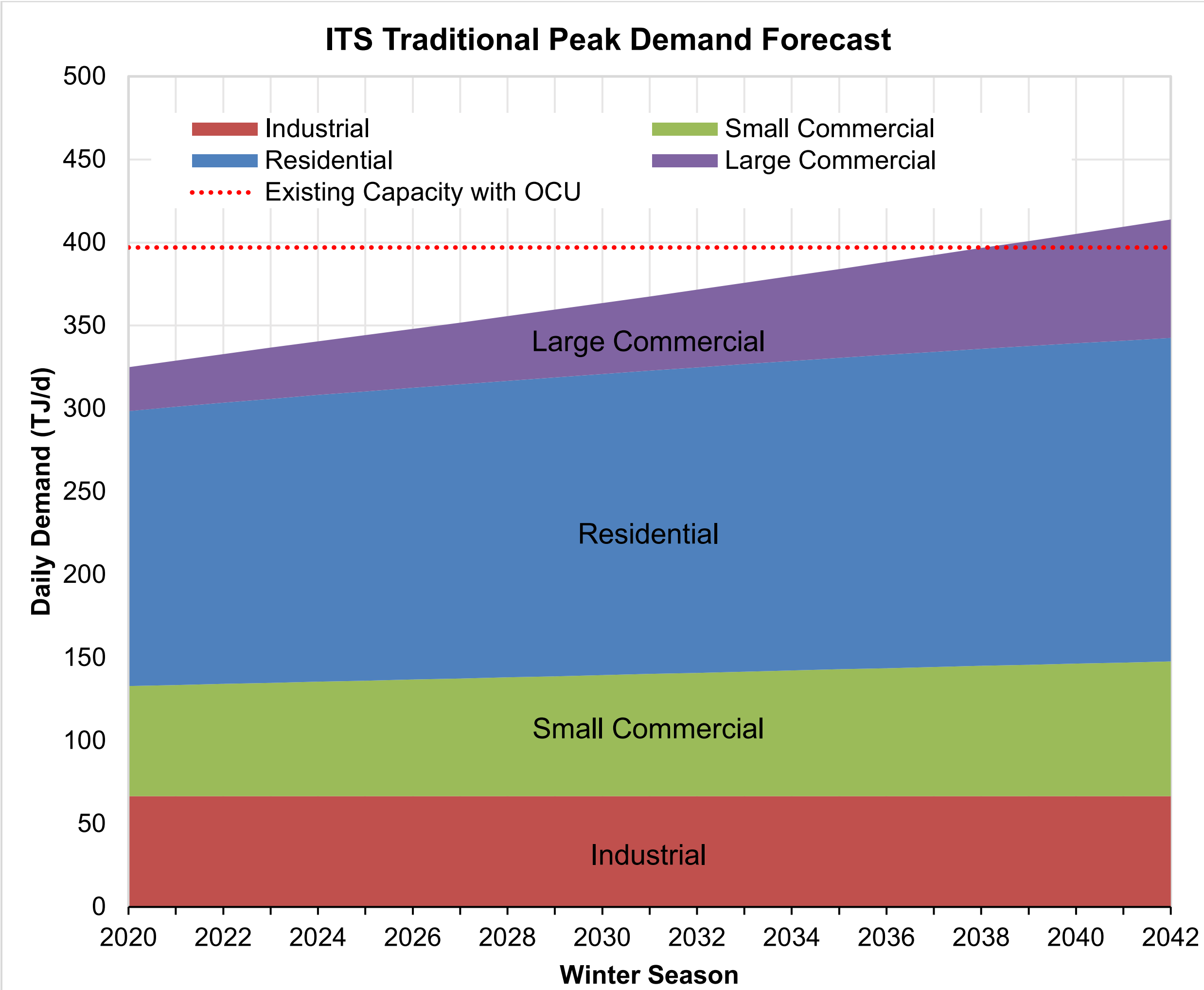
The requested revised figure is provided below showing ITS capacity before and after the OCU Project.



21.11 Figure 7-14: ITS Traditional Peak Demand Forecast makes it look (superficially) like growth in Residential peak load causes the capacity gap emerging in 2038. Please provide a version of Figure 7-14 with Industrial, Small Commercial, Residential, and Large Commercial from the bottom to the top.

Response:

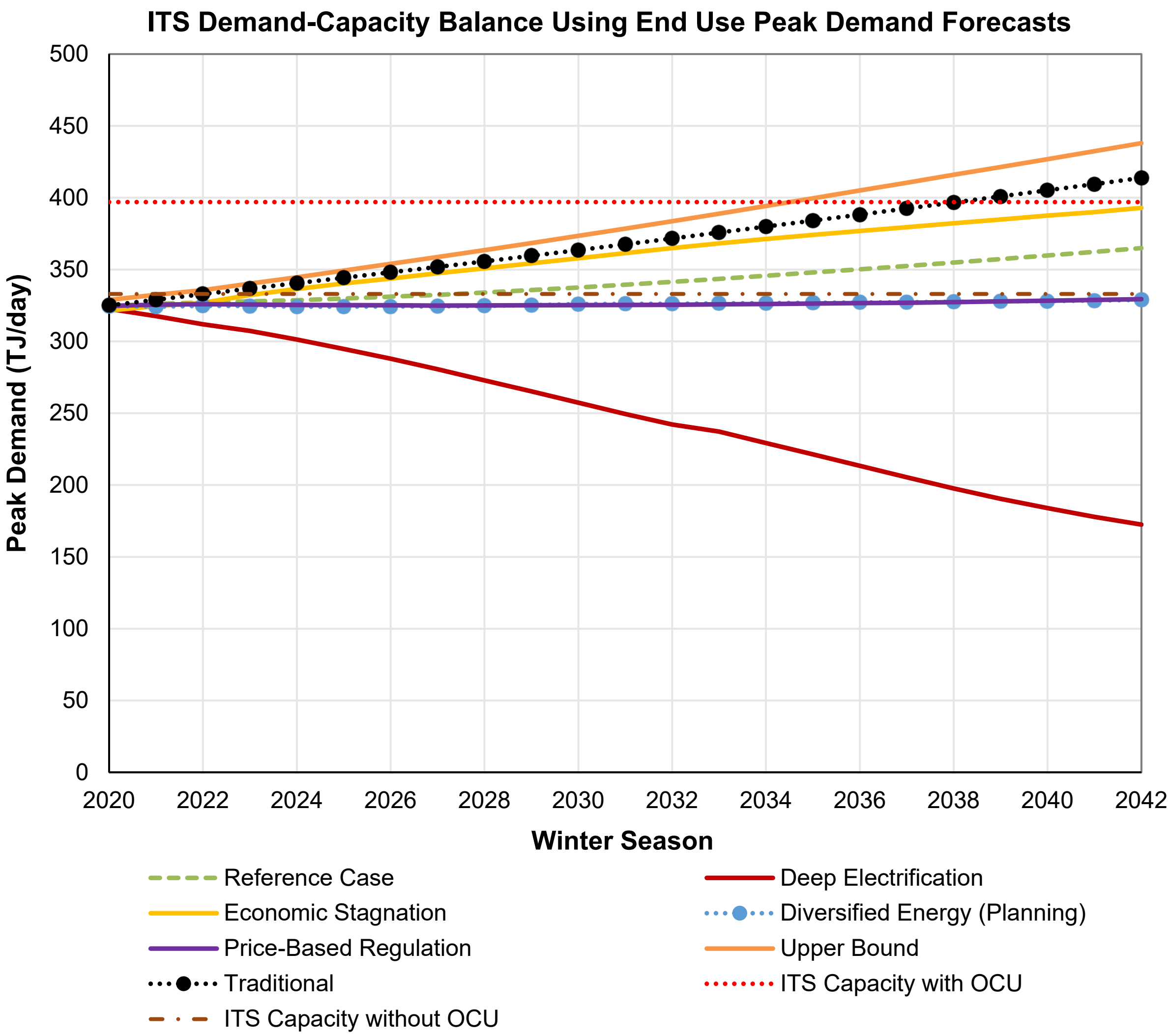
The requested revised figure is provided below. The peak demand on the system is the summation of the peak demand contribution from all customers on the system. BCSEA is correct that it would be a superficial assessment to attribute responsibility for the system peak demand exceeding capacity to any one customer group simply according to the way they are stacked in the graphical representation.



21.12 Figure 7-15: ITS Demand-Capacity Balance Using End Use Peak Demand Forecasts shows Existing Capacity with OCU as a dotted red line. Please provide a version of Figure 7-15 showing Existing Capacity without OCU, as well as Existing Capacity with OCU.

Response:

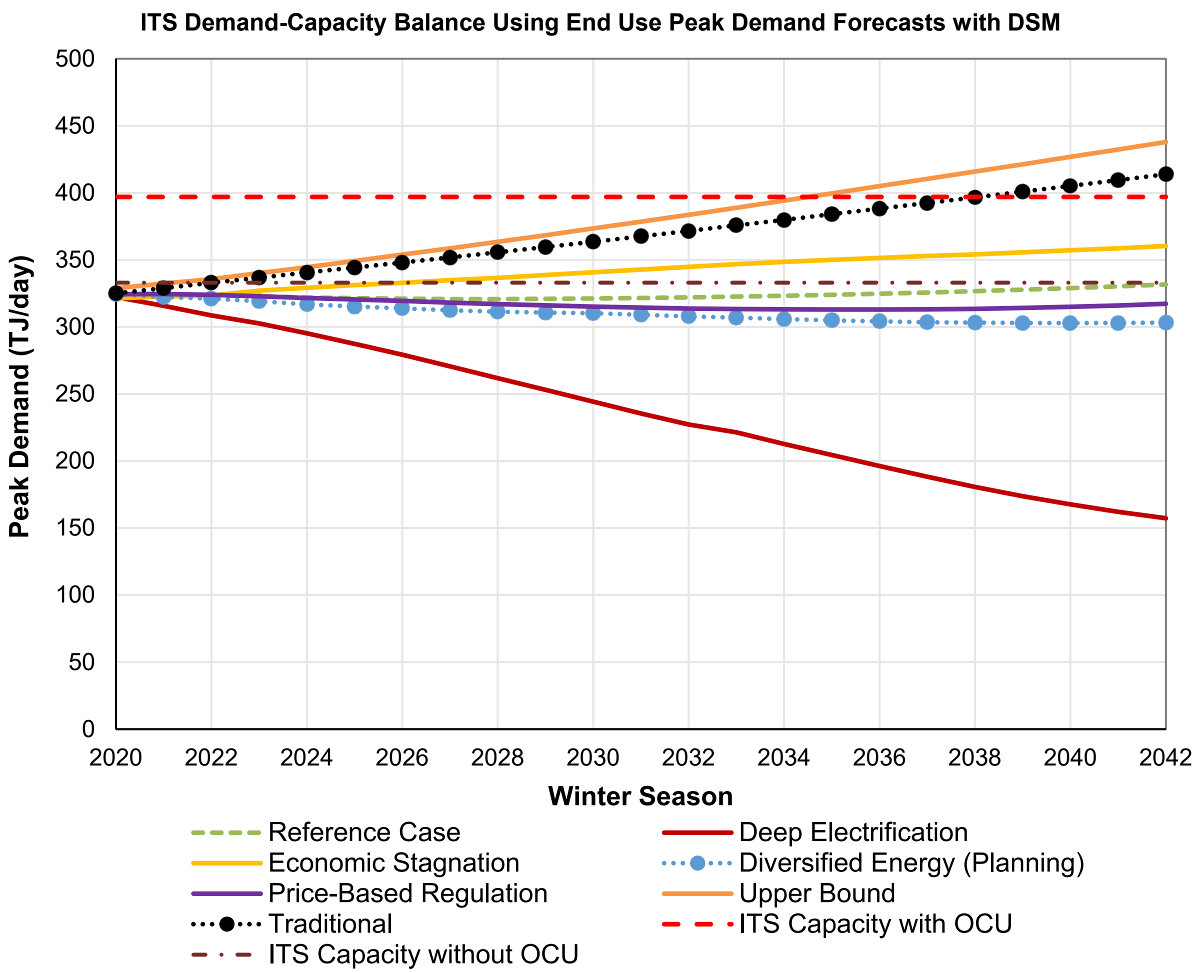
The requested revised figure is provided below showing ITS capacity before and after the OCU Project.



21.13 Figure 7-16: ITS Demand-Capacity Balance Using End Use Peak Demand Forecasts with DSM shows Existing Capacity with OCU as a dotted red line. Please provide a version of Figure 7-16 showing Existing Capacity without OCU, as well as Existing Capacity with OCU.

Response:

The requested revised figure is provided below showing ITS capacity before and after the OCU Project.



21.14 With reference to Figure 7-16, please confirm, or otherwise explain, that the Reference Case with DSM forecast and the Diversified Energy (Planning) with DSM scenario do not show a capacity constraint over the planning period in relation to ITS Existing Capacity without OCU.

Response:

Not confirmed. While Figure 7-16 and the revised figure provided in the response to BCSEA IR1 21.13 (illustrating the current ITS capacity without the OCU Project) show that peak demand in terms of energy delivery on a peak day may decline below the capacity line, the current ITS capacity shown in the figure cannot be directly related to forecasts like the DEP Scenario forecast that includes renewable gases like hydrogen. In Appendix D-3 of the Application, FEI provided some examples of the effect of hydrogen on the capacity to move energy in a fixed system. The current capacity lines shown in these figures only reflect capacity to move natural gas. Because specific details of where renewable gases will enter the ITS are still in early stages of development, there is insufficient information presently available to quantify how the ITS capacity may change over time with the level of renewable gases incorporated in each forecast. Upgrades of the existing system to facilitate moving higher volumes of low-carbon gases while delivering less energy may be required to meet the DEP Scenario forecast or the Reference forecast. Therefore, the improvement in capacity that the OCU Project will provide for the ITS, and that is required to meet current peak demand, will enhance FEI's ability to supply renewable gases like hydrogen in the region, even with a decline in peak demand such as the decline represented in the DEP Scenario or Reference forecasts.

21.15 What measures would FEI take to increase ITS capacity or to decrease peak load in the event the OCUP is not completed?

Response:

FEI expects that the OCU Project will be completed. If the preferred alternative cannot be constructed for any reason, FEI outlined the other alternatives in the OCU CPCN Application.[27] The alternatives could be more extensive pipeline looping from Savona eastward, or an LNG peak-shaving facility in the north Okanagan region. If no permanent upgrade is constructed to address the current capacity shortfall on the system, FEI would not be able to offer firm service in peak demand conditions to new customers choosing gas, as to do so would increasingly erode the ability to maintain reliable service to existing customers. FEI would continue to investigate peak-targeted demand-side management programs, but until some means of measuring and verifying the effectiveness of such programs in reducing peak demand is available, FEI would not be able to ensure that existing customers would continue to receive reliable service in peak demand conditions.

In section 7.3.3.4, FEI addresses ITS System Expansion Alternatives and states:

> “The three reinforcement alternatives described below have been identified to meet the demand forecast and would be required, in addition to completion of the OCU project, by the winter of 2038-2039 for the Traditional forecast and could be

[27] FortisBC Energy Inc. Certificate of Public Convenience and Necessity for the Okanagan Capacity Upgrade Project BCUC Proceeding, Exhibit B-1-2, submitted January 13, 2021.

required for the winter of 2035-2036 to meet the Upper Bound forecast. The proposed OCU project provides sufficient capacity to meet the capacity requirements of all other peak demand forecasts though the forecast period." [page 7-29, pdf p.283]

21.16 In the context of the Planning Environment described in section 2 of the 2022 LTGRP, please explain why FEI does not examine demand-side alternatives to meet potential ITS capacity constraints.

Response:

As discussed in the response to BCSEA IR1 20.1, FEI is studying demand-side management as an alternative to address capacity constraints, but does not presently have sufficient means to reliably verify the extent to which peak demand can be reduced. If demand does not respond as anticipated and a capacity shortfall arises, the impacts would be severe in a system like the ITS which serves large populations in the central and north Okanagan. When FEI can examine and measure alternative approaches to addressing capacity shortfalls, FEI will initially consider systems other than the ITS that are smaller, at lower risk and provide more time to effectively implement such alternatives.

In the OCUP CPCN application, FEI states:

"The peak day demand forecast methodology that FEI used to assess the need for the OCU Project is consistent with the methodology FEI has used in previous CPCN applications and long-term resource plans filed with the BCUC." [Exhibit B-1-2, OCUP CPCN Application, p.20, pdf p.32]

21.17 Please explain how the peak day demand forecast methodology that FEI used in the 2022 LTGRP differs from the methodology used to assess the need for the OCU Project (in the OCUP CPCN application).

Response:

The peak demand forecast methodology used to prepare the forecasts is the same in both applications; however, different peak demand forecasts were used in each application. FEI utilized the most recent forecast available when the analysis supporting each filing was undertaken. The Application is based on the 2020 Peak Demand Forecast, which used a 20-year account forecast starting with existing customers at year-end 2019 and using customer UPC_{peak} calculated from customers' consumption in 2018 through 2019. The OCU Project CPCN application used the 2019 Peak Demand Forecast which was prepared a year earlier and which used a 20-year account forecast starting with existing customers at year-end 2018 and using customer UPC_{peak} calculated from customers' consumption in 2017 through 2018.

22.0 Topic: ITS Potential New Industrial Load

Reference: Application, Exhibit B-1, 7.3.3.5 Potential New Industrial Load, p.7-31, pdf p.285

FEI states on page 7-31:

> "Based on the FBC 2021 LTERP filed with the BCUC in August 2021, a simple cycle gas-fired turbine (SCGT) power generating plant was identified as one of the preferred long-term options in the Okanagan area to meet growing peak electricity demand. Such a plant could be installed in two phases between 2031 and 2035. The potential to add a 100 MW SCGT, expanding to 148 MW by 2035, proposed to be fuelled by RNG, would drive additional expansion of the ITS. The upgrade options would depend on the future location of the facility in the Kelowna area. Adding this load would impact the preferred ITS expansion options and would support an extension of the OCU project much further north into the Kelowna area than is previously described in Option 2. For the Traditional forecast, a future SCGT would require an OCU pipeline extension just before the generating station's proposed in-service date of 2031." [p.7-31, pdf p.285]

22.1 Would system upgrades necessitated by an FBC SCGT be paid for by FEI customers or FBC customers?

Response:

At this time, FEI does not have any details on the system upgrades necessitated by an FBC SCGT plant or how costs would be allocated between FEI or FBC customers. FEI expects more information would be available if FBC moves ahead with plans to install the SCGT plant in the Kelowna area. As with the cost allocation relating to any major project, FEI would consider the benefits provided to gas and electric customers, akin to how the mains extension test operates.

23.0 Topic: Revelstoke Propane System

Reference: Application, Exhibit B-1, 7.3.5.2 Revelstoke Propane System, pp.7-32 to 7-33, pdf pp.286-287; Decision and Order G-245-20

FEI states on page 7-33 of the 2022 LTGRP:

> "In October 2020, FEI received approval for the Revelstoke Propane Portfolio Cost Amalgamation Application that provided a favourable reduction in energy costs for FEI's propane customers in Revelstoke. <u>Core demand growth in Revelstoke is forecast to increase and FEI continues to assess the impact of the amalgamation on Core and Industrial demand</u>. FEI expects to expand the propane system with additional storage tanks and some pipeline looping when increased demand warrants the expansion." [underline added]

In Decision and Order G-245-20, the BCUC approved FEI's Revelstoke Propane Portfolio Cost Amalgamation Application.

BCSEA was an intervener in the proceeding. BCSEA argued, among other things, that "the primary impact of FEI's proposal would be to encourage more use of propane, which in turn would lead to increased GHG emissions." [Decision and Order G-245-20, p.19 of 28]

FEI's response was paraphrased by the Panel as follows:

> "FEI responds that the GHG concerns put forward by BCSEA and CBER are both speculative and overstated. FEI affirms its studies show propane as having low price elasticity. There is no expectation customers would appreciably change their consumption in the immediate or near future in response to a lower commodity cost as such decisions are influenced by a variety of factors.
>
> FEI maintains that in previous years, customers in Revelstoke did not increase their energy usage in response to lower rates. FEI points to its evidence regarding price elasticity and submits the BCUC should refrain from basing a decision upon speculation that is disconnected from the facts. …" [Decision and Order G-245-20, p.21 of 28, footnotes omitted]

Panel accepted FEI's position, stating on page 21 of 28:

> "The Panel is persuaded by the evidence that the price elasticity of propane customers is low. Therefore, <u>it accepts the likelihood of significantly increased rates of propane consumption per customer is low</u>, with the associated effect on increased GHG emissions also remaining low. Moreover, the Panel notes there may in fact be some offsetting reduction in GHG emissions, following an anticipated conversion from heating oil to propane, given the latter's lower carbon

content. The Panel acknowledges that this is consistent with BC energy objectives in encouraging fuel switching from higher GHG fuels.

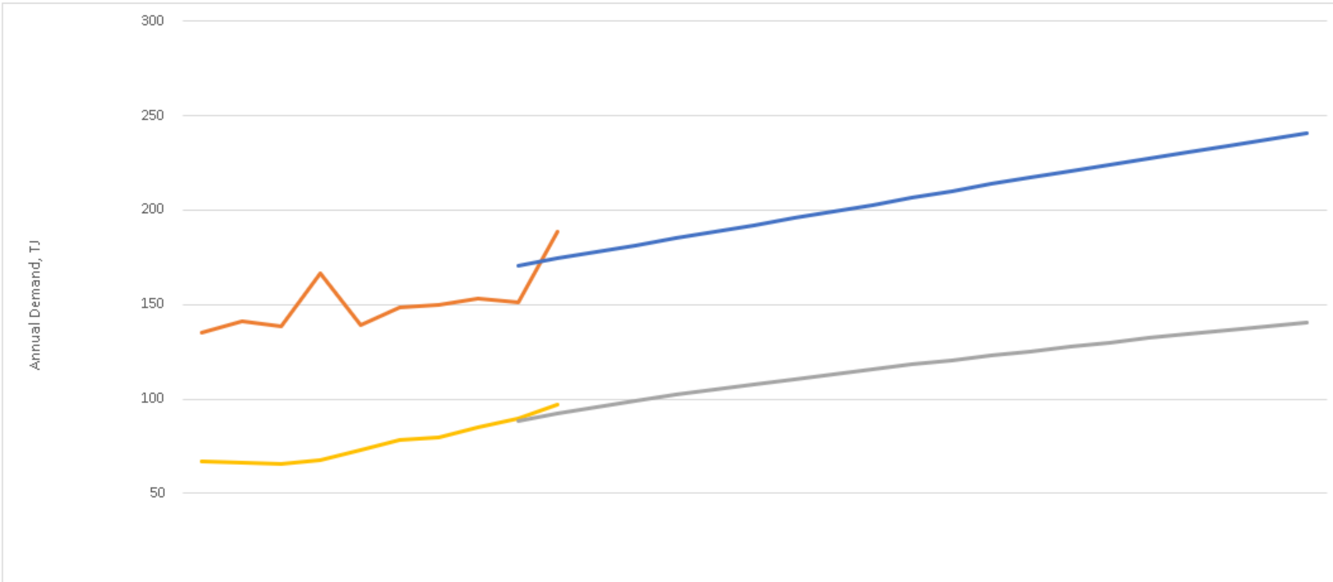
The Panel does not however view a considerable migration to propane from other fuel usage sources as probable. It notes conversions from electricity, wood pellets and the RCEC's service are likely to be low due to the relatively high capital costs involved for customers. Furthermore, the Panel is satisfied by the evidence there will be limited opportunity to increase market share given, amongst other factors, that currently 90% of new builds already use propane." [underline added]

23.1 Please quantify the forecast increase in core demand growth for piped propane in Revelstoke.

Response:

The following figure shows the forecast for core demand growth (residential and commercial rate classes) for piped propane in Revelstoke. Ten years of historical weather normalized actual demand is also shown. FEI notes that the forecast trend is consistent with the historical actual data. FEI also notes that there are no industrial customers in Revelstoke.

The amalgamation of natural gas and propane costs in Revelstoke was effective on January 1, 2021. As shown in the figure below, there is no material impact to the residential demand when comparing the residential demand between 2021 and prior to 2021. For example, the residential demand increased by approximately 5 TJ from 2019 to 2020 and increased by 7 TJ from 2020 to 2021. For commercial customers, there appears to be a bigger growth in demand in 2021 when compared to prior years; however, given commercial demand can be impacted by various factors such as market/economic conditions as well as the impact of the COVID-19 pandemic, FEI is unable to determine if the increase is strictly related to the amalgamation of natural gas and propane costs that was effective January 1, 2021. FEI is also unable to determine if the increase in commercial demand in 2021 is a one-time event or will be a sustained increase based on just the one data point of 2021.



	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Comm. Actual	135	141	139	167	139	148	150	153	151	188																			
Comm. Forecast									171	174	178	181	185	189	192	196	199	203	206	210	214	217	221	224	227	231	234	238	241
Res. Actual	67	66	66	68	73	78	80	85	90	97																			
Res. Forecast									89	92	96	99	102	105	108	110	113	116	118	121	123	125	128	130	132	134	137	139	141

Comm. Actual Comm. Forecast Res. Actual Res. Forecast

23.2 Please quantify FEI's assessment of the impact of the decrease in propane rates on Core and Industrial demand for piped propane in Revelstoke.

Response:

Please refer to the response to BCSEA IR1 23.1.

23.3 Does FEI consider that the decrease in rates for piped propane in Revelstoke has led to an increase in demand and a corresponding increase in GHG emissions?

Response:

No. First, as shown in the response to BCSEA IR1 23.1, there does not appear to be a material increase in residential demand since the amalgamation of natural gas and propane costs. Second, as discussed in FEI's Revelstoke Propane Portfolio Cost Amalgamation Application (approved by Order G-245-20), FEI expects conversion of other fuel types to propane in Revelstoke will likely come from heating oil, thereby resulting in a reduction in GHG emissions. Finally, the commercial demand increased by approximately 37 TJ from 2020 to 2021, which as discussed in the response to BCSEA IR1 23.1, FEI is unable to determine if this is related to the amalgamation of gas costs or other factors based on just one data point. \

23.4 How much will it cost for FEI to expand the piped propane system in Revelstoke to respond to the induced growth in demand?

Response:

FEI is monitoring the load development and customer growth in Revelstoke as FEI indicated in the Application. FEI is unable to quantify the need to expand the piped propane system as well as the costs based on just one data point (i.e., actual of 2021 only). However, to be responsive, FEI notes that, as part of the Revelstoke Propane Portfolio Cost Amalgamation Application, FEI estimated that the cost for three new propane storage tanks and system improvements is approximately $2.8 million (2019 dollars).

24.0 Topic: Gibsons Distribution System

Reference: Application, Exhibit B-1, 7.3.5.4 Gibsons Distribution System, pp.7-33 to 7-34, pdf pp.287-288

24.1 Please confirm, or otherwise explain, that FEI is not seeking any remedies regarding the Gibsons Capacity Upgrade project in the LTGRP proceeding.

<u>Response:</u>

Confirmed. FEI is not seeking BCUC approval of any projects or expenditures in the Application.

25.0 Topic: Hydrogen

Reference: Application, Exhibit B-1, 7.4 Integration of Renewable and Low-Carbon Gas, p.7-34, pdf p.288

FEI states on page 7-34:

> "FEI is planning for gas supply resources made up of increasing amounts of renewable and low-carbon gas over the next 20 years and beyond. The components of this resource mix are expected to include RNG, <u>hydrogen</u>, natural gas, and smaller amounts of syngas and lignin, supplemented later in the planning period by CCUS." [underline added]

25.1 When FEI talks about "hydrogen" (as distinct from green hydrogen, blue hydrogen, turquoise hydrogen) in the 2022 LTGRP, does this refer to hydrogen as defined in the GGRR, that is, "green" or "waste" hydrogen?

<u>Response:</u>

"Hydrogen" in the Application refers to hydrogen as defined in the GGRR ("green" or "waste" hydrogen) as well as low-carbon hydrogen whose carbon intensity falls below the federally recommended 34.6 gCO2e per MJ emissions intensity.

26.0 Topic: Renewable and Low-Carbon Gas

Reference: Application, Exhibit B-1, 7.4 Integration of Renewable and Low-Carbon Gas p.7-36, pdf p.290

FEI states on page 7-36:

> "Although FEI is securing about as many contracts for supply within BC as outside of BC, the larger producers, in the near term, are outside of the province. <u>Therefore, in the early years of the planning horizon, FEI's supply will predominantly be acquired and used outside of FEI's service territory. As a result, during this early part of the planning horizon, the system capacity impacts will remain largely unchanged from what FEI would have otherwise anticipated without renewable gases, as the transmission and distribution systems continue to predominantly move conventional natural gas.</u> By 2030 and through the end of the planning horizon, on-system delivery of renewable gases supplied within FEI systems or by upstream pipeline systems will expand." [p.7-36, pdf p.290, underline added]

26.1 Please explain the underlined passage more fully. Is it the case that the physical presence of RNG rather than conventional NG in FEI's system does not affect system capacity, but the location of injection of RNG may impact local system capacity constraints?

<u>**Response:**</u>

Yes, BCSEA's interpretation is generally correct. For clarity, RNG (biomethane from upgraded biogas) that is injected into the gas system is a "drop-in" fuel that replaces conventional natural gas (NG) in the gas system and reduces overall emissions. FEI acquires RNG for delivery to customers by displacement, which is the same way that conventional NG is currently traded across the contiguous gas system. Therefore, as alluded to in the information request, it is not the case that the physical presence of RNG rather than conventional NG affects system capacity; rather, the point at which RNG production facilities interconnect with the local gas system network may impact local system capacity constraints.

To explain further, there are two main ways RNG will interact with FEI's assessment of system capacity:

1. **On-System RNG Production and Delivery** – FEI acquires RNG produced at locations within FEI's system that is injected into the distribution or transmission pipeline network which will reduce the quantity of conventional NG delivered onto its system. FEI customers directly use the RNG delivered. As the RNG is injected into the system at intermediate points within the system and closer to the end user, the flow path is shortened between producer and consumer and the volume delivery over longer pipeline distances is reduced because of the more local supply. This contributes to reducing the pressure losses incurred by gas flowing long distances in the system. This has a beneficial impact on the capacity of the systems allowing them to deliver more gas to consumers before low

delivery pressures arise, limiting the capacity to deliver more. FEI would therefore assess that this mode of delivery will increase system capacity if the supply of on-system RNG delivered can be considered reliable in peak winter conditions (i.e., that pipeline capacity is not required to protect against production outages).

2. **Off-System RNG Production and Delivery** - FEI acquires RNG produced outside of FEI's service territory and it is received by FEI consumers by displacement as explained above. Customers receive credit for the low-carbon environmental attributes of the RNG they purchase. As FEI customers receive RNG by displacement, FEI's gas supply and delivery though the system remains unchanged. As a result, FEI's assessment of the system capacity required to move that gas through the system is unchanged. As RNG is a methane-rich renewable gas that falls within the physical property specifications FEI has for conventional NG, the flow characteristic will be unchanged from what FEI would plan for if the supply were only conventional NG. As the combined volumes of RNG/conventional NG and the flow path of gas delivered to customers through FEI's system would remain unchanged (that determines the pressure losses incurred in delivery), FEI's assessment of system capacity for this mode of delivery would remain unchanged.

27.0 Topic: Renewable and Low-Carbon Gas

Reference: Exhibit B-1, s. 7.4, Integration of Renewable and Low-Carbon Gas, pdf pp. 288-296

In section 7.4, FEI discusses, at a high level, issues that arise for its system when renewable and low-carbon gas is added to the fuel mix.

27.1 For a convenient date, say 2030 or 2040, please provide a map or maps of FEI's transportation system showing what gas mixes it anticipates moving through the various sections of its transportation system. Please indicate where FEI anticipates injecting or separating out hydrogen or other fuels. If FEI anticipates there will be significant differences in the renewable/low carbon gas mixes provided to different distribution areas, please indicate those.

Response:

FEI anticipates several different potential scenarios could emerge in terms of the long-term deployment of renewable and low-carbon gas mixes in the gas system and is undertaking scenario analysis and planning to better understand potential future impacts. However, at present it is not feasible for FEI to provide the detail or maps requested because the locations and volumes of on-system renewable and low-carbon gas supply projects that will be in operation by 2030 or 2040 is currently unknown.

28.0 Topic: Renewable and Low-Carbon Gas

Reference: Application, Exhibit B-1, 7.4.1.1 Overview of System Planning Considerations in Integrating Renewable and Low-Carbon Gas, p.7-36, pdf p.290

FEI states on page 7-36:

> "Each of FEI's regional pipeline systems have unique considerations with regards to the potential opportunities to bring on renewable and low-carbon gas to displace the need for pipeline delivery of conventional gas. From now until 2030, FEI expects a larger share of on-system renewable and low-carbon gas contribution will come from on-system RNG, syngas and lignin production, and CCUS. By 2042, as technology advances to produce hydrogen electrolytically, by pyrolysis or reformation, hydrogen is expected to be a larger share of FEI's fuel mix. By 2030 and through the rest of the planning horizon FEI's on system supplies will be increasingly enhanced by off system production of renewable gases that is delivered into and through FEI systems." [pdf p.290]

28.1 Please explain what FEI means by "on system supplies will be increasingly enhanced by off system production of renewable gases that is delivered into and through FEI systems."

Response:

FEI means that in the later part of the forecast period and beyond, the volume of renewable and low-carbon gas supply produced in western Canada could significantly increase such that some of the renewable and low-carbon gas produced might physically move through the regional gas transmission system and onto the FEI system. FEI uses the term "increasingly enhanced" in the broad context of this potential future scenario when regional renewable and low-carbon gas production could increasingly displace conventional gas supply in the regional gas system and therefore add to supply from on-system production developed earlier in the forecast period.

G. Consultation

29.0 Topic: GHG Emissions Reporting

Reference: Application, Exhibit B-1, Table 8-5: Overview of Community Engagement Sessions – Feedback on Key Discussion Topics, page 8-20, pdf p.324

In its report on community engagement meetings on October 14 and 16, 2021 for the Lower Mainland and South Coast, FEI states on page 8-20:

> "Requested FEI to provide more gas consumption information to local governments including percentage of renewable and percentage of fracked conventional gas. FEI responded that it is exploring enhancements to Community Energy and Emissions Inventories reporting with the Climate Action Secretariat." [pdf p.324, underline added]

29.1 Please elaborate on the enhancements to the Community Energy and Emissions Inventories reporting that FEI is exploring with the Climate Action Secretariat.

Response:

At the time of writing, there are no further enhancements to report regarding the inclusion of renewable and low-carbon gas in Community Energy and Emissions Inventories; however, FEI continues to collaborate with the Climate Action Secretariat to enhance reporting.

H. Rate and Bill Impact

30.0 Topic: Rate and Bill Impact

Reference: Application, Exhibit B-1, 9.4 Rate Impact Implications of the Diversified Energy (Planning) Scenario, page 9-11, pdf p.344

FEI states on page 9-11:

> "To provide context for FEI's long-term volume forecasts Figures 9-7 through 9-10 provide a 20-year directional view at the potential impact on customer rates under the Reference Case, Diversified Energy (Planning), Deep Electrification, and the Upper Bound Scenarios for Residential (RS 1), Small Commercial (RS 2), Large Commercial (RS 3), and Industrial General Firm Service (RS 5) customers, respectively." [pdf p.344]

FEI states on page 9-15:

> "The cumulative effective rate impacts shown in the figures above are made up of individual impacts in all components of FEI's rates, including delivery, cost of gas, storage & transport, and carbon tax." [pdf p.348]

On page 9-15, Table 9-2 is titled: "Summary and Comparison of Average Projected <u>Delivery</u> Rate Changes" [underline added]. Despite the term "Delivery Rate Changes" in the title, the RS 1 DEP cumulative change is 118%, which is the same figure (118%) shown in Figure 9-11 for the RS1 DEP cumulative annual <u>bill</u> impact.

Also on page 9-15, Figure 9-11: Breakdown of the Cumulative Effective Rate Impact for Residential RS 1 under the Diversified Energy (Planning) Scenario says "Rate Impact" in the title and "Bill Impact" in the y-axis.

30.1 Please clarify whether the "rate impacts" discussed in section 9.4 are "delivery rate impacts," or, in effect, "<u>bill</u> impacts" (delivery rates, plus storage & transport and commodity costs).

<u>Response:</u>

The rate impacts discussed in Section 9.4 of the Application are "bill impacts"; they include the individual impacts of all components of FEI's rates, including delivery, cost of gas, storage and transport, and carbon tax. FEI notes that the title of Table 9-2 as referenced in the preamble above contains a typographical error. Table 9-2 should have been titled "Summary and Comparison of Average Projected <u>Effective</u> Rate Changes" instead of delivery rate changes.

30.2 If necessary, please provide a version of Table 9-2 showing bill impacts rather than delivery rate impacts.

Response:

Please refer to the response to BCSEA IR1 30.1.

FEI says in the 2023 DSM Expenditure Schedule application that the average annual natural gas use for all residential customers within FortisBC's service territory is approximately 90 GJ per year. [footnote 33, pdf p.295] The rate impact results presented in section 9.4 of the 2022 LTGRP assume Residential average annual consumption of 60 GJ.

30.3 Please discuss the rationale for selecting 60 GJ/year as the assumed Residential average consumption rather than 90 GJ/year.

Response:

The 60 GJ per year used for the rate impact analysis in Section 9.4 was based on the average residential use per customer (UPC) from 2023 to 2042 under the DEP Scenario[28].

FEI notes that the residential average use rate of 90 GJ per year was based on an historical average and, for consistency purposes, FEI has been using this UPC for residential customers in its gas cost reports and annual reviews so that the impact from these applications would be isolated from the use of different average residential UPCs.

FEI used the average UPC of 60 GJ per year in this Application as it appropriately reflects the expected residential UPC over the 20-year planning period under the DEP Scenario. If FEI used the historical 90 GJ per year for the bill impact analysis shown in Figure 9-11, the result would have only changed slightly in percentage terms, from 118 percent to 124 percent; however, it would have overstated the impact in absolute dollars and does not truly reflect the expected average residential UPC under the DEP Scenario.

30.4 Directionally, what is the impact on the illustrative rate impacts of the four scenarios over the planning period of selecting 60 GJ/year, rather than 90 GJ/year, as the Residential average consumption?

[28] Appendix B-4, Section 1.2, Annual Use Rate per Customer, RATE 1, 2023 to 2042.

Response:

Please refer to Table 1 below which shows the cumulative impact in 2042 of the four scenarios for both 60 GJ per year and 90 GJ per year for residential average UPC.

Table 1: Comparison of Cumulative impact in 2042 for Residential UPC of 60 GJ/yr and 90 GJ/yr

Cumulative Rate Change (2042)	RS 1 UPC @ 60 GJ/yr	RS 1 UPC @ 90 GJ/yr
Reference	73%	77%
Upper Bound	77%	81%
Diversified Energy (Planning)	118%	124%
Deep Electrification	235%	246%

30.5 Please confirm, or otherwise explain, that by selecting a fixed annual average consumption (by customer class) over the planning period the methodology intrinsically excludes consideration of any price elasticity of demand.

Response:

Not confirmed. FEI clarifies that the analysis in Section 9.4 of the Application provides a directional illustration of the bill impact for an average customer over the 20-year planning period as a result of the various scenarios, and also provides a comparison between the scenarios. Having a fixed UPC over the 20-year analysis period ensures the rate comparisons are consistent and also avoids artificially showing a higher or lower bill impact over time simply because of using a different UPC value. If the individual customer consumes higher or lower than the average UPC used in Section 9.4 over the 20-year period or at any point during that 20-year period, then it can be expected that the customer will experience a higher or lower bill impact than what is shown in Section 9.4 for the average customer.

FEI also clarifies that the delivery margin that forms the basis of the rate calculations is based on a 20-year demand and customer count forecast (please refer to Section 5 of the Application), and that demand forecast and the resulting revenue requirement impacts reflect changes in UPC due to changes in demand and customer count. Please also refer to the response to BCOAPO IR1 9.6 which explains that the declining demand under the DEP Scenario plays an important role in the overall delivery rate increases.

With respect to price elasticity of demand, please refer to the responses to BCSEA IR1 10.1 and 10.3.

30.6 Would it be accurate to assume that including price elasticity of demand in the analysis would tend to increase the rate impacts over the planning period, due to lower throughput putting upward pressure on delivery rates?

Response:

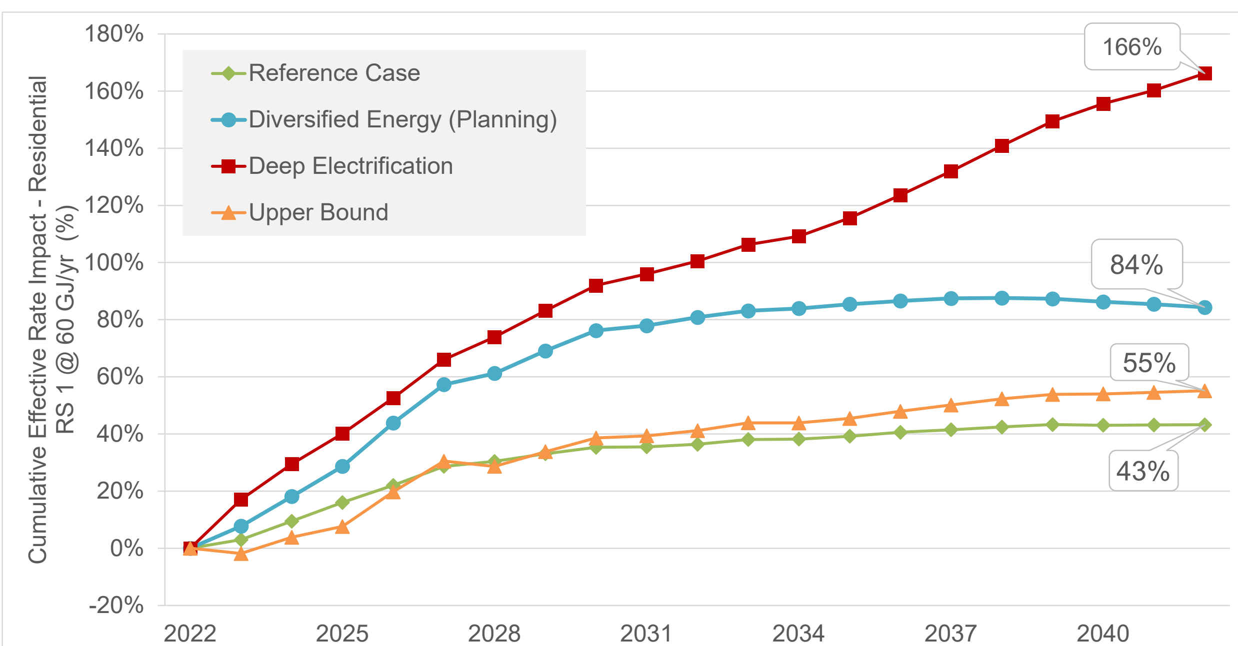
FEI's bill impact analysis already includes the impacts of the price elasticity of demand through its impact on the demand forecast. Please refer to the responses to BCSEA IR1 10.1 and 10.3. FEI notes that the impact of the price elasticity of demand is not specific to the DEP Scenario, but would have a similar effect on gas rates in other scenarios, such as the Deep Electrification Scenario, and would impact electricity rates as well.

30.7 For Figures 9-7 through 9-10 and Table 9-2, are the effects of inflation removed? If not, please provide versions of the figures and table with inflation removed.

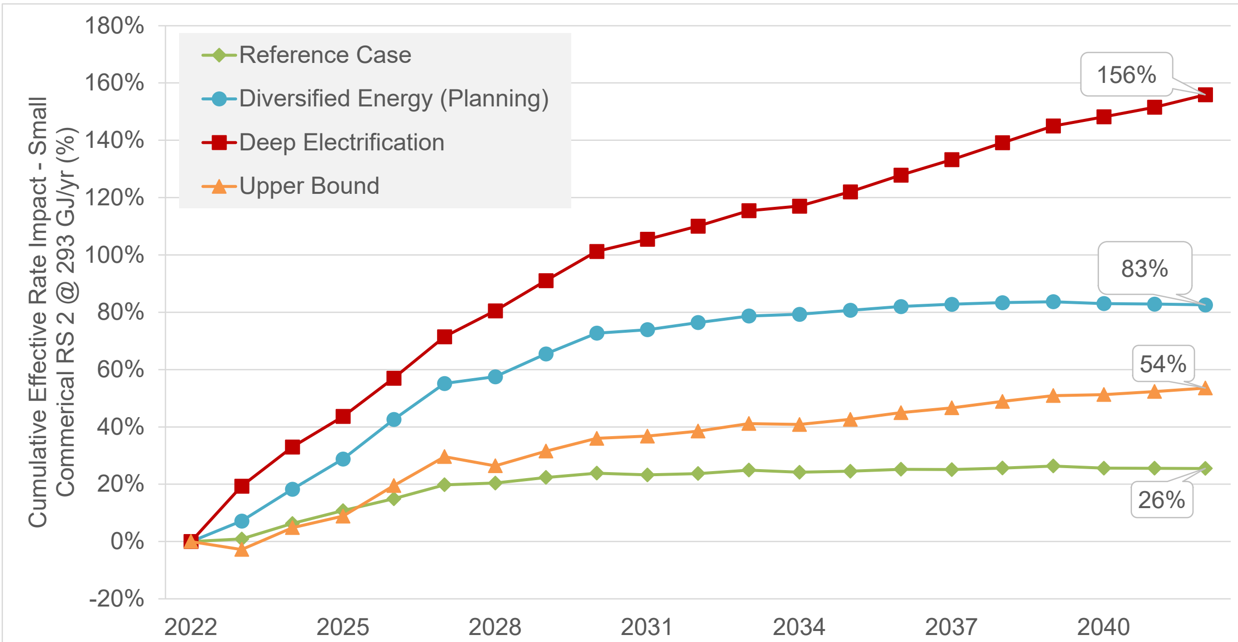
Response:

Figures 9-7 through 9-10 and Table 9-2 do include inflation. Please see the below updated figures and table with inflation removed.

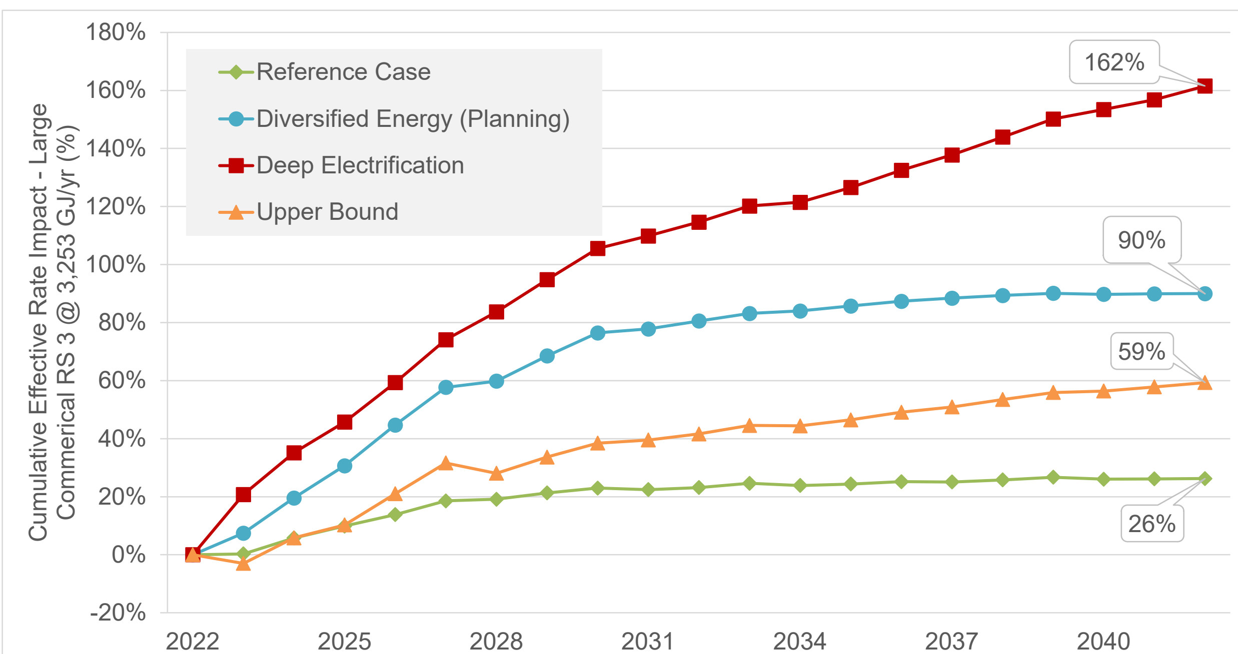
Updated Figure 9-7: Cumulative Effective Rate Impact (2022 – 2042) – Residential RS 1, Avg. UPC 60 GJ



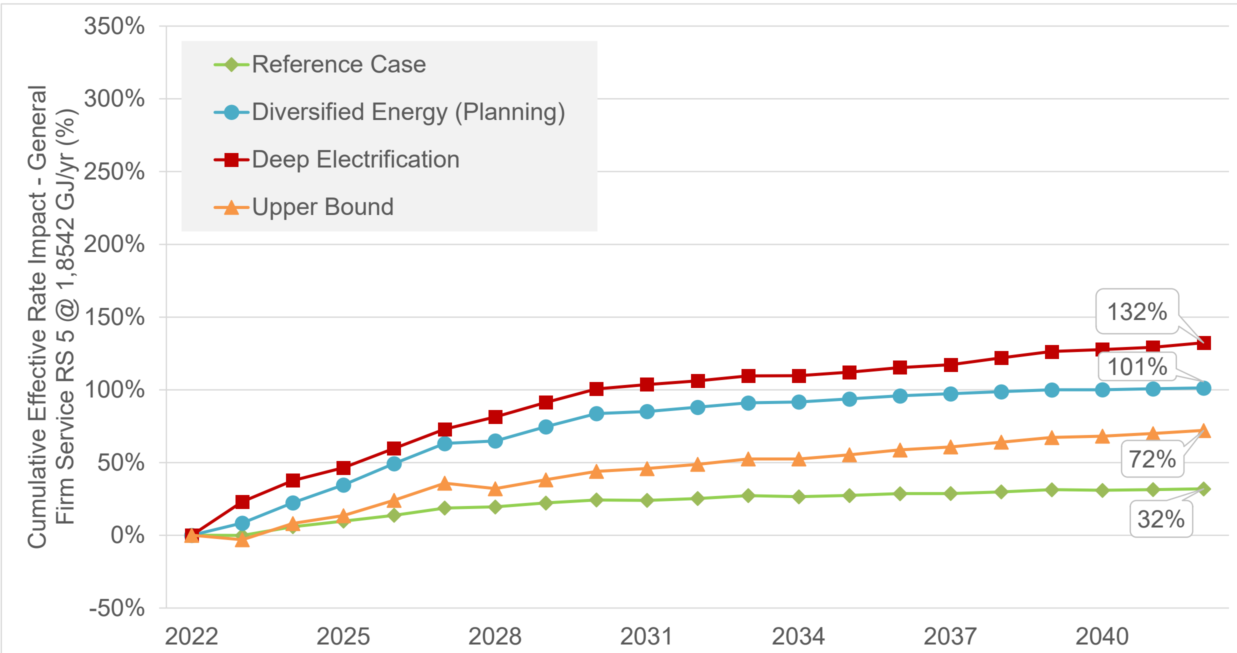
Updated Figure 9-8: Cumulative Effective Rate Impact (2022 – 2042) – Small Commercial RS 2, Avg. UPC 293 GJ



Updated Figure 9-9: Cumulative Effective Rate Impact (2022 – 2042) – Large Commercial RS 3, Avg. UPC 3,253 GJ



Updated Figure 9-10: Cumulative Effective Rate Impact (2022 – 2042) – General Firm Service RS 5, Avg. UPC 18,542 GJ



Updated Table 9-2: Summary and Comparison of Average Projected Delivery Rate Changes

	Effective Rate Change (2022 - 2042, %)								
	Average UPC (2022 - 2042)	Reference		Upper Bound		Diversified Energy (Planning)		Deep Electrification	
		Cumulative	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative	Annual
Residential (RS 1)	60	43%	1.8%	55%	2.2%	84%	3.1%	166%	5.0%
Small Commercial (RS 2)	293	26%	1.1%	54%	2.2%	83%	3.1%	156%	4.8%
Large Commercial (RS 3)	3,253	26%	1.2%	59%	2.4%	90%	3.3%	162%	4.9%
General Firm Service (RS 5)	18,542	32%	1.4%	72%	2.8%	101%	3.6%	132%	4.3%

Figure 9-11 shows a breakdown of the cumulative rate impacts for RS 1 under the Diversified Energy (Planning) scenario.

30.8 If possible, please provide a breakdown of the item “Delivery (Base + C&EM + LCT)” shown in Figure 9-11.

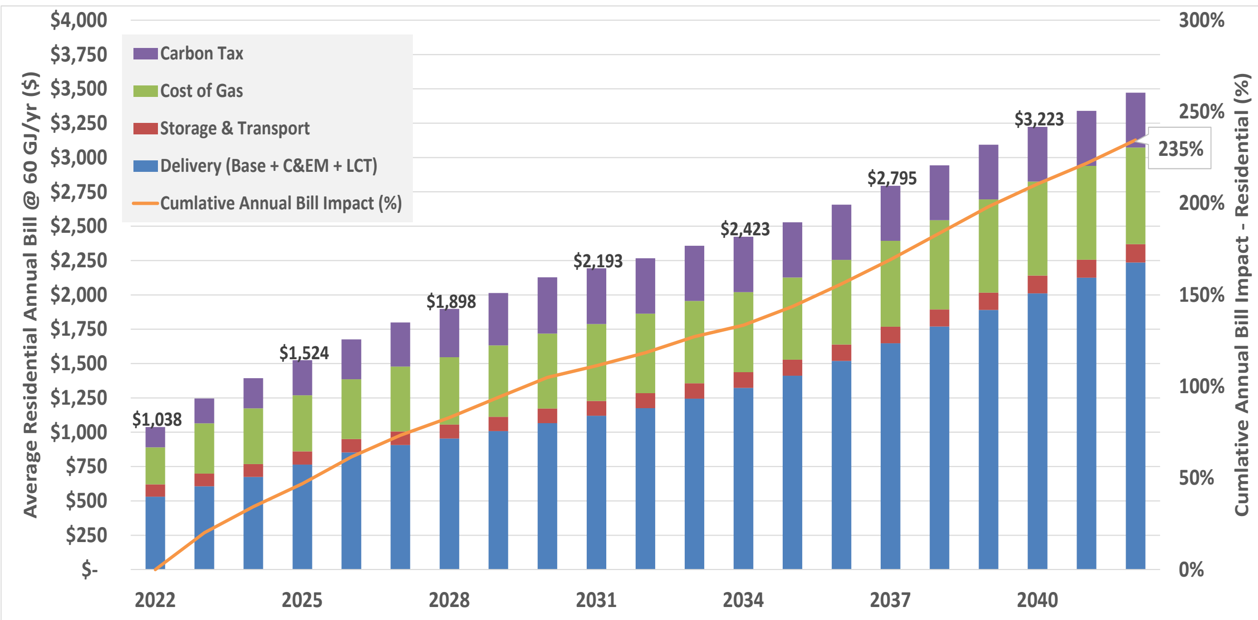
Response:

Please refer to the response to BCOAPO IR1 9.7.

30.9 Please provide a version of Figure 9-11 for the Deep Electrification Scenario, rather than the DEP Scenario.

Response:

Please see the figure below for a version of Figure 9-11 for the Deep Electrification Scenario.



30.10 Has FEI assessed the energy affordability implications of the rate (and bill) increases depicted in section 9.4? Aside from generally working to keep rates low, will FEI take any measures to keep energy rates affordable for its various customer classes?

Response:

Please refer to the response to BCOAPO IR1 9.2.

J. FEI and BC Hydro Energy Scenarios

31.0 Topic: Energy Scenarios initiative – coordination of energy demand forecasting in BC between electricity and gas

Reference: Application, Exhibit B-1, Section 4, Annual Energy Demand Forecasting; Exhibit B-4, BC Hydro and FEI Energy Scenarios, FEI Supporting Commentary Regarding the Supply Resource Impacts, Rate Impacts and Association GHG Emission Impacts, Stage Two; BCUC letter of December 3, 2021 to FEI and BC Hydro (https://docs.bcuc.com/Documents/Proceedings/2021/DOC_65110_2021-12-03-BCUC-Request-Information-on-FEI-BCH-Energy-Scenarios.pdf)

By letter dated December 3, 2021, the BCUC invited FEI and BC Hydro to participate jointly in an exercise of identifying the energy supply resources needed to meet the future needs of FEI and BC Hydro customers in the context of the CleanBC plan and BC's legislated GHG emissions reduction targets.

FEI and BC Hydro agreed and began a process to share their respective gas and electricity load forecast information and to comment on each other's forecasts.

FEI's second substantial submission, its Stage Two submission is filed in this proceeding as Exhibit B-4. It contains extensive comparisons between FEI's and BC Hydro's load scenarios out to 2042.

31.1 Has FEI incorporated the findings of the Energy Scenarios initiative into its 2022 LTGRP, or will it incorporate them into its future long term gas resource planning?

31.1.1 If yes, how with FEI do so?

Response:

The information used to develop the FEI-BC Hydro Energy Scenarios is the same as that used to develop the scenarios provided in the Application. The results of the additional demand forecasts do not suggest any changes need to be made to the Application recommendations or Action Plan. FEI's Stage 1 and Stage 2 reports are filed in the LTGRP regulatory proceeding, thus incorporating them into the regulatory process. As such, FEI does not plan to further incorporate the findings in the Application but would welcome further collaboration with BC Hydro on modelling future demand, and energy system and customer impacts of alternative, long-term decarbonization pathways.

K. Action items

32.0 Topic: Preferred Scenario

Reference: Application, Exhibit B-1, 10, Action Plan, pdf p.351

FEI states on page 10-1:

> "This Action Plan describes the activities that FEI intends to pursue over the next four years based on the information and recommendations provided in this 2022 LTGRP. FEI has built its Action Plan based on the Diversified Energy (Planning) Scenario modelled on the Clean Growth Pathway to achieve the GHG emission reduction targets outlined in the Roadmap. The Action Plan sets FEI on a path to decarbonization that provides the most viable opportunity to meet British Columbia's energy needs and carbon reduction targets, in a cost effective, reliable, and resilient manner." [pdf p.354

32.1 Given the uncertainties, including about Renewable and Low-Carbon Gas supply, is it premature for FEI to choose the Diversified Energy (Planning) Scenario over other scenarios such as the Deep Electrification Scenario?

Response:

No, it is timely for FEI to pursue the DEP Scenario. FEI has conducted in-depth analysis with multiple research teams to evaluate whether a diversified approach that leverages the gas delivery system with low-carbon gases is a beneficial decarbonization pathway for BC. The Clean Growth Pathway to 2050 Report,[29] the Pathways Report, and a research paper from the Institute for Integrated Energy Systems at the University of Victoria (University of Victoria Paper)[30] conclude that the use of renewable and low-carbon gases in the gas system to help decarbonize industry, transport and buildings appears to be a lower-cost, more feasible and more resilient route for BC. Furthermore, the BC Renewable and Low-Carbon Gas Supply Potential Study[31] has shown that in a maximum scenario, BC as a province could produce more than 400 PJ of renewable and low-carbon gases, double the current throughput of gas, by 2050. This means that there is more than enough renewable and low-carbon supply potential to be sourced from within BC, and FEI has obtained enough information to confirm the viability of the DEP Scenario. For these reasons and others, FEI has chosen to pursue the DEP Scenario.

In planning for the future of the BC energy system, there are a number of uncertainties that need to be considered. BC offers a significant number of natural resources that support both the gas and electric systems which provide low-cost and reliable energy to British Columbians. In order to maintain a cost-effective and reliable energy system, it is necessary to account for uncertainties that can occur in either the electric or the gas system. Based on the analysis undertaken in the Pathways Study[32], an electrification pathway, while offering reduced emissions, is an inherently

[29] Exhibit B1-1, Application, Appendix A-1.
[30] Exhibit B1-1, Application, Appendix A-9.5.
[31] Exhibit B1-1, Application, Appendix D-2.
[32] https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/guidehouse-report.pdf#:~:text=In%202018%2C%20FortisBC%20Energy%20Inc.%20%28FortisBC%29%20developed%20its,reduction%20by%20using%20BC%E2%80%99s%20electricity%20and%20gas%20infrastructure.

more expensive option (by $100 billion dollars) than a diversified pathway which utilizes both the electric and gas systems. Further, it is uncertain that an electrification-only approach will offer the same resilience during peak energy events and extreme weather. Last year on December 27, 2021, during the cold weather event that hit BC, the FEI gas system supplied the equivalent of 20,120 MW while the electric grid provided 10,902 MW, meaning the gas system carried almost twice the energy load of the electric system.

The University of Victoria Paper demonstrates that even in the temperate climate of Metro Vancouver, an electrification-only pathway potentially causes resiliency issues. According to the research, during a hypothetical five-day cold weather event with little variable renewable energy available, space heating demand would exceed hydroelectric production capacity very quickly. This research calculated that Metro Vancouver would need to build approximately 350 GWh of electrical storage in order to meet that demand, which would equate to 35 pumped hydro storage facilities.

Based on some of the identified uncertainties inherent in a deep electrification future as discussed in this response, it is imperative to begin planning for and pursuing a diversified energy future today.

32.2 To what extent is the decision in the 2022 LTGRP to prefer the Diversified Energy (Planning) Scenario in the 2022 LTGRP irreversible?

Response:

A BCUC decision to accept the Application, which presents an Action Plan to pursue FEI's Clean Growth Pathway, would be making a determination regarding near-term actions and would not lock FEI or the Province into one path over the long term. The BCUC may, for instance, make decisions on future LTGRPs which could alter the pathway based on new and revised information.

As discussed in the Application and evaluated in the Pathways Report,[33] a diversified energy pathway has significantly more benefits for British Columbians in the energy transition. In contrast to the diversified energy pathway, if BC were to follow a deep electrification pathway, the Province would be locked into that future and its associated uncertainties, most of which stem from the phasing down of gas infrastructure and the subsequent negative consequences of higher infrastructure costs and reduced resilience across the BC energy system compared to the diversified energy pathway. Further, the diversified pathway offers flexibility for BC as it optimizes both the electricity and gas systems.

[33] Exhibit B-1, Appendix A-2, Pathways for British Columbia to Achieve its GHG Reduction Goals.

32.3 What red flags would indicate that implementation of the Diversified Energy (Planning) Scenario was not going as planned?

Response:

FEI considers that it will be important to monitor all aspects of the planning environment as described in Section 2 of the Application and continually assess each of the critical uncertainties used to develop the long-term, end-use demand forecast. The undertaking of successive long-term resource plans will ensure FEI is anticipating changing trends in energy use. More specifically, important red flags that would indicate that the DEP Scenario was not going as planned would include:

- Federal, provincial, local and Indigenous policy that prevent FEI from implementing a diversified pathway;
- A lack of technological progress necessary to implement a diversified pathway;
- Inability to receive necessary regulatory approvals; and/or
- A lack of market uptake/adoption of new technologies and solutions necessary for a diversified pathway.

33.0 Topic: Action Item 1

Reference: Application, Exhibit B-1, 10, Action Plan, pdf p.354

"Action Item 1. Accelerate the development and acquisition of renewable and low-carbon gas supplies to meet customer energy needs and contribute to provincial emission reduction targets (Clean Growth Pathway – Pillar One)." [pdf p.354]

33.1 Is Action Plan item #1 – accelerate the development and acquisition of renewable and low-carbon gas supplies – contingent on the Commission's forthcoming decision in the Stage 2 Comprehensive Review and Application for Approval of a Revised Renewable Gas Program proceeding?

Response:

Action Item 1 is not contingent on the Revised Renewable Gas Program Application. However, FEI does intend to continue to accelerate the development and acquisition of renewable and low-carbon gas, and the pace and degree of that acceleration will depend on a number of factors, one of which is the outcome of the Renewable Gas Comprehensive Review application. Please refer to BCUC IR1 28.1 for discussion of the impact if the Renewable Gas Connections service is denied or approved.

33.2 What are FEI's next steps regarding acquisition of hydrogen? How soon does FEI expect to enter a supply purchase agreement for hydrogen?

Response:

Please refer to the response to BCUC IR1 61.3 for a discussion on FEI's overall hydrogen deployment strategy, and the responses to BCUC IR1 62.2 and 62.4 regarding anticipated timelines.

33.3 What are FEI's next steps regarding injection of hydrogen into the FEI system?

Response:

Please refer to the response to BCUC IR1 61.3 for a discussion on FEI's overall hydrogen deployment strategy, and the responses to BCUC IR1 62.2 and 62.4 regarding anticipated timelines.

33.4 Does "Support the development of BC's hydrogen economy through implementing hydrogen blending and hydrogen hubs, and plan for transitioning to hydrogen compatible infrastructure" mean that FEI would itself be involved in implementing hydrogen blending and hydrogen hubs?

Response:

Yes, FEI intends to be involved in implementing hydrogen, as outlined in the Application.

33.5 What form of CCUS would FEI accelerate the adoption of, and what form would CCUS service offerings and rates take? Does FEI have any particular projects in mind?

Response:

Please refer to the response to BCUC IR1 64 series regarding FEI's support of CCUS technologies.

34.0 Topic: Action Item 2

Reference: Application, Exhibit B-1, 10, Action Plan, pdf p.355

"Action Item 2. Pursue approval of DSM funding for the period beyond 2022 by submitting for BCUC approval a DSM expenditure plan in 2022 (Clean Growth Pathway – Pillar Two)." [pdf p.355]

34.1 Please provide additional detail on how FEI will assess the implications of increasing amounts of renewable and low-carbon gas on FEI's DSM activities, program modeling and reporting tools.

Response:

FEI anticipates that incorporating the implications of increasing amounts of renewable and low-carbon gas into DSM program planning and implementation will be straight forward, although it is subject to some regulatory uncertainty. Energy efficiency measures that meet required cost-effectiveness criteria will lower the overall demand for energy and will reduce the amount of conventional natural gas that needs to be acquired, allowing the renewable and low-carbon supplies to make up a growing proportion of the supply mix. Subject to any future changes to the BC DSM Regulation, long-standing principles for DSM evaluation and cost-effectiveness calculations will continue to be applied. Existing reporting tools will continue to track activities and are sufficiently flexible to adapt to changes in input values caused by the transition to lower carbon fuels and potential future regulation changes. For the foreseeable future, DSM annual reports will continue to report on energy savings that result from DSM activities and GHG emission reductions resulting from the amount of conventional natural gas reduced. Emission factors to be used in calculating emission reductions will be based on values or calculation methods accepted by the provincial government, which FEI anticipates will be addressed in upcoming regulation amendments, and the best available information.

From a resource planning perspective, future modelling of DSM activities will continue to see improvements, such as the ability to apply DSM to the blend of gaseous fuels, improving the accuracy of the estimate of total energy savings from the measures, as well as the ability to test the cost-effectiveness of using DSM to reduce carbon emissions. This will enable an analysis that compares DSM with other resource cost tests such as the acquisition of low-carbon or renewable gases.

35.0 Topic: Action Item 3

Reference: Application, Exhibit B-1, 10, Action Plan, pdf p.355

"Action Item 3. Continue pursuing FEI's LCT and global LNG initiatives to address market opportunities for load growth in support of customer rates and reducing local and global GHG emissions. (Clean Growth Pathway – Pillars Three and Four)." [pdf p.355]

35.1 Please describe how Action Item 3 would be recast if the Commission was to determine that the 2022 LTGRP should be limited to initiatives to reduce GHG emissions that are reportable to the Province of B.C.

Response:

Action Item 3 would not need to be recast. The options available to the BCUC with regard to the Application are to accept the plan as being in the public interest, reject the plan, or reject part of the plan. If part of the plan is rejected by the BCUC, then those parts of the plan not rejected will continue to be implemented and FEI will incorporate any directions it receives from the BCUC regarding its integrated resource planning into the next LTGRP or interim filings as required. FEI considers that important actions it can take to reduce global emissions and lower rate pressures for customers in BC, as in Action Item 3, are in the interests of all energy consumers and the public in BC.

35.2 Please explain why the "global LNG initiatives" shouldn't be considered the purview of FortisBC Holdings Inc. rather than FEI.

Response:

Please refer to the response to BCSEA IR1 8.4.

36.0 Topic: Action Item 4

Reference: Application, Exhibit B-1, 10, Action Plan, pdf p.356

"Action Item 4. Continually improve engagement processes and activities with Indigenous groups and BC communities on FEI's long-term gas resource planning." [pdf p.356]

FEI states on page 10-3:

> "FEI will:
>
> Continue to assess and incorporate the use of new communication technologies to provide greater reach and improved input into the LTGRP; …"

36.1 Please elaborate on the new communication technologies that FEI intends to deploy.

Response:

In light of the COVID-19 pandemic, FEI adapted its engagement process on the LTGRP to include virtual methods of engagement, such as Microsoft Teams. FEI intends to continue to leverage virtual engagement methods, along with in-person workshops, and will explore best practices for offering hybrid engagement throughout the development of future resource plans. In addition, FEI may explore different technology options to develop surveys or electronic message boards as a means to expand outreach opportunities with various customer groups. Internal discussions and feedback from participants will assist in identifying best practises for communication moving forward.

37.0 Topic: Action Item 5

Reference: Application, Exhibit B-1, 10, Action Plan, pdf p.357

"Action Item 5. Seek BCUC approval for a deferral account to capture the costs of advancing the development of the Regional Gas Supply Diversity (RGSD) project." [pdf p.357]

37.1 When does FEI expect to file a CPCN application for the RGSD Project?

Response:

Based on the current preliminary RGSD Project's timeline, FEI anticipates filing a CPCN sometime in the second half of 2024.

38.0 Topic: Action Item 6

Reference: Application, Exhibit B-1, 10, Action Plan, pdf p.358

"Action Item 6. Continue to develop and implement FEI's Gas System Resiliency Plan." [pdf p.358]

"FEI will: …

Continue to monitor regional issues in the PNW for developments that could impact the resiliency of gas supplies for FEI's customers."

38.1 Please provide examples of the developments in the PNW that could impact the resiliency of gas supplies for FEI's customers.

Response:

Resiliency has become an increasingly important consideration in the PNW, especially in light of several instances of low probability, high-impact events in recent years. These include the 2018 T-South incident, flooding in the Sumas Prairie following record flows in adjacent rivers, as well as regional pipeline issues caused by extreme cold weather events (for example in February 2019 and December 2021). FEI has ongoing discussions with gas utilities and pipeline operators in the PNW to explore ways to enhance system resiliency and meet the needs of the region. Further, FEI is a member of the Northwest Gas Association and discusses a variety of topics in that forum, including resiliency. The gas utilities in the US PNW are not as dependent on the T-South system in comparison to FEI, as they have greater physical pipeline diversity and access to more on-system storage (e.g., NW Natural's storage at Mist). Therefore, other market participants may have a differing perspective on their needs and requirements, including resiliency, based on their market views of the region and their specific needs. Although there are developments in the PNW that could impact the resiliency of the region, FEI is not aware of any specific resiliency investments proposed or forthcoming from other utilities or third-party operators that would greatly improve FEI's resiliency.

Specifically, the impact of any infrastructure development from an external party in the PNW that would positively impact the resiliency of gas supplies for FEI's customers would depend on the pipeline size (flow capacity per day), costs, and the proposed pipeline route. For example, on November 4, 2022 Enbridge announced that it will move ahead with plans to expand the T-South system, after its open season was fully subscribed for 300 MMcf per day, as discussed in the response to BCSEA IR1 19.2. This expansion will likely include pipeline looping and compressor upgrades within the existing pipeline corridor. Increasing capacity of the existing T-South system will help offset some of the recent and forthcoming demand in the region (i.e., demand for gas-fired electricity in the PNW and future demand coming from the Woodfibre LNG project). However, it will not have a significant positive impact on FEI's customers as it will result in higher tolling costs for existing T-South shippers, including FEI, while only providing minimal incremental resiliency benefits to FEI. This is because any future incident could still disrupt the entire T-South path in the common corridor.

Additionally, there is a potential expansion of the Gorge pipeline by NWP. It is FEI's understanding that this would be a major expansion that would increase physical supply to the Lower Mainland and enhance the resiliency of gas supplies for FEI's customers. However, this project has not yet advanced to a point where NWP is able to provide reasonable expansion scenarios or their estimated costs.

Given the limited resiliency investments forthcoming from other utilities and third-party operators in the PNW, FEI is proposing to improve the resiliency of gas supplies for FEI's customers through projects that have the most resiliency benefits to FEI's service area, as further detailed in the response to BCUC IR1 57.2.

39.0 Topic: Action Item 7

Reference: Application, Exhibit B-1, 10, Action Plan, pdf p.358

"Action Item 7. Plan for and prepare CPCN applications for near-term system requirements identified in Section 7 to support safe, reliable and cost-effective gas delivery to FEI's customers." [pdf p.358]

39.1 Does the 2022 LTGRP contemplate reviewing system infrastructure projects through the lens of the anticipated GHG Reduction Standard?

Response:

Yes. The Application does contemplate reviewing system infrastructure projects based on the proposed GHGRS emission cap to the extent possible given the information provided by the Province to date around details of the GHGRS. In Section 7.4 of the Application, FEI discusses the integration of renewable and low-carbon gas within its long-term system planning objectives. All upcoming infrastructure projects will take these considerations into account. FEI's existing infrastructure will support delivery of renewable and low-carbon gases for both near-term projects and into the future. Further, FEI considers how infrastructure upgrades can best support its customers in the changing energy environment. Any projects developed in the near term (the OCU Project, for example) address current levels of peak demand to ensure existing customers have secure access to energy under peak winter conditions. These projects will continue to contribute to FEI's Clean Growth Pathway as FEI navigates the future energy transition, guided in part by the anticipated GHGRS.

40.0 Topic: Action Item 8

Reference: Application, Exhibit B-1, 10, Action Plan, pdf p.359

"Action Item 8. Continue monitoring, analysing and contributing to the energy planning environment while working with government on policy framework for deep decarbonization." [pdf p.359]

FEI states on page 10-6:

> "FEI's low-carbon transition will influence the renewable and low-carbon gas marketplace in BC and beyond."

40.1 Does FEI see indications that other gas distribution utilities in Canada and the US are moving toward a low-carbon transition?

<u>Response:</u>

Yes, FEI does see some other gas distribution utilities, both in Canada and the US, planning to decarbonize and transition towards a low-carbon energy future to help mitigate the effects of climate change. Some noteworthy examples are provided below:

- Énergir Inc., in Quebec, is planning to reach 10 percent of renewable natural gas by 2030, reduce GHG emissions related to natural gas use in the building sector by 30 percent by 2030, and achieve net zero emissions for energy distributed in 2050[34];
- Enbridge Gas Inc., in Ontario, is on track to meet its 2030 emissions reduction target of 30 percent below 2005 levels, and is assessing the feasibility of two pathways to net zero by 2050[35]; and
- Northwest Natural Gas Company, in Oregon and Washington, is committed to a low-carbon energy future, in a diversified, reliable energy system, and plans to achieve carbon neutrality by 2050.[36]

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34 https://www.energir.com/en/about/the-company/who-we-are/our-engagement/.
35 https://www.enbridgegas.com/sustainability/pathway-to-net-zero.
36 https://www.nwnatural.com/about-us/the-company/carbon-neutral-future.

41.0 Topic: Action Item 9

Reference: Application, Exhibit B-1, 10, Action Plan, pdf p.360

"Action Item 9. Protect and promote the interests of FEI's customers by securing reliable, cost-effective, long-term gas supplies that include increasing proportions of renewable and low-carbon gas." [pdf p.360]

41.1 Do the acquisitions of renewable and low-carbon gas under this Action Item extend beyond prescribed undertakings under the GGRR and section 18 of the CEA?

Response:

Yes. As the BC government has shifted the 2018 CleanBC goal from a 15 percent renewable gas target to a GHG emissions reduction target for gas distribution utilities in the 2021 CleanBC Roadmap, FEI believes that additional renewable and low-carbon gas activities beyond those currently outlined under the GGRR and section 18 of the CEA will be required.

42.0 Topic: Action Item 10

Reference: Application, Exhibit B-1, 10, Action Plan, pdf p.361

"Action Item 10. Continue monitoring for and evaluating system expansion needs across FEI's service regions." [pdf p.361]

42.1 Does the 2022 LTGRP provide that the evaluation of system expansion needs will take into account the anticipated GHG Reduction Standard?

Response:

Yes. FEI's future system expansion needs will take into account the proposed GHGRS to the greatest extent possible. FEI's gas system must be improved to meet future demand growth and optimize operation of the system as a whole. With annual increases in forecast peak demand, potential new sources of demand from Low-Carbon Transportation and industrial sources, and the introduction of renewable and low-carbon gas in significantly increasing quantities, the VITS, CTS and ITS could all require capacity-enhancing projects to meet peak demand forecasts while enabling FEI's Clean Growth Pathway.

System expansion needs are examined annually through FEI's routine business operations activities. Annual demand overwhelmingly determines the effectiveness in meeting GHG emissions targets. However, peak demand remains a critical consideration to ensure customers are not subjected to risk during extreme cold weather events. Therefore, reduced demand resulting from FEI's GHG emission reduction initiatives cannot be the only consideration in deferring infrastructure expansion. Since projects take lead time to get approval and to develop, it is important that system expansion projects are not suppressed based solely on FEI's GHG reduction initiatives. Instead, projects will be identified annually, with the understanding that projects only move to implementation if supported by updated forecasts that prevail at that future time.

43.0 Topic: Action Item 11

Reference: Application, Exhibit B-1, 10, Action Plan, pdf p.361

"Action Item 11. Prepare and submit FEI's next LTGRP." [pdf p.361]

FEI states:

> "FEI anticipates filing its next LTGRP approximately 2 to 3 years following the conclusion of the regulatory process for its 2022 LTGRP." [pdf p.362]

43.1 Please confirm, or otherwise explain, that FEI intends its next Long-Term Gas Resource Plan (following the 2022 LTGRP) to take into account the requirements of the anticipated Greenhouse Gas Reduction Standard.

Response:

Confirmed.

43.2 After implementation of the anticipated Greenhouse Gas Reduction Standard, how long will it take FEI to develop compliance pathways and to prepare and file the next LTGRP?

Response:

Under the Clean Growth Pathway, FEI has undertaken much of the work to develop at a high level the compliance pathways that it would need to undertake to comply with the GHGRS. If the Province were to include other GHG mitigation compliance pathways, FEI would incorporate those as well. FEI's objective will be to execute on those pathways once the details of the GHGRS are provided by the Province.

Further, once sufficient detail on the regulatory approach is provided by the Province (potentially in 2023), FEI anticipates that its compliance pathways will be outlined in the next LTGRP with a possible short-term initial application to expedite immediate action areas.