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December 22, 2022

Residential Consumer Intervener Association
c/o Midgard Consulting Inc.
Suite 828 – 1130 W Pender Street
Vancouver, B.C.
V6E 4A4

Attention: Mr. Peter Helland, Director

Dear Mr. Helland:

Re: FortisBC Energy Inc. (FEI)

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

Response to the Residential Consumer Intervener Association (RCIA) 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 RCIA IR No. 1.

In its responses, FEI has identified responses which were provided by, contributed to, or developed with its consultants, the Posterity Group, Guidehouse and ICF Consulting Canada Inc. (ICF Consulting).

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

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. Reference: Exhibit B-1 Plan p.2-3 to 2-5

Federal Legislation and Requirements

On page 2-3 of its Plan, FEI states: "However, while natural gas is one of the most widely used fuels in Canada, there is no specific federal climate policy direction on the future of the gas delivery system."

On page 2-4 of its Plan, FEI states: "This means that there is currently no federal mandate for gas utilities to decarbonize their fuel and signals that there is no longer-term vision for the low-carbon solutions delivered by the gas system as part of the federal government's overall approach to climate action, despite the merits of this approach to decarbonization."

1.1 Are there any federal regulations or requirements that put an obligation on FEI (as opposed to its customers) to reduce GHG or otherwise hold FEI accountable for the emissions of its customers? If so, please itemize.

Response:

No, there are no existing or proposed federal regulations or mandates that obligate FEI to reduce GHG emissions or otherwise hold FEI accountable for the emissions of its customers.

2. Reference: Exhibit B-1 Plan p.2-7 to 2-9

Provincial Legislation and Requirements

On page 2-7 of its Plan, FEI states: “the provincial government has intensified its efforts to address climate change through a variety of policies, measures and proposals discussed below, which suggest that both electrification and the decarbonization of the gas system are key strategies to meet the provincial government’s climate goals. The depth and intensity of measures reflects that, while BC has made progress to reduce the carbon intensity of its economy, it is not on pace to achieve its 2030 target of a 40 percent reduction from 2007 levels. Therefore, further initiatives are underway to accelerate climate action, which create new opportunities and challenges for FEI and its customers.”

2.1 Identify which provincial Acts and regulations hold FEI accountable for GHG emissions or emission reductions.

Response:

Although FEI expects the GHGRS will provide accountability for GHG emissions reductions in the buildings and industrial sectors at some point in the future, there are no existing acts or regulations that obligate FEI to reduce its scope 3 GHG emissions.

However, there are various regulations that put requirements on individual stations or systems such as provincial methane regulations. The *Climate Change Accountability Act* sets legislated targets to achieve sectoral GHG reductions by 2030, which will require concerted effort by FEI to achieve; however, no statutory obligation, mandate or other measure is included in the act that makes FEI accountable for achieving the target.

On page 2-8 of its Plan, FEI states: “The Roadmap, includes ambitious measures that place FEI at the forefront of the global energy transition. It is also anticipated to have a significant impact on FEI’s customer rates, competitiveness and throughput.”

2.2 Confirm whether the Roadmap provides any guidance with respect to its expectations on the impact on gas supply or gas distribution rates.

2.2.1 If confirmed, provide the relevant guidance.

Response:

The CleanBC Roadmap provides guidance on the overall GHG reduction obligation it intends to place on natural gas utilities through the GHG emissions cap on natural gas utilities (i.e. the GHGRS). The emissions cap aims to reduce GHG emissions associated with energy delivered by natural gas utilities to the buildings and industrial sectors by an aggregate 47 percent below

2007 levels by 2030. The CleanBC Roadmap does not provide any further guidance on how this will impact gas supply or distribution rates.

On page 2-9 of its Plan, FEI states: "The GHGRS is the first of its kind in Canada, and will mandate FEI to invest in carbon saving technologies and solutions to displace natural gas consumption by 2030. As described in the report, 'the cap will be set at approximately 6 Mt of CO2e per year for 2030, which is approximately 47 percent lower than 2007 levels.' The GHGRS would require a GHG reduction of approximately 5.5 Mt of CO2e, which is equivalent to displacing approximately half of the natural gas delivered by FEI."

On page 9-3 of its Plan, FEI states: "The Province's Clean BC Roadmap states that the GHGRS emissions cap on gas utilities will be approximately 6 Mt CO2e in 2030. Accounting for the fact that FEI is not the only gas utility in BC, the portion of the cap that applies to FEI is estimated to be 5.7 Mt CO2e."

2.3 What are the consequences to FEI if it exceeds the GHGRS cap of 5.7 Mt?

Response:

Details on compliance and consequences of non-compliance with the GHGRS have not yet been provided by the provincial government.

2.4 If the Province has provided any additional details on the GHGRS, please provide them.

Response:

While FEI has engaged in discussion with the Province on the goals and design of the GHGRS, the Province has not yet determined the details of the GHGRS. As such, FEI is unable to provide any additional details at this time.

2.5 How will FEI's expansion to serve Woodfibre LNG and other LCT uses affect FEI's ability to meet the cap?

2.5.1 Will the added compression and fugitive emissions from Woodfibre LNG negatively affect FEI's compliance with the cap?

Response:

Please refer to the response to RCIA IR1 8.1.

3. Reference: Exhibit B-1 Plan p.2-16

Municipal By-Laws and Requirements

On page 2-16 of its Plan, FEI states: "Along with these commitments, a growing number of local governments are implementing changes to their building codes63, planning guidelines, and zoning bylaws in order to reduce GHG emissions in new building construction projects and in some cases with existing building retrofits and improvements."

3.1 Do any municipal regulations or by-laws preclude FEI from connecting new customers or supplying natural gas to customers?

3.1.1 If so, please identify the municipalities and briefly summarize the by-laws that limit FEI's ability to distribute gas.

Response:

Yes; there are municipal regulations that will preclude FEI from connecting new customers or supplying natural gas to customers. Please refer to the response for BCUC IR1 4.1 for a discussion on the regulations, bylaws and measures impacting FEI's ability to connect customers.

B. Clean Growth Pathway

4. Reference: Exhibit B-1 Plan p.3-16; Appendix D-3 p.3

Hydrogen Blending

On page 3-16 of its Plan, FEI states: "The unique physical, chemical, interchangeability, and utilization characteristics when compared to conventional natural gas may limit hydrogen gas as a drop-in replacement fuel, beyond a percentage blend expected to be in the concentration range of 2 to 20 percent by volume. As hydrogen is less dense, it will require somewhat larger pipes and more compression to deliver similar amounts of energy."

On page 3 of Appendix D-3 of its Plan, FEI states: "Hydrogen has a heating value of 12.1 MJ/m3. As a result, if hydrogen is directly substituted for natural gas, around three times the volume of hydrogen must be delivered to customers to meet the same energy delivery of unit volume of natural gas."

4.1 What is the reduction in transmission pipeline capacity that would result from utilizing a 20% blend of H2? Is this the same capacity reduction as for distribution pipelines?

Response:

FEI has analyzed select segments of existing transmission pressure pipeline systems and select distribution networks to understand the potential impact to capacity when operating on different hydrogen blend levels. FEI's analysis indicates that there are multiple factors at play when determining actual capacity requirements to blend hydrogen. Utilizing up to 20 percent hydrogen would require additional detailed analysis of each system to ensure distribution pressure networks and transmission systems would retain the necessary capacity.

Sample Technical Analysis

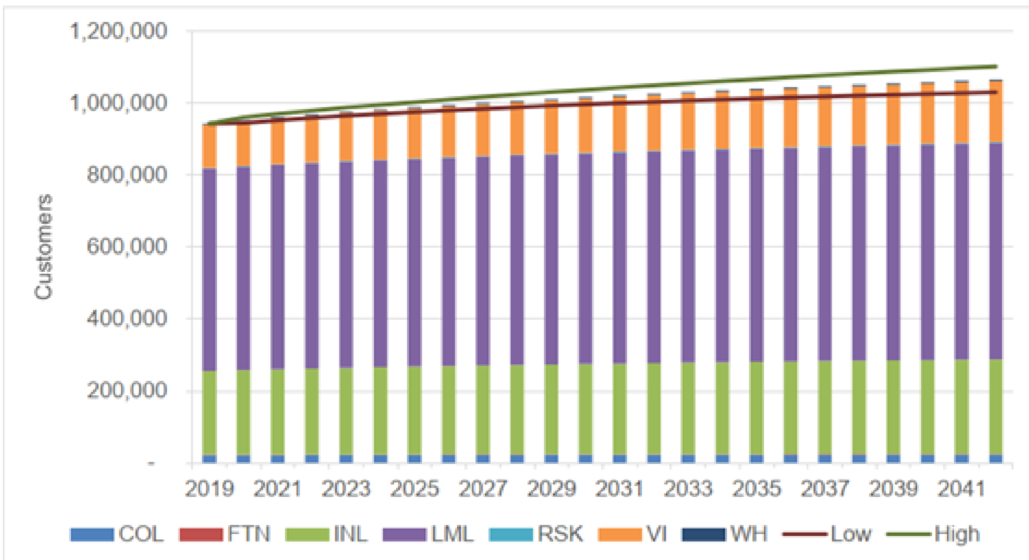
As outlined in the technical analysis discussion provided here using the same approach that was used in developing Table D3-1 in Appendix D-3 of the Application, and carefully selecting simple pipe segments and setting conditions where the limiting constraint remains consistent in each case, a 20 percent blend of hydrogen would result in a reduction of energy capacity of approximately 7 percent in both systems compared to a 0 percent hydrogen scenario. However, there are a variety of parameters that may constrain or define pipeline capacity based on the operating conditions and configuration of the system. It can be misleading to apply a generalization of changes in capacity to transmission or distribution systems. Increasing the hydrogen content in a pipeline tends to decrease the energy delivery capacity but increase the resulting gas velocity and volumetric throughput. While a pipe flowing natural gas with no hydrogen may be constrained by the minimum delivery pressure at the delivery point, a blend of, 20 percent hydrogen for example, could cause the pipe to be constrained instead by high gas velocity. Table D3-1 in Appendix D-3 of the Application illustrates this difference with a comparison (using 100 percent hydrogen) defining the pipeline energy delivery capacity based on different limiting constraints. Gas properties used in gas flow equations can change with hydrogen blends as well. Transmission systems will operate over a broader range of pressure (spanning thousands of kPa) than in distribution systems (spanning hundreds of kPa), and, as a result, shifts in constraints as described above may be more likely to occur, and the effect of variation in physical properties affecting flow may contribute to some small changes in capacity in a transmission system that would not be noticed in a distribution system. Additionally, distribution systems are typically very interconnected, and the system itself does not have overall capacity that can be easily quantified. This is because capacity constraints are localized and sensitive to the distribution of demand in the network, so a change in blend percentages may trigger capacity constraints in some systems more than others.

C. Demand Forecast

5. Reference: Exhibit B-1 Plan p. 4-5

At page 4-5 of its Plan, FEI provides Figure 4-2:

Figure 4-2: Long-Term Residential Customer Forecast by Region[134]



COL: Columbia	**INL:** Inland	**RSK:** Revelstoke	**WH:** Whistler
FTN: Fort Nelson	**LML:** Lower Mainland	**VI:** Vancouver Island	

5.1 Please explain the assumptions were used by FEI to generate these figure, including:

5.1.1 cost of natural gas (and volumes) by year;

5.1.2 cost of Renewable gas by product (and volumes) by year;

<u>Response:</u>

The residential customer forecast is based on the most recent actual customer additions data for single- and multi-family residences. The impact of gas prices is assumed to be intrinsic in the historical data used. The forecast of future single- and multi-family net customer additions is then calculated based on single- and multi-family housing starts growth rates as forecast by the Conference Board of Canada. For more information, please refer to the response to BCUC IR1 11.1. FEI's response to BCUC IR1 14.3 discusses why critical uncertainties, such as gas prices, are examined in FEI's end use demand forecasting modelling and not through the customer forecast.

5.2 Do these projections consider the impacts on customer counts of municipalities that have enacted policies that restrict natural gas installations for new homes? If yes, please discuss how. If no, why not?

Response:

Please refer to the response to BCUC IR1 14.3.

6. Reference: Exhibit B-1 Plan p. 4-9; Exhibit B-1 Plan, Appendix B-2, p. 11 End Use Models

At page 4-9 of its Plan, FEI states: "In its Decision on the 2017 LTGRP, the BCUC directed FEI to update its detailed analysis of the relative benefits and shortcomings of its particular end use method as compared to other end use methods. The original analysis for the 2014 LTRP was completed by Boreas Consulting Ltd. (Boreas). In that study, Boreas concluded that almost half of the 30 surveyed North American entities use end use models for all or part of their long-term forecasts and that FEI's end use model compares well with other North American end use methods. The update to the Boreas study for the 2017 LTGRP was conducted by Energitix Consulting. Energitix confirmed that using an end use demand forecasting method remains a common practice among gas and electric utilities, particularly those that are of a similar size and facing similar challenges to FEI."

6.1 Please confirm if Energitix's report discussed the effectiveness or accuracy of End Use models.

Response:

Not confirmed. Assessing the effectiveness or accuracy of the end use forecasting models against actual demand or comparing their accuracy and effectiveness to other forecasting models was not an objective of the Energitix study. Please see Appendix B-2, Section 2, Introduction, for a description of the study purpose.

6.2 Please describe FEI's process to calibrate their End Use model.

Response:

Please refer to the response to BCUC IR1 17.4.

6.3 Please describe steps, if any, that FEI (or their consultants) take to ensure inputs to End Use models are objective or independently determined.

Response:

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

FEI and its consultants ensure that inputs to the end use models are objective using the following techniques and approaches:

- Calibration of models to actual consumption where appropriate;
- The independent consultant's use of engineering judgement and experience in other jurisdictions to assess inputs for reasonableness; and
- Review and collaboration with internal and external stakeholders to develop a range of settings for critical uncertainties to be included as model inputs.

In addition, FEI's approach to developing multiple scenarios is inherently objective. A range of possible future states is examined rather than risking introducing bias by developing a single forecast built on a single set of input assumptions.

These techniques and approaches are discussed below with respect to development of the common base year, and the development of the Reference Case and scenarios.

Base Year

The base year is the foundation on which the rest of the model is built. The consultant calibrated the base year to actual consumption data from the utility, to make sure the starting point for the model was true to the energy consumption of real customers. The breakdown of facility-level energy use into different end uses, with end use saturations, fuel shares, and unit energy consumption, draws on data from sources such as the Residential End Use Survey. Many of these sources are unique to the jurisdiction, but the consultant can draw on many years of similar studies in other jurisdictions to benchmark the assumptions. The combination of benchmarking, engineering judgment, and calibration to real consumption data ensures that the base year assumptions are objective. The response to BCUC IR1 17.4 further discusses how the base year is built and calibrated.

Reference Case and Scenarios

The Reference Case and other scenarios each involve assumptions for the future state of input critical uncertainties, such as future energy or carbon pricing, customer growth, future policy around fuel switching or codes and standards, considering the degree of uncertainty. FEI and its consultants consider the best way to treat these uncertainties is to "bracket" them and, in collaboration with stakeholders, FEI discussed the likely range of trajectories each one may follow. Several settings for each uncertainty were then developed, so that the range of potential trajectories could be modeled.

Individual settings for critical uncertainties are not meant to be objective. Rather, they are meant to represent a plausible future for the behavior of a metric (carbon price, for example) whose future state is unknown. Taken together, the settings for a critical uncertainty are meant to represent a plausible range of values for that metric into the future, under the conditions that the utility might reasonably expect to face.

The use of multiple scenarios representing a range of trajectories for the critical uncertainties is meant to be an objective approach. A single forecast built on a single set of input assumptions would risk producing results biased in one direction or another. The range of trajectories for each input assumption is intended to capture a variety of viewpoints. Each scenario is modeled at the same level of granularity and with the same attention to detail. No judgement is made about the relative likelihood of each setting. In this way, the modeling process treats the input choices objectively.

At page 11 of Appendix B-2 of the Plan, Energitix states: "Some of the leading jurisdictions in energy efficiency policy and regulation have used end-use modeling since the introduction of energy efficiency regulation over 20 years ago and continue to do so. One of the energy planning entities that prepares its own long-term forecasts for the state and the utilities in the state has used end-use forecasting since 1975."

6.4 Please provide any data, information, and analysis that Energitix has or is aware of regarding the accuracy and/or effectiveness of the end use modeling that has been carried out in other jurisdictions since over the long term (e.g., the referenced jurisdiction that has used it since 1975).

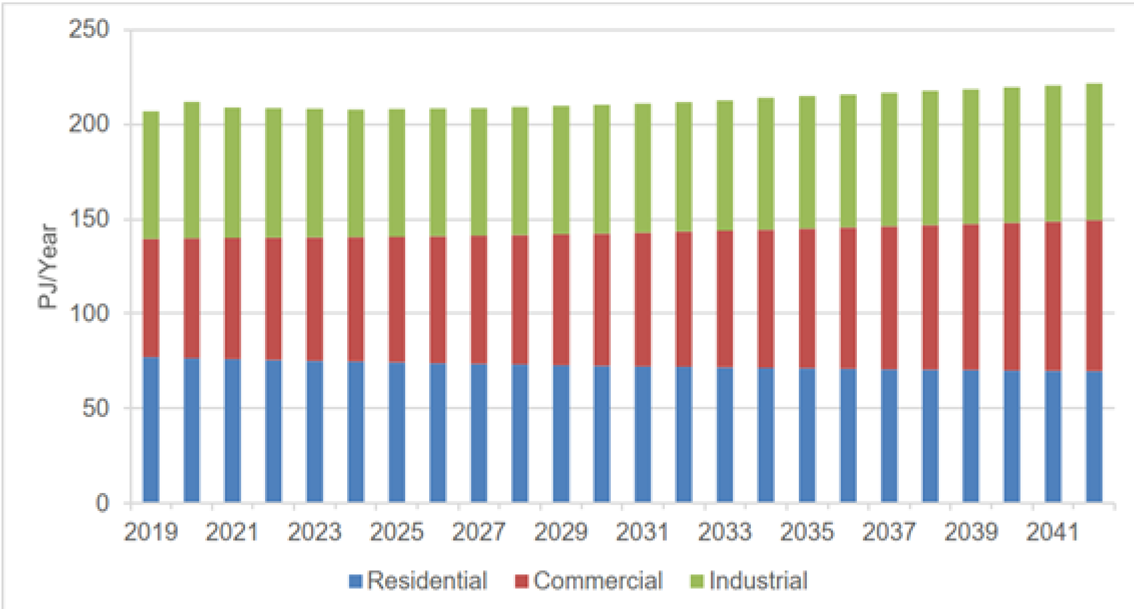
Response:

Please refer to the response to RCIA IR1 6.1. All of the information that Energitix obtained while undertaking the study is contained in Appendix B-2 of the Application.

7. Reference: Exhibit B-1 Plan p.4-12

Reference Case Demand

At page 4-12 of its Plan FEI provides Figure 4-5:



RCIA notes that under this reference case, residential consumer demand is projected to drop between 2019 and 2042, while commercial demand is projected to increase in the same timeframe.

7.1 Please discuss the factors that materially differentiate residential demand and commercial demand over this timeframe.

Response:

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

The rate of customer growth in the Reference Case is assumed to be higher in the commercial sector than in the residential sector. The compound annual growth rate (CAGR) for residential customers is forecast to be 0.53 percent per year between 2019 and 2042. In the commercial sector, the CAGR for the number of customers for all rate classes is expected to be higher at 1.03 percent per year.

In the Reference Case, residential usage per customer (UPC) declines by approximately 1 percent per year, which follows a long-term trend. The result of this annual decline in UPC is a decrease in residential UPC of approximately 20 percent between 2019 and 2042. This is caused by several factors, including:

- New homes are assumed to meet up-to-date codes and have appliances that meet new standards. They also have somewhat lower gas fuel shares for space heating and water heating, based on the residential end-use survey (REUS) findings for homes in the newest vintage.

- In existing dwellings, space heating appliances, water heaters, and other appliances are assumed to be replaced at their normal rate with new appliances that meet up-to-date minimum energy performance standards. Using an assumption about the rate of renovations, there are also improvements to the building envelope which also reduce UPC.

In the commercial sector, average UPC in the Reference Case is assumed to change very little. There are reductions in consumption per square metre of floor space (Energy Utilization Index or EUI), due to new construction that meets the latest building codes and natural replacement of space heating and water heating equipment with units that meet new minimum energy performance standards. For example, between 2019 and 2042, EUI is expected to decrease by approximately 0.6 percent per year in the average Rate Schedule (RS) 2 commercial building and by approximately 0.7 percent per year in the average RS 3 commercial building. These improvements are almost exactly offset by an average increase in floor space size. Although the overall rate of customer growth in the commercial sector, stated above, is about twice as fast as in the residential sector, some rate classes are forecast to grow much faster than others. The number of RS 3 customers is expected to grow at an annual compound rate of 2.9 percent per year while the number of RS 2 customers only grows at a compounded rate of 0.9 percent per year. On average, RS 3 customers are over nine times as large as RS 2 customers, so the average floor area of a commercial customer is growing in the Reference Case.

In summary, residential demand declines in the Reference Case because the assumed decrease in UPC is greater than the assumed increase in customer numbers. Commercial demand rises in the Reference Case because assumed improvements in EUI are roughly offset by an increase in the average size of commercial customers and the substantial growth in customer numbers.

8. Reference: Exhibit B-1 Plan p.4-17, 9-3, 9-4, 9-5

Scenarios to Meet GHGRS Cap

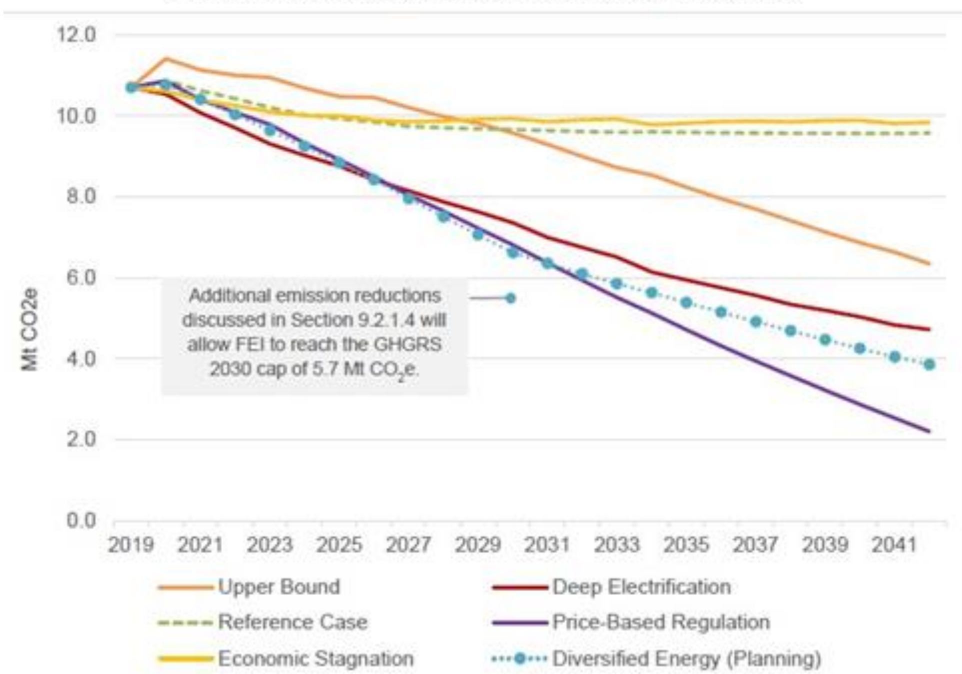
On page 4-17 of its Plan, FEI states: "The Diversified Energy (Planning) Scenario sets the planning context for FEI's 2022 LTGRP and the actions FEI will take over the next four years to ensure it can meet customers' energy needs over the planning horizon and beyond. For the residential, commercial and industrial demand category, the Diversified Energy (Planning) Scenario meets the BC GHGRS cap on carbon emissions for gas utilities."

On page 9-3 of its Plan, FEI states: "FEI expects these opportunities to result in a further 0.9 Mt CO2e reductions or more by 2030."

On page 9-4 of its Plan, FEI states: "With these additional reductions, FEI reaches the GHGRS 2030 cap on emissions. Figure 9-2, therefore, provides a comparison of the different demand and supply inputs modelled for each scenario in terms of GHG emissions reductions."

On page 9-5, FEI provides a graph of the emissions reductions for the various scenarios modeled in the development of the LTGRP.

Figure 9-2: GHG Emission Reductions (End Use) Modelled for the Reference Case and Alternate Scenarios – Residential, Commercial and Industrial Customers



8.1 Explain whether the Diversified Energy (Planning) Scenario requires the development of Pillars 3 and 4 of the Clean Growth Pathway in order to meet the GHG Reduction Standard emissions cap.

Response:

The proposed GHGRS cap only applies to GHG emissions from FEI's residential, commercial and industrial customers, as the standard only applies to the buildings and industrial sectors. Therefore, GHG emission reductions related to Pillars 3 and 4 (LCT and global LNG, respectively) will not count towards the GHGRS emissions cap target. While GHG reductions achieved through Pillars 3 and 4 of the Clean Growth Pathway will likely not count toward compliance with the GHGRS, there is still benefit to FEI's ratepayers of continuing to serve these markets and generating GHG abatement in BC and globally. The policy and market imperative to reduce GHG emissions across all sectors of the economy will continue to increase in ambition. Providing low-carbon solutions in as many sectors as possible will help diversify the use of FEI's infrastructure and investment. These activities will benefit customers in ensuring that FEI's infrastructure will continue to be used through the clean energy transition and will lead to lower costs for all ratepayers using the system.

8.2 Explain whether a scenario with Pillars 1 and 2 of the Clean Growth Pathway, with FEI implementing the DSM measures and low carbon fuels modeled in the Diversified Energy (Planning) Scenario, is able to meet the GHGRS emissions cap (with the additional reductions described in Section 9.2.1.4).

Response:

Pillars 1 and 2 of the Clean Growth Pathway could enable FEI to meet the GHGRS emissions cap, as explained in Section 9.2.1.5 of the Application. Please also refer to the responses to BCUC IR1 71.7, 72 series and 74.2, that discuss emission reduction initiatives and supporting calculations FEI is undertaking to meet the proposed GHGRS emissions cap.

8.3 Provide a version of Figure 9-2 with the GHG emissions reductions from the Diversified Energy (Planning) scenario but without any contribution from Pillars 3 and 4 of the Clean Growth Pathway. If FEI is unable to model these emissions reductions, then describe the approximate reductions in relation to the other scenarios shown in Figure 9-2.

Response:

Figure 9-2 in the Application, and cited in the preamble, already provides the scenario described in the information request as it represents GHG emissions reductions from residential, commercial and industrial customer groups. These reductions are achieved through Pillars 1 and 2 only. Pillars 3 and 4 of the Clean Growth Pathway are not factored into Figure 9-2.

9. Exhibit B-1 Plan, Appendix B-3 p. 6

Rate Schedule 23 Forecast

At page 6 of Appendix B-3 of its Plan, FEI provides Figure B3-5:

Figure B3-5: Customer Forecast Parameters – Rate Schedule 23

9.1 Please comment on and explain the apparently sudden change in the trend displayed on Figure B3-5 (i.e. from a sharp decrease between 2016 and 2019, to an increasing trend in the forecast period).

Response:

The steep decline of customers in Rate Schedule 23 was due to the significant increase in Transportation Service customers returning to the bundled service following the T-South Incident. As discussed in Section 6.2.4.2 of the Application, 42 percent (900 transportation service customers) provided notice to FEI of their intention to return to bundled service as of November 1, 2019.

As described in Section 1.1.1.2 of Appendix B-1, and to offset the impacts of rate-switching on the customer forecast, customers in Rate Schedules 3 and 23 were forecast as a single group. The resulting customer forecast was then proportioned between the two classes based on the 2019 year-end actual customer count. Therefore, because of the recent upward trend in Rate Schedule 3 customers (illustrated in Figure B3-4) and the upward trend in Rate Schedule 23 customers up to 2016, this method results in a forecast upward trend for Rate Schedule 23 customers.

The forecast growth trend is similar to the trend observed from 2010 to 2015. FEI considers that the forecast is reasonable.

10. Exhibit B-1 Plan, Appendix B-3 p. 7-8

Price Elasticity

At page 7 of Appendix B-3 of its Plan, FEI states: "The natural gas market price forecasts are based on an average of the market price forecasts provided within the Northwest Power and Conservation Council (NPCC) 2021 Eighth Power Plan (2021 Power Plan) and the long-term North American Gas Market Outlook from IHS Markit (IHS), released in February 2021.

The Reference trajectory is based on expectations for natural gas prices, with prices increasing most years as demand increases due to LNG exports from BC and coal plant retirements in the PNW. The high and low-price trajectories provide reasonable extremes of possible future prices. The high trajectory assumes rapid world economic growth, increasing the demand for natural gas supplies. The low trajectory assumes slow economic growth with reduced demand for natural gas in favour of lower-carbon renewable energy sources."

At page 8 of Appendix B-3 of its Plan, FEI states: "FEI and FBC collaborated to develop their long-term carbon pricing trajectories by consulting internal and external subject matter experts. The resulting carbon pricing planning trajectory takes into account the Canadian federal carbon pricing backstop mechanism.

The trajectories were determined early in the LTGRP planning process and have been validated by the LTGRP RPAG and reviewed by the LTGRP stakeholders (in the RPAG and FEI's community engagement workshops)."

10.1 Please confirm if FEI's forecasts for natural gas and carbon pricing are using price elasticity in deriving the results.

10.1.1 If yes, please provide details of these calculations.

__Response:__

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

FEI's forecasts for natural gas pricing are based on the third-party sources outlined in the preamble to this question. FEI's forecasts for carbon price are based on consultation with internal and external subject matter experts, in collaboration with FBC.

The long-run price elasticity of demand for natural gas was used in modeling the two price-driven fuel switching critical drivers for the LTGRP demand forecast scenarios: carbon price and natural gas price. The approach to modeling these critical drivers has been described in the response to BCUC IR1 27.6.

10.2 Please comment on how the price elasticity treatment varies between natural gas and carbon pricing.

Response:

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

The price elasticity treatment does not vary between natural gas and carbon pricing. The same price elasticity of demand value is used to estimate changes in gas consumption resulting from changes in carbon prices and changes in gas prices.

In other words, if an increase in commodity price or an increase in carbon price results in the same change in price per GJ, the model's response with respect to gas demand is the same.

D. DSM

11. Reference: Exhibit B-1 Plan p.5-41; Appendix C-3 p.5

Non-Pipe Solutions to Peak Demand Constraints

On page 5-41 of its Plan, FEI states: “To help meet this directive, FEI commissioned ICF to update its review of the state of the North American gas utility industry in exploring opportunities and implementing DSM programs that could potentially replace or defer infrastructure. ICF’s report, titled Non-Pipe Solutions Status Update, is found in Appendix C-3. Non-pipe solutions are non- traditional and/or demand-side solutions that may be used to defer investment in the gas distribution system infrastructure. These non-traditional investments may include approaches such as energy efficiency, natural gas demand response, decarbonization approaches174 and others. The report focused on demand-side non-pipe solutions, through a review of jurisdictions with relevant non-pipe solutions activity. The report highlights that there is only modest experience to date with implementing non-pipe solutions projects to address peak demand constraints, but interest is starting to grow, especially in response to decarbonization activities.”

On page 5 of Appendix C-3, ICF states: “The majority of the relevant pilots that ICF identified have been implemented by utilities in NY State… ICF’s research suggests that the majority of NPS pilots have tested NGDR technologies. This has included direct load control of smart thermostats to reduce space heating loads during peak demand periods. Some utilities have also piloted behavioural NGDR programs in large commercial and industrial buildings… ICF identified some recent progress with regards to NPS both in New York State and in other jurisdictions, mostly as NPS are increasingly being considered as a novel component of reformed long-term natural gas infrastructure planning in the context of long-term decarbonization strategies.”

In 2017 and 2020, Consolidated Edison of New York issued requests for proposals or information for non-pipe solutions to address capacity constraints. These are found at the following links:

https://www.icf.com/insights/energy/non-pipeline-solutions

https://www.coned.com/-/media/files/coned/documents/business-partners/business-opportunities/non-pipes/non-pipeline-solutions-to-provide-peak-period-natural-gas-system-relief-rfi.pdf?la=en

11.1 Identify the natural gas demand response technologies that have been tested in New York (as referenced above) and provide a summary of the results of these tests and pilot projects.

<u>Response:</u>

The following response has been provided by ICF Consulting.

Please refer to Section 4.1 of the ICF Report,[1] which provides an overview of natural gas demand response (NGDR) pilots, and Appendix A of the ICF Report, which provides additional details on each pilot. The ICF Report includes references to the relevant pilot program filings. The ICF Report notes that several New York utilities have run NGDR pilots focused on direct load control of smart thermostats. Further, New York utilities have piloted behavioural NGDR programs that have relied on notifications of demand response events or marketing by emails and other communication channels to facilitate reductions in peak demand through manual adjustments to gas-fired equipment at the facility level. FEI is also aware that Consolidated Edison Inc. (ConEdison) has tested direct load control with advanced water heater controllers. The associated report was filed after the ICF Report was completed.[2]

11.2 Summarize the results of the Consolidated Edison requests for proposals in terms of the approaches or technologies selected for implementation.

Response:

The following response has been provided by ICF Consulting.

The results of the ConEdison requests for proposals in terms of the approaches or technologies selected for implementation are discussed in the ConEdison reports on the demand response programs that came out of these requests for proposals.

To summarize, two programs emerged from the proposals. The first is described as a performance-based demand response offering for gas customers using firm gas delivery service, who can curtail gas consumption or reduce gas usage by switching to electricity or steam during calls for curtailment. The pilot programs primary focus is on commercial and industrial gas customers and multi-family buildings with centralized gas heating systems. The second program was described as a direct load control gas demand response offering with a residential-focused component of the demand response pilot. Participants in this offering use wi-fi enabled thermostats (i.e. smart thermostats) which control heating equipment and reduce gas demand at times of critical system need. Links to these reports on the demand response programs are provided below:

- ConEdison, Updated Gas Demand Response Report on Pilot Performance – 2019/2020, Case 17-G-0606 and Case 14-E-0423, Oct. 28, 2020, available at: https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={7FA119BD-B04D-4378-95A3-BB26697815AC}

[1] Exhibit B1-1, Appendix C-3, Non-Pipe Solutions Status Update Final Report.

[2] ConEdison, Gas Demand Response Report on Pilot Performance – 2021/2022, Case 17-G-0606 and Case 14-E-0423 (July 15, 2022) online: https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={AD51AA7B-5BD2-4A9B-AE57-720C636ED6C0}.

- ConEdison, Gas Demand Response Report on Pilot Performance – 2021/2022, Case 17-G-0606 and Case 14-E-0423, July 15, 2022, available at: https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={AD51AA7B-5BD2-4A9B-AE57-720C636ED6C0}.

11.2.1 Comment on the viability of these approaches or technologies to aid FEI in meeting its peak demands in the context of localized areas where there is or will imminently be a pipeline capacity shortage.

Response:

The following response has been provided by ICF Consulting in consultation with FEI.

The ICF Report points to several options that can be considered to help address peak demand constraints, including both distributed infrastructure options (supply-side alternatives) and non-infrastructure options (demand-side alternatives). These options can also be coupled with supply-side alternatives, such as CNG or LNG, used in conjunction with demand-side alternatives, such as Enhanced Targeted Energy Efficiency (ETEE) or NGDR, to help reduce peak demand impacts and mitigate risk and reliability issues. The State of New York, in conjunction with the New York utilities, as well as Enbridge and several other states, has determined that there is sufficient merit in these approaches to justify pilot projects designed to reduce peak period load in the context of localized areas where there is or will imminently be a pipeline capacity shortage. Although preliminary research and pilot test results suggest that these approaches may be viable alternatives in some situations, there are limited full-scale results to help address challenges with the broader implementation of non-pipe solutions. In addition, the benefits of an equivalent amount of peak period demand reduction will differ widely between utilities and within each utility's service territory, depending on the specific capacity constraint being addressed.

12. Reference: Exhibit B-1 Plan p.5-1

DSM Settings

On page 5-1 of its Plan, FEI states: "In particular, FEI's future DSM expenditure plans that will be filed with the BCUC for acceptance will be guided by the High DSM Setting analysed in this LTGRP."

12.1 Explain why future DSM expenditure plans will use the High setting. Is it FEI's view that in order to achieve the targets and stay under FEI's share of the GHGRS cap of 5.7 Mt CO2e that FEI must achieve the maximum amount of GHG emission reductions?

Response:

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

High levels of DSM investment will be required for multiple reasons, including the following:

- To maximize GHG reductions as a key pillar in FEI's initiatives towards the anticipated GHGRS cap;
- To contribute to the accelerated building retrofit activity and commercial and industrial upgrades for community climate action initiatives; and
- To ramp up advanced DSM activities that may require higher incentive levels than FEI's historical levels (by approximately 50 percent).

It is FEI's view that a high level of DSM expenditures will be required to achieve the necessary DSM-related emissions reductions and contribute toward meeting the GHGRS cap. However, not achieving the maximum amount of GHG emissions reductions as identified in the Conservation Potential Review (CPR) does not mean that FEI will not achieve the planned GHGRS cap. A number of FEI's other current and potential future carbon emission reduction initiatives will also be contributing to meeting the proposed GHGRS cap and may be called upon to a greater extent if the high level of DSM spending does not achieve all of the carbon emission reductions estimated in the Application.

The High DSM Setting was designed to capture the high market potential scenario in the 2021 CPR (refer to Table 5-3 in the Application), which in turn will maximize energy savings and GHG emissions reductions for residential, commercial and industrial customers as Pillar 2 of FEI's Clean Growth Pathway. The High DSM Setting demonstrates FEI's commitment toward a high investment in energy conservation activities over the long term.

On page 5-1 of its Plan, FEI states: "The Diversified Energy (Planning) Scenario (DEP) is now the equivalent to the "reference" scenario referred to in the directive, and was used as the basis for a sensitivity analysis demonstrating the effects of the Low, Medium and High DSM settings on DSM expenditures, energy savings and cost-effectiveness tests."

12.2 Confirm which of the DSM settings (Taper Off, Low, Medium, High) comply with the DSM Regulation.

12.2.1 If any settings do not comply, please explain why not.

Response:

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

All of the DSM settings used in the Application comply with the DSM Regulation; please refer to the response to BCSEA IR1 14.1 regarding a potential need for a change to the DSM regulation to achieve all savings after 2030. FEI will consider the DSM Regulation during detailed program design and will prepare future DSM expenditure plans to comply with the DSM Regulation in effect at that time.

13. Reference: Exhibit B-1 Plan p.5-1

DSM Cost-Effectiveness

On page 5-1 of its Plan, FEI states: "These cost-effectiveness tests include Total Resource Cost (TRC), Modified Total Resource Cost (MTRC) and Utility Cost Test (UCT) results expressed as a ratio and the Cost of Conserved Energy (CCE) expressed as $/GJ."

13.1 Explain how the cost-effectiveness tests (TRC, MTRC, UCT, and CCE) are used by FEI in developing its DSM plan and which tests are used and for which purposes.

13.1.1 Confirm whether the participant cost test (PCT) or ratepayer impact measure (RIM) are used in the development of the DSM plan.

Response:

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

FEI presents all cost-effectiveness tests to the BCUC in its DSM Expenditure Plan applications and Annual DSM Reports. The most critical cost-effectiveness test is the combined Total Resource Benefit/Cost, including the MTRC Benefit/Cost test where applicable, such that the overall portfolio will have a TRC-MTRC hybrid ratio of 1 or higher.

While the TRC and MTRC are the governing tests that FEI uses to determine the cost effectiveness of its DSM Plan on a portfolio basis, the Company has also historically reported and considered a range of other industry standard cost-effectiveness tests, including the Ratepayer Impact Measure (RIM),[3] the UCT[4] and the Participant Cost Test (PCT),[5] applied at the program, program area, and portfolio levels. The basis of these cost-effectiveness tests is the California Standard Practice Manual: Economic Analysis of Demand-Side Programs and Projects (California Manual).[6] The BC DSM Regulation prescribes how the cost tests are to be applied in British Columbia. The CCE is used by FEI in the LTGRP and some other situations to provide insights into the Cost of Conserved Unit of Energy ($per GJ) but is not currently prescribed in the DSM Regulation.

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[3] The RIM test measures what happens to customer bills or rates due to lost utility revenues and recovery of costs caused by the program (incentives + administration) less avoided costs (e.g., power purchase reductions). The BCUC may not determine that a proposed DSM measure is not cost-effective based on the result of the RIM test (*Demand Side Measures Regulation*, Section 4 (6)).

[4] Referred to as Program Administrator Cost Test in the California Manual. The Program Administrator Cost Test measures the net costs of a demand side management program as a resource option based on the costs incurred by the program administrator (including incentive costs) less avoided costs e.g., power purchase reductions.

[5] The PCT is the measure of the quantifiable benefits (utility incentive, reduction in utility bills) and costs (principally the Measure cost) to the customer due to participation in a program.

[6] California Public Utilities Commission, 2001. California Standard Practice Manual – Economic Analysis of Demand Side Program and Projects. Retrieved from: https://www.cpuc.ca.gov/-/media/cpucwebsite/files/uploadedfiles/cpuc_public_website/content/utilities_and_industries/energy_-_electricity_and_natural_gas/cpuc-standard-practice-manual.pdf.

Please refer to the responses to BCUC IR1 35 series for more information about the assumptions and values used in the calculation of DSM cost-effectiveness for the Application.

13.2 Confirm whether the DSM measures considered in the Diversified Energy (Planning) Scenario meet the TRC test (i.e. greater or equal to 1.0) or MTRC test or both.

13.2.1 If any measures do not pass the TRC or MTRC, please identify them and explain why they are included in the DSM projections.

Response:

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

All measures included in the DEP Scenario passed either the MTRC test, or both the MTRC and more stringent TRC test.

14. Reference: Exhibit B-1 Plan p.5-2

DSM Cost-Effectiveness With Low-Carbon Gases

On page 5-2 of its Plan, FEI states: "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."

14.1 Explain how increasing amounts of RNG will affect the TRC, MTRC, UCT, and CCE of the DSM measures proposed for Diversified Energy (Planning) Scenario.

<u>Response:</u>

Please refer to the response to BCSEA IR1 14.3.

14.1.1 Explain whether any DSM measures contemplated in the Plan will no longer be cost-effective as the proportion of RNG increases, or whether there will be additional DSM measures that can be added.

<u>Response:</u>

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

No DSM measures contemplated in the Application will cease to be cost-effective as the proportion of RNG increases. In most scenarios, the MTRC test is the dominant screen in determining whether a measure is considered cost-effective. RNG is not a factor in the MTRC test and therefore has no effect on the cost-effectiveness of measures in these scenarios.

In those scenarios where MTRC is not used, the cost of RNG increases the likelihood of a measure being cost-effective. The model is using an avoided cost that reflects the marginal cost of the next GJ of renewable or low-carbon fuel that could be added to the supply. This avoided cost is higher than that of conventional natural gas and therefore each measure is more likely to pass the TRC test.

14.2 Explain how increasing amounts of H2 will affect the TRC, MTRC, UCT, and CCE of the DSM measures proposed for Diversified Energy (Planning) Scenario.

<u>Response:</u>

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

Increasing amounts of hydrogen in the overall mixture of gaseous fuels supplied over time does not affect the avoided cost used in the economic screening tests for the same reasons that increasing amounts of RNG does not affect the avoided cost, as discussed in the response to BCSEA IR1 14.3 As such, increasing amounts amount of hydrogen over time do not impact the results of the cost effectiveness tests.

14.2.1 Explain whether any DSM measures contemplated in the Plan will no longer be cost-effective as the proportion of H2 increases, or whether there will be additional DSM measures that can be added.

Response:

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

No DSM measures contemplated in the Application will cease to be cost-effective as the proportion of hydrogen increases, for the same reasons that no DSM measure will cease to be cost-effective due to increasing proportions of RNG, as discussed in the response to RCIA IR1 14.1.1.

15. Reference: Exhibit B-1 Plan p.5-14

DSM Level

On page 5-14 of its Plan, FEI states: "In recognition of the key role for DSM in decarbonization and as a key pillar in the Clean Growth Pathway, and in response to positive support in RPAG, EECAG and community engagement sessions for FEI to undertake high levels of DSM, FEI selected the High DSM Setting for the Diversified Energy (Planning) Scenario."

15.1 Provide the feedback (or a summary of the feedback) from the RPAG, EECAG, and community engagement with respect to the levels of DSM that FEI should pursue.

Response:

In providing this response, it is important to note that the Application is intended to provide a theoretical model of long-term DSM programming with the objective of providing DSM savings estimates for resource planning purposes. It is not intended to be the blueprint for ongoing DSM plan development. The High DSM Setting was designed to capture the high market potential scenario in the 2021 CPR (refer to Table 5-3 in the Application) and incentive levels were set at 100 percent of measure incremental cost to do so. FEI develops short-term DSM expenditure plans that consider the most cost-effective DSM alternatives. As discussed in the response to BCUC IR1 38.4, FEI does not necessarily intend to set its incentive levels at 100 percent in line with the High DSM Setting.

Throughout the 2022 LTGRP RPAG, Indigenous, and community engagement sessions, FEI described the role of the DEP Scenario as part of the solution to BC's energy system decarbonization objectives. The sessions focused on the Clean Growth Pathway and that FEI's DSM programs comprise a key pillar of the pathway. The messaging was clear that FEI needs to respond to the CleanBC Roadmap to 2030; however, there was recognition that affordability remains a key consideration. FEI considers that the High DSM setting will enable FEI to continue to support its residential, commercial and industrial customers in energy savings and associated GHG emission reductions over the planning horizon. The following outlines feedback received by FEI in relation to DSM levels and balancing the costs against other important issues to attendees through the engagement activities cited:

- The November 3, 2021 RPAG meeting focused on DSM Scenarios. Participants recognized that the longevity of DSM and energy efficiency programs is going to be critical over the planning horizon. FEI received feedback to focus on building envelope measures in addition to mechanical systems. This objective will be accomplished through an increasing focus on Deep Energy Retrofits and Advanced DSM. RPAG members were supportive of future LTGRP DSM models to incorporate all gaseous fuels including natural gas, RNG and hydrogen as each unit of saved energy benefits customers overall. This advice further strengthens the focus on FEI's decarbonization plans as a whole.

- In dialogue and engagement with Indigenous groups, FEI received positive feedback on its Conservation and Energy Management programs. FEI was advised to continue expanding opportunities for energy efficiency collaboration with local communities as a means to reduce high energy bills, and to support local housing improvements and community development projects. Cost and affordability were noted as key priorities, as many community members deal with high electricity and natural gas bills. The costs of decarbonizing BC's economy will need to be balanced with the needs for communities who are struggling with energy poverty.
- In community engagement sessions, attendees at Vancouver Island and Interior sessions voiced concerns about energy affordability and the need to balance energy costs and GHG emission reductions. Attendees at Lower Mainland sessions were more vocal about the need for climate action. Community representatives expressed their desire to collaborate with FEI on community energy plans. This would include general support for accelerated building retrofit strategies. A number of attendees agreed that the DEP Scenario with complementary and robust gas and electric systems will be more resilient for BC's energy future in the long term and is even more critical in rural areas where electric outages are more common.
- Historically, FEI's Energy Efficiency and Conservation Advisory Group (EECAG) has shown a positive response to FEI's ongoing expanded investment in DSM programs, as this group of energy professionals has consistently expressed the view that all available DSM opportunities should be pursued. This group is instrumental in providing advanced feedback for FEI's shorter term DSM Plans, where developing cost-effective DSM programming is a priority. The EECAG will play a key role in guiding FEI on its DSM plans over the planning horizon.
- Throughout these events, there was general support to further FEI's current DSM program initiatives in light of the urgent need for climate action while balancing affordability concerns.

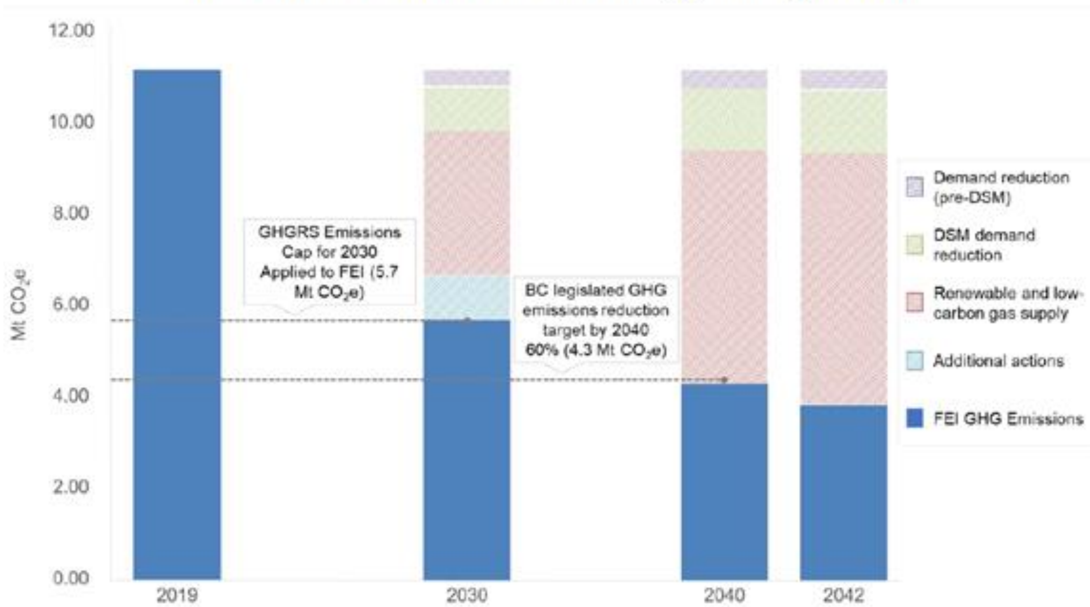
FEI's continued commitment to DSM investment is an important component of FEI's Clean Growth Pathway. FEI will continue to consult with RPAG, EECAG, Indigenous groups, and communities across BC to provide cost-effective DSM programming over the planning horizon.

16. Reference: Exhibit B-1 Plan p. 9-4

DSM Measure Life and Meeting GHGRS Emissions Caps

At page 9-4 of its Plan, FEI provides Figure 9-1:

Figure 9-1: GHG Emission Reductions for Residential, Commercial and Industrial Customers Meets the GHGRS for the Diversified Energy (Planning) Scenario



16.1 Provide a spreadsheet of all measures included in the Diversified Energy (Planning) scenario – High DSM setting, organized by program and program area, showing the annual gas savings, GHG emissions reductions, measure life, persistence, NPV gas savings, and NPV emissions reductions.

Response:

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

Please refer to Attachment 16.1 for a live spreadsheet of all measures in the DEP Scenario – High DSM setting, organized by program area and measure for the base year 2020 and milestone years 2030 and 2042. Note that the CPR and hence the LTGRP DSM scenarios look at customer sectors (program area) and measures. DSM Expenditure Plans are where programs are developed and listed.

For each measure, the list illustrates annual gas savings, GHG emissions reductions, measure life, NPV gas savings, and NPV emissions reductions. As part of the LTGRP planning process, measure savings were assumed to reflect an average of both measure persistence (i.e. how many measures stay installed for the measure life) and savings persistence (i.e. how the savings degrade over the measure life). Thus, the persistence for all measures is assumed to be 100 percent.

Note that some measures have potential savings in early years of the 2019-2042 planning horizon but do not have modeled savings in 2030 and 2042 milestone years. This is because emergent efficiency standards and building codes will cause some measures to eventually become base case measures that cannot be supported through DSM activities. For other measures, FEI was uncertain about the longer-term savings potential in 2019 when the CPR was developed.

16.2 Does FEI favour measures with longer lives over measures with shorter lives? Explain why or why not.

Response:

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

No. FEI does not favour measures with longer lives over measures with shorter lives. As described in Table 5-3 of the Application and discussed in the response to RCIA IR1 12.2, measures are screened through economic screens based on cost-effectiveness tests in both the CPR and the LTGRP. Measure lives are not used as a criterion in selecting measures for inclusion in DSM programming.

16.3 Explain how measure life and persistence affect FEI's achievement of the targets in the CleanBC Roadmap to 2030, specifically the GHGRS emissions cap of 5.7 Mt in 2030 and the 2040 emissions cap of 4.3 Mt.

Response:

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

Measure life and measure persistence will contribute to cumulative energy savings achieved over the planning horizon. They represent contributing factors to achieving demand reductions through DSM initiatives. As discussed in RCIA IR1 16.2, FEI does not select measures on this basis. Some measures, such as building envelope improvements and high-performance homes, have long measure lives and persistence (greater than 20 years). Other measures, such as recommissioning and strategic energy management, have shorter measure lives and persistence (less than 5 years). All measures, regardless of measure life and persistence, have a role in achieving energy savings that lead to cumulative GHG reductions. Regarding the proposed GHGRS cap targets, if a measure is in place in a given year, it will contribute to energy savings results and emission reductions as reported for that year.

17. Reference: Exhibit B-1 Plan Appendix C-1 p.xiv

DSM Incentive Costs

On page xiv of Appendix C-1, Posterity Group states: "EX 4 (TRC) and EX 5 (MTRC) show the incentive and non-incentive spending required to achieve the medium and high market potential. Medium and high market incentives are 50% and 100% of measures' incremental costs, respectively."

17.1 Explain why the High market incentive costs are more than double the Medium market incentive costs, if the high market incentives are 100% and the medium market incentives are 50% of the incremental costs.

<u>Response:</u>

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

As stated, High market incentives are set at 100 percent of incremental costs and Medium market incentives are set at 50 percent of the incremental costs. In aggregate, the High market incentive costs are more than double the Medium market incentive costs because higher incentives drive higher participation; in the High scenario, incentives per unit are doubled, and the measure uptake represents a greater number of units.

E. Gas Supply Portfolio Planning

18. Reference: Exhibit B-1 Plan p.6-10; p.7-35

U.S. H_2 Supplies

On page 6-10 of its Plan, FEI states: "By leveraging the energy trading capabilities made possible by the existing gas transportation network, discussed in Section 6.2.2.1 above, renewable and low-carbon gases can be purchased from producers across Canada and the US, with the carbon reduction benefits of that production being delivered to FEI's customers in BC. FEI expects this source of supply to be an important part of its transition to renewable and low-carbon gas supplies, particularly in the early years of the transition."

18.1 Explain how the U.S. Inflation Reduction Act (and its production tax credits and investment tax credits for the production of H2) will affect the availability and price of H_2 supplies to FEI.

Response:

FEI expects the *Inflation Reduction Act*, and its production tax credits and investment tax credits to produce hydrogen, will advance the development of clean energies including hydrogen; however, given its recent introduction in the US, FEI has yet to determine the effect it will have on the availability and price of hydrogen supplies to FEI.

18.2 Provide the ranges of production tax credits available to U.S. producers of H_2.

Response:

Please refer to section 45V of the US Internal Revenue Code of 1986 for the tax credits provided in the *Inflation Reduction Act*. Based on currently available guidance literature, FEI's understanding is that the IRA provides tax credits ranging from \$0.60/kg to \$3/kg for projects that meet certain requirements (time period, wage, labor, etc.), and \$0.12/kg to \$0.60/kg for projects that are not eligible for credits.

On page 7-35 of its Plan, FEI states: "If the supply is a blend of hydrogen, there will be some capacity reduction for the reasons discussed below and in Appendix D-3."

On page 3 of Appendix D-3 of its Plan, FEI states: "As the percentage of hydrogen flowing in the systems increases, the upgrades required to support future energy delivery requirements on the system will change. If a system is forecast to have a capacity deficit, higher blends of hydrogen supplied into the system will require system upgrades sooner, or at a lower system demand, than if the system were to deliver 100 percent natural gas."

18.3 Explain whether the issues with reduced pipeline capacity will also apply to U.S. H2 producers and how this may affect the price and availability of H2 supplies to FEI.

Response:

FEI expects that potential issues with reduced pipeline capacity that hydrogen or hydrogen blends impart when moved through pipeline systems will need to be considered in other jurisdictions such as the US; however, FEI is not sufficiently informed to comment on how this may affect hydrogen producers or the effect on the price and availability of hydrogen supplies. FEI anticipates that initially off-system supply and delivery would be sourced from local hubs that may not incur pipeline capacity issues and would therefore enable FEI to acquire off-system hydrogen at the best available price.

19. Reference: Exhibit B-1 Plan p. 6-7

On-System RNG and H2 Supplies

At page 6-7 of its plan, FEI states: "The locations where FEI can purchase its gas supply resources and the physical gas storage and pipeline resources that FEI has access to are the foundation of FEI's gas supply planning activities. While there are various contracting and trading instruments that FEI can utilize to acquire gas supplies throughout the year, the physical resources needed to store and transport these supplies onto FEI's system for distribution to customers when needed are the bases for FEI's market planning and actions. These resources are also critical for FEI's use of displacement mechanisms that allow FEI to purchase natural, renewable and low-carbon gas supplies elsewhere in North America while ensuring the physical delivery of energy to customers in BC. As FEI moves forward on its Clean Growth Pathway, access to renewable and low-carbon gas supplies will leverage these physical resources within the PNW for the delivery of the energy customers require. Sections 6.2.2.1 and 6.2.2.2 provide an overview of the gas supply resources that FEI relies on for acquiring and delivering energy to its customers."

19.1 Confirm whether FEI has any obligations to purchase or transport RNG or H2 from on-system producers who have sold the environmental attributes of the RNG or H2 to other parties.

19.1.1 Explain the factors that FEI would consider if such a proposal were brought to FEI.

<u>Response:</u>

FEI does not have any obligations to purchase or transport RNG or hydrogen from on-system producers who have sold environmental attributes to other parties as FEI is not an open-access carrier.

20. Reference: Exhibit B-1 Plan p.6-10, 6-13

Meeting Peak Day Requirements with Low-Carbon Gas

RNG Used to Meet Peak Day Requirements

On page 6-10 of its Plan, FEI presents Table 6-2:

Table 6-2: FEI's 2021/2022 Planned Core Peak Day Portfolio[183]

Peak Day Portfolio	2021/2022 Portfolio-Planned (TJ/day)
Fort Nelson Supply	**5**
Alberta Baseload Supply	103
Station 2 Baseload Supply	308
Total Commodity Supply	**411**
Seasonal Supply	135
Seasonal Storage	201
Market Area Storage	211
Spot Supply	120
Mt. Hayes LNG	163
Tilbury LNG	163
Industrial Curtailment	26
Total Midstream Supply	**1020**
Total Resources	**1,436**
Peak Day Demand	**1,436**

On page 6-13 of its Plan, FEI states: "As the supply of renewable and low-carbon gas grows, FEI will monitor whether the supply is directly connected to FEI's system (on-system) or delivered to FEI's system through displacement (off-system). FEI will also assess the firm amount of supply delivered on FEI's system, or at the Huntington/Sumas, AECO/NIT, or Station 2 market hubs. RNG purchases have different contractual obligations than FEI's conventional natural gas purchases. This is because contracted RNG projects can have either an annual or monthly supply requirement to FEI, or a minimum daily firm amount. Therefore, the volumes delivered to FEI can fluctuate during the month, based on whether the RNG plant is running and other market conditions. This will require FEI to maintain a portion of conventional natural gas within the portfolio to manage the risk of any supply variability."

20.1 Confirm whether FEI plans to include on-system RNG or H_2 in its core peak day portfolio, either imminently or at some time in the planning period.

20.1.1 If confirmed, explain how FEI will manage the risk of forced outages of the RNG or H_2 production that coincide with the peak day requirements.

20.1.2 If FEI is required to arrange for alternative RNG, H_2, or gas supplies to have the option of using them on the peak day, explain the cost implications to FEI.

Response:

Over the past several years, the expected amount of renewable and low-carbon gas has become an important component in the overall strategic planning of the Annual Contracting Plan. However, the expected volumes related to on-system projects have not been certain or material enough to currently contribute to FEI's peak day portfolio, as was illustrated in Table 6-2 of the Application. FEI does expect to include RNG, whether on-system or off-system, in its planned core peak day portfolio shortly, likely within the next year or two. Further short-term actions that FEI is undertaking or planning to undertake in regard to incorporating renewable and low-carbon gas supplies are described in the response to BCUC IR1 52.22.

As for hydrogen, FEI cannot speculate at which time in the planning horizon it would begin to incorporate these supplies into its core peak day portfolio, as FEI does not currently have any contracts for hydrogen supply, and this would depend on many factors, including volume, location, firmness, and contractual obligations. Additionally, if the hydrogen supply was constrained to a hydrogen hub, this could result in additional regional-specific considerations for managing peak day requirements.

In any case, FEI will manage the risk of outages of the RNG or hydrogen production in the same manner as FEI currently mitigates the risk of forced outages with the production and delivery of conventional gas under most operating conditions. This is done through maintaining a diverse portfolio of resources (commodity, pipeline capacity, and storage resources) that considers the following measures:

- Holding contingency resources within the portfolio, as discussed in Section 6.2.4 of the Application, to mitigate the risk of future supply disruptions (pipeline and storage) during the winter season;
- Procuring market area and seasonal storage resources to mitigate disruptions associated with well freeze-offs and upsets in processing plants; and
- Utilizing Mt. Hayes and Tilbury LNG storage facilities to provide high-volume gas supply to FEI on very short notice. This can mitigate several short-term outages, as well as third party pipeline or storage capacity disruptions given their on-system location near major load centres.

These same measures will apply when on-system RNG or hydrogen is included in FEI's peak day portfolio. For example, FEI may purchase additional conventional natural gas within the peak day portfolio, as a contingency resource or a back-up supply option to manage the risk of any supply variability.

However, FEI is not required to arrange for alternative RNG, hydrogen, or other gas supplies to have the option of using them on the peak day. If there were a forced outage for RNG, hydrogen, or other low-carbon gas supplies, FEI expects to utilize its own resources if possible, or procure conventional natural gas as needed. In the longer term, if hydrogen markets evolve, then FEI could acquire alternative hydrogen supplies in light of a forced outage, but FEI could not speculate on the cost of such a transaction. Please also refer to the responses to BCUC IR1 52 series for further discussion on gas supply portfolio management and contingencies as more renewable and low-carbon gas is added to the portfolio.

21. Reference: Exhibit B-1 Plan p.6-19

Transportation Service

On page 6-13 of its Plan, FEI states: "Transportation Service customer movement does pose risks to FEI's gas supply portfolio, such as not being able to secure enough incremental resources in the region to serve more Transportation Service customers moving to FEI's bundled service. As previously discussed, FEI has mitigated this risk in the past by securing contingency resources above what Core customers require within its portfolio and will continue to annually assess the planning margin for contingency resources. If additional Transportation Service customers elect to return to bundled service, the existing contingency resources could mitigate a portion, if not all, of this increased Core customer demand within FEI's supply portfolio. However, this will come at the expense of a potentially lower than recent contingency margin."

21.1 Confirm whether FEI has an obligation to accommodate Transportation Service customers who want to switch to bundled service.

21.1.1 Are there any circumstances where FEI would not be required to accommodate Transportation Service customers who request bundled service?

Response:

FEI is obligated as long as FEI is able to secure the necessary gas supply to accommodate the Transportation Service customers who want to switch to the bundled service. This is indicated in Section 26.2 (b) in the General Terms and Conditions of FEI's gas tariff shown below:

26.2 Direct Purchase Customers Returning to FortisBC Energy System Supply[7]

Where a Customer has acquired Gas under a direct purchase arrangement and later wishes to return to the system Gas supply of FortisBC Energy:

(a) FortisBC Energy may require that the Customer provide FortisBC Energy up to one Year's written notice before the date on which the Customer wishes to return to system Gas supply;

(b) FortisBC Energy will supply the Customer with system Gas when the Customer wishes to return to system Gas supply if FortisBC Energy is able to secure additional Gas supply and transportation to accommodate the Customer; and

(c) FortisBC Energy may, subject to British Columbia Utilities Commission approval, charge the Customer for any costs associated with the Customer

[7] FortisBC Energy Inc. gas tariffs: Mainland, Vancouver Island, and Whistler. https://www.fortisbc.com/about-us/corporate-information/regulatory-affairs/our-gas-utility/FortisBC-Energy-Inc.-Mainland-Vancouver-Island-and-Whistler-service-areas.

returning to system Gas supply. Such costs may include, among other things, the costs of securing additional Gas supply and transportation to accommodate the Customer. FortisBC Energy may bill the Customer for such costs as part of the regular FortisBC Energy bill for Service.

21.2 Explain why FEI holds contingency resources to accommodate Transportation Service customers who could switch to bundled service, considering the resources that previously served those customers may become available to FEI.

Response:

As discussed in Section 6.2.4.2 of the Application, the Transportation Service customers have been able to serve their demand requirements by accessing some transportation capacity in the secondary market and by purchasing gas supply at the Huntingdon/Sumas market. They do not have the credit or financial capabilities to secure long-term firm resources (i.e., pipeline capacity on third-party pipelines). Further, the amount of transportation capacity that they have accessed in the secondary market will be less once the Woodfibre LNG project is in service.[8] As a result, it is FEI's view that there would be no available resource to secure if these customers switch to the bundled service.

While in the past FEI held contingency resources to mitigate the risk of Transportation Service customers returning to the bundled service, the contingency resources are now in place to mitigate the risk of future supply disruptions, as discussed in the response to BCUC IR1 52.12. FEI may use these contingency resources if additional Transportation Service customers switch to the bundled service; however, that decision would be made in future Annual Contracting Plans.

8 Woodfibre LNG has already secured firm long-term transportation service capacity on the Westcoast T-South system for a significant portion of its demand requirements.

22. Reference: Exhibit B-1 Plan p.6-24

Mist Storage

At page 6-24 of its Plan, FEI states: "The Mist storage facility is located in Oregon and owned and operated by NW Natural. FEI currently has a variety of market area storage contracts at Mist, each with different capacities, expiry dates, and injection and withdrawal capabilities. FEI's market area storage contracts at Mist are recallable, which means once these contracts expire, NW Natural may take back all or a portion of the storage capacity for their customer load requirements. This has not been an issue for FEI in the past because recalls have impacted other Mist customer contracts. NW Natural has also added less-than-firm resources in their supply portfolio which have provided additional supply resources in the near term, but are expected to be discontinued once Woodfibre LNG project is in service, since the amount of demand from Woodfibre LNG project could affect regional gas flows. If this change occurs in NW Natural's resources, it will cause a recall and could cut into the Mist capacity FEI has historically held."

22.1 Under what conditions can NW Natural recall FEI's storage capacity at Mist?

Response:

Please refer to the response to BCUC IR1 52.20.

22.2 Are FEI's U.S. pipeline displacement contracts subject to recall?

Response:

All of FEI's pipeline capacity in the US is associated with the gas delivery to and from its market area storage resources (Mist and Jackson Prairie Storage). The pipeline capacity is contracted on the Williams' Northwest Pipeline (NWP), which is regulated by the Federal Energy Regulatory Commission (FERC). Consistent with FERC policy, Section 25.5 of the General Terms and Conditions of NWP's tariff stipulate that a shipper must receive service at the maximum base rate for a term of twelve consecutive months or longer to be eligible for a right of first refusal (i.e., renewal rights).[9] A portion of FEI's capacity on NWP has been negotiated at a discounted rate, which includes paying a maximum base rate for the winter months only, which is when FEI requires the capacity.

[9] Northwest Pipeline. "General Terms and Conditions." http://www.northwest.williams.com/NWP_Portal/extLoc.action?Loc=FilesNorthwesttariff&File=tariff_GTC.pdf.

22.3 What are FEI's contingency plans if some or all of its Mist storage capacity or U.S. pipeline displacement capacity are recalled?

Response:

As discussed in the responses to BCUC IR1 52.20 and 52.21, FEI has had preliminary discussions with NW Natural regarding the potential for NW Natural to further expand its Mist storage facility. This expansion would also require FEI to contract long-term capacity on Northwest Pipeline. The best-case scenario would be to have this Mist expansion in-service by the time that NW Natural recalls a significant volume of FEI's Mist capacity. If the Mist facility were not expanded, or terms and conditions were not agreed to by the parties, FEI would need to secure other resources to replace the supply lost from this asset and apply to the BCUC for approval of the resource.

23. Reference: Exhibit B-1 Plan p.6-23

Price Risk Management Plan

"Currently, FEI's PRMP has focused on mitigating any Sumas pricing exposure that the Core customers may have at the Huntingdon/Sumas market."

23.1 Confirm whether FEI hedges only its price risk for gas supplies acquired at Huntingdon/Sumas.

23.1.1 If not confirmed, explain what gas supplies FEI currently hedges.

Response:

At the time of filing the Application, FEI only had approval to hedge gas supply priced based on the Sumas market. However, in June 2022, FEI filed an AECO/NIT hedging strategy focused on mitigating price risk exposure and increasing the price diversity in the commodity portfolio, which was then approved by the BCUC. As such, FEI has hedged a portion of the commodity portfolio priced based on the AECO/NIT market.

23.2 Summarize the principles of the currently approved Price Risk Management Plan and the activities that FEI takes in support of these principles.

Response:

Please refer to the response to CEC IR1 23.1.

F. System Resource Needs and Alternatives

24. Reference: Exhibit B-1 Plan p.7-34

H2 Blending

On page 7-34 of its Plan, FEI states: "**Quantity and Timing of Resource Availability**: Although FEI has modelled the mix of renewable and low-carbon gas in certain proportions over time in the LTGRP planning scenario, 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."

24.1 Confirm whether the BC Oil and Gas Commission has granted approval for FEI to blend H2 into the gas stream for transmission and distribution in FEI's system.

24.1.1 If confirmed, explain any conditions imposed by the BCOGC and the maximum blend percentage(s).

24.1.2 If not confirmed, provide a timeline for the activities, filings, and milestones needed to obtain OGC approval to inject H_2 into FEI's gas transmission system.

24.1.3 If not confirmed, provide a timeline for the activities, filings, and milestones needed to obtain OGC approval to inject H_2 into FEI's gas distribution system.

Response:

The Government of BC recently announced changes to legislation affecting the BC Oil and Gas Commission (BCOGC) that will expand the regulator's responsibilities to include hydrogen[10] and provide a cohesive regulatory framework for hydrogen in British Columbia. It is proposed that the BCGOC will be renamed the BC Energy Regulator, which will reflect the transition and modernization of the regulator's role. FEI has not yet applied for approval from the BCOGC to blend hydrogen into the transmission system. FEI is involved in ongoing engagement with the BCOGC regarding hydrogen development activities, which will inform future applications to blend and transport hydrogen in the gas system. The associated timelines for the activities, filings, and milestones needed to obtain approvals from the BCOGC with respect to injecting hydrogen into FEI's transmission system are, therefore, currently under development and will be clarified upon the enactment of the Province's proposed legislative framework.

Please refer to the response to BCUC IR1 61.12 for discussion of the regulatory approvals FEI expects to seek prior to blending hydrogen into its transmission and distribution system.

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[10] Ministry of Energy, Mines and Low Carbon Innovation, "B.C. making changes to advance hydrogen industry" (October 27, 2022) online at: https://news.gov.bc.ca/27672.

24.1.4 If not confirmed, what are FEI's plans if such approval is not forthcoming, or FEI is only granted approval to blend H_2 in concentrations substantially less than envisioned by FEI in the 2022 LTGRP?

Response:

FEI has not included specific on-system renewable and low-carbon hydrogen blending targets in the DEP Scenario. As described in the response to BCUC IR1 61.12 and RCIA IR1 24.1, regulatory approval pathways and potential limitations for hydrogen blend concentrations in the gas system have yet to be determined. Therefore, FEI cannot comment on specific plans for future on-system hydrogen blending volumes. However, throughout the LTGRP planning horizon, FEI's renewable gas procurement strategy expects to integrate on-system and off-system hydrogen supply. This approach will enable FEI to diversify its hydrogen supply portfolio and maximize ability to acquire hydrogen envisioned in the Application.

24.2 Provide a graph or table showing the proportions of H2 that FEI expects to blend into its gas system according to the Diversified Energy (Planning) scenario by year through to 2042. Provide both the system average H_2 percentage as well as the maximum local percentages (for example, if FEI intends to blend a higher-than-system-average proportion of H2 in the Interior Transmission System, or in select portions of the Coastal Transmission System).

Response:

The reference to "modelled the mix…over time" in the preamble relates to the annual quantities forecasted to be supplied and is not in reference to detailed hydraulic modelling of the transmission and distribution systems. At this point FEI assumes that future hydrogen supply will include: (1) on-system hydrogen production and distribution as a blend with natural gas in the gas system; (2) distribution through dedicated hydrogen infrastructure that would interconnect production directly to hydrogen customers; and (3) off-system hydrogen supply that would be delivered by displacement to FEI customers. FEI's hydrogen deployment and customer uptake strategy is currently evolving according to provincial policy and regulations; therefore, as it is not yet clear where hydrogen production will develop, it is not yet possible for FEI to provide the specific hydrogen blending scenario criteria requested.

25. Reference: Exhibit B-1 Plan p.7-4, 7-5; Appendix D-3 p.3

Impact on Capacity of H2 Blending

On page 3 of Appendix D-3, FEI states: "FEI is planning for future pipelines to be hydrogen ready."

25.1 Confirm and explain whether FEI will now be sizing its pipeline capacity upgrades to meet the demand forecasts (such as for a 20-year planning period) assuming a H2 blend and what blend percentage will be used.

25.1.1 If confirmed, how will this affect the Okanagan Capacity Upgrade project and its ability to meet the demand forecast for the next 20 years? [ref p.7-4, 7-5]

Response:

When FEI has sufficiently developed the future hydrogen deployment strategy and can assume a particular blend in the OCU Project or other ITS pipelines, FEI will size pipeline expansions with the anticipated blends of hydrogen accounted for. FEI is not currently sizing its upgrades like the OCU with a particular blend percentage in mind; however, the OCU Project will improve capacity to accept hydrogen blends above the current capability of the ITS. Future hydrogen blends could drive future expansions within the ITS to accommodate capacity reductions resulting from hydrogen blends or increased demand. Similarly, on-system production and injection of renewable gases at other locations within the ITS could potentially offset the capacity reduction effect that various blends of hydrogen might impart on the OCU pipeline.

26. Reference: Exhibit B-1 Plan p.7-35

Off-System Supply and Delivery – Impact on Capacity of H2 Blending

On page 7-34 of its Plan, FEI states: "**Off-System Supply and Off System Delivery:** Off-system supply is where FEI acquires renewable and low-carbon gases in other regions and the gas transportation and consumption is conducted completely outside of FEI systems. This process achieves carbon reduction and credit for FEI customers with the environmental attributes associated with renewable and low-carbon gas. However since FEI customers continue to physically receive conventional natural gas through FEI infrastructure the capacity requirements to meet peak demand forecasts remain the same on the FEI system. This capacity impact of off-system supply and delivery has the same neutral effect regardless of the form of the off-system energy delivered. The incorporation of these types of off-system supplies will play an important role while the transition to renewable and low-carbon gas occurs over the planning horizon until more on- or near-system resources that flow directly through FEI systems are developed.

…

Off-System Supply and On-System Delivery: Off-system supply of RNG and hydrogen physically delivered into FEI transmission systems from upstream pipelines will produce no net change in FEI transmission system capacity to meet peak demand forecasts if the supply is RNG. <u>If the supply is a blend of hydrogen, there will be some capacity reduction for the reasons discussed below and in Appendix D-3</u>." [underlining added]

26.1 Does FEI expect there to be sufficient availability of off-system H2 supply with off-system delivery such that it can meet its H2 blending targets in the 2022 LTGRP?

<u>Response:</u>

FEI expects that off-system renewable and low-carbon hydrogen will form a part of the overall renewable gas supply portfolio in meeting emission reduction targets. Please refer to the response to BCUC IR1 62.5.

26.1.1 Does off-system supply and delivery transfer the pipeline capacity problem (due to lower heating value from H2) to other pipeline operators and utilities, since these operators and utilities will need to connect supply locations with demand locations? Is large-scale purchasing of off-system H2 realistic, considering these other operators and utilities would need to potentially make substantial transmission and distribution investments?

Response:

Off-system supply and off-system delivery would require the other pipeline operators and utilities involved to undertake an assessment of the incorporation of hydrogen supply and delivery points to ensure it is safe and economic to do so. Since the impacts depend on many factors, including the location of supply and demand, as well as the current and future state of the infrastructure involved, there could be net benefits, or drawbacks, to considering off-system supply and delivery scenarios. For example, a pipeline operator or utility may be able to make use of pipeline infrastructure with low current or expected levels of utilization to transport hydrogen much more economically than a constrained pipeline system that would require expansion facilities to do so. In short, off-system supply and delivery does not necessarily transfer a pipeline capacity problem to other operators and utilities. Large scale purchasing of off-system hydrogen could be realistic, but it will depend on the pipeline operators and utilities involved.

27. Reference: Exhibit B-1 Plan p.7-40

On-System Supply and Delivery – Impact on Capacity of H2 Blending

On page 7-40 of its Plan, FEI states: "By 2030, FEI expects to have developed hydrogen production within portions of the CTS at various locations and will be developing upstream supply. FEI is also expecting the potential for some, but not large quantities of hydrogen delivered from pipelines upstream of Huntingdon Control Station by that time. The proportions of hydrogen and RNG delivered in the system by 2030 may be similar. By 2042, however, FEI expects that most of the hydrogen used in the CTS will be supplied from the pipelines upstream of Huntingdon, and hydrogen will comprise a much larger portion of the renewable and low-carbon gas delivered."

27.1 How will FEI accommodate local H2 production, which may be sized and operated to produce a relatively constant supply of H2, within its system which has strong shifts in consumption according to the seaon? For example, a local plant producing H2 sufficient for an adjacent local load with the excess injected into the FEI system may produce enough H2 to blend with the natural gas stream to 10% or 20% during periods of high demand, but this same volume of H2 will result in H2 blends substantially higher than 20% in the summer when natural gas flows are reduced.

<u>Response:</u>

FEI expects that hydrogen will not only be blended into the gas system but will also be delivered to existing customers in dedicated facilities such as local 100 percent hydrogen distribution networks where hydrogen production is developed in proximity to a large demand centre with residential, commercial, industrial and feedstock customers. FEI envisions that over the LTGRP planning period, hydrogen production in BC will initially emerge in the form of facilities producing in the range of 0.1 PJ per year up to 5 PJ per year. These facilities would be located where the resources to produce the hydrogen and demand customers coexist. Having dedicated hydrogen infrastructure interconnecting large flexible demand loads will provide for robust offtake strategies and with multiple use-cases, such as blending in the distribution system and converting large volume customers to 100 percent hydrogen, that will help with balancing supply and demand. FEI is currently executing early-stage feasibility analysis for several such opportunities in FEI's service territories. Therefore, the question posed by the RCIA reflects some of the considerations FEI is exploring as it develops and incorporates supplies of hydrogen.

FEI will need to consider how to best accommodate the daily and seasonal demand profile of the pipeline energy systems, while staying within the acceptable blend ratios that will be determined, and especially as the opportunities to develop very large-scale hydrogen production in BC starts to emerge. FEI expects that, in some cases, this may be accomplished by varying the rate of hydrogen production in concert with the demand variation - this could be easily facilitated where a large demand customer upgrades their plant operations to dual fuel capability and can automatically switch between methane and hydrogen.

In instances, particularly over the near term as hydrogen production initially starts to develop with relatively small-scale production and demand scenarios where the processes to produce hydrogen require a steady production rate (as suggested by the question), FEI may need to consider limiting the injection rate to produce the maximum acceptable blend ratio at the lower demand condition and accept lower blend ratios into the system at all other times, while additionally operating within ranges required by consumer appliances connected downstream. Otherwise, where possible, installation of local storage of hydrogen produced in daily low demand hours (to buffer the impacts of demand variation on production), can then be injected during higher demand periods of the day as required. Future facilities to produce and inject hydrogen for blending with natural gas may adopt one, or all, or some combination of these approaches to meet annual emission reduction targets.

28. Reference: Exhibit B-1 Plan p.7-40

On-System Supply and Delivery – Impact on Capacity of H2 Blending

On page 7-40 of its Plan, FEI states: "To keep the blended hydrogen from the upstream pipelines out of the CTS as it begins to arrive in more significant quantities after 2030 would require a hydrogen separation facility at Huntingdon and a dedicated hydrogen pipeline that would ultimately connect to FEI's initial hubs. This pipeline would share a common alignment with FEI's existing CTS pipelines so that hydrogen could be blended directly into the distribution systems at the gate stations served by the CTS."

28.1 Confirm whether FEI has developed any preliminary estimates for the cost of such a dedicated hydrogen pipeline, which would presumably terminate downstream of the take-off points supply Tilbury and Woodfibre LNG, and the cost of a separation facility at Huntingdon.

28.1.1 If confirmed, provide the preliminary estimate.

Response:

Not confirmed. FEI is in the early stages of developing the hydrogen deployment strategy and has not developed the scope or preliminary estimates of specific dedicated pipelines in the CTS or elsewhere. Additionally, FEI would not presume that any dedicated pipelines would need to terminate downstream of LNG facilities because initially, as described in the preamble, the dedicated pipelines could be separate from the CTS system supplying Tilbury and Woodfibre LNG.

Blue or turquoise hydrogen production on system (produced from conventional natural gas supplied from upstream) may not provide any upstream benefit.

28.2 How many GJ of blue or turquoise hydrogen are produced from 1.0 GJ of natural gas, including any energy input into the reforming or pyrolyzing processes (i.e. include any natural gas used in the reformation or pyrolysis processes)?

Response:

Blue or turquoise hydrogen can be produced through different technologies. For example, blue hydrogen is typically produced through steam methane reforming (SMR) or autothermal reforming (ATR) technologies, combined with carbon capture and sequestration. The natural gas consumed in the processes can be highly dependent on the technologies applied. The following examples are taken from the BC Hydrogen Study:[11]

- For blue hydrogen production using a conservative 75 percent efficiency, applying SMR to 1.0 GJ of natural gas would result in 0.75 GJ of hydrogen, or approximately 5.3 kg.
- For turquoise hydrogen produced through thermal pyrolysis technologies, energy inputs were estimated assuming a 90 percent pyrolytic reaction conversion efficiency of methane to hydrogen and carbon, and an 80 percent yield in the pressure swing absorption process which removes any unreacted methane from the hydrogen resulting in an estimated 0.32 GJ per kg hydrogen, of which 0.028 GJ per kg hydrogen is required to provide heat for the reaction. Therefore, applying pyrolysis to 1.0 GJ of natural gas would result in 0.44 GJ of hydrogen, or approximately 3 kg.

[11] zen-bcbn-hydrogen-study-final-v6.pdf (gov.bc.ca).

29. Reference: Exhibit B-1 Plan p.7-41

Impact on RGSD Capacity of H2 Blending

On page 7-41 of its Plan, FEI states: "Currently FEI is developing the RGSD pipeline. Should the potential project proceed, the pipeline and system upgrades which include additional compressor facilities along FEI's SCP. The RGSD would allow FEI to receive and deliver off-system hydrogen production from TC Energy and on-system supplies along the ITS and SCP to other locations along the ITS, but also as envisioned will have the capacity to move additional hydrogen and conventional gas required for the CTS via a new NPS 30 hydrogen ready pipeline between Oliver and the Lower Mainland."

29.1 What percentage H2 blend will RGSD be designed to carry?

Response:

In the development of the RGSD Project, FEI will ensure the design and construction of the system is fully compatible for high concentration hydrogen blends, and potentially able to evolve to full hydrogen in the future, although this will be reviewed more critically during the feasibility work. The design would also accommodate a reasonable baseline pipeline capacity to move hydrogen blends and effective ways to expand capacity over time to compensate for loss of energy delivery capacity as higher levels of hydrogen are blended, to ensure that future peak demand requirements can be met.

29.2 Explain whether the RGSD will be designed to meet the currently anticipated capacity requirements on natural gas, or whether it will be oversized (when carrying natural gas) so that it is capable of the same capacity when carrying a H2 blend?

Response:

The current preliminary design of the RGSD allows the line to deliver sufficient volumes of gas (at 100 percent natural gas), while addressing key issues by diversifying pipeline capacity (providing increased resiliency), alleviating current constraints at Huntingdon, promoting regional growth and providing a baseline but expandable capacity to allow hydrogen blends to be transported.

Over time, as greater levels of hydrogen need to flow on the RGSD line, incremental capacity may need to be added. Under that scenario, FEI can efficiently increase the RGSD pipeline's capacity by adding compression.

30. Reference: Exhibit B-1 Plan p.7-44

Distribution System Resiliency

On page 7-44 of its Plan, FEI states: "A NPS 24 IP pipeline located on the Ironworkers Memorial Bridge provides the only gas supply to more than 45,000 customers in North Vancouver and West Vancouver. Loss of this crossing would result is an extensive outage for these customers. Providing a second redundant crossing to the Northshore communities would significantly improve the resilience of this portion of the Metro Vancouver distribution system.

In the Interior region, West Kelowna is supplied by an NPS 8 IP pipeline that crosses Okanagan Lake between Kelowna and West Kelowna. While the system may require capacity upgrades later in the forecast period that could entail looping the lake crossing, looping the crossing would address capacity constraints but would not improve resiliency."

30.1 Explain why a redundant crossing to the Northshore communities would improve resilience but looping the Okanagan Lake crossing would not.

Response:

The last sentence in the preamble is incorrect. Looping the Okanagan Lake crossing will improve resiliency in the supply to West Kelowna.

G. Outcomes of the Clean Growth Pathway

31. Reference: Exhibit B-1 Plan p.9-4, 2-16; Utilities Commission Act

Obligation to Serve New Customers

On page 9-3 of its Plan, FEI states: "The Province's Clean BC Roadmap states that the GHGRS emissions cap on gas utilities will be approximately 6 Mt CO2e in 2030. Accounting for the fact that FEI is not the only gas utility in BC, the portion of the cap that applies to FEI is estimated to be 5.7 Mt CO2e."

Section 28(1) of the *Utilities Commission Act* states:

"Utility must provide service if supply line near

28(1) 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."

31.1 If FEI is at or in excess of its emissions cap, explain how FEI expects to fulfill its obligations to serve new customers as detailed in section 28(1) of the *Utilities Commission Act,* as the addition of more customers will further increase the emissions attributed to FEI.

<u>Response:</u>

The rules around the GHGRS emissions cap are not yet known as the Province has yet to enact legislation to effect the CleanBC Roadmap. As such, it is not possible to know what options FEI would have to meet the cap or to lower its emissions to be under the cap.

31.2 If FEI continued with a business-as-usual approach (i.e. the Reference Case scenario, as opposed to implementing the four pillars of its Clean Growth Pathway) and therefore was far in excess of the emissions cap, how would FEI reconcile its obligations to serve existing customers with the GHGRS emissions cap?

<u>Response:</u>

Please refer to the response to RCIA IR1 31.1

On page 2-16 of its Plan, FEI states: “Along with these commitments, a growing number of local governments are implementing changes to their building codes63, planning guidelines, and zoning bylaws in order to reduce GHG emissions in new building construction projects and in some cases with existing building retrofits and improvements. This is being achieved by:

- establishing GHG target limits for new construction, necessitating the use of low-carbon or renewable energies;”

Footnote 63 states: “Specifically, the City of Vancouver is enabled under the Vancouver Charter to adopt by-laws to regulate the design and construction of buildings. Other municipalities must follow the provincial building code but can provide zoning by-laws that can be enforced.”

31.3 Explain whether the by-laws enacted by the various municipalities preclude FEI providing service to homes and businesses and whether these by-laws potentially conflict with section 28(1) of the Utilities Commission Act.

<u>Response:</u>

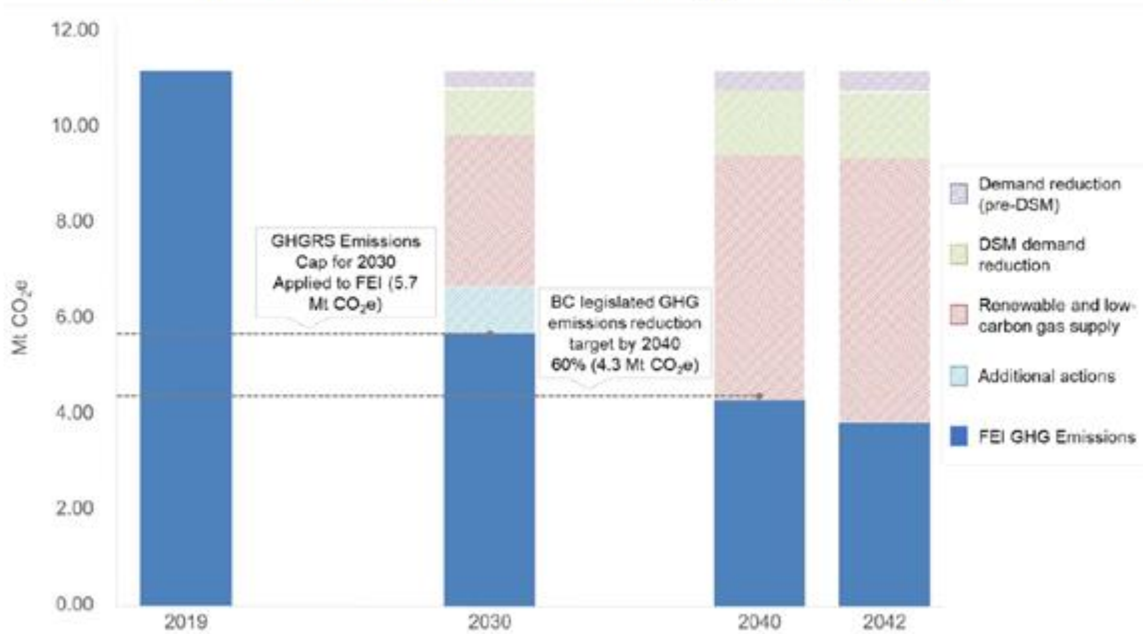
Where a municipality has effectively prohibited the use of appliances that use gas (through GHGi targets or other electricity related bylaws), this can preclude FEI from providing service as customers are not able to have gas appliances. Whether such bylaws conflict with section 28(1) of *Utilities Commission Act* is a legal question. FEI’s views on this matter are privileged and confidential.

32. Reference: Exhibit B-1 Plan pp.2-11, 9-4, 9-6

Emissions Reductions From LCT and Marine LNG

At page 9-4 of its Plan, FEI provides Figure 9-1:

Figure 9-1: GHG Emission Reductions for Residential, Commercial and Industrial Customers Meets the GHGRS for the Diversified Energy (Planning) Scenario



On page 9-6 of its Plan, FEI states: "FEI is not inferring ownership of any carbon credits with regard to Figure 9-3, but simply stating the emission reductions that will occur when natural gas displaces higher-carbon fuels for these uses."

On page 2-11 of its Plan, FEI states: "Under the BC-LCFS, organizations can generate credits by using fuels with a carbon intensity below the targets and receive debits for fuels with a carbon intensity above the targets. Each credit represents 1 tonne of CO2e that was either removed from the atmosphere or not released into the atmosphere as the result of direct, beyond business-as-usual action by a project proponent. These credits can be traded between companies or banked for future use."

32.1 Explain whether there is any way for FEI to benefit under the BC Low Carbon Fuel Standard in a manner that will affect FEI's compliance with the GHGRS emissions cap.

<u>Response:</u>

FEI expects that GHG reductions and subsequent emissions credits generated for compliance with the BC Low Carbon Fuel Standard will not count as progress toward the GHGRS. However, the details of the GHGRS are still being developed by the Province.

Nevertheless, FEI will continue to support GHG reductions in the transportation sector in order to assist its customers in complying with the goals of the Low Carbon Fuel Standard and to broaden its customer base and throughput on its system for the transportation market. This will enable all ratepayers to benefit from otherwise lower abatement costs, while optimizing the use of FEI's fixed assets.

32.2 Confirm whether the emissions reductions resulting from FEI supplying natural gas for low-carbon transportation and global LNG have any effect on FEI's compliance with the emissions cap.

Response:

Please refer to the response to RCIA IR1 8.1.

32.2.1 Explain whether there are any benefits to FEI's ratepayers of FEI's investments in the LCT and marine LNG markets (i.e. Pillars 3 and 4 of the Clean Growth Pathway) with respect to meeting the GHGRS emissions cap.

Response:

Please refer to the response to RCIA IR1 8.1.

32.3 Provide the possible variation of GHG emissions based on weather, from the warmest year emissions to the coldest year emissions, as well as the normal year emissions for the years 2022 and 2030.

Response:

The carbon emissions and emission reductions provided in the Application are based on a normal year and are presented in Figure 9-6, Section 9.2.3, starting on page 9-7 of the Application. Otherwise, FEI does not have sufficient information with which to respond to this request. It would be premature to pursue the information requested at this time as the Province has not yet determined the parameters of the GHGRS, including whether or not there is a need to account for warmest and coldest year emissions.

In general, FEI uses a process of weather normalization to recognize that while some years maybe colder than normal (and hence may require more gas use than normal), other years will be warmer than normal (and hence will require less gas than normal) and over time gas use (and the emissions from gas use) will average to approximately normal conditions.

32.3.1 If FEI has any information on how this weather variation will be taken into consideration when evaluating FEI's compliance with the GHG Reduction Standard emissions cap, please provide it.

Response:

FEI has not received detail on how variations in annual weather will be accounted for in the GHGRS from the Province. However, in the future, FEI believes that this policy issue can be addressed through weather-normalization practices or by blending annual performance into multi-year rolling averages.

33. Reference: Exhibit B-1 Plan pp.9-1, 2-10, 3-1

Clean Growth Pathway

On page 9-1 of its Plan, FEI states: "FEI's role in this future is to utilize, grow and strengthen its gas transmission and distribution systems for the continued delivery of safe, secure and reliable energy to customers, while reducing carbon emissions for customers through the four pillars of its Clean Growth Pathway."

On page 2-10 of its Plan, FEI states: "It is anticipated that the GHGRS policy framework will enable FEI to invest in a broad set of GHG-saving actions such as increasing renewable and low-carbon gases and incenting higher levels of energy efficiency and other measures."

On page 3-1 of its Plan, FEI states: "FEI's Clean Growth Pathway is supported by four key pillars:

Pillar 1: Transitioning to renewable and low-carbon gases to decarbonize the gas supply;

Pillar 2: Investing in DSM programs in support of energy efficiency and conservation measures to reduce energy use among residential, commercial and industrial customers;

Pillar 3: Investing in low-carbon transportation infrastructure to reduce emissions in this sector; and

Pillar 4: Investing in LNG to lower GHG emissions in marine fueling and global markets."

33.1 Confirm whether FEI has evaluated plans or pathways other than the Clean Growth Pathway that have the potential to achieve the GHG emissions reductions required to meet the GHGRS emissions cap. For example, did FEI evaluate a pathway that excluded the Pillars 3, 4, or both from the pathway?

33.1.1 If confirmed, did FEI establish that its LTGRP with the Clean Growth Pathway is the lowest cost or lowest rate impact approach to meeting the GHGRS emissions cap?

<u>Response:</u>

Confirmed. A comparison between a deep electrification and a diversified energy pathway is included in Appendix A-2 of the Application and supported by information provided in Appendix A-9 of the Application. Further, the Pathways Report in Appendix A-2 concluded that a diversified pathway is more cost effective than one based on electrification. FEI has not yet undertaken further analysis or evaluation of alternate pathways to achieve the cap because details on the nature of the cap including its scope, reduction requirement, allowed abatement activities and other critical design components have not yet been fully developed by the

Province. As such, it is difficult for FEI to speculate on materially different abatement pathways beyond high-level approaches conducted to-date. Please also refer to the response to RCIA IR1 8.1.

34. Reference: Exhibit B-1 Plan p.9-10

Electrification

On page 9-10 of its Plan, FEI states: "The electrification of a degree of current gas load is expected to happen over the planning horizon as one of the solutions to reduce carbon emissions in the Diversified Energy (Planning) Scenario. Total electrification of FEI's existing gas demand, however, creates challenges for electricity capacity requirements that FEI considers are not plausible. FEI's Clean Growth Pathway is based on using the right energy, for the right purpose at the right time.

34.1 Provide any statements by BC Hydro that FEI is aware of with respect to the amount of electrification of FEI's gas demand that could be electrified.

Response:

FEI is not aware of any statements by BC Hydro that indicate the amount of FEI's gas demand that could be electrified. The BCUC declined to direct BC Hydro to provide any long-term plans and targets for low-carbon electrification, which may have indicated the totality and feasibility of electrification of gas demand within the province.

This information was provided in Chapter 3 of BC Hydro's 2021 Integrated Resource Plan, Section 3.2.1 (g) beginning at Line 19 on page 3-7:

> In Commission Order No. G-28-21 the Commission directed that BC Hydro file its next long-term resource plan no later than December 31, 2021. This Application is filed in accordance with that directive. Also in Commission Order No. G-28-21, the Commission declined to direct BC Hydro to include in the 2021 IRP any long-term plans and targets for low-carbon electrification, concluding that "there is no obligation for BC Hydro to produce such plans outside of how they affect the key components of the IRP"; . . .

34.2 What is the maximum amount of electrification of FEI's gas load that is modeled in FBC's most recent electric Long Term Electricity Resource Plan?

Response:

The maximum amount of electrification of FEI's gas load that is modeled in FBC's most recent electric Long-Term Electricity Resource Plan (the 2021 LTERP) was included in the Upper Bound, Scenario 1. In this scenario, it is assumed that FBC will achieve 30 percent of the 2035 technical potential in the June 2019 update of the Conservation Potential Review (CPR) and maintain that level of achievement through 2040. The technical potential estimates from the CPR are presented in the following table:[12]

Table 7 Impacts of Fuel Switching – Gas to Electric

Energy Type	Total Impact (for 2035)
Electric Energy	1,032 GWh/year
Electric Demand	276 MW
Gas Energy	-4,406 TJ/year*

*reduced natural gas demand

Therefore, based on 30 percent achievement of the CPR technical potential, the annual energy and peak demand impacts from this fuel switching electrification are 310 GWh and 83 MW, respectively, by 2040.

[12] FBC 2021 LTERP, Appendix H – Load Scenarios Assessment report, page 19.

35. Reference: Exhibit B-1 Plan p.9-12, 9-13; 2017 LTGRP Exhibit B-1 p.212

Rate Impacts

On page 9-12 of its Plan, FEI states: "The 2022 approved delivery margin as the baseline cost of service plus annual escalation by inflation as well as the incremental cost of service for the capital expenditures on FEI's major transmission systems (VITS, CTS, and ITS) related to capacity upgrades, integrity, and resiliency depending on the peak demand forecast in each scenario;"

35.1 Confirm whether the capital expenditures factored into the analysis on effective rate impacts includes the capital expenditures necessary to accommodate increasing proportions of hydrogen blended into the gas stream, such as dedicated H2 pipelines or H2 separation facilities at Huntingdon, Tilbury, and Coquitlam (Woodfibre LNG).

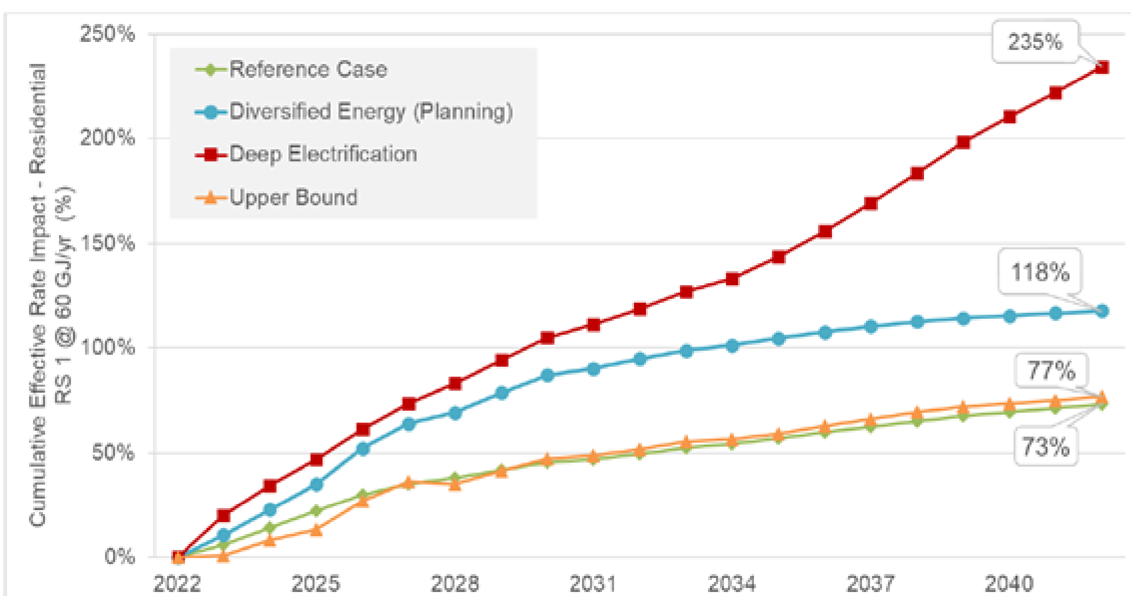
35.1.1 If not confirmed, explain the relevance of the rate impact analysis considering the potential magnitude of the required capital expenditures to facilitate H2 blending into FEI's system.

Response:

Please refer to the response to BCUC IR1 77.4.1.

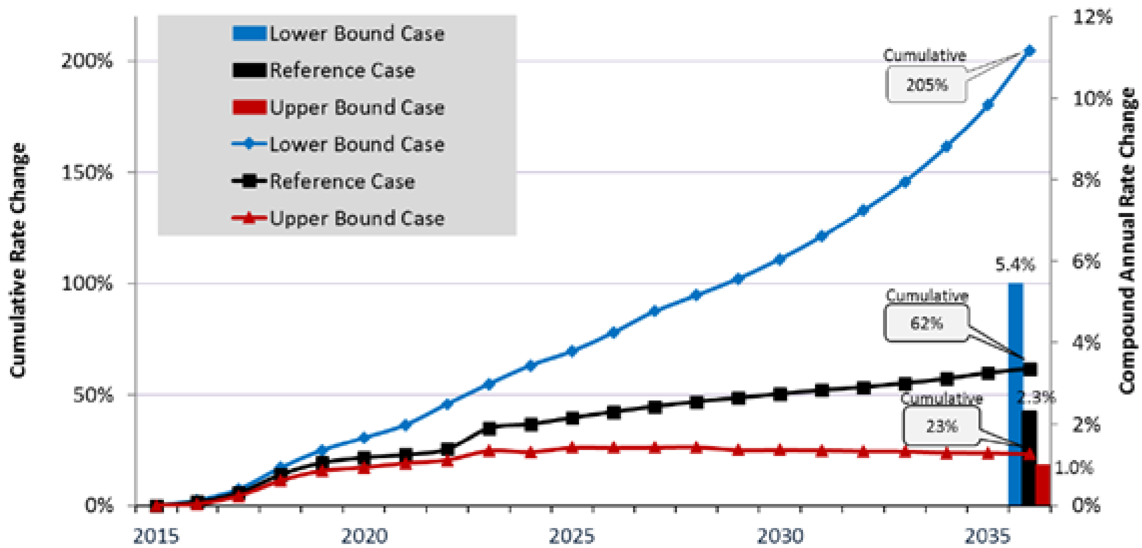
On page 9-13 of its Plan, FEI provides the Residential rate impacts for four scenarios:

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



On page 212 of its 2017 Long Term Gas Resource Plan, FEI provides the overall rate impacts for three scenarios:

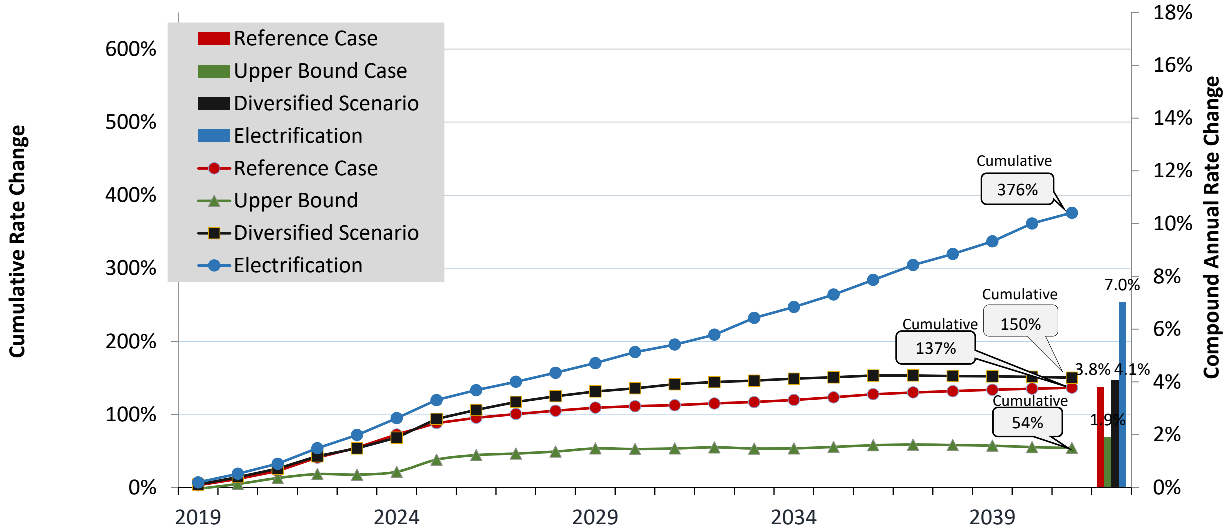
Figure 8-9: Delivery Rate Direction – All Rate Schedules with C&EM and NGT



35.2 Provide the indicative rate impacts for all rate schedules (combined), similar to Figure 8-9 from the 2017 LTGRP.

Response:

Figures 9-7 to 9-10 in the Application show the total bill impact per rate schedule including delivery, cost of gas, storage and transport, and carbon tax. Figure 8-9 of the 2017 Long Term Gas Resource Plan only shows the delivery rate impact. To be responsive, FEI has included the delivery rate impact of the 2022 LTGRP similar to Figure 8-9 from the 2017 LTGRP.



35.3 Explain whether the Reference Cases in each of Figure 9-7 and 8-9 are approximately equivalent or whether there are substantial differences.

35.3.1 If they are substantially different, explain in what ways they are different.

<u>Response:</u>

FEI notes the Reference Case is based on end use patterns observed, as well as any new changes in law or policy that will affect future demand as of the base year. The Reference Case from the 2017 LTGRP is equivalent to the 2022 LTGRP; however, the basis of the two reference cases is different. First, the base year of the 2017 LTGRP is 2015 while the base year of the 2022 LTGRP is 2019.

In summary, as explained in Section 4.4.1.2 of the Application, the Reference Case of the 2022 LTGRP includes:

- FEI's 2021 Conservation Potential Review (2021 CPR);
- FEI's 2017 Residential End use Survey (REUS) which represents FEI's most recent REUS at the time the forecast modelling was undertaken;
- FEI's 2019 Commercial End Use Survey (CEUS) which represents FEI's most recent study of its commercial customers; and
- Research and data analysis from the 2017 LTGRP which FEI included to utilize and build upon work that had already been completed for the 2017 LTGRP.

In contrast, Section 3.4.1 of the 2017 LTGRP explained the Reference Case included:

- The 2015 BC Conservation Potential Review (BC CPR) which represents a collaborative provincial forecast (sponsored by FEI, FBC, BC Hydro, and Pacific Northern Gas) of energy conservation potential and thus benefits from data supplied by all sponsors as well as the rigour of multiple entities acting as reviewers;
- FEI's 2012 Residential End-Use Survey (REUS) (FEI's 2017 REUS was not complete at the time of filing the 2017 LTGRP);
- FEI's 2015 Commercial End-Use Survey (CEUS) which represents FEI's most recent study of its commercial customers; and
- Research and data analysis from the 2014 LTGRP which FEI included to utilize and build upon work that had already been completed for the 2014 LTGRP.

On page 9-12, FEI states: "The analysis on effective rate impacts compares the changes in rates to the current 2022 approved rates with the following assumptions:

- The incremental cost of service (including any offsetting revenue) related to FEI's major capital projects recently filed (or expected to be filed) or approved by BCUC, including:
  - Inland Gas Upgrades (IGU) CPCN;
  - Pattullo Gas Line Replacement (PGR) CPCN;
  - Tilbury LNG Storage Expansion (TLSE) CPCN;
  - Advanced Metering Infrastructure (AMI) CPCN;
  - CTS and ITS Transmission Integrity Management (TIMC) CPCNs;
  - OIC Tilbury Phase 1B; and
  - Woodfibre Gas Pipeline."

35.4 Explain why the Okanagan Capacity Upgrade is not included in the rate impact analysis.

Response:

FEI clarifies that the OCU project was included in every scenario in the rate impact analysis presented in Section 9.4 of the Application. The list of major capital projects listed on page 9-12 of the Application and as referenced in the preamble above inadvertently excluded the OCU project.

36. Reference: Exhibit B-1 Plan p. 9-15

At page 9-15 of its Plan, FEI presents Table 9-2:

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	73%	2.8%	77%	2.9%	118%	4.0%	235%	6.2%
Small Commercial (RS 2)	293	41%	1.7%	64%	2.5%	102%	3.6%	207%	5.8%
Large Commercial (RS 3)	3,253	40%	1.7%	69%	2.6%	107%	3.7%	206%	5.7%
General Firm Service (RS 5)	18,542	44%	1.9%	80%	3.0%	114%	3.9%	150%	4.7%

FEI goes on to state: "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. Using Residential (RS 1) as an example, Figure 9-11 below provides a breakdown of the annual bill projections for the average residential customer under the Diversified Energy (Planning) Scenario from 2022 to 2024. It can be seen that the total residential bill is estimated to increase from approximately $1,029 in 2022 to $1,958 in 2031, and to approximately $2,215 in 2040 under the Diversified Energy (Planning) Scenario."

36.1 Please confirm if the dollar figures quoted above are presented in real or nominal dollars.

<u>Response:</u>

The dollar figures quoted in the preamble above are presented in nominal dollars.

36.2 For Table 9-2, please provide:

36.2.1 the assumed delivery volumes (in % change, 2022 - 2042), and

36.2.2 the capital expenditure assumed (in nominal $ by year).

<u>Response:</u>

Please refer to the response to BCUC IR1 75.4 and related attachment 75.4 for the delivery volumes (in % change, 2022 - 2042) and Attachment 36.2.2 for the capital expenditures assumed (in nominal $ by year) for the four scenarios as referenced in the preamble above.

Attachment 16.1

REFER TO LIVE SPREADSHEET MODEL

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 36.2.2

Capital Expenditure (Reference)	Cumulative (2023-2042)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Regular Capital	1,498	383	367	369	380	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IS Upgrade	42	-	20	21	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Capacity Upgrades (VITS, CTS, ITS)	280	2	4	4	60	120	12	6	32	-	-	-	-	-	-	-	-	40	-	-	-
Resiliency Upgrades (Distribution)	1,130	-	-	5	10	10	150	300	25	1	6	11	41	177	278	109	8	-	-	-	-
Integrity Upgrades	144	3	13	16	19	18	3	2	23	45	4	-	-	-	-	-	-	-	-	-	-
CPCNs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
T1B	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TLSE	739	166	252	210	111	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AMI	473	91	168	150	64	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TIMC-CTS	100	5	93	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TIMC-ITS	82	4	11	33	33	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PGR	17	17	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OCU	253	113	139	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGU	104	69	33	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Regular/Major Capital, Escalated (2027-2042)	10,437	-	-	-	-	546	564	575	588	602	613	626	636	662	676	695	701	714	729	751	759
Total ($000s)	**15,299**	**854**	**1,099**	**812**	**679**	**694**	**728**	**883**	**668**	**648**	**623**	**637**	**677**	**839**	**954**	**804**	**709**	**754**	**729**	**751**	**759**

Capital Expenditure (Upper)	Cumulative (2023-2042)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Regular Capital	1,499	384	367	369	380	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IS Upgrade	42	-	20	21	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Capacity Upgrades (VITS, CTS, ITS)	779	6	12	12	180	360	34	20	75	-	-	-	-	-	-	-	-	80	-	-	-
Resiliency Upgrades (Distribution)	3,479	-	-	15	30	30	455	910	85	153	311	46	96	325	495	334	60	44	10	41	41
Integrity Upgrades	289	3	33	38	44	22	4	3	45	90	8	-	-	-	-	-	-	-	-	-	-
CPCNs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
T1B	1,076	451	365	260	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TLSE	739	166	252	210	111	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AMI	473	91	168	150	64	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TIMC-CTS	100	5	93	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TIMC-ITS	82	4	11	33	33	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PGR	17	17	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OCU	253	113	139	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGU	104	69	33	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Regular/Major Capital, Escalated (2027-2042)	10,437	-	-	-	-	546	564	575	588	602	613	626	636	662	676	695	701	714	729	751	759
Total ($000s)	**19,369**	**1,309**	**1,493**	**1,112**	**844**	**957**	**1,057**	**1,508**	**793**	**845**	**931**	**672**	**732**	**987**	**1,171**	**1,029**	**761**	**838**	**739**	**791**	**800**

Capital Expenditure (Diversified Energy Planning)	Cumulative (2023-2042)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Regular Capital	1,498	383	367	369	380	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IS Upgrade	42	-	20	21	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Capacity Upgrades (VITS, CTS, ITS)	679	6	12	12	180	360	31	6	32	-	-	-	-	-	-	-	-	40	-	-	-
Resiliency Upgrades (Distribution)	1,130	-	-	5	10	10	150	300	25	1	6	11	41	177	278	109	8	-	-	-	-
Integrity Upgrades	144	3	13	16	19	18	3	2	23	45	4	-	-	-	-	-	-	-	-	-	-
CPCNs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
T1B	1,076	451	365	260	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TLSE	739	166	252	210	111	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AMI	473	91	168	150	64	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TIMC-CTS	100	5	93	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TIMC-ITS	82	4	11	33	33	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PGR	17	17	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OCU	253	113	139	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGU	104	69	33	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Regular/Major Capital, Escalated (2027-2042)	10,437	-	-	-	-	546	564	575	588	602	613	626	636	662	676	695	701	714	729	751	759
Total ($000s)	**16,774**	**1,308**	**1,472**	**1,080**	**799**	**934**	**748**	**883**	**668**	**648**	**623**	**637**	**677**	**839**	**954**	**804**	**709**	**754**	**729**	**751**	**759**

Capital Expenditure (Deep Electrification)	Cumulative (2023-2042)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Regular Capital	1,498	383	367	369	380	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IS Upgrade	42	-	20	21	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Capacity Upgrades (VITS, CTS, ITS)	80	-	-	-	-	-	2	6	32	-	-	-	-	-	-	-	-	40	-	-	-
Resiliency Upgrades (Distribution)	1,130	-	-	5	10	10	150	300	25	1	6	11	41	177	278	109	8	-	-	-	-
Integrity Upgrades	144	3	13	16	19	18	3	2	23	45	4	-	-	-	-	-	-	-	-	-	-
CPCNs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
T1B	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TLSE	739	166	252	210	111	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AMI	473	91	168	150	64	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TIMC-CTS	100	5	93	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TIMC-ITS	82	4	11	33	33	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PGR	17	17	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OCU	253	113	139	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGU	104	69	33	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Regular/Major Capital, Escalated (2027-2042)	10,437	-	-	-	-	546	564	575	588	602	613	626	636	662	676	695	701	714	729	751	759
Total ($000s)	**15,099**	**852**	**1,095**	**808**	**619**	**574**	**718**	**883**	**668**	**648**	**623**	**637**	**677**	**839**	**954**	**804**	**709**	**754**	**729**	**751**	**759**