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December 22, 2022

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Ms. Sara Hardgrave, Acting Commission Secretary

Dear Ms. Hardgrave:

Re: FortisBC Energy Inc. (FEI)

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

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

On May 9, 2022, FEI filed the LTGRP referenced above. In accordance with the amended regulatory timetable established in BCUC Order G-287-22 for the review of the LTGRP, FEI respectfully submits the attached response to BCUC 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, FEI has occasionally provided an internet address for referenced reports instead of attaching lengthy documents to its IR responses. FEI intends for the referenced documents to form part of its IR responses and the evidentiary record in this proceeding.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

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A. PLANNING ENVIRONMENT

1.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1 (LTGRP or Application), Section 1.5.4, p. 1-14; Section 2.2.2.2.2, p. 2-9

Resource Portfolios

On page 1-14 of the 2022 Long Term Gas Resource Plan (LTGRP or Application), FortisBC Energy Inc. (FEI) provides Table 1-6 which outlines how the LTGRP addresses the British Columbia Utilities Commission's (BCUC) Resource Planning Guidelines (Guidelines).

With respect to section 5 of the Guidelines (development of multiple resource portfolios), FEI states:

> FEI is not a vertically integrated utility, and does not develop and compare multiple integrated resource portfolios. Rather, in the 2022 LTGRP, FEI plans to the Diversified Energy (Planning) Scenario. However, in the future, this may change as FEI transitions to renewable, low-carbon gas and community solutions, which may require future resource plans to examine alternative supply resource portfolios.

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

> The move from a voluntary renewable gas target to a mandated GHG [Greenhouse Gas] emissions cap is a substantial change in direction for provincial policy. While details on the GHGRS [Greenhouse Gas Reduction Standard] remain under

development, FEI expects that it will place a stringent emissions reduction obligation on gas utilities. Compliance pathways to achieve the cap have not yet been developed; however, these pathways will be highly consequential for the overall role of gas utilities and for customers that rely on the energy that natural gas utilities deliver.

1.1 Please further explain why FEI considers the comparison of resource portfolios is a potential future matter, rather than a matter for the 2022 LTGRP.

1.1.1 Please further elaborate on the circumstances under which FEI considers the development and evaluation of multiple resource portfolios would be appropriate.

Response:

FEI's discussion of comparing resource portfolios is intended to refer to the emerging opportunity for FEI to develop its own renewable and low-carbon gas generation (production) resources or perhaps put out a call for renewable and/or low-carbon gas acquisitions from independent producers. FEI has not historically owned its own sources of supply or undertaken a call for production of this nature to others. Rather, FEI currently relies (and has historically relied) on contracting for supply resources in the open market for natural gas, for which portfolio considerations are examined by the BCUC through FEI's Annual Contracting Plan and related studies. It is only the transition to renewable and low-carbon supply resources driven by the Province's emission reduction targets that creates the potential for future development of gas production resource options studies and a comparison of alternative resource portfolios to become part of FEI's LTGRPs.

A comparison of renewable and low-carbon gas portfolios is a potential future matter rather than a matter for the Application because the marketplace for these resources is still new and there are currently not enough supply resource alternatives from which to develop and assess a robust set of alternative portfolios. As the development of and market for these supply resources matures, FEI anticipates that this type of portfolio analysis may well become part of FEI's future LTGRPs.

1.1.2 In consideration of FEI's Diversified Energy (Planning) Scenario and FEI's forecast of renewable and low-carbon gas supply provided in the Application, please discuss in what approximate timeframe FEI expects a future resource plan may examine alternative supply resource portfolios.

Response:

FEI anticipates that more information about the evolving market for renewable and low-carbon gas will be included in each of its successive LTGRPs. However, due to the rapid transition to renewable and low-carbon gas required to meet the forthcoming Greenhouse Gas Reduction Standard (GHGRS) announced by the BC Government, FEI estimates that the opportunity to develop a broad range of renewable and low-carbon gas supply resource alternatives for examination in an LTGRP may not be practical until near or perhaps after 2030, which is the milestone year indicated by the BC Government for the proposed GHGRS emissions cap for gas utilities. Until that time, the anticipated legal requirement to rapidly decarbonize the energy supply to buildings and industry in BC as a result of the cap means that FEI's Clean Growth Plan will involve purchasing most of the reasonably priced renewable and low-carbon gas available to it, thereby supplanting the opportunity to develop alternative portfolio options.

1.2 Please discuss whether FEI modelled different compliance pathways to meet the proposed GHGRS cap.

Response:

In the Application, FEI modelled two pathways to rapidly reduce carbon emissions: The Diversified Energy (Planning) (DEP) Scenario and the Deep Electrification Scenario. Meeting the GHGRS cap was not set as a constraint for the future scenarios modelled by FEI, since:

a) The GHGRS was not announced at the time the scenario modelling for the Application was conducted; and

b) Placing this type of constraint on a long-term future scenario at the outset of the modelling process (i.e. forcing modelled scenarios to reach a prescribed outcome) limits the value of the modelling exercise for understanding the implications of various policies and actions under the future scenarios.

For example, the DEP Scenario is a future condition that enables FEI to implement its Clean Growth Pathway. Under this future condition, FEI is also able to adjust its future resource acquisitions to meet the GHGRS cap constraint introduced late in the resource planning process. FEI's evaluation of the Deep Electrification Scenario against the GHGRS cap during the BCUC's Energy Scenarios for BC Hydro and FEI process[1] indicated that Deep Electrification did not meet the cap and did not allow for FEI to adjust resource acquisitions to do so. Further, FEI's review of BC Hydro's submission during that process identified that forcing the Accelerated Electrification scenario modelled by BC Hydro to meet the GHGRS Cap required making assumptions about FEI's resource acquisitions that BC Hydro is not able to fully evaluate or implement.

[1] See the FEI Reports: British Columbia Hydro and Power Authority and FortisBC Energy Inc. Energy Scenarios - FEI Modelling Results (Stage 1) and FEI Supporting Commentary Regarding the Supply Resource Impacts, Rate Impacts and Associated GHG Emission Impacts (Stage 2). These can be found on the BCUC web site here: https://docs.bcuc.com/Documents/Proceedings/2022/DOC_67461_2022-08-12-FEI-Stage2-Submission.pdf.

1.2.1 Does FEI view the consideration of different compliance pathways to meet the proposed GHGRS cap as similar to analysis of multiple resource portfolios? Please explain.

Response:

No. FEI considers that modelling different future conditions or compliance pathways involves a higher (i.e. less granular) level of analysis and has a different intended purpose than that required for evaluating alternative resource portfolios. Examining alternative resource portfolios in an integrated resource plan includes defining various types of resource alternatives and their attributes (e.g. locations, associated GHG emissions), determining their quantities and costs and then comparing resource alternatives based on a specified set of evaluation metrics. The resources or resource portfolios are typically developed to meet the requirements of a specific forecast or forecast range of future demand. Modelling different compliance pathways, however, first sets an emissions target and then examines alternate demand and resource pathways that need to achieve the stated limitation. Thus, examining compliance pathways is much broader in scope.

2.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1, Section 2.2.2.1, pp. 2-7 – 2-8

Climate Change Accountability Act

On pages 2-7 and 2-8 of the Application, FEI states:

> The CCAA [*Climate Change Accountability Act*] required the Minister of Environment and Climate Change to establish sector-specific targets for GHG reductions by March 31, 2021, and to then review these targets by the end of 2025 (and at least once every five years thereafter). In March 2021, sectoral targets for 2030 were established as follows, expressed as a percentage reduction from 2007 sector emissions:
>
> - Transportation – 27 to 32 percent;
> - Industry – 38 to 43 percent;
> - Oil and Gas – 33 to 38 percent; and
> - Buildings and Communities – 59 to 64 percent.
>
> These targets will apply a more focused and directed approach to reducing emissions in these sectors. Notably, FEI delivers the majority of its energy to the industry and buildings and communities sectors, which are the sectors with the most ambitious 1 targets. This places significant pressure on FEI to source affordable, reliable and low-carbon energy. While oil and gas are considered in the sectoral targets, the CCAA provides little detail on how various sectors are to achieve the targets and how these targets will be incorporated into future climate plans and reporting.

2.1 Please outline the proportion of BC's total GHG emissions resulting from energy supplied by FEI in the following sectors: (i) Industry, and (ii) Buildings and Communities.

<u>Response:</u>

For 2019, FEI estimates that its customer-related emissions (life cycle) as a proportion of BC's total GHG emissions inventory are as follows:

- Industry – 7 percent; and
- Buildings and communities – 12 percent.

FEI estimated the buildings and communities' proportion by adding the total emissions of FEI's residential and commercial customers in comparison to B.C.'s total emissions.

3.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1, Section 2.2.2.2.6, p. 2-12

Upstream Gas Emissions

On page 2-12 of the Application, FEI states:

> The Roadmap aims to reduce methane emissions from upstream oil and gas, reduce oil and gas emissions in line with sectoral targets, advance CCUS [carbon capture utilization and storage], and engage industrial customers in GHG reduction planning. While there are few details on the cap for oil and gas emissions, the benefits of reduced emissions reduction in upstream gas production will reduce the carbon intensity of natural gas that FEI distributes and provincial emissions. However, these initiatives could potentially increase the commodity cost of gas in the province, impacting FEI customer rates.

3.1 Please further clarify how FEI considers reduced emissions from upstream gas production will reduce the carbon intensity of natural gas distributed by FEI. Please discuss whether this would impact FEI's end-use GHG emissions.

Response:

Reducing emissions from upstream gas production would reduce the lifecycle carbon intensity associated with the natural gas distributed by FEI.

FEI is evaluating all options to reduce GHG emissions associated with the energy it distributes to its customers, including emissions associated with the upstream extraction, processing and transmission of natural gas to its system. The emissions associated with direct combustion of natural gas are approximately 0.04987 tCO_2e per GJ (Table 1-2 of the Application), whereas the indirect upstream emissions are much smaller at approximately 0.00993 tCO_2e per GJ, resulting in an approximate lifecycle GHG carbon intensity of 0.0598 tCO_2e per GJ for natural gas in BC.

The GHG-reducing opportunities to reduce the carbon intensity associated with upstream natural gas activities being examined by FEI and the industry in general include using carbon capture, utilization and sequestration, electrification of upstream compression, and methane reduction technologies. Employing these technologies on the natural gas supply that FEI acquires would reduce the lifecycle carbon intensity associated with the indirect upstream emissions of natural gas that FEI distributes.

3.2 Please discuss whether FEI is able to estimate the potential impact upon the commodity cost of gas in the province resulting from reducing upstream gas production emissions, or provide the likely order of magnitude cost impact.

Response:

It is difficult to estimate the impacts of GHG-reducing activities on upstream natural gas extraction and processing on FEI's commodity cost of gas for two reasons.

First, the additional costs of GHG-saving technologies and practices are still not well understood at this time. For example, the cost impacts of carbon capture and sequestration (CCS) on gas processing facilities will depend on the throughput to the facility, total site-specific investment required, the composition of formation CO_2 and/or acid gas in the raw gas, the carbon price the facility will pay, other government incentives and other supportive policies for CCS adoption. FEI is evaluating these cost drivers and is engaging with upstream producers to build understanding; however, costs are likely to be site-specific and change over time.

Second, the scale of GHG-saving investments required for upstream natural gas producers to comply with federal and provincial climate policy is not well understood.

Both the provincial and federal governments have indicated that they intend to develop a GHG emissions cap on upstream oil and gas extracting sectors and that additional policies will aim to reduce the carbon intensity of these sectors to 2030. Under these policies, upstream producers would be obligated to reduce their emissions, so investing in these opportunities would likely become a business-as-usual activity. The costs of these investments would, therefore, be consistent across any of the planning scenarios. Only the incremental costs, over and above compliance with government policies, should be considered were FEI to specifically acquire lower-carbon gases.

Since there are currently few details known on the cap for oil and gas emissions, FEI is unable to estimate what the impact on the commodity cost of gas may be. There are many reasons as to why the cost of a commodity can increase or decrease; however, in general, it is expected that the reduction of upstream emissions will have an increased cost associated with it.

4.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1, Section 2.2.3, pp. 2-16 – 2-17

Local Government Actions

On pages 2-16 to 2-17 of the Application, FEI states:

> Along with these commitments, a growing number of local governments are implementing changes to their building codes, 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; and
> - incenting developers to use electricity as a low-carbon solution (or in some cases to not connect to a "fossil fuel supply grid" system).

4.1 Please provide a summary of specific changes being implemented by local governments to building codes, planning guidelines, or zoning bylaws, which would (i) prevent new natural gas connections, or (ii) limit the consumption of natural gas by a certain amount.

Response

The following response provides examples of specific changes being implemented by local governments to building codes, planning guidelines, or zoning bylaws which impact new gas connections or limit the consumption of natural gas. The following is not intended to be an exhaustive review but rather an indication of the types of activities that FEI is aware of, in this regard.

An area of significant change in FEI's planning environment since the 2017 LTGRP is the evolution of municipal and local government initiatives to reduce emissions which have the effect of reducing or constraining the use of natural gas in buildings.

A number of local governments have adopted the BC Energy Step Code (Step Code) along with a GHGi[2] target for new building construction projects. The Step Code is an optional provincial building code that provides the tools for municipalities to adopt a higher level of energy efficiency in new construction that goes above and beyond the requirements of the BC Building Code. Local governments can reference the Step Code in a policy, program or bylaw, requiring that builders comply with the Step Code for new construction projects. Adoption of the Step Code results in improvements in energy efficiency and lower gas consumption. According to the BC Energy Step Code website,[3] 85 local governments have submitted their initial notification, indicating they have

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2 Greenhouse Gas Emissions intensity (GHGi) is the total annual GHG emissions from all the energy use for the operation of a building. GHGi is calculated per square meter per year, by multiplying the total amount of a building's energy use in one year by the carbon intensity of each energy source and dividing it by the building's gross floor area. The unit of measure is in $kgCO_2e/m^2$ per year.

3 https://energystepcode.ca/implementation_updates/.

started to consult on the Step Code. In addition, UBC has its green building rating system and the City of Vancouver has its own zero emissions building plan.

Along with adopting the Step Code, a growing number of local governments are implementing changes to their building codes, planning guidelines, or zoning bylaws in order to reduce GHG emissions in new building construction projects and, in some cases, existing building retrofits and improvements. These measures prevent new natural gas connections, as natural gas does not meet their requirements. These measures include:

- Establishing GHGi target limits for new construction necessitating the use of low-carbon or renewable energy discussed below; and
- Incentivizing developers to use electricity as a low-carbon solution (or in some cases to not connect to a "fossil fuel supply grid" system).

The discussion on establishing GHGi target limits for new construction to be met with low-carbon or renewable energy is provided below, and the "incentive" to use electricity measures are described in the response to BCUC IR1 4.2.

In addition to the Step Code, some local governments have developed and implemented their own GHGi targets for new building construction projects. The addition of GHGi targets, in conjunction with Step Code performance targets, means that only an energy source with lower carbon emissions can be used in new construction.

Table 1 sets out some of the common current GHGi target levels added to the Step Code and their impact on gas appliances using conventional natural gas.

Table 1: Common Examples of GHGi Targets for New Single-Family Homes

GHGi Levels	Natural Gas Appliance Use to Meet Target
6 $kgCO_{2e}/m^2$	Domestic hot water only, or convenience gas appliances only such as fireplace, cooktop and/or BBQ
3 $kgCO_{2e}/m^2$	Convenience gas appliances only such as fireplace, cooktop and/or BBQ. No space or water heating.
1 $kgCO_{2e}/m^2$	No gas appliances. Note: that at current carbon intensity levels, electricity is unlikely to meet this target in many buildings.

One example of a local government adopting its own policies in addition to the Step Code is the District of North Vancouver (DNV), which passed a bylaw adopting a low-carbon energy approach in December 2020. The new bylaw came into effect on July 1, 2021 and offers two compliance pathways for new construction buildings. Part 9[4] residential buildings (i.e., single family home, coach houses and townhouses) have to be designed and constructed to meet either Step 5 of the Step Code with a GHGi of 3kg $CO_2e/m^2/yr$, or Step 3 with a Low Carbon Energy System (LCES). The DNV describes an LCES as an energy system "that uses primarily low carbon energy sources to provide heating, cooling, and hot water for a building, and has a total modelled greenhouse gas

[4] Part 9 is reference to Part 9 of the BC building code which is intended for single family and small commercial buildings.

intensity of no more than 3kg $CO_2e/m^2/yr$".[5] The current GHGi baseline for new construction using conventional natural gas is in the range of approximately 11 to 27 kg CO_{2e}/m^2 for homes.

The adoption of GHGi targets at the local government level has resulted in a complex patchwork of regulations across BC. The implementation of GHGi targets, and the range of targets that have been set, varies substantially, from 3-6 $kgCO_{2e}/m^2$ to even to 1 $kgCO_{2e}/m^2$. Municipalities may adopt a GHGi regulation for the entire geographic bounds of a city, as seen in the DNV, but limit the application of such regulation to certain building types or sub-building types. Similarly, GHGi requirements may be set at the permit level for a specific home or development or may be required through a rezoning application. In some cases, municipalities may use a combination of one or more of these mechanisms to effect the desired GHG reduction outcome. Therefore, there is no consistency in approach or adoption across FEI's service territory.

To the best of FEI's knowledge, the local governments that have adopted GHGi targets are:

- City of Vancouver;
- City of Surrey;
- City of Burnaby;
- District of North Vancouver;
- City of Richmond; and
- District of West Vancouver.

Please note that there may be additional local governments that are contemplating implementing GHGi targets. Given the complexity of GHGi regulations at the local government level, it is difficult for FEI to know if a local government is considering a GHGi measure or emissions reduction regulation.

In addition to the local governments listed above, a number of local governments have included emission-related or other targets as part of re-zoning activities. These specific bylaws and/or policies to reduce GHG emissions use a technical measure, such as GHGi, through rezoning or planning approvals, and are likely to influence future building code regulations. As such, a service offering that reduces GHG emissions for local governments, while also being available across FEI's service territory, creates certainty and assurance to builders and developers at the planning stage of their developments.

Furthermore, FEI is aware of the proposed amendments to the City of Vancouver's bylaws and climate policies that were presented to council on May 17, 2022. The proposed amendments contemplate changes to GHGi targets, bylaws restricting the use of gas appliances, and the addition of energy use metrics that have the effect of eliminating gas as an option. There is also a general direction that City of Vancouver staff prioritize electrification measures over renewable gas. If approved, these various measures would apply to new and existing buildings. The additional bylaws and policy updates (which have not been finalized and are subject to change) currently focus solely on electricity use to meet the proposed changes to its building code for commercial buildings to require a heat use intensity that gas equipment and gas heated buildings

[5] https://www.dnv.org/building-development/energy-step-code.

may not be able to meet, despite the GHG emissions from RNG potentially being lower than electrically heated buildings.

As noted above, meeting GHGi targets set by local governments can be challenging, leading builders and developers to select electricity, which they perceive to be simpler, instead of gas-based energy solutions. While it is possible for a developer to opt to add in a convenience gas appliance, this adds both costs and emissions which may need to be counted in the building design. This can impact building approval timelines and potentially impact a final building permit approval. Therefore, builders and developers design their houses to be 100 percent electric to ensure a timely approval from a municipality.

4.2 Please provide examples of incentives being provided for developers to use electricity as a low-carbon solution.

Response:

The following is from Section 4.2.3.2.2 of Appendix A of the FEI Business Risk Assessment filed in the BCUC 2022 Generic Cost of Capital – Stage 1 proceeding (Exhibit B1-8-1).[6]

Local governments rely on "incentives" for builders to reduce emissions in new construction. Individual municipalities have different approaches and incentives may be limited to specific projects or may apply across the municipality.

FEI provides two publicly-available examples of a municipality incentivizing developers to use renewable energy (rather than natural gas). However, there are many more instances where a developer, through the zoning negotiation process, is deterred from installing natural gas service.

- **City of Surrey**: In May 2021, the council for the City of Surrey approved a Zero Carbon Incentive to be applied to new buildings built in the Darts Hill Neighbourhood. The incentive is intended to encourage the construction of zero-carbon operation buildings. The Zero Carbon Incentive allows for additional densities measured in Floor Area Ratio (FAR), or Units Per Hectare (UPH). To qualify for the incentive, buildings must have 100 percent of the operational energy needs of the site and building met with non-polluting energy, including heating, hot water, and cooking, and the building must not be connected to a fossil fuel supply grid. This is in addition to any Step Code incentives and City of Surrey energy and sustainability provisions already in effect.[7]
- **District of Squamish:** On April 20, 2021, the District of Squamish adopted a Low Carbon Incentive Program Bylaw to encourage the construction of buildings that use low carbon energy sources, such as electricity, rather than high carbon energy sources, such as fossil fuels. The focus of the energy use is ongoing operations, most notably space and water

[6] https://www.bcuc.com/OurWork/ViewProceeding?applicationid=849.
[7] https://www.surrey.ca/sites/default/files/media/documents/DartsHillNCP.pdf.

heating appliances, such as furnaces or hot water tanks. The Low Carbon Incentive would apply community-wide to all new residential developments within certain zoning. The proposed incentive structure is to establish a new base maximum floor area ratio in the subject zones that is one third of the existing maximum density. This reduced density would be the density that could be achieved for buildings that use higher carbon energy sources, such as natural gas powered furnaces or hot water tanks. Developments that utilize low carbon energy sources could achieve a bonus maximum floor area ratio, which would be the equivalent of the current density. Given the significant density bonus for low carbon development, it is expected that most builders would utilize low carbon energy sources[8] such as electricity to meet the District's requirements and gain the added floor area ratio.

In addition to a direct financial impact on developers, city planners exert influence on builders to conform to local government policies (whether adopted in a bylaw or other policy). This is primarily achieved by streamlining the permitting process for electric-only options which will have the same effect. For instance, as stated in the City of Vancouver's Climate Emergency Action Plan (CEAP) Report, the streamlined permitting process for standard electric heat pump installation is one of the key measures used to incent adoption of electric heat pumps:

> Overly complicated and restrictive permitting requirements for standard heat pumps installations is identified as a key barrier to early owner action in the forthcoming BC Building Electrification Road Map. Of particular importance in the near-term will be to establish a simple, consistent and low-cost process for low-carbon retrofits, focused on simplifying the process for installing an electric heat pump. In 2020, the City took a number of steps to start to address this issue, including:
>
> - A new page dedicated to electric heat pump permitting on the City of Vancouver website.
> - A revised, simplified bulletin for low-rise housing. If an installation meets specific criteria, the project only requires an online electric permit.
> - A public-friendly "Neighbourly Noise Guideline" to help owners and contractors select and install a quiet, hassle-free system.
>
> Additional steps that will be taken over the next year include: 1) establishing a low-cost, flat fee for any heat pump permit, and 2) streamlining the heat pump permit process for pad mounted residential heat pumps.[9]

From a practical standpoint, as developers' primary objective is to garner the best return on their construction project, any request that could either add to their cost (direct financial impact) or delay the approval of permits (indirect financial impact) will motivate a developer to take the action

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[8] https://squamish.ca/yourgovernment/projects-and-initiatives/2020-zoning-bylaw-update/low-carbon-incentive/.

[9] City of Vancouver Climate Emergency Action Plan (October 2020); Appendix J, p. 25, online at: https://vancouver.ca/green-vancouver/vancouvers-climate-emergency.aspx.

stipulated by the local government. The effect of the policy or bylaw is that it impedes the ability of customers to choose gas as their energy source and prohibits FEI from connecting the new customer.

4.3 Please discuss whether any of FEI's load forecast scenarios specifically take into account limitations on natural gas connections or consumption for new buildings, resulting from regulations being implemented by local governments.

Response:

Yes, FEI's modelling of future gas load under different future scenarios accounts for the impacts of potential future limitations, although specific municipal actions or bylaws were not defined other than for the City of Vancouver. The New Construction Code Critical Uncertainty used to create the load forecast scenarios has an "Accelerated" setting that reflects earlier adoption of steps in the BC Energy Step Code, which includes energy performance requirements. FEI applied the "Accelerated" setting to the Deep Electrification and Lower Bound scenarios. This setting did not impact the forecast of customer additions, but rather the amount of gas used by each customer as described in Section 4.4.1.2 of the Application. This modelling characteristic is employed to avoid potential double counting of energy reductions that might occur if both the customer additions and the energy use per end-use were both being adjusted at the same time. While the BC Energy Step Code does restrict the use of conventional natural gas, FEI's modelling did not assume that municipal gas connection policies would prevent the use of low-carbon and renewable sources of gas.

FEI defined specific municipal actions for the City of Vancouver because it is regulated under the Vancouver Charter, a provincial statute which enables the City with broader authority than other municipalities in BC to pass bylaws that regulate activities within the City. One such bylaw, the Vancouver Building Bylaw, has more stringent energy performance requirements than what is applicable in other regions of the Province.

Table B3-2 from Appendix B-3 of the Application, reproduced below, provides the assumptions for the New Construction Code Critical Uncertainty.

Table B3-2: New Construction Code Settings Assumptions

Setting	Years	Residential Assumptions	Commercial Assumptions
Reference	2020-2042	Step 4 (City of Vancouver)	Step 3 (City of Vancouver)
	2020-2042	Step 3 (all other regions)	Step 2 (all other regions)
Accelerated	2020-2027	Step 4 (City of Vancouver)	Step 3 (City of Vancouver)
	2028-2042	Step 5 (City of Vancouver)	Step 4 (City of Vancouver)
	2020-2027	Step 3 (all other regions)	Step 2 (all other regions)
	2028-2032	Step 4 (all other regions)	Step 3 (all other regions)
	2033-2042	Step 5 (all other regions)	Step 4 (all other regions)
Delayed	For all regions including the City of Vancouver: New buildings perform at discounted rates related to the code-mandated level. Based on industry research of how well BC buildings perform in relation to mandatory new construction performance requirements, the 2017 LTGRP assumed such buildings to perform at 63 and 70 percent of mandated performance, respectively, for residential and commercial buildings. We have applied these de-rated savings to the Reference Case to generate the savings in the delayed case for the 2022 LTGRP.		

As noted above, FEI applied the Accelerated setting for the New Construction Code critical uncertainty to the Deep Electrification and Lower Bound scenarios.

5.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1, Section 2.2.4, pp. 2-18 — 2-20

Policy Actions in US Jurisdictions

On pages 2-18 to 2-20, FEI states:

> The following two sections detail recent policy action affecting natural gas utilities in two relevant PNW states, Washington and Oregon, as these policies may impact BC's energy market…
>
> A potential piece of legislation, Washington HB 1084, the Healthy Homes and Clean Buildings Act, could substantially reduce, and potentially eliminate, natural gas utilities' role in delivering energy to many state ratepayers. This bill would require all new buildings in Washington to be zero-carbon by 2030 and seek to eliminate fossil fuel consumption in existing buildings by 2050, through providing a roadmap to phasing out gas utility service in Washington. However, this could potentially increase the replacement of conventional natural gas with RNG [renewable natural gas] and other low-carbon gas, as a new policy in Washington State provides utilities the flexibility to develop RNG programs. This legislation, if enacted, would put Washington on pace to become the first US state to implement statewide restrictions on natural gas infrastructure in new construction, while simultaneously tackling retrofits in existing buildings…
>
> As a result of the OCAP [Oregon Climate Action Plan], in December 2021, Oregon enacted a Climate Protection Program which will set enforceable limits on GHG emissions from fossil fuel use. Beginning in 2022, Oregon has set an emissions cap for fossil fuel providers, which includes natural gas utilities, and the cap will tighten each year through 2050. However, the Climate Protection Program provides several compliance pathways for fossil fuel providers, which includes companies incorporating renewable fuels into their supply mix or contributing to projects that support communities' transition from fossil fuels. Lastly, Oregon governor signed Senate Bill 98 in 2019, setting voluntary RNG goals for gas utilities in the state. This means that as much as 30 percent of RNG could be added into the system by 2050.

5.1 Please discuss the extent to which Western US states besides Washington and Oregon affect BC's natural gas market.

<u>Response:</u>

Developments in the downstream markets south of the Sumas/Huntingdon marketplace can directly (such as through demand) or indirectly (such as through policy) affect BC's natural gas market, with Washington and Oregon being the two most relevant Pacific Northwest (PNW) states.

Please refer to Figure 6-2 in the Application, which illustrates the primary pipeline network that impacts BC's natural gas market and FEI's service territory. This figure illustrates that the two Canadian-United States cross-border interconnections (Sumas and Kingsgate), connected to Northwest Pipeline (NWP) and Gas Transmission Northwest (GTN), are primarily for transportation of natural gas production in Canada to Washington and Oregon states.

Due to this physical connection, as well as the trading interconnectivity between energy markets in the West, supply and demand imbalances in Western US states, including California and the states around the Rocky Mountain basin, can affect pricing in BC and Alberta's natural gas market, on which FEI relies. Similarly, developments in upstream markets (such as gas production, Woodfibre LNG demand, etc.) in BC can directly (such as through remaining supply available for export) or indirectly (such as through price) affect Western US states.

Natural gas markets can also be affected by factors beyond Western US states, such as through geopolitical issues like the Russian invasion of Ukraine, which has led to US LNG exports running at full capacity and has increased global demand and prices for North American natural gas.

5.1.1 Please summarize any relevant policy actions in other states that significantly affect BC's natural gas market.

Response:

FEI has summarized the relevant US state policies that affect the natural gas market that FEI relies on in BC to serve its customers in Section 2.2.4, starting on page 2-17 of the Application. Other than those already discussed in the Application, FEI is not aware of other relevant policy actions in other states that FEI expects would significantly affect BC's natural gas market.

5.2 Please discuss how policy actions taking place in Washington and Oregon may affect (i) FEI's competitive landscape for procuring RNG by 2030 and 2050, and (ii) regional prices for conventional natural gas.

Response:

Generally, the policy actions taking place in Washington and Oregon, in addition to the policies already in place in other jurisdictions such as British Columbia and California, are resulting in pressure on gas utilities and distributors to add renewable gas to their systems to meet the policy requirements and the utilities' own objectives. At the time of writing, Washington HB 1084 has still not been passed and signed into law;[10] however, SB 98 was passed in Oregon in 2019 as noted in the preamble. NW Natural, for example, has already signed agreements to purchase or develop RNG totaling 3 percent of their 2021 annual sales volumes in Oregon, is on track to

[10] https://app.leg.wa.gov/billsummary?BillNumber=1084&Initiative=false&Year=2021.

surpass 5 percent within the next two years, and is planning to reach the voluntary target of 10 percent under SB 98 by 2029.[11] Policy change, as well as decarbonization goals from other natural gas utilities, is changing the market dynamic for procuring renewable gases, and therefore, providing more options for renewable gas suppliers to sell their gas, and increasing the competitive landscape across the North American gas system.

The broader GHG emission reduction policy, the *Climate Commitment Act* (CCA) in Washington, may impact conventional natural gas prices and demand more directly. However, FEI is not able to speculate on the impacts of this bill as the specifics are still under development, and utilities have multiple compliance options available. The state policy actions to reduce GHG emissions and phase out fossil fuels may impact conventional natural gas prices in future years. Other market developments, such as LNG exports in the region, may also have an impact on natural gas prices. At this time, FEI is not able to speculate on the magnitude of the impact on regional prices.

[11] https://www.nwnatural.com/about-us/environment/renewable-natural-gas.

6.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1, Sections 2.3.1, pp. 2-22 – 2-23

Indigenous Groups – Legislative and Policy Developments

On page 2-22 of the Application, FEI states:

> Both the Declaration Act and the UNDRIP [United Nations Declaration on the Rights of Indigenous Peoples] Act have raised questions and differing perspectives as to the meaning of "free, prior and informed consent" (FPIC) in the UN Declaration and what obligations may exist with respect to seeking consent from Indigenous groups. At this point, neither the Declaration Act nor the UNDRIP Act include a definition of consent or FPIC. Many Indigenous groups assert that FPIC requires that consent be obtained from Indigenous groups for a project to proceed. The conflicting perspectives on FPIC's meaning have created new risks for FEI, including cost escalation, project delays, uncertain timelines and risks that authorizations may be challenged where decisions are made without the consent of Indigenous groups.

On page 2-23 of the Application, with respect to the *Environmental Assessment Act*, FEI states:

> In the context of resource planning, FEI must therefore take into account longer lead times for project development and the potential to enter into agreements with Indigenous groups with respect to projects.

6.1 Please further explain how FEI has taken into account longer lead times for project development in the LTGRP. Please outline any actions FEI plans to take to manage any associated risks.

<u>Response:</u>

FEI has accommodated the expected and recently experienced longer lead times by identifying and starting project development activities earlier. This earlier start allows FEI to identify potential risks associated with the proposed work and gives time for mitigation plans to be developed and incorporated into the project life cycle. Typically, mitigating actions where the risks exist would consist of longer engagement periods, made possible by being prepared to start the engagement earlier.

Early in the project cycle, FEI engages with local Indigenous communities whose territories, lands or rights may be impacted by a specific project. FEI shares information on the project with Indigenous community representatives in line with FEI's Statement of Indigenous Principles and in line with regulatory standards for engagement and consultation. Through this engagement, FEI gathers community input and integrates feedback into the project planning process. This may include enhancing public, environmental or archaeological impact mitigation measures, identifying business development and employment opportunities, exploring project agreements and identifying best practises for continued engagement with Indigenous communities throughout the project planning process. Early engagement with Indigenous communities mitigates project risk, identifies mutually beneficial objectives for project success, and is aligned with the key principles of the UN Declaration.

7.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1, Section 2.4, pp. 2-23 – 2-24, 2-29, 2-32, 2-34, Section 9.4, p. 9-15; British Columbia and Hydro Authority's (BC Hydro) website

Competitive Environment

On pages 2-23 to 2-24 of the Application, FEI states:

> The competitive environment for FEI's products has grown more complex as a multitude of pricing and non-price considerations are influencing customer energy choices. In terms of pricing, forecasting energy prices into the future is a complex and challenging task with significant uncertainty.…

Non-price considerations include of a number of factors influencing FEI's competitive position. For example, consumer, builder and developer, commercial and industrial end user preferences influence the use of gas versus electricity, choice among alternative energy solutions and potential use of other sources of energy. Factors influencing non-price considerations may include the following:

- GHG emission concerns;
- Type of housing mix, the size of new dwellings, and commercial building requirements;
- Builder and developer preferences;
- Capital costs, installation requirements, operating and maintenance costs over the lifetime of the equipment;
- Customer perceptions;
- Availability of new technologies;
- Availability of utility and government incentives and rebates for new construction, retrofits, commercial buildings and industrial facilities;
- Commercial and industrial end user requirements; and
- Government policies (such as local governments' support for non-fossil fuel alternatives through updates to building codes and bylaws, which is discussed in Section 2.2.3).

On page 2-29 of the Application, FEI states:

> All else equal, and considering the projected increases to provincial carbon tax, as well as BC Hydro's proposed rate changes in its recently-filed 2023-2025 Revenue Requirements Application, FEI expects the decline in price differential to continue in the coming years. Gas prices will continue to rise as renewable and low-carbon gas comprises a larger share of the fuel mix. However, electricity rates associated with electrification may also rise due to the need for more transmission, distribution, and substation infrastructure to meet increases in electricity peak demand.

7.1 Please discuss whether and how FEI is monitoring changes in non-price considerations influencing FEI's competitive position, as outlined above.

Response:

Business units across FEI are monitoring changes in non-price considerations and their impact on FEI's competitive position. The Energy Solutions team monitors trends in new construction and retrofits, energy preferences, new technologies, climate action initiatives in communities and other factors influencing the built environment and commercial and industrial processing. The Market Research team surveys customers and stakeholders to gain feedback on customer satisfaction and energy preferences. The Policy team actively engages with all levels of government on GHG emission reduction strategies, climate policy updates, and oversees the implementation of FEI's Clean Growth Pathway. The Conservation and Energy Management team collaborates with other utilities and government to provide FEI's customers with access to incentives for energy savings and to support the acceleration of building retrofits. The Community Relations team engages with communities and Indigenous groups to ensure FEI is meeting their energy needs. In summary, monitoring non-price considerations is a critical part of FEI's business operations.

7.1.1 Please explain whether any of the load scenarios in the LTGRP reflect changes in such non-price considerations.

Response:

Yes, the load scenarios in the LTGRP reflect changes in such non-price considerations. The following critical uncertainties directly reflect some of the non-price considerations for energy use:

- Appliance standards;
- New construction codes; and
- Non-price driven fuel switching.

The load scenarios incorporate different input settings for these critical uncertainties, as explained in Section 4.5 and detailed in Table 4-1 of the Application. Please see Appendix B-3 of the Application for a description of the critical uncertainties and details of the input settings.

Other non-price considerations such as advancing provincial carbon emission policy are indirectly reflected in either price (for example, carbon tax setting) or non-price (for example, non-price driven fuel switching) related critical uncertainties.

7.2 Please explain whether FEI has undertaken any analysis or made any assumptions in the LTGRP regarding future increases in electricity rates. If so, please summarize.

Response:

Future increases in electricity costs were examined in the "Pathways for British Columbia to Achieve its GHG Reductions Goals" study and report (Pathways Report) (see Appendix A-2 of the Application) which has informed FEI's Clean Growth Pathway. FEI has also undertaken an assessment of electricity rates and electricity equipment costs on current and near-term competitiveness of electricity versus gas energy services in Section 2.4.2 (page 2-28) of the Application.

FEI has not made assumptions about future electricity prices over the planning period nor incorporated a range of electricity rates as part of its gas demand forecasting. Incorporating considerations for electricity rates in the price-driven fuel switching modelling would increase complexity and require an assumption for cross-price elasticity between gas and electricity, a value likely to be imprecise when modelling choice for customers across FEI's service territory. The prices of carbon and natural gas are used as critical uncertainties in the scenarios which help to assess price impacts on FEI's demand, while avoiding the need to develop and model assumptions about future electricity prices which would create additional complexity and uncertainty in modelling results.

On page 2-32 of the Application, FEI provides the following table:

Table 2-1: Upfront Costs and Efficiency Estimates for Space and Water Heating[94]

	Space Heating Options			Water Heating Options	
Equipment	Gas Furnace	Electric Baseboard	Electric Heat Pump	Gas Water Heater Tank	Electric Water Heater Tank
Capital Cost[95]	$18,000	$9,200	$21,000	$2,800	$1,550
Efficiency Rate	96%	100%	200%	67%	100%

Footnote 95 on page 2-32 of the Application states:

> Both gas furnace and central heat pump cost estimates include the cost of ductwork that is usually contracted out to the sheet-metal contractor who does all the ducting and exhaust fans in a new home. Per the BC Building Code, the electric baseboard cost estimate includes the cost of a mechanical ventilation system that would be needed in a house with no forced-air space heating system.

On BC Hydro's website,[12] it states:

> On average, you can expect to pay around $6,000 for a single head heat pump, $10,000 for a multi-head unit and $14,000 for a variable speed central system.

[12] https://www.bchydro.com/powersmart/residential/building-and-renovating/considering-heat-pump-info-tips.html.

> Cold climate heat pumps typically cost between $15,000-$18,000. Heat pump rebates are available from BC Hydro, CleanBC and the federal government.

BC Hydro's website[13] also outlines potential rebates available for electric heat pumps:

> You could get up to $11,000 for switching to an electric heat pump from a fossil fuel heating source. This includes a $3,000 rebate top-up from BC Hydro, which is in addition to CleanBC's existing $3,000 rebate. This means eligible applicants can receive a combined rebate of up to $6,000 from BC Hydro and CleanBC in one application while funding lasts.
>
> You may also be eligible for up to $5,000 in additional rebates from the federal government's Canada Greener Homes Grant. This is a separate program with its own eligibility criteria and application process, which requires registration and a home evaluation before making any upgrades.

On page 2-34 of the Application, FEI provides the following table:

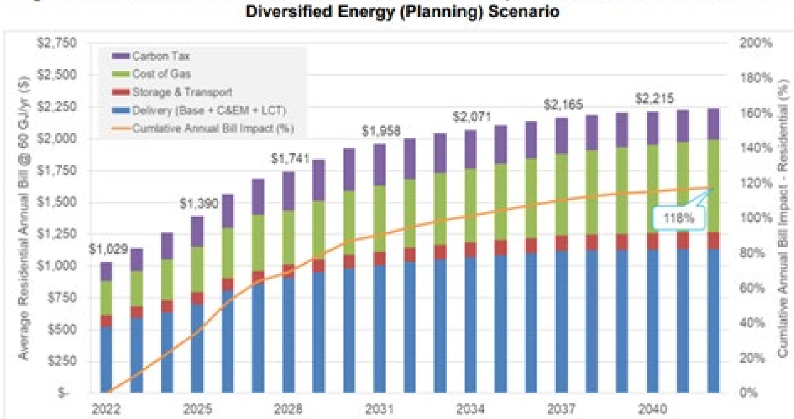
Table 2-3: Operating Cost Advantage vs Capital Cost Differential between Gas and Electric Equipment[99]

	Space Heating (Gas Furnace)		Water Heating (Gas vs Electric)
	vs Heat Pump	vs Baseboard	
BCH Step 1 Rate Adjusted for Efficiency	$12.3	$24.7	$17.2
BCH Step 2 Rate Adjusted for Efficiency	$18.5	$37.0	$25.9
FEI's Burner Tip Rate	$15.6	$15.6	$15.6
FEI's Operating Cost Advantage vs BCH Step 1 Adjusted Rate	**($3.3)**	**$9.0**	**$1.6**
FEI's Operating Cost Advantage vs BCH Step 2 Adjusted Rate	**$2.9**	**$21.4**	**$10.2**
Difference in capital and maintenance costs between gas and electric equipment ($/GJ)	**($6.8)**	**$22.4**	**$6.2**

Footnote 99 states: "Based on FEI's Approved Rates for 2022 and BC Hydro's proposed rates in its 2023-2025 RRA."

On page 9-15 of the Application, FEI provides the following figure:

Figure 9-11: Breakdown of the Cumulative Effective Rate Impact for Residential RS 1 under the Diversified Energy (Planning) Scenario



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13 https://www.bchydro.com/powersmart/residential/rebates-programs/home-renovation/renovating-heating-system/fuel-switching.html.

7.3 Please discuss whether FEI's space and water heating cost comparison analysis, as summarized in the preamble, factors into any of its load forecast scenarios.

Response:

The results of this cost comparison analysis are not a direct input into the load forecast scenarios. However, the load forecast scenarios do consider the impact of the prices of carbon and natural gas as they influence the fuel choice of customers. Increases in the carbon price and natural gas price relative to the reference prices are expected to decrease demand for natural gas. This is modelled in the load scenarios by reducing the gas fuel share and increasing the electric fuel share as consumers choose electric options when replacing equipment.

The objective of Sections 2.4.2.1 and 2.4.2.2 of the 2022 LTGRP is to provide background on FEI's current competitive position, including energy rates and cost comparisons of installing and operating space and water heating end uses in new construction and how these influence customer energy choices. The analysis also illustrates how FEI's cost advantage over electricity has been diminishing in recent years. The analysis was not intended to be incorporated into load forecast modeling and scenario development but sets the stage for factors influencing FEI's long-term resource planning.

7.4 Please explain the basis for FEI's assumption of 200% efficiency rates for electric heat pumps.

Response:

The 200 percent efficiency assumption used in the analysis is informed by input from third-party studies as well as FEI's own judgement. FEI notes that the 200 percent figure is an assumption, and that the actual efficiency of a heat pump can be higher or lower. As stated in footnote 93 of the Application, the actual efficiency of heat pumps may be lower than the nameplate efficiency depending on outside temperature and other factors.

For instance, Natural Resources Canada (NRCAN) website states that the Coefficient of Performance (COP) of an air-source heat pump depends on outdoor air temperature and, assuming a -8 degrees Celsius temperature, the efficiency can drop well below the assumed 200 percent efficiency:[14]

> The major benefit of using an air-source heat pump is the high efficiency it can provide in heating compared to typical systems like furnaces, boilers and electric baseboards. At 8°C, the coefficient of performance (COP) of air-source heat pumps typically ranges from between 2.0 and 5.4. This means that, for units with a COP of 5, 5 kilowatt hours (kWh) of heat are transferred for every kWh of electricity supplied to the heat pump. As the outdoor air temperature drops, COPs

[14] https://www.nrcan.gc.ca/energy-efficiency/energy-star-canada/about/energy-star-announcements/publications/heating-and-cooling-heat-pump/6817.

are lower, as the heat pump must work across a greater temperature difference between the indoor and outdoor space. At –8°C, COPs can range from 1.1 to 3.7.

The 200 percent efficiency rate is also reasonable when compared to the future minimum Heating System Performance Factor 2 (HSPF2) that NRCAN is considering applying to products manufactured on or after January 1, 2025.[15] HSPF2 can be used to compute the minimum COP. As shown in the table below, the HSPF2 for Region V, which includes Vancouver Island and Coast, and Region IV, which includes BC Interior, are 5.4 and 6.7 respectively. The formula below can be used to convert HSPF to COP[16]:

COP = 0.293 * HSPF

Therefore, the minimum COP for a single packaged air-sourced heat pump[17] in Interior regions of BC and Vancouver Island are computed at 1.58 and 1.96 respectively, both of which are below the assumed COP of 2 (200 percent efficiency).

Climate Region	HSPF2[18]	COP	Calculation of COP
Region V	5.4	1.58	(0.293 * 5.4 = 1.58 COP)
Region IV	6.7	1.96	(0.293 * 6.7 = 1.96 COP)

7.4.1 Please discuss whether this represents an annual average efficiency value, or seasonal efficiency value.

Response:

The 200 percent efficiency value represents a seasonal space heating efficiency value.

7.5 Please explain the basis for FEI's estimate of $21,000 for an electric heat pump. Please explain the differences in the assumed costs with those outlined on the BC Hydro's website.

15 https://www.nrcan.gc.ca/energy-efficiency/energy-efficiency-regulations/central-air-conditioners-and-central-heat-pumps/24436 (see below the table).
16 https://learnmetrics.com/hspf-to-cop-heat-pumps/.
17 Central heat pumps ("Single Package-units") were chosen because of the popularity of central ducted heating systems in residential homes in BC in general.
18 The HSPF2 minimum values (5.4 and 6.7) are based on energy efficiency standard in Canada as provided in the following link: https://www.nrcan.gc.ca/energy-efficiency/energy-efficiency-regulations/planning-and-reporting/central-air-conditioners-and-heat-pumps/23613.

Response:

As explained in Section 2.4.2.2 (footnotes 94 and 95), cost estimates for Table 2-1 (which includes the $21,000 upfront cost for a central electric heat pump) were provided to FEI by an independent consultant (Ecolighten Energy Solutions Ltd.). The independent consultant's cost estimates were based on the input from multiple HVAC contractors in the province regarding the upfront capital and installation costs associated with a standard efficiency central electric heat pump (not a cold climate heat pump) for a new medium-sized house and includes the average cost for the necessary duct work, installation and the appliance itself.

FEI cannot comment on the assumptions used for cost estimates provided by other sources. However, it may be that the cost estimates on BC Hydro's website exclude the necessary duct work. The cost estimates for both natural gas furnaces and central heat pumps in Table 2-1 include $8,000 for the necessary ductwork in a new house, plus installation costs for each. Further, BC Hydro's costs may be for a split system, and may not include an air handler, whereas the costs estimated for FEI are for a central system.

7.5.1 Please discuss whether the electric heat pump used in FEI's analysis is assumed to be single head heat pump, a multi-head unit, a variable speed central system, cold climate heat pump, or otherwise.

Response:

The cost estimate was for a standard efficiency central air-source heat pump (not a cold climate heat pump or a ductless system such as single or multi-head split units). The consultant considered different brands, efficiency rates and warranties to come up with the estimate. No other details were requested from the HVAC contractors when they were surveyed.

7.5.2 Please confirm, or explain otherwise, that the $21,000 capital cost does not include any rebates.

Response:

Confirmed.

7.5.3 Please re-perform the analysis for Table 2-3, assuming the cost of an electric heat pump is the average cost outlined on the BC Hydro website. Please identify the appropriate type(s) of heat pump for the purposes of the comparison with a gas furnace with supporting rationale. Please also include a sensitivity analysis to include a $3000 rebate, a $6000 rebate, and $11000 rebate for the electric heat pump.

Response:

FEI does not consider it appropriate to re-perform the analysis for Table 2-3, as there are a number of variables that must be taken into consideration and the results of re-performing the analysis would not result in an accurate comparison. The information was not used in developing FEI's load forecasting modeling nor scenario development and therefore does not affect FEI's LTGRP recommendations.

The rebates quoted in the preamble are for fuel switching within existing homes while the analysis in Table 2-3 was based on the costs in Table 2-1, which are for new construction. Therefore, the fuel switching rebates quoted do not apply.[19] This distinction is important as the comparison costs are different depending on the circumstances for the two different installation situations. For new construction, the comparison is to the cost of a new gas heating system, whereas, for fuel switching, the comparison is to maintaining an existing gas system or perhaps replacing an existing furnace with a more efficient one. The analysis would have to include selecting a system with the capacity to replace an existing gas heating system, such as a central air-source heat pump or cold-climate heat pump in colder regions of the province. In addition, these retrofits commonly require significant additional costs such as retrofitting duct work to accommodate airflow requirements and electrical panel / service upgrades.

7.6 Please explain why FEI uses its 2022 rates vs BC Hydro's 2023-25 rates.

Response:

FEI clarifies that both the FEI and BC Hydro rates used in the analysis are based on rates effective as of April 1, 2022, which were approved on a permanent basis for FEI by Order G-366-21 and on an interim basis for BC Hydro by Order G-47-22. Footnote 99 of the Application, as referenced in the preamble above, is referring to the fact that the BC Hydro rates used for the analysis in Table 2-2 were from BC Hydro's Fiscal 2023 to 2025 Revenue Requirements Application. Only BC Hydro's rates for Fiscal 2023, approved on an interim basis effective April 1, 2022, were used for the comparison. The comparison was not between FEI's approved rates for 2022 and BC Hydro's rates over the period from 2023 to 2025.

7.7 Please confirm, or explain otherwise, that using current or proposed rates does not reflect the lifecycle costs of gas or electric equipment.

[19] The BC Hydro heat pump offers for New Construction are fully subscribed and are no longer in market.

Response:

Confirmed. However, Table 2-3 of the Application is not a comparison of lifecycle costs between gas and electric equipment. A lifecycle cost analysis would require considering the forecast gas and electricity rates which are not available over the measure life of the equipment (please refer to the response to BCSEA IR1 4.1).

Table 2-3 considers both capital and operating costs (i.e., cost of energy) for new construction at a point in time. Using heat pumps for space heating as an example, based on current capital cost estimates, BC Hydro's rates (efficiency adjusted) will need to be at least $6.80 per GJ lower than FEI's equivalent burner tip rates per GJ over the life of the equipment. At current rates (i.e., rates effective as of April 1, 2022 for both BC Hydro and FEI as discussed in the response to BCUC IR1 7.6), gas furnaces currently still have a small advantage over electric heat pumps.

As summarized at the end of Section 2.4.2.2 of the Application, FEI acknowledges the price competitiveness of natural gas versus electricity has reduced over time from both the energy price and total cost perspectives, and FEI expects this reduced competitiveness for natural gas will likely continue considering the expected increases in carbon taxes, increases in natural gas and renewable gas costs, as well as the rebates available to households for converting to or installing new electric heat pumps.

7.8 Please confirm, or explain otherwise, that based on the analysis in Figure 9-11 the LTGRP, FEI rates are set to increase in the period 2023-25.

Response:

Confirmed. However, as explained in Section 9.4 of the Application, the residential bill impacts shown in Figure 9-11 of the Application do not consider future rate design changes and are not indicative of a detailed rate forecast. The figure is simply a directional view of how FEI's rates are influenced by the DEP Scenario over a 20-year period.

7.8.1 Please provide analysis to show the impact upon the cost comparison analysis of using the projected FEI rates for 2023-25.

Response:

As explained in the response to BCUC IR1 7.6, Table 2-3 of the Application provided BC Hydro's electricity rates (efficiency adjusted) and FEI's natural gas rates that were effective on April 1, 2022. It was not a comparison between FEI's 2022 approved rates and BC Hydro's rates from 2023 to 2025. Please also refer to the response to BCUC IR1 7.7 which explains that Table 2-3 of the Application considered the capital and operating costs between electric and gas heating equipment for new construction at a point in time and is not a lifecycle cost comparison.

However, in order to be responsive to this question, please refer to Table 1 below for an expanded version of Table 2-3 of the Application including the estimated rates for 2023 and 2024. FEI did not include 2025 in the table below as BC Hydro's rates for Fiscal 2025 are effective from April 2024 to March 2025; therefore, the forecast rates for the entire calendar year of 2025 are not available in BC Hydro's Fiscal 2023 to 2025 Revenue Requirements Application. FEI's rates shown in Table 1 below are based on Figure 9-11 of the Application, which, as explained in the response to BCUC IR1 7.8, are for illustrative purposes only.

Table 1: Operating Cost Advantage vs. Capital Cost Differential between Gas and Electric Equipment (2022 to 2024)

	Space Heating (Gas Furnace)						Water Heating (Gas vs Electric)		
	vs Heat Pump			vs Basebaord					
	2022	2023	2024	2022	2023	2024	2022	2023	2024
BCH Step 1 Rate Adjusted for Efficiency	$ 12.3	$ 12.7	$ 13.0	$ 24.7	$ 25.3	$ 26.0	$ 17.2	$ 17.7	$ 18.2
BCH Step 2 Rate Adjusted for Efficiency	$ 18.5	$ 18.8	$ 19.3	$ 37.0	$ 37.5	$ 38.5	$ 25.9	$ 26.2	$ 26.9
FEI's Burner Tip Rate	$ 15.6	$ 17.3	$ 19.2	$ 15.6	$ 17.3	$ 19.2	$ 15.6	$ 17.3	$ 19.2
FEI's Operating Cost Advantange vs BCH Step 1 Adjusted Rate	$ (3.3)	$ (4.7)	$ (6.2)	$ 9.0	$ 8.0	$ 6.8	$ 1.6	$ 0.4	$ (1.1)
FEI's Operating Cost Advantange vs BCH Step 2 Adjusted Rate	$ 2.9	$ 1.5	$ 0.1	$ 21.4	$ 20.2	$ 19.3	$ 10.2	$ 8.9	$ 7.7
Difference in capital amd maintenance costs between gas and electric Equipment ($/GJ)	($6.8)			$22.4			$6.2		

As shown in Table 1 above, and consistent with the assessment summarized at the end of Section 2.4.2.2 of the Application, the price competitiveness of gas over electric equipment is expected to continue to decrease considering the ongoing increases in carbon taxes, increases in natural gas and renewable gas costs, as well as the rebates available to households for converting to or installing new electric heat pumps.

8.0 Reference: PLANNING ENVIRONMENT

Exhibit B-1, Appendix D-1 (Natural Gas Market Overview), p. 3

Long Term Natural Gas Price Forecast

Appendix D-1 to the Application provides a natural gas market overview. On page 3 of Appendix D-1, FEI states:

> Figure D1-2 below shows IHS Markit's (S&P Global) long term natural gas price forecast, released in February 2022, for the Henry Hub and AECO/NIT markets in real 2021 dollars.
>
> …
>
> Additionally, this forecast was completed prior to the Russian invasion of Ukraine and thus does not include the impact of the current geopolitical climate and does not illustrate the current futures price market. IHS Markit has since noted[6] that they will be revising their outlooks to reflect "these new realities that we believe will endure over the next few years" which should be adjusted in their August 2022 long-term forecast.

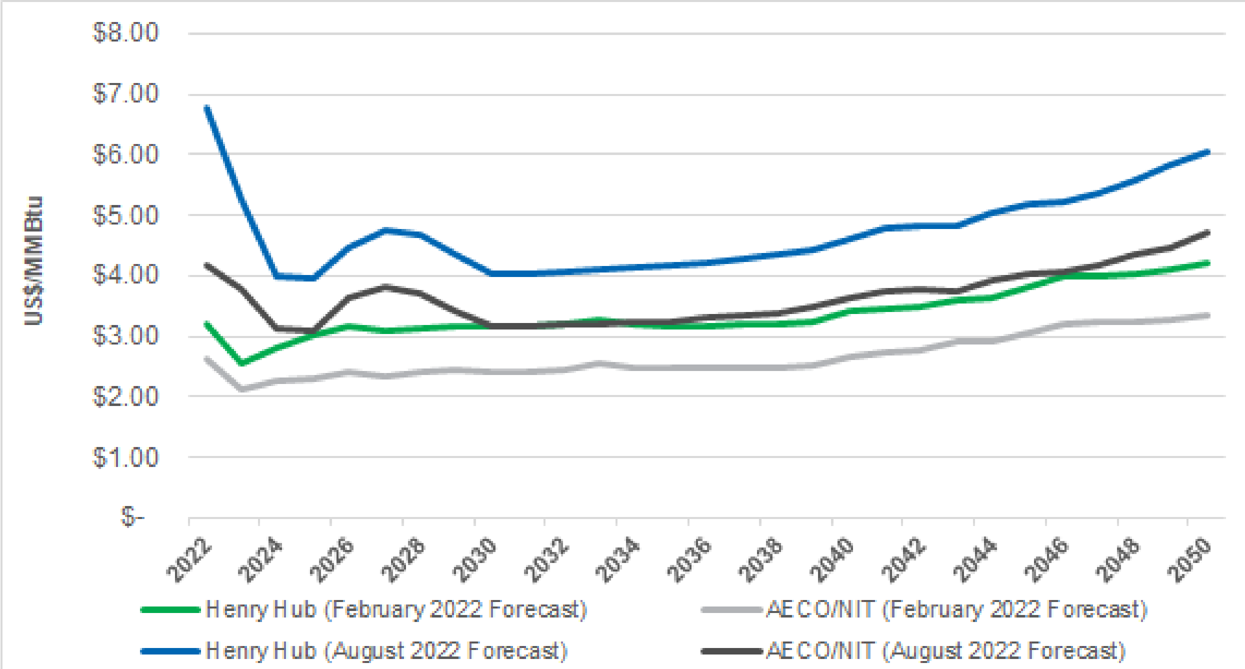
8.1 Please discuss whether IHS Markit has adjusted its long-term natural gas price forecast to include the impact of the current geopolitical climate.

8.1.1 If yes, please describe the adjustment(s) made by IHS Markit. Please also discuss whether these adjustments would result in any material changes to the analysis presented in the Application that relies on the long-term natural gas price forecast and if so, what these changes would be.

8.1.2 If no, please discuss whether and when future updates are expected.

Response:

IHS Markit released its latest long-term natural gas price forecast in August 2022. The latest price forecast has been updated based on the most current market conditions, at that time, and includes the impact of the current geopolitical climate. The updated figure below shows the latest long-term natural gas price forecast and the previous long-term natural gas price forecast for Henry Hub and AECO/NIT markets, in real 2021 dollars.



As shown in the updated figure above, IHS Markit has increased the price forecast in the August 2022 outlook compared to the February 2022 outlook. According to IHS Markit's August 2022 outlook, in the near-term, increased demand from LNG exports into the global market and higher power generation demand have increased prices in 2022; however, increased production begins to moderate prices in 2023. In the long-term, increased renewable generation capacity helps to reduce power generation from natural gas; however, rising LNG exports and exports to Mexico, along with declining production of natural gas, help balance out the market to keep some upside pressure on prices.

Although the adjustment to the IHS Markit price forecast shows a significant price increase for 2022, the prices drop back down to within the ranges shown in Figure B3-7 of the Application. Given the short-term nature of this price increase, the adjustment made by IHS Markit does not result in any material changes to the analysis presented in the Application.

B. CLEAN GROWTH PATHWAY

9.0 Reference: CLEAN GROWTH PATHWAY
Exhibit B-1, Section 3.2.2.4.1, p. 3-8
Innovative Technology

On page 3-8 of the Application, FEI states:

> FEI is contributing to various projects that support commercializing innovative gas utilization technologies that will help FEI meet its customers' needs while also addressing societal plans for reducing GHG emissions. Such technologies achieve this goal by raising the efficiency of gas end uses and also reducing the GHG emissions intensity of both the gas stream as well as individual end uses. The initiatives include:
>
> …
>
> - Evaluating the potential for dual-fuel (hybrid) heating systems with smart controls, replacing a conventional air-conditioner with a higher efficiency air-source heat pump, and pairing it with a gas furnace and smart controls;
> - Support for small-scale residential and commercial carbon capture projects to capture carbon emissions from end use appliances and make them commercially usable, including from appliances such as commercial furnaces;

9.1 Please provide further information regarding the support FEI is providing for small-scale residential and commercial carbon capture projects.

Response:

FEI currently supports small scale carbon capture projects in two ways:

1. FEI's Clean Growth Innovation Fund provides funding to support the development of new technologies which offer the potential to reduce the emissions associated with natural gas use in British Columbia. FEI is currently supporting a project with a focus on small-scale carbon capture. This project is in early development and testing stages, and the technology is not yet ready for commercialization.

2. FEI is engaged in a pilot project to test the effectiveness of a small-scale carbon capture unit manufactured by CleanO2, a Canadian company located in Calgary, Alberta. CleanO2's product can be installed on gas-fired appliances of moderate output, as would be typically found in small- to mid-sized commercial or multifamily residential applications. The potential benefits of the units include reduced GHG emissions, and reduced energy consumption. There are currently six units installed. The initial indications are that the units are able to reduce the CO_2 emissions in the flue gases of gas burning appliances by approximately one third. FEI anticipates that it will complete the pilot study by late 2023 or early 2024.

The economics of small-scale carbon capture projects continue to be challenging. In addition to higher fixed costs per kg of CO_2 captured (all else equal), it is also more expensive to transport the captured or utilized CO_2 in small quantities. Nevertheless, carbon capture is attracting increased investment at smaller scales. At "medium scale", FEI is having discussions with, and providing grants to, startup companies including Pondtech (https://pondtech.com/) and Ionada (https://ionada.com/).

9.1.1 Please discuss FEI's understanding of the progress of such technologies and projects in other jurisdictions.

Response:

FEI's understanding of the progress of small-scale residential and commercial carbon capture projects in other jurisdictions is limited. FEI understands that the primary issue is the scarcity of commercially-available solutions for carbon capture at small scales.

The small-scale carbon capture unit manufactured by CleanO2 unit referred to in response to BCUC IR1 9.1 has been installed in three countries including 10 units installed elsewhere in Canada, 15 units in the United States and 8 units in Japan.

9.1.2 Please discuss if FEI is aware of any indicative cost forecasts for these technologies.

Response:

FEI is not aware of any indicative cost forecasts that it believes credibly predict the costs for small-scale residential and commercial carbon capture technologies.

FEI believes that the use of these small-scale carbon capture technologies will depend on cost, but also on investment incentives, carbon pricing and alternative low-carbon solutions to address emissions sources from end-users where this technology may apply.

9.1.3 Please discuss the potential timelines for understanding whether such technologies will become commercially viable.

Response:

FEI is not able to speak with authority on the timing of market viability of small scale residential and commercial CCUS technologies in general. In FEI's experience, most attempts to address small-scale residential and commercial carbon capture are at an early stage of development. The timing to commercialization of early stage, pre-commercial projects is difficult to predict as they are typically affected by many variables, which cannot necessarily be foreseen at the project outset.

FEI is familiar with CleanO2 which currently has a commercially-available technology addressing this market need, although there are two barriers which hinder the broad adoption of the technology in British Columbia. The first barrier is that the units are not yet approved for installation in flue stacks of forced draft flue vents as are found with condensing gas burning appliances. Near-condensing gas burning appliances may be eligible for approval on a case-by-case basis by Technical Safety BC upon application. They are, therefore, primarily targeted at applications with conventional draft gas burning appliances. The second barrier is that the cost to install the units in British Columbia appears to have increased since the COVID-19 pandemic. This may be mitigated to a degree as the cost of the carbon tax increases to approximately $8.40 per GJ by 2030. Moreover, CleanO2 is also a company that is still in an early stage of its development. Its product is only available in one size, and it does not yet have a well-developed network of distributors and installers. FEI therefore believes that it will be several years before this technology could become commercially viable in British Columbia.

Please also refer to the responses to BCUC IR1 9.1 and 9.1.2.

9.2 Please discuss, at a high level, the role that FEI envisages for dual fuel heating systems in BC. Please discuss whether gas supply would be primarily used for peak heating purposes in such systems.

Response:

Residential dual fuel (hybrid) heating technologies have been identified as a promising DSM measure that will support energy savings, reduce GHG emissions, optimize energy use, provide energy system resiliency and reduce long-term energy costs. Hybrid heating systems can be defined as an electric air source heat pump and a natural gas furnace that are sequentially operated by controls to efficiently heat and cool a home. As a DSM measure, gas supply may be primarily used for peak heating purposes in such systems, although further work needs to be conducted to better understand the interactive effects from operating both systems together.

Hybrid heating technologies offer both potential opportunities and challenges to FEI. Hybrid systems could lead to significant reductions in customer natural gas consumption and a corresponding reduction in GHG emissions as the gas heating system would only be used during the coldest season. Hybrid systems can also act as a peaking service, making an important contribution to moderating peak loads on the electric system and offering significant value to the electric system operator. In an electric system with surplus generation, hybrid systems also offer new load opportunities, creating further value. This value could be transferred to the gas system operator for providing peaking services and serve to moderate gas rate increases. The biggest challenge resulting from hybrid systems is quantifying the value of the peaking service and mitigating the potential increase in gas rates resulting from decreased gas load.

FEI's approach to hybrid heating systems is still at an exploratory stage. Hybrid heating systems are one of three emerging energy efficiency technologies, referred to as Advanced DSM Programming in the 2023 DSM Plan Application. They are expected to have a higher potential impact on gas demand than was modelled in the 2021 CPR or in the 2022 LTGRP. If the benefits are proven through FEI's pilots and studies, it is anticipated that hybrid systems will take a larger role in upcoming DSM Plans and the next CPR and LTGRP.

Hybrid heating system research is being initiated through the Innovative Technologies Program Area as an Advanced DSM Measure. FEI is currently underway with phase one of a pilot project to assess the performance and customer acceptance of residential systems that are already installed in the field. This project aims to fill information gaps related to system performance, customer behaviour with use of controls and customer acceptance of the system. The phase one pilot will help inform opportunities for a phase two early adopter offer, which will explore opportunities to optimize hybrid heating systems to further drive energy savings and customer acceptance in 2023.

In parallel, FEI is conducting a hybrid heating prefeasibility study to obtain information to support further pilot research. The study, with an expected completion date of Q4, 2022, will further assess:

- Available technologies, controls and manufacturers;
- Supply chain;
- Market potential;
- Risks;
- Energy savings and GHG reduction potential; and
- Measure input assumptions and forecasted cost-benefit calculations.

Please also refer to the BCUC IR1 46 series for more discussion on the development pathway of hybrid/dual fuel equipment as an Innovative Technology for reducing carbon emissions while meeting customer needs for energy.

9.2.1 Please explain whether the air-source heat pump included in the system is an electric or natural gas heat pump.

Response:

At the time of writing, the hybrid heating system initiative for residential customers is based on an electric air source heat pump with a natural gas furnace operated by smart controls.

9.2.2 Please discuss whether FEI is co-ordinating with electric utilities in BC regarding hybrid heating systems.

Response:

Yes, FEI is in discussions with both FBC and BC Hydro regarding hybrid heating systems. The pilot project summarized in response to BCUC IR1 9.2 is jointly evaluating residential dual fuel hybrid heating systems with FBC to identify the impacts and benefits to both utilities. Additionally, through the Home Renovation Rebate Program, FEI and FBC collaborate with BC Hydro and the Ministry of Energy, Mines and Low Carbon Innovation on a variety of measures, including hybrid heating.

9.2.3 Please discuss FEI's understanding of the progress of such technologies and projects in other jurisdictions.

Response:

In other jurisdictions, both Enbridge and Energir are investigating dual-fuel (hybrid) heating systems and their progress is positive, as described below.

- In Ontario, Enbridge has a pilot in partnership with London Hydro to install heat pumps with advanced controls across 1,000 homes to evaluate utilizing the most economical fuel source by factoring time of use rates and outdoor air temperature. Enbridge is offering incentives of up to $4,500 for electric heat pumps and controls, and through sub-meter measurement and verification equipment, is seeking to understand system performance and energy savings with results targeted for 2023.
- In Quebec, Energir, in partnership with Hydro-Quebec, launched a hybrid heating program that provides incentives of up to $5,800 for customers to adopt electric heat pumps and/or new furnaces with new electric heat pumps. These systems support fuel switching of primary heating load from natural gas to electricity while still offering the ability for resilient heating in cold winter temperatures. In addition, they support electricity peak demand response with the potential for deferring infrastructure upgrades and investments for Hydro-Quebec.

In BC, the provincial government's CleanBC program has offered an incentive for dual fuel installations since September 2018. Although overall uptake has been low, this is to be expected in early stage adoption of new technologies. There has been increased traction over the last few years as customers begin to understand the benefit of having efficient cooling and heating systems that leverage the existing gas system.

Although there has been some recent progress, information gaps exist in understanding customer behaviour, technology limitations, and system performance levels, as well as quantifying the benefits of innovative control strategies that can be used to optimize the performance of both systems working together. Given these identified information gaps, FEI is conducting pilots as well as monitoring projects in other jurisdictions to leverage learnings while determining the feasibility of launching larger scale incentive programs.

9.2.4 Please discuss if FEI is aware of any indicative cost forecasts for these technologies.

Response:

FortisBC's hybrid heating pre-feasibility study is underway to gather measure input assumptions related to costs. The study is due to be complete in Q4 2022.

9.2.5 Please discuss whether any of the scenarios contained in the LTGRP contemplate a significant role for hybrid heating systems.

Response:

FEI's approach to hybrid heating systems is still at an exploratory stage and did not contribute significantly to energy savings in the 2021 Conservation Potential Review (CPR) or in any scenarios that were developed for the 2022 LTGRP. FEI believes hybrid heating systems could have an important role in the overall carbon abatement path for building heating. If the benefits are proven through pilots and studies, it is anticipated that hybrid systems will take a larger role in upcoming DSM Plans and the next CPR and LTGRP.

9.3 Please discuss whether FEI considered a scenario in the LTGRP, facilitated by hybrid systems or otherwise, which modelled higher levels of fuel switching for annual energy requirements (for example, as modelled in the Deep Electrification scenario), but a continued prominent role for the natural gas system in the delivery of energy during peak periods.

9.3.1 Please discuss at a high level whether FEI considers such a scenario is plausible.

9.3.2 Please discuss the pros and cons of such a scenario compared to the Deep Electrification scenario modelled in the LTGRP.

Response:

The extent to which the natural gas system and technologies such as dual fuel systems can play a role in meeting both future annual and peak energy demand, in combination with the electricity system in BC, requires further study and offers an important opportunity for collaboration between gas and electric utilities, as well as municipal and provincial governments. Such initiatives are viewed by FEI to be more in line with its DEP Scenario and Clean Growth Pathway, than a separate and distinct scenario from those modelled for the 2022 LTGRP.

The role of the natural gas system in delivering peak energy requirements into the future has been a prominent consideration for FEI, and the role of dual fuel systems and gas-fired heat pumps is an emerging opportunity that has been considered to the degree possible in the DEP Scenario.

Although FEI did not evaluate a scenario in which the natural gas system is used only to serve peak heating requirements, consideration can still be given to dual fuel systems potentially playing an important role in the energy transition. FEI considers, however, this opportunity is more appropriately examined for its potential to benefit the electric system. Some customers choosing to electrify their space heating equipment, and retaining their existing gas system to deliver energy during peak periods, can help to defer investment in electric generation, transmission and distribution resources, potentially benefitting the customer through lower bills, as well as indirectly benefitting all other electric customers. Back-up systems operating on low-carbon fuels can provide critical energy supply for buildings during peak periods, manage the cost of decarbonizing space heating and, therefore, provide a more cost-effective and reliable option overall. However, the benefits are not equally distributed. The gas system would see reduced overall throughput and increasing customer rates; therefore, optimization of the energy systems in this way would need to also include a benefit sharing mechanism.

Regarding the reference to carbon capture projects in the preamble, the potential future role of technologies like end-use carbon capture were recognized in the 2022 LTGRP as an opportunity to reduce carbon emissions but were not specifically modelled in the demand forecasting analysis since such systems remained in early stages of development at the time the modelling was undertaken. Such technologies would unlikely be fully developed under a Deep Electrification scenario.

10.0 Reference: CLEAN GROWTH PATHWAY

Exhibit B-1, Sections 3-1 p. 3-1, Section 3.2, p. 3-3; Appendix A-2 (Pathways for British Columbia to Achieve its GHG Reduction Goal (Pathway Report), pp. 14 – 20, 26

Pathways Report

On page 3-1 of the Application, FEI states:

> As concluded in the Guidehouse Pathways Report in Appendix A-2, a Diversified Pathway has the advantage of leveraging FEI's extensive existing infrastructure and the resilience and reliability of the provincial energy system as a whole. The Diversified Pathway achieves GHG reductions aligned with the provincial government's objectives, and is a more affordable, resilient and practical long-term pathway for BC.

On page 3-3 of the Application, FEI adds:

> The Pathways Report concludes that "the Diversified Pathway can achieve the same level of provincial GHG emissions reductions as the Electrified Pathway at a significantly lower cost to British Columbians. Although initiatives are used to different extents, both pathways defined in this study would require transformative changes in every sector of BC's economy. By 2050, the societal value of achieving the Diversified Pathway is expected to be in excess of $100 billion higher than the Electrification Pathway."

10.1 Please outline all areas where assumptions or results contained in the Pathways Report were used as an input or guidance for the development of the 2022 LTGRP.

<u>Response:</u>

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

The Pathways Report was used to help inform the nature of the DEP and Deep Electrification scenarios examined in the 2022 LTGRP. However, the only information from the Pathways Report that was used as a direct input into the 2022 LTGRP demand forecast analysis was the extent to which electrification of gas load was modelled in each of these scenarios through the fuel switching critical uncertainty. As explained in Appendix B-3, the Pathways Report was used as a guide to develop gas fuel share reduction targets for 2042. Page 12 of Appendix B-3 states:

> For 2042, a linear interpolation was used to set the following electrification assumptions consistent with the Pathways Report of modelled values in 2050:
>
> - Moderate electrification (aligned with the 'Diversified Pathway'): ~14 percent decline in gas fuel share;
> - Accelerated electrification (aligned with the 'Electrification Pathway'): ~56 percent decline in gas fuel share

All other settings for this and other critical uncertainties were developed based on updated information since the Pathways Report was completed (for example, gas prices and carbon prices) and/or developed separately from the Pathways Report, but alignment with the study was maintained where appropriate (for example, new construction step code and appliance standards). Please see Appendix B-3 for a full description of the critical uncertainties and settings for the various scenarios.

10.2 Please discuss whether FEI anticipates updating the Pathways Report to account for more up to date information, and if so, the anticipated timeframe.

Response:

FEI believes an update to the Pathways Report to evaluate a future based on net-zero emissions by 2050 will be useful; however, a timeframe has not been finalized.

On page 14 of Appendix A-2 to the Application (Pathways Report), Guidehouse states:

> The Electrification Pathway aims to increase the use of electricity for all applicable end uses, so renewable and low carbon natural gas use is limited to those sectors where no alternatives are available.

10.3 In the Electrification Pathway, please clarify the sectors where no alternatives to renewable and low carbon natural gas use are assumed to be available.

Response:

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

FEI clarifies that no assumption has been made with respect to entire sectors that cannot be electrified (i.e., where no alternatives to renewable and low-carbon gas use for decarbonizing are available), rather FEI considers that, within a number of sectors, it will be very difficult to electrify end uses. Examples include the greenhouse industry within the agricultural sector where, in addition to the heat provided by methane, the CO_2 captured within the greenhouses is also very important to plant development and production, making gas use difficult or expensive to substitute. Other applications where gas provides more cost-effective process heat include the cement production industry which requires high intensity heat.

The Electrification Pathway was developed with fuel switching to electricity as the primary path to decarbonization. However, full electrification was not modeled to account for feasibility considerations with respect to the state of different electrification technologies. In the Electrification Pathway, it was assumed that 10 percent of commercial vehicles are not electrified and consume a mix of natural gas, renewable natural gas or biodiesel. For the industrial sector, it was assumed that 20 percent of current fossil fuel use is converted to electricity. For the agriculture sector, it was assumed that 50 percent of end use demand is satisfied by electricity.

Figure 9 on page 15 of the Pathways Report (Appendix A-2) outlines the "Pathway Total Societal Cost Impacts," and includes the following components:

- Consumer Equipment Investment;
- Retrofit Cost; and
- Underutilized Capacity Costs.

10.4 Please further explain what types of costs are captured in each of the above noted components of Figure 9.

Response:

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

The types of costs that are captured in each of the noted components of Figure 9 are as follows.

- **Consumer equipment investment**: This component captures the incremental cost of low-carbon equipment over business-as-usual equipment. For example, the incremental cost of an electric vehicle over an internal combustion engine vehicle.
- **Retrofit cost**: This component captures the costs of building retrofits, including thermal building shell improvements, taken from the 2019 CPR.
- **Underutilized Capacity Costs**: This component captures the estimated excess costs of maintaining and sustaining FEI's existing gas system which would be oversized based on declines in load in the Electrification Pathway. FEI worked with Guidehouse to estimate the additional costs to 2050 of maintenance and sustainment using historical cost trends compared to a system that was scaled to meet load levels that were approximately two thirds lower in 2050. In this exercise, Guidehouse simulated the assumption that the full gas system would need to be sustained to 2050, accounting for the fact that individual customer defections from the system would not follow a reliable pattern that would enable a planned shut down of elements of the system. Guidehouse then estimated the sustainment costs if a gas system were ideally-sized and built to meet 2050 loads. The analysis did not estimate decommissioning costs of the gas system.

10.4.1 Please provide the aggregate costs for each component, for both the Electrification Pathway and Diversified Pathway.

<u>Response:</u>

The following response has been provided by Guidehouse.

The table below provides the requested costs for the components of the Pathway Total Societal Cost Impacts. Note that the consumer equipment investment relates to building costs for customers and reflects the cost of adopting new heating systems.

Table 1: Cumulative incremental costs to 2050 for Electrification and Diversified Pathways

	Electrification Pathway ($ billions)	Diversified Pathway ($ billions)
Consumer Equipment Investment	$29.4	$37.0
Retrofit Cost	$29.7	$22.4
Underutilized Capacity Costs	$17.0	n/a

On page 16 of the Pathways Report (Appendix A-2), the following table is provided:

TABLE 1. INITIATIVES BY PATHWAY

Initiative	Electrification Pathway	Diversified Pathway
Electric Peak Demand	Peak demand increases to 21,600 MW in 2050, requiring 8,800 MW of new peak capacity versus the BAU case.	Peak demand increases to 17,700 MW in 2050, requiring 4,900 MW of new peak capacity versus the BAU case.
Renewable Gas	Of end-use natural gas demand, 35% (26 PJ) is served by renewable gas in 2050 (mix of hydrogen and renewable natural gas). Incremental 1.8 MT of carbon sequestered per year through carbon capture by 2050.	Of end-use natural gas demand, 73% (136 PJ) is served by renewable gas in 2050 (mix of hydrogen, renewable natural gas, and synthetic methane). Incremental 1.8 MT of carbon sequestered per year through carbon capture by 2050.
Transportation	Transition to 100% zero-emissions light duty vehicles. Significant role for MHD electric vehicles (EVs) (60% EV, 40% CNG/LNG and internal combustion).	Transition to 100% zero-emissions light duty vehicles. Significant role for gases in MHD vehicles (75% CNG, 20% EV, 5% fuel cell vehicles).
Fuel Switching	Transition 100% of residential and commercial space and water heating to electricity with electric heat pumps and other appliances, 20% of industrial fuel switching.	Transition up to 25% of residential and commercial space and water heating to electricity, 10% of industrial fuel switching.
Energy Efficiency	Improve envelope of 1.6 million homes and 436 million m² of commercial floor space.	Improve envelope of 1.7 million homes and 328 million m² of commercial floor space. Deploy gas heat pumps in ~70% of buildings.

On pages 17 to 18 of the Pathways Report (Appendix A-2), the following table is provided:

TABLE 2. SELECT MODELLING INPUTS

Input	Assumption/Description
Cost of New Electricity Generation	$126/MWh was assumed in both pathways. This value represents an estimate of the expected cost of Site C[14] and is considered a conservative estimate of new renewable power costs. It is conservative because solar, wind, and energy storage costs are significantly higher and do not provide the same level of inter-seasonal storage. These higher priced renewable assets may need to be deployed due to the difficulty of developing large hydro in Canada. It is assumed that hydro resources will be available at the levels modelled in the pathways, which further assumes the deployment of multiple large hydro facilities (similar in size to Site C) in both pathways.
Renewable Gas Costs	RNG production costs were derived from Hallbar Consulting's report on RNG potential in BC and range from $14 to $28 per GJ.[15] It is assumed that progress will be made in wood-to-RNG technology to achieve the levels of RNG modelled in the two pathways. Green hydrogen (i.e., hydrogen produced with renewable electricity) and synthetic methane costs were developed from current production cost estimates (roughly $40/GJ for hydrogen, ~$10/GJ extra to create synthetic methane based off FortisBC pilot projects). These costs were extrapolated for the forecast, taking into consideration cost declines due to technology improvements. Guidehouse also aligned hydrogen production costs with the cost of renewable electricity because that is the primary input for producing green hydrogen. The weighted average cost across all renewable gases for each pathway in 2050 are: • Electrification Pathway: $19/GJ ($0.068/kWh equivalent) • Diversified Pathway: $23/GJ ($0.083/kWh equivalent) The Diversified Pathway renewable gas cost is higher because it requires more RNG at higher prices and includes a small amount of synthetic methane, which is the most expensive renewable gas.
Peak Demand Impacts	Annual hourly load shapes were selected or developed using public sources for each of the initiatives described in Table 1. These load shapes were applied to the energy consumption of each initiative to determine peak demand impact.
Electric Heat Pump Characteristics	Electric heat pump costs were modelled to align with the BC Conservation Potential Review, which included a specific assessment of the achievable potential of electric heat pumps in BC. The incremental cost for electric heat pumps was modelled as approximately $376 per residential household and $16,500 per 1,000 m^2 of commercial floor space. Electric heat pumps were modelled with 190% efficiency for both residential and commercial applications.[16] This efficiency depends on climate and likely will vary by region within BC.
Gas heat Pump Characteristics	Gas heat pump costs were derived from a heat pump feasibility study provided by FortisBC and interviews with developers.[17] Initial costs were set at roughly $6,800 and $45,000 for a residential home and commercial building, respectively. Both residential and commercial gas heat pumps were modelled with a 140% gas utilization efficiency. This efficiency depends on climate and likely will vary by region within BC.
Natural Gas System Utilization	The utilization of the gas system differs significantly between the two pathways. In the Electrification Pathway, the 2050 throughput drops to roughly 40% of the 2019 throughput. Conversely, the 2050 throughput of the Diversified Pathway is not significantly less than the 2019 throughput.[18] Electrification Pathway: • 2019 throughput = 200 PJ • 2050 throughput = 75 PJ Diversified Pathway: • 2019 throughput = 200 PJ • 2050 throughput = 186 PJ

10.5 Please provide a breakdown of the incremental electric peak load in the Electrification Pathway compared to the Diversified Pathway resulting from (i) fuel switching, and (ii) transportation.

Response:

The following response has been provided by Guidehouse.

The contribution of peak load increases due to fuel switching and transportation vary by year and pathway. In 2050, the incremental electric peak loads are as follows:

	Electrification Pathway	Diversified Pathway
Fuel Switching	4,578 MW	1,467 MW
Transportation	4,250 MW	2,731 MW

10.6 Please explain in the Diversified Pathway, whether the fuel switching for space and water heating is assumed to be to electric heat pumps.

Response:

The following response has been provided by Guidehouse.

In the Diversified Pathway, fuel switching for space heating is assumed to be a combination of gas and electric heat pumps.

10.7 Please explain the basis for the assumed of 190% efficiency rates for electric heat pumps.

Response:

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

A COP of 1.90 (i.e. 190 percent efficiency) was a reasonable average efficiency for heat pumps, accounting for real-world use cases and duty cycles, rather than an upper-level nameplate efficiency, at the time of the study in 2019. This value aligns with the baseline assumed efficiency for air source heat pumps in Navigant's 2019 BC Conservation Potential Review, which reflects FEI's understanding of COPs at that time. FEI understands that COPs for heat pumps have been improving related to technological progress and better installation practices which have been reflected in more recent studies and analyses on their potential. For example, please refer to the response to BCUC IR1 7.4 for discussion of why FEI used a COP of 2.0 for its analysis in the Application.

10.7.1 Please discuss whether this rate represents annual average efficiency, or seasonal efficiency.

Response:

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

This rate is based on constant annualized efficiency. Because the model used to conduct the analysis operates in annual intervals, it requires an average annual efficiency rating. As such, an annualized efficiency average was developed using a more detailed analysis on seasonal and hourly heat pump performance to account for the impact of changing weather.

10.8 Please explain the basis for the assumed electric heat pump costs, for residential and commercial customers. Please clarify if the analysis assumes any future cost reductions.

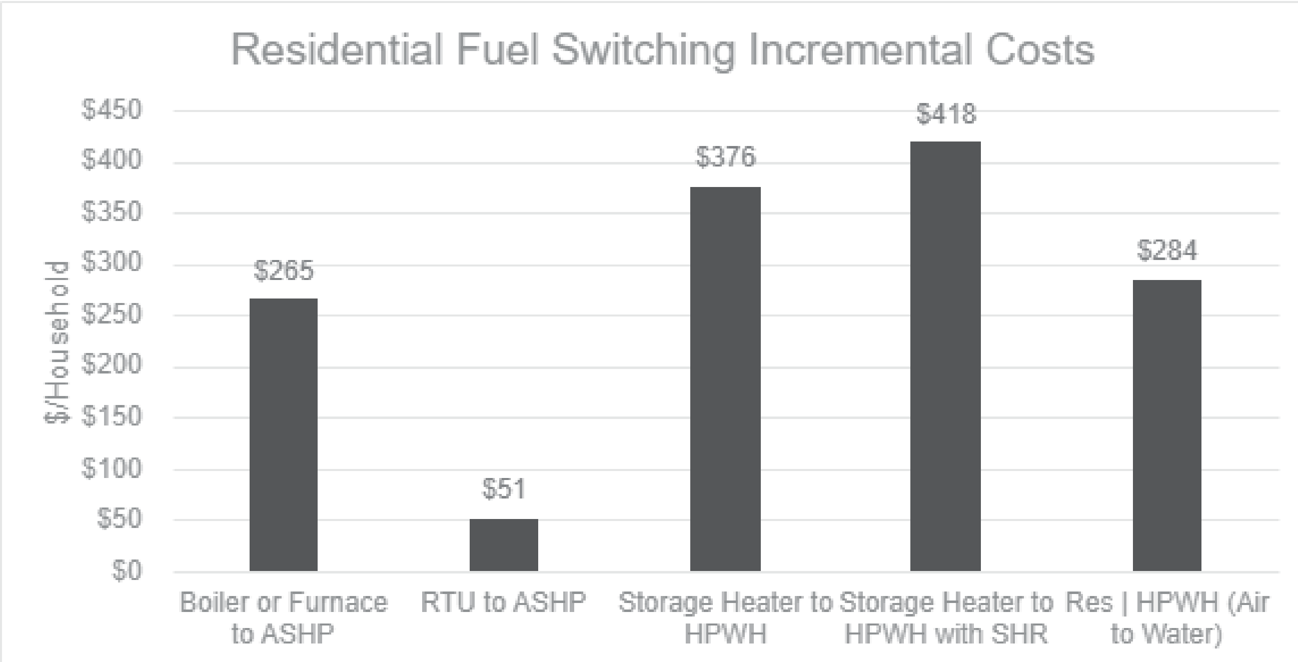
Response:

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

The costs were developed based on the measure characterization in the 2017 CPR. The 2017 CPR included the incremental costs (i.e., relative to gas equipment) for the following residential fuel switching measures:

- Gas boiler/furnace to air source heat pump (ASHP);
- Gas roof top unit (RTU) to ASHP;
- Code compliant gas storage water heater to electric heat pump water heater (HPWH);
- Code compliant gas storage water heater to electric HPWH with sewage heat recovery; and
- Code compliant gas storage water heater to electric HPWH (air to water).

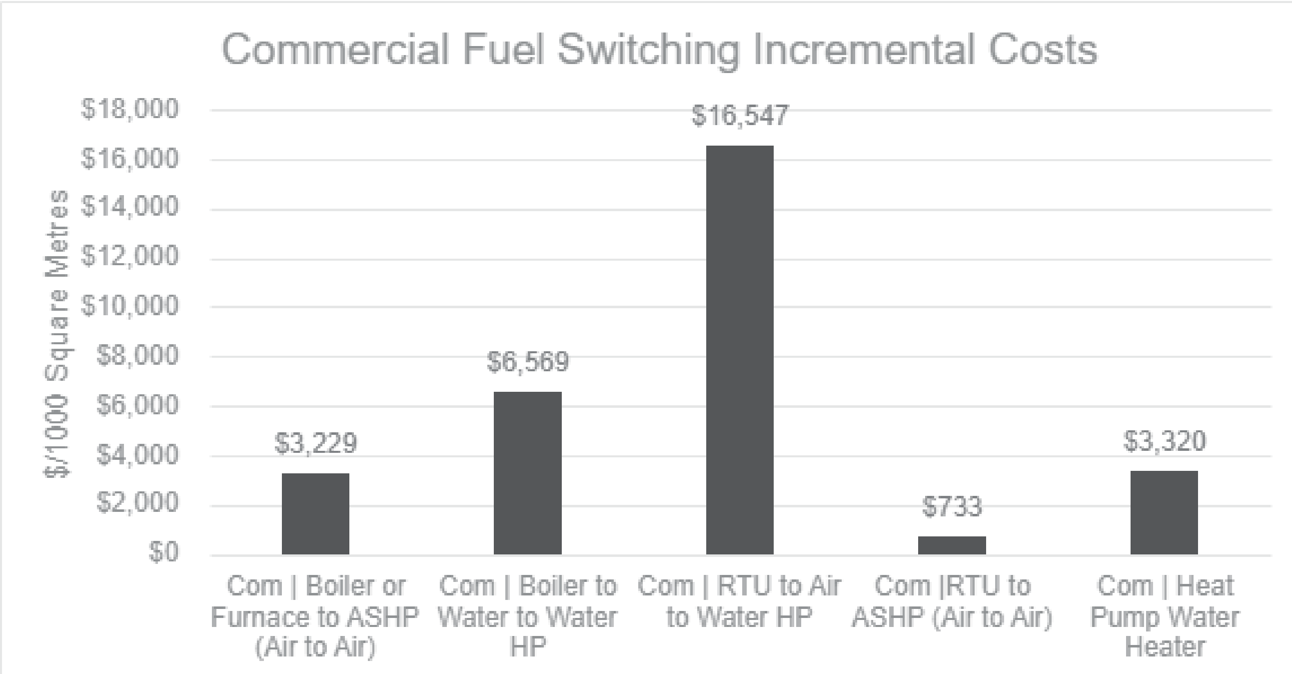
These incremental costs have been scaled to be reported in dollars per residential household. At the time, Navigant (Navigant is now a part of Guidehouse) developed an incremental cost de-escalation factor based on assumptions in the 2017 CPR. Given the technology development maturity of residential heat pump equipment, Navigant assumed a 5 percent year-over-year reduction in incremental costs.



The 2017 CPR includes the incremental costs for the following commercial fuel switching measures:

- Gas boiler to ASHP;
- Gas boiler to water source heat pump (WSHP);
- Gas storage water heater to HPWH;
- Gas RTU to WSHP; and
- Gas RTU to ASHP.

These incremental costs have been scaled to be reported in dollars per 1,000 square metres of commercial floor space. Navigant developed an incremental cost de-escalation factor based on assumptions in the 2017 CPR. Given the technology development maturity of commercial heat pump equipment, Navigant assumed a 5 percent year over year reduction in incremental costs.



10.9 Please further explain the basis for assuming a gas heat pump cost of $6800 for residential and $45000 for commercial customers.

Response:

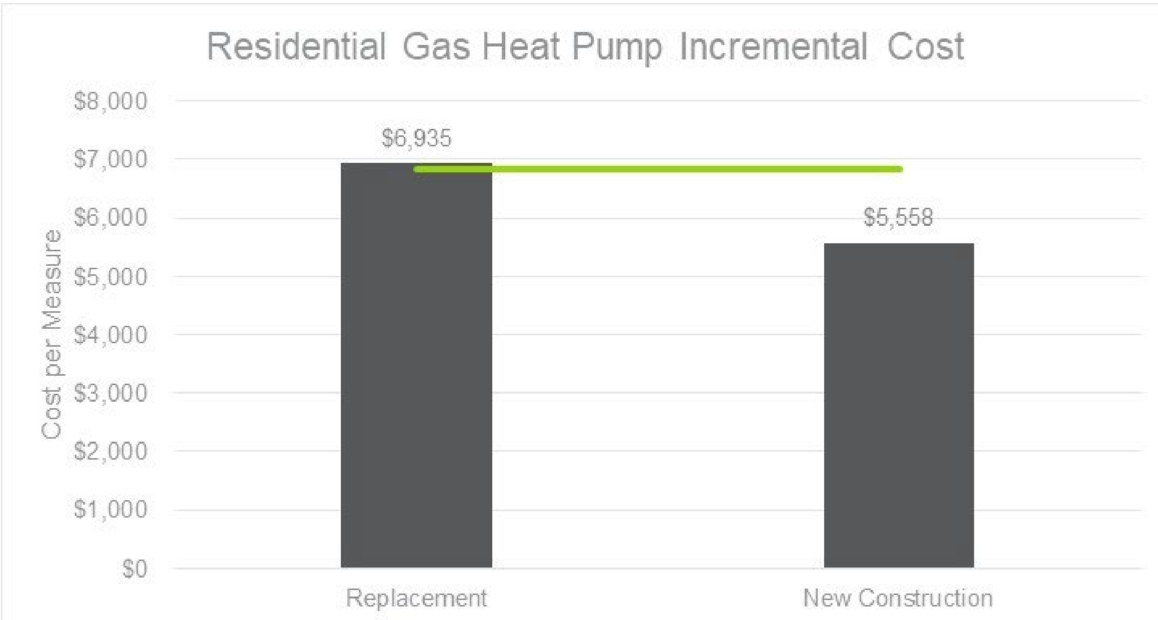
The following response has been provided by Guidehouse in consultation with FEI.

FEI notes that these are incremental costs. The incremental costs were developed based on Posterity Group's Prefeasibility Study on Natural Gas Heat Pumps (2017). The methodology for the development of the heat pumps costs is as follows:

- Incremental costs were analyzed under two applications: gas heat pump replacement of existing heating system, and new construction installation of gas heat pumps.
- The proportion of replacements and new installations was determined. Gas heat pumps are much more likely to replace an existing system given the size of the housing stock and the frequency of heating system replacement relative to the smaller amount of new housing builds in a given year.
- The weighted average of the applications was used as the representative incremental cost.
- The incremental costs assumes the gas heat pump market is mature (given the duration of the planning period) and assumes base case of conventional code-compliant, gas equipment.

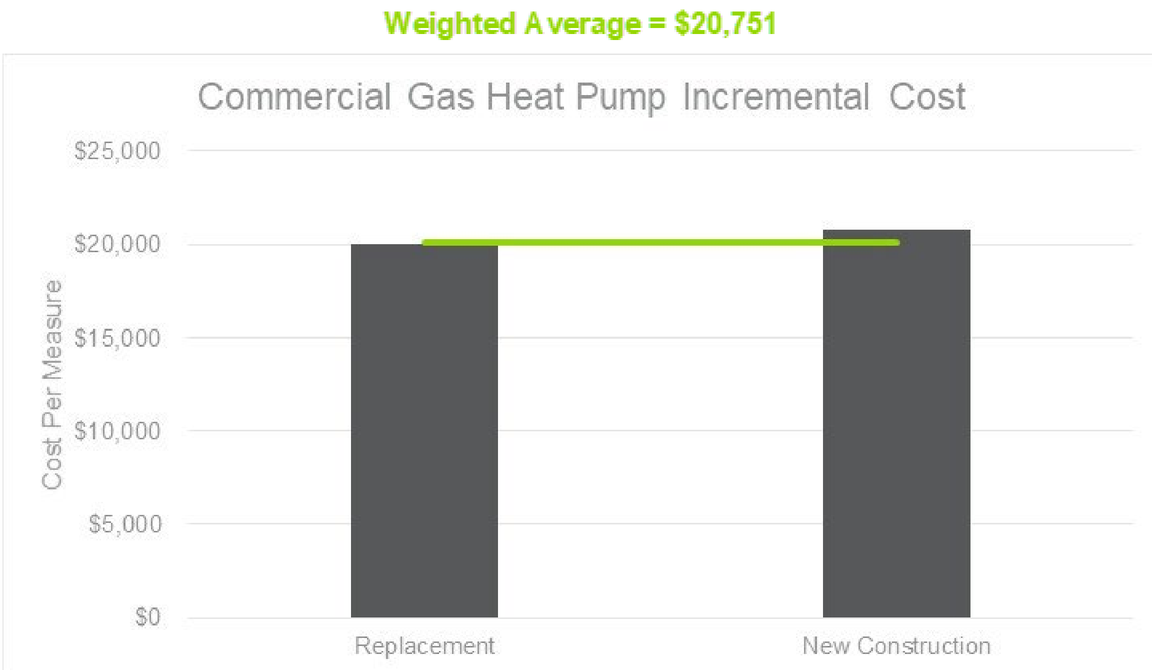
The following figure shows the incremental gas heat pump costs for residential replacement versus new construction.

Weighted Average = $6,820



The commercial incremental gas heat pump cost is also based on a weighted average from the two applications. Similarly, gas heat pumps are much more likely to replace an existing system given the size of the commercial floorspace stock and the frequency of heating system replacement relative to the smaller amount of new commercial builds in a given year.

The following figure shows the incremental gas heat pump costs for commercial replacement versus new construction.



10.9.1 Please discuss whether FEI has more up to date estimates for the cost of gas heat pumps.

Response:

FEI provides a response for both residential and commercial gas heat pumps below. By way of background, the cost estimates in the Pathways Report[20] reflect the best available information at the time of study in 2019. The study assumed that the costs of gas heat pumps would decrease over time as the units become more commercially available. Thus, the nominal price of gas heat pumps available and installed by early adopters in 2019 would not necessarily reflect the nominal costs in future years.

FEI does not have updated costs for residential gas heat pumps. FEI is currently conducting pilots on two units (Stone Mountain Technologies and ThermoLift) that are estimated to complete in 2024. FEI expects to have updated costs following the end of the pilots.

FEI launched its commercial gas heat pump retrofit early adopter offer in 2022 and received engineering quotes from ten participants. The costs ranged significantly based on which gas absorption heat pump was selected, building size, building type, existing building infrastructure, and building end uses retrofitted. The total estimated installed costs (including all associated piping, controls, engineering, and commissioning) ranged from $71,000 (for a 28,000 square foot multi-unit residential building installing two 120 MBH (thousand BTU's per hour) units for domestic hot water and space heating) to $498,000 (for a 110,000 square foot university building installing eight 120 MBH units for domestic hot water, space heating, and ventilation). FEI notes that the

[20] Exhibit B1-1, 2022 LTGRP Application, Appendix A-2.

stated costs are estimated total installed costs and, therefore, are not comparable to the incremental costs discussed above.

10.10 Please explain the basis for the assumed of 140% efficiency rates for gas heat pumps.

Response:

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

At the time of conducting the Pathways Report, limited field data on gas heat pump performance was available. A COP of 1.40 (i.e. 140 percent efficiency) was developed in consultation with Guidehouse and FEI subject matter experts to reflect approximate average operating efficiencies of available gas heat pump technologies with considerations of BC's climate zones.

Available performance ratings of gas heat pump technologies were utilized from GTI Energy's (formerly, Gas Technology Institute) Gas Heat Pump Technology and Roadmap Industry White Paper,[21] which showed a range in COP from 1.2 to 1.6. Performance ratings vary depending on the type of gas heat pump technology:

- Gas absorption/adsorption heat pumps, COP range of 1.2 to 1.4;
- Thermal compression heat pumps, COP range of 1.4 to 1.6; and
- Vapour compression (engine driven) heat pumps, COP range of 1.2 to 1.4.

10.10.1 Please discuss whether this rate represents annual average efficiency, or seasonal efficiency.

Response:

This rate is based on constant annualized efficiency. The model used to conduct the analysis operates in annual intervals, requiring an average annual efficiency rating. Please refer to the response to BCUC IR1 10.9.1 for more description of gas heat pump input assumptions.

10.11 Please explain why the Electrification Pathway assumes slightly less residential energy efficiency occurs, but more commercial energy efficiency.

[21] https://www.gti.energy/wp-content/uploads/2020/09/Gas-Heat-Pump-Roadmap-Industry-White-Paper_Nov2019.pdf.

<u>Response:</u>

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

The differences in energy efficiency are a function of the interaction between expert judgement, the 2017 CPR and the proprietary Guidehouse model. Specifically, in commercial buildings, greater energy savings were being delivered in the Electrification Pathways from transitioning to higher efficiency appliances and more building envelope improvements.

10.11.1 Please outline the associated difference in costs.

<u>Response:</u>

The following response has been provided by Guidehouse.

The following table provides the differences in costs for the initiatives included in the Pathways Report.

Initiative	Electrification ($millions)	Diversified ($millions)
Total initiative costs	**$132,360**	**$147,395**
Fuel Switching – Total	**$29,357**	**$36,961**
Residential Electric Heat Pumps	$23,524	$7,129
Residential Gas Heat Pumps	$0	$857
Commercial Electric Heat Pumps	$1,879	$0
Commercial Gas Heat Pumps	$0	$1,940
Flex Fuels	$3,954	$27,036
Built Environment Initiatives - Total	**$29,683**	**$22,415**
Residential Building Envelope	$16,805	$17,769
Commercial Building Envelope	$12,796	$4,552
Automated Building Controls	$82,979	$95
Transportation Initiatives – Total	**$73,140**	**$87,880**
Vehicles (EVs, LDV, MHD, CNG, bus, marine)	$21,362	$39,938
Vehicle charging and refueling **stations**	$51,778	$47,942
Industrial processes Improvements	**$179**	**$138**

10.12 Please discuss whether the Diversified Pathway includes any assumed capacity expansions required for the natural gas utility sector.

Response:

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

The Diversified Pathway includes costs to sustain the delivery of a portfolio of mostly renewable and low-carbon gases at an annual throughput that is at approximately the same as current levels. Expanding the gas system beyond a Business as Usual (BAU) demand projection is not assumed in the Diversified Pathway.

The scope of this analysis did not focus on specific changes in gas system capacity that may be needed. Instead, it considered the gas system as a whole out to 2050. Nevertheless, capacity expansions will be critical in the future to meet peak customer energy needs in specific regions.

10.13 Please explain whether costs are modelled for system upgrades required to integrate low carbon fuels, such as hydrogen, onto FEI's system in either of the pathways.

10.13.1 If so, please explain the assumptions used.

10.13.2 If not, please discuss how inclusion of such costs might affect the results of the analysis.

Response:

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

The costs for system upgrades are included in the analysis in the Pathways Report.[22] Note that in this analysis, a low level of hydrogen is assumed. At these levels, hydrogen can be blended directly into the gas system with fewer system upgrades and modifications required. The analysis did not assume new gas pipelines were required as a result of blending hydrogen and that existing system equipment replacement and maintenance requirements remained unchanged. As a result, only incremental costs associated with upgrades and modifications were included in overall costs.

The costs of hydrogen were developed at an aggregated $ per GJ level, including system upgrades, based on a review of available projects globally along with Guidehouse insights on data for expected costs, leading to current cost estimates (approximately $40 per GJ for hydrogen). These costs were extrapolated for the forecast taking into consideration cost declines due to technology improvements. Guidehouse also aligned hydrogen production costs with the cost of renewable electricity, as that is the primary input for producing green hydrogen.

[22] Exhibit B-1, Appendix A-2.

10.14 Please clarify the average cost of RNG used in the analysis for each pathway.

Response:

The following response has been provided by Guidehouse.

RNG production costs were derived from the best information source at the time, which was the Hallbar Consulting's Resource Supply Potential for Renewable Natural Gas in B.C. Report, and range from $14 to $28 per GJ.[23]

To achieve the 2050 RNG volume target, Guidehouse determined a production cost of approximately $17 per GJ for the Electrification Pathway and approximately $28 per GJ for the Diversified Pathway.

10.15 Please briefly outline the assumptions used to calculate GHG emissions reductions for renewable and low carbon fuels.

Response:

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

An emissions factor of 0.05 MT CO_2e per PJ was used to estimate emission reductions from switching from conventional natural gas to RNG. FEI considered both hydrogen and RNG to be clean fuels and emission- free with combustion or use in fuel cells. Upstream emissions from the production of hydrogen or RNG were not considered in the modelling and reporting.

10.16 Please further explain the assumed cost declines for hydrogen and synthetic methane.

Response:

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

These costs were extrapolated by taking into consideration cost declines due to technology improvements. Guidehouse also aligned hydrogen production costs with the cost of renewable electricity, as that is the primary input for producing green hydrogen. Costs for blue hydrogen (i.e.

[23] Hallbar Consulting & the Research Institute of Sweden (RISE), Resource Supply Potential for Renewable Natural Gas in B.C., (March 2017) online at: https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/resource_supply_potential_for_renewable_natural_gas_in_bc_public_version.pdf.

synthetic methane) were assumed to remain relatively constant at roughly $21 per GJ, while costs for green hydrogen were assumed to decrease from roughly $40 per GJ to $20 per GJ over the study period.

10.17 Please further explain why the cost of Site C is used as a proxy for future electricity costs.

Response:

Please refer to the response to BC Hydro IR1 6.4.

10.17.1 Please confirm, or explain otherwise, that no cost decline was modelled for future electricity costs.

Response:

The following response has been provided by Guidehouse.

The analysis took into account technology cost declines for utility-scale solar, wind, and battery energy storage. Data inputs used were Guidehouse's proprietary technology cost curves, and third-party cost curves from Lazard and the International Energy Agency (IEA) that project future technology costs. The cost of hydro generation was assumed to not decline from $126 per MWh in real terms over the study period. Please refer to the response to BC Hydro IR1 6.4 for more information on generation costs.

10.18 Please discuss whether the incremental costs of electrification capture costs of energy, capacity or both.

Response:

The following response has been provided by Guidehouse.

The incremental costs of electrification capture both energy and capacity.

10.18.1 Does the Pathways Report make any assumptions for the costs of constructing additional electricity transmission and/or distribution capacity?

10.18.1.1 If so, please explain the assumptions used.

10.18.1.2 If not, please discuss how inclusion of such costs might affect the results of the analysis.

Response:

The following response has been provided by Guidehouse.

Yes, the Pathways Report makes assumptions for the costs of constructing additional electricity transmission and distribution capacity. Guidehouse reviewed transmission and distribution costs from BC Hydro's Fiscal 2020 to Fiscal 2021 Revenue Requirements Application and assumed the growth capital was linked to the capacity growth and determined a $1 million per GWh construction cost. Guidehouse used this cost per GWh assumption for incremental capital for capacity growth for the forecasted years.

10.19 Please provide a detailed comparison of the two pathways in terms of risks, including but not limited to risks associated with commercialization of new technologies, resource availability, and cost uncertainty.

Response:

In general, the risks of the Electrification Pathway are associated with the practicality of building out the requisite firm peak generation and expanding the transmission and distribution systems to meet peak demand. This topic is further explored in the response to BC Hydro IR1 4.1. Within this broad category of risk, other important risks emerge, such as the risk of lowered reliability and resiliency of the overall energy system and risks related to costs, rates and affordability for ratepayers. Were the electric system required to be built out to the scale necessary, risks relating to the ability of the system to both reduce GHG emissions while maintaining reliable and affordable service would be increased. Additionally, broad scale appliance replacement will have risks of deployment and adoption.

The risks associated with the Diversified Pathway are technologically and feasibly expanding the supply of renewable and low-carbon gases to the volumes required, as well as deploying gas equipment that has not reached full commercial availability.

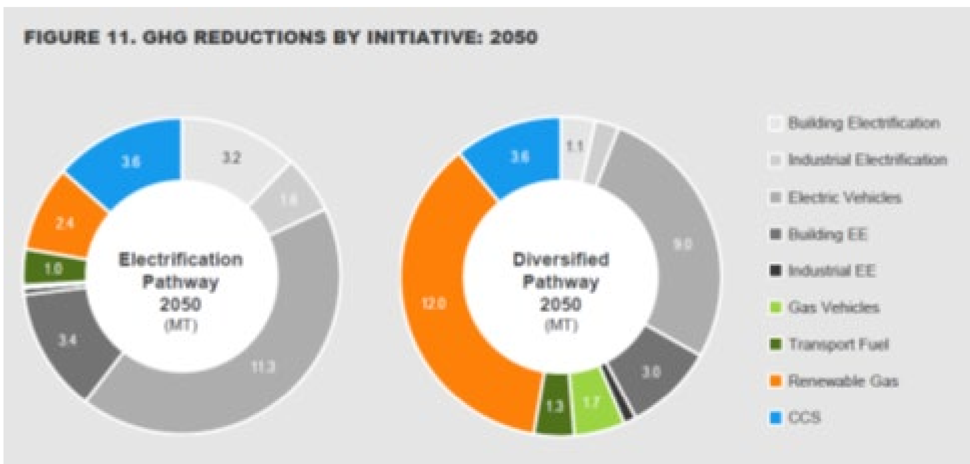
In conducting the sensitivity analysis discussed in the response to BCUC IR1 10.22, risks related to low-carbon gas costs, interest rates, infrastructure capital expenditures, and firm electric capacity costs were assessed to understand the impact those sensitivities had on the overall cost differential between the two pathways.

Risks associated with expanding the renewable gas supply are discussed throughout the BC Renewable and Low-Carbon Gas Supply Potential Study,[24] and more specifically in Chapters 5 and 6, and Tables 41 and 42, and the response to BCUC IR1 52.4.

Risks associated with expanding DSM to the investment levels needed are discussed in the responses to BCUC IR1 46.4 and 45.2.

In Figure 10 on page 19 of the Pathways Report (Appendix A-2), Guidehouse states: "Both pathways achieve roughly the same level of emissions reductions by 2050."

On page 20 of the Pathways Report (Appendix A-2), the following figure is provided:



10.20 Please confirm that the sum of the GHG reductions illustrated in the electrification pathway and diversified pathway in Figure 11 are not the same. BCUC staff calculate approximately 27 MT and 33 MT respectively. Please explain the reason for the differences.

Response:

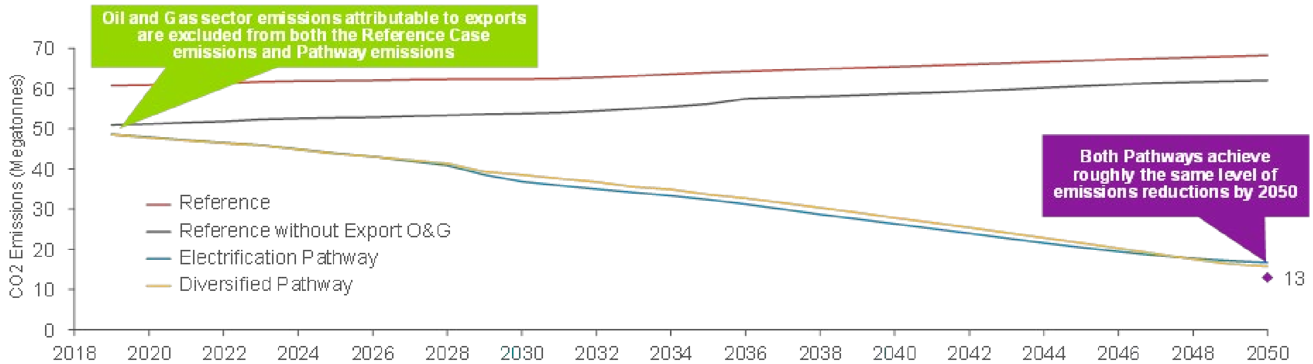
The following response has been provided by FEI in consultation with Guidehouse.

Confirmed. The totals in Figure 11 should have been 32 Mt for the Electrification Pathway and 33 Mt for the Diversified Pathway. The reason for the difference is due to a categorization error when Figure 11 was created.

The key point to be taken from Figure 11 is that both pathways achieve roughly the same emission reductions, as shown in the figure below from the Pathways Report in Appendix A-2 of the Application (Figure 10).

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

Pathways Report Figure 10: Total GHG emissions in scenarios in the Pathways to 2050 report



Oil and Gas export related emissions come from CanESS, which uses forecasts from the National Energy Board – Canada's Energy Future as its basis

On page 26 of the Pathways Report (Appendix A-2), Guidehouse states:

> $25 billion more spent on initiatives: These initiatives are summarized in Table 1 and include vehicles, building envelope improvements, space and water heating, industrial process improvements, and renewable gases. The Diversified Pathway has higher initiative costs than the Electrification Pathway due to the large amount of renewable gas needed to decrease emissions. Further, the Diversified Pathway implements higher priced energy efficiency initiatives (e.g., gas heat pumps are more expensive than electric heat pumps).
>
> …
>
> A cost sensitivity analysis was completed to determine the impact of a number of variables and found that cost drivers could increase the cost differential between the two pathways by $5 billion to $7 billion, or could narrow the gap by $5 billion to $12 billion. If conservative assumptions about key factors including the capital cost, the capital structure, or the cost of RNG or hydrogen are lower than expected, the cost differential between the two pathways will be greater. If these costs are higher, the Diversified Pathway will still be less expensive than the Electrification Pathway.

10.21 Provide a breakdown of the costs captured under "initiatives" for each pathway.

<u>Response:</u>

The following response has been provided by Guidehouse.

The following table provides a breakdown of the annual costs, at decade milestones, captured under initiatives for the Diversified Pathway. Initiatives are determined to be the incremental costs of capital stock investments for energy end-users required to achieve the GHG abatement targets of each pathway. Initiative costs do not include costs of energy infrastructure and energy production and corresponding higher fuel costs or energy rates. Fuel switching initiatives refer to the capital costs of adopting electric heat pumps in the Electrification Pathway and gas heat pumps using renewable gases in the Diversified Pathway for gas consumers.

Annual Initiatives Costs ($millions)	2020	2030	2040	2050
Transportation Initiatives	$51	$1,912	$4,214	$4,730
Built Environment Initiatives	$633	$576	$581	$809
Industrial Process Improvements	$1	$18	$4	$5
Fuel Switching	$1,023	$1,595	$904	$1,129
Total initiatives	$1,708	$4,100	$5,702	$6,673

The following table provides a breakdown of the annual costs, at decade milestones, captured under initiatives for the Electrification Pathway.

Annual Initiatives Costs ($millions)	2020	2030	2040	2050
Transportation Initiatives	$54	$1,545	$3,515	$3,941
Built Environment Initiatives	$584	$577	$1,042	$739
Industrial Process Improvements	$1	$32	$2	$2
Fuel Switching	$95	$538	$1,308	$1,334
Total initiatives	$733	$2,692	$5,867	$6,017

10.22 Please summarize the variables modelled in the sensitivity analysis and the assumptions applied.

Response:

The following response has been provided by Guidehouse.

The sensitivities which were assessed and the resulting impacts are identified in the figures below.

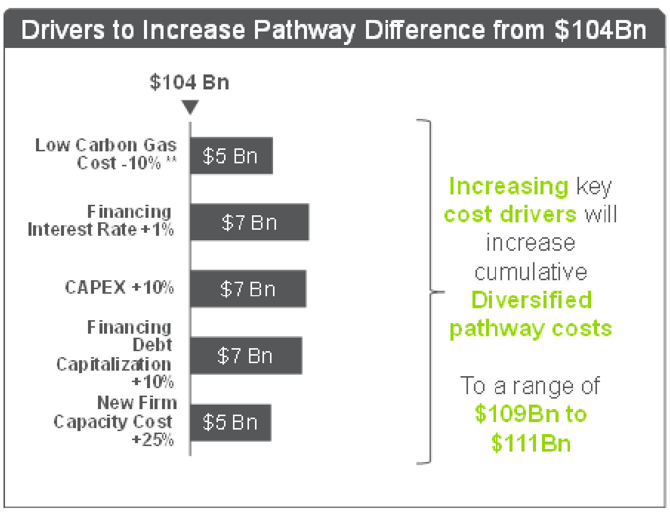
The approach to the sensitivity analysis was to evaluate sensitivities that would increase the cost differential between the Diversified and Electrification pathways (left figure) and sensitivities that would narrow the cost gap between the two pathways (right figure).

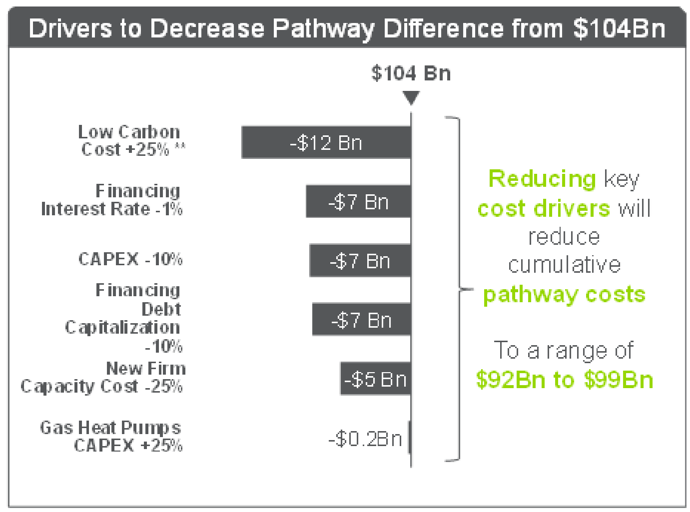
The sensitivities evaluated include the following:

- The production cost of low-carbon gas either increasing by 25 percent or reducing by 10 percent;
- Financing costs increasing or decreasing by 1 percent;

- Capital expenditure (capex) costs for infrastructure increasing or decreasing by 10 percent;
- Debt capitalization increasing or decreasing by 10 percent;
- New firm electric capacity costs increasing or decreasing by 25 percent; and
- The cost of gas heat pumps increasing by 25 percent.

As depicted in the figures below, the largest change in the cost gap is increasing the cost of low-carbon gases by 25 percent, which reduces the difference in costs by $12 billion. However, even if all of the sensitivities evaluated to narrow the cost gap between the Electrification and Diversified pathways materialized, the Electrification Pathway would still be $66 billion more costly.





C. ANNUAL ENERGY DEMAND FORECASTING

11.0 Reference: LONG-TERM CUSTOMER FORECAST METHOD AND RESULTS

Exhibit B-1, Section 4.3.1.1, p. 4-4; Appendix B-1, Section 1.1.1.1, p. 2; BCUC 2022 Generic Cost of Capital (GCOC) proceeding Stage 1 (Stage 1 GCOC proceeding), Exhibit B1-8, Section 4.1.1, pp. 15 16

Residential Customer Forecast

On page 2 of Appendix B-1 to the Application, FEI states that the residential net customer additions forecast was developed based on housing starts data from the Conference Board of Canada (CBOC) using the following methodology:

1) Determine the prior year actual net residential customer additions by region.
2) Based on internal data, proportion the net residential customer additions into single and multi-family additions.
3) Use the CBOC long term growth rates for single and multi-family housing starts to develop the long-term growth rate forecast for both single and multi-family net residential customer additions.
4) Sum up the single and multi-family net residential customer additions.
5) Add the additions to the prior year total customer count, starting with the base year.

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

> The FEI aggregate forecast predicts a compound annual growth rate of 0.48 percent across the 20-year planning period, with the regional distribution remaining relatively unchanged.

On pages 15 to 16 of Exhibit B1-8 in the Stage 1 GCOC proceeding, FEI states:

> FEI is already experiencing the effects of this shift in its net customer additions, particularly in the residential sector, where due to BC's high turnover rate, a large segment of its existing customers homes may be torn down and rebuilt with electric-only options to meet more stringent code requirements. Further, the gradual decline in the single-family dwelling segment, where FEI has higher capture rates, in favour of multi-family dwellings and the downward trend in the share of natural gas in space heating and water heating applications continue to impact FEI's risk profile. FEI's new residential customers continue to have lower use per customer (UPC) than average residential customers do. This is somewhat offset by load growth in the more volatile and economically sensitive transportation and industrial sectors.

11.1 Please provide an explanation of the methodology used to forecast residential customer additions based on the CBOC housing starts forecast.

Response:

The FEI residential and commercial customer forecasts are developed using the last known actual customer totals by region and rate class from the prior year, along with a forecast of customer additions. The customer forecasts are required at various levels of geographic granularity. The highest level is the complete FEI service territory, followed by the BC Stats Local Health Area (LHA) and, finally, the FEI municipal (or branch) level.

The regional residential net customer additions forecast is developed based on housing starts data from the CBOC Provincial Outlook Long-Term Economic Forecast. The regional commercial customer additions are calculated as an average of the net customer additions by region and rate class from the prior three years.

Once the regional forecasts are developed, they are proportioned into the various LHA and the FEI municipal (or branch) levels. The CBOC does not have branch level forecasts so the regional forecasts are split in such a way that they represent the expected growth trajectory for each branch. To do this FEI uses the more granular growth trajectories from the LHA forecast to split the regional forecasts. It is important to note that, once split, the sum of the both the branch-level and LHA forecasts equals the regional forecast. The LHA forecast growth rates are only used for determining the expected growth trajectory for the branches and LHAs. The LHA forecast is for household formations, not single-family (SFD) and multi-family (MFD) housing starts and, therefore, cannot be used to develop the official regional customer forecast.

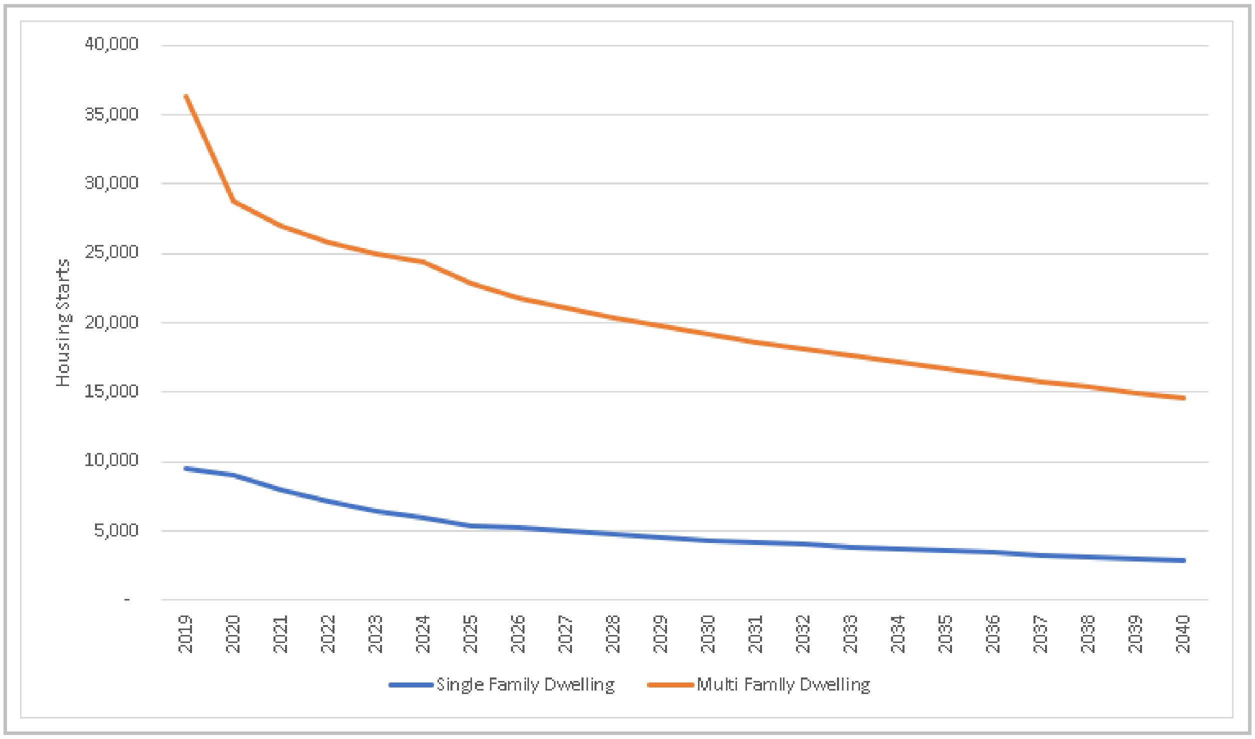
Attachment 11.1 contains a document which describes both the residential and commercial customer forecast methods in detail and includes with worked examples.

11.2 Please provide graphs of the CBOC forecast housing starts for each region over the planning period.

Response:

The CBOC forecast of single-family and multi-family dwellings is prepared at the provincial level only. The CBOC does not produce a regional forecast of housing starts.

The following figure shows the single-family and multi-family housing starts forecast for BC.



Source: The Conference Board of Canada, BC Housing Data Forecast, December 5, 2019.

11.3 Please discuss, with supporting data, whether FEI has experienced any changes to the capture rates (i.e., what proportion of housing starts are expected to be customers of FEI) over the past ten years.

<u>Response:</u>

FEI has residential capture rate data available for the six years prior to 2021. (Note that the capture rate is based upon the percentage of housing completions that become FEI customers, not housing starts.) Table 1 below shows how FEI's overall market capture rate reached a high of 85 percent in 2017 and has since declined.

Table 1: FEI's Overall Capture Rate Trend

	2015	2016	2017	2018	2019	2020
Market Capture	81%	83%	85%	82%	81%	78%

11.4 Please provide the assumed capture rates for the housing starts over the planning period and explain how the capture rates are expected to change over the planning period.

11.4.1 If FEI does not expect any changes to the capture rates over the planning period, please explain why.

Response:

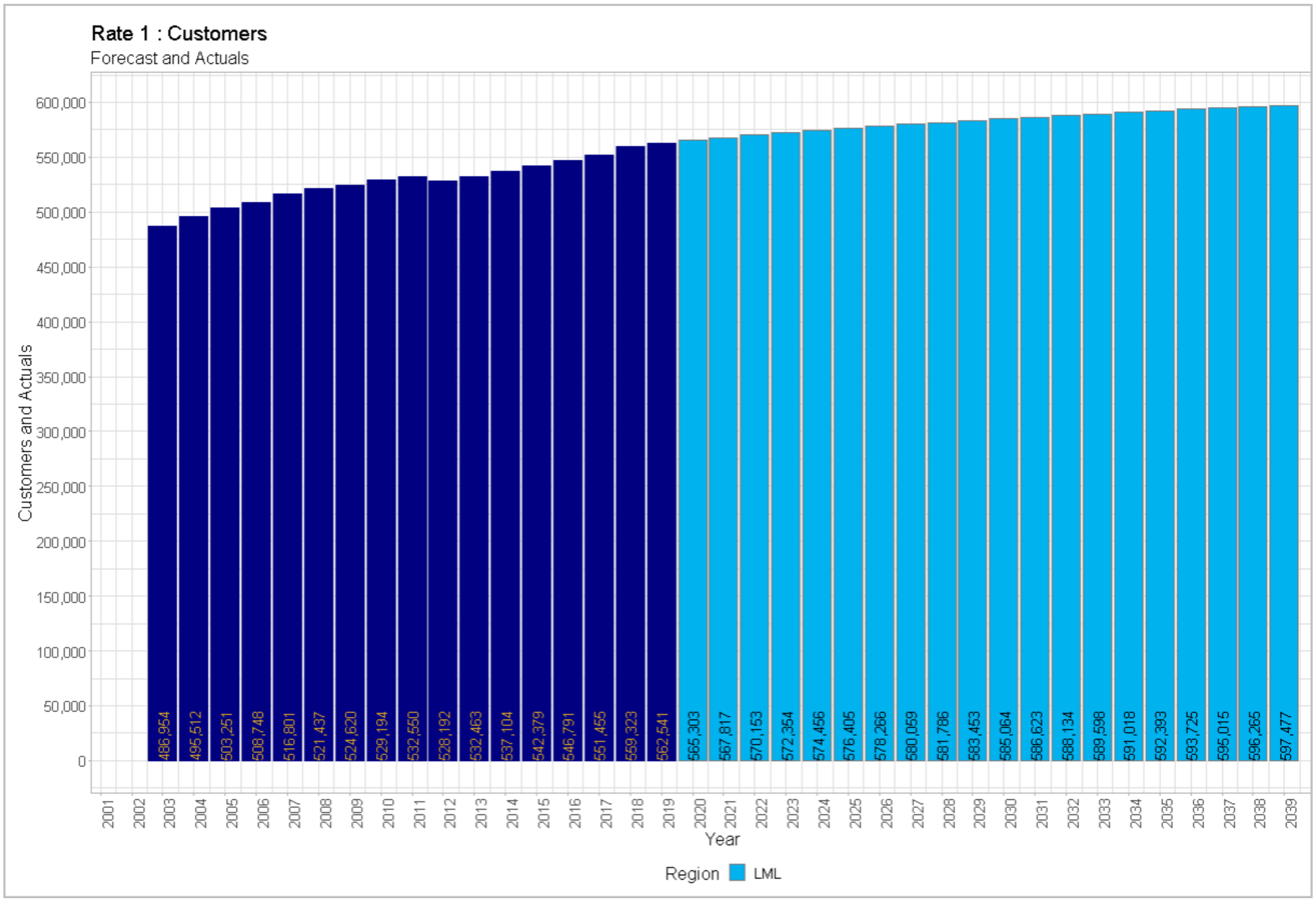
As discussed in the current GCOC proceeding referenced in the question preamble, based on the shift in its net customer additions, FEI expects this downward trend in capture rates to continue. FEI does not prepare a capture rate forecast and the historical capture rate is not an input into the residential customer forecast method. FEI's demand forecast method accounts for demand reductions (from electrification, for example) through its end-use forecast rather than its customer forecast, as discussed in the response to BCUC IR 1 14.3.

11.5 Please discuss whether the use of the prior year actual net residential customer additions accurately reflects the trend in net customer additions, as opposed to using historical data for multiple years. In the response, please explain what impact, if any, using actual net customer additions over multiple years would have on the forecast.

Response:

The trend in the customer forecast is affected by the CBOC single-family and multi-family growth rates rather than the actual net residential customer additions starting point for the forecast. The FEI residential customer method is based on third party (CBOC) growth rates and is not a time series forecast where a historical trend would influence the forecast trajectory.

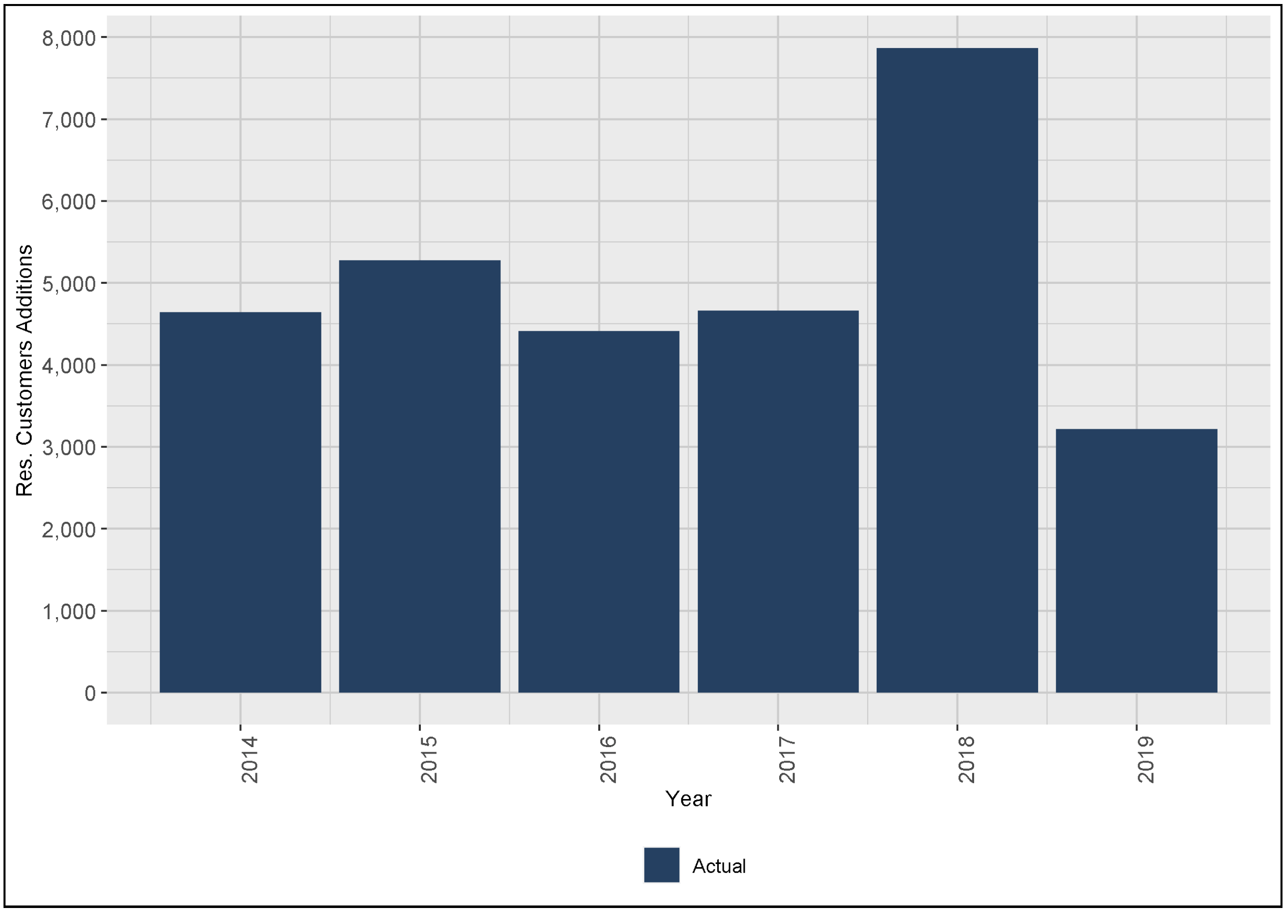
Adding the year end actual customers to the results from the CBOC growth rate customer additions forecast does result in a forecast that accurately reflects recent trends. The following figure shows the Lower Mainland residential customers since 2003 in dark blue along with the forecast based on 2019 year end actuals. As this figure shows, the forecast reflects the historical trend.



FEI notes that the starting point for the forecast can be changed by averaging the single-family and multi-family actual additions over a variety of time spans.

FEI has actual customer additions data from 2014.

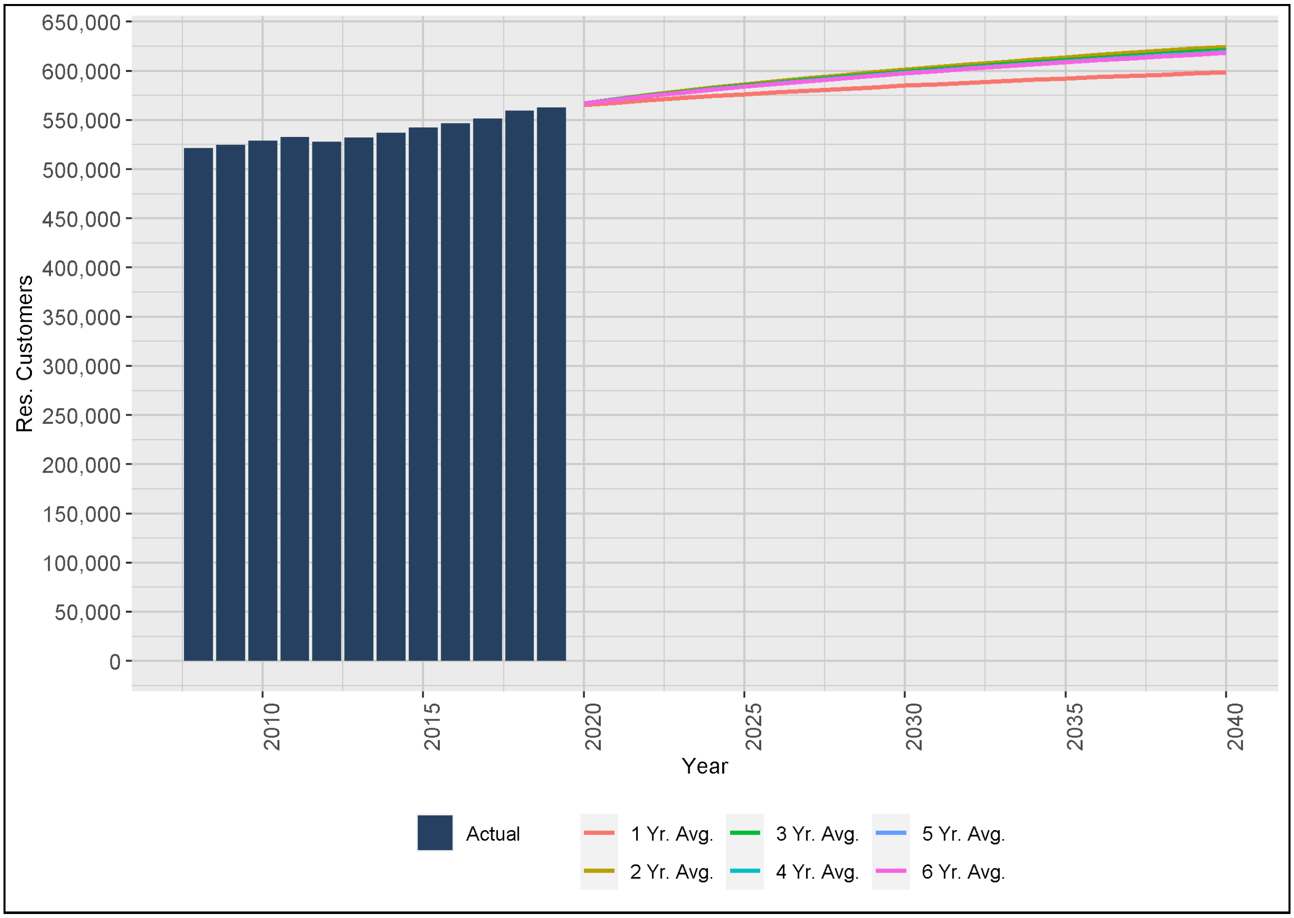
The following chart shows the actual Lower Mainland residential customer additions from 2014 to 2019.



From this data, average additions starting points for averages spanning two through six years were developed. Once the average additions were calculated, the CBOC growth rates were applied following the FEI forecast method.

As expected, the large number of additions recorded in 2018 results in the two year through six year averages being larger than the single year (2019) that FEI used to develop the as-filed forecast.

The starting point for the forecast does not affect the trajectory of the forecast. The following figure shows the Lower Mainland residential customer forecast resulting from the different starting points. The lower red line is the as-filed forecast developed with the 2019 data. The other lines are tightly grouped because the additions, and hence the averages, were very similar each year.



The following table shows that, in 2040, the two year through six year average models result in customer forecasts that are only about 3-4 percent higher than the as-filed forecast.

Model	2040 LML Residential Customers	Difference Compared to Original	Percent Difference Compared to Original
Original Forecast	598,654		
2 Yr. Avg.	624,727	26,072	4.4%
3 Yr. Avg.	621,423	22,769	3.8%
4 Yr. Avg.	619,018	20,364	3.4%
5 Yr. Avg.	619,513	20,859	3.5%
6 Yr. Avg.	618,385	19,731	3.3%

11.6 Please provide a comparison of the forecast net customer additions against the actual net customer additions over the past 10 years.

Response:

The following table shows the results of the residential forecast of net customer additions for the 10 years ending in 2019.

FEI Customer Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Average
Rate Schedule 1											
Forecast	7,012	7,724	8,984	9,352	6,647	9,710	9,461	11,522	9,141	10,724	
Actual	9,186	6,911	6,371	9,139	10,472	12,508	11,359	13,357	19,257	10,609	
Error = (ACT-FCST)	2,174	(813)	(2,613)	(213)	3,825	2,798	1,898	1,835	10,116	(115)	
Percent Error = (Error/ACT)	23.7%	-11.8%	-41.0%	-2.3%	36.5%	22.4%	16.7%	13.7%	52.5%	-1.1%	10.9%

The average annual variance over the 10-year timeframe was 10.9 percent.

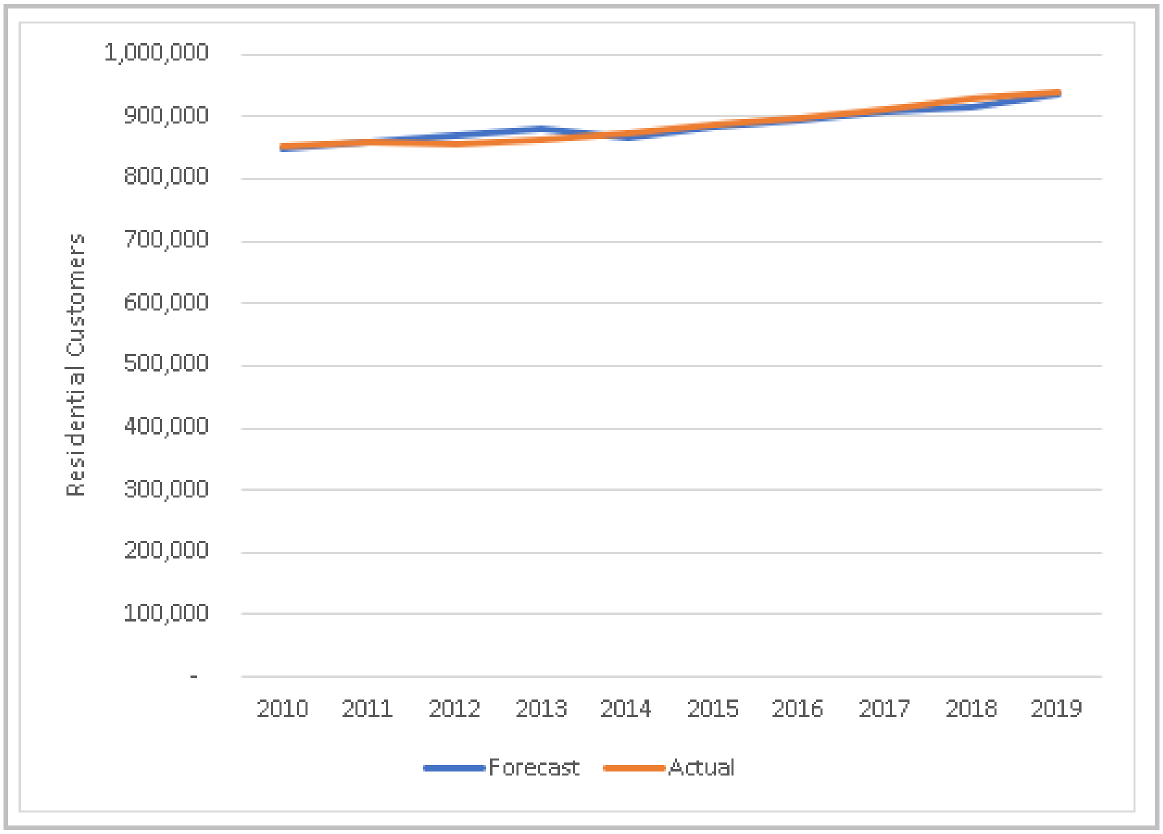
However, the customer additions forecast is an intermediate step in the development of the customer forecast. In the final step, the residential additions forecast is added to the year-end actual customers to develop the customer forecast. The customer forecast, and not the customer additions forecast, is then used for further demand calculations.

The following table shows the performance of the total residential customer forecast over the same period.

FEI Customers	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Average
Rate Schedule 1											
Forecast	849,539	857,592	870,980	880,331	866,852	883,371	892,830	909,727	916,365	934,804	
Actual	853,492	860,403	854,050	863,189	873,661	886,169	897,528	910,885	930,142	940,751	
Error = (ACT-FCST)	3,953	2,811	(16,930)	(17,142)	6,809	2,798	4,698	1,158	13,777	5,947	
Percent Error = (Error/ACT)	0.5%	0.3%	-2.0%	-2.0%	0.8%	0.3%	0.5%	0.1%	1.5%	0.6%	0.1%

Over the 10-year timeframe, the average variance was very low at 0.1 percent.

The following figure illustrates the residential customer forecast and actuals over the same time period.



11.7 Please discuss the capabilities of the customer forecast methodology in forecasting net customer additions over the short, medium and long-term.

Response:

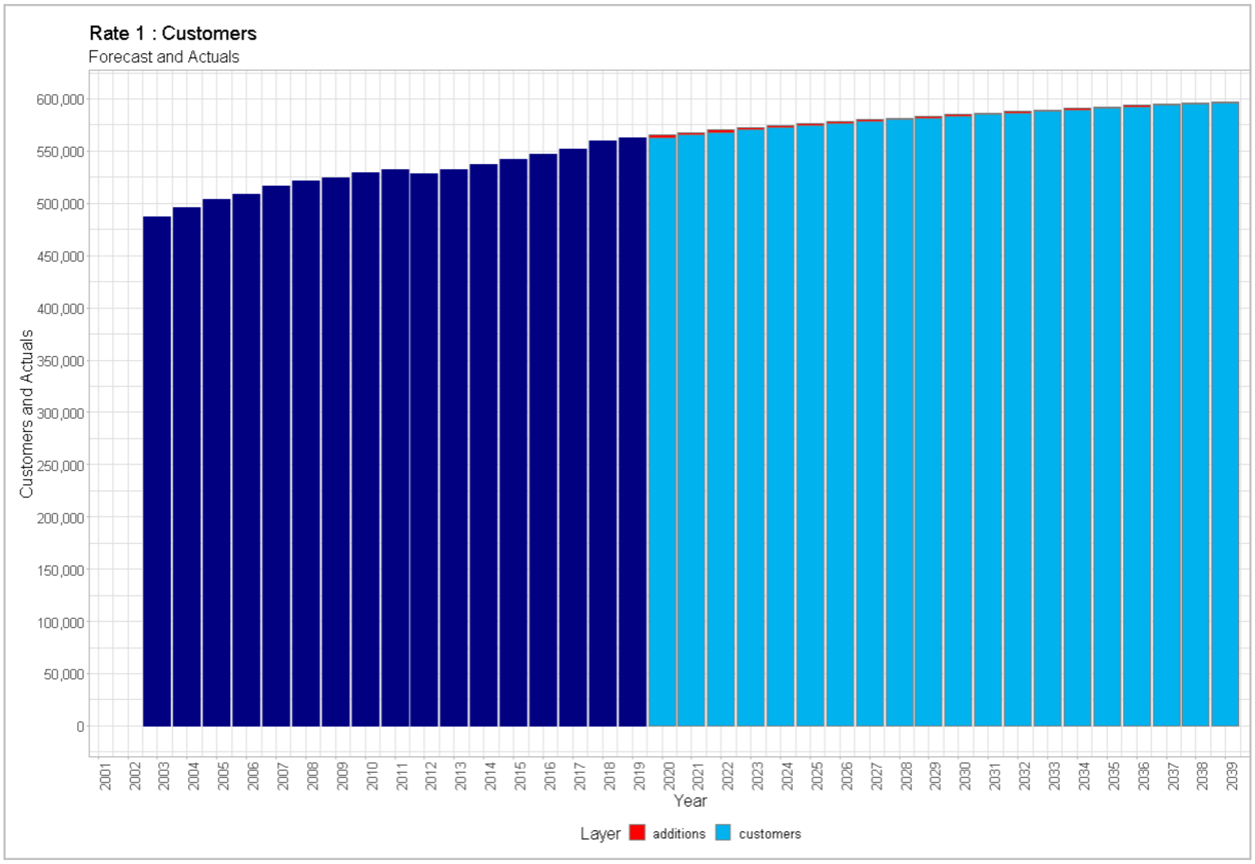
The net customer additions forecast method has the same short-, medium- and long-term prediction capabilities as the underlying econometric CBOC forecast. The CBOC is one of the foremost independent, applied research organizations in Canada and it is the only one that produces a long-term provincial single- and multi-family dwelling housing starts forecast. FEI continues to believe that the single/multiple family forecast is important in a changing housing market.

Predicting single- and multi-family housing starts of any duration in a volatile market is difficult, and the variances reported in the response to BCUC IR1 11.6 reflect these challenges. However, the FEI customer forecast is insulated from this volatility because the CBOC forecast is only applied to additions.

The FEI residential customer forecast relies on the following:

1. The prior year actual customer totals, and
2. The net customer additions forecast.

As the following figure shows, the net additions component (in red) is small compared to the prior year actuals.



11.8 Please explain how the residential customer forecast methodology accounts for any customer losses over the planning period.

Response:

The residential customer forecast method is based on net customer additions. Net customer additions are defined as gross customer additions less customer losses. For example, if the gross customer additions were 100, and 50 customers left the system, then the net customer additions would be 50. The CBOC growth rates are applied to the net customer additions, so that, if losses are relatively high, then the future forecast will be relatively lower, all else equal.

The net additions are calculated based on the last known actuals (2019) and used for the planning period. The customer forecast method does not include a separate customer losses forecast. The forecast is refreshed regularly, so that, if any customer losses trends were to develop, they would be identified and included in subsequent forecasts.

12.0 Reference: LONG-TERM CUSTOMER FORECAST METHOD AND RESULTS

Exhibit B-1, Section 4.6.1.2, p. 4-31; Appendix B-1, Section 1.1.1.2, p. 2

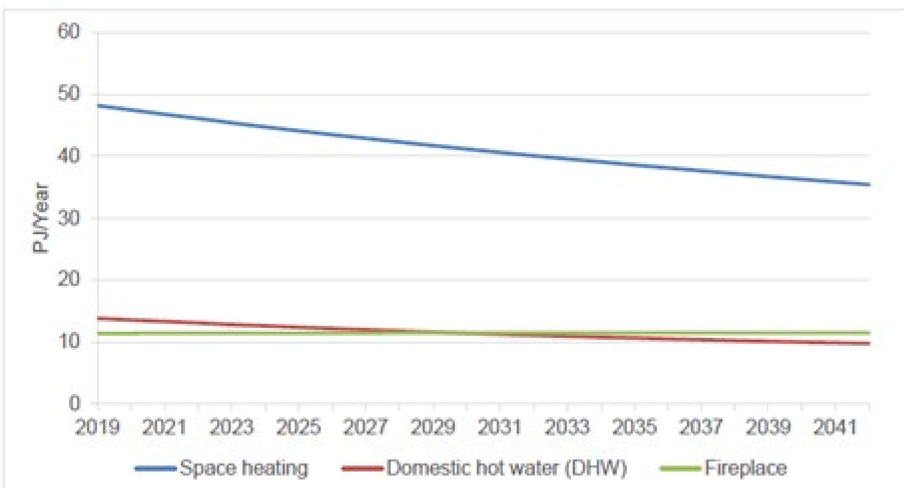
Commercial Customer Forecast

On page 2 of Appendix B-1 to the Application, FEI states:

> The commercial customer additions forecast is calculated as the average of the net customer additions by region and rate class (RS 2, 3 and 23) for the prior three years. The customer additions forecast is assumed to remain constant for the first five years and then adjusted based on the long-term BC STATS household formation forecast for the remaining 15 years. The customer additions are then added to each year of the forecast throughout the planning horizon.

On page 4-31 of the Application, FEI provides Figure 4-11, which shows the residential sector top end uses under the Diversified Energy (Planning) Annual Demand scenario:

Figure 4-11: Diversified Energy (Planning) Annual Demand – Residential Sector Top End Uses

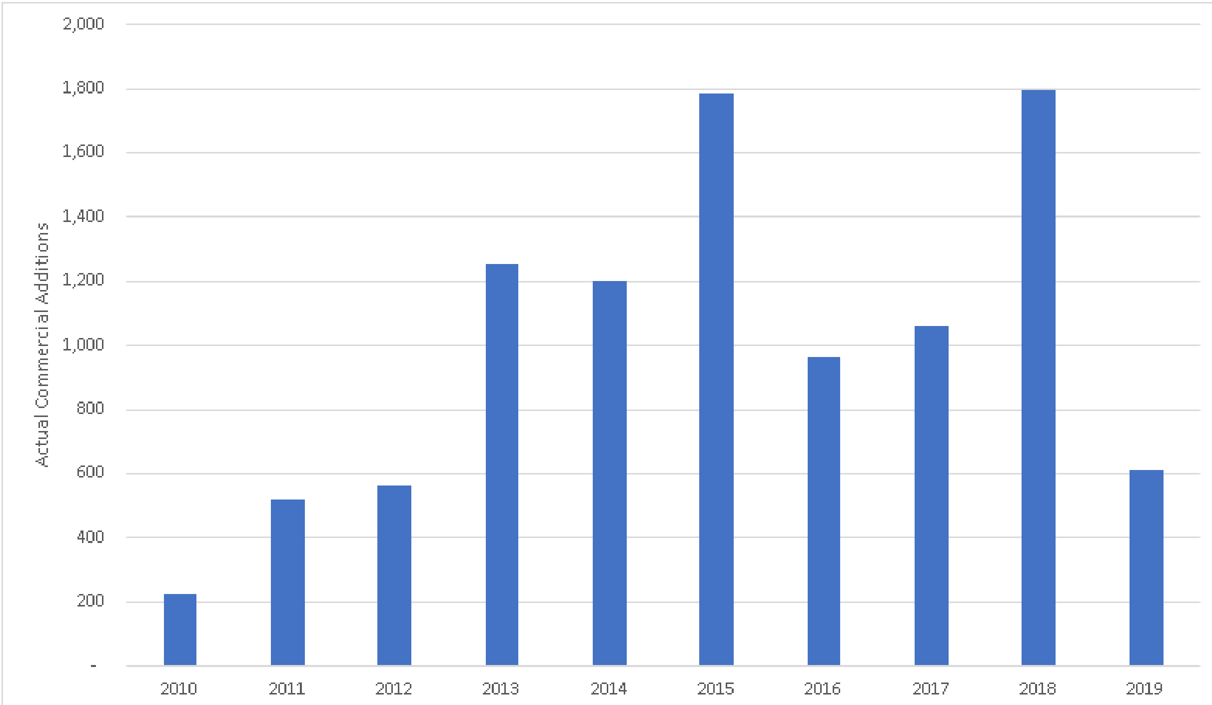


12.1 Please explain why the average net customer additions for the prior three years is used for the commercial customer count, as opposed to a different period of time (e.g., 5 years, 10 years, or the prior year as is used for the residential customer forecast).

<u>Response:</u>

Consistent with past practice, FEI uses a three-year average method to forecast commercial net customer additions to both smooth out recent fluctuations while at the same time providing a forecast that is responsive to recent trends. As shown in Figure 1 below, commercial account additions fluctuate significantly year over year.

Figure 1: Commercial Account Fluctuations 2010-2019



A three-year average is a reasonable way to account for these fluctuations. It is preferable for the purposes of comparability and consistency over time to continue to apply the existing forecasting method.

FEI recently completed the Forecasting Method Study, filed as Appendix B2 in FEI's 2020-2024 MRP Application. The Forecasting Method Study represented the culmination of a number of years of research and testing of alternative forecasting methods in response to the forecasting directives in BCUC Order G-86-15 and accompanying Decision related to the FEI Annual Review for 2015 Delivery Rates Application. As a result of this study, FEI concluded that the existing three-year average method for forecasting commercial customer additions resulted in the lowest demand variance. FEI has, therefore, continued to use this method to forecast demand in its revenue requirements applications.

12.1.1 Please explain why the previous year and previous three year periods are appropriate for the residential and commercial customer forecasts, respectively.

Response:

These methods are appropriate because they result in forecasts that produce minimal variances from actual customer levels. As shown in the response to BCUC IR1 11.6 (residential) and BCUC

IR1 12.2 (commercial), and reproduced here for convenience, the variances between customer forecasts and actual customers for both the residential and commercial classes are minimal.

The average residential customer count variance from 2010-2019 was only 0.1 percent.

FEI Customers	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Average
Rate Schedule 1											
Forecast	849,539	857,592	870,980	880,331	866,852	883,371	892,830	909,727	916,365	934,804	
Actual	853,492	860,403	854,050	863,189	873,661	886,169	897,528	910,885	930,142	940,751	
Error = (ACT-FCST)	3,953	2,811	(16,930)	(17,142)	6,809	2,798	4,698	1,158	13,777	5,947	
Percent Error = (Error/ACT)	0.5%	0.3%	-2.0%	-2.0%	0.8%	0.3%	0.5%	0.1%	1.5%	0.6%	0.1%

The average commercial customer count variance from 2010-2019 was -1 percent.

FEI Commercial Customers	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Average
Forecast	93,373	94,375	92,561	92,810	88,704	91,320	92,372	94,826	95,651	96,570	
Actual	92,065	92,588	87,863	89,115	90,316	92,101	93,066	94,126	95,920	96,530	
Error = (ACT-FCST)	(1,308)	(1,787)	(4,698)	(3,695)	1,612	781	694	(700)	269	(40)	
Percent Error = (Error/ACT)	-1.4%	-1.9%	-5.3%	-4.1%	1.8%	0.8%	0.7%	-0.7%	0.3%	0.0%	-1.0%

If these variances were significantly higher and contributed to elevated demand variances, FEI would assume that the methods are not appropriate. However, as these results show, the variances are very low and, as a result, FEI believes both methods remain appropriate for the development of the customer forecasts.

12.1.1.1 Please discuss the extent that the one year and three year observation periods accurately capture the effects of exogenous factors.

<u>Response:</u>

The short forecast method timeframes (one and three years) used for the starting point for both the residential and commercial customer additions forecasts ensures that exogenous events relevant to those years are captured in the customer additions forecasts.

FEI notes that, regardless of the duration of the observation period, the number of customer additions relative to total customers in any given year is small (averaging 1 to 1.2 percent), as illustrated in the figures below. Exogenous factors impacting net customer additions are intrinsic to the blue (top) bars in both figures. While the exact impact of exogenous factors on customer additions cannot be measured, the impact is assumed to be minimal, as these two figures show.

Figure 1: Actual Residential Customers and Additions

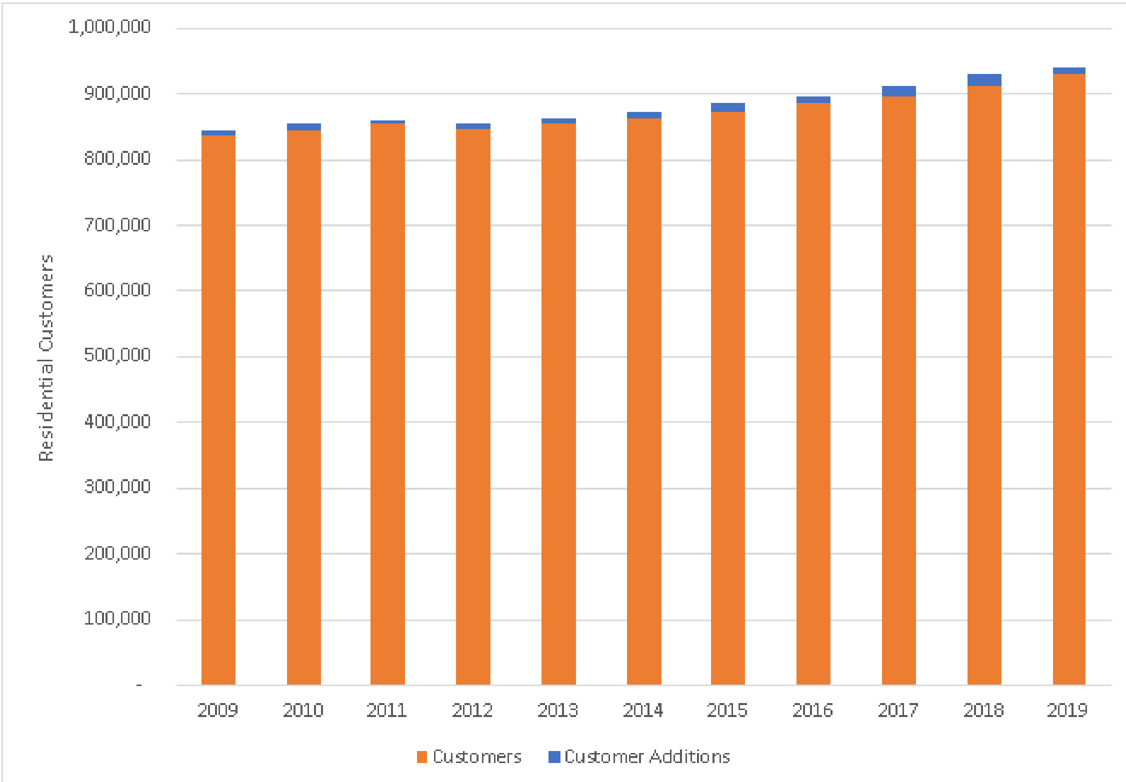
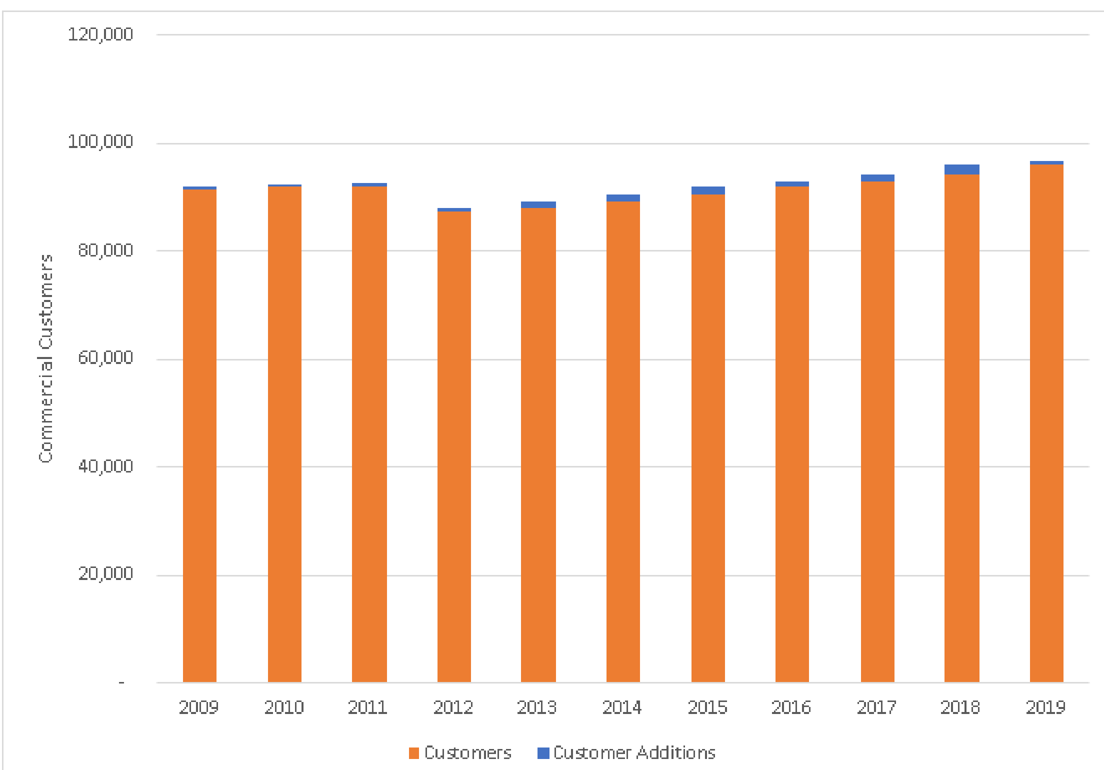


Figure 2 – Actual Commercial Customers and Additions



12.2 Please provide a comparison of the forecast net customer additions against the actual net customer additions over the past 10 years.

Response:

The following table shows the results of the forecast of commercial net customer additions for the 10 years ending in 2019.

FEI Commercial Additions	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Average
Forecast	944	1,000	249	249	472	1,004	1,005	1,362	1,294	1,222	
Actual	223	522	561	1,252	1,201	1,784	965	1,060	1,794	610	
Error = (ACT-FCST)	(721)	(478)	312	1,003	729	780	(40)	(302)	500	(612)	
Percent Error = (Error/ACT)	-323.3%	-91.6%	55.6%	80.1%	60.7%	43.7%	-4.1%	-28.5%	27.9%	-100.3%	-28.0%

The average annual variance over the 10-year timeframe was -28 percent.

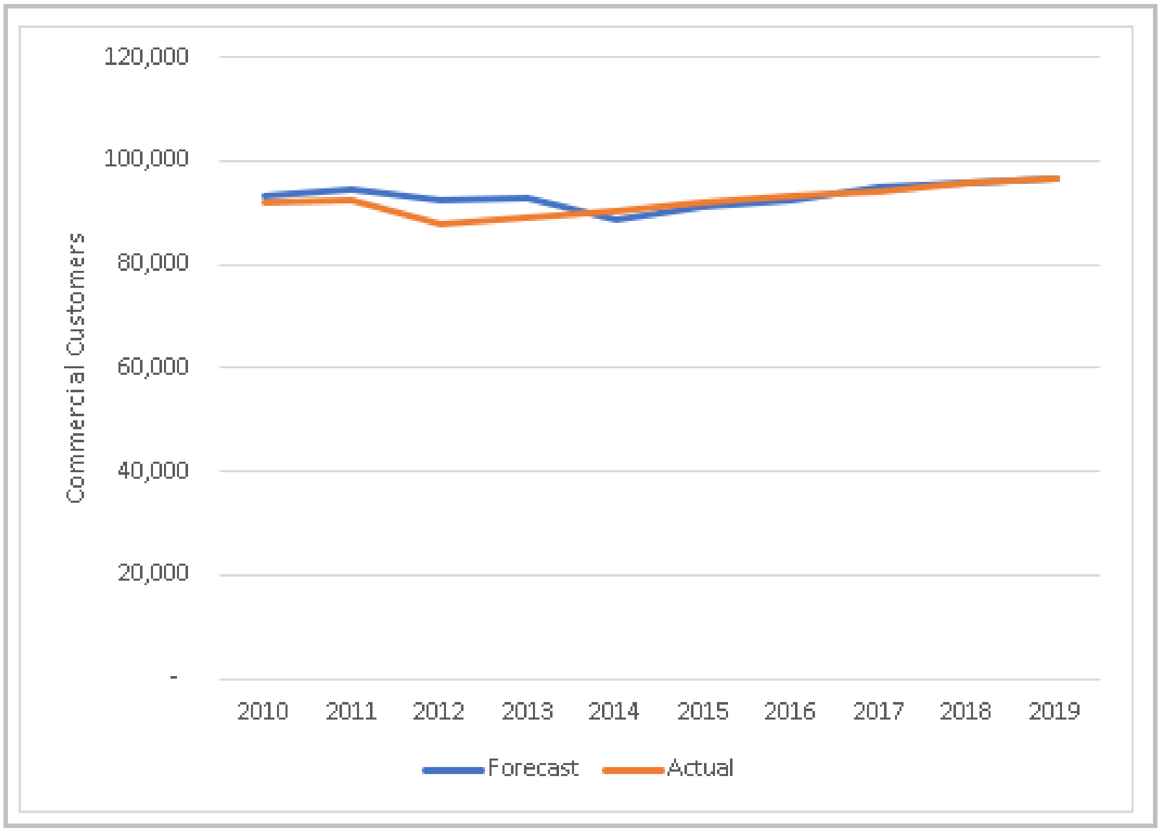
However, the customer additions forecast is an intermediate step in the development of the customer forecast. In the final step, the commercial additions forecast is added to the year-end actual customers to develop the customer forecast. The customer forecast, and not the customer additions forecast, is then used for the demand calculations.

The following table shows the performance of the customer forecast over the same period.

FEI Commercial Customers	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Average
Forecast	93,373	94,375	92,561	92,810	88,704	91,320	92,372	94,826	95,651	96,570	
Actual	92,065	92,588	87,863	89,115	90,316	92,101	93,066	94,126	95,920	96,530	
Error = (ACT-FCST)	(1,308)	(1,787)	(4,698)	(3,695)	1,612	781	694	(700)	269	(40)	
Percent Error = (Error/ACT)	-1.4%	-1.9%	-5.3%	-4.1%	1.8%	0.8%	0.7%	-0.7%	0.3%	0.0%	-1.0%

Over the 10-year timeframe the average variance was -1.0 percent.

The following figure shows the customer forecast and actuals over the same time period.



12.3 Please discuss the capabilities of the customer forecast methodology in forecasting net customer additions over the short, medium and long-term.

Response:

The customer forecast method is similarly capable of forecasting net customer additions over the short, medium and long term.

FEI has detailed electronic data extending back to 2003 and is able to use that data to prepare an illustrative example of the capabilities of the three-year average commercial customer forecast method. For brevity, this example uses data from the Lower Mainland[25] region rather than the entire FEI service territory.

For this simplified example,[26] the three-year average method was used for 2006, using 2004-2006 actual commercial customer additions. The three-year average of customer additions was then carried forward until 2021. With this data, comparisons can be made to the actual customer totals over the short, medium and long term.

[25] In 2021, 62 percent of all commercial customers were located in the Lower Mainland region.
[26] FEI notes that the municipal disaggregation step using BC STATS Local Health Area data was not used in this simplified example due to lack of historic data and calculation complexity.

The following table shows the actual year-end customer additions as of 2006. The customer additions forecast is the three-year average (460 additions per year).

Year	Year End Actual Comm. Customers	Comm. Customer Additions
2003	55,019	
2004	54,634	-385
2005	55,718	1,084
2006	56,399	681
	Average	460

The forecast through 2021 is then created by adding 460 commercial customers every year.

The following table shows the year-end actuals and forecast through 2021. The red labels coincide with the itemized list that follows the figure.

	A	B	C	D	E
1	Year	Year End Actual Comm. Customers	Comm. Customer Additions Forecast	Comm. Customer Forecast	Variance
2	2003	55,019			
3	2004	54,634			
4	2005	55,718			
5	2006	56,399	460	56,178	
6	2007	57,289	460	56,638	
7	2008	58,184	460	57,098	
8	2009	58,410	460	57,558	1.5%
9	2010	58,445	460	58,018	
10	2011	58,632	460	58,478	
11	2012	58,737	460	58,938	
12	2013	59,567	460	59,398	
13	2014	60,260	460	59,858	0.7%
14	2015	61,055	460	60,318	
15	2016	61,678	460	60,778	
16	2017	62,349	460	61,238	
17	2018	63,467	460	61,698	
18	2019	63,756	460	62,158	
19	2020	63,817	460	62,618	
20	2021	63,995	460	63,078	1.4%

1. The three-year average of additions is carried forward through 2021 (16 years).

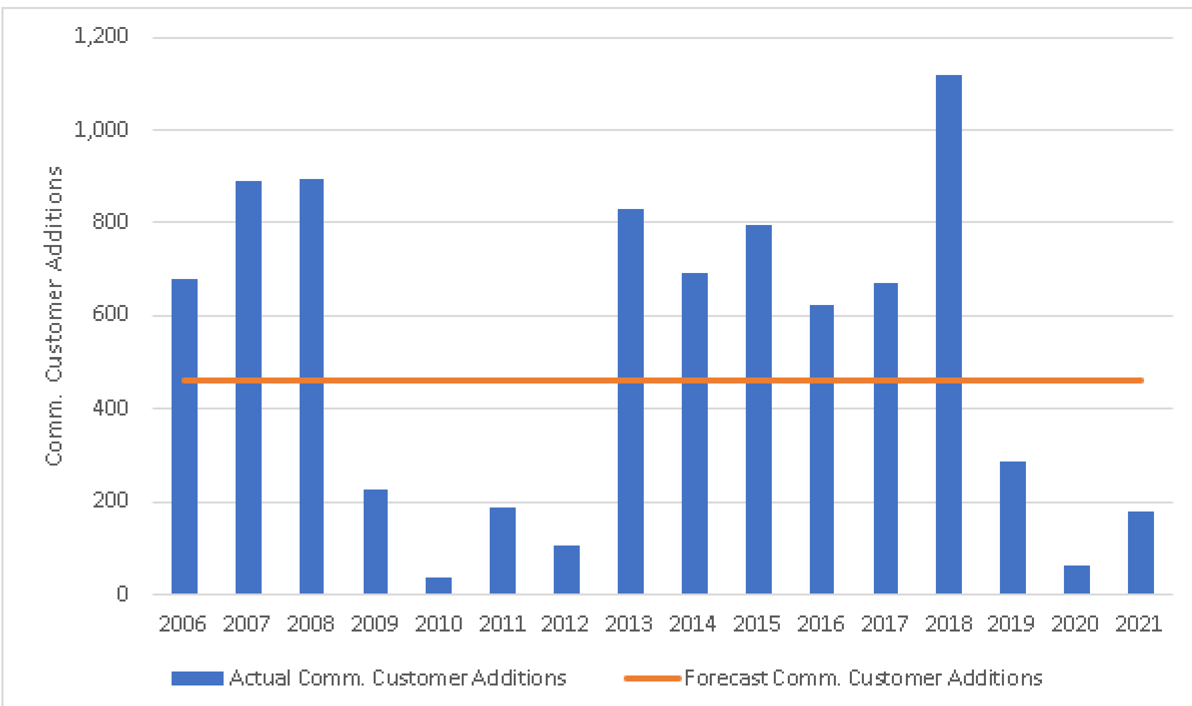
2. The customer forecast is the prior year-end customer total plus the forecast of additions.

3. For 2006 (for example), the forecast uses the 2005 year-end actual customer total (55,178) plus the customer additions forecast (460).

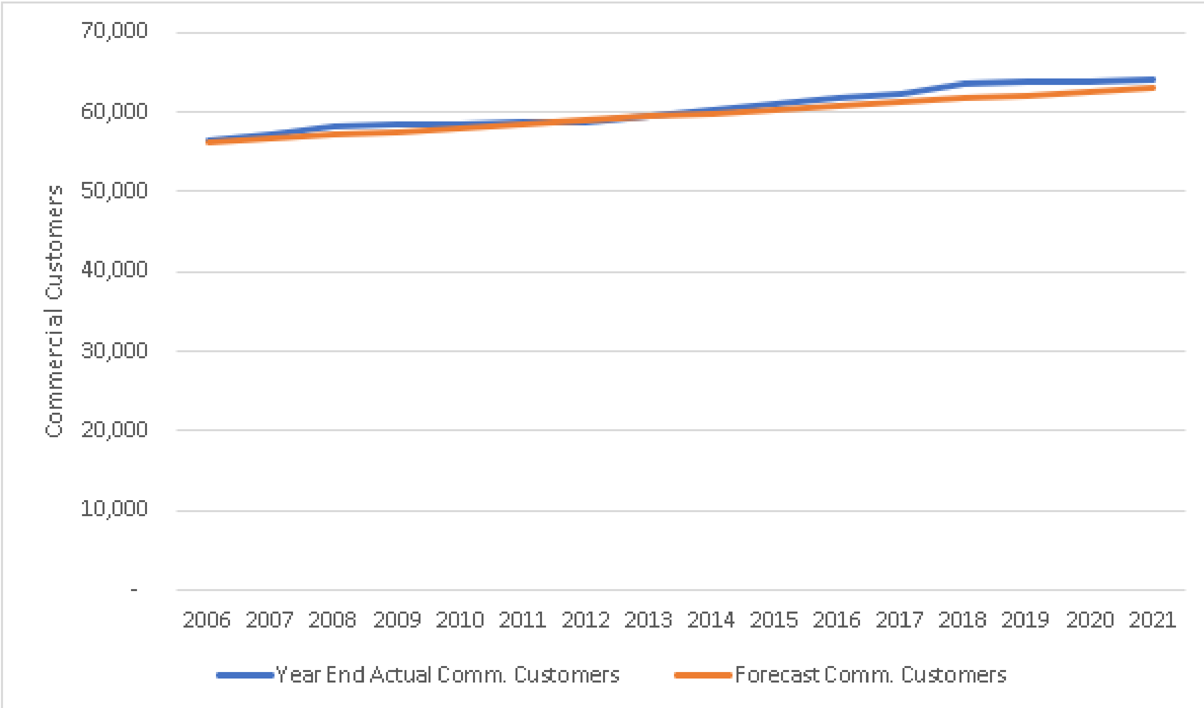
4. The commercial customer variance is calculated for the short, medium and long term. FEI notes there are no precise definitions for these timeframes so these specific year points are used for demonstration purposes. FEI notes that variances in the intervening years are similar.

As the results for this example show, the variances in the short, medium and long term are all very low. In the 16th year, the variance is only 1.4 percent.

The following figure shows the volatility of the actual number of customers compared to the three-year average forecast:



The following figure shows the actual commercial customer year-end totals compared to the forecast:



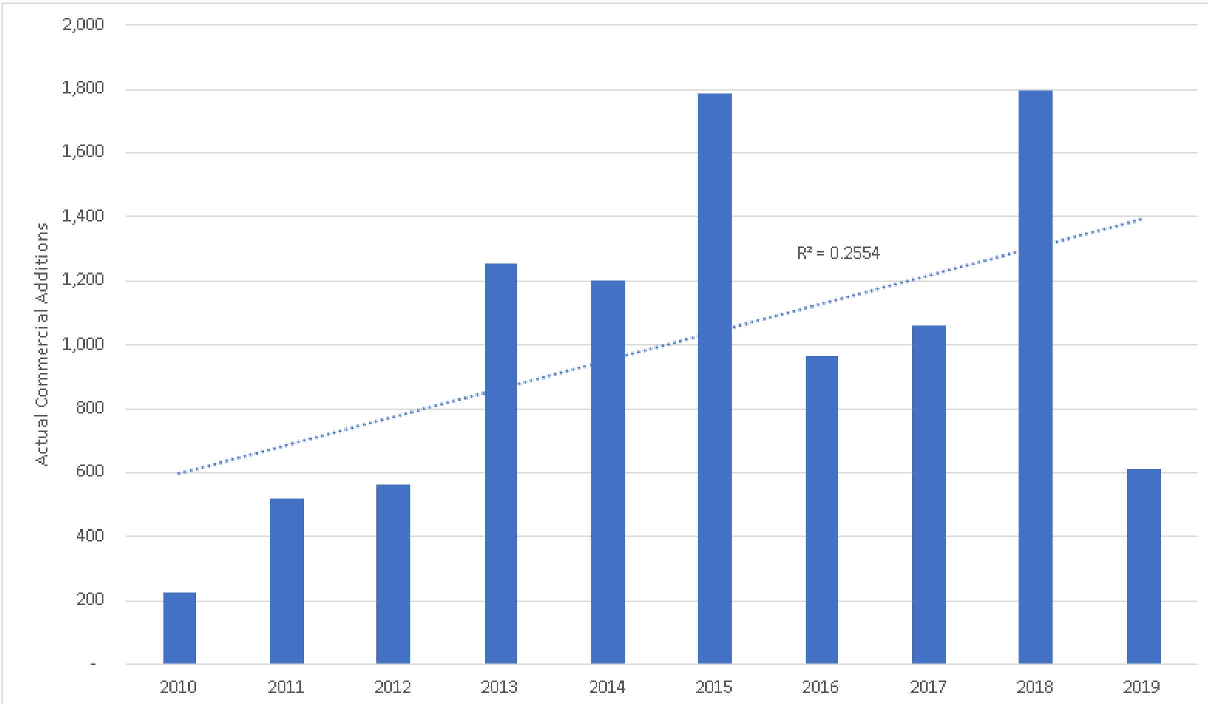
This simplified example shows how the year-over-year volatility in commercial customer additions can be approximated using a three-year average, and that the resulting forecast is reasonable in the short, medium and long term.

12.4 Please explain why the customer additions forecast is assumed to remain constant for the first five years.

Response:

The commercial customer additions are forecast to remain constant because there is no trend in the historical data as discussed below.

The following figure shows the recent 10 years of actual additions. The R^2 value of a trend line fitted through this data is very low at approximately 25 percent. As a result of the lack of trend, the method calculates the average additions and applies those additions for the five-year period.



12.5 Please provide an explanation of the methodology used to forecast commercial customer additions, including the use of the long term BC STATS household formation forecast. In the response, please explain the relationship between household formations and commercial customer counts.

Response:

Please refer to the response to BCUC IR1 11.1.

12.6 Please discuss the capabilities of the commercial customer forecast methodology in forecasting net customer additions over the short, medium and long-term.

Response:

Please refer to the response to BCUC IR1 12.3.

12.7 Please explain whether FEI has experienced a net increase or decrease in commercial customer numbers over the past 10 years.

Response:

In 2019, the actual commercial customer count was 96,530 customers. In 2010 the actual commercial customer count was 92,065 customers. FEI experienced a net increase of 4,465 commercial customers during the period from 2010 to 2019.

FEI Commercial Customers	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	Net Change
Actual	92,065	92,588	87,863	89,115	90,316	92,101	93,066	94,126	95,920	96,530	4,465

12.8 Please explain how the commercial customer forecast methodology accounts for any customer losses over the planning period.

Response:

The commercial customer forecast method is based on net customer additions. Net customer additions are defined as gross customer additions less customer losses. For example, if the gross customer additions were 100, and 50 customers left the system, then the net customer additions would be 50. The three-year average method is applied to the net customer additions so if losses are relatively high then then the future forecast will be relatively lower, all else equal.

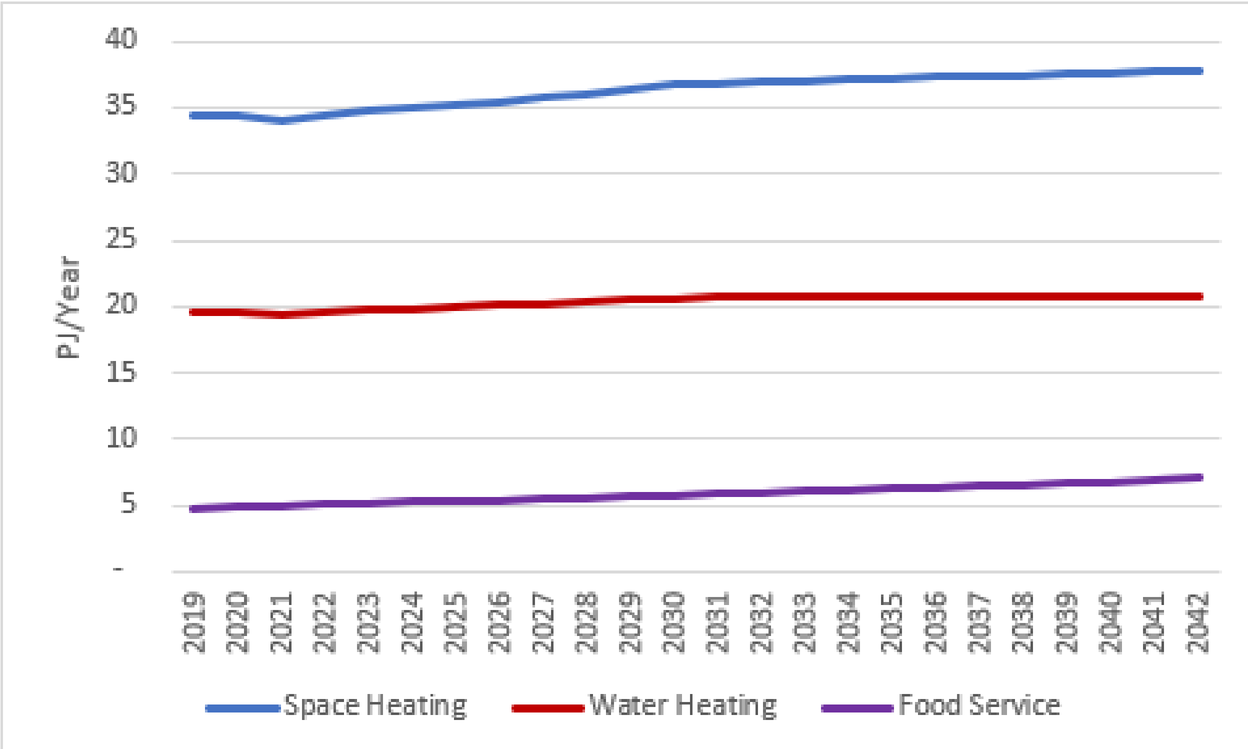
The net additions are calculated based on the average of the last three years of actual additions and used for the planning period. The customer forecast method does not include a separate customer losses forecast. The forecast is refreshed regularly, so if any customer loss trends develop they would be identified and included in subsequent forecasts.

12.9 In a format similar to Figure 4-11, please provide a graph showing the top end use for the commercial sector for the Diversified Energy (Planning) scenario.

Response:

The following figure shows the top end uses for the commercial sector for the DEP Scenario.

1 **Figure 1: DEP Annual Demand – Commercial Sector Top End Uses**



2

3

13.0 Reference: LONG-TERM CUSTOMER FORECAST METHOD AND RESULTS

Exhibit B-1, Section 4.3.1.3, p. 4-6; Appendix B-2, Section 5, p. 15

Industrial Customer Forecast

On page 4-6 of the Application, FEI states:

> The Company had 1,019 industrial customers at the end of 2019. At the time the long-term forecast was prepared, there were no firm commitments for new industrial customers to take conventional natural gas service or for existing customers to close their accounts. Hence, there is no forecast growth or decline in the industrial customer forecast.

Page 15 of Appendix B-2 to the Application states:

> Most organizations build their annual demand forecast for their large industrial customers from individual customer forecasts, which are often based on historical trends with adjustments that are based on customer feedback and future plans and economic forecasts.

13.1 Please provide the number of industrial customers as of September 2022.

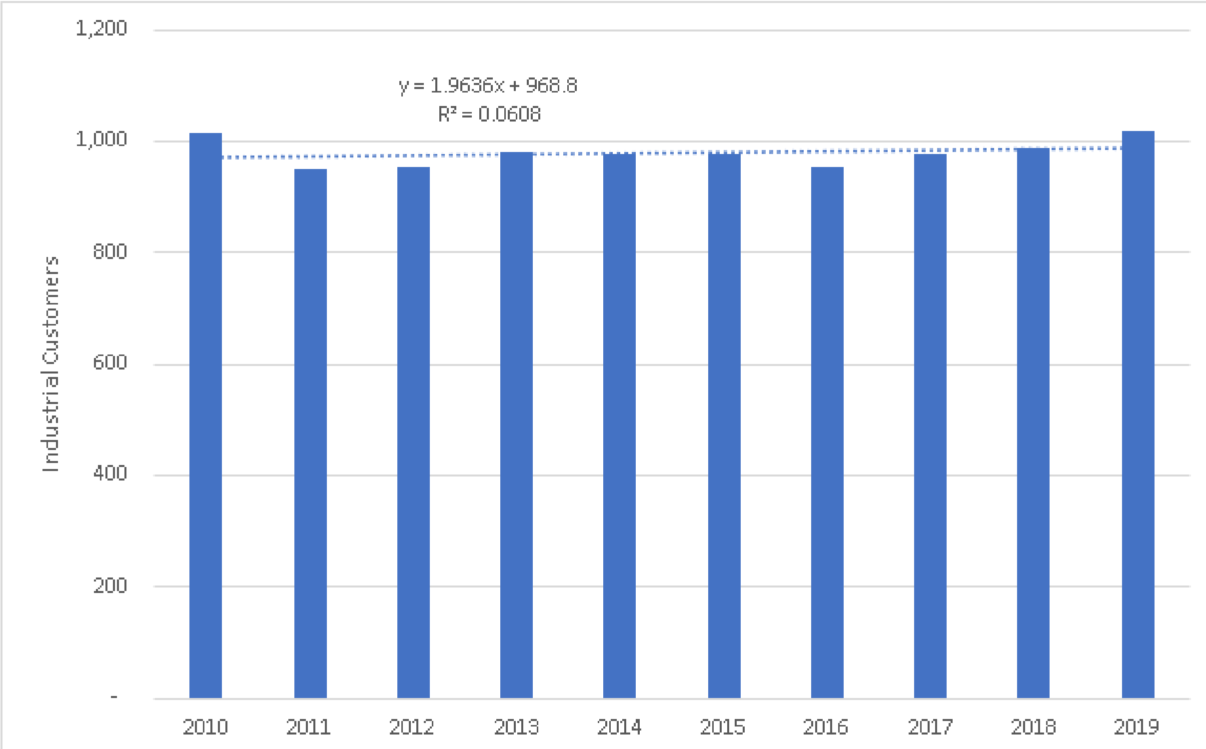
Response:

There were 1,029 industrial customers as of September 2022 month end.

13.2 Please provide the historical trend in the number of industrial customers for the last 10 years.

Response:

The LTGRP forecasts are based on actual data through 2019. The following figure shows the year-end industrial customer totals for the 10-year period ending in 2019. A trend line has been added and shows that, while the slope of the trend line is approximately +2 customers per year, the R^2 of approximately 6 percent indicates that time is a very poor predictor of customer growth.



13.3 Please explain whether FEI assessed the following, when developing the industrial customer forecast: (i) historical trends; (ii) adjustments based on customer feedback; and (iii) economic forecasts. If so, please provide details of the assessments and explain how they informed the forecast. If not, please explain why not.

Response:

FEI considered the three factors referenced in the IR when developing the industrial customer forecast and provides the following details of its assessments:

- As shown in the response to BCUC IR1 13.2, the historical trend is not usable for forecasting. The correlation between customers and years is very weak at just 6 percent.
- As discussed on page 4-6 of the Application, industrial key account managers were solicited for any new industrial operations that had made firm commitments to take conventional natural gas service or for existing customers to close their accounts. None were identified.
- As of 2019, FEI industrial customers operated in 79 different sectors, ranging from condominium strata councils to hospitals, pulp mills and coal mines. Due to the diverse

nature of the customers represented in the industrial rate classes, economic forecasts, such as GDP, cannot be used.

As a result of these assessments, FEI considers it reasonable to assume there would not be any growth or decline in the industrial customer forecast.

13.4 Please discuss why FEI considers it is reasonable to assume there will not be any forecast growth or decline in the industrial customer forecast, and explain whether this is consistent with historical trends.

Response:

Please refer to the response to BCUC IR1 13.3.

13.5 Please discuss whether FEI has considered any other methods for forecasting industrial customer numbers and if so, please explain why these methods were discounted.

Response:

FEI has not considered other industrial customer forecast methods. Please refer to the response to BCUC IR1 13.3.

14.0 Reference: LONG-TERM CUSTOMER FORECAST METHOD AND RESULTS

Exhibit B-1, Section 4.3.1.1, p. 4-4

Residential, Commercial and Industrial Customer Forecast

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

> It should be noted that considerations for future uncertainties around end use energy, such as potential for new large industrial demand, or potential for electrification, are addressed as part of the demand forecast and not as part of the customer forecast.

14.1 Please explain whether FEI has experienced a net increase or decrease in customer numbers for the residential, commercial and industrial sectors over the past 10 years.

Response:

As shown in the following table, FEI has experienced compound annual growth rates of approximately 1 percent in the residential class, approximately 0.5 percent in the commercial class, and approximately 0 percent in the industrial class.

FEI Customer Counts

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	CAGR
Residential	853,492	860,403	854,050	863,189	873,661	886,169	897,528	910,885	930,142	940,751	0.98%
Commercial	92,065	92,587	87,863	89,115	90,315	92,101	93,066	94,126	95,920	96,530	0.47%
Industrial	1,017	951	954	981	977	976	955	976	989	1,020	0.03%

14.2 Please discuss whether FEI forecasts any customer losses for the residential, commercial and industrial sectors over the planning period. If so, please discuss the main drivers for the customer losses. If not, please explain why not.

Response:

FEI's net customer additions forecast remains positive for all rate groups over the planning period.

As discussed in the response to BCUC IR1 11.8, the residential customer forecast is based on the housing starts growth rates forecast by the Conference Board of Canada (CBOC). The CBOC forecast of housing starts remains positive for the planning period and, as a result, the FEI residential net customer additions forecast is also positive.

As discussed in the response to BCUC IR1 12.8, the commercial net customer additions forecast is based on the most recent three years of actual net customer additions. As net customer additions have been positive in all of the last three years, the average and forecast is also positive.

As discussed in the response to BCUC IR1 13.3, FEI only forecasts reductions in the industrial customer count when customers are known to be leaving the system. At the time of the filing of the Application, no such customers were identified and, as a result, the industrial customer forecast remains unchanged from 2019 levels.

14.3 Please explain why future uncertainties around end use energy are addressed as part of the demand forecast and not as part of the customer forecast.

Response:

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

FEI has addressed these future uncertainties through its end use demand forecast modelling and not through its customer forecast because changing both customer additions and end use assumptions to address the same critical uncertainties in the scenarios would increase modelling complexity and the number of output permutations, while not increasing the value of the information provided by the overall demand forecast results.

FEI and Posterity Group prefer separating whether someone is a customer from what they use energy for, what fuel choices they make, and how much energy they use for each end use. The ability to model each of these considerations as separate model parameters provides a better understanding of what the customer's characteristics are and enhances the examination of changes to those characteristics. If energy use and customer numbers are all blended together into one parameter, understanding and testing the effects of specific changes is more difficult. As well, addressing a critical uncertainty such as fuel switching, for example, partially using assumptions about customer additions and partially through changes in energy end use patterns, would require additional checks and balances within the modelling to ensure that the impact of fuel switching on demand is not being double counted for any individual or group of customers.

14.3.1 Please explain whether FEI's forecast model can model future uncertainties around energy end use as part of the customer forecast.

14.3.1.1 If so, please explain why it is preferred to use the demand forecast and not the customer forecast.

Response:

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

While it is possible for changes to be made to the customer forecast, this approach is not recommended at this time for the reasons discussed in the response to BCUC IR1 14.3.

14.3.2 Please explain what impact, if any, using the customer forecast would have on the demand forecasts presented in the Application.

Response:

Please refer to the response to BCUC IR1 14.3.

14.4 Please discuss whether it is common practice for forecast models to use demand forecast as opposed to customer forecasts to address future uncertainties around energy end use.

Response:

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

The following excerpt from Appendix B-2 of the Application, "Long-Term Demand Forecasting Benchmarking Study on End-Use Methods, Industry Practices Review"[27], indicates that it is common practice to use end use demand modelling to examine future uncertainties in this way.

[27] Appendix B-2, Bikan Pourkarimi, P. Eng, "Long Term Demand Forecasting Benchmarking Study on End-Use Methods Industry Practices Review" (August 2020) at pp. 14-15.

The end-use models are often used to forecast use per customer, while econometric models are used to forecast growth in the number of customers. The rationale being that as energy efficiency and changes to

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energy and climate change policies become more prevalent, the future energy demand will look significantly different from historic energy demand. As a result, econometric regression models that relay on historic energy demand data are not necessarily suited for forecasting demand that is different from the past, whereas end-use models provide a much more detailed understanding of the impact of efficiency improvements and policy changes on energy demand and long-term forecasts, particularly in new construction and replacement of old equipment. Organizations that are considering switching from econometric models to end-use models are primarily driven by the need to prepare long-term forecasts for a future that could be considerably different from the past.

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.

In most cases, annual demand forecasts for residential and commercial customer classes are developed by multiplying the forecasted number of customers in each rate class by the average use per customer for that rate class. Economic forecasts from government agencies or other organizations are used to forecast the growth in number of customers. Average use per customer forecasts are based on either econometric models or end use models. Econometric models often use weather normalized historical consumption data and apply regression modeling to the data to forecast average use per customer. End-use models often use end-use data from end-use surveys to forecast average use per customer based on different end-uses.

14.4.1 Please provide details of any other utilities that use a similar method.

Response:

Please refer to the response to BCUC IR1 14.4 and Appendix B-2 of the Application.

15.0 Reference: LONG-TERM CUSTOMER FORECAST METHOD AND RESULTS

Exhibit B-1, Section 2.2, pp. 2-1 – 2-21; Section 9.2.3, p. 9-10; FEI System Extension Application (MX Test proceeding), Exhibit B-1, pp. 1, 36; Decision and Order G-147-16 dated September 16, 2016 (2016 MX Test Decision), Section 1.4, p. 5; FEI Biomethane Energy Recovery Charge Rate Methodology and Comprehensive Review of a Revised Renewable Gas Program proceeding (FEI BERC Rate proceeding), Exhibit B-11, Section 1.1, p. 2; BCUC Utility System Test Extension Guidelines, Section 8, p. 31

Main Extension Test

On page 1 of Exhibit B-1 in the FEI MX Test proceeding, FEI stated:

> The main extension test (MX Test, the Test, Economic Test or System Extension Test) serves as a practical means for determining whether a main extension to the Company's distribution system will be economic.

As outlined on page 5 of the 2016 MX Test Decision, in the MX Test proceeding, FEI sought approval, amongst other things, to discontinue the use of the 20-year term and instead apply a 40-year DCF [discounted cash flow] term in the MX Test. The amendment to the DCF term was approved by Order G-147-16, dated September 16, 2016.

On page 36 of Exhibit B-1 in the MX Test proceeding, FEI provided its rationale for seeking the amendment to the DCF term:

> The MX Test currently uses a 20 year DCF term which corresponds with FEI's Integrated Resource Plan[41] (IRP) planning horizon. This approach does not account for the full impact of the benefits of the system extension. The life of the main is a much more relevant DCF term benchmark, and it is consistent with the [BCUC Utility System Test Extension Guidelines] and common in the industry.

Section 2.2 of the Application provides an overview of the relevant policy and regulatory context facing FEI that impact future resource options, market prices, and influence customers' behaviour regarding energy use in the future. Further, on page 2-2 of the Application, FEI states that the "federal Liberal party committed to greater effort to meet and exceed the Paris targets, including a pledge to reach net-zero by 2050."

On page 9-10 of the Application, FEI states:

> FEI's existing gas delivery system will enable this transition from natural gas to renewable and low carbon gas in a number of different ways as outlined in Section 7, including the development of hydrogen hubs, the potential repurposing and upgrading sections of the existing gas grid to reliably supply clean, low-carbon hydrogen and the potential for dedicated hydrogen infrastructure.

On page 2 of Exhibit B-11 in the FEI BERC Rate proceeding, FEI states:

> FEI proposes a new Residential Gas Connections service under which FEI will permanently provide 100 percent Renewable Gas to new residential dwellings attaching to the system by a service line installed on or after the date of implementation of the service.

Page 31 of the BCUC Utility System Test Extension Guidelines states:

> The Commission recommends that the Utilities evaluate system extensions both from a social perspective, which applies a social discount rate, and a utility perspective, which applies a discount rate based on each utility's cost of capital.

15.1 With reference to the federal government's target of reaching net zero by 2050 and the relevant policy and regulatory context outlined in section 2.2 of the Application, please discuss what impacts, if any, these will have on the useful life of FEI's existing distribution infrastructure. In the response, please discuss the risks associated with stranded assets.

15.1.1 Please discuss, with rationale, whether the 40-year DCF term remains appropriate for FEI's MX Test.

Response:

FEI acknowledges that the policy and regulation landscape has changed substantially in recent years, as described in the various references noted in the preamble to this question. However, these changes to policy and regulations do not envision or prescribe an effective end in BC to energy delivery using the gas system. A net zero target relating to GHG emissions is not the same as not utilizing the existing gas system and related assets. FEI views these changes as an opportunity to evolve the energy delivery service provided through FEI's gas system to ensure that the system remains an integral component of the energy landscape in a future of net zero GHG emissions. FEI is confident that this can be achieved as outlined in the Clean Growth Pathway, described in more detail in Section 3 of the Application. FEI's gas system assets will continue to be used and useful in a low-carbon or net zero GHG emission future, which limits the risks associated with stranded assets. For the same reason, the 40-year discounted cash flow term used in the MX Test remains appropriate at this time.

15.2 In consideration of future capital costs required to transition from natural gas to renewable and low carbon gas, such as costs associated with dedicated hydrogen infrastructure, please discuss whether FEI anticipates including these capital costs s in its MX Test. If no, please explain why not.

Response:

Although FEI, along with utilities in other jurisdictions and entities conducting research, continues to advance a range of activities to study, test and verify the use of hydrogen in the existing gas system, FEI is currently not able to determine to what extent the existing gas system will need to be modified for hydrogen or how much dedicated hydrogen infrastructure will be needed. As such, FEI is, at this time, unable to comment if any costs related to hydrogen would be included in the MX Test. Should such costs arise, the system improvement component of the MX test might be an appropriate mechanism for inclusion of those costs, depending on their nature.

However, regardless of whether or not costs related to hydrogen are included in the MX Test, FEI is not expecting any changes will have to be made to the MX Test itself. The MX Test is a planning tool that compares the present value of the estimated delivery margin to be recovered from new customers against the present value of the estimated capital and O&M costs of the proposed extension (i.e., the costs of the mains, services, and meters to connect the new customers), which could be for assets that flow conventional gas or hydrogen or a mix of both. As long as the present value of the incremental delivery margin recovered exceeds the present value of capital costs,[28] then the new extension will be a net benefit to all customers. Neither the intent nor use of the MX Test changes due to the type of fuel flowing in the system. Nonetheless, if FEI determines that changes to the MX Test are required in the future, whether it is for hydrogen or other reasons, FEI will file such changes with the BCUC for review and approval.

15.3 If the Renewable Gas Connections service is approved, please discuss whether FEI anticipates updating its MX Test to reflect the costs associated with providing a 100 percent renewable gas to all new residential customers. If not, please explain why not.

Response:

The MX Test does not need to be updated to reflect the costs of renewable gas as part of the Renewable Gas Connections service, if it is approved.

As discussed in the response to BCUC IR1 15.2, the MX Test is a tool used to determine if the estimated incremental delivery margin recovered from the potential new customer exceeds the capital costs required to connect the new customer, thus resulting in an overall benefit to all customers through rates. As explained in Section 8 of FEI's Comprehensive Review and Revised Renewable Gas Program Application (Exhibit B-11 of FEI's BERC Rate Proceeding), the costs associated with the proposed Renewable Gas Program, including the Renewable Gas Connections service, will be captured by the proposed LCG Account and will be recovered through a commodity recovery rate named the LCG Charge as well as a storage and transport rider named the S&T LC rider. Similar to the existing commodity cost recovery charge and storage

[28] Individual main extensions must meet a minimum Profitability Index (PI) of 0.8 whereas the aggregate of all MX Tests in a calendar year must be at or exceed a PI of 1.1.

and transport charge, the costs for renewable gas are not infrastructure costs (part of FEI's delivery margin) and, therefore, are not included in the MX Test. As RNG is methane and therefore interchangeable with FEI's conventional natural gas supplies, there are no additional capital costs for providing it to customers instead of natural gas, and therefore no impact on the MX Test.

15.4 Please discuss whether FEI anticipates updating the MX Test to include societal costs, such as the carbon tax. If not, please explain why not.

Response:

FEI is not anticipating nor intending to change the MX Test to include societal costs, such as the carbon tax.

As explained in the responses to BCUC IR1 15.2 and 15.3, the purpose of the MX Test is to determine if the potential customer brings an overall benefit to FEI's delivery rates. Although societal costs, such as carbon tax, have an impact on customers' cost of energy, these costs are not part of FEI's delivery margin and have no impact on customers' delivery rates. For example, the carbon tax is a pass-through cost to customers and not part of the utility's cost of service, i.e., it is not a capital, operating or incremental cost to the existing cost of service for FEI to connect the new customer.

15.5 If FEI intends to update its MX Test to incorporate any of the changes referenced in the preceding IRs, or any other changes identified by FEI, please provide details of any changes currently being considered.

15.5.1 If so, please explain when FEI expects to update the MX Test.

15.5.2 If not, please explain why not.

Response:

Please refer to the responses to BCUC IR1 15.1 through 15.4. FEI currently does not have any plans to update or make any other changes to the MX Test.

15.6 If FEI intends to update the MX Test, please discuss what impact, directionally, the update may have on: (i) the cost of connection for new customers; and (ii) the customer forecast.

Response:

Please refer to the response to BCUC IR1 15.5.

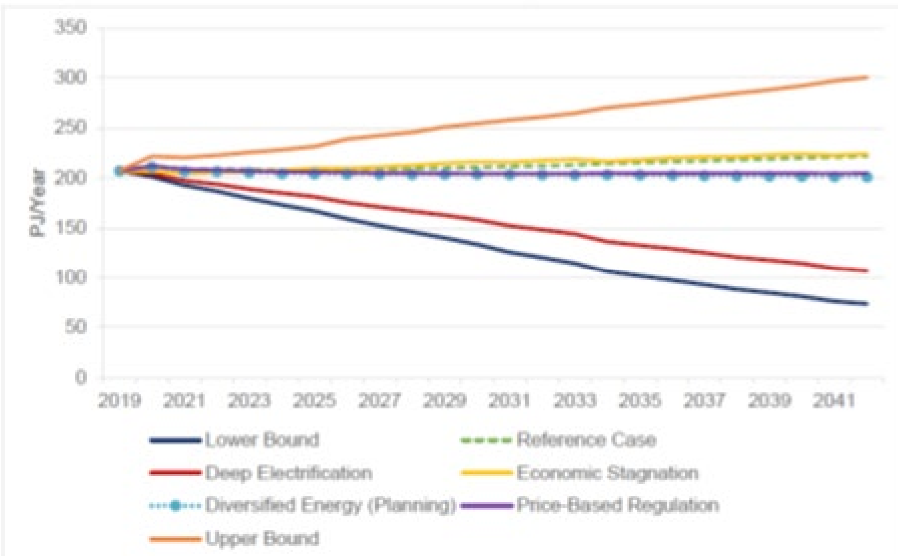
16.0 Reference: DEMAND SCENARIO RESULTS

Exhibit B-1, Section 4.6.1, p. 4-28

Impacts of Lower Load Scenarios

On page 4-28 of the Application, FEI provides the following figure which shows the range of demand scenarios for the Residential, Commercial and Industrial sectors:

Figure 4-9: Annual Demand Scenarios – Residential, Commercial and Industrial Sectors



16.1 In a scenario where load to Residential, Commercial and Industrial sectors were to decline (for example, the Deep Electrification scenario), please discuss the stranded asset risk resulting from customers losses.

16.1.1 Please discuss whether FEI considers there would be a material difference in stranded asset risk and cost if customers losses were to occur in a uniform manner across the FEI system, vs. customer losses being concentrated in certain geographic locations.

16.1.2 Please discuss whether FEI has considered any actions to monitor or mitigate such risks.

<u>Response:</u>

The risks to FEI under the Deep Electrification Scenario have been discussed extensively in FEI's evidence as part of the BCUC Generic Cost of Capital (GCOC) Proceeding.[29] Such a scenario likely will result in significant underutilized capacity of FEI's gas system (i.e., stranded asset risk). The loss of customers could occur in a uniform manner across the FEI system, or could be concentrated in certain geographic locations due to factors such as local government policy to reduce GHG emissions which impact the continued use of natural gas.

[29] Exhibit B1-8 and B1-8-1 of BCUC GCOC Proceeding.

As indicated in the response to BCUC IR1 10.2 of the GCOC Proceeding, one approach that FEI could take in the event of a decline in the use of FEI's delivery system for natural gas would be to develop pathways to pay for the early retirement of assets, such as accelerated depreciation. However, as stated in the response to BCUC IR1 47.2 of the GCOC Proceeding, a major drawback of accelerated depreciation methods is that the annual depreciation expense would not represent the true consumption patterns of assets and may create intergenerational inequities. Further, FEI would be required to seek the recovery of its costs from a progressively declining customer base, disproportionately increasing rates for remaining customers, many of whom may remain connected to the gas system because they cannot afford to fuel switch. The higher rates would jeopardize FEI's ability to pursue initiatives that could reduce its customers' GHG emissions and could lead to a downward demand spiral, as well as reduced natural gas competitiveness and province-wide energy affordability.

A better approach for FEI's customers is to manage the risk of stranded assets by developing alternative energy products and services that leverage existing assets while also reducing emissions, which is consistent with FEI's DEP Scenario as presented in this Application. As discussed throughout the Application, FEI's DEP Scenario plans to meet provincial emission reduction targets through accelerating its renewable and low-carbon gas supply, supporting the decarbonization of buildings through DSM activities, and growing customer demand in sectors that reduce GHG emissions. FEI's Clean Growth Pathway maintains a prominent role for FEI's infrastructure in achieving GHG reductions in alignment with the Province's objectives.

As such, FEI is not currently considering accelerated depreciation, as pursuing the early retirement of assets is conceptually at odds with the development of alternative products and services using those assets. FEI will continue to monitor the appropriateness of adopting accelerated depreciation methods as a pathway to mitigate stranded asset risk. This position was also expressed in the GCOC Proceeding.[30]

16.2 Please confirm, or explain otherwise, that in lower load scenarios (such as the Deep Electrification scenario), FEI assumes some new customers continue to be added to the system.

Response:

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

Confirmed. The Deep Electrification Scenario does include some new customers, as do the other low load scenarios. The following table shows the number of customers in the Deep Electrification Scenario by rate class and year. The number of customers is assumed to grow in the residential sector and in some commercial rate classes, while it is assumed to shrink in some of the industrial rate classes.

[30] Responses to BCUC IR1 10.2, 47.1, 47.2.

Year	RATE1	RATE2	RATE3	RATE23	RATE4	RATE5	RATE25	RATE6	RATE7	RATE27	RATE22	COMPANY_USE	HEATER_FUEL	TPT-1	TPT-2
2019	942,769	89,023	6,987	867	15	539	519	5	46	102	50	79	185	6	2
2020	944,540	87,601	6,896	815	4	518	442	4	45	95	46	78	184	6	2
2021	951,806	88,119	7,077	827	4	512	437	4	45	95	46	78	184	6	2
2022	958,311	88,628	7,263	847	3	506	432	4	45	94	46	78	184	6	2
2023	964,200	89,133	7,448	864	2	501	422	3	45	93	44	78	184	6	2
2024	969,655	89,642	7,635	875	1	497	414	3	44	93	44	78	184	6	2
2025	974,644	90,141	7,834	891	1	492	409	3	44	89	44	78	184	6	2
2026	979,303	90,649	8,030	915	1	489	402	3	44	87	40	78	184	6	2
2027	983,715	91,136	8,245	939	1	478	393	3	44	84	40	78	184	6	2
2028	987,779	91,631	8,458	964	1	468	384	3	44	81	40	78	184	6	2
2029	991,740	92,131	8,690	984	1	466	377	3	44	80	40	78	184	6	2
2030	995,502	92,620	8,915	1,004	1	460	370	3	42	78	39	78	184	6	2
2031	999,231	93,099	9,141	1,031	1	457	357	3	42	78	35	78	184	6	2
2032	1,002,653	93,596	9,383	1,056	1	450	351	3	42	77	35	78	184	6	2
2033	1,005,745	94,085	9,622	1,089	1	443	342	3	42	71	35	78	184	6	2
2034	1,008,839	94,565	9,863	1,120	1	436	339	3	42	70	30	78	184	6	2
2035	1,011,961	95,044	10,112	1,152	1	431	334	3	42	70	30	78	184	6	2
2036	1,014,583	95,507	10,367	1,184	1	425	326	3	42	70	30	78	184	6	2
2037	1,017,240	95,958	10,617	1,217	1	425	321	3	42	68	29	78	184	6	2
2038	1,019,758	96,388	10,861	1,244	1	422	313	3	42	67	28	78	184	6	2
2039	1,022,149	96,806	11,115	1,280	1	420	304	3	42	67	28	78	184	6	2
2040	1,024,423	97,208	11,357	1,317	1	417	297	3	42	66	26	78	184	6	2
2041	1,026,691	97,625	11,607	1,345	1	415	283	3	42	66	23	78	184	6	2
2042	1,028,963	98,017	11,864	1,380	1	414	268	3	42	66	22	78	184	6	2

In FEI's demand forecast modelling, decreases in demand due to electrification or other conditions are examined through adjustments to customer end-use rather than through alternative customer additions forecasts. Please refer to the response to BCUC IR1 16.1.

16.2.1 In such a scenario, please discuss the risks associated with such new customers connecting to the system, only to leave the system at a later date in the planning horizon (e.g. in response to more stringent GHG emissions requirements towards 2050).

Response:

In the scenario where a new customer connects to the system, only to leave at a later date in the planning horizon in response to a more stringent GHG emissions requirements towards 2050, FEI faces an increased risk of stranded assets for assets that were installed to service the customer. This may include assets directly related to providing service to the customer (i.e., service line, meter) and in some cases, capacity upgrades to FEI's delivery system to ensure sufficient gas supply.

However, as discussed in the response to BCUC IR1 16.1.2, FEI is taking actions to mitigate this risk. For example, FEI's proposed Renewable Gas Connections offering as part of the Comprehensive Review and Revised Renewable Gas Program Application includes the proposal that all new residential connections will receive 100 percent RNG, including new construction activity, conversions and retrofits. This will comply with municipal regulations (and proposed changes to the BC Building Code) which impose limitations on GHG emissions for new residential construction. The Renewable Gas Connections service also meets the CleanBC Roadmap objectives for new connections. Building regulations and policy dictate many aspects of the design of new buildings. FEI's Renewable Gas Connections offering responds to changing building emissions policies and creates a viable solution for builders and homeowners to continue to choose gas as their energy source.

From the utility and customer perspective, maintaining access to the gas system for new residential connections is central to the long-term viability of the utility, while also utilizing the assets of the utility more efficiently and keeping rates affordable for all customers. Adding customers helps to better utilize existing utility assets while bringing on additional revenue through the new residential construction market.

16.2.1.1 Please discuss whether FEI has considered any actions to mitigate such risks. Please include in your answer the potential role of system extension and customer connection policies.

Response:

Please refer to the response to BCUC IR1 16.1 for a discussion of actions that FEI is taking to mitigate the risk of stranded assets. Please also refer to the response to BCUC IR1 16.2.1 for discussion specifically related to new customers connecting to the system.

As to the role of system extension and customer connection policies in mitigating the risk of stranded assets, they can play an important role in promoting the continued use the province's gas infrastructure by supporting the adoption of alternative energy products and services that leverage FEI's existing assets while reducing their lifecycle carbon intensity. This is consistent with the guiding principles for the objectives of the system extension and customer connection policies.

In the FEI 2015 System Extension Application, based on stakeholder consultation, five guiding principles concerning the objectives of the system extension and customer connection policies were developed. One of the objectives was to "Support Government Objectives", which include the importance of natural gas in sustaining and growing BC's economy, encouraging the creation and retention of jobs through the use of natural gas, and reducing GHG emissions. With the introduction of the CleanBC Plan in 2018, reducing GHG emissions and moving to a decarbonized environment have been an important priority of the provincial government. Enhancing the system extension and customer connection policies to encourage adoption of alternative energy products and services using FEI's gas delivery system would be consistent with the guiding principle "Support Government Objectives" which encompass reducing GHG emissions.

17.0 Reference: LONG-TERM CUSTOMER FORECAST METHOD AND RESULTS

Exhibit B-1, Section 4.4.1.2, p. 4-9, Section 4.4.1.3, pp. 4-10 – 4-11; FEI 2017 LTGRP proceeding, Exhibit B-2,BCUC IR 16.2.

End Use Annual Method of Demand Forecasting for the Residential, Commercial and Industrial Demand

On page 4-10 of the Application, FEI states:

> The End Use Annual Method forecast process starts with developing a Reference Case forecast. 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 and have been, or are quite certain of becoming, enshrined in legislation, codes, standards or bylaws in and as of the base year. The Reference Case keeps these patterns constant throughout the planning period.

17.1 Please provide details of the new changes in law or policy that have been included in the Reference Case.

Response:

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

As explained in Section 4.4.1.3 of the Application, the Reference Case incorporates laws and policies that affect energy use. Because the Reference Case was developed in 2019, it reflects what was enshrined, and was likely to become enshrined, in law at the time. Expected changes in relevant laws or policies incorporated in the Reference Case are described below based on the applicable Critical Uncertainties:

- New construction code: When the Reference Case was developed, it was anticipated that in 2022 the BC Energy Step Code levels would become requirements under the BC Building Code, as the CleanBC Plan had 2022 as its target implementation date. To reflect this expected change, the Reference Case assumes the associated Steps are adopted according to the target deadlines.[31]
- Appliance standards: The Reference Case assumes that the 2019 in-market mandatory or legally-enshrined appliance standards continue across the entire forecast period.
- Carbon price: The Reference Case trajectory assumes the carbon tax is held constant once the maximum announced value (as of the time the settings were determined) was reached and held constant throughout the planning horizon.[32]
- LNG and CNG: The Reference Case assumes that incentives supporting LNG and CNG infrastructure under the GGRR will be extended to beyond 2030.

[31] The specific assumptions are provided in Table B3-2, Appendix B-3 of the Application.
[32] For details on the BC Carbon Tax, please see Section 2.2.2.2.1 of the Application, pp. 2-9.

17.2 Please elaborate further on the statement that end use patterns observed are kept constant throughout the planning period and explain why the patterns are kept constant.

Response:

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

The Reference Case includes those trends, regulations and policies that are known at the time the analysis is undertaken, or are very certain to come to pass. These considerations are then held static through the planning horizon. This condition of the Reference Case therefore provides a reference point from which to model and compare other scenarios, with other Critical Uncertainty settings.

For example, for a given building type, the Reference Case does not include changes in the percentage of customers applying an end use (e.g., the percentage of customers who have a fireplace) or the fuel shares for the end use (e.g., the percentage of fireplaces that burn gas). The effects of Critical Uncertainties that affect fuel choice modelled in other scenarios are more easily seen against this baseline.

However, the unit energy consumption for the end uses is not assumed to be constant since that would ignore both the codes, standards, standard building practices and purchasing patterns in effect. Instead, the Reference Case includes assumed rates of building renovations, equipment stock turnover and replacement by new equipment that meets the standard, and the natural rate of adoption of efficiency measures. The effects of Critical Uncertainties that change codes and standards, or that include increased DSM program activity modelled in other scenarios, are more easily seen against this baseline.

In the Reference Case, new buildings are assumed to have different end use patterns than the corresponding existing buildings. As an example, the Residential End Use Survey data could be segmented by building vintage, enabling FEI to estimate the percentage of new homes with fireplaces and the percentage of those that burn gas, as compared to the values for older existing buildings. The unit energy consumption of most end uses in new buildings also tends to be lower, because of better building envelopes and newer, more efficient equipment. The Reference Case usage per customer is accordingly not static, but rather decreases as more new construction occurs. The Critical Uncertainties that affect new construction in other scenarios can be easily seen against this baseline through variation in use per customer and overall demand.

17.2.1 Please explain whether natural changes in average appliance efficiencies across the planning period are included in the Reference Case.

Response:

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

Natural changes in average appliance efficiencies across the planning period are included in the Reference Case. The Reference Case assumes an average life expectancy for the equipment serving each end use. As stock turns over, it is assumed to be replaced by new equipment that meets or exceeds the codes and standards that are expected to be in force in the year of turnover. The future changes to codes and standards that were known at the start of the study were included.

Equipment buyers purchase a range of equipment, with some buying equipment that barely meets codes and standards, and others buying equipment that performs better than the minimum, to varying degrees. This pattern is assumed to continue in the Reference Case.

On page 4-11 of the Application, FEI states: “Anticipated changes in the saturation and gas shares for specific end uses were also included.”

17.3 Please elaborate further on the anticipated changes in saturation and gas shares for specific end uses over the planning period.

Response:

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

The Reference Case includes no assumed changes in end use saturation for a given type of building. Fuel shares in the Reference Case change as the reference amounts of RNG and hydrogen displace conventional natural gas. The sum of these three fuel shares remains unchanged from the initial fuel share for gas.

The Reference Case includes different assumptions for saturation and gas shares in new buildings than in the corresponding existing buildings. For example, the saturation and gas share of fireplaces in new dwellings was based on the data from the Residential End Use Survey on the newest vintage of homes and were therefore different than the saturation and gas share of fireplaces in the average existing home. Therefore, as this proceeds through the study period, the overall average saturations and gas shares of various end uses do evolve as more new construction occurs.

Further on page 4-10 Application, FEI states:

> FEI and Posterity used the following data sources to calibrate[139] the forecast model to FEI's 2019 base year actuals and to identify Reference Case end use changes across the forecast horizon:
>
> 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.
>
> 139 The calibration process ensures that the sum total annual gas demand of all base year end uses in the End Use Annual Method demand forecast model matches FEI's base year actuals.

In response to BCUC information request (IR) 16.2 in the FEI 2017 LTGRP proceeding, FEI stated:

> FEI intends to conduct End-use Surveys every two to three years. The Residential End-use study takes approximately 30 months from start to finish, while the Commercial End-use study takes approximately 24 months.

17.4 Please explain how the above noted data sources are used to calibrate the forecast model.

Response:

The following response has been provided by Posterity Group.

The forecast model's base year was calibrated to FEI's 2019 actual data. The future years in the forecast model were not calibrated. Each sector was calibrated somewhat differently, because the data sources were not the same, so the following discussion is separated by sector.

Residential

The accounts data were based on the regional numbers of accounts from FEI's 2019 actual data. We used data from the 2017 REUS to subdivide the regional totals into numbers of houses by predominant heating fuel and by vintage. Each account was assumed to be associated with one dwelling, assuming that accounts with more than one dwelling and dwellings with more than one account would roughly cancel out.

End use saturation and fuel share values were drawn from the 2017 REUS. For Unit Energy Consumption (UEC), we started with UEC values from 2017 LTGRP, which had a base year of 2015. We calculated the change in space heating UEC between 2015 and 2019 based on the natural replacement of heating equipment and the efficiency of the replacement equipment. A similar process was used for other end uses. In the case of domestic hot water, the natural changeover of clothes washers and dishwashers was included in the calculation, because newer versions of these appliances use substantially less hot water.

The total consumption for each region was then compared to the 2019 actual data. We adjusted each region's total by applying a factor to the space heating UEC. On average, the overall adjustment was only about 2 percent, but some regions required more adjustment than others. Space heating UEC was chosen for adjustment because it is the largest end use and because there is more uncertainty about its value than there is about UEC for appliances like a clothes dryer or range.

Commercial

The accounts data were based on numbers of accounts from FEI's 2019 actual data, which were segmented by municipality, rate class and North American Industry Classification System (NAICS) code. We assigned accounts to commercial segments based on a mapping of NAICS code. We assigned accounts to the LTGRP region based on a mapping of municipalities to the LTGRP regions. We did not change the rate class.

Saturation for space heating, service hot water, food service, and other gas was 100% for all segments. Saturation of pools was based on the 2019 Commercial End Use Study. Fuel share estimates were based on the 2017 LTGRP.

We calculated 2019 UEC values based on the 2017 LTGRP UEC values, estimating the change between 2015 and 2019 using a similar approach to that used for the residential sector.

The product of saturation, fuel share and UEC gives the Energy Utilization Index (EUI) for each end use, per square metre of floor space. Summing the EUIs for all the end uses provides a whole facility EUI per square metre. In the commercial sector model, building units are in square metres of floor space. The product of building units multiplied by whole facility EUI is the total gas consumption for each group of buildings (region, rate class and segment). The total gas consumption is a known value from the 2019 actuals. In general, commercial floor area is a difficult value to estimate with confidence, and the numbers going into the calculation of whole facility EUI have much less uncertainty.

To calibrate the commercial model, therefore, we divided the 2019 actuals for each group of buildings by the whole facility EUI for those buildings, giving an estimate of the floor area. Using the floor area values in the commercial model produced an exactly calibrated base year.

Industrial

The accounts data were based on numbers of accounts from FEI's 2019 actual data, which were segmented by municipality, rate class and NAICS code. We assigned accounts to industrial segments based on a mapping of NAICS code. We assigned accounts to the LTGRP region based on a mapping of municipalities to the LTGRP regions. We did not change the rate class.

Saturation for each end use was either 0% or 100%, depending on whether it was applicable to a given segment. Fuel share estimates were based on the 2017 LTGRP.

We used the EUIs from the 2017 LTGRP to calculate UEC by region, segment and end use. The building units for the industrial sector are in units of total base year GJ. We considered using industrial production as the unit of analysis instead, but this data are more difficult to obtain and many more segments would be required so that each segment did not include an impossible mixture of products. In any case, since base year total GJ is the unit of analysis, the sum of the end use EUIs in the base year is always 1 GJ per unit for all segments. We divided the EUI into fractions based on the end use breakdown from the 2017 LTGRP and divided by the fuel shares to obtain the UEC.

The product of saturation, fuel share and UEC gives the EUI. The end use EUI values roll back up to 1 GJ per unit. Multiplying those values by the number of units gives the base year consumption. Therefore, using these values of UEC in the industrial model produced an exactly calibrated base year.

17.5 Please explain why the Residential End Use Survey (REUS) has not been updated since 2017.

Response:

The REUS/CEUS cycle elapsed time is approximately four to five years. The 2017 cycle started in October 2017 and, as a result, the next cycle, which includes the 2022 REUS study, was not available in time to inform the end-use demand forecast for the 2022 LTGRP.

The 2017 REUS was in the field from October 2017 through January 2020 (approximately 30 months). Actual data through year-end 2019 was used to inform the 2022 LTGRP, and was, therefore, well aligned with the 2017 REUS that had just completed.

17.5.1 Please provide the frequency at which FEI updates its REUS and explain when FEI will undertake the next update.

Response:

FEI conducts the REUS on a four- to five-year schedule. The survey portion of the latest REUS was conducted between June 20 and August 7, 2022. FEI expects the report will be available in time to inform the next LTGRP.

17.6 Please discuss the typical period of validity for a REUS and explain what impact a more recent REUS would have upon the reliability of the demand forecast.

Response:

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

The REUS collects data regarding natural gas uses including space and water heating and cooking appliances. The survey also collects data on dwelling characteristics which impact energy consumption. Results from the Residential End Use Studies conducted in 2008, 2012 and 2017 indicate that changes in heating fuels, appliance types and dwelling characteristics, such as the replacement of windows, are not significant and do not pose a significant risk to the validity of REUS data based on the current schedule. Changes driven by legislation, such as the establishment of heating equipment minimum-efficiency standards can pose a greater risk; however, that risk is mitigated by the use of a multi-scenario planning approach which incorporates different assumptions about how the market will shift from the base-year assumptions derived from the REUS data.

17.7 Please elaborate further on the research and data analysis from the 2017 LTGRP used to calibrate the forecast model.

Response:

The following response has been provided by Posterity Group.

Please refer to the response to BCUC IR1 17.4, which describes the values from the 2017 LTGRP and approach that were used to calibrate the base year of the forecast model.

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

> Further, while such utilities do tailor the end use modelling to address the specific challenges they are facing over the planning horizon, the FEI modelling includes the key components that are common to all of the end use modelling practices examined as part of the study.

17.8 Please explain whether FEI has tailored the end use model to address specific challenges it may be facing over the planning period.

Response:

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

FEI's end use demand forecast modelling is designed to address a wide range of potential challenges by adjusting the Critical Uncertainties and Critical Uncertainty settings. The review and development of the Critical Uncertainties is completed early in the resource planning process cycle and identifies those factors that are expected to have meaningful impact on the demand forecast. Please see Section 4.5.2 (p. 4-18) and Appendix B-3 of the Application for more detailed information on how the Critical Uncertainties are developed and used in modelling alternative long-term gas demand forecasts. As described in the Application, the end use model is inherently designed to address both specific and general challenges FEI expects it will face over the planning horizon.

17.8.1 Please provide a list of the specific challenges that FEI expects to face over the planning period and explain what changes it has made to the end use model to address these challenges. In the response, please explain how these changes address the challenges identified.

17.8.2 If no changes have been made, please explain why not.

Response:

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

The table below presents new key challenges that are expected over the planning horizon that have emerged for the 2022 LTGRP and that were not previously modelled. FEI also presents any related adjustments that have been made to the end use demand forecast modelling. New challenges that may have emerged after the completion of the demand forecast modelling for the 2022 LTGRP will be addressed in the next LTGRP.

Table 1: End Use Annual Demand Forecasting Key Challenges and Modelling Adjustments for the 2022 LTGRP

New Key Challenges for the 2022 LTGRP	Related Modelling Adjustments
The urgency to decarbonize the use of gas in BC on behalf of customers and related advancement of government policy and regulation: - GHGRS Emissions Cap - Step Code Advancement - Clean fuel standards - Increased carbon price (tax)	• Added the City of Vancouver as its own region in the model (the 2017 LTGRP model had the City of Vancouver embedded in the Lower Mainland region). This enabled modelling building codes in the City of Vancouver, which tend to be stricter than what is applicable to the rest of the province. • In addition to the Reference Case and several other scenarios, modelled the DEP Scenario that has the objective of meeting the GHGRS Emissions Cap. • Used lifecycle emission factors to estimate GHG emissions and reductions. • Considered higher levels of supply availability of renewable and low-carbon gas.
Growing international demand for LNG.	• Modelled 'LNG Export' to differentiate between LNG used domestically in BC.

New Key Challenges for the 2022 LTGRP	Related Modelling Adjustments
Expanding opportunities for FEI to help reduce global GHG emissions not accounted for in BC.	• The LNG demand for 'LNG Export' was assumed to displace coal which presents a GHG reduction opportunity outside of BC. • Modeled LNG fuel for trans-Pacific shipping.
The emergence of alternative pathways (electrification or a diversified pathway) to decarbonize energy use in BC.	• Modelled several scenarios, including the Deep Electrification Scenario and the DEP Scenario which represent different uses of the gas and electricity systems while both lowering GHG emissions relative to the Reference Case. • Sensitivity analysis was conducted on the DEP Scenario for various DSM settings to provide additional insights into the way DSM could contribute to decarbonization in a diversified energy pathway.
The requirement for rapid deployment of renewable and low-carbon gas supplies to meet government policy and regulation.	• Modelled use of renewable and low-carbon gas scenarios, and applied lifecycle emission factors to estimate GHG emission impacts.

18.0 Reference: END USE ANNUAL METHOD OF DEMAND FORECASTING FOR THE RESIENTIAL, COMMERCIAL AND INDUSTRIAL DEMAND

Exhibit B-1, Section 4.4.1.2, p. 4-10

Peer Review

On page 4-10 of the Application, FEI states it engaged Posterity Group to support FEI in preparing the End Use Annual Method forecast for the 2022 LTGRP.

18.1 Please confirm, or explain otherwise, whether the annual demand forecasts developed by FEI have been peer reviewed. If not, please explain why not.

18.1.1 If confirmed, please provide the results of the peer review.

Response:

FEI's demand forecasts have not been formally peer reviewed, nor is FEI aware of a standard practice for utilities' demand forecasts to be peer reviewed. FEI's demand forecasting methods receive BCUC and stakeholder review through the development of the LTGRP and other regulatory proceedings. Appendix B-2 of the Application also presents a long-term demand forecasting methods benchmarking study commissioned by FEI.

19.0 Reference: LONG-TERM CUSTOMER FORECAST METHOD AND RESULTS

Exhibit B-1, Section 4.3.3, p. 4-7, Section 4.6.3, p. 4-38, Section 4.4.3, p. 4-16; Section 4.6.3, p. 38; FEI and BC Hydro Energy Scenarios – FEI Stage One Submission – Modelling Results (Energy Scenarios – Stage 1 Submissions), Section 2, p. 6

Customer Forecast and End Use Annual Method of Demand Forecasting for the New Large Industrial Demand Category

On page 6 of FEI's Energy Scenarios – Stage 1 Submissions, FEI states:

> FEI notes that although the in-service date for the Woodfibre facility has recently been revised, for consistency with its LTGRP, FEI used the same timing (2025) for the facility's in-service date as was used for the FEI scenarios which were modelled before the in-service date was extended.

19.1 Please provide the new in-service date for the Woodfibre liquefied natural gas (LNG) facility.

Response:

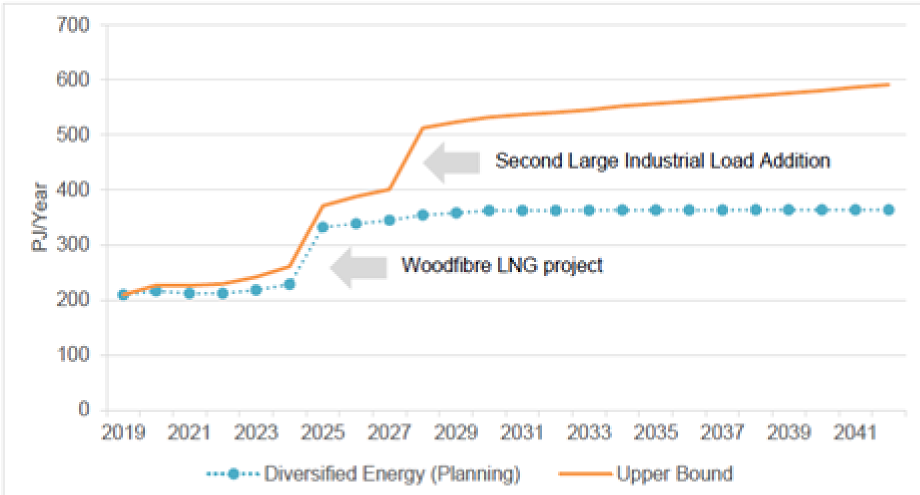
The latest publicly available information indicates that Woodfibre LNG expects to reach substantial completion in 2027.[33]

On page 4-7 of the Application FEI states: "FEI's consideration of new large industrial customers is limited to two customers, each with similar, very large annual demand. The first of these is Woodfibre LNG project […]"

On page 4-38 of the Application, FEI provides Figure 4-18, which shows the total annual demand for the Diversified Energy (Planning) and Upper Bound scenarios illustrating the inclusion of the new Large Industrial demand:

[33] Woodfibre LNG issues Notice to Proceed to McDermott International - Woodfibre LNG.

Figure 4-18: Total Annual Demand for the Diversified Energy (Planning) and Upper Bound Scenarios illustrating the inclusion of the New Large Industrial demand



19.2 Please discuss the likelihood of a second industrial customer with a similar annual demand expectation to that of Woodfibre LNG being developed in the planning period. Please also provide a high level estimate of lead times for projects of this scale.

Response:

FEI has not assessed the likelihood of a second large industrial load of similar demand to that of the Woodfibre LNG project. The purpose of modelling this demand was not to determine the probability of such an occurrence, but rather to understand the implications of such a step change in demand on the need for future resources. FEI does periodically receive inquiries regarding industrial customers looking for natural gas service; however, FEI is not currently advancing projects to serve any such load addition inquiries of the magnitude shown and therefore cannot comment on the likelihood of such a load materializing.

When such an inquiry is received, FEI will assess the potential customer location(s) and provide high-level information around the capacity available, and upgrades required, to provide service to the proposed customer locations. Industrial load addition inquiries vary in magnitude and the majority are smaller than the generic load addition shown in the Upper Bound forecast, but some are of similar scale. Many inquiries of this nature do not proceed but a certain portion do materialize. As the specific customer location and demand requirements can determine the scope of upgrades that may be required, the lead time would vary but would likely be several years in development.

19.2.1 Please explain whether FEI is aware of any potential projects within its service territory that may become a new large industrial customer. If so, please provide details of the projects, including anticipated lead times.

Response:

FEI is not aware of any specific new industrial customers that align with the magnitude and timing of the second large industrial load addition. The load addition is generic and intended to assess impacts if such a customer were to materialize within the forecast period.

19.2.2 With reference to the anticipated lead times for a potential second Large Industrial customer, please explain (i) why a second Large Industrial load addition is forecast for 2027 to 2028 under the Upper Bound scenario; and (ii) what actions FEI would need to undertake in the near term to provide load to a second Large Industrial customer.

Response:

The second large industrial load addition was intended to be generic, with an unspecified location, and should only be considered representative of a large industrial customer addition for forecast modelling and assessing the general implications for system requirements. Since this additional load remains hypothetical at this time (please refer to the response to BCUC IR1 19.2), the precise timing of the load addition modelled is less important than is understanding the system implications for meeting such potential new load. In practical terms, if the load addition were to materialize and in a location that required significant capacity upgrades to serve, the in-service timing would be limited by the lead time requirements for planning and seeking the necessary approvals. Please note that most of the demand forecast modelling inputs for this scenario, including the timing of the second new large industrial customer, were developed in 2019.

On page 4-16 of the Application, FEI states:

> FEI is currently developing the Eagle Mountain Woodfibre Gas Pipeline (EGP) Project that would expand the existing gas pipeline that runs between Coquitlam and a site near Squamish to provide pipeline service to Woodfibre LNG project, a new LNG processing and export facility, which has announced its intention to proceed to construction. […]
>
> The interest by this large industrial user of conventional natural gas in locating in BC has caused FEI to consider what impacts the potential for a second large industrial customer locating in BC's Lower Mainland could have on the conventional natural gas system in the region. […]
>
> FEI expects the Woodfibre LNG project demand to materialize.

19.3 Please confirm, or explain otherwise, that the Reference Case for the New Large Industrial Demand category does not assume a new large industrial demand customer.

19.3.1 If confirmed, and with reference to FEI's statement that the Woodfibre LNG project demand is expected to materialize, please discuss why the Reference Case assumes no new large industrial customer.

Response:

Confirmed. The Reference Case does not assume the Woodfibre new large industrial customer because the Reference Case captures the continuation of conditions and trends present as of 2019. At the time that the scenarios were modeled, the Woodfibre LNG project was still somewhat more uncertain than when the LTGRP was finalized. Since the Reference Case provides a reference against which to compare the trajectories of other demand scenarios, FEI believed that not including Woodfibre demand in the Reference Case provided better understanding of demand forecasts for the other scenarios. To capture the impacts of the Woodfibre LNG project, it was included in the DEP, Upper Bound and Deep Electrification scenarios. While certainty that the Woodfibre LNG project load will materialize has increased since the scenarios were modelled, FEI considers that capturing future demand from Woodfibre LNG in this range of future scenarios, including the DEP, adequately considers the implications of this new load on FEI's system.

19.4 Please explain whether a new large industrial customer would only be expected in the Lower Mainland region of FEI's service territory. If so, please explain why.

Response:

FEI has no reason to expect that a new large industrial customers could only be located in the Lower Mainland region. FEI chose the Lower Mainland as the location of a hypothetical new large industrial customer based on its proximity to the coast and it being the largest population and business centre within BC. Regardless of location, this facilitated FEI's exploration of the impacts of an additional large industrial demand in annual demand forecast scenarios.

19.5 Please discuss whether FEI would face any constraints to connecting a new large industrial customer in the Lower Mainland or any other areas within its service area.

Response:

It is possible FEI would need to address constraints in connecting loads similar in scale to the Woodfibre LNG project. Significant new large industrial load has the potential of exceeding the capacity of the existing system, whether in the Lower Mainland or other regions in FEI's service area. Whether a constraint occurs or not, and the scope of upgrades required to address any potential constraint, is highly dependent on the location and magnitude of the proposed load in the system and how the customer intends to operate under peak conditions. FEI's discussion in Section 7.3.2.4 of the LTGRP provides examples of how load additions at the Tilbury site in the Lower Mainland might be constrained and require various types of upgrades to address constraints. Loads of similar magnitude at other locations within the Coastal Transmission System or in other FEI transmission systems would require different upgrades specific to the location where the customer intends to locate.

20.0 Reference: LONG-TERM CUSTOMER FORECAST METHOD AND RESULTS

Exhibit B-1, Appendix B-1, Section 1.1.1, p. 3; FEI 2017 LTGRP proceeding, Exhibit B-1, Appendix B-3, p. 1; Exhibit B-2, BCUC IR 14.1.

Traditional Annual Method Residential Use per Customer

On page 3 of Appendix B-1 to the Application, FEI states that ten years of weather normalized actual use rate data is used to calculate the use per customer (UPC).

On page 1 of Appendix B-3 to Exhibit B-1 in FEI's 2017 LTGRP proceeding, FEI stated:

> The Company's Traditional Annual Method for forecasting residential and commercial demand involved determining a forecast natural gas Use per Customer (UPC) and multiplying it by the number of customers forecasted for each year of the study period. … The analysis was conducted for each residential and commercial rate class, based on the most recent three years of data.

BCUC IR 14.1 in the FEI 2017 LTGRP proceeding requested FEI to explain the pros and cons of using 3 years of historical data to forecast 20 years, when compared to using more years of historical data (for example 5 or 10 years) to forecast 20 years. In response, FEI stated:

> Using different inputs to the time series methods will certainly result in different forecasts (for example using 10 years of historic data instead of three years) but it is not clear that a different result would also be a more accurate result.
>
> The traditional forecast presented in the LTRP is intended to provide a check on the end use forecast results. If FEI were to start using untested methods (such as a 10 year time series) then it is not clear if the results would form a reliable check on the end use method.

20.1 Please confirm the number of years of historic data that has been used to develop the UPC forecast for the residential and commercial customer categories using the Traditional Annual Method and explain whether the period(s) used is different to that used in the 2017 LTGRP.

20.1.1 If so, please explain why and explain whether the results are considered to form a reliable check on the End Use Annual Method.

20.1.2 If so, please explain whether there have there been any significant changes observed in historical UPC trends since 2017 that caused FEI to use a different period.

<u>Response:</u>

FEI now uses the Exponential Smoothing method (ETS) to forecast residential and commercial uses rates. The ETS method uses 10 years of historical weather normalized actual data.

FEI's use rate forecast methods employed for the Traditional Annual Method of demand forecasting in the 2022 LTGRP are consistent with the recommendations in the FEI Forecasting Method Study filed as Appendix B2 in FortisBC's 2020-2024 MRP Application. The Forecasting Method Study represented the culmination of a number of years of research and testing of alternative forecasting methods in response to the forecasting directives in Order G-86-15 and accompanying decision related to the FEI Annual Review for 2015 Rates Application. As a result of this study, FEI adopted the ETS method for the purpose of forecasting residential and commercial use rates, as ETS proved to be the most accurate method for this purpose.

As described in Appendix B2 of FortisBC's 2020-2024 MRP Application, the ETS use rate calculations result in slightly lower variances compared to the prior methods and as a result are fully compatible with the rest of the BAU forecast. The ability of the BAU forecast to provide a reliable check on the forecast developed with the End Use Annual Method is unchanged.

The adoption of the ETS method was a result of research done in response to the forecasting directives in Order G-86-15 and accompanying decision related to the FEI Annual Review for 2015 Rates Application, and was not due to any trends observed since 2017.

21.0 Reference: LONG-TERM CUSTOMER FORECAST METHOD AND RESULTS

Exhibit B-1, Section 4.1, p. 4-1, Section 4.4.1.1, pp. 4-8 – 4.9, Section 4.4.1.4, pp. 4-13 –4-14; Appendix B-6, p. 2; FEI 2017 LTGRP Decision and Order G-39-19 February 25, 2019, Directive 2

Traditional Annual Method and End Use Annual Method of Demand Forecasting for the Residential, Commercial and Industrial Demand

On page 4-1 of the Application, FEI states: “The current planning environment is undergoing rapid change and therefore subject to more uncertainty than seen in resource planning processes over the past two decades or more.”

On pages 4-8 to 4-9 of the Application FEI states:

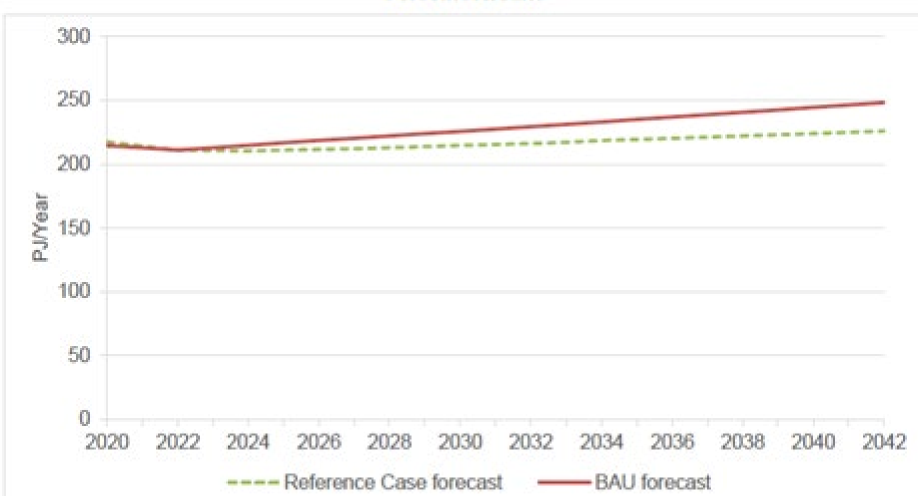
> Extending the Traditional Annual Method over the longer-term planning horizon for the LTGRP in this manner provides a reference point against which to compare the outcomes of FEI’s End Use Annual Method under various future scenarios. As it is based on historical data, however, the Traditional Annual Method is limited in its ability to incorporate rapid change in the planning environment and uncertainty in how the longer-term future could unfold.

Directive 2 of Decision and Order G-38-19 directed FEI to “continue use of its Traditional Method as a comparison to test its End-Use Method until such time as the BCUC approves a new demand forecast methodology.”

On pages 4-13 to 4-14 of the Application, FEI states:

> Figure 4-7 below compares the BAU forecast annual demand with the Reference Case forecast. By the end of the planning period, the two forecast methods differ by only five percent […]

Figure 4-7: Comparing the End Use Reference Case and Traditional BAU Annual Demand Method Forecast Results



On page 4-13 of the Application, FEI states: "Comparing the Reference Case forecast with the BAU [business as usual] forecast shows that the results of the End Use Annual Method and the Traditional Annual Method are reasonably aligned for a future that remains relatively unchanged from conditions present as of the base year."

On page 2 of Appendix B-6 to the Application, FEI states: "Figures B6-1 and B6-2 demonstrate that the results from the two methods are comparable in the early years of the forecast, and therefore it is reasonable to use the extended capabilities of the end use method to examine future scenarios."

21.1 With reference to the statements that the current planning environment is undergoing rapid change and the Traditional Annual Method is limited in its ability to incorporate rapid change in the planning environment, please discuss, with supporting rationale, whether FEI expects the Traditional Annual Method to continue to provide a useful reference point against which to compare the outcomes of the End Use Annual Method for the purposes of long term resource planning.

Response:

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

The Traditional Annual Method is based on a set of long-standing and well-understood methods that are also used for short-term rate setting forecasts. The Traditional Annual Method is significantly different than the End Use Annual Method, which continues to make the Traditional Annual Method a useful check on the End Use Annual Method.

FEI expects the Traditional Annual Method to result in a forecast that is slightly higher than the Reference Case Forecast, especially over the long-term, for the reasons noted in the preamble. However, as shown in Figure 4-7 of the Application, the differences are only approximately 5 percent at the end of the planning period. If a future draft Reference Case Forecast was found to be significantly different to the Traditional Annual Method result, it would signify the need for additional research or data validation.

21.1.1 In light of the rapid changes expected in the planning environment, please discuss whether FEI expects to see a greater divergence between the Traditional Annual Method and the End Use Annual Method. If not, please explain why not.

Response:

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

If the changes expected in the planning environment occur rapidly in the short term and are captured in the End Use Annual Method, then FEI expects that the divergence between the Traditional Annual Method and the End Use Annual Method could increase. If changes develop more slowly, however, then the forecast from Traditional Annual Method would reflect the slower rate of change and FEI would expect the divergence to be not as great.

21.2 Please discuss the parameters used by FEI to determine whether the results from the Traditional Annual Method and the End Use Annual Method are reasonably aligned and comparable.

Response:

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

FEI compared the forecast annual energy load from the two methods on an annual basis, as shown in Figure 4-7 of the Application, which shows that the End Use Annual Method and the Traditional Annual Method are reasonably aligned.

21.3 In the event that FEI is no longer directed to continue the use of its Traditional Annual Method as a comparison to test the End Use Method, please discuss whether FEI would continue to use the Traditional Annual Method internally for comparison purposes.

21.3.1 If not, please discuss how FEI would test the outcomes of the End Use Annual Method.

21.3.1.1 If FEI would not test the outcome of the End Use Annual Method against another forecast method, please explain why not.

Response:

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

FEI intends to continue to compare the results from the End Use Annual Method with those from Traditional Annual Method. The Traditional Annual Method relies on the same methods and data as are used for the short-term rate setting forecast and can be easily and efficiently extended to provide the 20-year comparison.

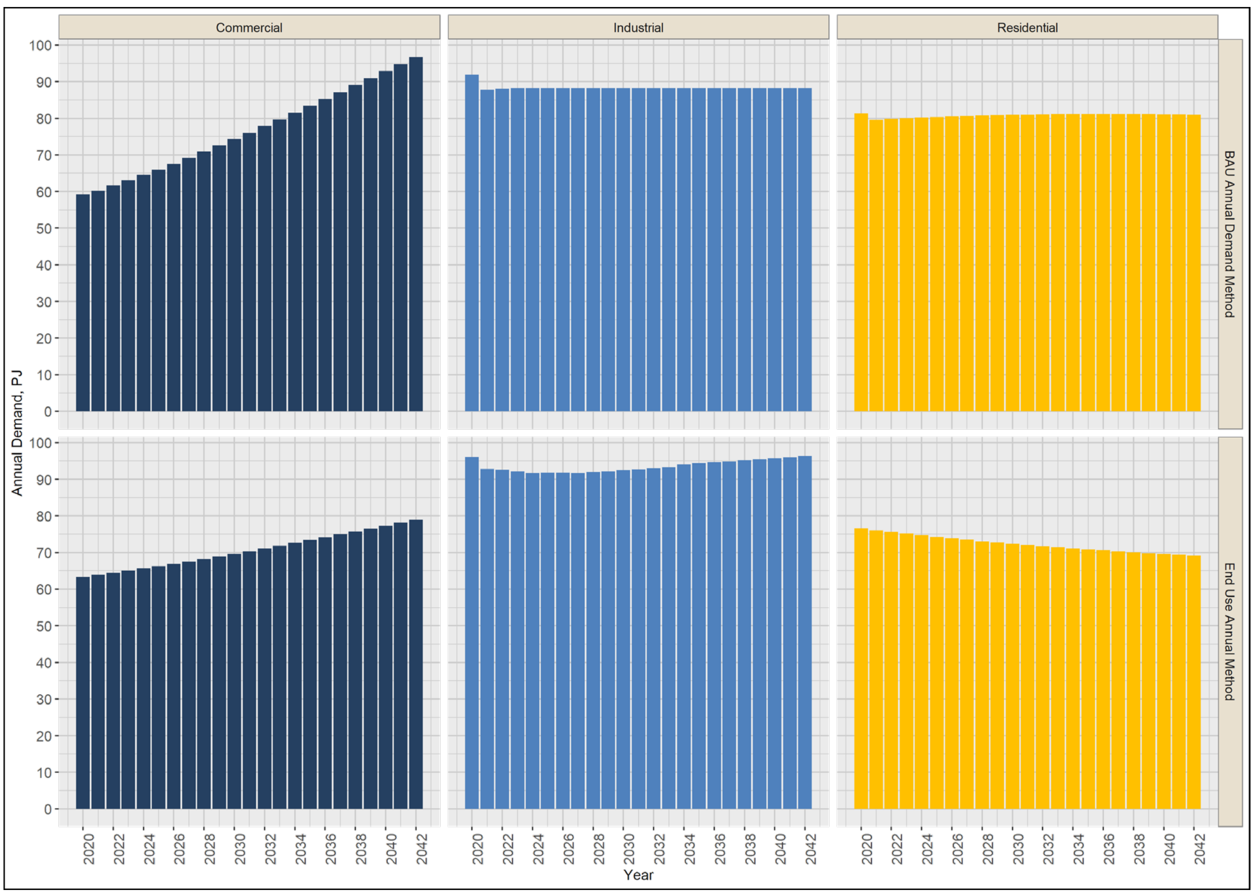
21.4 Please provide a graph comparing the forecast results for the End Use Annual Method and BAU Annual Demand Method broken down according to residential, commercial and industrial customers.

Response:

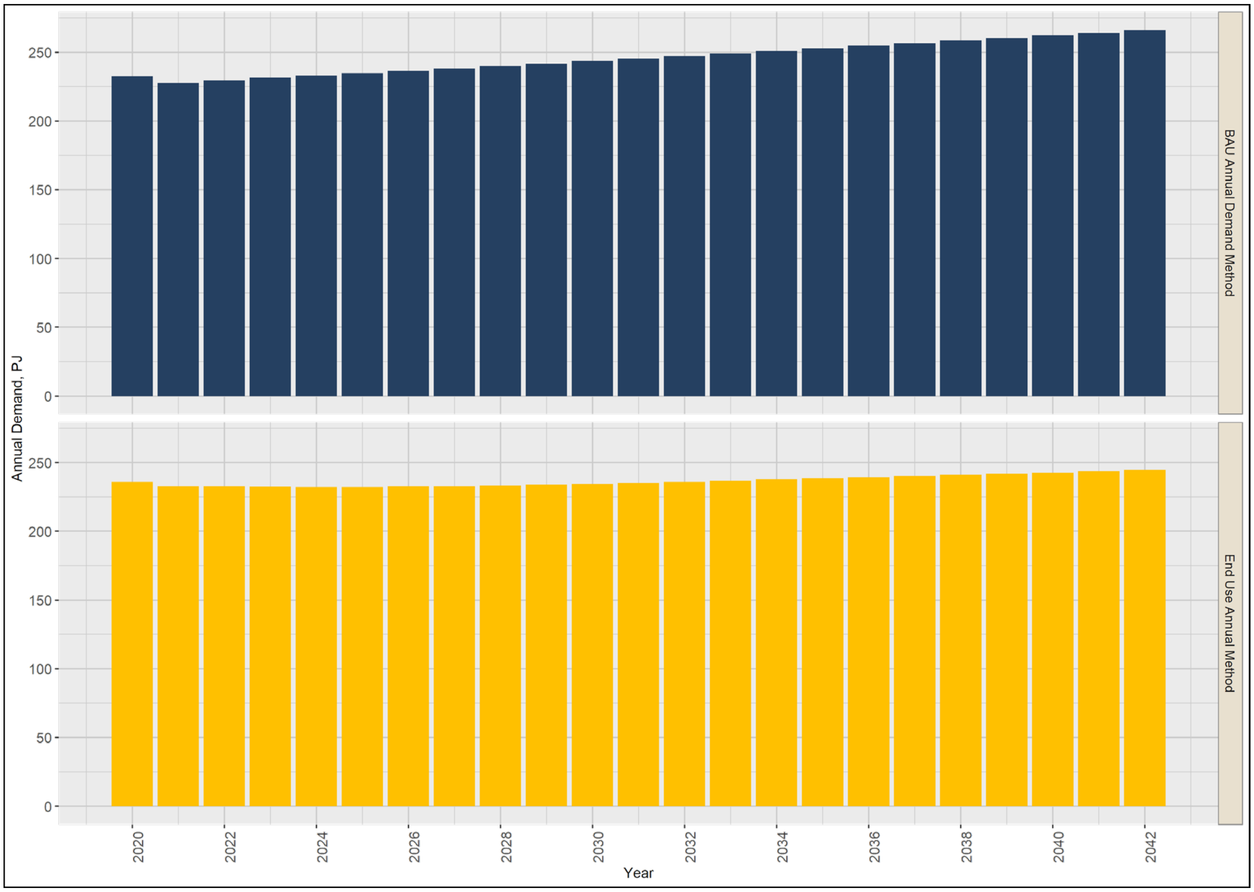
The following response has been provided by FEI in consultation with Posterity Group.

The following figure compares the forecast results for the End Use Annual Method Reference Case and the BAU Annual Demand Method according to residential, commercial and industrial customers.

- FEI notes the following:
- BAU commercial demand grows more quickly as a result of recent UPC trends.
- BAU industrial demand remains flat relative to the End Use Annual Method Reference Case based on recent customer surveys.
- BAU residential demand is flat relative to the End Use Annual Method Reference Case because recent trends in increasing customers are offsetting recent declining UPC trends.



As a further comparison between the results of the two methods, the following figure shows the aggregate demand from the figure above. By 2042 the aggregate demand from the BAU Annual Method is slightly higher than the demand from the End Use Annual Method.



21.4.1 For each of the customer classes, please discuss the key drivers for the differences between the results.

<u>Response:</u>

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

As the following table shows, the key drivers for the different results stems from how the use rates are calculated.

Residential	Traditional Annual Method	End Use Annual Method
Customers	The same long term customer forecast underlies both demand forecasts.	
Use Rates	The Exponential Smoothing (ETS) method is used with 10 years of weather-normalized historic actual data by region. The method assumes all factors are intrinsic in actual data and will continue on current trajectories for the planning period.	• Different energy profiles are used for different types and vintages of dwellings, at the end use level. • New homes added to the model have the characteristics of the newest of the seven vintages, and the growth rate is much larger for attached homes than for detached. This means the Use Per Customer (UPC) of the new homes is much less than for the existing stock. Code improvements also further improve these new home UPCs. • Some demolition is assumed, so some of the existing stock was removed from the model and replaced by additional new homes with these lower UPCs. • In existing dwellings, assumptions are made about renovations that improve the building envelope. • Assumed natural replacement of appliances with new ones that meet or exceed the new appliance standards, lowering the usage from most end uses.
Demand	Demand is calculated as Customers multiplied by End Use	
Commercial	**TAM**	**EUM**
Customers	The same long-term customer forecast underlies both demand forecasts.	
Use Rates	ETS method is used with 10 years of weather-normalized historic actual data by region. The method assumes all factors are intrinsic in the actual data and will continue on current trajectories for the planning period.	• Data incorporated from the Industrial Survey (to the extent that it applied to the commercial segments) in the SIZE factor in the commercial model, so some building segments were assumed to be growing or shrinking in average floor area per account. • The UPC or some end uses is assumed to be lower in new commercial construction relative to the average existing stock. That causes UPC to be lower for the new buildings. Codes further improve the new building UPC. • Assumed some demolition, so some building stock is replaced by new construction with these lower UPCs. • Assumed natural replacement of equipment with new equipment that meets or exceeds the new equipment standards, lowering the usage particularly from space and water heating.
Demand	Demand calculated as Customers X End Use	

Residential	Traditional Annual Method	End Use Annual Method
Industrial	**TAM**	**EUM**
Customers	NA	Zero customer growth is assumed in the industrial rate classes
Use Rates	NA	• Incorporated the data from the Industrial Survey in the SIZE factor in the industrial model, so some building segments were assumed to be growing or shrinking in average production capacity per account. • There is no demolition in the industrial sector. • Assumed a slow improvement in UEC (in both existing and new stock) for most end uses as plants upgrade their equipment naturally.
Demand	Demand based on responses to annual industrial survey.	Demand calculated as Customers X End Use

22.0 Reference: LONG-TERM CUSTOMER FORECAST METHOD AND RESULTS

Exhibit B-1, Appendix B-2, p. 18

Long-term Demand Forecasting Benchmarking Study on End Use Methods Industry Practice Review

Page 18 of Appendix B-2 to the Application provides Table 1, which shows the end use model characteristics for the organizations reviewed as part of the benchmarking study:

Table 1. End-Use Model Characteristics

Organization Code	No. of Gas Customers	Utility Ownership	DSM Activity	Degree of Data Intensiveness	Degree of Customization	Ability to Examine End-use Trends/Scenarios	Ability to Show How Changes to Model Inputs Affect Results	Informs both Annual and Peak Demand	Cost to Maintain	Forecast Tested Against Actuals
A	5.9 million	IOU	High	High	High	Yes	Medium	Yes	Moderate	Some
B	873,000	IOU	High	High	High	Yes	Medium	Yes	Moderate	Some
C	1.4 million electric	IOU	High	High	High	Yes	Medium	Yes	Moderate	Some
D	N/A	N/A	High	High	High	Yes	Medium	Yes	Moderate	Yes
G	N/A	Crown	High	High	High	Yes	High	Yes	N/A	Yes
H	285,000	Crown	High	Moderate	High	Yes	Medium	No	Moderate	Yes
K	42,000	IOU	Low	Moderate	High	Yes	High	Yes	Moderate	Some
P	1 million	IOU	Low	Moderate	Moderate	N/A	N/A	No	N/A	N/A
Q	500,000	IOU	Low	Low	Low	Low	Low	No	Low	Yes
R	N/A	Municipal	Low	High	High	High	High	Yes	Low	Some
FEI	1.1 million	IOU	High	High	High	Yes	Yes	No*	Moderate	Not Yet**

*Linkage with peak demand is being addressed as part of the ongoing improvement to the forecasting model.

**To date there has not been enough actual history to compare to the end-use demand forecast. Once enough historic data is available, FEI plans to compare end-use demand forecast to actual consumption.

22.1 Please elaborate further on the statement that "linkage with peak demand is being addressed as part of the ongoing improvement to the forecasting model," explaining (i) why the end use model is currently not able to inform the peak demand; (ii) what work FEI is undertaking to improve the forecasting model; and (iii) when FEI expects that the end use model will be able to inform both the annual and peak demand.

<u>Response:</u>

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

FEI's 2017 LTGRP discussed the considerations relevant to the ability of the End-use Demand Forecasting Model to accurately model peak and annual demand.[34] The following response builds on that discussion. These considerations are directly related to FEI's updates in the Application on investigating the ability of DSM activities to potentially delay or defer infrastructure requirements.[35]

1. The End-use Demand Forecast Model results are not used by FEI for planning purposes, as this modelling is based on hourly load profiles of similar electric equipment to that of the gas equipment being modelled. Gas equipment hourly load profiles throughout the

[34] FEI 2017 LTGRP, Exhibit B-1, Application, p. 154; Appendix B-2, End-Use Demand Forecast Method Analysis.

[35] 2022 LTGRP, Exhibit B-1, Application, Item 4 of Table 1-7, p. 1-16; Appendix C-3, Section 5.

year are not yet widely available due to the limited granularity of gas use metering currently in place in most jurisdictions in North America. This affects FEI's ability to analyze the relationship between peak demand and temperature with precision. FEI therefore considers the peak demand results of the End-use Demand Forecast Model to remain exploratory at this time and will continue to undertake that exploration as it is able.

2. To improve the end-use forecast modelling, FEI is monitoring the advancements in peak demand forecast modelling and hourly equipment load profile analysis in other jurisdictions to understand how advancements are taking place and what steps FEI might be able to take to improve confidence in modelling end-use peak gas demand trends. FEI is optimistic that the implementation of Advanced Metering Infrastructure (AMI), which is currently before the BCUC, would improve FEI's understanding of peak demand trends, but other customer energy use studies and measuring equipment may also be needed.

3. FEI is hopeful that it will have better end-use data to analyze once the implementation of AMI is largely complete (if approved) and sufficient data have been collected to analyze peak demand trends. However, FEI cautions that these data might not be sufficient on their own to determine whether or not FEI should adjust its peak demand forecasting practices for system planning purposes.

Until the time that AMI is implemented, FEI will continue to examine developments on end-use peak demand forecasting in other jurisdictions and will continue to explore such modelling through the current end-use demand forecasting model. Further, FEI will continue to improve the end-use demand forecasting model's ability to accurately model peak demand across a range of demand forecasting critical uncertainties.

22.1.1 Please explain the pros and cons of having both the annual and peak demands being informed by the end use model.

Response:

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

Notwithstanding the response to BCUC IR1 22.1, FEI and Posterity Group offer the following pros and cons of using the end-use demand forecast method to inform both annual and peak demand:

Pros:

- The variation in annual usage and peak demand are related, because the relationship between annual and peak demand at the level of individual end uses in different building types is expected to be relatively consistent. Once you have calibrated these end use factors and have confidence in them, you can explore changes to end use assumptions and the same model will produce estimates of changes to both annual and peak UPC.

- Doing this peak demand forecast modelling and exploration in one model saves effort.
- Using a single model can permit modelling and exploration of more, and more varied, future scenarios of both annual and peak demand.

Cons:

- The stakes are high in system planning, because of the obligation to serve customers under extreme weather conditions. As a result, although with the end-use method FEI can present and discuss the potential implications of a variety of scenarios, FEI cannot plan infrastructure requirements against some of the less tangible influences, such as the extent to which annual savings from DSM activities translate into peak savings, that the end-use method is able to illustrate in the forecasts.
- The hydraulic models used to estimate peak demand for system planning are highly sophisticated. The end use model does not have the geographic granularity to show how demand is distributed along the FEI systems, nor the sophisticated handling of the interaction between pressure, volumes, and energy flow of the hydraulic model currently used for peak demand forecasting.
- As renewable gases are incorporated, the end use model, while being representative at a higher regional level, does not convey how different localities will be served and specifically with what forms of renewable gases will be delivered and specific locations, all of which impact the capacity to serve peak demand.

22.2 Please explain when FEI expects to have sufficient historic data to compare the end-use demand forecast to actual consumption.

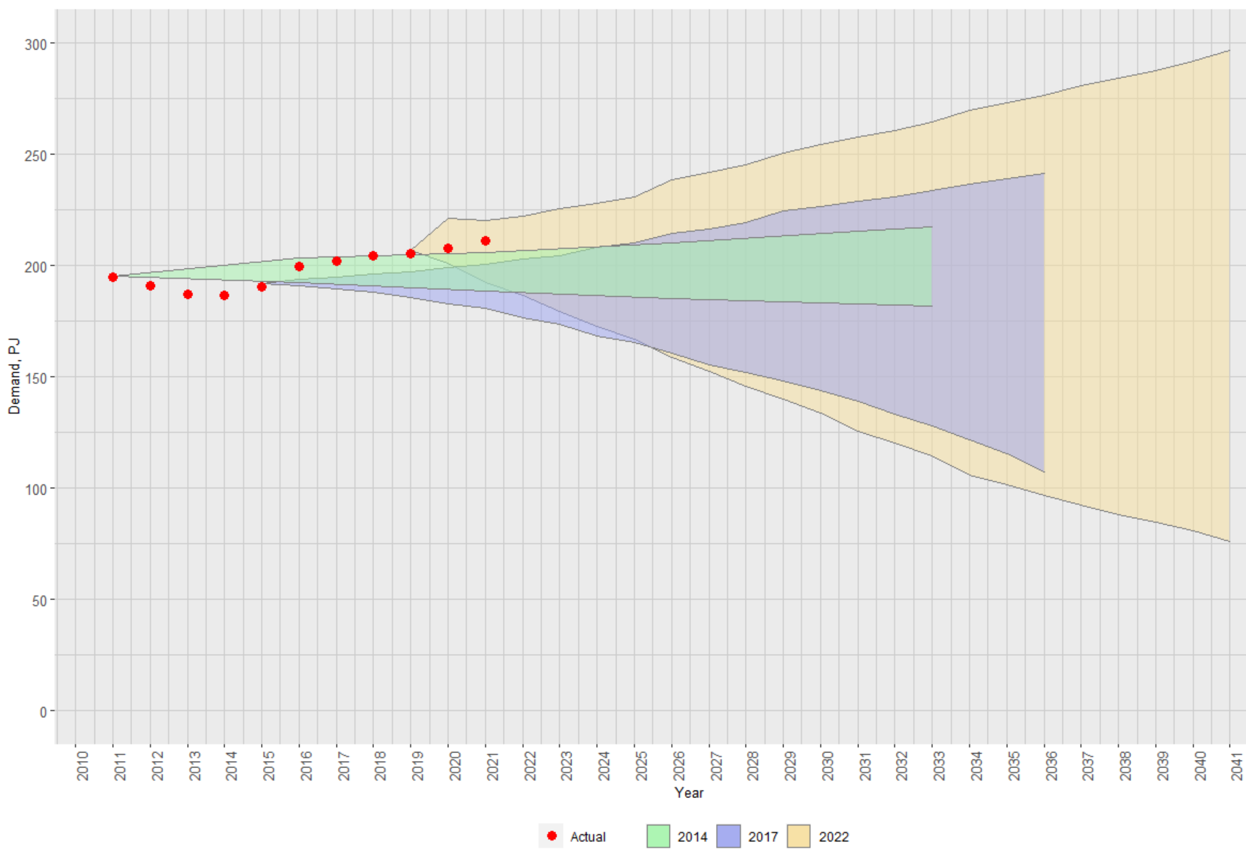
<u>Response:</u>

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

The conclusion in the referenced appendix that insufficient history exists with which to compare forecast to actuals was carried over from the first bench marking study submitted with the 2017 LTGRP. FEI now has actual data which is presented in Figure 1, below.

The actuals may or may not line up to the planning forecasts put forward in the 2014 or 2017 forecasts. In the 2014 LTGRP, there were no true “bookend” upper and lower scenarios, so the shaded regions for that earlier forecast is narrower. Where upper and lower scenarios do exist (2022) the actual results should fall between those scenarios. It should be noted that for the 2017 and 2022 LTGRP end-use demand forecast ranges, the “new large industrial” customer category, which includes the Woodfibre LNG export facility, has been removed from the graph since these customers represent very large step changes in demand and are either on or off depending on the scenario.

Figure 1: Actual Demand Data Compared to Forecast Demand Ranges Presented in Prior Gas Resource Plans that Employed the End-Use Demand Forecast Method.



23.0 Reference: CRITICAL UNCERTAINTIES AND THEIR FORECAST MODELLING INPUT SETTINGS FOR THE END USE METHOD DEMAND FORECAST SCENARIOS

Exhibit B-1, Section 2.2, pp. 2-1 – 2-21; Appendix B-3, Section 1.1.1.1.2, p. 7

Natural Gas Prices

Section 2.2 of the Application provides an overview of the relevant policy and regulatory context facing FEI that impact future resource options, market prices, and influence customers' behaviour regarding energy use in the future.

On page 7 of Appendix B-3 to the Application, FEI states:

> 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.

23.1 Please explain how FEI established the High and Low trajectories for natural gas price. In the response, please provide details of any assumptions made, including those made with respect to upstream GHG reduction initiatives.

Response:

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) at the Sumas market hub, released in February 2021. FEI did not make particular assumptions with respect to upstream GHG reduction initiatives, since the cost of carbon has been modelled through alternative carbon tax settings. Upstream carbon reduction initiatives would reduce the amount of carbon tax customers would have to pay. Modelling the onset of upstream carbon reduction costs and corresponding offset of carbon tax costs (reductions) would add challenging and unnecessary complexity to the price forecasts.

FEI applied the forecasts as follows:

- The reference setting is based on then current expectations for natural gas prices, with prices increasing most years as demand increases due to LNG exports from B.C. and coal plant retirements in the Pacific Northwest (PNW).
- The high setting includes rapid world economic growth, which increases the demand for natural gas supplies.
- The low setting assumes slow economic growth with reduced demand for natural gas in favour of lower-carbon renewable energy sources.

23.2 With reference to the policy and regulatory context outlined in section 2.2 of the Application, please discuss why FEI considers the Reference trajectory to be a realistic expectation for natural gas prices over the planning period.

Response:

Please refer to the response to BCUC IR1 23.1 for a description of the third-party gas price forecast sources used by FEI. Both of the third-party forecasts (NPCC and IHS) used by FEI for demand forecast modelling incorporated known policies or policy trends and market factors at the time of the release; thus, FEI considers the reference trajectory to be a realistic expectation for natural gas prices over the planning period at the time of filing the LTGRP.

24.0 Reference: CRITICAL UNCERTAINTIES AND THEIR FORECAST MODELLING INPUT SETTINGS FOR THE END USE METHOD DEMAND FORECAST SCENARIOS

Exhibit B-1, Section 2.2.1.4.2, pp. 2-5 –2-6; Section 2.2.2.2.1, p. 2-9; Appendix B-3, Section 1.1.1.1.3, p. 9.

Carbon Price

On pages 2-5 to 2-6 of the Application, FEI states:

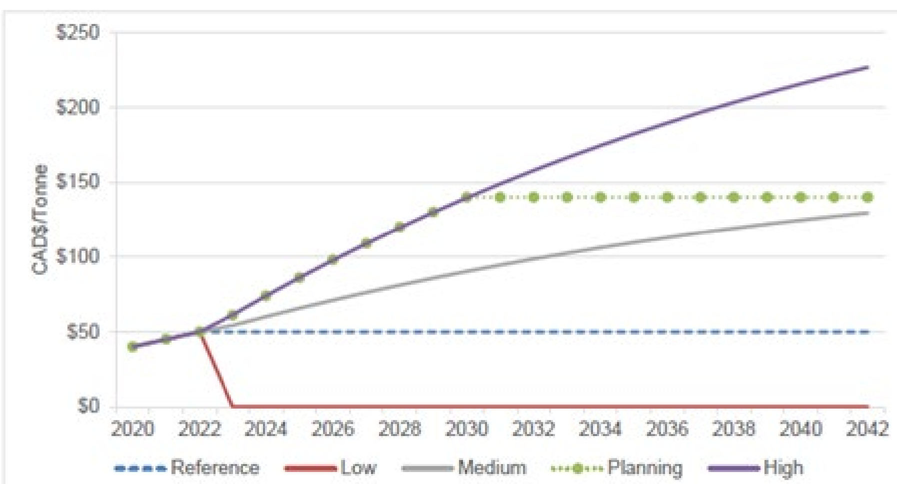
> As part of the HEHE plan, the federal government announced that it plans to increase the price on carbon as part of a push to meet and surpass Canada's goal of reducing GHG emissions by 30 per cent below 2005 levels by 2030. The carbon price would rise by $15 per tonne a year for the next eight years beginning in 2023, to reach $170 per tonne in 2030. There are still some key unknowns on the future of carbon pricing in Canada.

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

> Among the measures announced in the [CleanBC Roadmap to 2030], the carbon price of $50 will either match or exceed the federal carbon price, which is expected to rise to $170 per tonne by 2030, with annual increases of $15 starting in 2023.

On page 9 of Appendix B-3 to the Application, FEI provides Figure B3-8, which shows the settings for carbon price:

Figure B3-8: Settings for Carbon Price (2020$ Real)



24.1 With reference to the federal government's announcement that the carbon price will rise by $15/tonne a year, reaching $170/tonne in 2030, please discuss the rationale of maintaining the carbon price at $50/tonne for the Reference setting.

Response:

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

The Reference setting is designed to be used in the Reference Case Scenario. Since the Reference Case Scenario is intended to reflect the continuation of policies and laws in place in 2019, the $50 per tonne carbon price is appropriate. The federal government's new carbon price trajectory was announced (but not legislated) after the scenario inputs for FEI's forecast modelling had been initially developed. Since this new carbon price trajectory is being used for the Planning setting applied to the DEP, FEI considers that it has appropriately reflected alternative carbon prices in the Application.

24.2 Please explain how the Medium setting was established, providing details of any assumptions made.

Response:

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

The Medium setting for the carbon price Critical Uncertainty assumes a lower level of consistent annual increase of the federal carbon tax ($5 per tonne per year) over the planning horizon relative to the High setting. As discussed in Appendix B-3, the range in the carbon price settings is intended to account for considerable policy uncertainty that existed at that time in relation to provincial (BC), federal (Canadian), and broader (North American) developments in carbon pricing over the planning horizon.

24.2.1 Please confirm, or explain otherwise, that the Medium setting has not been used for any of the scenarios.

Response:

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

Confirmed. When the scenarios were being modelled, it was determined that the other carbon price settings that were available provided an effective representation of possible future outcomes. The setting was included in Appendix B-3 to show the considerations FEI and Posterity Group undertook in developing the settings and scenarios.

24.3 Please explain how the Provincial government's intention to match or exceed the federal carbon price has been incorporated into the settings for carbon price. In the response, please detail any assumptions made and identify which settings reflect the impact of the provincial carbon tax.

Response:

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

As explained in Appendix B-3, the Reference setting assumes the carbon tax is held constant throughout the planning horizon once the provincial maximum announced value was reached. At the time the setting was developed, the provincial carbon tax was announced to reach $50 per tonne.

Settings that went beyond the provincial carbon tax are the Planning and High settings: The Planning trajectory (applied to DEP Scenario) matches the federal carbon price announcement and grows to $170 per tonne in 2030 (in nominal dollars), remaining constant thereafter. The High trajectory continues this level of annual increase beyond 2030, growing by $15 per tonne each year. These various carbon price settings are intended to account for considerable policy uncertainty in relation to BC provincial, Canadian federal, and wider North American developments.

25.0 Reference: CRITICAL UNCERTAINTIES AND THEIR FORECAST MODELLING INPUT SETTINGS FOR THE END USE METHOD DEMAND FORECAST SCENARIOS

Exhibit B-1, Appendix A-1, p. 16; Appendix B-3, Section 1.1.1.1, p. 12

Non-Price Driver Fuel Switching

Page 16 of Appendix A-1 to the Application (Pathways Report) provides Table 1. Initiatives by Pathway. Table 1 is reproduced in part:

Initiative	Electrification Pathway	Diversified Pathway
Fuel Switching	Transition 100% of residential and commercial space and water heating to electricity with electric heat pumps and other appliances, 20% of industrial fuel switching.	Transition up to 25% of residential and commercial space and water heating to electricity, 10% of industrial fuel switching.

On page12 of Appendix B-3 to the Application, FEI states:

> The targets were set for reductions in gas fuel share by 2042 relative to the 2019 fuel share for space and water heating end uses in existing residential and commercial buildings. In the case of the City of Vancouver region, separate targets were set, as the City has more stringent building code requirements.
>
> For 2042, a linear interpolation was used to set the following electrification assumptions consistent with the [Clean Growth Pathway to 2050] Report of modelled values in 2050:
>
> > Moderate electrification (aligned with the 'Diversified Pathway'): ~14 percent decline in gas fuel share;
> >
> > Accelerated electrification (aligned with the 'Electrification Pathway'): ~56 percent decline in gas fuel share; and
> >
> > Extensive electrification: ~67 percent decline in gas fuel share.

25.1 Please explain how the 25 percent and 10 percent electrification figures for the residential and commercial, and industrial demands, were established. Please provide details of any assumptions made.

<u>Response:</u>

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

The Pathways Report chose 25 and 10 percent electrification as indicative values based on expert judgement for feasible levels of electrification in each sector. The Diversified Pathway assumed that 25 percent of residential and commercial space and water heating, and 10 percent of industrial end use, would transition to electricity.

To model the 'moderate electrification' setting for the 2022 LTGRP, the following steps were taken:

1. FEI calculated the 2050 fuel share target: For residential and commercial sectors, this meant subtracting 25 percent from the base year fuel share for space and water heating end uses, respectively. For the industrial sector, 10 percent was subtracted from end-uses that were assumed to be able to switch to electricity.

2. FEI calculated the 2042 fuel share target: a linear interpolation from 2020 (first year of the forecast period) to 2042 (last year of the forecast period) was used.

3. FEI modelled reductions to gas fuel shares for applicable end uses: the model switches fuel shares using an equipment turnover rate. It is assumed equipment is replaced when it reaches end of life (i.e., no early replacement). When gas-using equipment reaches end of life, it is assumed to be replaced with an electric option.

25.1.1 Please explain why FEI considers the 25 percent and 10 percent electrification figures to be appropriate.

Response:

The goal of the Pathways Report was to provide two distinct indicative decarbonization pathways for the purposes of comparing their outcomes. This is described as "what-if" scenario modeling whereby purposefully different scenarios are constructed to compare and contrast the impacts of different approaches to decarbonization. The Pathways to 2050 report is not attempting to model what is likely to pass or what is appropriate, but what the impacts of different policy decisions and decarbonization investments may bring to the system as a whole. The Pathways Report inputs were chosen for use in the 2022 LTGRP as it was the most comprehensive examination of BC's entire energy system and decarbonization pathways in BC that was available.

25.2 Please provide the percentage of electrification assumed for the residential, commercial and industrial sectors by the end of the planning period (i.e., 2042).

Response:

The following response has been provided by Posterity Group.

The table below provides the 2042 average gas fuel share reduction targets for existing dwellings (i.e., not new construction) by sector for each setting in the 2022 LTGRP. The average gas fuel shares across all regions were used, except for the City of Vancouver (CoV) which has its own target. As explained on page 12 of Appendix B-3, targets focus on space and water heating end uses in the residential and commercial sectors, as it is thought that policies and incentives for electrification would focus on these end uses for these sectors. Non-price driven fuel switching is assumed to occur in the industrial sector as well, as there are spillover effects from the electrification of other sectors. Fuel switching in the industrial sector occurs in the end uses that are assumed to be able to switch to electricity as indicated in the table.

	Residential				Commercial				Industrial	
Region:	All regions except CoV		CoV only		All regions except CoV		CoV only		All regions except CoV	CoV only
End Use:	Space Heating	DHW	Space Heating	DHW	Space Heating Gas Fuel Share	Water Heating Gas Fuel Share	Space Heating Gas Fuel Share	Water Heating Gas Fuel Share	Direct-fired heating, heat treating, kilns[36], ovens, product drying, space heating, water heating	
"Moderate Electrification"	17%	14%	17%	17%	12%	11%	12%	12%	7%	7%
"Accelerated Electrification"	69%	58%	68%	66%	47%	45%	48%	47%	15%	16%
"Extensive Electrification"	82%	69%	82%	79%	56%	53%	57%	56%	23%	25%

25.3 Please explain how the percentage declines in gas fuel share under the Moderate electrification, Accelerated electrification and Extensive electrification were established. Please provide details of any assumptions made.

Response:

The following response has been provided by Posterity Group.

The percentage declines in gas fuel shares for the settings were established using the following steps:

- Develop a 'narrative' for the setting:
    - Moderate electrification setting was designed to align with the Diversified Pathway;

[36] Kilns in the Pulp & Paper – Kraft segment.

- Accelerated electrification setting was designed to align with the Electrification Pathway; and
- Extensive electrification pathway was designed to have more electrification than the other two settings.

- Establish gas fuel share reduction targets:
  - The Pathways Report provided the level of electrification and thus reduction in gas fuel share by 2050 which was used for the Moderate and Accelerated settings; and
  - For the Extensive setting, it was decided that there would be 100% electrification of space and water heating in residential and commercial sectors by 2045.
- Calculate 2042 gas share fuel share reduction targets:
  - A linear interpolation was used from 2019 gas fuel shares (i.e., the starting point) to calculate the required gas fuel share in 2042 to reach the 2050 or 2042 target.

25.4 Please provide details of the reduction targets for gas fuel share for the City of Vancouver and provide details of any assumptions made.

Response:

The following response has been provided by Posterity Group.

The City of Vancouver's more aggressive gas fuel share reduction targets are illustrated in the response to BCUC IR1 25.2. As described in Appendix B-3 of the Application, the model differentiated the City of Vancouver from the other regions due to the City's more stringent building code requirements. The targets differ somewhat from other regions due to the City's expanded authorities under the Vancouver Charter which allows it to develop its own GHG reduction policies in the Climate Emergency Action Plan.

The fuel share reduction targets were developed using the following approach:

1. Take the desired level of fuel switching from the setting (2050 targets for Moderate and Accelerated settings; 2045 target for the Extensive setting);
2. Identify the base year gas fuel share for space and water heating end uses in the residential and commercial sectors, and end uses that can electrify in the industrial sector; and
3. Use a linear interpolation to calculate the 2042 gas fuel share reduction using the 2019 fuel shares as a starting point and the 2045/2050 targets as the end point.

26.0 Reference: CRITICAL UNCERTAINTIES AND THEIR FORECAST MODELLING INPUT SETTINGS FOR THE END USE METHOD DEMAND FORECAST SCENARIOS

Exhibit B-1, Section 2.2.1.1, p. 2-3, Section 2.2.2.2.3, p. 2-10; Appendix B-3, Section 1.1.1.1.4, pp. 9 - 10, Appendix A-5 (CleanBC Roadmap to 2030), pp. 40–41; BC Government Website, Buildings and Communities

Codes and Standards

New Construction Code and Efficiency Standards

On page 2-3 of the Application, FEI states:

> In 2017, the [Pan-Canadian Framework] set an aspirational goal that by 2035 all space heating technologies sold will have a performance of greater than 100 percent efficiency. This would effectively ensure that only electric or gas heat pumps would be available for use by this time.

On page 2-10 of the Application, FEI states:

> […] gas heat pumps are not yet commercially available for residential customers, leading to uncertainty regarding gas heat pump adoption timelines in reference to the 100 percent efficiency standard in 2030.

On page 10 of Appendix B-3 to the Application FEI provides Table B3-2, which summarizes the new construction code settings assumptions:

Table B3-2: New Construction Code Settings Assumptions

Setting	Years	Residential Assumptions	Commercial Assumptions
Reference	2020-2042	Step 4 (City of Vancouver)	Step 3 (City of Vancouver)
	2020-2042	Step 3 (all other regions)	Step 2 (all other regions)
Accelerated	2020-2027	Step 4 (City of Vancouver)	Step 3 (City of Vancouver)
	2028-2042	Step 5 (City of Vancouver)	Step 4 (City of Vancouver)
	2020-2027	Step 3 (all other regions)	Step 2 (all other regions)
	2028-2032	Step 4 (all other regions)	Step 3 (all other regions)
	2033-2042	Step 5 (all other regions)	Step 4 (all other regions)
Delayed	For all regions including the City of Vancouver: New buildings perform at discounted rates related to the code-mandated level. Based on industry research of how well BC buildings perform in relation to mandatory new construction performance requirements, the 2017 LTGRP assumed such buildings to perform at 63 and 70 percent of mandated performance, respectively, for residential and commercial buildings. We have applied these de-rated savings to the Reference Case to generate the savings in the delayed case for the 2022 LTGRP.		

Page 40 of the CleanBC Roadmap to 2030 (Appendix A-5) states:

> Current requirements for new construction focus on energy efficiency without directly addressing the issue of GHG emissions. Since natural gas is still a dominant, low-cost energy source for buildings, efficiency requirements alone are not enough to meet our climate targets. That's why we're adding a new carbon pollution standard to the BC Building Code, supporting a transition to zero-carbon new buildings by 2030.

Page 41 of the CleanBC Roadmap to 2030 (Appendix A-5) states that after 2030, all new space and water heating equipment sold and installed in B.C. will be at least 100 percent efficient, significantly reducing emissions compared to current combustion technology.

26.1 With reference to the CleanBC Roadmap to 2030, please discuss, with rationale, whether the new construction code settings assumptions remain appropriate.

Response:

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

The 2022 LTGRP was developed at a time of unprecedented change in policy and market forces. The Critical Uncertainty settings could not explicitly incorporate the requirements of the CleanBC Roadmap to 2030 because the November 2021 announcement occurred too late in the development cycle to make such a significant change to the modelling of both the Conservation Potential Review (CPR) and LTGRP. However, although not explicitly incorporated, both the DEP and Deep Electrification Scenarios produce outcomes that are in close alignment to the CleanBC Roadmap requirements with respect to new construction code in the sense that these scenarios do anticipate increasingly stringent, carbon emission reduction related policy. However, only the DEP achieves the target.

The Reference Case assumes that the 2019 in-market mandatory or legally enshrined codes, standards and policies continue across the entire forecast period. The Accelerated new construction code setting was designed to accommodate increasing stringency in building codes over the planning horizon. The Accelerated settings include improved performance based on 2019 knowledge of upcoming codes and standards, which are outlined in Appendix B-3, pages 9-10 (new construction code), 10 (retrofit code), and 10-11 (appliance standards). The next LTGRP will explicitly incorporate the specific CleanBC Roadmap and all other policy updates that will be clarified in that time frame.

It remains to be seen how the CleanBC Roadmap and the transition to zero-carbon new buildings will be actualized by 2030, as anecdotal examples of electricity capacity challenges are already being experienced by City of Vancouver builders. In addition, the role of renewable and low-carbon gas is still uncertain for long-term planning purposes.

Therefore, FEI considers that the new construction code settings and assumptions remain appropriate for the purposes of dealing with the policy uncertainties in the Application. FEI is aware that these considerations will need to be updated for the next LTGRP when there will be some more certainty around policy implementation, electric system capacity, and other market forces.

26.2 Please discuss what impact, if any, the transition to zero-carbon new buildings by 2030 will have on the scenarios presented in the Application.

Response:

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

While there is policy regarding net zero-carbon buildings, it is challenging to discuss the impact that such a policy will have on the scenarios as the details of the policy are unknown, including if or how the policy will be implemented, what fuels may be considered zero carbon, and what potential technologies will be available to reduce emissions. For example, the supply of renewable and low-carbon gases to newly constructed homes and businesses could satisfy zero carbon requirements.

Please also refer to the response to BCUC IR1 26.1 for additional discussion.

26.3 Please explain what assumptions FEI has made with respect to the use of electric and gas heat pumps in the load forecast model. In the response, please detail any assumptions made with respect to the use of renewable gases for gas heat pumps.

Response:

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

FEI has not made assumptions regarding electric equipment choices in the LTGRP scenario modelling. Gas heat pumps are included in the scenario modelling as a Demand Side Management measure in Post-DSM demand analysis. DSM settings vary by scenario (please see the response to BCUC IR1 70.1 for further discussion) and derived gas heat pump savings vary according to the inputs in the DSM setting.

Renewable and low-carbon gases are allocated in varying proportions of FEI's fuel mix serving residential, commercial and industrial load in each scenario. However, renewable gases are not differentiated across end/use or equipment categories. Therefore, there are no assumptions made with respect to the use of renewable gases for gas heat pumps.

26.4 Please explain how the requirement for all new space and water heating equipment sold and installed to be 100 percent efficient by 2030 has been incorporated into the settings.

Response:

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

In the 2022 LTGRP, the Accelerated setting for appliance standards was not yet updated to incorporate the policy direction in the CleanBC Roadmap to 2030. As discussed in the response to BCUC IR1 26.1, the announcement of the CleanBC Roadmap was too late in the development cycle to make such a significant change to the modelling of both the CPR and LTGRP. The Reference Case assumes that the 2019 in-market mandatory or legally enshrined appliance standards continue across the entire forecast period. The Accelerated setting provided additional performance requirements for appliances based on 2019 knowledge of upcoming codes and standards and these are outlined in Appendix B-3, pages 10-11. The next LTGRP will incorporate the CleanBC Roadmap and all other policy updates that will be clarified in the short term.

Please also refer to the responses to BCUC IR1 26.1 and 26.2 for further details.

On page 9 of Appendix B-3 to the Application, FEI states:

> Codes & Standards accounts for the impact of building codes (for new construction) and retrofit code and appliance standards (for retrofits in existing buildings or appliance installations during new construction) that may prompt customers to switch from gas to another end use fuel type.

The BC Government's Buildings and Communities website states:[37]

> Under the Roadmap to 2030, B.C. will add a new carbon pollution standard to the BC Building Code, to make all new buildings zero carbon by 2030.

26.5 Please explain what assumptions FEI has made in the load forecast model with respect to the anticipated carbon pollution standard in the BC Building Code.

Response:

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

As discussed in the response to BCUC IR1 26.1, the Roadmap to 2030 was released after the critical uncertainty settings were developed, and there is no specific assumptions for potential adoption of the new carbon pollution standard. Further, the details of such carbon pollution standard remain unknown to FEI at this time. For example, the supply of renewable and low-carbon gases to newly constructed homes and businesses could satisfy its requirements. Accordingly, FEI considers that its approach to new construction in its demand forecast modelling remains appropriate.

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[37] https://www2.gov.bc.ca/gov/content/environment/climate-change/clean-buildings.

To capture the evolving nature of the regulatory environment for building standards in the Province, FEI created settings for relevant Critical Uncertainties to reflect potential requirements for new construction beyond what was enshrined at the time. These settings include:

- "Accelerated" setting for new construction codes: The "accelerated" setting reflects earlier adoption of higher steps in the BC Energy Step Code. Table B3-2 presents the new construction code setting assumptions:

Setting	Years	Residential Assumptions	Commercial Assumptions
Reference	2020-2042	Step 4 (City of Vancouver)	Step 3 (City of Vancouver)
	2020-2042	Step 3 (all other regions)	Step 2 (all other regions)
Accelerated	2020-2027	Step 4 (City of Vancouver)	Step 3 (City of Vancouver)
	2028-2042	Step 5 (City of Vancouver)	Step 4 (City of Vancouver)
	2020-2027	Step 3 (all other regions)	Step 2 (all other regions)
	2028-2032	Step 4 (all other regions)	Step 3 (all other regions)
	2033-2042	Step 5 (all other regions)	Step 4 (all other regions)

- "Accelerated" setting for equipment standards: Assumes the introduction of additional performance requirements for appliances, as detailed in Appendix B-3 (page 11).
- "High" setting for DSM: Adoption of measures is based on incentives covering 100 percent of a measure's incremental code (as explained in Table 5-3 on page 5-11 of the Application).

These settings—especially when applied together in a scenario—reflect a potential future where policies, such as the proposed carbon pollution standard, could create the conditions for new construction to be zero carbon.

27.0 Reference: CRITICAL UNCERTAINTIES AND THEIR FORECAST MODELLING INPUT SETTINGS FOR THE END USE METHOD DEMAND FORECAST SCENARIOS

Exhibit B-1, Section 4.2.1, p. 4-3, Section 6.2.2.2, p. 6-10; Appendix B-3, Section 1.1.1., p. 3, Section 1.1.1.1, p. 4, Section 1.1.1.2, pp. 12 — 13

Critical Uncertainty Impacts on the Forecast Model – Residential, Commercial and Industrial Demand Category

On page 4-3 of the Application FEI provides Figure 4-1 which shows the 2019 customer base and demand overview. Industrial customers are shown to account for 33.77 percent of FEI's annual demand.

On page 4 of Appendix B-3 to the Application, FEI states:

> The 2022 LTGRP provides further analysis to simulate the impact of economic growth on customer counts that relies on a statistical approach using confidence intervals (CI) […] Note that rate schedules with fewer customers experience a greater range between their high and low outcomes than larger rate schedules.

27.1 Please explain whether FEI assessed the impact of losing or one or more industrial customers on the annual demand forecasts. If so, please identify the relevant scenarios and provide a discussion on the impact on annual demand. If not, please explain why not.

Response:

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

In the scenarios that use the low forecast for customer growth, there is loss of industrial customers in some rate classes. The Deep Electrification, Economic Stagnation, and Lower Bound scenarios all use this low customer growth forecast. In these scenarios, the following industrial rate classes are forecast to lose customers between 2019 and 2042: 4, 5, 25, 6, 7, 27, and 22.

To assess the impact of losing customers, the model projects decreasing consumption for these rate classes and the affected segments. The modeling team did not make judgments about which segments would lose these accounts. A percent reduction was applied to the number of accounts in all customer segments in a rate class and region. In the model for the LTGRP, the number of accounts is rounded to whole numbers. For segments with only a small number of customers, sometimes the percent reduction had to be increased until the number of customers changed. For example, if a region/rate class had four pulp mills and a mine, and the number of customers was supposed to decrease by 20 percent by a certain year, FEI applied a large enough percent reduction to change four pulp mills to three.

The figures below show annual demand for the seven industrial rate classes, in the three scenarios that use the low customer forecast. The figures illustrate the "lumpiness" that results from customer numbers decreasing in whole numbers, particularly in Rate Schedule 22.

Figure 1: Industrial Post-DSM Annual Demand - Deep Electrification Scenario

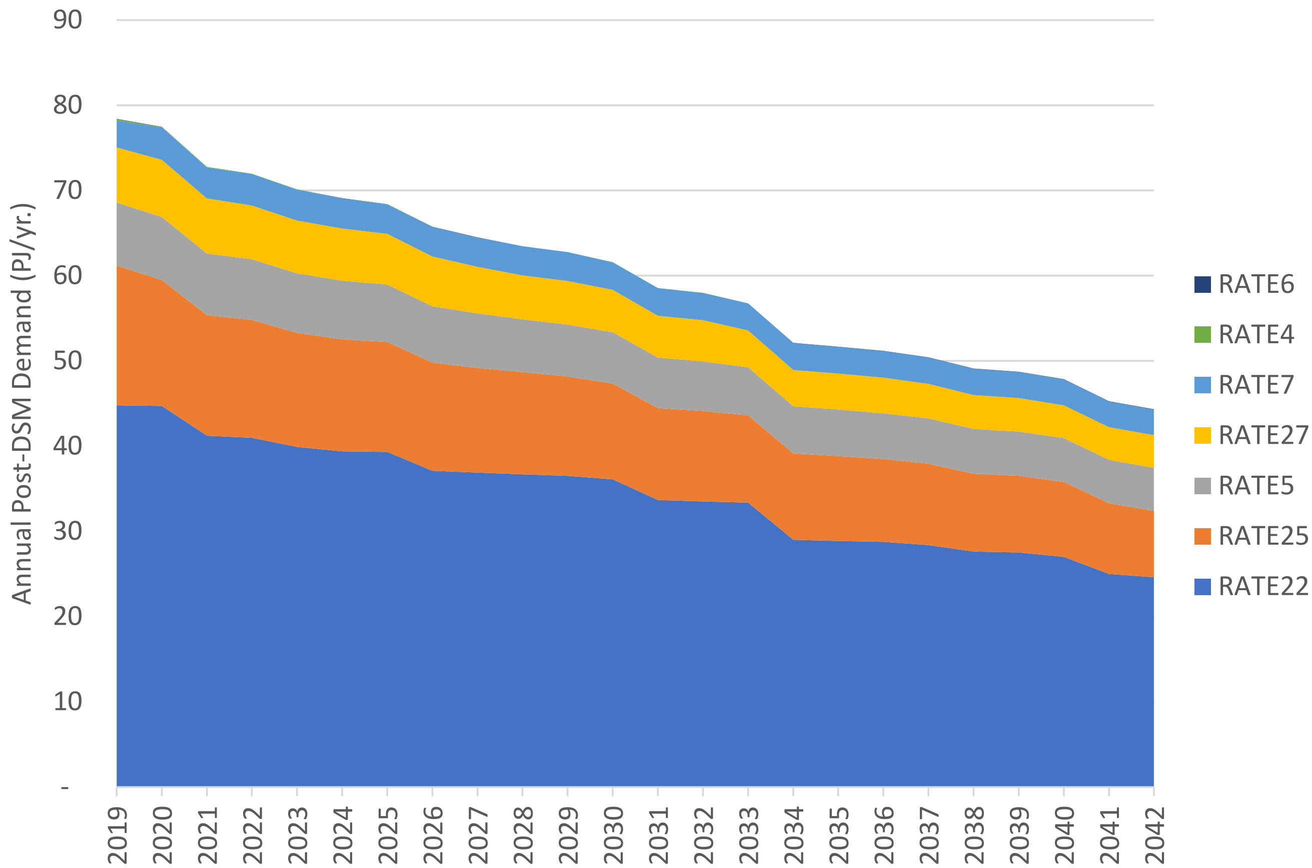


Figure 2: Industrial Post-DSM Annual Demand - Economic Stagnation Scenario

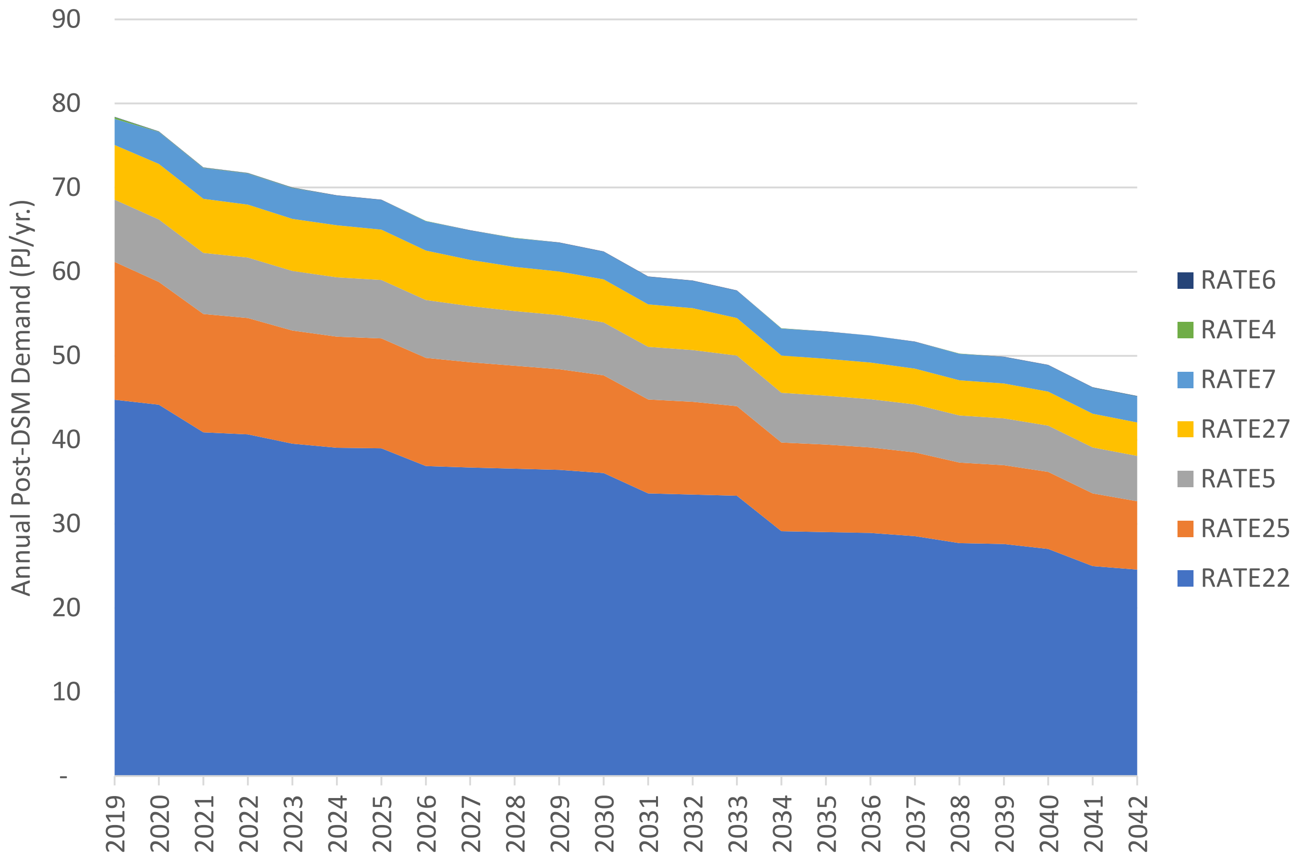
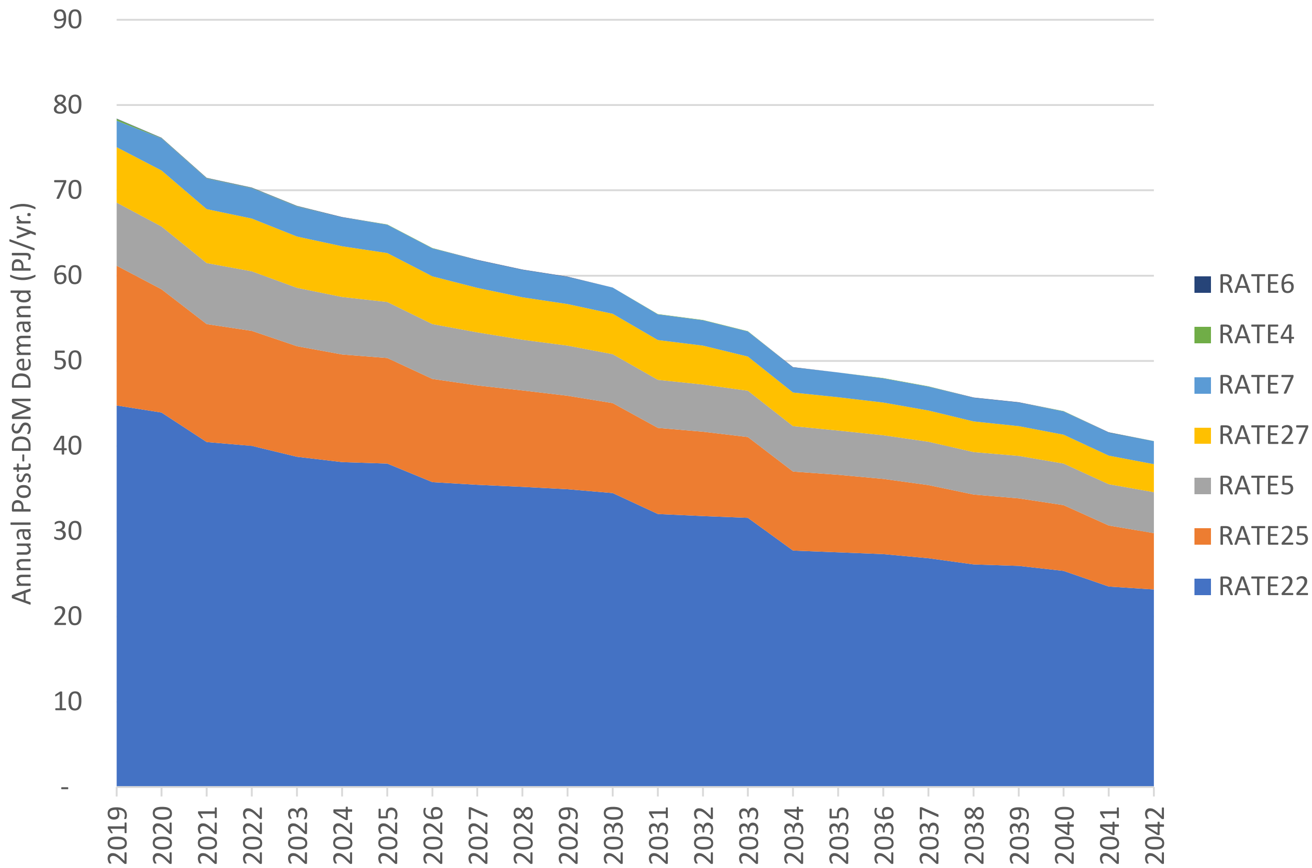


Figure 3: Industrial Post-DSM Annual Demand - Lower Bound Scenario



On page 3 of Appendix B-3 to the Application, FEI provides Table B3-1, which summarizes the modelled critical uncertainty trajectories for the residential, commercial and industrial demand categories.

On pages 12 to 13 of Appendix B-3 to the Application, FEI provides Table B3-3, which summarizes how each critical uncertainty impacts the mechanics of the 2022 LTGRP forecast model and discusses the attributes of individual critical uncertainties.

27.2 For each critical uncertainty listed in Table B3-3, please explain how the Model Levers were selected and discuss the ability of the levers to accurately reflect the impacts of the critical uncertainties (i.e., the correlation between the levers and the uncertainties).

Response:

The following response has been provided by Posterity Group.

The Model levers were selected as discussed below.

Appliance Standards

Appliance standards increase the efficiency with which an appliance converts input energy into a useful energy service. If the energy service (i.e., demand) is unchanged, increased efficiency reduces the unit energy consumption for the end use associated with the standard. For example, if furnace efficiency standards increase, the unit energy consumption for space heating decreases, all else being equal. The correlation between the uncertainty and the lever is inverse: the unit energy consumption is reduced in inverse proportion to the increase in efficiency from the improved standard.

Carbon Price

Carbon price is assumed to affect natural gas fuel share because energy users' fuel choices when replacing equipment will be affected by the increased cost of natural gas fuel caused by increased carbon tax price. The amount of change in the gas fuel share is calculated by applying a price elasticity of demand for natural gas with the change in carbon price. The price elasticity of demand value reflects how sensitive demand for natural gas is in response to a change in price (values are provided in Table B3-3 in the row for Natural Gas Price). Price elasticity of demand for gas is negative, therefore an increase in the carbon price results in a decrease in the fuel share for gas, all else being equal.

Customer Growth

The greater the number of customers (reflected in building stock for the residential sector, floor area for the commercial sector, and facilities for the industrial sector), the greater the demand for gas, all else being equal. However, how this demand is modelled has nuances by sector, as explained below.

In the residential sector, customer growth in accounts is assumed to have a one-to-one relationship with number of dwellings (multi-family buildings, except where suites are individually metered, are in the commercial sector). The residential building stock in number of dwellings is therefore directly proportional to the customer growth uncertainty. Except for a modest number of conversions, the new dwellings added in the model are assumed to have the characteristics of the newest vintage of existing dwellings, so the percentage increase in consumption is somewhat less than the percentage increase in accounts.

In the commercial sector, customer growth in accounts is directly proportional to the amount of commercial floor area added in the model, because new accounts are assumed to have the same average floor area as existing accounts in the same segment, region, and rate class. Because of improved codes and standards, new commercial buildings have lower consumption per unit of floor area than their existing counterparts, so the percentage increase in consumption is somewhat less than the percentage increase in floor area.

In the industrial sector, customer growth in accounts is directly proportional to the production capacity, because new accounts are assumed to be the same average size as existing accounts in the same segment, region, and rate class. Because production of industrial products would be very challenging to model, the LTGRP model uses base year facility gas consumption as a proxy.

Plant capacity in the model is essentially the amount of gas the facilities would use if their efficiency and other energy characteristics were frozen at base year conditions. The consumption in the base year is the same as the plant capacity proxy, but in later years it diverges as efficiency improves and fuel shares change. As with the other sectors, the percentage increase in consumption is somewhat less than the percentage increase in industrial production capacity.

Natural Gas Price

Natural gas price is assumed to affect natural gas fuel share, because energy users' fuel choices when replacing equipment will be affected by fluctuations in the cost of natural gas. The amount of change in the natural gas fuel share is calculated by applying a price elasticity of demand for natural gas with the change in natural gas price. The price elasticity of demand value reflects how sensitive demand for natural gas is in response to a change in price (values are provided in Table B3-3). Price elasticity of demand for gas is negative, therefore an increase in the natural gas price results in a decrease in the fuel share for gas, all else being equal.

New Construction Code

More stringent building codes reduce loads on appliances that provide heating and cooling. For example, an improved building envelope reduces the heating load the furnace must meet. A furnace of the same efficiency will use less energy in direct proportion to the reduced heating load from the building envelope. If the efficiency is unchanged by improved appliance standards, the unit energy consumption therefore decreases in proportion to the change in load from the building code measure.

Non-Price Driven Fuel Switching

Non-price driven fuel switching is assumed to affect energy users' fuel choice directly when they replace equipment. Fuel shares are the model lever that serve as a proxy for equipment choice. For example, if a customer chooses an electric heat pump instead of a natural gas furnace, the gas fuel share for space heating declines. When policies require electrification of space and water heating end uses, natural gas fuel shares are reduced for those end-uses while electric fuel shares increase, all else being equal.

Retrofit Code

The retrofit code has the same effect as the new construction code: more stringent building codes reduce loads on appliances providing heating and cooling. However, instead of applying to all new construction, the retrofit codes applies to a proportion of the existing buildings (buildings that are demolished and replaced are included in new construction).

27.3 For each critical uncertainty listed in Table B3-3, please explain which critical uncertainties have the largest and smallest impacts on the load forecast.

Response:

The following response has been provided by Posterity Group.

We interpret "impact on the load forecast" to mean the percentage change in the demand for gas, either increasing or decreasing. Note that the impact on the load forecast is a product of the modelling approach for estimating the effect of each critical uncertainty and the input values for the settings established.

The following table shows the order of the critical uncertainties, as presented in Table 4-1 of the Application, from largest to smallest impact on the gas demand in 2042.

Order of Impact	Critical Uncertainty
1	Non-Price Driven Fuel Switching
2	Global LNG Demand
3	New Large Industrial Demand Growth
4	Low-Carbon Transportation Demand
5	Carbon Price
6	Natural Gas Price
7	Customer Growth
8	Codes & Standards

27.4 For the Carbon Price, Natural Gas Price and Non-price Driven Fuel Switching critical uncertainties, please provide the long run natural gas fuel share used as a proxy for each trajectory. In the response, please explain how the long run gas fuel share percentages (or similar) were established, detailing any assumptions made.

Response:

The following response has been provided by Posterity Group.

The following table shows the approximate percentage change in fuel share that would be expected by 2042 for the applicable end uses, for the high, planning and low settings for the carbon price and natural gas price critical uncertainties.

2042 Percent Fuel Share Change						
Setting	Residential End Uses		Commercial End Uses		Industrial End Uses	
	Carbon Price	Natural Gas Price	Carbon Price	Natural Gas Price	Carbon Price	Natural Gas Price
Low	15%	12%	14%	11%	30%	23%
Planning	-19%	0%	-19%	0%	-26%	0%
High	-24%	-12%	-22%	-11%	-40%	-22%

In each case, the expected percentage change is based on the long-run price elasticity of demand for the sector. The elasticity values obtained from a search of the literature were -0.38 for residential, -0.35 for commercial and -0.7 for industrial. FEI used the same elasticity whether the change in gas price was caused by changes in carbon price or commodity price or a combination of the two. To calculate the change in quantity demanded (Q) caused by a change in price (P), we used the formula for mid-point arc elasticity:

$$elasticity = \frac{\frac{Q_2 - Q_1}{0.5 * (Q_2 + Q_1)}}{\frac{P_2 - P_1}{0.5 * (P_2 + P_1)}}$$

The percent change in gas demand for 2042 is provided by this calculation. This expected percent change is then applied to the respective end uses in each group of buildings in the sector. For example, the 12 percent reduction for residential end uses in the high gas price scenario was an expected reduction for gas share in space heating, domestic hot water, fireplaces, dryers and pools. The 2042 natural gas share for these various end uses in all the different dwelling types in the different service regions ranged from zero percent to 100 percent, with a weighted average of 72 percent. On average, therefore, in this scenario the target long-run fuel share for these end uses was (1 – 0.12) * 72% = 63%. In the model, the end uses in each group of buildings undergo a different reduction in fuel share, depending on their 2042 natural gas fuel share in the reference case (which is the starting point).

In contrast to price-driven fuel switching, where the estimated changed in demand is calculated using a price elasticity value, the amount of change due to non-price driven fuel switching is driven by targets we assumed would be established by government policy. The following table shows gas fuel share reduction targets for 2042 for each non-price driven fuel switching setting. There is no setting for this critical uncertainty that has the gas fuel share increasing. In a scenario where there is no non-price driven fuel switching, such as the Upper Bound scenario, this critical uncertainty is not applied so there are no gas fuel share targets to achieve, such as in the Reference Case.

	Residential				Commercial				Industrial	
Region:	All regions except CoV[38]		CoV only		All regions except CoV		CoV only		All regions except CoV	CoV only
End Use:	Space Heating	DHW	Space Heating	DHW	Space Heating Gas Fuel Share	Water Heating Gas Fuel Share	Space Heating Gas Fuel Share	Water Heating Gas Fuel Share	Direct-fired heating, heat treating, kilns[39], ovens, product drying, space heating, water heating	
"Moderate Electrification"	17%	14%	17%	17%	12%	11%	12%	12%	7%	7%
"Accelerated Electrification"	69%	58%	68%	66%	47%	45%	48%	47%	15%	16%
"Extensive Electrification"	82%	69%	82%	79%	56%	53%	57%	56%	23%	25%

For scenarios in which there are both expected gas share reductions from price-driven fuel switching (either carbon or commodity) and gas share reduction targets from non-price-driven fuel switching, for each end use the model uses whichever change is larger.

27.4.1 Please explain whether there are any limitations associated with using the same model lever for three critical uncertainties. If not, please explain why not.

<u>Response:</u>

The following response has been provided by Posterity Group.

FEI does not consider that there are any practical limitations with using the same model lever for the carbon price, natural gas price and non-price driven fuel switching critical uncertainties. Using the fuel share as the lever for each of the cited critical uncertainties is sensible because the expected impact on gas consumption is the same: gas consumption declines as customers switch to other fuels (likely electricity), when gas or carbon price increases, and on account of fuel switching policies. In all these cases, it is assumed gas demand changes via fuel switching, therefore fuel share is the logical model lever to adjust.

In scenarios where both the carbon price and the natural gas commodity price are expected to change, the elasticity of demand was assumed to be the same for both and therefore the two

[38] City of Vancouver.
[39] Kilns in the Pulp & Paper – Kraft segment.

changes could be added together. The expected reduction (or increase) in gas demand would, therefore, be calculated using the method described in the response to BCUC IR1 27.4. In scenarios where there is both a price-driven expected change in gas demand and a policy-driven target change in demand, the two levers might affect fuel switching to varying degrees. In these scenarios, for each end use, the larger of the two changes was applied. The price-driven change was assumed to contribute towards meeting the policy-driven change (or in some cases go beyond it). There was not a scenario where policy-driven fuel switching and the price-driven critical uncertainties went in opposite directions.

To ensure fuel switching does not occur faster than is realistic, the rate of fuel share change is limited by the rate of equipment turnover because most customers are assumed to only change equipment when their existing appliance reaches its end of life. Therefore, the rate of fuel share change is limited by the equipment turnover rate, which is based on the average life expectancy of equipment by end use.

A limitation of the model in general is the limited ability to quantify the impact of each individual critical uncertainty on changes in demand in each scenario. This is due, however, to the complex nature of interactive effects between critical uncertainties that the model is designed to capture. This limitation is considered a reasonable trade-off against the likelihood of distorted results if over-simplifying the model to avoid such interactive effects.

On page 6-10 of the Application FEI states: "At this time, the key resources that FEI anticipates acquiring over the next 20 years and beyond to increasingly displace conventional natural gas supplies are RNG, hydrogen, syngas and lignin, as discussed in Section 3."

27.5 Please confirm, or explain otherwise, that the cost impact of displacing natural gas supplies with RNG, hydrogen, syngas and lignin is not a modelled critical uncertainty.

27.5.1 If confirmed, please explain why not.

27.5.2 If confirmed, please explain whether the cost impacts of displacing natural gas supplies with alternative fuels can be modelled and provide details of the assumptions/levers that would be used.

27.5.3 If not confirmed, please explain how the cost impact of displacing natural gas supplies with alternate fuels is modelled.

Response:

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

FEI confirms that the cost of RNG, hydrogen, syngas and lignin is not itself a modelled critical uncertainty. The drivers for these fuels were modeled by providing the model with specific amounts of energy supplied by each fuel in each year. The model replaced conventional natural gas with these amounts mechanically, without regard for the cost of any of the fuels or the elasticity of demand.

As explained on page 4-20 of Section 4.5.2 in the Application, renewable and low-carbon gas supply options are modelled along with demand uncertainties across the scenarios to understand how gas demand can be met while reducing GHG emissions relative to historical emissions at a point in time (i.e., 2007) or relative to a scenario where load is primarily met with conventional natural gas (i.e., the Reference Case).

The reason that these costs are not a critical uncertainty is that the production, technologies and market for these fuels is still emerging and market data for these fuels is not available in the same way that it is for conventional natural gas. In addition, an independent variable is required to model alternative gas supplies. If cost and supply for these fuels were both modelled as uncertainties, it would create a circular loop in the model, as costs and supply affect one another. Finally, FEI included the impact of these higher prices (as presented in Figure 2-3 on page 2-25 of the Application) in the rate impact analysis presented in Section 9.4 of the Application. As the market for renewable and low-carbon gas supplies grows and more market data becomes available to FEI (note that FEI is already seeing more market analysts developing preliminary data on these supplies), alternative price trajectories may be incorporated into the critical uncertainty analysis. Data on the relationship between the demand for these fuels by FEI customers and the prices of the fuels would need to be sufficient to determine a modelling approach. While it is assumed that as the price of natural gas or carbon increases, demand for natural gas declines, that same assumption may not hold in the future with respect to low-carbon fuel. For example, a higher carbon price may increase demand and thus supply for these lower carbon fuels. However, the model lever used to model the change in demand for these fuels would likely be the same (adjusting fuel shares).

27.6 Please explain whether the model accounts for the impacts of natural gas price elasticity. If so, please explain how the impacts are modelled. If not, please explain why not.

Response:

The following response has been provided by Posterity Group.

The long-run price elasticity of demand for natural gas was used in modeling the two price-driven fuel switching critical drivers: carbon price and natural gas price. The approach to modeling these critical drivers is discussed in the response to BCUC IR1 27.4.

27.7 Please explain how the model accounts for the impact of fuel switching due to either increasing natural gas prices, renewable or low carbon fuel prices, and overall rate increases.

Response:

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

Natural gas prices and carbon price are both included in the avoided cost of conventional natural gas. The model uses the difference between the avoided cost in each scenario and the avoided cost in the Reference Case to estimate the amount of price-driven fuel switching that would occur in the scenario. Please refer to the response to BCUC IR1 27.4 for a detailed description of how price-driven fuel switching was modelled.

The prices of renewable or low-carbon fuels did not factor into price-driven fuel switching, because their introduction was handled in other, dedicated critical uncertainties. The interaction between prices of multiple fuels would have been a very complex, iterative modeling problem and would have involved estimating elasticities that are not available in the literature. Instead, the supply amounts of these gases were modelled as critical uncertainties and their prices were not. Please refer to the response to BCUC IR1 27.5 for a discussion of how renewable and low-carbon gases were modelled.

Retail rates are assumed to follow avoided cost in the long term, though not necessarily in lockstep. Because the relationship of rates to avoided costs is not linear and varies by rate class, including rates in the fuel switching analysis would have increased the complexity of the model. Although it was recognized that retail rates are the mechanism that ultimately changes customer behavior and causes price-driven fuel switching, rates and costs track each other in the long term. To avoid added complexity, therefore, gas prices and carbon pricing are assumed to drive fuel switching from gas to electricity (and potentially the other way if they decrease relative to the Reference Case).

27.8 Please explain how the model accounts for the impact of rate increases upon the number of customers (residential, commercial and industrial).

Response:

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

The model does not change the number of accounts based on changes in rates. Rates are assumed to follow avoided costs in the long run, but the modeling assumes the changes in rates caused by changes in commodity or carbon price will drive the price-driven fuel switching. Customer growth follows the selected Reference, High, or Low setting for the scenario.

Accordingly, in some scenarios, customers are added in the model and then a percentage of them subsequently undergo price-driven fuel switching for some end uses. A percentage of the new customers may use natural gas for cooking, fireplaces, or barbecues, but not for their space and water heating. Nonetheless, these customers remain on the system in the model. FEI and Posterity Group used this approach because incorporating price-driven changes to both customer additions and changes in use per customer would add complexity, potentially overstate (or double count) the effect of increased costs, and multiply the number of potential scenario outcomes without necessarily improving the value of the forecast results.

28.0 Reference: ALTERNATE FUTURE SCENARIOS AND CRITICAL UNCERTAINTY SETTINGS

FEI BERC Rate proceeding, Exhibit B-11, Section 1.1, p. 2; Exhibit B-17, BCUC IR 12.2.1, 12.2.2

Biomethane Energy Recovery Charge Rate

On page 2 of Exhibit B-11 in the FEI BERC Rate proceeding, FEI states:

> - FEI proposes a new Residential Gas Connections service under which FEI will permanently provide 100 percent Renewable Gas to new residential dwellings attaching to the system by a service line installed on or after the date of implementation of the service […] This new service will enable FEI to continue to add customers, encouraging the efficient use of the existing gas delivery system and providing energy choice for British Columbians.

In response to BCUC IR 12.2.1 in the FEI BERC Rate proceeding (Exhibit B-17), FEI stated:

> If the Renewable Gas Connections service is not approved and tailored to the new residential construction sector as proposed, FEI expects that some of this load would be served by conventional natural gas for the municipalities that do not adopt GHGi metrics. However, there would be a loss of customer attachments and associated potential load without a Renewable Gas Connections program that would increase out to 2030 […]
>
> In a scenario which assumes that provincial building stock turnover is approximately 2 percent per year and none of those new buildings connect to the gas system, resulting in FEI losing 2 percent of its residential and commercial customers per year, FEI could expect the total volume of gas sold to residential and commercial customers to be 20 PJ or 18 percent lower than it would be if the Renewable Gas Connections service was approved.

In response to BCUC IR 12.2.2 in the FEI BERC Rate proceeding (Exhibit B-17), FEI stated:

> FEI used the Diversified Energy Future (Planning) scenario from the LTGRP, which includes forward looking demand reflective of the Renewable Gas supply embedded in the Application. Under this scenario, customer growth continues to occur and the existing gas infrastructure is used to deliver low carbon energy solutions to customers.

28.1 Please explain whether the scenarios presented in the 2022 LTGRP (Reference Case, Upper Bound, Diversified Energy (Planning), Price-Based Regulation, Economic Stagnation, Deep Electrification, Lower Bound) assume that the Renewable Gas Connections service is approved.

28.1.1 If yes, please explain how the scenarios account for the Renewable Gas Connections service.

28.1.1.1 If the Renewable Gas Connections service is denied, please discuss, and quantify, the impacts on the annual demand forecasts and the customer forecasts for each scenario presented in the Application.

28.1.2 If no, please explain why not.

28.1.2.1 If the Renewable Gas Connections service is approved, please discuss, and quantify, the impacts on the annual demand forecasts and the customer forecasts for each scenario presented in the Application.

Response:

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

The approval or not of FEI's Renewable Gas Connections service was not a modelled critical uncertainty in the 20-year demand forecasts for the 2022 LTGRP. Rather, the extent to which electrification might occur over the next 20 years (which could be partly determined by the final decision on the Renewable Gas Connections service) was modelled as a critical uncertainty. FEI considers that the DEP Scenario is more akin to a scenario where the service is approved, whereas the Deep Electrification Scenario is more akin to a future where the service is not approved.

FEI considers that the Renewable Gas Connections service is an important early step in FEI's implementation of its Clean Growth Pathway. Approval of the service will allow FEI to continue to add new customers and maintain a viable gas system, taking a diversified approach to emissions reductions, which includes both gas and electric systems. This is consistent with the DEP Scenario.

Denial of the FEI's Renewable Gas Connections service is expected to reduce gas throughput, which is consistent with the Deep Electrification Scenario. However, with rapid and unforeseeable changes in local and provincial legislation, it is not possible to predict with certainty the resulting changes in customer additions, losses or demand if the Renewable Gas Connections service is not approved.

With or without the service, FEI expects to take the steps necessary so that its total GHG emissions from the use of natural gas by residential, commercial and industrial customers will meet the 2030 GHG emissions cap expected to be implemented by the Province. The availability of Renewable Gas Connections service will inform the strategies FEI must employ to meet the GHG emissions cap.

FEI will further assess the outcomes of the BCUC's decision on the Renewable Gas Connections service, as well as all other aspects of the energy planning environment, for its next LTGRP in order to determine the critical uncertainties that are impacting the demand forecasts at that time.

29.0 Reference: ALTERNATE FUTURE SCENARIOS AND CRITICAL UNCERTAINTY SETTINGS

Exhibit B-1, Section 2.2, pp. 2-1–2-21; Section 4.5.1, p. 4-17; Section 4.5.3, p. 4-22; Appendix B-3, Section 1.1.1.1, p. 8.

The Diversified Energy (Planning) Scenario

Section 2.2 of the Application provides an overview of the relevant policy and regulatory context facing FEI that impact future resource options, market prices, and influence customers' behaviour regarding energy use in the future.

On page 4-17 of the Application, FEI states that the Diversified Energy (Planning) Scenario sets the planning context for the 2022 LTGRP. FEI further states:

> The Diversified Energy (Planning) Scenario includes essential elements of the Clean Growth Pathway, such as accelerated acquisition of renewable gas supply, growth in the use of low-carbon gas as a transportation fuel, and electrification[149] initiatives in BC that impact gas demand.
>
> [149] The Diversified Energy (Planning) Scenario is modelled with the assumption that 25% of residential and commercial gas demand, and 10% of industrial gas demand is electrified by 2050, with a straight line interpolation for each year of the forecast period.

On page 4-22 of the Application, FEI provides Table 4-1, which summarizes the six alternate future scenarios that FEI has modelled. Table 4-1 is reproduced in part:

Scenario	Description	Input Settings		Discussion
Diversified Energy (Planning)	The Diversified Energy (Planning) Scenario's key planning assumptions build upon a diversified approach to energy delivery and emissions reductions to British Columbians. Under this scenario, customer growth occurs for both electric and gas utilities and the existing gas infrastructure is used to deliver low-carbon energy solutions to customers. FEI uses the Diversified Energy (Planning) Scenario as its planning scenario.	**Residential, Commercial and Industrial Demand Category**		The explanation of the Diversified Energy (Planning) Scenario and its selection as FEI's planning scenario is provided in Section 4.5.1.
		Appliance Standards	Reference	
		Carbon Price	Reference	
		Customer Forecast	Reference	
		Fuel Switching	Moderate electrification	
		Natural Gas Price	Reference	
		New Construction Code	Reference	
		Retrofit Code	Reference	
		Low-Carbon Transportation and Global LNG Demand Category		
		LCT Demand	Planning	
		Global LNG Demand	Planning	
		New Large Industrial Demand Category		
		Industrial Demand Growth	Planning	

On page 8 of Appendix B-3 to the Application, FEI states:

> The Reference trajectory assumes the carbon tax is held constant once the maximum announced value (as of the time the settings were determined) was

reached and held constant throughout the planning horizon. The Planning trajectory matches the federal carbon price announcement and grows to $170/tonne in 2030 (in nominal dollars), remaining constant thereafter.

29.1 For each of the following Input Settings, please elaborate further on the reasons why the Reference settings were selected: (i) Appliance Standards; (ii) Customer Forecast; (iii) Natural Gas Price; (iv) New Construction Code; and (iv) Retrofit Code.

Response:

The following response has been provided by Posterity Group.

In considering both the setting values developed for each critical uncertainty and the settings selected for modelling each scenario, it is important to keep in mind that the demand forecast is one of the earliest steps in the resource planning process and that these values and selections are based on the planning environment that prevailed when those steps were undertaken. For the 2022 LTGRP, this work was undertaken in late 2019 and 2020, as described in Appendix B-3.

Use of the Reference setting for the listed critical uncertainties in the DEP Scenario is discussed below.

(i) Appliance Standards

FEI developed two settings for appliance standards: Reference and Accelerated. FEI does not envision a future where appliance standards would become less stringent, and FEI considered that creating different levels of accelerated appliance standards would not have a strong basis nor add value to the modelling exercise.

The Reference setting included all appliance standard advancements that were known at the time the settings were developed. FEI considers that limiting the advancement of appliance standards to those that are known is a practical and conservative approach to estimating future demand in its planning scenario, since speculative changes to such standards can be applied to other scenarios to examine those “what if” conditions. Using this approach in the context of meeting the GHGRS offers additional opportunities to further reduce GHG emissions over the planning horizon. Further, while FEI envisioned at that time that the development or advancement of appliance standards for use of hydrogen in appliances would occur in the DEP Scenario, such work was assumed to be focused on safety rather than efficiency improvements and so would not impact the overall need for energy. Thus, an additional setting for advancing hydrogen equipment standards would not add value to the demand forecast modelling exercise.

(ii) Customer Forecast

Consistent with past practice in long-term gas resource planning, FEI considers the Reference customer forecast to be the Planning customer forecast and so a separate “Planning” setting was not created. Higher and lower customer forecasts were applied to other settings to test those potential scenarios. The method used by FEI to create the reference, higher, and lower customer forecasts is described in Section 4.3 of the LTGRP and, for residential and commercial customers, is further detailed in the response to BCUC IR1 11.1. Each of these customer forecasts provide the number of accounts by year for each region and rate class, and serve as inputs to the LTGRP model.

(iii) Natural Gas Price

Consistent with past practice in long-term gas resource planning, FEI considers the Reference natural gas price forecast to be the Planning price forecast and so no separate "Planning" setting was developed. Higher and lower natural gas price forecasts were applied to other settings. Further, carbon price, through a carbon tax on natural gas, was used to model the impact of increasing natural gas related costs in a future in which deep decarbonization of energy use (as is the case in the DEP scenario[40]) is a priority. Since a "Planning" setting was developed and implemented for carbon tax in the DEP Scenario, also increasing the price of natural gas based on pressures as a result of carbon reduction would be double counting such an impact. At the time the settings were determined, other factors that might influence natural gas price were assumed to be embedded in the Reference setting.

(iv) New Construction Code

As described in Appendix B-3, consideration of the new construction code was based on the BC Energy Step Code. FEI considers that the Reference setting, which includes what was in place and known to be changing at the time that the scenarios were developed, was the most reasonable assumption for its Planning scenario and so no separate planning setting was developed for the new construction code. FEI also considers that speculation of accelerated or delayed amendments to the Step Code beyond those known at the time were more appropriately modelled in other scenarios. Applying this logic to the new construction code also maintains consistency with the treatment of appliance standards in demand forecast modelling.

(v) Retrofit Code

FEI developed two settings for the building code for a potential future energy retrofit code: Reference and Accelerated. FEI considers that the Reference setting, which includes what was in place and known to be changing at the time that the scenarios were developed, was the most reasonable assumption for its Planning scenario and so no separate planning setting was developed for a potential retrofit code. Since no retrofit code existed or was known to be scheduled for implementation at that time, a 'lower' setting is not plausible. FEI considered that exploring the impacts of advancing a retrofit code was best applied in alternative scenarios. Applying this logic to the retrofit code also maintains consistency with the treatment of appliance standards and new construction codes in demand forecast modelling.

Finally, updates to any of these critical uncertainties that occurred after the demand forecast modelling for the LTGRP was completed will be considered in the next LTGRP. FEI considers this a reasonable approach for planning over a 20-year planning horizon.

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[40] See the response to BCUC IR1 29.

29.2 For the Diversified Energy (Planning) Scenario, please explain why the setting for the Carbon Price was set at Reference ($50/tonne until 2042) and not, for example, the Planning setting (increasing to $170/tonne in 2030). Please discuss why FEI considers the Reference setting to be more likely.

29.2.1 If the setting for Carbon Price were to be set at Planning, please explain the impact on the demand forecasts for the residential, commercial and industrial sectors.

Response:

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

FEI acknowledges an error in Table 4-1 of the Application. The actual setting used for the carbon tax in the DEP Scenario was the Planning setting (increasing to $170 per tonne in 2030) and not the Reference setting as shown in Table 4-1. The Planning setting was used to model future changes to the carbon price in the DEP Scenario.

29.3 With reference to the policy and regulatory context outlined in section 2.2 of the Application, please explain why, other than Fuel Switching, all settings for the Planning Scenario remain the same as the Reference Case for the residential, commercial and industrial sectors.

Response:

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

The narrative of the DEP Scenario is reflected in the setting choices for the critical uncertainties and is supported by the use of the "Planning" setting. As explained in the response to BCUC IR1 29.1, where the Reference settings were used to model the DEP Scenario, the Reference settings were determined to be the Planning settings as well and so no separate Planning settings were created for those critical uncertainties. As explained in the response to BCUC IR1 29.2, there was an error in Table 4-1 and for the carbon tax a separate Planning setting was created and used for modelling the DEP Scenario.

29.4 Please discuss the factors that led FEI to select the Diversified Energy (Planning) scenario as the planning scenario. In the response, please explain whether this scenario closely reflects FEI's view of the future.

Response:

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

The factors that led FEI to select the DEP Scenario as the planning scenario are discussed in Sections 2 and 3 of the Application. They include the research conducted by FEI and others on the benefits and costs of a diversified energy future as contained in the 2022 LTGRP appendices. The final factor that led FEI to select the DEP Scenario as its planning scenario is the consideration that this scenario reflects FEI's view of the future. FEI considers that pursuing its Clean Growth Pathway to bring about a diversified energy future best meets the LTGRP planning objectives discussed in Section 1.4 of the Application.

29.5 Please discuss the factors that could lead to the long-term energy demand over the planning period being lower than the load forecast in the Diversified Energy (Planning) scenario.

Response:

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

Based on the Critical Uncertainties modelled for this LTGRP, changing any of the settings used in the DEP Scenario to lower energy demand would cause a forecast with lower demand. Specifically, adjusting the following factors would have this effect:

- Lower customer account forecast, i.e., fewer customer accounts;
- Lower demand for gas from the transportation sector;
- Lower demand for renewable and low-carbon gas supply;
- Higher natural gas prices;
- Higher carbon prices;
- Accelerated implementation of more stringent building codes or equipment standards; and
- Accelerated or enhanced policies that incentivize or mandate gas-to-electric fuel switching.

However, as with all scenario analysis, the outcome of the confluence of these factors is difficult to predict; therefore, several scenarios were developed for the LTGRP to capture the range of various policy and economic conditions. Consideration of all of these settings occurring in a single scenario was modelled in the Lower Bound Scenario in Figure 4-9 on page 4-28 of the Application.

29.5.1 Please discuss the risks to FEI should the Deep Electrification scenario materialize.

Response:

Should the Deep Electrification Scenario materialize, it will likely result in significant underutilized capacity of FEI's gas system (i.e., stranded asset risk). For discussion on stranded asset risk as well as discussion on actions that FEI is taking to mitigate such risks, please refer to the response to BCUC IR1 16.1.

Other risks to FEI are also discussed extensively in FEI's evidence as part of the BCUC Generic Cost of Capital (GCOC) Proceeding.[41] For example, under the Deep Electrification Scenario, a system that is large geographically but with a small customer base and limited throughput would create significant operational challenges. Given the potential for customers leaving the system in a "demand death spiral" situation, FEI expects there would be difficulty in attracting new investors and hiring new or retaining existing employees, as well as increased opposition to new infrastructure or facilities for any growth or sustainment purposes.

29.6 In the event that the 2022 LTGRP is accepted by the BCUC, please explain whether FEI intends to use the Diversified Energy (Planning) scenario as the basis for future applications to the BCUC, such as certificates of public convenience and necessity, expenditure schedules and energy supply contracts.

Response:

Yes, FEI has selected the DEP Scenario as its planning scenario and it is the basis for the Action Plan to implement FEI's Clean Growth Pathway presented in Section 10 of the Application. This Action Plan includes actions and initiatives that will require future applications to the BCUC, including CPCNs, DSM expenditure plans and energy supply contracts.

29.7 In the event that actual energy demand is higher or lower than the demand forecasted under the Diversified Energy (Planning) scenario, please discuss what changes would be required to the near-term actions. In the response, please

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[41] Exhibit B1-8, B1-8-1 and B1-8-1-1 of the BCUC GCOC Proceeding:
https://docs.bcuc.com/Documents/Proceedings/2022/DOC_65493_B1-8-FEI-FBC-Evidence-on-Stage1.pdf.
https://docs.bcuc.com/Documents/Proceedings/2022/DOC_65494_B1-8-1-FEI-FBC-Evidence-on-Stage1-Appendices.pdf.
https://docs.bcuc.com/Documents/Proceedings/2022/DOC_68393_B1-8-1-1-FortisBC-AppendixA-errata-BusinessRisk.pdf.

explain what challenges a higher or lower demand would pose to FEI over the near-term.

Response:

The LTGRP is a long-term plan that considers energy demand trends over a 20-year planning horizon. In the short term, actual demand is likely to be higher or lower than the long-term demand forecast and such short-term fluctuations in anticipated demand in one year could be offset by demand growth in the opposite direction in the next year. A long-term energy demand forecast, therefore, avoids undue influence of such short-term fluctuations. As such, changes to the near-term actions presented in the 2022 LTGRP Action Plan would not be needed if actual short-term demand is somewhat higher or lower than anticipated by the DEP Scenario demand forecast.

Over the long term, FEI modelled the potential for the demand for gas to be higher or lower than the DEP Scenario in the alternative scenarios. The contingencies for actions that FEI would need to take in response are presented in Sections 6 and 7 of the Application. Further, if other changes in the planning environment occur after the demand forecast modelling for the 2022 LTGRP was completed to suggest that higher or lower demand would result over the long term, such changes will be considered in preparing the next LTGRP. Ensuring that such changes are considered in long-term resource planning is the reason that a new LTGRP is prepared approximately every three to five years.

30.0 Reference: ALTERNATE FUTURE SCENARIOS AND CRITICAL UNCERTAINTY SETTINGS

Exhibit B-1, Section 4.5.3, p. 4-25; Section 4.6.1.1, p. 4-29; Appendix B-3, Section 1.1.1.1.3, p. 8; FEI and BC Hydro Energy Scenarios – Stage 1 Submissions, p. 5; BC Hydro 2021 Integrated Resource Plan (2021 IRP) proceeding, Exhibit B-1, Appendix B, Section 8.2, p. 50

Lower Bound and Deep Electrification Scenarios

On page 4-29 of the Application, FEI states:

> Both the Lower Bound and the Deep Electrification scenarios create technical and logistical requirements for alternative energy systems to be able to manage the scale of shifting energy resources that are not plausible, particularly to support peak energy, reliability and resiliency requirements. Since the Lower Bound scenario is a mechanical scenario that does not have a logical explanatory narrative, but simply examines what demand would look like if all settings were set to minimize demand as much as possible, it is considered untenable, and no further examination of this scenario is conducted in the 2022 LTGRP.

On page 4-25 of the Application, FEI provides Table 4-1, which summarizes the input settings for the Deep Electrification scenario. The setting for Carbon Price is noted as Reference.

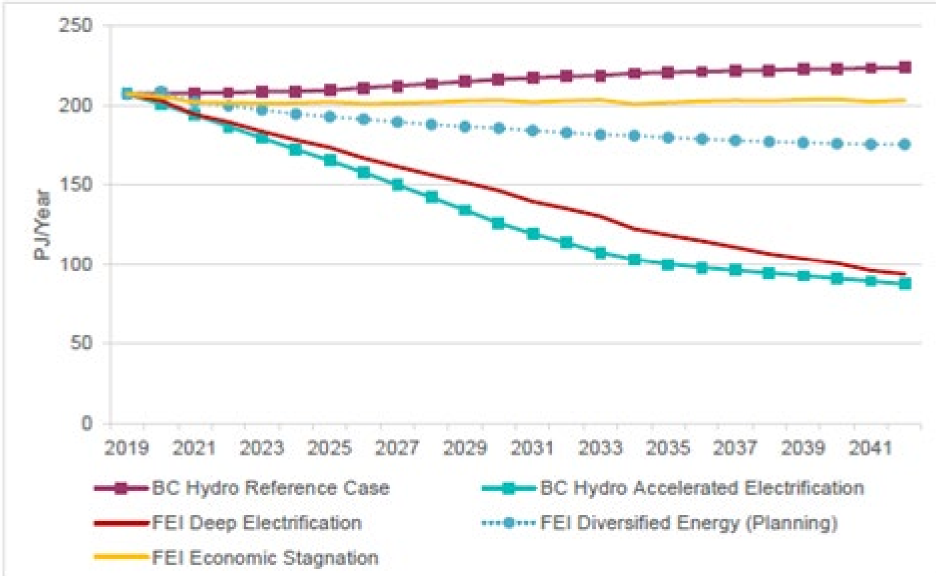
On page 8 of Appendix B-3 to the Application, FEI states:

> The Reference trajectory assumes the carbon tax is held constant once the maximum announced value (as of the time the settings were determined) was reached and held constant throughout the planning horizon. The Planning trajectory matches the federal carbon price announcement and grows to $170/tonne in 2030 (in nominal dollars), remaining constant thereafter.

On page 4-25 of the Application, FEI states: “To support economic growth, the BC government supports LNG exports to other jurisdictions. Despite these exports, the domestic shift towards electricity causes a regional conventional natural gas supply glut, leading to low regional gas prices.”

On page 5 of the Energy Scenarios – Stage 1 Submissions, FEI provides Figure 2, which shows the forecast of total annual gas demand by scenario for residential, commercial and industrial customers:

Figure 2: Forecast of Total Annual Gas Demand by Scenario – Residential, Commercial and Industrial Customers[3]



On page 50 of the 2021 IRP in the BC Hydro 2021 IRP proceeding, BC Hydro states:

> 8.2 The contingency scenarios we are preparing for […]
>
> Accelerated electrification load scenario represents a case where load grows rapidly. It looks at the demand that could arise from BC Hydro's Electrification Plan and electricity demand from actions to meet the Province's 2025, 2030, and 2040 greenhouse gas reduction target.

30.1 Please elaborate further on the rationale for developing the Lower Bound scenario.

Response:

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

The Lower Bound and Upper Bound scenarios are created to set the theoretical maximum and minimum for annual demand in order to create "boundaries" which the other demand forecast scenarios fall within. For scenario analysis and long-term planning, the Upper Bound and Lower Bound are developed to estimate the outcome if all the critical uncertainties are set at their maximum settings to create the highest and lowest demand forecasts possible and ensure these outcomes are explored. The Lower Bound illustrates the most extreme, low-gas-demand scenario from an annual demand perspective.

30.2 Please explain whether the Upper Bound scenario is also a mechanical scenario that examines what demand would look like if all settings were set to maximize demand as much as possible.

30.2.1 If so, please discuss whether FEI considers the Upper Bound scenario to also be untenable.

Response:

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

Yes, the Upper Bound Scenario is developed by using the settings that cause the maximum increase in demand for all of the critical uncertainties. Though FEI does not consider the Upper Bound a very likely scenario, FEI does not view this scenario as untenable in the same way as the Lower Bound Scenario. Whereas the Lower Bound Scenario would include vast infrastructure challenges, as well as associated high cost and customer rate impacts for both the gas and electric systems (as gas demand would be shifted to the electric system, the gas demand in the Upper Bound Scenario does not involve a massive shift of demand from one of these two systems to the other. Instead, the majority of the increased growth in gas demand is caused by a few sectors in which new customers that are not currently gas or electric customers in BC would be added to the gas system. The driver of such large increases in demand would likely be carbon reductions in the transportation (particularly marine transportation) and/or industrial sectors that are difficult to decarbonize. The need for new infrastructure would be significant, but, for the most part, would be focused in fewer locations and energy infrastructure corridors, and would be paid for by those new customers that are added to the system rather than by all gas and electric customers. FEI acknowledges that the Upper Bound Scenario may be somewhat overly optimistic with regard to the time it would take to develop the necessary infrastructure in place to serve this level of demand growth. Finally, while the Upper Bound Scenario is not limited by current policy trends nor developed to meet the proposed GHGRS cap, FEI's Clean Growth Pathway could still be pursued under an Upper Bound Scenario.

30.3 With reference to Figure 2, which indicates that the Deep Electrification and BC Hydro's Accelerated Electrification scenarios forecast a comparable level of total annual gas demand, and noting that BC Hydro contemplates the Accelerated Electrification scenario as part of the 2021 IRP, please elaborate further on the reasons why FEI considers the Lower Bound and the Deep Electrification scenarios to be untenable.

Response:

This response also addresses BC Hydro IR1 4.1 and 4.2, as well as BCSSIA IR1 9.1 and 9.2.

FEI concludes that the Lower Bound and the Deep Electrification Scenarios, modelled as part of its 2022 LTGRP and which involve rapid and extensive declines in annual gas demand, are not plausible by drawing on its examination of alternative pathways to decarbonize as well as the extensive experience of FortisBC's gas and electric utilities in acquiring, transmitting and distributing gas and electricity to customers in BC. Additionally, there is a lack of clear evidence that these scenarios are plausible when fully considering all of the challenges of completely electrifying buildings and industry in BC. This conclusion is supported by a number of studies and documents that FEI has appended to the Application (Appendices A-1, A-2, and A-9). Due to the extreme challenges of converting the peak heating load for more than 1 million gas customers to an alternative energy source and system, namely electricity, within the time required, these two scenarios would involve high costs and implementation delays that would stall efforts to decarbonize, cause high gas and electric rate increases and potentially place existing energy delivery networks at greater risk.

To further support this conclusion, FortisBC is analyzing the impacts of electrification on its electric and gas utilities, examining the challenges for the planning and installation of electricity infrastructure in BC, and finalizing its Kelowna Electrification Case Study for one city in its shared service territory to illustrate the extreme scale of impacts on peak electricity demand and the subsequent transmission and distribution infrastructure requirements.

The case study examines the relationship between weather and peak demand for electricity to show the amount of capacity resources that would be required to electrify the City of Kelowna alone, and the scale of the associated costs under different levels of electrification. Even before considering the costs involved in obtaining the necessary generation projects and the land acquisition costs and challenges for the incremental generation, transmission and distribution infrastructure, preliminary results from this study show that at 100 percent electrification of gas load and a mean daily temperature of -26C, peak demand in 2040 would more than triple, from 476 MW to 1,547 MW, resulting in a high level estimate of $2.1 billion in capital expenditures on the electric distribution and transmission system which would be needed in less than 20 years. At even a moderate level of electrification of 25 percent of gas load, peak demand would increase to 744 MW and result in an estimated $930 million in capital expenditures over this same timeframe. For context, FBC's peak demand and rate base for its entire service territory in 2021 was 777 MW and $1.5 billion respectively. FortisBC plans to have the study finalized and filed on the record in this proceeding. FortisBC is continuing to examine the full implications of a Deep Electrification pathway within its greater combined service territory.

Finally, since the Deep Electrification scenario is not considered plausible, it stands to reason that the Lower Bound Scenario, which results in lower gas demand than the Deep Electrification Scenario, is also not plausible, as there is no other realistic means to serve that scale of peak energy demand.

30.4 Please discuss the rationale for setting the Carbon Price setting at Reference as opposed to the Planning setting for the Deep Electrification scenario.

<u>Response:</u>

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

The narrative for the Deep Electrification scenario includes "*The BC government does not increase carbon taxes to avoid electoral backlash"* but uses all other policy levers to electrify the economy in order to achieve domestic carbon abatement." To reflect this narrative, the Reference setting is used for the carbon price critical uncertainty because it holds the carbon price constant at $50 per tonne starting in 2022 to the end of the forecast period, consistent with this narrative. In the Planning setting, the carbon tax increases over the planning period, which does not align with the narrative of the Deep Electrification scenario. The underlying assumption is that the other government policy levers would be strong enough to render the carbon tax increase unnecessary.

30.4.1 If the Carbon Price setting was set at Planning, please discuss the impact on the demand forecast.

Response:

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

FEI interprets the question to be asking how the demand forecast for Lower Bound and Deep Electrification Scenarios on FEI's 2022 LTGRP would be impacted by changing the carbon price setting, not the BC Hydro scenarios FEI modelled for the BC Hydro / FEI Energy Scenarios project.

Without rerunning the analysis, FEI and Posterity Group expect that the following impacts would occur:

- **Lower Bound scenario**: changing the carbon price setting from High to Planning would result in a decrease in the carbon price and, therefore, an increase in demand for natural gas, all else being equal. In this scenario, however, the policy-driven fuel switching critical uncertainty is set to a very aggressive setting. In the modeling, the amount of fuel switching is always the greater of fuel switching caused by price signals and fuel switching induced by policy. Since the policy-driven fuel switching is so large in this scenario, the lower carbon price would make little difference to the forecast. Only end uses unaffected by the policy levers but susceptible to a price response would change. For most end uses, the same change would occur, but less of it would be caused by price signals and more by other policy levers.
- **Deep Electrification scenario**: changing the carbon price setting from Reference to Planning would result in an increase in the carbon price and, therefore, a decrease in demand for natural gas, all else being equal. In this scenario, however, the policy-driven fuel switching critical uncertainty is set to a very aggressive setting. In the modeling, the amount of fuel switching is always the greater of fuel switching caused by price signals and fuel switching induced by policy. Since the policy-driven fuel switching is so large in this scenario, the higher carbon price would make little difference to the forecast. Only end uses unaffected by the policy levers but susceptible to a price response would change. For most end uses, the same change would occur, but more of it would be caused by price signals and less by other policy levers.

30.4.2 Please discuss, with rationale, whether the Deep Electrification scenario would be considered more or less plausible if the Carbon Price setting was set at Planning.

Response:

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

As discussed in the response to BCUC IR1 30.4.1, the higher carbon price in the Planning setting would have little impact on the results for the Deep Electrification Scenario since, in this scenario, the non-price levers (i.e., policy) have such a large impact on gas demand.

30.5 Please elaborate further on the link between a domestic shift towards electricity and low regional gas prices. In the response, please discuss what impact external markets could have on natural gas prices.

Response:

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

The relationship between domestic electricity demand and regional gas prices is specific to each scenario and is dependent on the other economic and policy conditions present in the scenario. For example, the Price-Based Regulation Scenario assumes the provincial government uses price signals to drive carbon reductions, which causes regional gas prices to increase without advancing electrification policies (i.e., non-price driven fuel switching or codes and standards). In contrast, the Deep Electrification Scenario envisions that the government uses policies other than carbon price to encourage electrification, which is assumed to cause a regional supply glut of natural gas which depresses gas prices.

FEI did not develop a separate critical uncertainty for the impact of external markets on gas prices, but rather considered that potential future issues, such as competition for gas supply, could be one of several drivers of increased prices. Since potential price increases are modelled in the scenarios, FEI does not consider it necessary to fully define the reason for the price increases. This topic has been reviewed with FEI's RPAG in this and previous resource plans and FEI has found general agreement within that group with its approach.

30.6 Please discus whether FEI identified or considered a scenario where the energy demand is lower than that presented under the Deep Electrification scenario, but greater than the energy demand presented under the Lower Bound scenario. If so, please provide details of the scenario and explain why it was not considered any further. If not, please explain why not.

Response:

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

Figure 4-9 of the Application presents the results of modelling the different scenarios for the residential, commercial and industrial customer groups and shows that the Lower Bound and Deep Electrification Scenarios are not significantly different in terms of annual gas demand. There would be no practical value in developing another scenario for which the demand falls between these two scenarios, as the implications of such a scenario can already be examined from the scenarios that were modelled. Proper modelling of scenarios should examine the critical uncertainties that could lead to different demand outcomes to ensure that these considerations have been appropriately modelled, rather than targeting a specific demand outcome.

31.0 Reference: FEI AND BC HYDRO JOINT ENERGY SCENARIOS

Exhibit B-1, Section 4.5.3, pp. 4-22 – 4-25; Appendix B-3, Section 1.1.1.1.3, p. 8; FEI Energy Scenarios – Stage 1 Submissions, Section 3, p. 6; Section 4, pp. 7 8; FEI and BC Hydro Energy Scenarios – FEI Stage Two Submission (Energy Scenarios – Stage 2 Submissions), Section 1, p. 1; Section 2.3, p. 19; Appendix B, p. 1; Appendix C, p. 1.

FEI and BC Hydro Joint Energy Scenarios

On page 6 of the Energy Scenarios – Stage 1 Submissions, FEI states:

> To match the gas demand in the BC Hydro Reference Case, it was necessary to model substantial electricity-to-gas fuel switching for the major end uses in all three sectors. FEI's 2022 LTGRP did not contemplate any scenarios where fuel switching away from electricity and towards natural gas would occur on this scale.

31.1 Please elaborate further on the need to model substantial electricity-to-gas fuel switching for the major end uses in all three sectors. In the response, please discuss the implications on the overall validity of the results.

<u>Response:</u>

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

The modelling objective was to achieve the closest match possible to the BC Hydro Reference Case gas consumption for the sum of the three built environment sectors: residential, commercial, and industrial. Since the base year gas consumption in the two models was not the same,[42] the goal was to match the *percentage change* in consumption from 2020 to 2040, rather than absolute values. As the LTGRP model explicitly includes DSM and the BC Hydro model does not, this meant matching the LTGRP model's post-DSM percentage change with the percentage change in the BC Hydro Reference Case.

In the data provided by BC Hydro for the industrial sector, gas consumption was estimated to rise from approximately 91 PJ in 2020 to approximately 126 PJ in 2040, an increase of 39 percent. FEI and PG understood these figures did not account for DSM activity. Based on the initial modelling using the BC Hydro Reference Case assumptions (but starting with the LTGRP base year), the industrial consumption rose from approximately 74 PJ in 2020 to approximately 83 PJ in 2040, an increase of only 12 percent. To make up the difference, fuel shares for the end uses that are considered able to switch between gas and electricity were increased. This added approximately 9 PJ to the 2040 demand, so that the gas consumption from 2020 to 2040 rises by 23 percent.

In the commercial sector, the data provided by BC Hydro indicated a fall in gas consumption from 48 PJ in 2020 to 43 PJ in 2040, a drop of 11 percent. In the model runs using the BC Hydro Reference Case assumptions (but starting with the LTGRP base year), the commercial

[42] This is due to key differences in the models: Posterity Group's (PG's) is of FEI's service territory with a 2019 base year that is calibrated to FEI actuals; Navius' model is of the province of BC calibrated to federal GHG and energy demand data, and 2020 was the first year data was provided to FEI for the Joint Energy Scenarios project

consumption rose from 63 PJ in 2020 to 70 PJ in 2040. Because this sector was already using much more gas than the BC Hydro commercial Reference Case, no fuel switching to gas was introduced in this sector.

In the residential sector, the data provided by BC Hydro indicated a fall in consumption from 80 PJ in 2020 to 73 PJ in 2040, a decrease of 9 percent. In the initial model runs using the BC Hydro Reference Case assumptions (but starting with the LTGRP base year), residential consumption fell from approximately 76 PJ in 2020 to approximately 59 PJ in 2040, a decrease of approximately 23 percent. With fuel switching from electricity to gas in residential space and water heating, the decrease was set to approximately 11percent.

This was sufficient to achieve the overall target percentage change in gas demand (i.e., when the results of all the sectors were combined). The overall target decrease for the residential, commercial, and industrial sectors together was 7.1 percent. The BC Hydro Reference Case, as per the LTGRP model, shows a decrease of 7.3 percent.

Reviewing this aspect of the modeling, FEI and PG acknowledge that there is room for improvement in the collaboration on scenario modelling. The two models function very differently and require inputs in very different forms. Further collaboration could improve how each of the models and modelling exercise address such differences.

On page 7 of the Energy Scenarios – Stage 1 Submissions, FEI states:

> In addition to the scenario descriptions presented in Section 1, BC Hydro and Navius provided FEI with the following data for all of the BC Hydro service territory and for multiple energy sources (see below) for the milestone years 2020, 2025, 2030, 2035, and 2040:
>
> - 'Drivers of growth': GDP growth, population growth, natural gas price, and oil price;
> - Scenario indicators: natural gas production, commercial and institutional floor area, residential floor area, housing starts, and retail spending;
> - Economic sectors used in the modelling (i.e., segments);
> - Residential and Commercial building area and thermal energy demand intensity by building type and end use (including energy consumption for load served by electricity and energy resources other than electricity like natural gas including RNG, oil, wood and other);
> - Natural gas, including RNG, and electricity consumption by industrial sub-sector;
> - Carbon prices and gas supply costs; and
> - Forecasts for hydrogen, renewable natural gas (RNG) and carbon capture, storage, and utilization (CCUS) by sector.

31.2 Please explain whether the data provided by BC Hydro, outlined in the preamble above, is consistent with the assumptions applied by FEI in the 2022 LTGRP. If not, please outline the differences and explain what adjustments FEI made to the data for the purposes of modelling the energy scenarios.

Response:

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

Much of the data provided by BC Hydro was different than the information or assumptions used by FEI and PG to develop the load forecast scenarios for the LTGRP. In considering this request, FEI/PG offer the following observations about the differences in the nature of the models used by each utility and their consultants in the FEI and BC Hydro joint energy scenarios.

The model used by FEI/PG for modelling future demand under each of the scenarios is an end-use model of FEI's service territory that has a base year (2019) calibrated to FEI data. In contrast, it is FEI's and PG's understanding that the model used for the BC Hydro scenario analysis is an economic model that reflects the entire province of BC and is calibrated to federal GHG data. 2020 was the first year of data provided to FEI and PG. With that said, FEI/PG address each of the groups of data by the bullet points in the preamble.

Drivers of Growth

FEI's LTGRP model does not use GDP growth, population growth, natural gas price, or oil price in the forecast of customer growth. Customer growth is a direct input to the model, taken from FEI's accounts forecast. PG, therefore, took the percentage increase in residential accounts, commercial floor area, and industrial output from the data for each of the BC Hydro scenarios and applied those increases to the base year customer numbers in the LTGRP model. The LTGRP model then directly followed the BC Hydro assumptions for customer growth to model the BC Hydro scenarios.

Scenario Indicators

Natural gas production is not an input to the LTGRP model. Commercial floor area is an input to the model as discussed above. The dwelling is the unit of analysis for the residential sector in the LTGRP model. Analysis of floor area for different types of dwellings and its effects on usage per customer and end-use breakdown is conducted exogenously to the model itself. Housing starts data were used mainly to estimate the relative growth of different types of dwellings within the overall rate of growth from the FEI accounts forecast. Retail spending is not an input to the LTGRP model.

Economic Sectors (Segments)

The FEI LTGRP model is divided into four sectors: residential, commercial, industrial, and low-carbon transportation and LNG export. The BC Hydro data provided information on the first three. There were some differences in segmentation within each sector. After discussion with the BC Hydro modeling team, agreement was reached on a workable mapping from the segmentation in one model to the segmentation in the other. In general, the base year gas consumption for segments and sectors from BC Hydro did not closely match the base year gas consumption in the LTGRP model. Since the LTGRP model used a highly detailed dataset of 2019 gas demand data by region, rate class, and North American Industry Classification System (NAICS) code to establish the segmented consumption, base year demand was not changed to match BC Hydro values. Instead, where BC Hydro data was available by segment, the percentage change to establish targets was used for the LTGRP model.

Building Area, Thermal Energy Demand Intensity (TEDI) and End Use

As discussed above, commercial building area is a direct input to the LTGRP model but residential floor area is not. TEDI is not a direct input to the model, though it can be used to establish targets for fuel switching. In this case, the LTGRP modeling team's objective was to model the impacts on the gas system of the BC Hydro scenarios. The team sought to match the BC Hydro scenarios in terms of changing demand for conventional natural gas and the lower-carbon gaseous fuels such as RNG, but did not focus on estimating the impacts on wood or oil use. The team produced an estimate of the amount of change in electricity consumption among FEI customers, specifically for the end uses subject to fuel switching between gas and electricity. This work did not include producing an overall estimate of electricity consumption for the province, since such demand will not be served by FEI.

Natural Gas, RNG, and Electricity Consumption by Industrial Sub-Sector

As discussed above, the base year gas consumption by segment (or sub-sector) from BC Hydro did not generally match well with the base year gas consumption by segment in the LTGRP model. The percent change in natural gas consumption for the sector in each scenario was used to establish the target change for the LTGRP model. Attempting to match the percentage change in each segment was not undertaken. The amounts of renewable and low-carbon fuels in the BC Hydro scenarios were also used as targets at the sector level, not by individual segment. The overall electricity amounts from the BC Hydro scenarios were not used as inputs to the LTGRP model because the LTGRP model includes only a subset of the electrical end uses BC Hydro would have modeled.

Carbon Prices and Natural Gas Prices

The LTGRP modeling team used the carbon and natural gas prices supplied by BC Hydro as inputs to the critical drivers for price-driven fuel switching. The model lever for fuel switching used these settings for the initial runs, but the initial results did not closely match the BC Hydro scenarios. As discussed in the response to BCUC IR1 31.1, the LTGRP modelling team used the fuel switching model lever to calibrate the results to the amount of change in each of the BC Hydro scenarios, so the pricing signals were effectively overridden.

Forecasts of Renewable and Low-Carbon Gases by Sector

The forecasts of renewable and low-carbon gases by sector were used as direct inputs to the model, to cause traditional natural gas to be displaced by the provided amounts. The forecast of CCUS was used as a direct input to the industrial sector model. The LTGRP model includes the assumption that the displacement of traditional natural gas by natural gas with CCUS would all take place in the industrial sector.

31.3 Please confirm, or otherwise explain, whether both FEI and BC Hydro assume similar rates of population growth and total number of customers to be served by electricity and/or gas.

31.3.1 If not confirmed, please explain what adjustments were made to the models. If no adjustments were made, please discuss the impact on the overall validity of the results.

Response:

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

The LTGRP demand forecast modeling team uses the FEI accounts forecast to model the number of customers. Please refer to the response to BCUC IR1 11.1 for an explanation of how the Conference Board of Canada housing starts data is used to develop FEI's customer forecast. Population growth is not a direct input to the FEI's customer forecast or LTGRP end use demand forecast model and no assumption was made by FEI or PG about it. As such, FEI cannot confirm that similar rates of population growth and customers served by each utility were used by BC Hydro and FEI in the scenario modelling exercise.

FEI offers the following discussion, to the best of its understanding, regarding similarities and differences between the utilities' modelling and any adjustments that were made by FEI and PG related to its customer forecast.

The BC Hydro model does not include number of customers in the commercial or industrial sectors, whereas the LTGRP model includes numbers of customers by region, rate class, and segments that correspond to specific groupings of NAICS codes. For the residential sector, the LTGRP model includes the number of FEI customers (the unit of analysis in the residential sector model is dwelling) while the BC Hydro model includes many dwellings that are not connected to FEI's gas distribution system. In addition, the BC Hydro model includes a number of multi-unit residential dwellings, which are individual suites. Suites are usually individually metered for electricity but not for gas; therefore, in the LTGRP model, suites appear as part of multi-unit buildings in the commercial sector.

For the purposes of this modeling, FEI retained the customer numbers in the LTGRP base year, because it was carefully calibrated to granular customer data. Instead of trying to match the absolute numbers of customers from the BC Hydro scenarios, FEI instead matched the percentage growth rates in dwellings, commercial floor space, and industrial output to that of BC Hydro. FEI believes this was the best approach available and was a valid interpretation of the BC Hydro data. FEI does not believe this approach affected the validity of the results.

On page 8 of the Energy Scenarios – Stage 1 Submissions, FEI states:

> The following adjustments were employed to meet these challenges […]
>
> - In some cases, FEI data was used if and when BC Hydro did not have explicit data on an input required for the FEI models;
> - Where necessary, an iterative, targeting approach was employed to match the overall level of the residential, commercial and industrial sectors end use changes in the Posterity end use model to the overall percent changes in fuel use in the Navius modeling inputs;

31.4 Please provide examples of instances where FEI data was used.

Response:

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

FEI provides the following examples of instances where FEI data was used to supplement BC Hydro data in the FEI and BC Hydro scenario modelling.

BC Hydro did not have explicit data or assumptions on the Low-Carbon Transportation (LCT) sector and how much CNG or LNG would be used for that sector. To model the BC Hydro Reference Case, FEI used the same LCT assumptions that were used in the LTGRP Reference Case. To model the BC Hydro Accelerated Electrification scenario, FEI used the same LCT assumptions that were used for the LTGRP DEP Scenario.

BC Hydro did not have explicit data or assumptions on natural gas DSM. For both of the BC Hydro scenarios, FEI used the same DSM settings that were used in the LTGRP Reference Case.

On page 1 of the Energy Scenarios – Stage 2 Submissions, FEI states:

> - There are limitations to the extent of detailed conclusions that can be drawn from this common scenario exercise due to the use of very different forecast modelling tools and processes between the utilities and their respective consultants. FEI supports further collaboration in this regard.

31.5 Please elaborate further on the limitations of the common scenario exercise, detailing the key differences between the two modelling tools and what measures could be undertaken in the future to overcome these limitations.

Response:

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

The limitations on the scenario exercise are in part due to the differences in the modelling tools, and the inputs and assumptions used to develop scenarios by each model. Please also refer to the response to BCUC IR1 31.2 for a discussion of FEI and Posterity Group's understanding of differences in the two modelling tools.

The Posterity Group software used for the FEI LTGRP model is an end-use model that was built to reflect FEI's service territory. The Navius software used for the BC Hydro model is an economic model and was built to reflect the province of BC. Each model uses inputs and assumptions not used by the other. For example, economic growth is an input assumption that the Navius model uses to drive growth in customer numbers and energy use. For the LTGRP model, economic growth is not an input; customer forecasts come from the FEI customer account forecast.

Conversely, the LTGRP model contains highly detailed energy end-use assumptions about specific groups of FEI customers. The LTGRP model begins with construction of a highly detailed base year, calibrated to the customer numbers and annual gas consumption in 2019 for groups of customers separated by region, rate class, and segments based on specific groups of NAICS[43] codes. In each scenario, changes to customer numbers and energy consumption patterns are imposed, but the original granularity is maintained for all the future years. For example, in each LTGRP scenario, there is a specific assumption about the average unit energy consumption in 2030 for gas space heating in attached, primarily gas-heated homes in the City of Vancouver constructed between 1976 and 1985. This granularity in the input data is required for the end-use model structure, where outputs are provided at the end-use level (and can be rolled up to the region, segment, sector, etc. level)

One of the ways in which the differences in the models and their associated input data complicated the scenario exercise was that the base years did not align: the BC Hydro base year assumptions about natural gas consumption did not agree with the LTGRP model's calibrated base year. Conversely, the LTGRP model's base year assumptions about electricity consumption are only partial, including only electricity consumption for FEI's customers and only for end uses that are either also gas end uses or are relevant to evaluating DSM measures that affect gas. It is not that one model was accurate and one was inaccurate, but rather the models serve different purposes and therefore have different structures, scope, and outputs.

Another limitation was the lack of shared assumptions about DSM. The BC Hydro model did not include explicit assumptions about natural gas DSM and the LTGRP model did not include explicit assumptions about electricity DSM. FEI considers that continued collaboration between the utilities on the modelling of future scenarios could help to overcome these comparative modelling challenges.

On page 19 of the Energy Scenarios – Stage 2 Submissions, FEI states:

[43] North American Industry Classification System.

- […] FEI's Diversified Energy (Planning) and Deep Electrification scenarios assume annual escalation of a carbon tax until it reaches $170 per tonne in 2030 and then holding constant until 2042.

Table 4-1 on pages 4-22 and 4-25 of the Application FEI shows the Input Setting for Carbon Price under both the Diversified Energy (Planning) and the Deep Electrification scenarios as 'Reference.'

On page 8 of Appendix B-3 to the Application, FEI states:

> The Reference trajectory assumes the carbon tax is held constant [at $50 per tonne] once the maximum announced value (as of the time the settings were determined) was reached and held constant throughout the planning horizon. The Planning trajectory matches the federal carbon price announcement and grows to $170/tonne in 2030 (in nominal dollars), remaining constant thereafter.

31.6 Please explain why, under the energy scenarios, the 'Planning' trajectory was used, as opposed to the 'Reference' trajectory.

Response:

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

There is an error in Table 4-1 of the Application—the DEP Scenario actually used the 'Planning' setting for the carbon price (see also the response to BCUC IR1 29.2).

There is also an error on page 19 of the Stage 2 Submission, as FEI's DEP Scenario does use the Planning trajectory for carbon price, which assumes annual escalation of the carbon tax until it reaches $170 per tonne in 2030 and then holding constant until 2042. However, FEI's Deep Electrification Scenario uses the Reference setting for carbon price, which reaches $50 per tonne in 2022 and stays constant for the remainder of the forecast period.

Regarding what carbon prices were used to model the BC Hydro scenarios using the LTGRP model, Navius provided the carbon prices used in their modelling of BC Hydro's IRP scenarios. These values were used as inputs in the LTGRP model. Two carbon price settings were provided: one which was applied to the BC Hydro Reference Case and the other to the BC Hydro Accelerated Electrification Scenario.

On page 1 of Appendix B to the Energy Scenarios – Stage 2 Submissions, FEI provides Tables B-1and B-2, which summarize the key modelling inputs and outputs for the BC Hydro Reference Case and Accelerated Electrification Scenarios. Table B-1 is reproduced below:

Table B-1: Key Modelling Inputs and Outputs - BC Hydro Reference Case Scenario

Category	BC Hydro Assumptions for Electricity Demand obtained from BC Hydro's 2021 IRP	FEI Assumptions for Gas Demand interpreted for the scenario based on information provided by BC Hydro
Transportation	In 2040: ▪ Electric light-duty vehicles: 50 percent market capture ▪ Electric buses: 34 percent market capture ▪ Electric medium-duty vehicles: 10 percent market capture ▪ Electric heavy-duty vehicles: 20 percent market capture	The transportation segment for gas demand is mapped in the Low-Carbon Transportation sector.
Natural Gas Production	In 2040 the fraction of electric compressors is 19%.	The natural gas production segment is excluded from FEI's 2022 LTGRP as it represents supply activity upstream from the FEI gas system and therefore is not served by FEI.
Buildings	Electric heat pump adoption in 2040: ▪ Residential - space heating adoption: 6 percent market capture ▪ Commercial electric heat pump for space heating adoption: 23 percent market capture	In 2040 relative to 2020 data: ▪ Residential gas consumption for space heating decrease: 12 percent (6 PJ) ▪ Commercial gas consumption for space heating increase: 3 percent (1 PJ)
Mining and Other Industry[1]	In 2040, electric heat pumps supply 0.1 percent of industrial process heat.	In 2040 relative to 2020 data: ▪ Gas consumption increase: 26 percent (17 PJ)

31.7 For the Reference Case and Accelerated Electrification scenario, please explain how FEI established the assumptions for gas demand.

Response:

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

FEI discusses the assumptions for gas demand for the BC Hydro Reference Case and Accelerated Electrification Scenario in the order presented in Table B-1These assumptions were made through discussions between the consultant teams during the BC Energy Scenarios Project.

Transportation

During the modelling exercise, the two modeling teams agreed that the transportation category in each of the two models mapped to each other. Since the BC Hydro model had no explicit assumptions about natural gas transportation, FEI used input assumptions developed for LCT in the LTGRP scenarios. LCT assumptions from the LTGRP Reference Case were used for LCT in the BC Hydro Reference Case. LCT assumptions from the LTGRP DEP Scenario were used for LCT in the BC Hydro Accelerated Electrification scenario. These LCT input settings were used because the project team thought they best aligned with the descriptions and intentions of the BC Hydro Scenarios.

Natural Gas Production

Natural gas production is not included in the LTGRP model and is not an input to it. Therefore, no assumptions were made on this topic.

Buildings

The changes to space heating listed in the table under gas assumptions are based on the outputs of the LTGRP model. These are the approximate percent changes in residential and commercial space heating after the BC Hydro assumptions were implemented in the model inputs and the model was run. Gas fuel shares for specific end uses were increased or decreased to adjust gas demand to match the overall 2040 percent change targets in gas demand.

Mining and Other Industry

The change in gas consumption listed in the table under gas assumptions is based on the outputs of the LTGRP model. This is the approximate change in gas consumption for mining and other industry after the BC Hydro assumptions were implemented in the model inputs and the model was run. Gas fuel shares for specific end uses were increased or decreased to adjust gas demand to match the overall 2040 percent change targets in gas demand.

On page 1 of Appendix C to the Energy Scenarios – Stage 2 Submissions, FEI states: "Specifically, [Posterity Group] adjusted fuel switching and fuel share assumptions to calibrate to the 2040 gas demand targets."

31.8 Please provide details of the adjustments made to the fuel switching and fuel share assumptions.

Response:

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

The adjustments to fuel switching to calibrate to the BC Hydro Reference Case are described in the response to BCUC IR1 31.1.

A very similar process was used to ensure that the percentage change in gas consumption for the residential, commercial, and industrial sectors (in total) matched, as closely as possible, the percentage change in gas consumption forecast by the BC Hydro Accelerated Electrification scenario. In all three sectors, PG had to increase the electrification targets from the original assumptions in the BC Hydro supplied data to obtain a better match with the percentage change in gas consumption in BC Hydro's scenario results. As with the Reference Case, the objective was to match the percentage change in natural gas consumption to within 2 percent of the 2040 percentage change in gas demand for the total of the three residential, commercial, and industrial sectors.

In the residential sector, the following changes were made in the BC Hydro Accelerated Electrification scenario:

- In the BC Hydro supplied data, the cooking end use had an increase in gas share, which was in the opposite direction to the electrification occurring in space and water heating. This assumption was overridden, so there was no fuel switching in cooking.

- The fuel share changes for space and water heating were “grossed up” by multiplying the target percentage change by the ratio of all gaseous fuels consumption to natural gas consumption. This is because the BC Hydro model applied electrification to all gaseous fuels and the LTGRP model applies it only to natural gas.

The commercial sector was treated similarly to the residential sector. The residential targets for fuel switching were used for the apartment segment in the commercial sector.

In the industrial sector, simply grossing up the targets based on the ratio of all gaseous fuels consumption to natural gas consumption produced results that had too much industrial natural gas consumption which caused the all-sector total to be too high. Therefore, electrification in the applicable end uses[44] was further increased. Increasing the fuel share percentage change from a reduction of approximately 45 percent to a reduction of 60 percent produced a sufficient match to the target percentage change for the three sectors.

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[44] PG and FEI used subject-matter expertise to establish fuel switching assumptions by end use for each LTGRP model sector.

32.0 Reference: ANNUAL DEMAND FORECAST TABLES

Exhibit B-1, Section 4.6.1.2, p. 4-30; Appendix B-4, pp. 1 — 6

Annual Demand Forecast Tables

In Appendix B-4 to the Application, FEI provides the Annual Demand Forecast Tables for the following scenarios: Reference Case, Diversified Energy (Planning), Deep Electrification, Priced-Based Regulation, Economic Stagnation and Upper Bound.

On page 2 of the Appendix B-4 to the Application, FEI provides the Annual Demand by Rate Schedule (GJ) Table for the Diversified Energy (Planning) Scenario. In 2019 the total annual demand for Rate 1 is 77,329,188 GJ. In 2042 the total annual demand for Rate 1 is 40,475,157.

On page 4-30 of the Application, FEI provides Figure 4-10, which shows the Annual Demand Scenarios for the Residential Sector:

Figure 4-10: Annual Demand Scenarios – Residential Sector

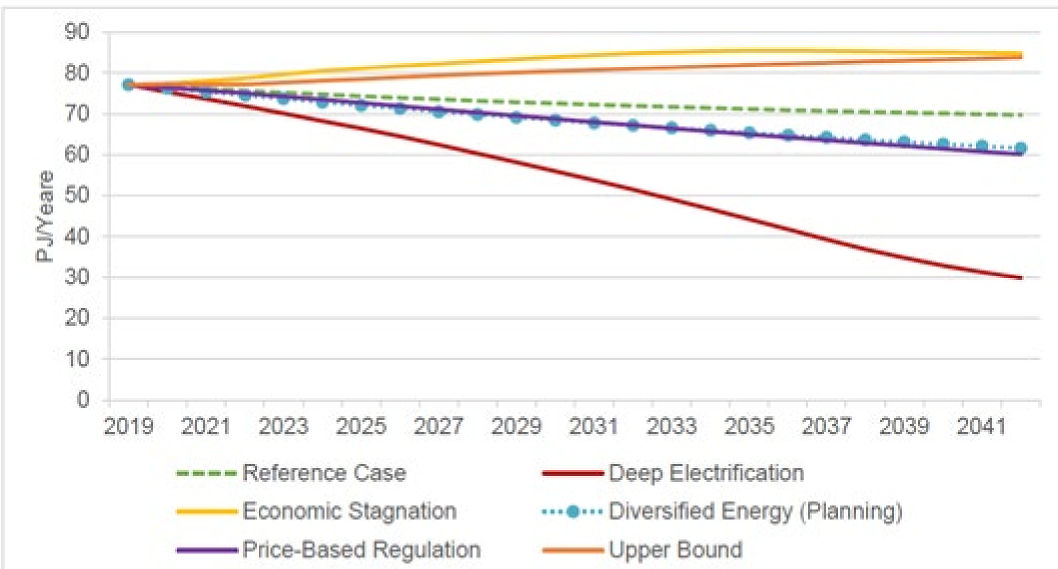


Figure 4-10 shows the total annual demand for the residential sector to be approximately 77PJ in 2019 under the Diversified Energy (Planning) Scenario. In 2042 the total annual demand for the residential sector is approximately 62PJ.

32.1 Please explain why the data presented in Figure 4-10 differs to the data presented on page 2 of Appendix B-4.

<u>Response:</u>

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

As explained in the footnote on page 1 of Appendix B-4, the values in the tables in Appendix B-4 exclude renewable and low-carbon gas, the impact of Conservation and Energy Management

Programs, and the Woodfibre LNG project. This differs from the results presented in Figure 4-10, which include renewable and low-carbon gas as well as the impact of Conservation and Energy Management Programs.

32.2 For all scenarios, where there are discrepancies between the data presented in the figures included in section 4 of the Application and the data presented in the tables presented in Appendix B-4, please update the figures and/or the tables as appropriate.

Response:

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

As explained in the footnote on page 1 of Appendix B-4, the values in the tables exclude renewable and low-carbon gas, the impact of Conservation and Energy Management Programs, and the Woodfibre LNG project. This differs from the results presented in Section 4 which includes the impacts from these variables/inputs. No figures or tables require updating. The reader should consult either the figures in Section 4 or the tables in Appendix B-4, depending on the information they require.

33.0 Reference: DEMAND FORECASTING

Exhibit B-1, Section 4, pp. 4-14, 4-15, 4-18, 4-34, 4-35; Appendix B-3, pp. 4 — 12, 14, 16 –19

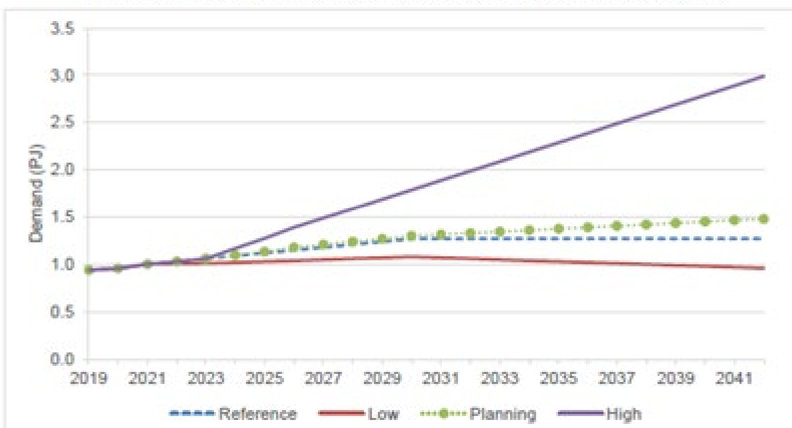
Low-Carbon Transportation and Global LNG Demand Category

On pages 4-14 to 4-15 of the Application, FEI states:

> To derive the CNG [compressed natural gas] demand forecasts, FEI formulated the CNG demand forecast settings (Reference, Planning, High, Low) by accounting for commitments that have been made by customers to take CNG supply and by forecasting the impacts of a variety of factors. These factors include inflation, discussions on new station builds, vehicle incentive applications, regulatory changes that are expected to drive conventional natural gas adoption and assumptions regarding adoption rates based on past experience.

On page 4-34 of the Application, FEI provides Figure 4-14 as follows:

Figure 4-14: Annual Demand Forecast for the CNG Demand Settings (2020-2042)



33.1 Please describe the commitments that have been made by customers to take compressed natural gas (CNG) supply from FEI. In the response, please discuss the nature, certainty and term length of the commitments made, the demand volumes (PJ) and expected timeframes. Please also discuss the risk factors that may impact the commitments.

Response:

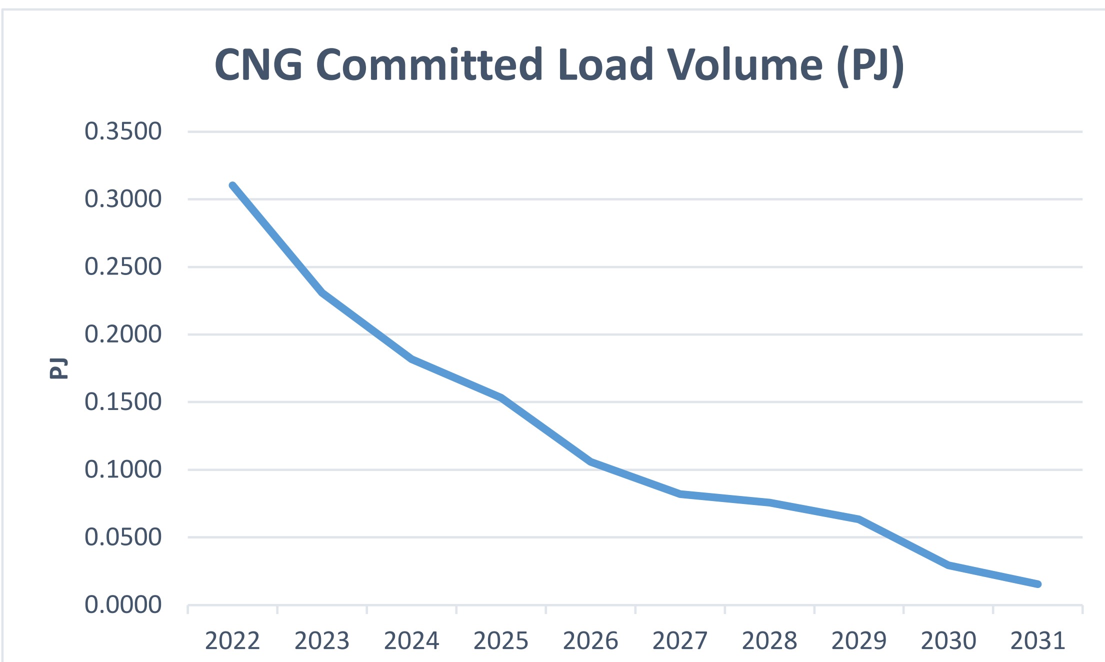
Please see the below table showing the total CNG committed volumes up to the period of 2031. All current CNG contracts range from 3 to 8 years and currently there are no current contracts that extend past 2031. These committed volumes represent the minimum annual load a customer is required to purchase; however, customers often consume significantly more than their minimum. For example, in 2021, the total committed load was approximately 0.3 PJs, and actual consumption from the same customers was approximately 1.4 PJs. These volumes represent contractual commitments and FEI expects to be able to realize these volumes. The single largest risk factor, which is outside of FEI's control, would be the default of a customer.

Year	CNG Committed Load Volume (PJ)
2022	0.3104
2023	0.2309
2024	0.1819
2025	0.1534
2026	0.1059
2027	0.0821
2028	0.0757
2029	0.0635
2030	0.0295
2031	0.0155

33.2 Please plot the demand expected solely based on commitments made by customers to take CNG supply from FEI on Figure 4-14, if possible.

Response:

The following graph shows the total CNG committed volumes up to the period of 2031. It should be noted that the committed volumes show a decline over time as the graph represents <u>current</u> volume commitments and those contracts have termination dates between now and 2031.

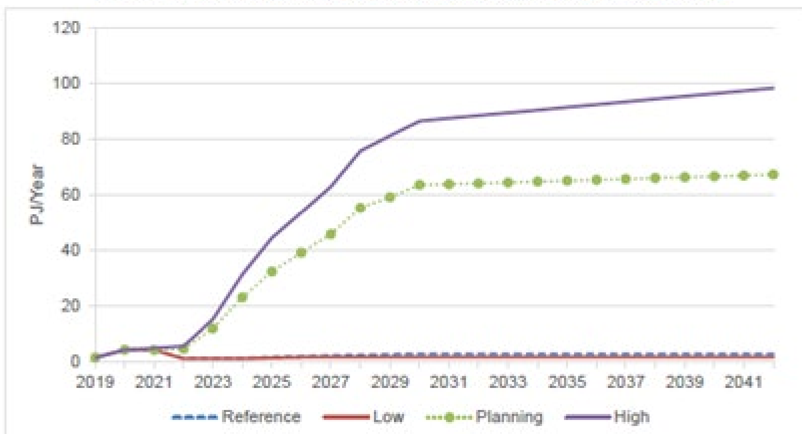


On page 4-15 of the Application, FEI states:

> FEI formulated the LNG demand forecast by accounting for commitments that have been made by customers to take LNG supply, and by forecasting the impacts of a variety of factors. These factors include the availability of Original Equipment Manufacturer (OEM) technology capable of adopting conventional natural gas, regulatory changes (see Section 2.2.2.3) that are expected to drive conventional natural gas adoption and assumptions regarding adoption rates based on past experience for some of the market segments.

On page 4-35 of the Application, FEI provides Figure 4-14 as follows:

Figure 4-15: Annual Demand Forecast for LNG Demand Settings (2020-2042)



33.3 Please describe the commitments that have been made by customers to take LNG supply from FEI. In the response, please discuss the nature, certainty and term length of the commitments made, the demand volumes (PJ) and expected timeframes. Please also discuss the risk factors that may impact the commitments.

<u>Response:</u>

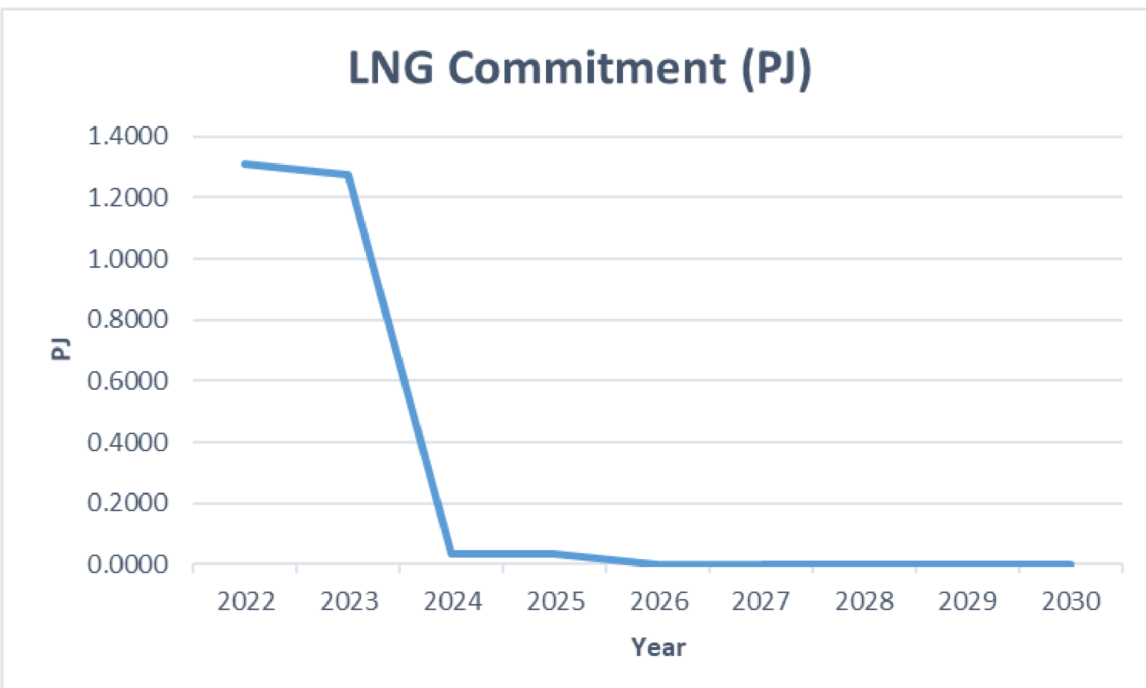
Please see the below table summarizing all LNG committed volumes. FEI interprets "commitment" in this IR to mean "contracted". The majority of LNG customers are currently on contracts that automatically renew each year pursuant to section 16.2 of FEI's Rate Schedule 46 (RS 46), and the customer may terminate their contract with two months' notice prior to the end of the contract year. These LNG customers have made significant investments in LNG vessels, and FEI expects this load to continue for many years, even though their contractual commitments do not extend beyond the standard annual renewal requirements of RS 46. Given the short-term contractual commitment of these contracts, there are minimal risk factors that will impact the customers' ability to satisfy their commitments.

Year	LNG Commitment (PJ)
2022	1.3104
2023	1.2751
2024	0.035
2025	0.035

33.4 Please plot the demand expected solely based on commitments made by customers to take LNG supply from FEI on Figure 4-15, if possible.

Response:

The following graph illustrates the total LNG committed (i.e., contracted) volumes. Please refer to the response to BCUC IR1 33.3 regarding how FEI's LNG customers under RS 46 have made significant investments in LNG vessels, and FEI expects this load to continue for many years, even though their contractual commitments do not extend beyond the standard annual renewal requirements of RS 46.



Appendix B-3 to the Application provides the critical uncertainties and their forecast modelling input settings for the end use method demand forecast scenarios. On page 14 of Appendix B-3, FEI states:

FEI developed four long-term forecast demand settings or trajectories for the CNG segment and LNG segment, based on core end use forecast scenario parameters for this category. These parameters are: (1) GGRR [Greenhouse Gas Reduction (Clean Energy) Regulation] vehicle incentive applications that FEI uses for incentive funding for LCT [low-carbon transportation] customers; (2) industry research; (3) policy expected to impact the demand for natural gas as a transportation fuel in the future; (4) the allowed funding period permitted under the GGRR; (5) actual LCT customer additions to date; and (6) the relative price of competing or incumbent fuels such as diesel. Sections 3.4.7.1 and 3.4.7.2 further elaborate on these factors.

33.5 Please clarify the location of Sections 3.4.7.1 and 3.4.7.2, which further elaborate on these factors.

Response:

The references to Sections 3.4.7.1 and 3.4.7.2 on page 14 of Appendix B-3 are incorrect. Further information related to the long-term forecast demand settings or trajectories for the CNG segment and LNG segment, based on core end use forecast scenario parameters for this category, are described in Section 4 and more specifically in the following sections of the Application.

- Section 4.4.2 describes the End Use Annual Method of Demand Forecasting for the Low-Carbon Transportation and Global LNG Category;
- Section 4.4.3 describes the End Use Annual Method of Demand Forecasting for the New Large Industrial Demand Category;
- Section 4.6.2 provides information on the Low-Carbon Transportation and Global LNG Demand Category; and
- Section 4.6.3 provides information on the New Large Industrial Demand Category.

33.6 Please explain how the parameters noted above, used for developing the long-term forecast demand settings or trajectories for the CNG segment and LNG segment, were determined. In the response, please identify whether any other parameters were considered and why they were rejected.

Response:

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

FEI determined the parameters noted above from page 13 of Appendix B-3 based on FEI's understanding of the developing CNG and LNG market, which FEI has been involved with for many years. Specifically, FEI utilized its market and industry knowledge which, for the marine bunking market segment, includes various forecasts from external consultants, various discussions with LCT customers on their view of the market, and FEI's historical experience in the market.

Sections 1.2.1.1 through 1.2.1.4 on pages 16 to 17 of Appendix B-3 to the Application summarizes assumptions for FEI's Reference, Low, Planning and High LNG Forecast settings. For example, section 1.2.1.1 regarding FEI's LNG reference demand forecast setting states:

> For the Reference forecast setting, FEI has assumed that incentives supporting LNG infrastructure under the GGRR will be extended to beyond 2030 with development in the short sea market segment as FEI's customers proceed with adoption of additional LNG marine vessels. The Reference setting assumed that there is no growth in trans-Pacific marine vessels adopting LNG as a fuel. As such, the marine bunkering jetty3 at Tilbury is not constructed and does not apply in this setting. Similarly, completion of the EGP project is not assumed and the addition of Woodfibre LNG demand is not included. A solution to the discontinued 15L road engine for truck fleet customers does not emerge and consumption by these on-road customers will halt by 2026. Over the forecast horizon to 2042 in the Reference setting, FEI has forecast an average growth rate of about 1 percent from 2020 to 2030 and no growth beyond 2030.

33.7 Please tabulate the assumptions made for each of FEI's LNG Demand Forecast Settings (Reference, Low, Planning, High) in the same or similar format to the table shown below. If available, please include approximate annual volumes attributed to each assumption (for example, approximately how may PJ/year can be attributed to assuming that incentives supporting LNG infrastructure under the GGRR will be extended beyond 2030.)

Parameter	LNG Demand Forecast Setting			
	Reference	**Low**	**Planning**	**High**
Example: *Incentives supporting LNG infrastructure under the GGRR*	*FEI assumes that incentives supporting LNG infrastructure under the GGRR will be extended to beyond 2030.*	*FEI assumes that incentives supporting LNG infrastructure under the GGRR are not extended.*	*FEI assumes that incentives supporting LNG infrastructure under GGRR will be extended beyond 2030.*	*FEI assumes that incentives supporting LNG infrastructure under the GGRR will be extended beyond 2030.*

Response:

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

The following table shows the assumptions made for each of FEI's LNG Demand Forecast Settings and the approximate annual load impact between the Forecast Settings in the year 2040. Note that, while included in this table for completeness in responding to the information contained in the preamble, information contained in this table for 'EGP Project' and 'Other New Large Industrial Customer' is discussed in Section 4.3.3, Section 4.4.3, Table 4-1 and Section 4.6.3 of the Application under the demand category 'New Large Industrial Demand' rather than the 'Low-Carbon Transportation and Global LNG' demand category.

Parameter		LNG Demand Forecast Setting			
		Reference	Low	Planning	High
On Road: Customer Demand		Current contracted customer demand only	Current contracted customer demand only	Current contracted customer demand only	Current contracted customer demand contract renewal and new customers
On Road: GGRR Provision Extensions		GGRR provisions extended beyond 2030	GGRR provisions not extended beyond 2022	GGRR provisions extended beyond 2030	GGRR provisions extended beyond 2030
On Road: Technology Advancements		No significant technology advancements	No significant technology advancements	No significant technology advancements	Technological advancement of the high horsepower (400HP) and engine is available to the on-road market
	On Road: Load Impact in 2040 (PJ)	0	0	0	0.1
Short Sea Marine Market Growth		Increased LNG vessel adoption by short sea customers	Limited LNG vessel adoption by short sea customers	Increased LNG vessel adoption by short sea customers	Increased LNG vessel adoption by short sea customers
	Load Impact in 2040 (PJ)	3	2	3	3
Marine Bunkering Jetty (Transpacific Shipping)		No adoption of LNG for Marine Bunkering Jetty	No adoption of LNG for Marine Bunkering Jetty	Adoption of LNG for Marine Bunkering Jetty - Jetty is built and transpacific vessels utilize LNG	Adoption of LNG for Marine Bunkering Jetty - Jetty is built and transpacific vessels utilize LNG with slightly increased demand
	Load Impact in 2040 (PJ)	0	0	53	70
Remote Power and Mining Industry Growth		Limited to no growth	Limited to no growth	Forecasted Mine and Remote Power industry growth	Slightly higher Forecasted Mine and Remote Power industry growth
	Load Impact in 2040 (PJ)	0	0	4	7

Parameter		LNG Demand Forecast Setting			
		Reference	Low	Planning	High
EGP Project Completion		Not completed	Not completed	EGP completed resulting in increased load	EGP completed resulting in increased load
	Load Impact in 2040 (PJ)	0	0	95	95
Other Large Industrial Load (LNG Facility)		Not completed	Not completed	Not completed	Other Large Industrial Load (LNG Facility) of 95PJ
	Load Impact in 2040 (PJ)	0	0	0	95
ISO Export Market Growth		Limited to no Growth	Limited to no Growth	Steady ISO Export Market Growth	Increased ISO Export Market Growth
	Load Impact in 2040 (PJ)	0	0	6	16
Total LNG Load Forecast (PJ)		**3**	**2**	**161**	**286**

33.8 Please discuss, at a high level, the basis for the LNG forecast assumptions described in Sections 1.2.1.1 through 1.2.1.4 of Appendix B-3 and the responses preceding IRs and how they were determined.

Response:

The bases for the LNG forecast assumptions are as follows:

Parameter	Basis for Forecast Assumption
On Road: Customer Demand	Customer demand and knowledge is used as a predictor of customer trends and behaviors
On Road: GGRR Provision Extensions	GGRR provisions determine incentive levels for customers to enhance demand and load growth
On Road: Technology Advancements	Technology advances allow for customers to continue fueling with LNG for on road heavy duty transportation vehicles
Short Sea Marine Market Growth	Short Sea and Marine industry growth is used as a predictor of LNG sales for domestic BC marine customer.
Marine Bunkering Jetty (Transpacific Shipping)	The marine bunkering jetty is required to enable ship-to-ship bunkering from Tilbury, which will open new markets in the transpacific shipping industry
Remote Power and Mining Industry Growth	The remote power and mining market segments are high fuel consumers and they are increasingly looking for alternative energy solutions which can result in an increase in the demand for LNG
EGP Project Completion	EGP Project completion is an important factor in determine forecasted load throughput on the FEI system through Rate Schedule 50

Parameter	Basis for Forecast Assumption
Second large LNG Facility	Second large LNG Facility is an important factor in determine forecasted load throughput on the FEI system through Rate Schedule 50
ISO Export Market Growth	Small scale LNG export from Tilbury based on global LNG market factor, including global market prices and shipping costs and availability

All of these parameters were assessed based on FEI's understanding of the LNG market, discussions with LCT customers and prospects, and historical experience in the market when developing the demand forecast settings.

33.9 Please discuss risk factors that may affect the certainty of acquiring and retaining LNG customers.

33.9.1 Please discuss how FEI has assessed these risk factors in the preparation of its LNG demand forecast.

Response:

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

The risk factors that may affect the certainty of acquiring and retaining LNG customers are:

- <u>Marine bunkering jetty</u>: FEI requires a jetty to enable ship-to-ship bunkering and serve transpacific vessels, one of the most significant opportunities for LNG growth.
- <u>Project-specific risks</u>: project-specific risks, including permitting risk, construction risk, and the feasibility of the project, can change and influence volumes.
- <u>Government Policy</u>: unpredictable government policy changes can impact the industry and industry behaviors and the transition away from higher carbon fuels.
- <u>Technology</u>: technical and economic feasibility of new technology or failure of current technology can impact the on-road customer demand volumes.
- <u>Market demand</u>: customer behaviors and trends are unpredictable and there is risk of customers shifting to other alternative fueling solutions, driven by costs and other internal decision-making parameters.
- <u>Global LNG market factors:</u> LNG demand and price fluctuations, geo-political conditions, international shipping costs and accessibility impact the growth of the ISO export market, marine market and the larger scale export market.

33.9.2 Please also discuss how these risk factors may differ from FEI's other demand categories, such as its residential, commercial, industrial categories etc.

Response:

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

The risk factors discussed in the response to BCUC IR1 33.9 differ from FEI's other demand categories, such as its residential, commercial and industrial categories, as each category has different impact sensitivities. For instance, when considering political risks, one of the LNG demand category's focuses is the GGRR and the impacts it can have on incentives and growth, whereas the GGRR as it relates to the transportation load growth is not relevant to the residential demand category. Although all demand categories must consider the risks around policy, each demand category has differing opportunities and threats that drive their specific demand forecasts.

On page 17 of Appendix B-3 to the Application, in describing the LNG High Demand Forecast Setting, FEI states:

> The High setting begins to diverge from the Planning setting beginning in 2022 and 2023, as the marine transportation market begins addressing the impending IMO sulphur cap on marine industry emissions. The IMO sulphur cap regulation accelerates a need for gas as an alternative fuel to meet these tighter emissions restrictions.

33.10 Please expand on the IMO sulphur cap regulation and why its impacts appear to only be incorporated into the LNG High Demand Forecast Setting, as opposed to other LNG demand forecasts, such as the LNG Planning Demand Forecast Setting.

Response:

The IMO sulphur cap regulation limits the sulphur content in the fuel oil used on marine ships, which is an important factor to consider in regard to transpacific marine LNG adoption (ship-to-ship bunkering through the marine bunkering jetty). This regulation is expected to impact the industry in all scenarios, but in the LNG High Demand Forecast it is assumed to drive higher increases in LNG demand as compared to the LNG Planning Demand Forecast Setting. The scenarios are intended to present different cases and show different assumptions related to LNG load growth.

Sections 1.2.1.5 through 1.2.1.8 on pages 17 and 18 of Appendix B-3 to the Application summarizes assumptions for FEI's Reference, Low, Planning and High CNG Forecast settings.

33.11 Please tabulate the assumptions made for each of FEI's CNG Demand Forecast Settings (Reference, Low, Planning, High) in the same or similar format to the table shown above for the LNG Forecast settings. If available, please include approximate annual volumes attributed to each assumption (for example, approximately how may PJ/year can be attributed to assuming that incentives supporting CNG infrastructure under the GGRR will be extended beyond 2030.)

Response:

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

The following table shows the assumptions made for each of FEI's CNG Demand Forecast Settings. FEI cannot differentiate the annual volumes attributed to each parameter, as they are highly integrated and interdependent. As such, FEI is only providing the approximate annual volume on a total basis in 2040.

Parameter	CNG Demand Forecast Setting			
	Reference	Low	Planning	High
Customer Demand	Current contracted customer demand without contract renewal and without new demand	Current contracted customer demand without contract renewal and without new demand	Current contracted customer demand without contract renewal and without new demand	Current contract customer demand with renewals and with new customer demand
GGRR Provision Extensions	GGRR provisions extended beyond 2030	GGRR provisions not extended beyond 2030	GGRR provisions extended beyond 2030	GGRR provisions extended beyond 2030
Adoption of Alternative Fuel	EV and Hydrogen technology adoption is slow due to technology uncertainty and high cost	EV and Hydrogen technology adoption is accepted	EV and Hydrogen technology adoption is slow due to technology uncertainty and high cost. Lack of EV and Hydrogen infrastructure.	EV and Hydrogen technology adoption is slow due to technology uncertainty and high cost. Lack of EV and Hydrogen infrastructure.
Technological Advancements	CNG engine technology continues to be improved and manufactured	CNG engine technology does not improve	CNG engine technology continues to be improved and manufactured	CNG engine technology continues to be improved and manufactured
Pricing and Cost	Cost difference between delivered diesel and CNG remains at least $0.25/DLE & price of CNG vehicles remains the same or decreases.	Cost difference between delivered diesel and CNG is lower than $0.25/DLE & price of CNG vehicles increases.	Cost difference between delivered diesel and CNG increases & Electrical and Hydrogen costs are not economical. Price of CNG vehicles remains the same or decreases.	Cost difference between delivered diesel and CNG increases & Electrical and Hydrogen costs are not economical. Price of CNG vehicles decreases.

Parameter	CNG Demand Forecast Setting			
	Reference	Low	Planning	High
Load Impact in 2040 (PJ)	1.2	0.9	1.5	2.8

33.12 Please discuss at a high level the basis for the CNG forecast assumptions described in Sections 1.2.1.5 through 1.2.1.8 of Appendix B-3 and the preceding IRs and how they were determined.

Response:

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

The basis for the CNG forecast assumptions is as follows:

Parameter	Basis for Forecast Assumption
Customer Demand	Customer demand and knowledge is used as a predictor of customer trends and behaviors
GGRR Provision Extensions	GGRR provisions determine incentive levels for customers to enhance growth and demand
Adoption of Alternative Fuel	Adoption of alternative fuels such as EV and Hydrogen influence customer decisions on their choice of alternative fuel for their foreseeable future
Technological Advancements	CNG vehicles improvements and advancements influence customers on their reliability of CNG engines and CNG growth
Pricing and Cost	Commodity pricing and cost of capital (vehicles and station costs) are factors considered by customers on determining the economic feasibility of CNG as their choice for alternative fuel

All of these parameters were assessed based on FEI's understanding of the CNG market, discussion with LCT customers and historical experience in the market when developing the demand forecast settings.

33.13 Please discuss risk factors that may affect the certainty of acquiring and retaining CNG customers.

33.13.1 Please discuss how FEI has assessed these risk factors in the preparation of its CNG demand forecast.

Response:

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

The main risk factors that may affect the certainty of acquiring and retaining CNG customers are:

- Technology: technical and economic feasibility of new technology or failure of current technology can impact the on-road customer demand volumes
- Government Policy: unpredictable government policy changes that can impact the industry and industry behaviors and the transition away from higher carbon fuels
- Market Demand: customer behaviors and trends are unpredictable and risk of customers shifting to other alternative fueling solutions, driven by costs and other internal decision-making parameters

33.13.2 Please also discuss how these risk factors may differ from FEI's other demand categories, such as its residential, commercial, industrial categories etc.

Response:

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

The risk factors discussed in the response to BCUC IR1 33.13 differ from FEI's other demand categories, such as its residential, commercial and industrial categories. These risk factors differ as each category has different impact sensitivities. For instance, when considering political risks, one of the CNG demand drivers is the GGRR and the impacts it has on vehicle incentives and load growth, whereas the GGRR as it applies to transportation is not relevant to the residential demand category. Although all demand categories consider the risks around policy, each demand category has differing opportunities and threats that drive their specific demand forecast.

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

> FEI has grouped the critical uncertainties under demand (residential, commercial and industrial), supply (renewable and low-carbon gas supplies) and transportation (new demand for gas as a transportation fuel) uncertainties. The 2022 LTGRP's critical uncertainties break down as described below.
>
> - Residential, Commercial and Industrial Demand:
>   - Economic growth, represented by account growth values and increases in commercial and industrial floor area in the forecast model;
>   - Conventional natural gas commodity price, based on a multitude of third-party forecasts (this accounts for price changes motivated by various factors, such as demand-supply balance or upstream regulatory changes);

- Carbon price, which accounts for provincial and federal carbon pricing actions and is agnostic to the specific pricing mechanism (the forecast model simply assumes a stream of price values without identifying, for example, whether these are the result of a carbon tax or a cap and trade system);
- Non-price policy levers, which account for changes in the building code, energy performance standards, and any requirements for switching from one fuel type to another (e.g., district energy systems150).

- LCT and Global LNG Demand:
  - Demand for CNG and LNG in the conventional natural gas for transportation sector and for global LNG demand. Demand for these fuels impacts FEI's system and reduces GHG emissions as CNG and LNG displace fuels that emit more GHGs.

…

Section 1.1.1.1 and its subsections on pages 4 to 12 of Appendix B-3 provides further detail on the Critical Uncertainty Inputs for the Residential, Commercial and Industrial Demand Category, such as section 1.1.1.1.2, which provides setting options for natural gas price (reference, low high) and section 1.1.1.1.3, which provides settings for Carbon Price (reference, low, medium, planning, high).

33.14 Please explain, with rationale, what inputs identified for the Residential, Commercial and Industrial Demand Categories are assumed for each of the CNG and LNG Demand Forecast Settings (Reference, Low, Planning, High) (i.e.: what conventional natural gas commodity price is assumed for each of the CNG and LNG Demand Forecast Settings, what carbon price is assumed for each of the CNG and LNG Demand Forecast Settings, etc.)

<u>Response:</u>

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

The assumptions for the CNG and LNG Demand Forecast settings, as identified in BCUC IR1 33.7 (for LNG) and BCUC IR1 33.11 (for CNG) are unique to LNG and CNG, and the inputs in the Residential, Commercial and Industrial Demand Categories are not used in determining the CNG and LNG Demand Forecasts. As discussed in the response to BCUC IR1 33.9.2, the opportunities and threats that drive the specific demand forecasts for CNG and LNG are different than other customer classes.

On page 16 of Appendix B-3 to the Application, in describing the LNG Planning Demand Forecast Setting, FEI states: "The Planning setting includes completion of the EGP project resulting in an average of 94.8 PJ annually of LNG from 2025-2042."

On page 19 of Appendix B-3 to the Application, in describing the critical uncertainties for the new large industrial demand category, FEI states:

> The New Large Industrial Demand Category is in itself a critical uncertainty in that such demand is either added or it is not. There are only three settings for new large industrial demand:
>
> - High – in which both Woodfibre and a second generic large industrial facility are added to FEI's demand in 2025 and 2028, respectively.
> - Planning – in which only Woodfibre is added to FEI's demand in 2025.
> - Reference – in which no new large industrial facilities are added to FEI's demand over the planning horizon.

33.15 Please clarify whether the Woodfibre LNG demand is included in the LNG Demand Category, the new large industrial demand category, both, or explain otherwise.

33.15.1 If included in the LNG Demand Category, please explain why Woodfibre demand is referenced in describing the new large industrial demand forecast settings in section 1.3 of Appendix B-3.

33.15.2 If included in the new large industrial demand category, please explain why Woodfibre Demand is referenced when describing the LNG demand forecast settings in sections 1.2.1.1 through 1.2.1.4 in Appendix B-3.

33.15.3 If both, please provide the rationale for this approach.

Response:

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

The Woodfibre LNG demand is included in the description of the LNG Demand Category in Appendix B-3 but is analyzed as part of a separate New Large Industrial Demand Category in the Application. A decision was made during the later stages of the LTGRP preparation to move the Woodfibre project into a separate large industrial category that better represented the large, one-time step-change in demand that it would cause. This change would also allow the modelling of a second similar size and similar step change industrial demand in the Upper Bound Scenario. The second large industrial load in the Upper Bound was not assumed to be an LNG export facility, though it could be. FEI identified that modelling this second load would have a similar annual load addition profile to that of modelling Woodfibre and that modelling both loads in a separate demand category would provide for a more clear and transparent explanation of the various loads that make up the overall annual demand forecast.

FEI acknowledges the oversight of not fully making this same adjustment in Appendix B-3. The New Large Industrial demand category was added to the LTGRP and the simplicity of modelling these demands as either on or off in the different scenarios did not warrant more detailed explanation in Appendix B-3. However, the discussion of these loads was not fully removed from the discussion of the Low-Carbon Transportation and Global LNG in Appendix B-3. FEI will make this adjustment as appropriate in the next LTGRP.

D. DEMAND-SIDE RESOURCES

34.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Section 5.3.4, p. 5-12; Appendix C-1, pp. 3-4; Appendix C-2, pp. 4, 7, 10; FEI 2021 DSM Expenditures Plan proceeding, Exhibit B-1, p. 24; BC Hydro 2021 IRP proceeding, Exhibit B-1, Appendix L, p. 18; DSM Regulation, section 4 (1.1)

Cost-effectiveness

On pages 3 to 4 of Appendix C-1 to the Application, FEI describes the Modified Total Resource Cost (MTRC) as follows:

> A modified version of the TRC test that includes an alternate avoided cost and an adder for non-energy benefits. Per section 4(1.1)(a) of the province's DSM Regulation, the MTRC test incorporates the avoided cost of electricity – BC Hydro's marginal cost of acquiring electricity generated from clean or renewable resources, called the Zero Emission Energy Alternative (ZEEA) - rather than the marginal cost of new gas supply.

Section 4 (1.1)(a) of the DSM Regulation states in part:

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

FEI states on page 24 of Exhibit B-1 in the FEI 2023 DSM Expenditures Plan Proceeding, that "the ZEEA value used in the MTRC calculation is $106/MWh, or 29.45/GJ. The source for this number is BC Hydro's Waneta 2017 Transaction Application to the BCUC that established BC Hydro's LRMC at $106/MWh in F2018$."

In the ongoing BC Hydro 2021 IRP proceeding, BC Hydro provides an updated energy reference price of $65/MWh, and an updated capacity reference price of $109kW-year on page 18 of Appendix L.

On page 5-12 of the Application, FEI states:

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

34.1 Please provide the ZEEA value used by FEI to represent the long-run marginal cost of acquiring electricity generated from clean or renewable resources in British Columbia in the estimation of cost-effectiveness in the 2022 LTGRP.

Response:

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

In the Application, FEI used a ZEEA value of $106/MWh based on the last long-run marginal cost value accepted by the BCUC, which was from BC Hydro's Waneta 2017 Transaction Application. Please refer to BCUC IR1 34.2 for the results of using a ZEEA value of $65/MWh.

In Appendix C-2 to the Application, FEI provides cost-effectiveness test results for each of the sectors in Table C2-1, Table C2-2, and Table C2-3.

34.2 If the ZEEA value provided in response to the previous IR is higher than the energy reference price provided by BC Hydro in the IRP of $65/MWh, please provide a revised version of Tables C2-1, C2-2 and C2-3 using a ZEEA value of $65/MWh.

Response:

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

The ZEEA value used in Appendix C-2 is $106/MWh. Revising the analysis using a ZEEA value of $65/MWh results in the following outcomes illustrated in Tables 1 through 3 below. As shown in the tables below, FEI's High DSM for the DEP scenario remains cost effective with a ZEAA of $65/MWh at the aggregate portfolio level and for each of the residential, commercial and industrial sectors.

Table 1: Revised C2-1: Estimated DEP – High DSM Cost Effectiveness Test Results – Residential Sector, ZEEA Value of $65/MWh

Year	TRC	MTRC	UCT	CCE ($/GJ)
Portfolio Aggregate	**4.7**	**10.1**	**4.5**	**9.4**
Residential Aggregate	**2.0**	**3.9**	**1.8**	**12.3**
2022	1.7	3.2	1.3	14.7
2023	1.7	3.3	1.4	14.5
2024	1.7	3.4	1.5	14.1
2025	1.8	3.6	1.6	13.8
2026	1.8	3.7	1.6	13.5
2027	1.9	3.8	1.7	13.2
2028	1.9	3.9	1.8	13.0
2029	2.0	4.0	1.8	12.8
2030	2.0	4.0	1.8	12.6
2031	2.0	4.1	1.9	12.4
2032	2.1	4.2	1.9	12.2
2033	2.0	4.1	1.9	12.1
2034	2.0	4.1	1.9	12.0
2035	2.1	4.2	2.0	11.8
2036	2.0	4.1	1.9	11.8
2037	2.1	4.2	2.0	11.6
2038	2.0	4.1	1.9	11.5
2039	2.0	4.0	1.9	11.4
2040	2.0	4.0	1.9	11.4
2041	2.0	3.9	1.9	11.3
2042	2.0	3.9	1.9	11.3

Table 2. Revised C2-2: Estimated DEP – High DSM Cost Effectiveness Test Results – Commercial Sector, ZEEA Value of $65/MWh

Year	TRC	MTRC	UCT	CCE ($/GJ)
Portfolio Aggregate	**4.7**	**10.1**	**4.5**	**9.4**
Commercial Aggregate	**2.2**	**4.1**	**1.7**	**11.7**
2022	2.2	4.3	1.8	10.2
2023	2.2	4.4	1.8	10.3
2024	2.2	4.4	1.8	10.4
2025	2.2	4.4	1.8	10.5
2026	2.2	4.4	1.8	10.7
2027	2.2	4.3	1.8	10.8
2028	2.2	4.3	1.8	11.0
2029	2.2	4.2	1.8	11.1
2030	2.2	4.2	1.8	11.2
2031	2.2	4.2	1.8	11.3
2032	2.2	4.2	1.7	11.4
2033	2.2	4.1	1.7	11.5
2034	2.2	4.1	1.7	11.6
2035	2.2	4.1	1.7	11.8
2036	2.2	4.1	1.7	11.9
2037	2.2	4.1	1.7	12.0
2038	2.2	4.1	1.7	12.1
2039	2.2	4.1	1.7	12.2
2040	2.2	4.1	1.7	12.3
2041	2.2	4.1	1.7	12.4
2042	2.2	4.1	1.7	12.5

Table 3: Revised C2-3: Estimated DEP – High DSM Cost Effectiveness Test Results – Industrial Sector, ZEEA Value of $65/MWh

Year	TRC	MTRC	UCT	CCE ($/GJ)
Portfolio Aggregate	**4.7**	**10.1**	**4.5**	**9.4**
Industrial Aggregate	**10.7**	**23.8**	**10.9**	**3.6**
2022	14.9	34.4	15.0	3.3
2023	13.6	31.5	13.7	3.4
2024	12.7	29.2	12.8	3.5
2025	11.9	27.3	12.0	3.6
2026	11.3	25.8	11.4	3.7
2027	10.8	24.6	10.9	3.8
2028	10.4	23.7	10.6	3.9
2029	10.2	22.9	10.3	4.0
2030	10.0	22.5	10.2	3.9
2031	10.0	22.2	10.1	3.8
2032	9.9	22.0	10.1	3.7
2033	9.9	21.9	10.1	3.7
2034	10.0	21.9	10.1	3.6
2035	10.0	21.8	10.1	3.6
2036	10.0	21.8	10.2	3.6
2037	10.0	21.6	10.1	3.5
2038	10.1	21.7	10.2	3.5
2039	10.1	21.7	10.3	3.5
2040	10.2	21.8	10.3	3.5
2041	10.3	21.9	10.4	3.5
2042	10.4	21.9	10.5	3.5

35.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Section 5.4.1, p. 5-17, Section 5.4.5, p. 5-34

Long-Term Cost-Effectiveness Estimates for all Sectors Combined

On page 5-17 of the Application, FEI states:

> In Figure 5-4, the Cost per unit of Conserved Energy (CCE $'s/GJ) is provided and demonstrates the effect of the DSM Settings over the planning horizon. In 2042, the CCE would be forecast as:
>
> - $11.1 per GJ for the DEP [Diversified Energy (Planning)] High Scenario;
> - $5.9 per GJ for the DEP Medium Scenario;
> - $2.8 per GJ for the DEP Low Scenario; and
> - $5.2 per GJ for the Reference Case
>
> In Section 2.4, Figure 2-3, FEI forecasts that in 2042 natural gas plus carbon tax would be over $12 per GJ and renewable and low-carbon gas would be over $24 per GJ. Therefore, the CCE value of $11.1 per GJ for the DEP High Scenario will be cost effective. The CCE illustrates that DSM activities are valuable tools in GHG emission reductions, as saving one additional unit of energy (renewable, low-carbon or conventional natural gas) will be beneficial to customers over the planning horizon.

On page 5-34 of the Application, FEI states:

> The 2022 LTGRP DSM cost effectiveness test results also display the CCE in dollars per GJ. The CCE is an industry standard method for expressing the TRC results in dollars per GJ. Electric utilities use the CCE to express the net cost of saving one unit of utility-supplied energy. The CCE can be used to express UCT results in dollars per GJ by applying the UCT benefit and cost inputs.171 The aggregate portfolio CCE across the planning horizon is $11.3 $/GJ as illustrated below.

Table 5-8: Estimated Diversified Energy (Planning) Cost-Effectiveness Test Results – All Sectors Combined

Year	TRC	MTRC	UCT	CCE ($/GJ)
Aggregate	4.1	14.2	4.0	11.3

Footnote 171: In this case, the CCE represents the annualized and, where applicable, discounted UCT net costs (i.e. sum of UCT costs minus sum of UCT benefits, excluding cost savings for utility fuel sales) divided by annual energy savings. This information fulfills BCUC Directive from the 2017 LTGRP.

35.1 Please provide a list of all supporting portfolio assumptions and values used in the calculation of cost-effectiveness for the TRC, MTRC, UCT and CCE, including any variations between scenarios, if relevant.

Response:

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

The following three tables provide a list of all supporting portfolio assumptions and values used in the calculation of cost-effectiveness for the Reference Case and alternate scenarios.

Table 1: General Cost-Effectiveness Assumptions Over the Planning Horizon (2020 to 2042)

Assumption	Reference Case	DEP	Deep Electrification	Price-Based Regulation	Economic Stagnation	Upper Bound
Inflation	2.20%	2.20%	2.20%	2.20%	2.20%	2.20%
Utility Discount Rate	4.61%	4.61%	4.61%	4.61%	4.61%	4.61%
MTRC Non-Energy Benefits Adder	15%	15%	15%	15%	15%	15%
NPV, Incremental Cost ($000's)	$2,612,702	$3,625,907	$1,283,049	$1,934,687	$1,594,241	$0
NPV, Incentive Cost ($000's)	$1,306,351	$3,625,907	$776,079	$701,987	$893,671	$0
NPV, Admin Cost ($000's)	$195,953	$543,886	$116,412	$105,298	$298,186	$0
NPV, Gas Savings (PJ)	252	311	172	164	214	0

Table 2: Avoided Cost of Gas and Carbon, Nominal ($/GJ)

Year	Reference Case	DEP	Deep Electrification	Price-Based Regulation	Economic Stagnation	Upper Bound
2019	$23.06	$23.06	$23.06	$23.06	$23.06	$23.06
2020	$23.06	$23.06	$23.06	$23.06	$23.06	$23.06
2021	$23.53	$23.53	$23.53	$23.53	$23.53	$23.53
2022	$24.03	$24.03	$24.03	$24.03	$24.03	$24.03
2023	$24.52	$24.52	$24.52	$24.52	$24.52	$24.52
2024	$26.07	$26.07	$26.07	$26.07	$26.07	$26.07
2025	$27.02	$27.02	$27.02	$27.02	$27.02	$27.02
2026	$27.24	$27.24	$27.24	$27.24	$27.24	$27.24
2027	$28.25	$28.25	$28.25	$28.25	$28.25	$28.25
2028	$24.34	$24.34	$24.34	$24.34	$24.34	$24.34
2029	$24.76	$24.76	$24.76	$24.76	$24.76	$24.76
2030	$25.19	$25.19	$25.19	$25.19	$25.19	$25.19
2031	$23.77	$23.77	$23.77	$23.77	$23.77	$23.77
2032	$24.14	$24.14	$24.14	$24.14	$24.14	$24.14
2033	$24.51	$24.51	$24.51	$24.51	$24.51	$24.51
2034	$24.89	$24.89	$24.89	$24.89	$24.89	$24.89
2035	$25.27	$25.27	$25.27	$25.27	$25.27	$25.27
2036	$25.67	$25.67	$25.67	$25.67	$25.67	$25.67

Year	Reference Case	DEP	Deep Electrification	Price-Based Regulation	Economic Stagnation	Upper Bound
2037	$26.07	$26.07	$26.07	$26.07	$26.07	$26.07
2038	$26.19	$26.19	$26.19	$26.19	$26.19	$26.19
2039	$26.23	$26.23	$26.23	$26.23	$26.23	$26.23
2040	$26.26	$26.26	$26.26	$26.26	$26.26	$26.26
2041	$26.30	$26.30	$26.30	$26.30	$26.30	$26.30
2042	$26.34	$26.34	$26.34	$26.34	$26.34	$26.34

Table 3: Zero Emission Energy Alternative, Nominal (ZEEA) ($/GJ)

Year	Reference Case	DEP	Deep Electrification	Price-Based Regulation	Economic Stagnation	Upper Bound
2019	$29.45	$29.45	$29.45	$29.45	$29.45	$29.45
2020	$29.45	$29.45	$29.45	$29.45	$29.45	$29.45
2021	$29.45	$29.45	$29.45	$29.45	$29.45	$29.45
2022	$29.45	$29.45	$29.45	$29.45	$29.45	$29.45
2023	$29.45	$29.45	$29.45	$29.45	$29.45	$29.45
2024	$29.45	$29.45	$29.45	$29.45	$29.45	$29.45
2025	$29.45	$29.45	$29.45	$29.45	$29.45	$29.45
2026	$29.45	$29.45	$29.45	$29.45	$29.45	$29.45
2027	$29.45	$29.45	$29.45	$29.45	$29.45	$29.45
2028	$29.45	$29.45	$29.45	$29.45	$29.45	$29.45
2029	$29.45	$29.45	$29.45	$29.45	$29.45	$29.45
2030	$29.45	$29.45	$29.45	$29.45	$29.45	$29.45
2031	$29.45	$29.45	$29.45	$29.45	$29.45	$29.45
2032	$29.45	$29.45	$29.45	$29.45	$29.45	$29.45
2033	$29.45	$29.45	$29.45	$29.45	$29.45	$29.45
2034	$29.45	$29.45	$29.45	$29.45	$29.45	$29.45
2035	$29.45	$29.45	$29.45	$29.45	$29.45	$29.45
2036	$29.45	$29.45	$29.45	$29.45	$29.45	$29.45
2037	$29.45	$29.45	$29.45	$29.45	$29.45	$29.45
2038	$29.45	$29.45	$29.45	$29.45	$29.45	$29.45
2039	$29.45	$29.45	$29.45	$29.45	$29.45	$29.45
2040	$29.45	$29.45	$29.45	$29.45	$29.45	$29.45
2041	$29.45	$29.45	$29.45	$29.45	$29.45	$29.45
2042	$29.45	$29.45	$29.45	$29.45	$29.45	$29.45

35.2 Please provide the full formula for the CCE, including the components of the UCT costs and benefits used in the calculation.

Response:

The formula for the CCE used in Table 5-8, including components of the UCT costs and benefits used in the calculation, is as follows:

$$CCE = \frac{\sum_{t=1}^{n} \frac{ADMIN_t + INCENTIVE_t}{(1+d)^{t-1}}}{\sum_{t=1}^{n} \frac{SAVINGS_t}{(1+d)^{t-1}}}$$

Where:

- CCE is the utility Cost of Conserved Energy, in $/GJ
- n is the expected lifetime of the measure
- $ADMIN_t$ is the program costs incurred by FEI in year t (typically these are incurred in year 1), in dollars ($)
- $INCENTIVE_t$ is the program incentives provided by FEI in year t (typically paid in year 1), in dollars ($)
- d is the discount rate equal to FEI's Weighted Average Cost of Capital (WACC), as a decimal
- $SAVINGS_t$ is the natural gas DSM energy savings in year t, in GJ

Note that the formula is a time series over the lifetime of the measures included in the forecast.

35.3 Please explain whether the CCE enables the comparison of DSM resources across all resource alternatives, for example, can the cost of biomethane on a $/GJ basis be compared to the CCE expressed in $/GJ?

Response:

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

The CCE discussed in the preamble is the cost of conserved energy from the utility's perspective: the UCT expressed as a levelized cost per GJ (see footnote 171 in the Application). This version of the CCE can be used in some applications as an indicator of cost effectiveness when comparing DSM to gas supply options. However, there are limitations to its usefulness since there are other complexities associated with cost-effectiveness tests that must be taken into consideration.

An example of how calculating CCE from the utility's perspective may be useful in confirming that investments in DSM programs are more cost-effective than investments in acquiring additional units of renewable or low-carbon gas was provided in Section 5.4.1 of the Application. The forecast CCE for the DEP Scenario's High DSM Setting was $11.10 per GJ. The high-level outlook of energy costs[45] suggests that, in 2042, natural gas plus carbon tax would be over $12 per GJ and renewable and low-carbon gas would be over $24 per GJ. At a high level, the comparison provides one indicator that DSM activities are valuable tools in GHG emission reductions, as saving one additional unit of energy for all resource types (renewable, low-carbon or conventional natural gas) will be beneficial to customers over the planning horizon.

However, relying on the CCE alone as a means of choosing between investing in DSM or investing in other resource alternatives does not enable a fair comparison of all resource alternatives. One reason is that calculating CCE from the utility's perspective in this manner excludes costs and benefits that accrue outside of the utility. For example, bill savings are a DSM benefit that accrue to the customer, but are not considered in the calculation of UCT. Bill savings would not be expected to accrue to customers if other resource alternatives (i.e. biomethane or conventional natural gas) were chosen instead of DSM. Similarly, CCE does not indicate whether the DSM is beneficial for the participating customer (as evaluated through the PCT), all customers (as evaluated through the RIM), or as an overall resource factoring in all fuels and all costs (as evaluated through the TRC).

Thus, comparing DSM CCE to the cost of acquiring certain gas resources in some scenarios can be useful, the CCE comparison alone does not enable a complete evaluation in choosing between DSM or acquiring other resource alternatives.

[45] Please refer to Figure 2-3 in Section 2.4 of the Application. These forecasts are based on FEI's current understanding of what the long-term pricing could be for natural gas, renewable and low-carbon gas, electricity, and carbon taxes. However, market uncertainties, such as socio-political and environmental risks, will influence North American and world energy prices.

36.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Appendix C-1 (2021 Conservation Potential Review Report) (CPR Report), p. vii; 36 — 37; 57 — 59; 73, 107, 132, 136 – 139; Appendix C-2, p. 2; Appendix A-5, (CleanBC Roadmap to 2030), p. 41, 68

CPR – Measure Assessment

Polaris states on page 132 of the 2021 Conservation Potential Review Report (Appendix C-1) that:

> The total market potential savings for all sectors, with a TRC screen and with an MTRC screen, are shown in Exhibit 146 and Exhibit 147, respectively. The medium market potential using the MTRC screen is 50% higher than the market potential using TRC screen. By 2040, the total low, medium, and high market TRC potential savings are estimated to be 12 PJ, 16 PJ, and 27 PJ, respectively. By 2040, the low, medium, and high market MTRC potential savings are estimated to be 19 PJ, 24 PJ, and 46 PJ, respectively.

Polaris states on page 136 of the CPR Report (Appendix C-1) that:

> Under the TRC medium market scenario, by 2025, the industrial sector is estimated to have the most savings potential, followed by the residential and then commercial sectors. By 2030, the commercial sector overtakes residential. This is because there are only 14 residential measures that pass the TRC, and almost all of them are retrofit measures that can be implemented early in the study period. By 2040, potential savings from industrial, commercial, and residential sectors are estimated to be 7.3 PJ, 5.0 PJ,and 3.4 PJ, respectively.
>
> Under the MTRC medium market scenario, the residential sector is estimated to have the most savings potential throughout the study period, followed by industrial and then commercial. By 2040, potential savings from residential, industrial, and commercial sectors are estimated to be 9.9 PJ, 8.6 PJ, and 5.8 PJ, respectively.

Polaris states on page 58 of the CPR Report (Appendix C-1) that for the Residential sector MTRC market potential is almost three times the TRC market potential. The biggest difference between the two economic screen scenarios comes from measures that affect space heating.

Polaris states on page vii of the CPR Report (Appendix C-1):

- In the residential sector, only a small number of measures are cost-effective based on the TRC test, most being low-cost retrofit measures. Measures that pass the MTRC screen only become more important in the residential sector as the study period progresses.
- The opportunities for equipment replacement measures, especially space heating measures, are much smaller relative to previous studies. This is primarily due to

increasingly higher federal and provincial minimum energy performance standards (MEPS) for furnaces, which have caused DSM opportunities to become increasingly scarce.

The CleanBC Roadmap to 2030 (Appendix A-5) states on page 41 that: "After 2030, all new space and water heating equipment sold and installed in B.C. will be at least 100% efficient, significantly reducing emissions compared to current combustion technology."

The CleanBC Roadmap to 2030 (Appendix A-5) Portfolio of Measures on page 68 includes: "Phase out utility gas equipment incentives" in the near-term.

Exhibit 23 on page 36 of the CPR Report (Appendix C-1) lists the Residential Sector Conservation and Energy Management Measures.

36.1 Please provide an updated version of Exhibit 23 showing all the space and water heating equipment considered by FEI, along with the corresponding coefficient of performance (COP).

Response:

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

Seasonal efficiency ratings for space and water heating equipment shown in Exhibit 23 of the 2021 Conservation Potential Review (CPR)[46] are illustrated in Table 1, below. Seasonal efficiencies are expressed using industry standard metrics, including Annual Fuel Utilization Efficiency (AFUE), fireplace efficiency (FE), and Energy Factor (EF) and seasonal Coefficient of Performance (COP).

Table 1: Seasonal Efficiency Ratings for Residential Space and Water Heating Equipment Evaluated in the CPR

Equipment	Seasonal Efficiency
Space Heating – Equipment	
Boiler (Early Retirement)	90% AFUE
Electric Air Source Heat Pump with Existing Gas Furnace Backup	Not Applicable (controls-only measure)
Electric Air Source Heat Pump with New Gas Furnace Backup	Not Applicable (controls-only measure)
Furnace (Early Retirement)	95% AFUE
Gas Heat Pump – Space Heating	1.35 COP
High Efficiency Boiler	95% AFUE
High Efficiency Boiler Dual Fuel - Gas Primary	95% AFUE
High Efficiency Fireplace	62.4% fireplace efficiency (FE)
High Efficiency Furnace	97% AFUE
High Efficiency Furnace Dual Fuel-Gas Primary	97% AFUE

[46] Exhibit B-1, Application, Appendix C-1, p. 36.

Equipment	Seasonal Efficiency
Space Heating & Water Heating - Equipment	
Combination System - Type 1 and 2	95% Boiler AFUE and 0.82 EF Water Heater
Combination System - Type 3	97% Furnace AFUE and 0.95 EF Water Heater
Gas Heat Pump Combination System – Type 1 and 2	1.4 COP for Space Heating, 1.3 COP for Water Heating
Water Heating – Equipment	
Gas Heat Pump – Domestic Hot Water	1.4 COP
High-Efficiency Condensing Tankless Water Heater	0.90 EF
High-Efficiency Condensing Storage Water Heater	0.80 EF
High-Efficiency Storage Tank Water Heater	0.67 EF
Solar Water Heating System	1.86 SUEF

Exhibit 51, Exhibit 52, Exhibit 53 and Exhibit 54 on page 57 to 59 of the CPR Report (Appendix C-1) show the TRC and MTRC Medium Market Potential Savings by end use in 2025 and 2040 for the Residential sector.

36.2 Please provide updated versions of Exhibits 51 to 54 including the High Market Potential Savings in GJ and % of consumption.

Response:

The following response has been provided by Posterity Group.

Updated versions of Exhibits 51 to 54, including the High Market Potential Savings in GJ and percentage of consumption, are provided below.

Table 1: High Market Potential Savings by End Use in 2025 – Residential, TRC

Parent End Use	Ref Case Consumption (GJ)	High Market Potential Savings (GJ)	% of Consumption
Domestic Hot Water (DHW)	13,205K	832K	6%
Space Heating	46,600K	777K	2%
Fireplace	11,549K	390K	3%
Cooking	1,328K	11K	1%
Pool & Spa Heaters	528K	4K	1%
Clothes Dryer	229K	2K	1%
Other Gas Uses	2,112K	0K	0%
Total	**75,552K**	**2,016K**	**3%**

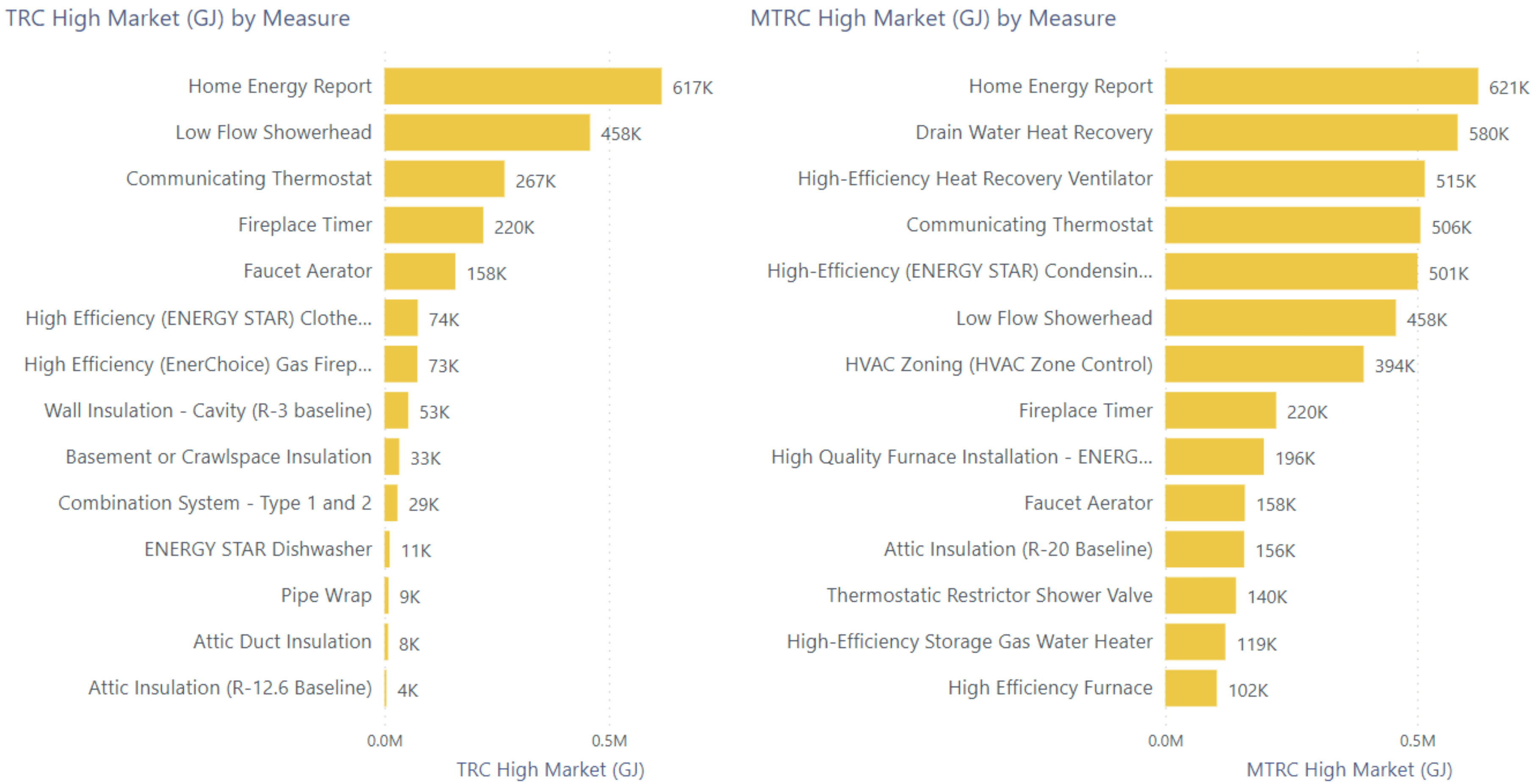
Table *2:* High Market Potential Savings by End Use in 2025 – Residential, MTRC

Parent End Use	Ref Case Consumption (GJ)	High Market Potential Savings (GJ)	% of Consumption
Space Heating	46,600K	3,131K	7%
Domestic Hot Water (DHW)	13,205K	2,202K	17%
Fireplace	11,549K	401K	3%
Pool & Spa Heaters	528K	105K	20%
Cooking	1,328K	11K	1%
Clothes Dryer	229K	6K	3%
Other Gas Uses	2,112K	0K	0%
Total	**75,552K**	**5,855K**	**8%**

Table 3: High Market Potential Savings by End Use in 2040 – Residential, TRC and MTRC

Parent End Use	Consumption (GJ)	High Potential Savings (TRC)	High Potential Savings (MTRC)	Difference (GJ)
Space Heating	43,877K	1,571K	8,001K	6,430K
Domestic Hot Water (DHW)	12,445K	1,733K	4,874K	3,141K
Pool & Spa Heaters	556K	3K	265K	261K
Fireplace	11,710K	951K	987K	36K
Clothes Dryer	238K	1K	17K	16K
Cooking	1,453K	8K	9K	0K
Other Gas Uses	2,728K	0K	0K	0K
Total	**73,006K**	**4,268K**	**14,153K**	**9,884K**

Table 4: High Market Potential (TRC on Left, MTRC on Right) - Top 14 Residential Measures in 2025 (GJ)



36.3 Please provide revised versions Exhibits 51 to 54 showing the potential DSM gas savings if space and water heating equipment with efficiency less than 100% is excluded.

Response:

The following response has been provided by Posterity Group.

Tables 1 through 4 below provide updated versions of the CPR Report Exhibits 51 – 54, in which the following residential space and water heating equipment types are removed:

- Combination systems;
- Furnace (natural and early replacement, and dual fuel versions);
- Boilers (natural and early replacement, and dual fuel versions);
- High quality furnace installation;
- Water heaters (storage and tankless types); and
- Fireplaces.

Table 1: Medium Market Potential Savings by End Use in 2025 – Residential, TRC

Parent End Use	Ref Case Consumption (GJ)	Medium Market Potential Savings (GJ)	% of Consumption
Domestic Hot Water (DHW)	13,205K	742K	6%
Space Heating	46,600K	608K	1%
Fireplace	11,549K	209K	2%
Cooking	1,328K	11K	1%
Pool & Spa Heaters	528K	4K	1%
Clothes Dryer	229K	2K	1%
Other Gas Uses	2,112K	0K	0%
Total	**75,552K**	**1,577K**	**2%**

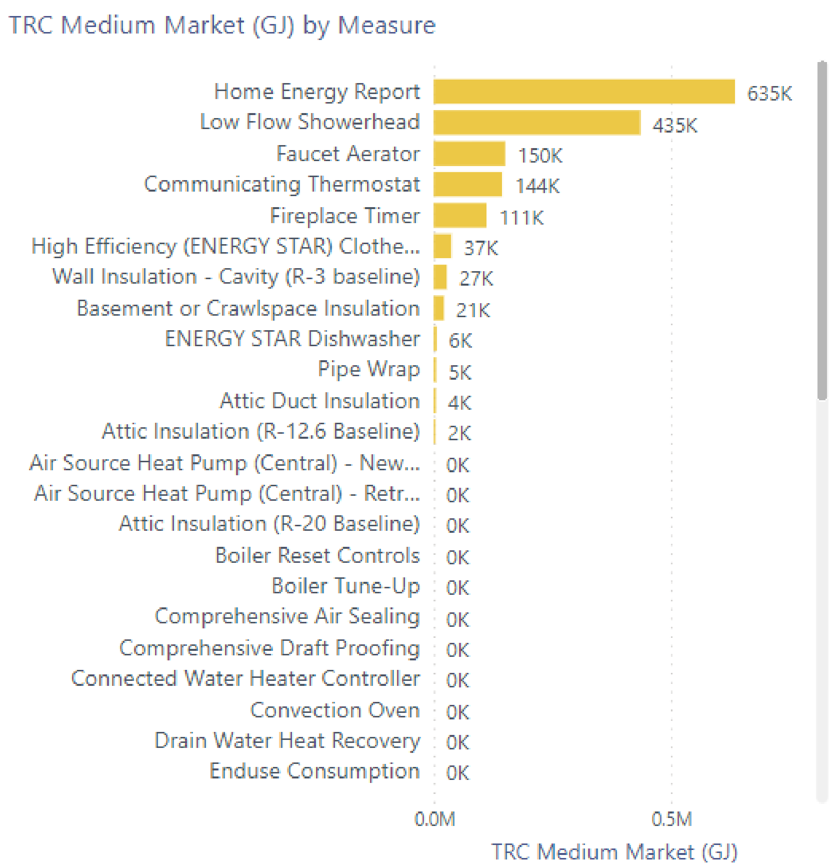
Table 2: Medium Market Potential Savings by End Use in 2025 – Residential, MTRC

Parent End Use	Ref Case Consumption (GJ)	Medium Market Potential Savings (GJ)	% of Consumption
Space Heating	46,600K	1,655K	4%
Domestic Hot Water (DHW)	13,205K	1,131K	9%
Fireplace	11,549K	211K	2%
Pool & Spa Heaters	528K	89K	17%
Cooking	1,328K	11K	1%
Clothes Dryer	229K	4K	2%
Other Gas Uses	2,112K	0K	0%
Total	**75,552K**	**3,101K**	**4%**

Table 3: Medium Market Potential Savings by End Use in 2040 – Residential, TRC and MTRC

Parent End Use	Medium Potential Savings (GJ) - TRC	Medium Potential Savings (GJ) - MTRC	Difference (GJ)
Space Heating	1,117K	4,443K	3,326K
Domestic Hot Water (DHW)	1,558K	2,551K	993K
Pool & Spa Heaters	3K	219K	216K
Clothes Dryer	1K	9K	8K
Fireplace	481K	482K	0K
Cooking	8K	9K	0K
Other Gas Uses	0K	0K	0K
Total	**3,170K**	**7,713K**	**4,543K**

Table 4: Medium Market Potential (TRC on Left, MTRC on Right) - Top 14 Residential Measures in 2025 (GJ)



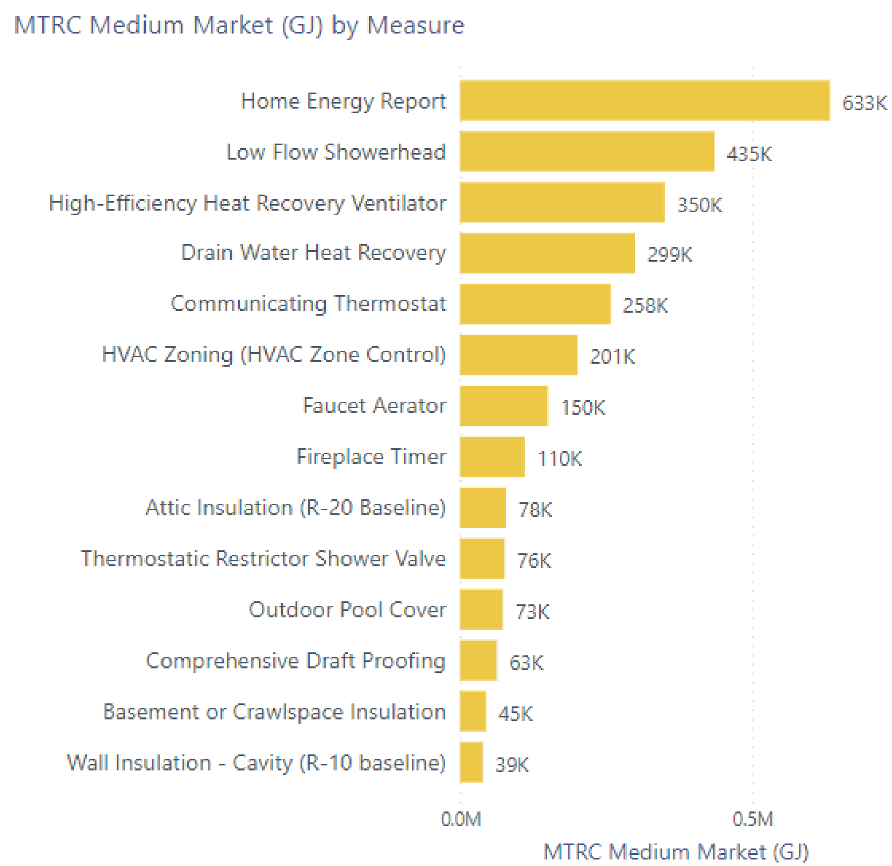


Exhibit 152 and 153 on pages 138 and 139 of the CPR Report (Appendix C-1) show the TRC and MTRC Medium and High Market Incentive Costs and Natural Gas Savings for All Sectors over the planning period.

36.4 Please provide revised versions of Exhibit 152 and Exhibit 153, showing the potential DSM incentive costs and gas savings if space and water heating equipment with efficiency less than 100% is excluded.

Response:

The following response has been provided by Posterity Group.

Revised versions of CPR Report Exhibits 152 and 153 are provided in Tables 1 and 2, below. These versions exclude the following equipment:

- Boilers;
- Combination systems;
- Water heaters;
- Unit heaters;
- Make up air units;
- Fireplaces; and
- Infrared heaters.

Please refer to the response to BCUC IR1 45.1 for an analysis showing that cumulative energy savings will be reduced by approximately 12 percent if incentives for conventional gas-fired heating equipment are discontinued.

Table 1: Medium and High Market Incentive Costs and Natural Gas Savings – All Sectors, TRC

Year	Medium Market Incentive Cost	Medium Market Non-Incentive Cost	Medium Market Total Costs	Medium Market Potential Savings (GJ)	Medium Incremental Savings (Year-over-Year, GJ)	High Market Incentive Cost	High Market Non-Incentive Cost	High Market Total Costs	High Market Potential Savings (GJ)	High Incremental Savings (Year-over-Year, GJ)
2020	$7.40M	$1.11M	$8.51M	879K	879K	$29.80M	$4.47M	$34.27M	1,633K	1,633K
2021	$8.11M	$1.22M	$9.33M	1,686K	807K	$33.46M	$5.02M	$38.48M	3,108K	1,475K
2022	$9.38M	$1.41M	$10.79M	2,470K	784K	$40.04M	$6.01M	$46.05M	4,526K	1,419K
2023	$11.05M	$1.66M	$12.71M	3,269K	799K	$43.97M	$6.60M	$50.57M	5,789K	1,263K
2024	$12.96M	$1.94M	$14.90M	4,119K	850K	$50.37M	$7.56M	$57.92M	6,964K	1,175K
2025	$12.09M	$1.81M	$13.90M	4,845K	726K	$59.93M	$8.99M	$68.92M	8,190K	1,225K
2026	$12.87M	$1.93M	$14.80M	5,540K	695K	$69.30M	$10.40M	$79.70M	9,455K	1,266K
2027	$13.74M	$2.06M	$15.80M	6,248K	707K	$75.44M	$11.32M	$86.75M	10,754K	1,299K
2028	$14.45M	$2.17M	$16.62M	6,958K	711K	$80.43M	$12.06M	$92.49M	12,066K	1,312K
2029	$14.81M	$2.22M	$17.03M	7,669K	711K	$82.71M	$12.41M	$95.11M	13,378K	1,311K
2030	$15.11M	$2.27M	$17.38M	8,375K	706K	$84.18M	$12.63M	$96.81M	14,677K	1,299K
2031	$15.25M	$2.29M	$17.54M	9,075K	700K	$85.01M	$12.75M	$97.76M	15,955K	1,278K
2032	$15.52M	$2.33M	$17.85M	9,769K	695K	$85.51M	$12.83M	$98.33M	17,186K	1,231K
2033	$15.13M	$2.27M	$17.40M	10,452K	683K	$82.01M	$12.30M	$94.31M	18,348K	1,162K
2034	$15.28M	$2.29M	$17.57M	11,129K	677K	$81.69M	$12.25M	$93.95M	19,384K	1,036K
2035	$15.01M	$2.25M	$17.26M	11,777K	649K	$80.11M	$12.02M	$92.12M	20,368K	984K
2036	$14.47M	$2.17M	$16.64M	12,312K	535K	$78.76M	$11.81M	$90.57M	21,334K	965K
2037	$14.46M	$2.17M	$16.63M	12,839K	527K	$78.15M	$11.72M	$89.87M	22,264K	930K
2038	$14.35M	$2.15M	$16.51M	13,360K	521K	$73.36M	$11.00M	$84.36M	23,089K	825K
2039	$13.99M	$2.10M	$16.09M	13,870K	510K	$66.72M	$10.01M	$76.73M	23,805K	716K
2040	$14.06M	$2.11M	$16.17M	14,374K	504K	$67.61M	$10.14M	$77.75M	24,506K	700K

Table 2: Medium and High Market Incentive Costs and Natural Gas Savings – All Sectors, MTRC

Year	Medium Market Incentive Cost	Medium Market Non-Incentive Cost	Medium Market Total Costs	Medium Market Potential Savings (GJ)	Medium Incremental Savings (Year-over-Year, GJ)	High Market Incentive Cost	High Market Non-Incentive Cost	High Market Total Costs	High Market Potential Savings (GJ)	High Incremental Savings (Year-over-Year, GJ)
2020	$36.25M	$5.44M	$41.69M	1,190K	1,190K	$146.86M	$22.03M	$168.89M	2,273K	2,273K
2021	$37.83M	$5.68M	$43.51M	2,317K	1,127K	$157.39M	$23.61M	$181.00M	4,432K	2,158K
2022	$39.99M	$6.00M	$45.98M	3,431K	1,114K	$172.72M	$25.91M	$198.62M	6,587K	2,155K
2023	$42.84M	$6.43M	$49.26M	4,573K	1,142K	$187.04M	$28.06M	$215.09M	8,649K	2,063K
2024	$45.53M	$6.83M	$52.36M	5,773K	1,201K	$196.86M	$29.53M	$226.39M	10,650K	2,001K
2025	$45.41M	$6.81M	$52.22M	6,858K	1,084K	$199.57M	$29.94M	$229.51M	12,677K	2,027K
2026	$47.02M	$7.05M	$54.07M	7,916K	1,058K	$221.24M	$33.19M	$254.42M	14,807K	2,130K
2027	$48.48M	$7.27M	$55.76M	8,989K	1,073K	$236.34M	$35.45M	$271.79M	17,015K	2,208K
2028	$49.48M	$7.42M	$56.91M	10,062K	1,073K	$249.30M	$37.39M	$286.69M	19,270K	2,256K
2029	$41.80M	$6.27M	$48.07M	11,058K	997K	$244.70M	$36.70M	$281.40M	21,512K	2,242K
2030	$42.86M	$6.43M	$49.29M	12,054K	996K	$230.97M	$34.65M	$265.62M	23,671K	2,158K
2031	$43.61M	$6.54M	$50.15M	13,047K	993K	$231.75M	$34.76M	$266.52M	25,799K	2,129K
2032	$44.56M	$6.68M	$51.25M	14,038K	991K	$243.52M	$36.53M	$280.05M	27,874K	2,075K
2033	$44.79M	$6.72M	$51.51M	15,022K	984K	$227.38M	$34.11M	$261.49M	29,782K	1,908K
2034	$45.62M	$6.84M	$52.46M	16,003K	981K	$226.33M	$33.95M	$260.27M	31,557K	1,775K
2035	$46.05M	$6.91M	$52.96M	16,957K	954K	$225.49M	$33.82M	$259.31M	33,275K	1,719K
2036	$44.62M	$6.69M	$51.32M	17,791K	834K	$222.59M	$33.39M	$255.98M	34,934K	1,658K
2037	$44.86M	$6.73M	$51.58M	18,616K	825K	$215.57M	$32.34M	$247.91M	36,506K	1,572K
2038	$44.44M	$6.67M	$51.10M	19,429K	813K	$193.34M	$29.00M	$222.34M	37,802K	1,296K
2039	$43.76M	$6.56M	$50.33M	20,225K	796K	$186.34M	$27.95M	$214.29M	38,987K	1,185K
2040	$44.07M	$6.61M	$50.68M	21,016K	791K	$188.55M	$28.28M	$216.84M	40,161K	1,174K

On page 2 in Figure C2-1 in Appendix C-2 to the Application shows the annual demand before and after estimated DSM Savings (Excluding LCT) – All Sectors Combined

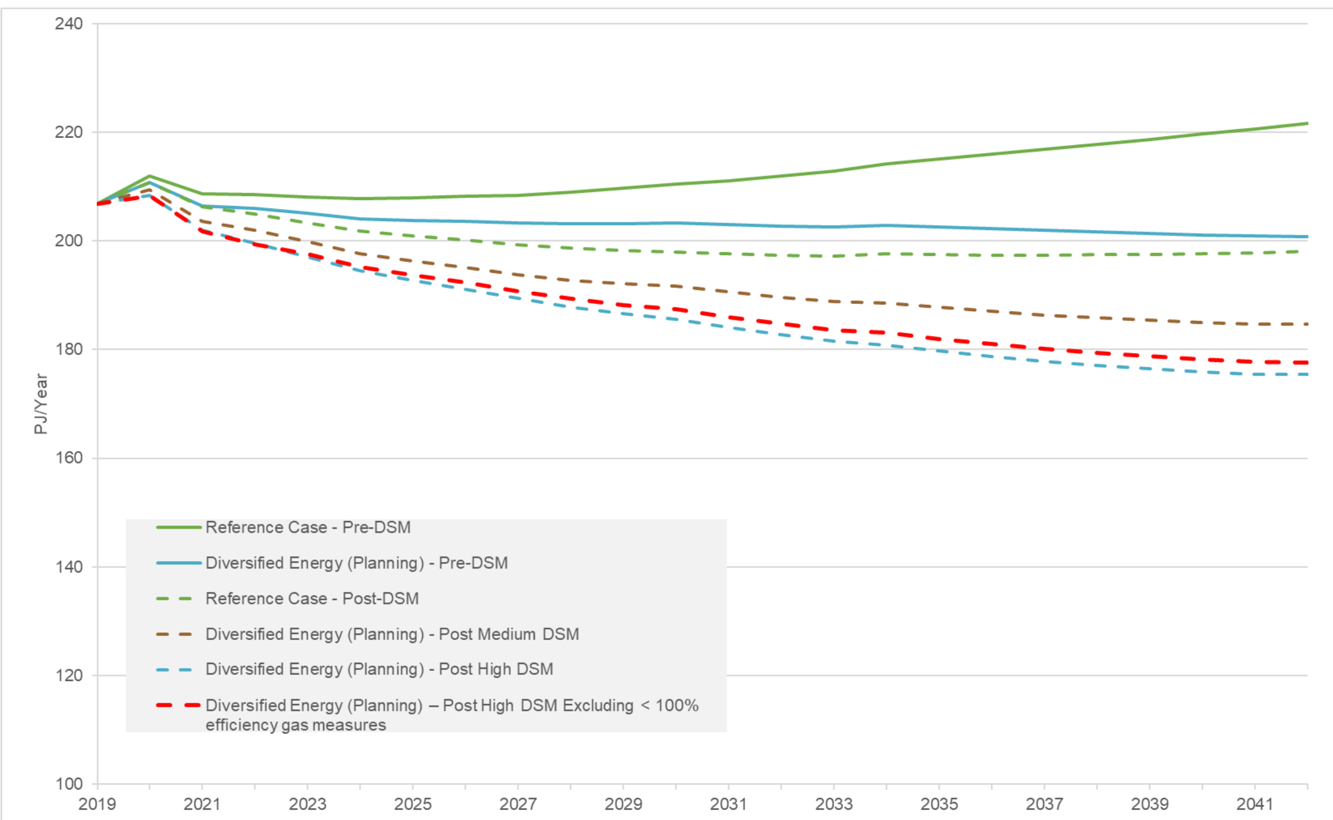
36.5 Please provide an updated version of Figure C2-1, the results of an analysis showing the DSM market potential under the DEP High Scenario, if space and water heating equipment with efficiency less than 100% is excluded.

Response:

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

Figure 1 below provides an updated version of Figure C2-1,[47] adding a line for the DSM market potential for the DEP High DSM Setting after the exclusion of space and water heating equipment with efficiency less than 100 percent.

Please refer to the response to BCUC IR1 45.1 for an analysis showing that cumulative energy savings will be reduced by approximately 12 percent if incentives for conventional gas-fired heating equipment are discontinued.



[47] Figure C2-1 is the same as Figure 5.9 discussed in Section 5.4.3 in the Application. During the IR response process, FEI noted that in Appendix C2 the Figure is listed incorrectly as "Figure 5.5 discussed in Section 5.4.2".

Polaris states on pages 37, 73 and 107 of the CPR Report (Appendix C-1) that the TRC and MTRC results are presented at the measure-level and exclude program costs and free ridership for the residential, commercial and industrial sectors respectively.

36.6 Please discuss to what extent the amount of potential cost-effective savings is over-estimated by excluding program costs and net-to gross adjustments such as free-ridership, and the relevance for including measures with cost-effectiveness ratios of close to 1.0 using the MTRC.

Response:

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

The amount of potential cost-effective savings that is over-estimated by excluding program costs and net-to-gross adjustments such as free-ridership should not significantly impact cost-effective savings.

Program Costs

The model does include non-incentive program costs (assumed to be 15 percent of the corresponding incentive costs) and therefore the administrative costs associated with program implementation have been accounted for in cost-effectiveness tests. The only additional non-incentive expenditures were those that support or enable DSM programs at the portfolio level, such as Enabling Activities and Conservation Education and Outreach expenditures.

The most recent reported year serves as a good annual proxy for these expenditures. In the FEI 2021 DSM Annual Report, the combined Conservation Education and Outreach, Enabling Activities, and Portfolio Level Activities expenditures were approximately $15 million out of $107 million total expenditures, about 14 percent of the total portfolio. This value is not likely to significantly impact the results of the TRC / MTRC.

Net-to-Gross Adjustments

Net-to-gross adjustments such as free-ridership and spillover are not taken into account in the CPR, as they are highly dependent on program design and delivery approaches.

FEI takes a conservative approach to assessing net-to-gross during DSM program development: free-ridership which discounts savings is taken into account, but spillover which adds additional non-participant savings that occur through promotional activities, for example, is not taken into account. As a result, in some jurisdictions, net-to-gross is a program benefit. Regardless, in FEI's experience, measures which pass cost-effectiveness tests in the CPR have been found to also pass cost-effectiveness tests in DSM program implementation.

Based on these points, continuing to include measures with MTRC ratios of close to 1.0 in the CPR, will not significantly impact future program savings. Through the DSM program implementation process, and ongoing evaluation of individual measures and programs, FEI will then determine if a measure remains in the program thus portfolio.

37.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Appendix C-1, pp. 91 – 92

Commercial Market Potential

Polaris states on page 91 of the CPR Report (Appendix C-1):

> By 2040, the commercial low, medium, and <u>high market TRC</u> potential consumption levels are estimated to be 78 PJ, 77 PJ, and <u>72 PJ</u>, respectively, while reference consumption is forecasted to reach 82 PJ. By 2040, the commercial low, medium, and high market MTRC potential consumption levels are estimated to be 78 PJ, 76 PJ, and <u>65 PJ</u>, respectively, while reference consumption is forecasted to reach 82 PJ. [Emphasis added]

Exhibit 93 and Exhibit 94 on pages 91 and 92 show the Commercial Market Potential Consumption using the TRC and MTRC tests respectively.

37.1 Please explain the factors underlying the results shown in Exhibit 93 and 94, where the MTRC results for the Commercial High Market scenario show the greatest increase in savings, while the Low and Medium Market scenarios are similar to the TRC results shown in Exhibit 93.

<u>Response:</u>

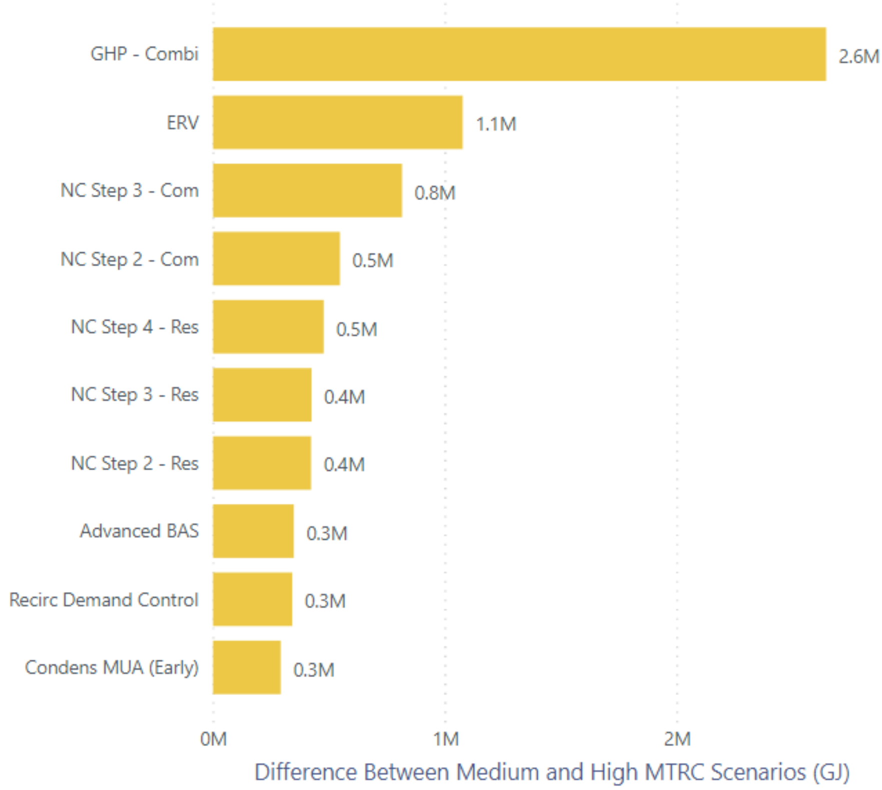
The following response has been provided by Posterity Group.

The factors explaining the reason for the relatively large potential savings in the Commercial High Market scenario are presented on pages 88-89 of the CPR Report, as follows:

> The high market potential scenario is much higher than the medium market potential in the MTRC scenario. By 2040, the difference in potential between the medium and high market MTRC scenarios is 11.6 PJ. In this case, gas heat pumps (GHPs) are a major factor contributing to the difference:
>
> - For all measures, medium and high scenarios assume that measure incentive levels will be 50% and 100% of incremental costs, respectively.
> - In addition to this, gas heat pumps were given different adoption curves in the two scenarios.
> - In the medium market scenario, GHPs are modeled as an innovative technology with no current market penetration and low forecasted growth.
> - In the high scenario, they are modeled as an innovative technology with no current market penetration, but with high forecasted growth, especially in the second half of the study period (2030-2040).
>
> The difference in MTRC medium and high potential scenarios by 2040, broken down by measure, is shown in Exhibit 91. Only the top 10 measures that contribute

to the difference are presented. Gas heat pumps top the list by a sizeable margin, but New Construction Step Code measures and energy recovery ventilators also influence the difference. For comparison, Exhibit 92 shows the difference in TRC medium and high potential scenarios - the absence of gas heat pumps is noticeable here.

Exhibit 91 – Top 10 Commercial Measures Contributing to Difference in Medium and High Market Potential Scenarios (Using MTRC Screen) by 2040



38.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Section 5.3.3, pp. 5-10 – 5-11; Section 5.4.5, p. 5-26

Level of DSM Savings – Key Variables

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

> The DSM Settings are based on the following three variables:
>
> - Incentive Level: The measure incentive levels (50 percent or 100 percent) of each measure's incremental cost. In general, higher incentives drive higher participation in DSM.
> - Economic Screen: The economic screens (TRC, MTRC, or UCT) that determine which measures are included in the analysis.
> - Budget Setting: Overall budget limitations, including both incentive spending and non-incentive program spending.

38.1 Please discuss if FEI considered modelling the results of other incentive levels besides 50 percent and 100 percent, for example, a 75 percent incentive level, and if not, why not.

<u>Response:</u>

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

Other incentive levels, such as 75 percent incentives, were not considered as part of the LTGRP. The LTGRP drew heavily on the work of the Conservation Potential Review (CPR) team for data on Demand-side Management (DSM) potential. The CPR included market potential scenarios at 25, 50, and 100 percent incentive levels; therefore, those were the levels used for the LTGRP.

The Application and the CPR were complementary projects. The LTGRP team produced the Reference Case for the CPR, and in turn, the CPR conducted the research and analysis on DSM measures and produced a set of DSM market potential scenarios. The market potential scenarios that were explored in the CPR were designed to satisfy the BCUC requirement that the LTGRP include: "The development of DSM funding scenarios, reflecting the results of the most recent CPR. At a minimum, this should include a 'reference' DSM funding scenario with 'high DSM' and 'low DSM' scenarios that are relative to the reference scenario."[48]

In the CPR, the incentive levels were chosen based on the following criteria:

- 25 percent incentives are the smallest FEI believes it could offer while still achieving program participation and therefore serves as a lower limit for the analysis;
- 50 percent incentives are consistent with the status quo for typical current programs; and
- 100 percent incentives replicate the "maximum market potential" which was requested after the previous LTGRP filing. This High DSM Setting was also used to maximize GHG emission reduction potential.

[48] 2017 Long Term Gas Resource Plan Decision and Order G-39-19.

A 75 percent incentive level was considered as part of the CPR modelling in place of the 25 percent level; however, the 25 percent incremental cost incentive level was important for modelling the “low DSM” scenario level.

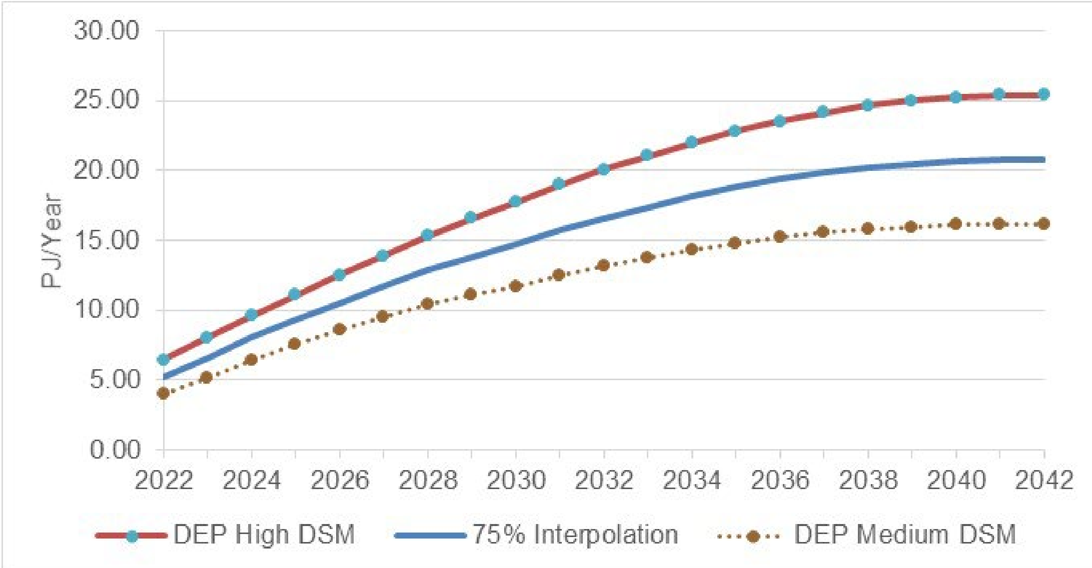
38.2 Please provide the results of an analysis comparing the estimated amount of DSM gas savings in GJ resulting from 50 percent, 75 percent and 100 percent incentive levels.

Response:

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

Developing estimated DSM gas savings resulting from 50 percent and 100 percent incentive levels was the result of several weeks of consultation and analysis. A true 75 percent incentive scenario would require review of the expected program participation response by a panel of stakeholders, as took place in the sector workshops as part of the 2021 Conservation Potential Review. The stakeholder panelists would need to be reassembled to discuss how program uptake might vary at incentive levels between 50 percent and 100 percent, for several example measures in each sector. Creating a modelled 75 percent incentive scenario without that step would be a purely mathematical exercise in interpolation. It is Posterity Group’s view that a purely mechanical approach to program uptake neglects many nonlinear factors having to do with market behavior, addressable market barriers, and customer preferences.

However, for illustrative purposes, FEI has created Figure 1 below based on Figure 5-2 on page 5-15 of the Application that illustrates the savings in PJ/year for the Medium DSM Setting (50 percent incentive level) and High DSM Setting (100 percent incentive level) as applied to the DEP Scenario. For illustrative purposes, the 75 percent interpolation line represents the average of these two datasets. It is expected that the 75 percent line, in actuality, would lie closer to the High DSM Setting than the midpoint illustrated below, due to higher participation rates at the higher incentive level.



38.3 Please provide any supporting evidence from other jurisdictions to support the assertion that higher incentives drive higher participation, including the relationship between the estimated amount of gas savings as the proportion of incentive increases.

Response:

BC is a unique regulatory environment and FEI's program measures are not necessarily offered to the same extent in other jurisdictions. Therefore, to prove the assertion that higher incentives drive higher participation, FEI relies less on program experience from other jurisdictions, and more on its own program development experience including historical participation trends, and industry consultation as noted in the response to BCUC IR1 38.4.

FEI has past experience of increased incentive levels resulting in increased program uptake and increased program savings. For example, uptake in the residential retrofit tankless water heater program increased by 58 percent between 2018 and 2019 when the rebate was increased from $500 to $1000, to the benefit of high-efficiency water heater market transformation over the 2019 – 2022 DSM Plan period.

In 2020, enhanced incentives were offered across all program areas through FEI's COVID-19 pandemic customer support initiatives. These initiatives resulted in a significant increase in participation across program areas for the eligibility period. In the residential program area, FEI offered a time-limited "Bigger Rebates Offer" which effectively doubled the rebate amounts for select heating system measures. Due to the higher home renovation activity associated with COVID-19 pandemic purchasing behaviour, and the higher incentives in the time limited offer, final participation counts resulting from the 90-day promotional code registration period exceeded

2019's full year of participation for furnaces, boiler and combination systems and fireplaces. The number of participants who accessed the 90-day registration period in the time limited offer and completed installation within the eligibility timeframe is compared to participation in the 2019 year program year in Table 1, below.

Table 1: Heating system program participation for the 2019 Program Year in Comparison to Participant Uptake in the 2020 Time Limited Bigger Rebates Offer

	2019	Promotion Participants
Furnace	9,301	11,339
Boilers and Combi- Systems	840	1,349
Fireplace	4,828	4,920
Total	14,969	17,608

FEI's experience demonstrates that higher incentive levels positively impact program participation levels, achieving higher energy savings across the programs. FEI will continue to evaluate incentive levels as a critical component in DSM program development where the objective is to drive maximum energy savings while providing cost-effective DSM programs to its customers.

On page 5-26 of the Application FEI states that estimated DSM expenditures are more than double 2021 levels as a result of using the DEP High DSM Setting which may cover up to 100 percent of incentive levels to accelerate the adoption of energy efficient measures and building upgrades. In the current DSM environment, incentive levels are on average set at about 50 percent of incremental costs for the upgrade. These ratios vary per measure, per program and per program area.

38.4 Please explain if FEI intends to apply a consistent 100 percent incentive across all measures in its DSM implementation plan, and discuss why or why not.

38.4.1 If not, please describe how FEI determines the level of incentive required for each measure, program or program area to achieve the DEP High DSM Setting.

Response:

FEI does not intend to apply a consistent 100 percent incentive across all measures in its DSM implementation plans over the planning horizon. FEI considers multiple factors when determining incentive levels for measures in a DSM implementation plan. These factors include:

- assessing incremental cost;
- optimizing the adoption of the measure and potential energy savings;
- assessing the overall cost effectiveness of programs, which may encompass multiple measures;

- engaging with key stakeholders such as contractors, customers, and interest groups to understand barriers and decision-making criteria; and
- leveraging program expertise to ensure offers are comparable, accessible and consistent over time.

Table 5-3 on page 5-11 of the Application includes the following description of the Medium DSM setting: “Any incentive level is permitted, but measures must pass UCT > 2 and MTRC or TRC >1. This represents more efficient budget spending.”

38.5 For the medium UCT DSM scenario, please discuss why a UCT of 2 was selected as the cut-off in this scenario, and how this represents more efficient budget spending.

Response:

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

The selection of a threshold of 2 for the Medium UCT DSM Setting was somewhat arbitrary but is equivalent to a measure with a TRC of 1 and an incentive of 50 percent of incremental cost. This incentive level is typical in current programs and is the incentive level used in the Medium DSM Setting. The setting represents more efficient budget spending because it produces more savings per unit of budget. This is because the UCT is essentially a ratio of benefits (mainly energy savings) to utility costs (mainly incentives and non-incentive administrative costs). In contrast, the TRC and MTRC are both ratios of benefits (mainly energy savings) to total measure costs, which are not as directly tied to utility program budgets. The UCT can be a good proxy for the ratio of energy savings to program spending.

In the Medium UCT DSM Setting, the model distributes more incentives and drives higher participation to the measures that are most economically attractive in terms of program budgets. Measures that are particularly expensive for the savings they provide (but still pass the MTRC), might not pass a UCT of 2 at 50 percent incentive, and will therefore be restricted to a 25 percent incentive, or be excluded from the scenario altogether. Alternatively, measures with very high savings per program dollar, will be allowed the 100 percent incentive. In this way, the Medium UCT Setting achieves higher savings for less spending than the Medium DSM Setting.

On page 5-11 of the Application FEI states:

> Consistent with the Clean Growth Pathway, the High DSM Setting maximizes energy savings potential and therefore the potential to reduce GHG emissions by accelerating building retrofits, high performance new construction and energy efficiency in commercial and industrial processes. The choice of the High DSM

Setting is also consistent with the positive support from the RPAG, Energy Efficiency Advisory Committee (EECAG) and community engagement sessions for FEI to undertake high levels of DSM.

38.6 Please discuss what steps FEI can take to maximize the efficiency of DSM spending in the context of the High DSM setting.

Response:

The DSM analysis in the Application is meant to assess the size of the available DSM resource rather than provide a cost-optimized estimate of program potential. For the purpose of long-term modeling, the DSM analysis in this High DSM Setting scenario applies incentives set at 100 per cent of incremental cost and applies standard non-incentive program costs that are 15 percent of the corresponding incentive costs. In practical application, FEI would optimize the costs of energy savings to the extent that there is not a large additional expenditure for a small amount of additional savings (i.e., where moving from an incentive level of 50 percent of incremental cost to 100 percent only attracts a few additional participants). FEI would also look to continue optimizing spending in the area of non-incentive expenditures.

39.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Section 4.5.3, pp 4-21 – 4.22; Section 5.4.7, p. 5-38

Energy Savings Market Potential to 2030 from Top Ten Measures

Table 5-9 on page 5-38 of the Application shows the Estimated 2030 Cumulative Savings from Top 10 Measures by Diversified Energy (Planning) – All Sectors Combined. In the case of low-flow showerheads, high-efficiency heat recovery ventilators and energy management (industrial), the Reference Case savings in GJ are higher in the reference case than in the Diversified Energy (Planning) scenario.

Table 5-12 indicates the top measure for the Industrial sector by energy savings is Steam to Hot Water Conversion (District Energy).

On pages 4-21 to 4-22, in section 4.5.3, of the Application, FEI outlines the critical uncertainty input settings for each future load forecast scenario.

39.1 Please explain why the amount of savings for these three measures is lower under the Diversified Energy (planning) scenario than the Reference case..

Response:

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

As described in Section 5.1 of the Application, the DSM analysis model was designed to prioritize reducing conventional gas. As an artifact of the logic in these models, the analysis may show curtailed DSM expenditures and savings in the DEP Scenario as the proportion of renewable and low-carbon gas increases and conventional natural gas declines. This reduction in savings is not present in the Reference Case due to the higher proportion of conventional natural gas. The DEP Scenario also includes some electrification of gas end uses, which does not occur in the Reference Case. This further reduces the savings potential for most measures. In general, then, the potential for most measures declines more in the DEP Scenario than in the Reference Case. The High DSM Setting used in the DEP Scenario uses the 100 percent incentive level versus the 50 percent incentive level used in the Reference Case. This makes a greater difference to uptake patterns for some measures than for others.

In the case of low-flow showerheads, which is a low-cost measure with a relatively fast payback even without incentives, the different DSM setting makes little difference. The measure saves almost the same percentage of Shower Domestic Hot Water (DHW) gas consumption in the DEP Scenario as it does in the Reference Case. The amount of Shower DHW gas consumption is lower in this scenario; however, due to the role of renewable and low-carbon gases and higher electrification, the savings for the measure are lower.

In the case of high-efficiency heat recovery ventilators, which is a higher cost measure with a longer payback, the 100 percent incentive level in the DEP Scenario has the effect of accelerating the uptake of the measure and causing it to save a higher percentage of the available space heating energy early in the forecast period. By 2026, it is saving 1.1 percent of the space heating gas consumption in the DEP Scenario. In the Reference Case, it is saving only 0.9 percent of the space heating gas energy by 2026. In both scenarios, uptake tails off later in the forecast, because fewer opportunities remain and because savings are eroded by housing demolition and natural adoption. This effect is more pronounced in the DEP Scenario because of the aggressive early uptake. The savings are further reduced by the amount of renewable and low-carbon gases and electrification used in residential space heating.

In the case of energy management (industrial), the savings as a fraction of the gas consumption in the affected end uses is considerably higher in the DEP Scenario. The higher incentive in the High DSM setting results in higher uptake and the savings are not eroded by natural conservation or demolition. As a result, by the end of the forecast period, the measure saves 1.9 percent of the consumption in the applicable end uses, versus only 1 percent in the Reference Case. Because of the amount of renewable and low-carbon gases and electrification, however, there is less conventional natural gas available to be saved.

39.2 Please further explain the "Steam to Hot Water Conversion (District Energy)" measure. Please discuss the potential number of customers this measure would be applicable to.

Response:

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

This measure is for converting the distribution system of a district energy system from steam to hot water. The baseline is a district heating system using steam to distribute heat to the end users. Costs and savings were based on UBC's conversion of their steam district heating system to hot water distribution between 2011 and 2016. Costs and savings were based on the conversion of a large system. The economics may not be quite as attractive for smaller systems, but the MTRC (Modified Total Resource Cost) for the system analyzed was 3.0, so it would likely pass for most sizes of systems.

There are 18 accounts in FEI's customer dataset categorized as district energy systems. The three accounts in the City of Vancouver account for approximately 90 percent of the gas consumption in the segment and nearly 90 percent of the savings potential for this measure. Most of the rest of the consumption and savings potential are in other systems in the Lower Mainland. There is also a small system in Whistler.

39.3 Please discuss how the different load forecast scenarios result in the differing estimates for savings potential. Please include an explanation of how the different critical uncertainty settings applied to the load forecast scenarios are applied to the DSM analysis.

Response:

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

The load forecast scenarios exhibit differing levels of estimated energy savings potential because of the Critical Uncertainty settings that are used to create the load forecast scenarios before DSM is applied, and the DSM setting used for post-DSM scenario demand. The Critical Uncertainty impacts are grouped into four categories: pre-DSM scenario demand, energy costs, codes and standards, and DSM settings.

Pre-DSM Scenario Demand

The amount of demand and the gas portfolio chosen for a scenario affect the amount of DSM savings potential. Specifically, this "pre-DSM" demand in each scenario is influenced by the following Critical Uncertainties:

- *Customer Forecast:* More growth in gas customers increases measure potential and less growth decreases it.
- *Fuel Switching:* Increased non-price driven fuel switching reduces DSM potential by lowering gas demand.
- *Carbon Price and Natural Gas Price:* Higher carbon or gas prices reduces gas demand and thereby reduces DSM potential, and lowering carbon or gas prices does the opposite.
- *Low-Carbon and Renewable Gas supply (RNG, Hydrogen, Syngas & Lignin, CCS):* The model currently applies DSM savings only to conventional natural gas. However, participation in DSM is adjusted in each scenario based on the amount of total piped fuels (ratio of (all gaseous fuels)/(traditional gas)). Despite this adjustment, scenarios with smaller amounts of conventional natural gas in the supply portfolio nonetheless have less DSM savings relative to scenarios with similar levels of total demand but a higher portion of conventional gas.

Energy Costs

Changes in energy costs affect the amount of DSM savings potential through the following Critical Uncertainties:

- *Natural Gas Price:* Increases in natural gas avoided cost improve the TRC results for measures, because other costs were not changed. If the DSM setting does not allow measures to pass on the basis of MTRC, more measures are included in the scenario. Conversely, decreases in natural gas avoided cost causes fewer measures to pass in such a scenario.

   - In addition to this effect, retail costs are assumed to follow avoided costs (at least in the long run), and therefore higher natural gas costs improve the customer payback after incentives. Faster payback tends to result in more program participation. A payback acceptance model was used to compare theoretical measure uptake with the baseline energy costs and with the energy costs in each scenario and the participation rates were modified accordingly.

- *Carbon Price:* Increases in carbon price are assumed to cause the same changes as increases in gas commodity prices, both in terms of TRC results and program participation. Decreases in carbon price are also assumed to cause the same changes as decreases in gas prices.

Codes and Standards

Codes and standards affect the DSM savings potential through the following Critical Uncertainties:

- *New or Retrofit Codes:* Some measures, particularly for building envelopes, are superseded in scenarios with substantial code improvements. In these cases, superseded measures were excluded from the analysis.
- *Appliance Standards:* Some measures are superseded in scenarios with substantial improvements in appliances standards. In these cases, superseded measures were excluded from the analysis.

DSM Settings

The DSM settings chosen for each scenario also affect the DSM potential. There are three components to the DSM setting which influence the amount of savings available:

- *Incentive Level:* Scenarios that include incentives at 100 percent of measure incremental cost result in higher program participation than those with incentives at 50 percent of incremental cost, all else being equal.
- *Economic Screen:* Scenarios that allow measures to pass based on MTRC, result in more DSM potential than those that require measures to pass based on TRC, all else being equal.
- *Budget Setting:* Scenarios that impose budget limits result in less DSM than those that do not, all else being equal.

40.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Section 5.4.5, pp. 5-27, 5-31

Commercial DSM

On page 5-31 of the Application FEI states that for the Commercial DSM sector, "(c)umulatively across the planning horizon, DEP [diversified energy (planning) scenario] High estimated expenditures exceed the DEP Medium by 753 percent and exceed the Reference Case by 559 percent."

On page 5-27 of the Application FEI states that for all sectors combined: "Cumulatively across the planning horizon, DEP High estimated expenditures exceed the DEP Medium estimated expenditures by 192 percent and exceed the Reference Case estimated expenditures by 166 percent."

40.1 Please discuss the factors behind the much greater increase in expenditures for the Commercial sector, compared to other sectors.

Response:

The following response has been provided by Posterity Group.

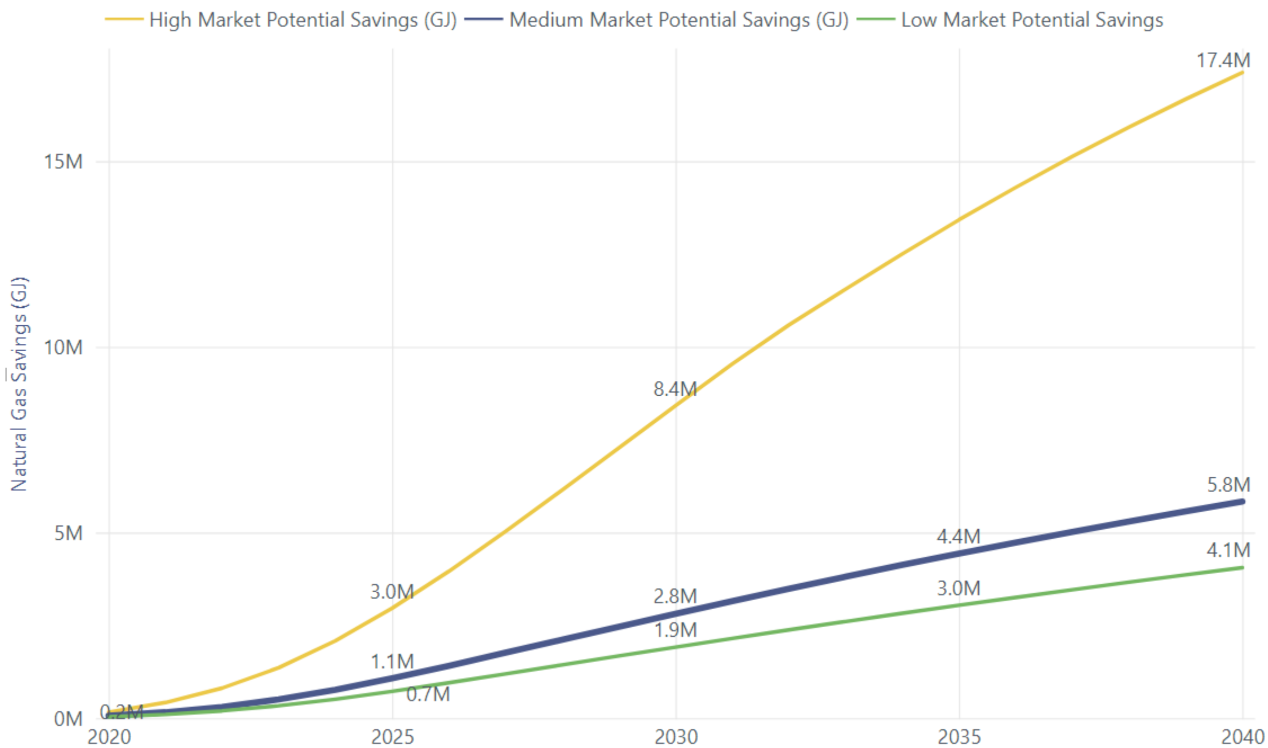
The greater increase in DSM expenditures in the commercial sector compared to other sectors is largely driven by the trajectory of gas heat pump (GHP) adoption, followed by New Construction Step Code measures and energy recovery ventilators. Residential DSM expenditures decline partly due to updates to gas appliance codes and standards and the greater natural conservation in this sector. The following discussion, which is extracted from Section 5, DSM analysis[49] in the Application and the 2021 Conservation Potential Review (CPR),[50] describes the performance of measures in the commercial sector in response to modeling inputs.

For illustration, it is beneficial to compare the DEP High scenario to the DEP Low scenario, because the two are identical except for the DSM settings. In the CPR, when these two DSM settings were both applied in the Reference Case, a similar large difference was seen in the commercial potential between the two. The CPR report included the following tables and commentary:

[49] Section 5.4.5, pp. 25-33.

[50] Exhibit B-1, Appendix C-1, section 5.7, pp. 113-121. Note: The 2021 CPR is the basis for FEI's long-term DSM program analysis.

Exhibit 90 – Market Potential Savings (GJ) – Commercial, MTRC

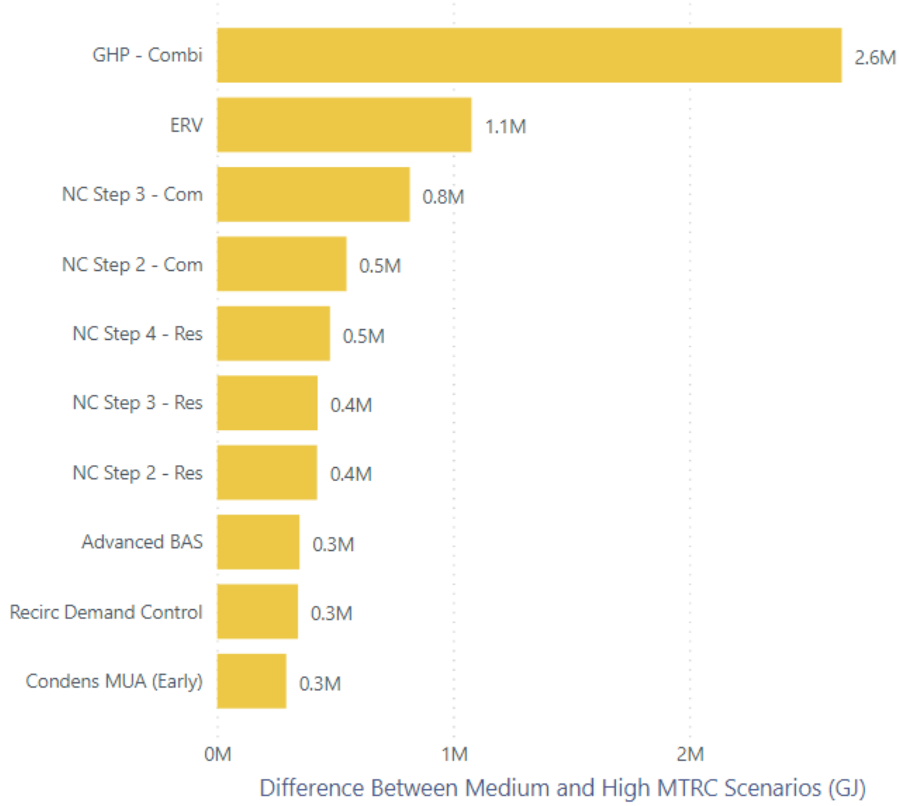


The high market potential is much higher than the medium market potential in the Modified Total Resource Cost (MTRC) scenario. In the CPR, the MTRC scenario permitted measures to be included in any of the three market potential levels if they passed either the TRC or the MTRC screening tests. (A more stringent scenario restricted measures in the three market potential levels to those passing the TRC test.) By 2040, the difference in potential between the medium and high market MTRC scenarios is 11.6 PJ. In this case, GHPs are a major factor contributing to the difference:

- For all measures, medium and high scenarios assume that measure incentive levels will be 50% and 100% of incremental costs, respectively.
- In addition to this, gas heat pumps were given different adoption curves in the two scenarios.
- In the medium market scenario, GHPs are modeled as an innovative technology with no current market penetration and low forecasted growth.
- In the high scenario, they are modeled as an innovative technology with no current market penetration, but with high forecasted growth, especially in the second half of the study period (2030-2040).

The difference in MTRC medium and high potential scenarios by 2040, broken down by measure, is shown in Exhibit 91, below. Only the top 10 measures that contribute to the difference are presented. GHPs top the list by a sizeable margin, but New Construction Step Code measures and energy recovery ventilators also influence the difference.

Exhibit 91 – Top 10 Commercial Measures Contributing to Difference in Medium and High Market Potential Scenarios (Using MTRC Screen) by 2040



While the High and Medium settings as applied in the residential and industrial sectors also include the difference in incentive level, the effects were not as dramatic. Notably, neither of them included a measure like GHPs. For other measures, there were some differences in the responsiveness to incentive levels between the three sectors:

- Measure participation was estimated in all three sectors using Navigator's payback acceptance system, which develops estimates of measure uptake based on diffusion curves.
- For the residential sector, participants in the achievable workshop offered a lot of feedback on measure uptake as related to incentive levels, so the initial estimates of participation based on payback acceptance were extensively adjusted by the sector analysts.
- For the industrial sector, many measures have a payback under one year even with just a 50% incentive, so the payback acceptance system showed a less dramatic difference between the High and Medium settings.
- The commercial sector showed the greatest response to incentive level of the three sectors, even for measures other than the gas heat pump.

As can be seen from this analysis, the greater difference between the High and Medium Settings in the Commercial sector is caused by different treatment of the GHP measure, less erosion of savings due to changes in codes and standards and natural conservation, and greater responsiveness of program participation to improved measures paybacks.

40.2 Please discuss how DSM expenditures are allocated between program areas, and how FEI ensures all customer segments have equivalent access to DSM.

Response:

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

In the DSM modelling for the DEP Scenario, the DSM budget was not constrained overall or by program area. Individual sectors are allocated as much DSM as is cost-effective with the screens applied to the DSM Setting (High in this case).

Within the DSM modelling, as with FEI's in-market DSM programming, all customer segments have access to DSM. FEI's first DSM Guiding Principle is that "Programs will have a goal of being universal, offering access to energy efficiency and conservation for all residential, commercial and industrial customers, including low income customers."

41.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Section 5.3.3, p. 5-11, Table 5-3, p. 5.13; Section 5.3.4, p. 5-13; Appendix C-1 (CPR Report), p. 2; Appendix C-2, Section 1.1, p. 3

Impact of Deep Electrification on DSM

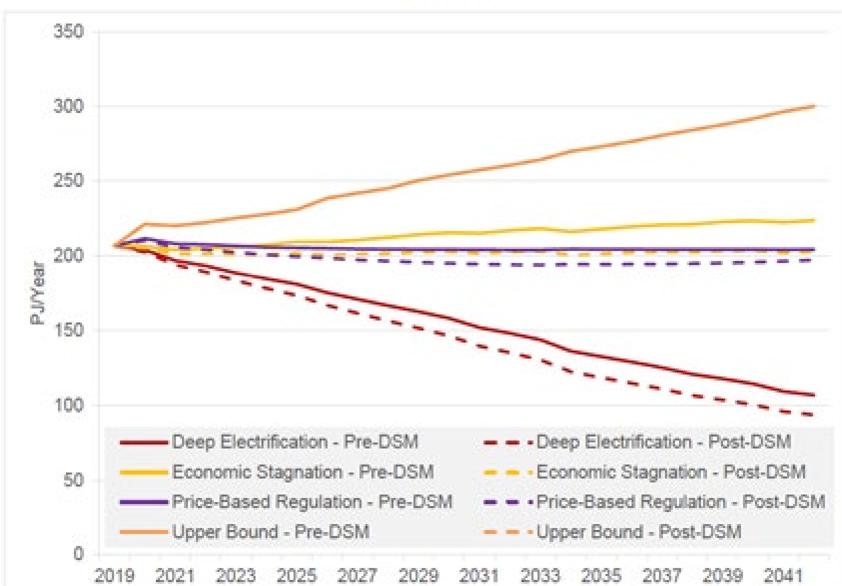
On page 2 of the CPR Report (Appendix C-1) states that "Scenarios with specific regulation/policy drivers, including high electrification, are not assessed within the scope of the CPR. High electrification scenarios have been modelled separately, in support of FortisBC's LTGRP."

FEI describes the Taper Off DSM setting in Table 5-3 on page 5-11 of the Application as "Assumes DSM spending tapers off as the province electrifies." The Budget for the Taper Off option was "limited to 50% of 2022 spending in 2023, declining to 25% of 2022 spending by 2042."

On page 5-13 of the Application FEI explains that for the Deep Electrification Scenario iterations were performed to find the optimal solutions of measures that meet the program budget limitations each year.

Figure C2-2 on page 3 of Appendix C-2 to the Application compares several annual energy demand forecasts, including Deep Electrification pre and post DSM.

Figure C2-2: Annual Demand Before and After Estimated DSM Savings (Excluding LCT) - All Sectors Combined



According to page 3 of Appendix C-2 to the Application, annual energy savings for the DEP, Reference and Deep Electrification scenarios are as follows:

- DEP High annual energy savings are forecast to account for a 13 percent reduction in demand in 2042 while DEP Medium savings are forecast to account for an 8 percent reduction;
- Reference Case annual energy savings are forecast to account for a 11 percent reduction in Reference Case projected demand in 2042;
- Deep Electrification annual energy savings are forecast to account for a 12 percent reduction in Deep Electrification projected demand in 2042;…"

41.1 Please provide a table comparing the annual demand and equivalent emissions by 2030 and 2042 of:

- o the DEP scenario and post-DSM using the High DSM setting, and
- o the Deep Electrification scenario, pre- and post- DSM.

Response:

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

The annual demand and end use emissions for 2030 and 2042 for the DEP and Deep Electrification scenarios are described in Table 1 below. Note these values are for the built environment only (residential, commercial and industrial customer types). FEI's Total GHG emissions Post-DSM included in the last row of Table 1 include emission reductions from DSM, fuel mix (gas, renewable and low-carbon gas), additional actions taken by FEI to 2030, and non-DSM reductions (natural efficiency and fuel switching).

Table 1: Comparison of the DEP and Deep Electrification Scenarios for Annual Demand and End Use Emissions at 2030 and 2042 Pre- and Post DSM

DSM Demand Reduction	Base Year	Diversifed Energy (Planning)		Deep Electrification	
	2019	2030	2042	2030	2042
Total Demand (PJ)	214.7	210.7	208.1	167.1	115.8
Total GHG Emissions (Mt CO2e)	10.7	10.5	10.4	8.3	5.8
Post-DSM Demand (PJ)		192.5	182.1	154.5	101.3
Post-DSM Emissions (Mt CO2e)		9.6	9.1	7.7	5.1
FEI Total GHG Emissions (Mt CO2e)	10.7	5.7	3.9	7.4	4.7
DSM GHG emission reductions (%)		8.6%	12.5%	7.5%	12.5%

41.2 Please provide the CCE in $/GJ for the DEP and Deep Electrification DSM gas savings over the forecast period of the 2022 LTGRP.

Response:

The following response has been provided by Posterity Group.

The following table provides the CCE in $/GJ for the DEP Scenario and Deep Electrification scenario DSM gas savings over the forecast period.

Year	DEP Scenario	Deep Electrification Scenario
2020	10.27	3.03
2021	10.67	3.38
2022	11.09	3.57
2023	11.25	3.62
2024	11.32	3.62
2025	11.26	3.66
2026	11.23	3.72
2027	11.24	3.72
2028	11.24	3.71
2029	11.22	3.70
2030	11.16	3.71
2031	11.11	3.82
2032	11.08	3.95
2033	11.06	4.16
2034	11.05	4.43
2035	10.99	4.75
2036	10.98	5.46
2037	10.92	5.76
2038	10.91	6.03
2039	10.92	5.99
2040	10.94	5.92
2041	10.92	5.84
2042	10.87	5.65

42.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Section 2.2.2.2.3, p. 2-10; Section 2.4.2.2, 2-32; Appendix A-2 (Pathways for British Columbia to Achieve its GHG Reduction Goals), pp. 16 – 17

Roadmap to 2030 - Gas Heat Pumps

On page 2-10 of the Application, FEI states that the Roadmap requires all new space and water heating equipment sold and installed in BC to be at least 100 percent efficient by 2030. Electric and high-efficiency gas heat pumps, hybrid systems, and deep energy retrofits will be used to reach this goal while incentives for conventional natural gas-fired equipment will be phased out. This suggests that the provincial government sees a declining role for conventional home heating and water heating appliances in favour of gas and electric heat pump solutions. However, <u>gas heat pumps are not yet commercially available for residential customers</u>, leading to uncertainty regarding gas heat pump adoption timelines in reference to the 100 percent efficiency standard in 2030. [Emphasis added].

FEI states on page 2-32 of the Application that as gas heat pump technology for the residential sector is still in the pre-commercialization phase, installed costs are still under investigation, but may be considered in the next LTGRP.

Section 2.4.2.2 of the Application contains an analysis of price competitiveness by considering the upfront capital cost differences between gas and electricity end use applications (space and water heating) for new construction, including the adoption of new technologies which support the use of electricity.

On page 17 of Appendix A-2, "Pathways for British Columbia to Achieve its GHG Reduction Goals," Guidehouse states:

> Electric heat pump costs were modelled to align with the BC Conservation Potential Review, which included a specific assessment of the achievable potential of electric heat pumps in BC. The incremental cost for electric heat pumps was modelled as approximately $376 per residential household and $16,500 per 1,000 m2 of commercial floor space. Electric heat pumps were modelled with 190% efficiency for both residential and commercial applications.16 This efficiency depends on climate and likely will vary by region within BC.
>
> 16 The 190% value is a conservative estimate for heat pump efficiency, which aligns with a baseline assumed efficiency for air-source heat pumps in Guidehouse's 2019 BC Conservation Potential Review. This conservative assumption was used to attempt to represent provincial efficiency as a whole because heat pump efficiency is assumed to vary significantly by climate zone.
>
> Gas heat pump costs were derived from a heat pump feasibility study provided by FortisBC and interviews with developers.17 Initial costs were set at roughly $6,800 and $45,000 for a residential home and commercial building, respectively. Both residential and commercial gas heat pumps were modelled with a 140% gas

utilization efficiency. This efficiency depends on climate and likely will vary by region within BC.

The following is an extract from Table 1 on page 16 of Appendix A-2:

TABLE 1. INITIATIVES BY PATHWAY

Initiative	Electrification Pathway	Diversified Pathway
Energy Efficiency	Improve envelope of 1.6 million homes and 436 million m² of commercial floor space.	Improve envelope of 1.7 million homes and 328 million m² of commercial floor space. Deploy gas heat pumps in ~70% of buildings.

42.1 Please clarify if the DEP High DSM scenario includes gas heat pumps for the commercial sector, or explain otherwise.

Response:

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

Yes, the DEP High DSM scenario includes gas heat pumps for the commercial sector.

42.1.1 Please explain whether the DEP DSM assumptions in the LTGRP align with the Diversified Pathway assumptions shown in Table 1 above with regards to gas heat pump deployment.

Response:

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

Savings from gas heat pumps are included in the DEP Scenario DSM assumptions. However, gas heat pump penetration, as modelled in the 2021 CPR, is much lower and deployment does not reach approximately 70 percent of buildings within the study period. Gas heat pump participation assumptions for the Application are discussed in the response to BCUC IR1 42.2, and estimated savings are discussed in the response to BCUC IR1 46.1.

There is a gap between the 2021 CPR and the 2019 Pathways Report because the Pathways Report built a normative scenario by which to achieve the Province's 2030 and 2050 targets, whereas the 2021 CPR is a techno-economic potential study that is not guided by achieving targets but rather by assessing the cost-benefit of efficiency investments. FEI identified that gas heat pumps could have significantly greater potential once emissions constraints are applied to 2030.

42.2 If applicable, please provide the measure assumptions used in the LTGRP for commercial heat pumps, including but not limited to participation rates, cost, and savings potential.

Response:

The following response has been provided by Posterity Group.

The tables below present measure assumptions for commercial gas heat pumps and dual-fuel heating systems in the Application's DSM Planning scenarios. Table 1 provides the assumptions for effective useful life (EUL), seasonal efficiency (COP), average incremental costs, average energy savings percentage by end-use, and average natural gas and electricity savings. Table 2 provides participation rates for both Medium and High DSM Settings.

Table 1: Measure Assumptions for Commercial Heat Pumps and Dual-Fuel Heating Systems

Measure	EUL (Years)	COP	Avg. Incr. Costs ($)	Avg. Energy Savings (%)	Avg. Natural Gas Savings (GJ)	Avg. Electricity Savings (kWh/kW/year)
Air-to-water Heat Pump – Retrofit Existing Gas Furnace/Boiler (used for backup)	12	N/A*	$100	5% - Space Heating	1.0 GJ per heat pump per year	-
Air-to-water Heat Pump – New Gas Furnace/Boiler (used for backup)	12	N/A*	$100	5% - Space Heating	0.9 GJ per heat pump per year	-
Gas Heat Pumps - Domestic Hot Water	18	1.29	$380/kW	30% - Domestic Hot Water	6 GJ per kW per year	109 kWh per kW per year
Gas Heat Pumps - Space Heating	18	1.29	$242/kW	30% - Space Heating	6 GJ per kW per year	109 kWh per kW per year
Gas Heat Pumps - Combination	18	1.29	$324/kW	30% - Space Heating 30% - Domestic Hot Water	6 GJ per kW per year	109 kWh per kW per year

* *Air-to-water heat pumps with gas backup were modelled as a controls-only measure in the CPR / LTGRP. Assumptions were made regarding space heating load reduction for furnaces / boilers. No assumptions of electric heat pump COP were made.*

Table 2: Participation Rates for Commercial Heat Pumps and Dual-Fuel Heating Systems for the Medium and High DSM Settings

Measure	Participation Rates - % ** Medium DSM Setting					Participation Rates - %** High DSM Setting				
	2023	2025	2030	2035	2040	2023	2025	2030	2035	2040
Air-to-water Heat Pump – Retrofit Existing Gas Furnace/Boiler (used for backup)	0	0	0	0	0	0.11	0.21	0.85	2.07	2.85
Air-to-water Heat Pump – New Gas Furnace/Boiler (used for backup)	0	0	0	0	0	0.11	0.21	0.85	2.07	2.85
Gas Heat Pumps - Domestic Hot Water	0.20	0.28	0.63	1.37	2.69	0.67	0.94	2.15	4.64	9.10
Gas Heat Pumps - Space Heating	0.32	0.45	1.02	2.20	4.32	0.67	0.94	2.15	4.64	9.10
Gas Heat Pumps - Combination	0.24	0.34	0.76	1.65	3.24	1.31	3.97	33. 4	57. 4	59.9

** *In the Application scenario models, participation rates are defined as percentages of the economic potential available in a given year that a hypothetical program can capture.*

42.3 Please provide the results of any pilots conducted by FEI to assess the performance of commercial and residential gas heat pumps, and any cost comparisons (both capital and operating) with electric heat pumps.

Response:

The following table summarizes the results from FEI's commercial gas absorption heat pump pilots from FEI's 2020 and 2021 Demand Side Management Annual Report. Please note that residential pilots are not included in this table as those activities are still underway and expected to be complete throughout 2023-2024. In addition, the results below are specific to one manufacturer of gas absorption heat pumps. It is important to note that several pilot projects are underway and planned to be underway to assess different gas heat pump categories and manufacturers as they become available in FEI's service territory. It is also important to note that when conducting these pilots, costing data is only compared to the baseline of the participants' existing systems which was heating systems fueled by natural gas. As such, results of the pilot do not include comparisons of alternative systems such as electric heat pumps and therefore the capital and operating cost comparisons are not available.

FEI's Gas Absorption Heat Pump Pilot Results 2020-2021				
Pilot Name	**End Use**	**Pilot Scope**	**Location**	**Results**
Commercial Gas Absorption Heat Pump Pilot – Phase 1 & 2	Domestic Hot Water (DHW)	Phase 1 & 2 assessed the energy savings, customer acceptance and installation of 14 Robur GAHP-A units for DHW across 7 commercial sites for a one year period to inform the feasibility of launching a DSM rebate program.	Site locations: 4 Vancouver 2 Richmond 1 Port Moody	Overall, the performance of the GAHP systems varied across the test sites with up to 21 percent energy savings realized during the testing period. In general, survey respondents provided positive feedback regarding the installation of the GAHP system in their building. As a result of the pilot and study results, FortisBC will be implementing the gas absorption heat pump measure under the commercial prescriptive program area.
Commercial Gas Absorption Heat Pump Pilot – Phase 3	DHW	Utilizing a participant from Phase 1 & 2, Phase 3 assessed the DHW system efficiency improvements by replacing back up mid efficient boilers with 2 condensing and modulating tankless units with sophisticated flow sequency controls to assess the increase in energy savings.	Vancouver, BC	The DHW system efficiency improvement trial realized 35.2 percent energy savings which is a significant increase from the original 21 percent that was evaluated from original field trials. Savings were attributed to replacing the existing aged mid-efficient boiler with two new condensing modulating tankless units and adding more sophisticated controls to control switchover points. As a result of the pilot studies, FortisBC will be implementing the gas absorption heat pump measure for multiple end uses under the commercial prescriptive program area in 2022.
Commercial Gas Absorption Heat Pump Pilot – Phase 4	DWH & Space Heating (SH)	Utilizing a participant from Phase 1 & 2, Phase 4 assessed energy savings, system performance and customer acceptance of gas absorption heat pumps for a hybrid DHW & space heating application.	Vancouver, BC	The Space heating trial identified greater potential to increase overall system efficiencies of the heating system by taking one of the GAHP units to tie into the space heating loop while the other GAHP unit satisfied the DHW heating loop. This space heating and DHW heating (hybrid) realized 27.9 percent energy savings which is significant increase from the original 15.7 percent savings that was evaluated from the original field trials. As a result of the pilot studies, FortisBC will be implementing the gas absorption heat pump measure for multiple end uses under the commercial prescriptive program area in 2022.

42.4 Please provide FEI's views on possible commercialization timelines for residential gas heat-pumps, and explain how this has been factored into the DEP High DSM forecast.

Response:

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

Residential gas heat pump assumptions underlying the DEP High DSM forecast were based on 2023 market entry estimates provided by manufacturers prior to filing the Application. FEI now projects residential gas heat pumps to enter the market in Q4 2024, rather than 2023, due to the impacts of the COVID-19 pandemic and supply chain disruptions. To mitigate the risk of further delays, FEI will continue to support pilot field trials to validate field performance, customer acceptance and installation requirements. These pilots will inform program design and implementation considerations for gas heat pumps. It is important to note that although pilot results may be promising, manufacturer market entry decisions are out of FEI's control and FEI has no influence over policy changes, supply chain impacts, costing and product availability.

The market entry timeline assumptions for gas heat pumps were factored into the DEP High DSM forecast in a similar manner to how measures were applied in FEI's 2021 Conservation Potential Review (CPR) High Market Potential Scenario. Although the forecast savings start in 2023, the potential for gas heat pumps in the late DEP High DSM forecast will diminish in comparison to the High DSM forecast in the CPR, due to reduced conventional natural gas use over time.

42.5 Please provide any information FEI has obtained regarding the performance of gas heat pumps in other jurisdictions.

Response:

To date, there is limited gas heat pump performance data for the different types of gas heat pump technologies across residential and commercial applications.

Below is a table that summarizes three utility performance reports and two industry white papers. The performance reports are specific to commercial gas absorption heat pumps. FEI is not aware of any other publicly available reports for residential or other gas heat pump types.

Organization	Province/State	Technology	Results	Link
SoCal Gas and GTI Energy (formerly Gas Technology Institute)	California	Stone Mountain Technologies Inc DHW	Installed two SMTI gas absorption heat pump 80k units for DHW applications for two restaurants in California. The research team found that therm savings at both sites were 16-26 percent for the Integrated GHP System and 52-53 percent for the heat pump itself. The daily net electricity increase for both sites (as-is) is 7-8 kWh. The therm savings translate to $970-$2,780/year, or $620-$2,530 when including electricity, and using mature quantity production estimates of GHP and other standard equipment costs. COP ratings averaged from 1.3 to 1.9. Simple paybacks for the Integrated GHP System range from 1.1 to 6.4 years (fuel savings basis). Lastly, the climate impact of the technology yielded a net greenhouse gas reductions of about 46-48 percent using 2018 CA-statewide emission factors.	https://www.gti.energy/wp-content/uploads/2021/03/WhitePaper-Commercial-Gas-Heat-Pumps-for-Hot-Water-AC-Demo-Restaurant-Applications_06Jan2021.pdf
Enbridge and The Atmospheric Fund	Ontario	Robur GAHP-A	Installed two Robur GAHP-A units for DHW in a senior care facility in Toronto Ontario. Performance results indicated COP of 1.14 during extreme cold weather (down to -13°C) with increased system efficiencies of a COP 1.25 percent efficiency, in line with manufacturer performance curves. The GHPs are expected to save nearly 5400 m^3 of natural gas and over 10 tonnes of carbon emissions annually compared to a 90 percent efficient condensing boiler. Findings have shown that GAHPs are significantly more efficient than conventional gas-fired heating equipment and can reduce emissions and gas consumption, while avoiding switching to a higher cost fuel.	http://taf.ca/wp-content/uploads/2018/10/TAF_GAHP-White-Paper_2018.pdf
Northwest Energy Efficiency Alliance	Oregon	Robur GAHP-A	Installed two Robur GAHP-A units for DHW in a retirement home in Salem, Oregon. Results: The GAHP-A provide a significant improvement in performance above conventional gas-fired technologies. With an annual COP of 1.06, the GAHP-A performance represents a 58 percent improvement above the DHW heaters and a 45 percent improvement above the HHW boiler. The end result is a total system fuel consumption reduction of 18 percent, even though the nominal capacity of the GAHP-A is a fraction of the capacity of the existing DHW/HHW system.	https://neea.org/resources/robur-heat-pump-field-trial
GTI Energy (formerly, Gas Technology Institute)	North America	Multiple technologies	Sponsored by 14 U.S. and Canadian utilities, the Gas Heat Pump Roadmap identifies opportunities, information gaps, impediments and strategies to accelerate the commercialization and market acceptance of gas heat pumps in North America.	https://www.gti.energy/wp-content/uploads/2020/09/Gas-Heat-Pump-Roadmap-Industry-White-Paper_Nov2019.pdf
North American Gas Heat Pump Collaborative	North America	Multiple technologies	Sponsored by 16 U.S. and Canadian utilities, the Gas Heat Pump Resource report outlines the opportunity to accelerate North America's Decarbonization strategy utilizing gas heat pump technologies.	https://gasheatpumpcollab.org/wp-content/uploads/2022-NAGHPC-Resource-Report.pdf

42.6 Please discuss what adoption barriers exist for gas heat pumps in general.

Response:

Please refer to response to BCUC IR1 46.4 for a summary of gas heat pump adoption barriers.

42.7 Please discuss any risks identified by FEI of gas heat pump technology, at any scale, not being commercially viable or competitive, and the implications of these risks to the long term DSM forecast.

Response:

Please refer to FEI's response to BCUC IR1 46.4 for a discussion of gas heat pump adoption barriers and risks, along with mitigation strategies to support market transformation efforts in order to achieve the long term DSM forecast.

43.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Section 5.4.2, pp. 5-18, 5-20, Section 5.4.5, pp. 5-25, 5-28; Appendix C-1, p. 139

Long-term DSM Expenditures

On page 5-27 of the Application, FEI presents a table of annual DSM expenditures for the DEP High DSM Setting.

Table 5-4: Estimated Diversified Energy (Planning) - High DSM Setting Expenditures – All Sectors Combined

	Diversified Energy (Planning) Scenario (Millions)		
Year	Incentive Estimate	Non-Incentive Estimate	Total Estimate
2022	$209	$31	$241
2023	$204	$31	$234
2024	$199	$30	$228
2025	$188	$28	$216
2026	$192	$29	$221
2027	$193	$29	$222
2028	$196	$29	$226
2029	$181	$27	$208
2030	$159	$24	$183
2031	$170	$26	$196
2032	$166	$25	$191
2033	$154	$23	$177
2034	$147	$22	$169
2035	$136	$20	$156
2036	$125	$19	$144
2037	$116	$17	$133
2038	$107	$16	$123
2039	$98	$15	$113
2040	$91	$14	$104
2041	$87	$13	$100
2042	$61	$9	$70

On pages 5-25 to 5-26 of the Application, FEI states that these results do not take into account the following factors which flow into DSM expenditure plans and DSM annual reports to the BCUC:

- Non-incentive expenditures that support or enable DSM programs at the portfolio level, such as Enabling Activities and Conservation Education Outreach expenditures;[167]
- Operational program delivery considerations, such as changes in required DSM staffing levels or program eligibility requirements;
- Unanticipated market uptake of current technologies, emergence of new technologies more than five years into the future, or technologies which are currently unknown that may increase aggregate energy savings opportunities and

thus enable greater actual DSM program expenditures and potentially savings across the planning period168; and

- Future DSM Regulation changes, and their impact on FEI's DSM portfolio, which could enable more DSM or result in fewer DSM program offerings. [Emphasis added]

On page 5-26 of the Application, FEI states that eestimated expenditures are more than double 2021 levels as a result of using the DEP High DSM Setting which may cover up to 100 percent of incentive levels to accelerate the adoption of energy efficient measures and building upgrades. In the current DSM environment, incentive levels are on average set at about 50 percent of incremental costs for the upgrade.

On page 5-28 of the Application, FEI states that:

> estimated [DSM] expenditures are expected to decline over the years as available energy savings opportunities decline, for example through the introduction of new Minimum Efficiency Performance Standards and other codes. However, the <u>decline in energy savings is partially an artifact of the current model where savings are based on reducing conventional natural gas</u>, whereas after 2030 the proportion of renewable and low-carbon gas in the fuel mix grows significantly. In addition, in future DSM plans for the residential sector, technologies such as gas heat pumps, hybrid heating systems and deep energy retrofits may provide a higher energy savings opportunity than was foreseen when the CPR was being developed in 2019. [Emphasis added]

43.1 Please provide an estimate of the total expected DSM costs once non-incentive expenditures and operational considerations such as staffing levels are included.

<u>Response:</u>

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

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. FEI expects there to be differences in expenditures and savings between the two analyses. Overall though, FEI considers that the estimated total expected DSM costs associated with the High DSM Setting, as illustrated in Table 5-4 in the Application, and the preamble, covers a sufficient range for future DSM expenditure plans for the following reasons:

- As stated in Section 5.3.4 (pp. 5-12 and 5-13) of the Application, program area non-incentive expenditures were included in each of the DSM Setting scenarios. Non-incentive program costs were assumed to be 15 percent of the corresponding incentive costs. The most recent DSM Annual Report year would act as a good annual proxy for these expenditures. In the FEI 2021 DSM Annual Report, non-incentive expenditures were close to 10 percent of incentive expenditures for the energy savings programs included in the LTGRP. Therefore, non-incentive expenditures in Table 5-4 may be higher than actual.

- Other expenditures not included in Table 5-4 were those that support or enable DSM programs at the portfolio level, such as Enabling Activities and Conservation, Education, and Outreach expenditures. As discussed in the response to BCUC IR1 36.6, FEI does not anticipate that these additional expenditures will significantly impact portfolio cost-effectiveness, however this analysis will be completed as a part of DSM Plan development.
- As discussed in the response to BCUC IR1 38.4, FEI does not necessarily intend to set its incentive levels at 100 percent. Through program development initiatives, FEI strives to provide the most cost-effective DSM program portfolio in the shorter term. Therefore, incentive expenditures in Table 5-4 may be higher than actual.

Based on the above considerations, FEI considers that the expenditures for the High DSM Setting should be at sufficient levels to align with upcoming DSM Expenditures Plans, without suggesting that additional funding will be required for non-incentive and non-program related activities, until at least 2030 at which time there will be more certainty as to the market and policy environment within which FEI is operating.

43.2 Please confirm that the decline in DSM expenditures after 2030 is due to the decline in modelled potential DSM opportunities from conventional natural gas equipment as a result of factors such as electrification, changing efficiency standards and market saturation, and should not be seen as indicative of all possible DSM expenditures over the planning period. If not, please explain otherwise.

Response:

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

FEI confirms that the decline in DSM expenditures after 2030 are as stated in the pre-amble. The 2021 Conservation Potential Review (CPR) and LTGRP market potential reflect the uncertainty of the policy environment and market conditions in which FEI will be operating in 2030 and beyond.

It is likely that emerging advanced DSM and other measures that are currently unknown or are still experimental may play a larger role in DSM programs in future decades. The set of measures captured in the LTGRP model did not include theoretical placeholder measures to represent these future opportunities.

On page 139 in Appendix C-1 to the Application, Exhibit 153 shows High Market Incentive costs for all sectors, using the MTRC. The High Market Total Costs column remains roughly at the same level over the planning period, with a slight peak in 2028.

43.3 Please explain why the total costs in Exhibit 153 do not show the same pattern as Table 5-4 over the planning period, explaining any differences in methodology between the CPR and the methodology used to produce the results shown in the Application.

Response:

The following response has been provided by Posterity Group.

The High Market Incentive DSM setting in Exhibit 153 uses the CPR Reference Case as the basis for applying DSM measures. The High DSM setting in Exhibit 5-4 uses the DEP Scenario as the basis for applying DSM measures. There are a number of important differences in these two scenarios, influencing both the estimated savings potential from the DSM measures and the estimated expenditures required to obtain those savings:

- There is substantially more fuel switching from natural gas to electricity in the DEP Scenario, including both price-driven fuel switching from higher assumed carbon pricing, and also non-price driven fuel switching. The switch to electricity reduces the opportunities for gas DSM.
- In the DEP Scenario, there is substantially more replacement of conventional natural gas by renewable and low-carbon gas alternatives (RNG, hydrogen, syngas & lignin, and CCS). In the version of the Navigator modeling software used for this filing, DSM could be applied only to conventional natural gas. In scenarios where a large proportion of conventional natural gas were replaced by low-carbon fuels, DSM became constrained. The modeling team attempted to compensate for this by increasing participation rates by the ratio of (all gaseous fuels)/(natural gas), but this process was imperfect and may have underestimated the DSM potential and spending for the blend of fuels.
- In the CPR Reference Case, Step Codes were held at a lower step than in the LTGRP scenarios, because the utility is permitted to take credit in its DSM programs for its role in code improvements. In the LTGRP scenarios, all the Step Code improvements currently planned were included in the baseline for DSM calculations, reducing the scope for many new construction measures later in the forecast period.

43.4 Please discuss FEI's ability to ramp up DSM expenditures to a level which is roughly double 2021 expenditures in the early years of the LTGRP, as shown in Table 5-4. Please include in the response a discussion of the extent to which the increase in expenditure is due to incentives alone, and the implications for staffing, or other operational factors, to achieve the anticipated level of savings.

Response:

In recent years, FEI has proven the ability to ramp up DSM expenditures year-over-year. Between 2018 and 2021, FEI has averaged an annual DSM expenditure increase of 46.5 percent. However, the LTGRP is intended to provide a long-term estimate of DSM savings as a factor in demand reduction for resource planning purposes, and corresponding expenditure estimates are developed using generic incentive levels and high-level estimates for non-incentive costs. FEI expects there to be differences in expenditures and savings between forecasts in DSM expenditures plans and the estimates in the 2022 LTGRP DSM analysis, especially in the short term.

For example, FEI's 2023 DSM Plan includes $141.077 million in expenditures. While the 2023 DSM Plan expenditures are less than set out in the 2022 LTGRP, they continue FEI's trajectory of increasing investments in DSM since the 2017 LTGRP and the energy savings (1.6 million incremental GJ) are aligned with the 2022 LTGRP High DSM setting (1.7 million incremental GJ). In future years, FEI expects its DSM expenditures to further increase in line with the 2022 LTGRP, but there will continue to be variations between the 2022 LTGRP analysis and DSM expenditure plans, as DSM expenditure plans reflect detailed program development, may include new or emerging DSM measures, and are responsive to changes in policy and stakeholder engagement.

As discussed in FEI's response to BCUC IR1 43.1, non-incentive program costs within the DSM analysis were set at 15 percent of the corresponding incentive costs. Therefore, this analysis assumed an equal ratio growth between incentives and non-incentives, with incentives driving overall growth. Staffing and program-related operational costs were considered within these non-incentive estimates and assumed to support the forecasted level of savings similarly to how they do so today.

43.5 Please provide a table showing the estimated annual costs of the DEP High DSM scenario, and the estimated annual forecast savings in GJ. Please include actual expenditures and savings achieved annually since 2016 for comparison.

Response:

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

FEI's actual DSM expenditures and energy savings achieved annually from 2016 to 2021 are provided in Table 1 and the estimated annual DSM expenditures and energy savings for the DEP High DSM scenario from 2022 to 2042 in Table 2.

Table 1: FEI's Actual DSM Expenditures and Energy Savings from 2016 to 2021

Year	DSM Expenditures ($ Million)	Annual Savings (GJ/yr)	Cumulative Savings (GJ/yr)
2016	$32.17	438,827	438,827
2017	$34.04	533,538	972,365
2018	$35.47	626,226	1,598,591
2019	$64.50	831,959	2,430,550
2020	$75.82	1,032,721	3,463,271
2021	$106.84	1,149,495	4,612,766

Table 2: FEI's Estimated DSM Expenditures and Energy Savings[51] from 2022 to 2042 in the DEP Scenario

Year	DSM Expenditures ($ Million)	Annual Savings (GJ/yr)	Cumulative Savings (GJ/yr)
2022	241	2,007,896	6,396,572
2023	234	1,657,431	8,054,003
2024	228	1,544,504	9,598,506
2025	216	1,442,769	11,041,275
2026	221	1,435,010	12,476,285
2027	222	1,399,364	13,875,649
2028	226	1,421,698	15,297,347
2029	208	1,297,125	16,594,472
2030	183	1,138,702	17,733,174
2031	196	1,221,184	18,954,358
2032	191	1,120,850	20,075,208
2033	177	981,998	21,057,206
2034	169	917,499	21,974,705
2035	156	847,711	22,822,417
2036	144	697,069	23,519,486
2037	133	632,235	24,151,721
2038	123	478,233	24,629,954
2039	113	345,062	24,975,016
2040	104	257,150	25,232,167
2041	100	163,336	25,395,503
2042	70	0	25,371,772

[51] Savings from measures implemented in a specific year are not an output of the model. The model does output the difference between pre-DSM and post-DSM consumption, which is the savings in the current year from all measures still in place from previous years and also the new measures for the current year. To calculate *new* savings from measures installed in a given year, which is what is provided in this table, the previous year's savings (pre-DSM minus post-DSM) were subtracted from the current year's (pre-DSM minus post-DSM consumption). The results are an approximation because the value does not account for changes in reference case adoption or demolition of older buildings. Note that TPT 1 and TPT 2 demand is not included in this analysis, aligning with the discussion in Section 5 of the application.

In section 5.4.2 of the Application, FEI provides a directional look at the potential delivery rate impact (compared to the approved 2022 delivery rates) of the different DSM Settings (Low, Medium, and High) under the DEP scenarios.

Figure 5-8 on page 5-20 of the Application presents the Estimated Cumulative Bill Impact for Residential Customers (5 GJ to 250 GJ) due to DSM under the Diversified Energy (Planning) Scenario – High DSM Setting. This shows an average annual bill impact due to DSM under the DEP High DSM scenario of 0.31 percent across all residential customers. For residential customers that have an annual consumption of approximately 75 GJ, which is the majority of FEI's residential customers, the cumulative bill impact in 2042 due to DSM programs under the DEP High DSM scenario is $15 per month average.

43.6 Please clarify if the directional bill impacts shown in section 5.4.2 include the (indicative) full costs of DSM to residential ratepayers, inclusive of enabling activities, adequacy programs, staffing costs, other overheads etc.

Response:

Please refer to the response to BCUC IR1 43.1 for the DSM expenditures that were incorporated into the DSM setting scenario analysis. These expenditures were then included in the directional bill impacts shown in Section 5.4.2.

44.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Section 5.1, p. 5-2

DSM Modelling Methodology for a Variety of Fuel Types

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

> In prior LTGRP submissions and in more traditional DSM modelling approaches, the savings of each additional unit of energy saved would be treated equally. However, in this LTGRP, where FEI is transitioning to renewable and low-carbon gas, the software model was designed to prioritize reducing conventional natural gas. Although the ability to apply DSM savings equally to all fuel types is discussed in the 2022 LTGRP, the analysis could not be completed in time for the 2022 LTGRP submission date since such analysis will require reconfiguring the software. The decision was made early in the LTGRP planning process, that the priority for DSM in this model was to focus on energy savings to reduce GHG emissions. As an artifact of the logic in these models, the analysis may show curtailed DSM expenditures after 2030 as the proportion of renewable and low-carbon gas increases and natural gas declines. This is not demonstrated in the Reference Case due to the higher proportion of natural gas. FEI will assess updating the model for the next LTGRP, which will result in DSM savings being applied proportionally to all fuel types including renewable and low-carbon gas, so that savings will not be curtailed as the conventional gas share decreases.155
>
> Footnote 155: RPAG members were in general agreement that DSM savings could be applied proportionally to all fuel types in a future model, recognizing the value in saving an additional unit of energy whether it be natural, renewable or low-carbon gas.

44.1 Please discuss what future updates to the modelling assumptions (e.g. differing avoided gas cost assumptions) might entail, how this would directionally affect the DSM analysis, and any advantages or disadvantages from FEI's perspective.

<u>Response:</u>

The following response has been provided by Posterity Group.

Since the Application was completed, the Navigator modeling software has been updated to include the capability to apply DSM to a blend of fuels. Two major clients were both requesting this capability. The Navigator developer did not have the time to add this feature during the LTGRP project, because it required alterations to ten different functions in the software. The code modifications for this feature are now complete and tested and will be available for the next LTGRP.

The expectation of the modeling team is that the measures can be applied to the blend with very little modification, assuming the fuel blend does not dramatically change the cost, lifetime, or savings of the measures. The avoided cost would be calculated based on the weighted avoided costs of the different marginal fuels in the blend. Advantages of the new feature include:

- The Navigator modeling software produces output showing the savings for every measure for every fuel in the blend, proportional to each fuel's share, at the same level of granularity currently provided.
- This eliminates the step of calculating adjusted participation rates to inflate the savings of conventional natural gas based on the ratio of (total gaseous fuels)/(conventional natural gas).

In some cases, the DSM potential may be slightly larger than it would be with the current approach of adjusting the participation rates for the blend ratio. This effect would be noticeable only in scenarios with a very high proportion of other gaseous fuels replacing conventional natural gas in the blend.

FEI is not aware of any disadvantages of this new approach.

45.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Section 2.2.2, p. 2-9; p. 5-25; Appendix A-5 (CleanBC Roadmap to 2030), p. 41

Greenhouse Gas Reduction Standard (GHGRS): Emissions cap for natural gas utilities and the DSM Regulation

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

> The GHGRS will establish an obligation for natural gas utilities to reduce GHG emissions from energy use in the buildings and industrial sectors. FEI expects compliance with the cap to be overseen by the BCUC and that enabling legislation will be developed that will further define how this policy will be implemented for gas utilities.
>
> The move from a voluntary renewable gas target to a mandated GHG emissions cap is a substantial change in direction for provincial policy. While details on the GHGRS remain under development, FEI expects that it will place a stringent emissions reduction obligation on gas utilities. Compliance pathways to achieve the cap have not yet been developed; however, these pathways will be highly consequential for the overall role of gas utilities and for customers that rely on the energy that natural gas utilities deliver.
>
> ….
>
> 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 <u>and incenting higher levels of energy efficiency</u> and other measures. Although many uncertainties remain for FEI, the 2022 LTGRP provides context around FEI's approach to addressing the Roadmap. [Emphasis added]

The Ministry sets guidelines for the evaluation of the cost effectiveness of DSM programs using the Demand-side Measures Regulation,[52] which was last updated in 2017.

On page 5-25 of the Application, FEI notes, that the DSM expenditures and cost-effectiveness results discussed in section 5.4.5 are based on current regulation. Any future regulatory amendments that are in effect before the next LTGRP will be captured at that time. The results do not take into account future DSM Regulation changes, and their impact on FEI's DSM portfolio, which could enable more DSM or result in fewer DSM program offerings.

On page 41 of the CleanBC Roadmap to 2030 (Appendix A-5) states:

> Instead of seeing incentives for conventional gas-fired heating equipment such as furnaces and boilers, consumers will see more support for building-envelope improvements such as insulation and better windows, and all kinds of high

52 B.C. Reg. 326/2008.

efficiency heat pumps – electric, gas and hybrid. We'll also look for ways to further coordinate and integrate energy efficiency programs to make them more effective and easier to access.

The Roadmap Portfolio of Measures on page 68 of the CleanBC Roadmap to 2030 (Appendix A-5) includes: "Phase out utility gas equipment incentives" in the near-term.

45.1 Please provide an analysis of the potential impact on FEI's forecasted DSM savings if incentives for conventional gas-fired heating equipment is phased out from 2023.

Response:

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

FEI has interpreted "conventional gas-fired heating equipment" to mean space and water heating equipment with less than 100 percent efficiency.

FEI's analysis below provides the potential impact on forecasted savings on the DEP Scenario - High DSM Setting if conventional gas-fired heating equipment is phased out. The comparison was made by "unselecting" these measures in the detailed output, and comparing the result with the total. In this analysis, dual fuel appliances where gas was the primary heat were removed, but gas heat pumps remained in the analysis. The analysis suggests cumulative energy savings will be reduced by approximately 12 percent.

Table 1: Comparison of Energy Savings in the DEP Scenario - High DSM Setting Before and After Removing Conventional Gas-Fired Equipment for the Residential, Commercial and Industrial Program Areas

Year	DEP High DSM Cumulative Savings (GJ)	DEP High DSM Cumulative Savings, Conventional Gas-Fired Heating Equipment Removed (GJ)	Percent Reduction
2020	2,437,556	2,437,556	**0%**
2021	4,677,797	4,677,797	**0%**
2022	6,685,693	6,685,693	**0%**
2023	8,395,289	7,449,972	**-11%**
2024	9,978,930	8,809,246	**-12%**
2025	11,456,536	10,066,012	**-12%**
2026	12,917,738	11,319,865	**-12%**
2027	14,325,779	12,536,682	**-12%**
2028	15,755,855	13,786,883	**-12%**
2029	17,052,687	14,928,023	**-12%**
2030	18,205,909	15,951,915	**-12%**
2031	19,450,760	17,052,360	**-12%**
2032	20,594,780	18,063,552	**-12%**
2033	21,592,354	18,941,085	**-12%**
2034	22,524,800	19,774,575	**-12%**

Year	DEP High DSM Cumulative Savings (GJ)	DEP High DSM Cumulative Savings, Conventional Gas-Fired Heating Equipment Removed (GJ)	Percent Reduction
2035	23,387,160	20,566,841	**-12%**
2036	24,095,086	21,201,048	**-12%**
2037	24,741,450	21,822,568	**-12%**
2038	25,227,260	22,282,285	**-12%**
2039	25,573,718	22,620,383	**-12%**
2040	25,833,077	22,877,596	**-11%**
2041	25,996,660	23,083,385	**-11%**
2042	25,970,378	23,106,457	**-11%**

For clarity, FEI provides the following list of equipment that was filtered out in the analysis:

Residential Program Area

- Boiler Early Retirement
- Combination System – Type 1 and 2
- Combination System –Type 1 and 2 Early Retirement
- Combination System – Type 3
- High Efficiency (EnerChoice) Gas Fireplace or Vertically Direct Vented Fireplace
- High Efficiency Boiler
- High Efficiency Boiler Dual Fuel – Gas Primary
- High Efficiency Furnace
- High Efficiency Furnace Dual Fuel – Gas Primary
- High Quality Furnace Installation – ENERGY STAR Verified
- High-Efficiency (ENERGY STAR) Condensing Gas Tankless Water Heater – Mature Market Costs
- High-Efficiency (ENERGY STAR) Condensing Gas Storage Tank Water Heater
- High-Efficiency Storage Gas Water Heater

Commercial Program Area

- Condensing Boiler (Early)
- Condensing Boiler (Replace On Burnout)
- Condensing On-Demand Water Heater
- Condensing Storage Water Heater
- Condensing Supply Boiler
- Condensing Unit Heater
- Condensing Makeup Air Unit (Early Replacement)
- Condensing MUA (Replace On Burnout)
- Direct Vented Fireplace
- Infrared Heaters
- Residential Furnace in Small Commercial Buildings (Early Replacement)
- Residential Furnace (Replace On Burnout)

Industrial Program Area

- Condensing Boiler
- Condensing Makeup Air Units Unit
- Condensing Unit Heaters
- Direct Contact Hot Water Heater
- Industrial Furnace Retrofit

On page 9-2 of the Application, FEI states that the Diversified Energy (Planning) Scenario high level of energy savings from DSM results in 0.9 Mt CO2e reductions in 2030 and 1.3 Mt CO2e reductions in 2040.

45.2 Please discuss any risk factors FEI has identified in terms of realizing the forecast DSM savings and associated emissions reductions.

Response:

As energy savings are primarily a factor of program participation, anything that impacts customer participation in DSM programs would impact risk and FEI's ability to achieve these energy savings. Some potential factors that could impact customer participation include:

- Policy updates that would result in the removal of conventional gas equipment incentives (refer to FEI's response to BCUC IR1 45.1 for further commentary on the impact of this risk);
- Priorities that take customer attention away from energy efficiency (e.g., rising cost of living, pandemics, fires, floods, earthquakes, etc.);
- New entrants in the energy efficiency marketplace shifting program participation from FEI to another entity (e.g., provincial, federal, municipal or any other third-party programs that have not been designed to work in conjunction with FEI's DSM programs); and
- External factors (e.g., economic recession, increased costs of financing, supply chain weaknesses, etc.).

45.3 Please discuss the risks of realizing the required emissions reductions from the DEP High DSM scenario, relative to other actions identified to meet the proposed GHGRS cap.

Response:

The BC Government has not yet established alternative options for FEI to meet the proposed GHGRS emission cap; however, please refer to the response to BCUC IR1 74.2 for a comprehensive discussion on FEI's emission reduction initiatives. DSM initiatives in the DEP Scenario High DSM Setting represent about 18 percent of FEI's proposed emission reductions in 2030 and 2040.

45.4 Please discuss how FEI would respond if DSM appeared to be underperforming compared to forecast.

Response:

If program areas were underperforming compared to forecast, FEI would use its promotional levers to drive program activity, for example: advertising, community partnerships, engagement with trade ally networks and working with associations. FEI may also consider time-limited offers as a way to drive participation and engage with program partners, such as the Province, to solicit support to drive DSM activity. As FEI develops its DSM Plans for 2024 and beyond, FEI will examine all opportunities to drive participation, including reassessing incentive levels and adjusting program design, through DSM plan development.

FEI will also be tracking its decarbonization initiatives across the organization to ensure all departments are working together to comply with GHG emission reduction targets. If DSM program activity was not meeting energy savings targets, FEI would also consider where other aspects of its carbon reduction initiatives might be able to play a bigger role in reducing greenhouse gas emissions.

45.5 Please discuss what other options FEI has identified in the event the anticipated reductions from DSM are not realized.

Response:

Please refer to FEI's response to BCUC IR1 74.2 for a comprehensive discussion on FEI's emission reduction initiatives.

46.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Section 9.2.4, p. 9-3; Appendix C-1 (CPR Report), p. viii

GHG Reductions in the DEP Scenario Resulting from DSM

On page 9-3 of the Application, FEI states that after completing the demand and supply modelling for the 2022 LTGRP, FEI identified further opportunities for additional emission reductions which FEI expects to incorporate into its Clean Growth Pathway, including…

> **Additional demand-side measures not modelled in the 2021 CPR**: Three promising energy efficiency technologies have emerged in recent months as having a higher potential impact on gas demand than was modelled in the 2021 CPR or in the 2022 LTGRP. These are deep energy retrofits, gas heat pumps and hybrid heating systems. As discussed in Section 5.4.4, FEI expects that these technologies will provide additional energy savings to those modelled in the 2021 CPR and the 2022 LTGRP DSM Analysis.
>
> ….
>
> FEI is still considering how these additional opportunities feed into the emissions reductions later in the planning horizon and so <u>has not included them in its assessment of 2040 emission reductions</u> at this time. FEI will formally include these additional opportunities in its demand and GHG emission modelling for the next LTGRP.

On page viii of the CPR Report (Appendix C-1), Polaris notes

- Commercial sector savings show the most variance between the high and medium market potential scenarios. Using the MTRC screen, by 2040 the difference in potential between the medium and high market scenarios is 11.6 PJ.

  Gas heat pumps (GHPs) and efficient new construction are major contributing factors to this difference. These measures have high technical and economic potential, but future uptake is uncertain. For example, in the medium scenario, GHPs are modeled as an innovative technology with low forecasted growth. In the high scenario, they are modeled as an innovative technology with high forecasted growth, especially in the second half of the study period (2030-2040).

46.1 Please clarify to what extent any of these technologies, including but not limited to commercial gas heat pumps, are included in the current estimate of gas savings in the DEP High DSM option.

<u>Response:</u>

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

The technologies described in the preamble, also referred to as Advanced DSM measures, although modeled in the CPR and LTGRP with conservative savings levels, are anticipated to achieve higher energy savings over the planning period. Table 1 below illustrates the energy savings attributed to these technologies in the DEP – High and Medium DSM Settings.

For 2030, energy savings estimates for Advanced DSM measures accounted for over 24 percent of total energy savings for the DEP – High DSM Setting as follows:

- Residential Deep Energy Retrofits[53] – individual measures that would comprise a deep retrofit package accounted for 8.7 percent;
- Commercial Deep Energy Retrofits[1] – individual measures that would comprise a deep retrofit package accounted for 10.2 percent;
- Residential Gas Heat Pumps accounted for 0.4 percent;
- Commercial Gas Heat Pumps accounted for 5.0 percent; and
- Dual-fuel hybrid heating systems for both residential and commercial applications were modeled as controls-only measures in the CPR / LTGRP, and therefore had relatively small savings potential.

Table 1: Energy Savings Estimates (PJ) for Advanced DSM Measures in the DEP High and Medium DSM Settings[54]

DSM Demand Reduction	Diversified Energy (Planning) - High DSM (PJ)			Diversified Energy (Planning) - Medium (PJ)		
	2030	2040	2042	2030	2040	2042
Residential Advanced DSM						
Deep Energy Retrofits - package of measures	1.6	2.1	2.1	1.6	1.7	1.7
Dual Fuel Heating Systems	0.0	0.0	0.0	0.0	0.0	0.0
Gas Heat Pumps	0.1	0.4	0.4	0.1	0.3	0.3
Total Residential Demand Reduction	6.7	8.6	8.4	6.5	8.2	7.9
Commercial Advanced DSM						
Deep Energy Retrofits - package of measures	1.9	3.9	4.1	0.3	0.6	0.6
Dual Fuel Heating Systems	0.0	0.0	0.0	0.0	0.0	0.0
Gas Heat Pumps	0.9	2.3	2.4	0.0	0.1	0.1
Total Commercial Demand Reduction	6.2	10.9	11.3	2.2	4.2	4.4
Total Industrial Demand Reduction	**4.8**	**5.8**	**5.7**	**3.0**	**3.8**	**3.8**
Total DSM Demand Reduction	**18.2**	**25.8**	**26.0**	**12.0**	**16.5**	**16.5**

[53] Due to the early stage in FEI's residential and commercial deep retrofit program development, FEI was not able to model forecasted savings of a standalone package of measures in the 2021 Conservation Potential Review (CPR) and the 2022 LTGRP. Instead, in this response, energy savings potential was estimated by adding the savings for the individual measures that FEI envisions will comprise a future deep energy retrofit package. The deep retrofit program savings would be over and above these savings from individual measures, for a subset of existing or new additional participants who would respond to higher incentive levels that would drive the bundling of multiple measures in a deep retrofit. Program eligibility will be based on reducing energy consumption by at least 50 percent to fit the deep energy retrofit definition. Please refer to CEC IR1 34.1 and 35.1 for further discussion.

[54] Analysis for Table 1 includes DSM savings potential for Vancouver Island Joint Venture.

FEI is incorporating these measures into upcoming DSM expenditure plans. It is anticipated that these emerging program measures may contribute to additional savings and GHG emission reductions depending upon policy and market influences from now to 2030 that may accelerate their adoption. CEC IR1 34.1, 34.2, 35.1, and 35.2 also seek additional information about advanced DSM measures that BCUC might find informative.

46.2 Please discuss the typical timelines, in years, to pilot and test new technologies such as deep energy retrofits, gas heat pumps and hybrid heating systems.

Response:

FEI pilot programs testing new technology typically range from one to three years to complete, depending on the technology, pilot objectives and scope, as well as a variety of factors including:

- Technology availability and readiness level
- Codes and standards
- Supply chain readiness
- Procurement and legal processes
- Contractor and trade availability
- Measurement and verification plans
- Shipping, installation and commissioning timelines
- Participant recruitment timelines

Further, upon completion, pilot learnings may identify additional information gaps and/or barriers that need to be addressed prior to a larger scale deployment. For example, for the Commercial Gas Absorption Heat Pump Pilot, although the pilot measured an average of 21 percent natural gas savings for domestic hot water, further evaluation was required to measure additional savings through expanding operation to serve other end uses such as makeup air and space heating, as well as optimizing system controls and companion equipment.

46.3 If the measures are deemed successful, please explain when savings from these technologies could start to be realized.

Response:

FEI assumes that energy savings for these advanced DSM measures that were not modelled in the 2021 CPR will be realized once a DSM incentive offer is in-market. It is important to note that although pilot results may be deemed successful, the following programmatic assessments must also be factored before launching a full-scale DSM offering:

- Cost effectiveness of the measure;
- Market awareness and maturity of the measure;
- Availability of any existing data on the measure and filling any information gaps;
- Customer and contractor awareness and acceptance of the technology;
- Ease of installation of the measure; and
- Availability of the supply chain for the measure and access to local distributors.

For information on targeted incentive timelines for advanced DSM measures, please refer to FEI's response to BCUC IR1 46.2.

46.4 Please discuss any risks identified by FEI which may impact the possible emissions reductions associated with these additional DSM measures.

Response:

FEI considers that the risks that may impact the emission reductions for these additional DSM measures are primarily associated with barriers to their market adoption. The tables below summarize current adoption barriers utilizing the "5 A's" framework for market transformation for gas heat pumps, hybrid heating systems and deep energy retrofits, as well as potential remedial actions to address these barriers. This methodology is used successfully in Canada to design effective market transformation programs for residential, commercial and industrial products. Each "A" in the framework represents a critical aspect of the market adoption path for a new technology. By considering the full market cycle of a technology, from production through to installation and operation, the framework facilitates group discussion and identification of critical barriers to market transformation. While the applicability of each of the steps in the cycle will vary depending on the technology or product under review, this approach enhances the analysis by characterizing the market barriers and understanding how the barriers can affect different market participants.

Please refer to the response to BCUC IR1 74.2 for a comprehensive discussion on FEI's emission reduction initiatives.

Barriers to Gas Heat Pump (GHP) Market Adoption				
Availability	**Awareness**	**Accessibility**	**Affordability**	**Acceptance**
• Limited technologies available • No residential technologies currently, targeting 2024 market entry	• Little to no market awareness for customers • Limited awareness and education for contractors, installers, engineers and architects	• Limited incentive programs • Lack of local dealers and suppliers • Low volume supplies	• High capital costs for equipment and companion components	• Limited performance data for commercial and residential technologies • Changing policy landscapes
Remedial Actions				
• Support large scale field pilots and research and development for various GHP technologies to identify new technologies • Encourage manufacturers to set up local distribution and representation to support DSM programs • Support manufacturers to certify products and raise investments to increase production and volume	• Support training of contractors, installers, engineers, designers and architects • Increase awareness of market participants by offering targeted workshops and providing GHP installation best practices • Prepare program marketing material for residential and commercial technologies • Leverage industry white papers, case studies and utility program data	• Assist manufacturers to establish sales and distribution channels • Support activities to provide easy access to purchasing GHPs • Collaborate with utilities through working groups and industry associations to create market pull • Educate policy decision makers regarding GHPs as a cost effective GHG emission reduction solution	• Identify strategies through pilot programs to support cost effective installations • Encourage manufacturers to kit companion components to reduce costs and to create plug and play solutions for contractors • Train contractors, installers, engineers and designers to reduce installation costs • Provide DSM incentive programs to accelerate market adoption • Support GHP manufacturers to produce large volumes to reduce costs • Develop financing programs to offset higher first cost and look at life cycle costs	• Work with manufacturers to address customer acceptance of their products by focusing on form, fit and function and performance • Support manufacturers to address space and installation challenges for the retrofit market • Educate the market on the benefits of GHPs • Work with policy makers to support GHPs as part of decarbonization goals • Support GHP codes and standards development

Barriers for Residential Hybrid Heating Market Adoption				
Availability	**Awareness**	**Accessibility**	**Affordability**	**Acceptance**
• Limited packaged systems • Limited availability of sophisticated controls • Limited controls for utility demand response	• Low market adoption with limited awareness to adopt/and or utilize both technologies as a “system” • Limited field data to identify customer acceptance, energy savings, system performance data and costs • Low contractor awareness on system installation approach • Low contractor awareness with sophisticated control strategy	• More data required to assess feasibility of installation for residential homes • Lack of local dealers and suppliers	• High capital costs to replace both systems • More data required to understand economics of adopting the system over baseline alternatives	• Lack of awareness of benefits to adopt a hybrid heating system • Lack of data to support customer acceptance of hybrid heating systems over baseline alternatives • No performance standards for unmatched and matched systems
Remedial Actions				
• Support field demonstrations of hybrid heating systems and encourage manufactures to establish local distribution and representation in FEI service territory • Encourage manufacturers to innovate packaged systems and utility enabled controls for demand response opportunities • Support manufacturers to certify products and raise investments to increase production and volume	• Support training of contractors, installers, engineers, designers and architects • Increase awareness of market participants by offering targeted workshops and providing hybrid heating installation best practices • Prepare program marketing material for residential and commercial technologies • Leverage industry white papers, case studies and utility program data • Partner with electric utilities to showcase dual fuel benefits	• Assist manufacturers to establish sales and distribution channels • Support activities to provide easy access to purchasing • Collaborate with utilities and government to create market pull • Educate policy decision makers regarding hybrid heating	• Provide DSM rebates to support adoption of hybrid heating systems • Understand economical balance point for customers to utilize hybrids to support affordability • Support hybrid heating manufacturers to produce large volumes of packaged systems to reduce costs • Encourage manufacturers to provide controls and packaged systems to create a plug and play solutions for contractors • Train contractors, installers, engineers and designers to reduce installation costs • Provide DSM incentive programs to accelerate market adoption • Partner with utilities to offset higher first cost and look at life cycle costs	• Work with manufacturers to address customer acceptance of their products by focusing on form, fit and function and performance • Support manufacturers to address space and installation challenges for the retrofit market • Educate the market on the benefits of GHPs • Work with policy makers to support GHPs as part of decarbonization goals • Support GHP codes and standards development

Barriers for Deep Energy Retrofit Market Adoption				
Availability	**Awareness**	**Accessibility**	**Affordability**	**Acceptance**
• Limited case studies for natural gas energy efficiency that prove emissions reductions of 50-80% • Limited data on emerging products/technique for control barriers • Limited trades to support comprehensive upgrades	• Limited industry knowledge on energy and non-energy benefits • Limited industry education on best practices to implement and evaluate deep retrofits	• Limited programs to support adoption • Limitations to implementation for scale such as lot line setbacks, height restrictions, code compliance upgrades and noise bylaws	• High capital costs to conduct a comprehensive retrofit over annual renewals • Limited financing models • Limited DSM incentives	• Limited case studies that show customer acceptance • Limited data on tenant acceptance
Remedial Actions				
• Supporting deep energy retrofit pilot projects and developing industry capacity to make the technology and process more available	• Raising awareness about deep energy retrofit methodology, design and implementation for potential building owners, contractors, installers, engineers, designers and architects	• Increase market participants by offering targeted recruitment for existing pilots • Support activities to provide easy access to deep energy retrofit implementation • Develop key messaging for communicating the potential with policy decision makers and municipalities	• Finding the most effective and balanced design to reduce the cost of deep energy retrofit • Finding alternative technologies for scalability of the technology and process • Support the bundling of different financial rebates for higher impact	• Leverage the final reports and learnings to provide reliable data and support potential energy and GHG emission reductions

47.0 Reference: DEMAND-SIDE RESOURCES

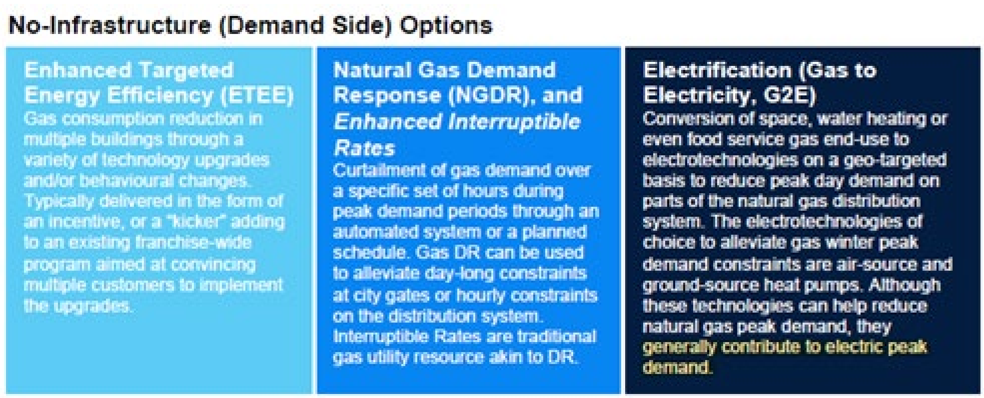
Exhibit B-1, Section 5.5, pp. 5-40 — 5-41; Appendix C-2, p. 2; Appendix C-3, pp. 2, 15

Non Pipe Solutions – Enhanced Targeted Energy Efficiency

On pages 5-40 to 5-41 of the Application, FEI states that in its Decision on the 2017 LTGRP, the BCUC requested that FEI

> provide an update of its analysis of opportunities for DSM to be used to cost-effectively replace or defer infrastructure investments in its next LTGRP." 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.
>
> Footnote 174: Note that impacts to the electric system were not examined in this study.

The following is an extract from page 2 of Exhibit 1 in Appendix C-2 to the Application, summarising the broad range of demand side non-pipe solution options:



On page 15 of Appendix C-3 to the Application, ICF Canada (ICF) states:

> Enhanced Targeted Energy Efficiency (ETEE) "has the following two characteristics that differentiate it from generic franchise-wide energy efficiency:
>
> > **ETEE are "geo-targeted" in that they focus on specific areas of the distribution network:** ... Geo-targeting generally requires additional promotion of some of the same EE technologies that are eligible to all customers in the distribution license. This can include additional marketing or increased incentives (sometimes called "incentive kickers"26). ETEE can also include incremental measures that are not eligible for rebates in the utility's broader EE programs.
> >
> > **ETEE focuses on reducing demand during specific hours:** Downstream constraints are often driven by hourly rather than daily peak

> demands and tend to be for a few hours at a time. The use of ETEE require a thorough understanding of the "load shape" of the gas savings, hour by hour. This is a critical aspect of ETEE because <u>ICF's research suggests that relatively little data collection and analytical work has been completed to date to quantify the hourly demand profile</u> from natural gas conservation measures.[27] Based on our current review of relevant pilot programs, this continues to be the case.

EETE programs can also be focused on alleviating peak demand constraints at the transmission level (i.e. upstream constraints), and they would then be focused on measures that reduce peak day demand rather than peak hour demand. [Emphasis added]

47.1 Please discuss if FEI has explored any ETEE initiatives, and the results of any explorations to date. If not, does FEI plan to explore ETEE projects in future, and why or why not.

<u>Response:</u>

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

The ICF report notes that there has been limited activity in North America regarding ETEE pilots. The report identifies four pilots focused on ETEE, with ConEdison's low-income weatherization program being "the only ETEE program that has yielded results to date". Page 38 of the ICF report also discusses the challenges around assessing impacts from ETEE programs, "because existing metering infrastructure does not have the granularity to track impacts in smaller facilities, such as individual homes".

Based on the limited activity around ETEE initiatives in other jurisdictions, the challenges associated with assessing impacts from ETEE programs, and the fact that ETEE significantly overlaps with FEI's ongoing DSM initiatives, FEI hasn't further explored ETEE initiatives at this time. However, FEI plans to monitor developments with ETEE initiatives in other jurisdictions and depending on those insights, may conduct further exploratory research in addition to assessing whether a pilot would be the appropriate next step. Any availability of gas AMI data would also factor into the consideration of ETEE initiatives in FEI's service territory.

47.2 Please discuss what data FEI has, or intends to collect, to better understand the load-shape of gas savings from energy efficiency measures.

<u>Response:</u>

As discussed in the response to BCUC IR1 47.1, given that there is limited data in assessing peak demand impacts of Enhanced Targeted Energy Efficiency (ETEE) measures, FEI plans to continue to monitor developments in other jurisdictions. Pending approval of FEI's Advanced Metering Infrastructure (AMI) Project, once meter deployment is sufficiently underway, FEI would assess piloting geotargeted programs to collect premise-level daily load shape data through annual weather cycles for different customer segments to measure the peak demand impact of these programs. In the absence of employing AMI, FEI would need to employ advanced measurement at a much smaller and more focused scale to collect similar information. This smaller scale would likely produce less evidence and require more assumptions regarding system-wide scalability and peak demand impacts.

47.3 Please discuss the role FEI believes ETEE can play in addressing FEI's long term resource planning objectives, and to what extent ETEE would be aligned with the energy efficiency goals of the existing DSM program.

Response:

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

Preliminary analysis, including research completed by ICF on behalf of Enbridge,[55] suggests that ETEE can make contributions to reducing natural gas peak demand, including both distribution-level (peak hour) and transmission-level (peak day) constraints. However, there is significant uncertainty on the peak demand impacts of ETEE measures given the limited pilots in this area. FEI plans to monitor developments with ETEE initiatives in other jurisdictions.

Although the goals of ETEE initiatives and DSM programs can be somewhat different, ETEE initiatives have the potential to be well-aligned with DSM programs since they may be able to generate both natural gas peak demand reductions and reductions in annual natural gas consumption. However, a focus on peak demand reductions would likely result in a different prioritization of energy efficiency measures, including differences in cost effectiveness of different energy efficiency measures compared to a program focusing on reductions in annual natural gas consumption.

[55] Exhibit B1-8, Appendix C-3, ICF Canada, "Non-Pipe Solutions Status Update Final Report" (March 25, 2022) at p. 15.

48.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Appendix C-3, pp. 40, 42

Non Pipe Solutions ─ Implementation Timelines

On page 40 of Appendix C-3 to the Application, ICF states:

> The lead time to implement NPS projects varies depending on the type of NPS, and depending on regulatory approval process. Traditional broad-based (i.e. franchise-wide) natural gas energy efficiency program filings are typically independent from leave to construct applications for new pipelines or compressor stations and also run on a different calendar. Gas utilities also often have some flexibility with regards to the scope and timing of their energy efficiency programs; especially if they are operating under multi-year DSM frameworks, similar to the approach used in BC. If the process to obtain regulatory approval for NPS projects is drawn out, this may lead to additional challenges with regards to timing.
>
> ….
>
> The amount of lead time to assess whether infrastructure projects can potentially be substituted by an NPS should thereby be dependent on whether the processes to obtain regulatory approval for the NPS is interlaced with the process to gain approval for traditional capital investments. If the NPS process is independent from the leave to construct application, a comfortable length of time of five years seems most appropriate for a large capital project. If the two are interlaced, perhaps starting immediately upon identifying the need for the new large capital project, it is conceivable to shorten the lead time down to 3 years with the first of the three years used to launch an NPS, monitor and report on impacts. [Emphasis added]

On page 42 of Appendix C-3 to the Application, ICF states:

> The timeline for NPS implementation is less of a hurdle if NPS decision and implementation is embedded in the capital project planning and decision process. If the NPS process was to overlap with the leave to construct application process, a three to five years lead time prior to forecasted capacity shortfall may be appropriate. It may be possible to implement smaller-scale NPS projects in a shorter timeline.

48.1 Please provide FEI's views on the most appropriate regulatory forum, or type of application to the BCUC, to consider NPS projects.

Response:

Depending on the amount and nature of expenditures required to implement an NPS project, the NPS project may be included in a revenue requirements application under sections 59 to 61 of the UCA, a CPCN application under sections 45-46 of the UCA, or a DSM expenditure schedule application under section 44.2 of the UCA. Regardless of the type of application, FEI anticipates that there would be a public review process before the BCUC.

48.2 Please discuss the advantages and disadvantages of requiring that NPS are considered as alternatives in all CPCN applications.

Response:

One advantage of requiring that NPS be considered as an alternative in all CPCN applications is if such a requirement led to the identification of distributed infrastructure alternatives (such CNG or LNG peak shaving) that could be employed to avoid or delay a project that would otherwise increase pipe capacity and such a solution would be both reliable and cost-effective. Since FEI already considers such infrastructure alternatives in its planning for system growth and sustainment, this advantage already exists and would not be enhanced by such a requirement. Another possible advantage of such a requirement that might be viewed from the BCUC's perspective is the knowledge that FEI is continually assessing potential NPS and is therefore aware of advancements in technologies and techniques for implementing NPS. However, FEI considers that there are other ways for the BCUC to measure FEI's awareness of the state of the industry for NPS than formally establishing such a requirement.

The disadvantages of formally requiring that NPS be considered in all CPCN applications are primarily that it will in many cases create additional and unnecessary delays and costs to the project approval process. This is particularly the case where a CPCN application, such as the FEI's Advanced Metering Infrastructure (AMI) application, is not related to system capacity requirements. Further, except for considering distributed infrastructure options like CNG or LNG peak shaving solutions, NPS alternatives can present a risk of large system outages if they underperform expectations that are very difficult to quantify. It is therefore difficult to rank and assess such alternatives against the more verifiable increases in capacity to meet peak demand inherent in hard infrastructure assets.

Until such time the FEI can verify the effectiveness of non-pipe solutions in reducing future peak demand, FEI cannot see the advantages of considering these alternatives in all CPCN applications. Regardless of whether FEI considers such alternatives directly in the development of CPCN applications, currently FEI does regularly respond to information requests as part of the CPCN application process around the potential effectiveness of NPS in applications for system upgrade projects. As a result, FEI does not consider that making such a requirement would create an overall advantage.

49.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Appendix C-3, p. 43

Non Pipe Solutions - Next Steps

ICF recommends the following potential options as next steps for NPS pilots and/or research for FEI on page 43 of Appendix C-3 to the Application:

- Enhanced smart thermostat NGDR pilot program: NGDR using smart thermostats are relatively easy and fast to deploy, which explains why a relatively large portion of the pilot projects we identified focused on this technology. ICF noted that existing smart thermostat DR programs are focused only on curtailing the natural gas peak demand. FortisBC may want to consider a residential and small business smart thermostat DR program in coordination with BC Hydro and FortisBC's Electric Utility that focused on both summer peak load curtailment (AC) and winter gas peak demand curtailment. A joint program will be more cost-effective since it can yield additional benefits. A smart thermostat NGDR pilot program would have the added benefit of yielding a wealth of data about the baseline load profile of space heating in British Columbia through analyzing the data feed from the smart thermostats (e.g. duty cycle, indoor temperature).
- C&I ETEE pilot: ICF's research suggests that there has been much less focus on ETEE as an NPS, including any M&V of the associated peak demand impacts of gas EE measures. FEI may want to consider an ETEE pilot focused on larger facilities, where it is simpler and more cost-effective to deploy the necessary telemetric equipment to measure peak demand impacts. FEI could employ a combination of incentive kickers and enhanced customer marketing and direct outreach.
- G2E with ground-source heat pumps (GSHP): GSHPs are significantly more efficient than air-source heat pumps. As an added benefit, GSHPs have a lower winter peak impact because they maintain their performance even during the worst cold snaps. ConEd has been testing the deployment of GSHPs as an NPS, and NYSEG is interested in pursuing community/ district heating-style geo-exchange loops. GSHPs and/or geo-exchange loops may be interesting for FEI to consider as well, since utilities are well-positioned to fund capital intensive projects that can be funded over an extended period.

While many of the challenges that were highlighted in the Enbridge 2018 IRP Study and the Enbridge 2020 study are being addressed, the industry is still a long way from a mature practice of NPS. …. To help advance the consideration of NPS in BC, FEI may be interested in submitting an application to BCUC to formalize a framework for the consideration and deployment of NPS projects. Following the model of frameworks that have been developed in New York State and Ontario, this would provide guidance and direction regarding important aspects such as the assessment process for NPS projects, the approach for cost-effectiveness analysis, the allocation of risk, monitoring and reporting requirements, timeline, sourcing, and cost recovery. [Emphasis added]

49.1 Please provide FEI's views on the options presented by ICF. Does FEI intend to pursue any of the suggested NPS pilots at this stage, and if so, what are the current timelines?

Response:

At the time of filing, FEI plans on exploring demand response natural gas solutions as part of its Innovative Technologies portfolio in the 2023 DSM Expenditures Plan. Although design work has not commenced, a prefeasibility study is underway to identify information gaps such as technology options, market potential, costing inputs and energy savings. FEI expects to complete this analysis by Q1 2023.

49.2 Please discuss whether FEI is considering submitting an application to the BCUC to formalize a framework for the consideration and deployment of NPS projects at this time. If not, why not. If yes, please provide FEI's views on possible timeframes for submitting such an application.

Response:

FEI does not presently have sufficient information to develop a framework. As discussed in the responses to BCUC IR1 47.2 and 47.3, FEI is currently assessing means of collecting data to measure the impact of programs or projects on peak demand and is monitoring initiatives in other jurisdictions. As discussed in the response to BCUC IR1 49.1, FEI is also undertaking pre-feasibility work for potential future NPS activity and will continue to explore the merits of a potential NPS framework during that investigation.

50.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Appendix C-3, pp. 5; 12, 13

Non Pipe Solutions – Natural Gas Demand Response Technologies

On page 5 of Appendix C-3 to the Application, ICF states:

> ICF's research suggests that the majority of NPS pilots have tested NGDR [Natural Gas Demand Response] 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.

50.1 Please discuss if FEI has explored any NGDR projects, and the results of any explorations to date. If not, does FEI plan to explore NGDR projects in future, and why or why not.

Response:

Please refer to the response to BCUC IR1 49.1.

On page 12 of Appendix C-3 to the Application, ICF states:

> The gas industry has been implementing an approach to DR, using interruptible rates, for quite some time. Interruptible rates were originally designed to improve load factors, by "filling valleys" or increasing demand during off-peak periods. This allows gas utilities to amortize infrastructure costs over larger volumes of natural gas sales. It also reduces the need for high cost capacity during peak demand periods. Interruptible rates encourage customers to subscribe by offering lower rates in exchange for the ability for the gas utility to interrupt service during peak demand periods. <u>Subscribers are typically required to shift to alternate fuels during interruptions – most often petroleum products</u>.[18] The backup fuel equipment and storage capacity is an eligibility requirement for participation in many of these programs. Subscribers to interruptible rate programs may have to react to up to two dozen service interruptions per year. [Emphasis added]

On page 13 of Appendix C-3 to the Application, ICF states:

> National Grid also required participants in its NGDR program to implement "clean DR". "Clean DR" is any NGDR approach that avoids the use of a fossil fuel-based back-ups during curtailment periods.[20] While the majority of traditional interruptible rates require a reliable fossil fuel-based back-up, a clean DR approach may see customers making use of biofuels, switching to resistive electric heating,[21] and/or relying on a thermal storage system.[22]

Footnote 20: "Clean DR" was introduced by the regulator of New York State at the start of a recent proceeding on gas planning that we will discuss in the remainder of this report. The regulator did not define it, however, except for mentioning that it would avoid the combustion of a petroleum product as a back-up energy source.

Footnote 21: Because interruption callups would likely happen during short periods of time, during cold snaps, electric resistance is probably the most technically and economically feasible solution from a customer standpoint. Heat pumps are more expensive than resistive heat, making economic viability challenging for so few hours of use. Heat pumps' performance and capacity is hampered during cold snaps while resistive heating equipment is not. However, it should be noted that using resistive electric heating during peak demand periods will contribute to electric system peak demand. Depending on the electric generation mix at this time, this may not result in net GHG emissions reductions.

Footnote 22: A gas-fired thermal storage solution would be a novel technology to be developed. To ICF's knowledge, mature thermal storage technologies are only electric.

50.2 Please provide FEI's views on the merits of requiring that any future NGDR participant be required to implement "clean DR."

Response:

While FEI views clean DR as a reasonable means of avoiding additional GHG consumer emissions, the ultimate objective is to avoid permanent infrastructure required to support peak demand periods. As the peak demand periods and the need to initiate DR throughout the year is limited, the net contributions of clean DR to GHG emissions would also be limited. If a requirement to implement clean DR is mandated, that requirement might increase costs of the DR solution and/or limit the participation of customers in the program. Limited participation in a DR solution could limit the effectiveness of the program to avoid capacity upgrades. FEI would see merit in encouraging and supporting clean DR alternatives but would consider a mandate to be unnecessary.

50.3 Given the possible impact of any NGDR on electric system peak demand, please provide FEI's views on the feasibility of cooperating with BC Hydro or FBC on any NPS projects which may impact the electrical grid or system planning in some way.

Response:

FEI already has Natural Gas Demand Response (NGDR) programs in place, in the form of interruptible rates for industrial customers, to the extent that is practical and to which the market will bear. As such, collaboration with BC Hydro or FBC on FEI's current interruptible rate program is not necessary.

If 'Clean DR' were made a requirement in BC (as discussed in the preamble), it would remain to be seen to what extent customers would seek peaking service from BC Hydro or FBC, versus sources of renewable and low-carbon gas as a back-up fuel, versus ceasing operations during that period. If, in a diversified energy future, there were instances in which using the electricity system to avoid peak demand on the gas system made sense, then FEI could collaborate with BC Hydro and FBC. However, since the gas system has such a large capacity to handle peak demand and the electric system does not, FEI does not see such a solution as practical given that peak winter demand on the electric system would be expected to closely align with peak demand on the gas system.

51.0 Reference: DEMAND-SIDE RESOURCES

Exhibit B-1, Appendix C-3, pp. 42 – 43

Non Pipe Solutions – Electrification and Decarbonization

On page 42 of Appendix C-3 to the Application, IFS states that "jurisdictions that are planning for franchise-wide [Electrification: Gas to Energy] G2E in the medium or long term are considering NPS to solve local peak demand constraints or avoid obsolete pipe replacements without traditional gas infrastructure projects, which are typically amortized over 40+ years. … In Colorado, NPS are being considered in the context of legislation encouraging widespread electrification of the building stock."

On page 43 of Appendix C-3 to the Application, ICF states:

> While GHG emission reductions are not the primary benefit utilities are seeking through NPS opportunities, decarbonization goals and policies are a key driver for adopting NPS. Not all NPS options lead to GHG emissions reductions, and the emissions abated by specific NPS projects are only ancillary to the policy goal of NPS. NPS are relevant to gas system decarbonization pathways since they can be used to avoid deploying new natural gas infrastructure whose medium- and long-term utilization may be significantly impacted by future decarbonization policies. This helps avoid potential issues with amortizing the cost of infrastructure over 40+ year timelines, during which it may become underutilized or obsolete.

51.1 Please discuss to what extent FEI considers NPS could assist with GHG emission reductions. Would NPS reductions result in a permanent reductions in load from an energy perspective, or would they be targeted at periods of peak demand?

Response:

The extent to which a Non-Pipe Solution (NPS) could assist with GHG reductions and result in permanent reductions in load would depend on the objective and nature of the NPS implemented. The following examples are intended to illustrate.

- Example 1: Delivering gas by LNG tanker to a location on the system experiencing a system constraint would only avoid emissions if the LNG were produced from RNG. The contribution to GHG reduction would be limited since this NPS is only implemented for short durations.
- Example 2: A behavioral program such as a voluntary thermostat or water heater setback would be temporary and would only reduce GHG emissions if the customers were using conventional natural gas rather than renewable and low-carbon gas. The GHG reductions could be more substantial if the targeted customers choose to apply the approach more consistently throughout the winter and not just on the coldest days.
- Example 3: If the NPS was an alternative energy system, such as a geo-exchange district energy system or a hydrogen hub that was facilitated by the gas system, then the solution could be both substantive and long lasting in terms of GHG emissions. The extent to which

the employed NPS is successful would also have a bearing on the amount and longevity of GHG emissions.

E. GAS SUPPLY PORTFOLIO PLANNING

52.0 Reference: Gas Supply Portfolio Planning

Exhibit B-1, Section 4, p. 4-38, Section 6, pp. 6-4 – 6-6, 6-10, 6-12, 6-13, 6-15, 6-20, 6-23, 6-24, 6-29; FEI's Revised Renewable Gas Program Application – Stage 2 proceeding, Exhibit B-17, BCUC IR 3.1

Gas Supply Portfolio Planning

On page 6-4 of the Application, FEI states:

> The LTGRP establishes long-term planning principles, objectives, and a framework that is used to help ensure the long-term provision of safe, reliable, and cost effective service to all customers. In doing so, the LTGRP also sets out gas supply contracting and price risk management principles within the context of a 20-year outlook. The ACP and the PRMP each describe more detailed strategies and tactics for managing either the physical availability of gas supply or the impact of gas costs on rates.

52.1 Please discuss how FEI considers its gas supply contracting and price risk management principles set out in the 2022 LTGRP have changed as compared to its 2017 LTGRP. Please summarize key changes, with rationale, as applicable.

Response:

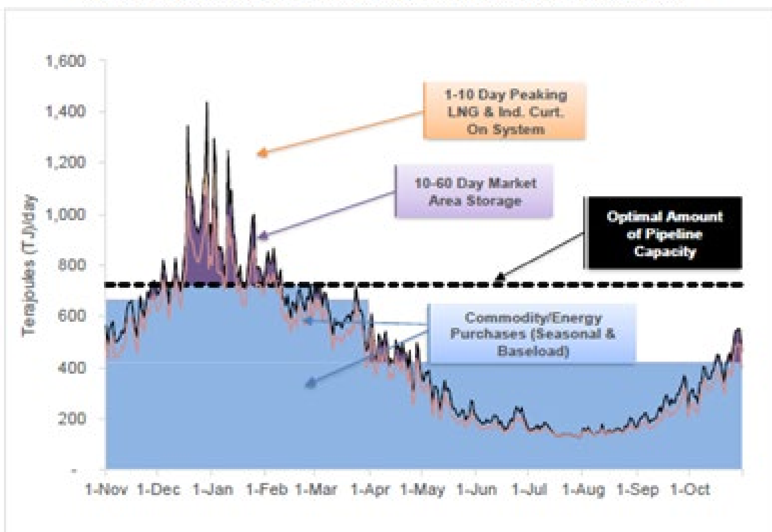
FEI's gas supply contracting principles have evolved since the 2017 LTGRP due to the October 2018 T-South incident. Specifically, FEI has placed more emphasis on enhancing gas supply resiliency within its portfolio, which includes holding contingency resources for its Core customers, and increasing the diversity of supply to mitigate against the risk of a future supply disruption. The rationale for enhancing resiliency is supported by the Guidehouse Report on Natural Gas System Resiliency, filed as Appendix A of the Tilbury LNG CPCN Application. For additional detail and rationale for contingency resources, please refer to the response to BCUC IR1 52.12.

FEI has not changed its price risk management principles in the 2022 LTGRP compared to the 2017 LTGRP. FEI's price risk management principles consist of managing the impacts of market price volatility on commodity rates and in capturing market price opportunities to help provide customers with affordable rates. FEI's development of price risk management strategies is an iterative process and FEI continues to monitor market conditions at AECO/NIT and Station 2. 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 approved by the BCUC.

On pages 6-5 to 6-6 of the Application, FEI states:

> The fundamental design principle of constructing an efficient gas supply portfolio of resources, which FEI has used for many years in the ACP, is to match the resource characteristics to the demand characteristics. In broad terms, that efficient supply portfolio consists of:
>
> - Purchasing firm natural gas commodity volumes and contracting third-party pipeline capacity to address seasonal and base load requirements (i.e., consistent demand for the 151-day winter season and annual demand);
> - Shorter duration market area storage to provide short- to medium-duration seasonal supply; and
> - On-system storage resources for short-duration supply to cover events such as winter demand peaks.
>
> The resulting gas supply portfolio for a system such as FEI's that has pronounced demand seasonality (i.e., high load in winter and low load in summer), and therefore a low annual load factor, is illustrated in Figure 6-1 below. This figure illustrates the ACP resources that were planned to be used in the 2021/2022 gas contract year (November 1, 2021 to October 31, 2022), and how their duration fits the forecast annual normal and design load for Core customers.

Figure 6-1: 2021/2022 FEI Forecast Design and Normal Loads vs. Resources[182]



On page 4-38 of the Application, FEI states:

> FEI's expectation of future annual energy demand for planning purposes is represented by the outputs of the Diversified Energy (Planning) Scenario analysis illustrated in Figure 4-19 below. This planning scenario includes some electrification of gas demand captured historically by FEI in the residential, commercial and industrial sectors, though FEI continues to add customers in these

sectors through the planning horizon. Observed growth in annual demand in the first half of the planning horizon is driven by load growth in the transportation sector and LNG export market, primarily with the large load step increase when the Woodfibre LNG project is modelled to begin operation in 2025[154].

52.2 Please discuss whether FEI expects any material shift(s) in its demand seasonality due to its forecasts described in the Application, such as decreases in demand in the residential, commercial and industrial sectors due to electrification of gas demand captured historically by FEI, or growth in the transportation sector and LNG export market.

52.2.1 If yes, please discuss whether this shift in seasonality may result in any necessary changes to FEI's supply contracting principles and/or price risk management principles. If so, please describe any changes expected.

52.2.2 If not, please explain why not.

Response:

As FEI's DEP Scenario anticipates that 10 percent of industrial gas load will be electrified by 2050, the Application does not contain a material shift in the seasonality of industrial demand due to electrification in the near to medium term. At this time, FEI anticipates that growth in demand for the transportation sector and global LNG (in this case including demand from the Woodfibre facility) will be baseload throughout the year, which may increase daily demand (including potentially on a peak day), but not result in materially different seasonality than currently exists.[56] Changes to residential and commercial demand seasonality may occur over time; however, it is not possible at this time to determine how substantially factors such as electrification and shifts in end-use technologies might impact how demand may change seasonally for these customer groups over the next two decades. FEI offers the following additional points on how demand could change due to some of the several (non-price driven) critical uncertainties set out in Table 4-1 and demand side measures (DSM) as discussed in Section 5 of the Application:

- **Gas to electric fuel switching**: This would decrease annual demand; however, depending on whether the "electrified" customer retains their existing non-electric heating system to utilize during the coldest winter periods, this may "trim the edges" of seasonal winter demand while having little to no effect on gas demand during the "peakiest" periods. FEI's DEP Scenario envisions that 25 percent of residential and commercial gas demand will electrify by 2050 with the interim years of the planning period interpolated from that data point. This means that any related shifts in seasonal demand that may occur are unlikely to materially arise until well into the 20-year planning horizon.
- **Building Codes and Appliance Standards**: Heating equipment installed in new buildings and in retrofit situations is more efficient and, in some cases such as gas fired heat pumps,

[56] This does not consider forced outages or planned maintenance periods, or impacts to global LNG markets that could temporarily affect demand such as was seen immediately after the COVID-19 pandemic in the summer of 2020.

may result in a different demand profile than the older equipment it replaces. FEI is continuing to examine these types of potential end-use trends and technology advances, as well as the range of potential rates of change toward these newer technologies given stock turnover rates, market conditions and the influence of demand side management activities.

- **Demand-side management**: DSM activities may also shift the way that energy is used by some customer groups. For example, deep energy retrofits and building envelope improvements over time will improve efficiency and may change the energy demand profile for customers that take advantage of such programs.

The potential impacts of electrification, codes and standards and future DSM are not yet fully known and are being investigated by FEI. As FEI works to better understand the impacts of the above mentioned factors, it will be able to better model the impact on seasonal demand profiles like that presented in Figure 6-1 of the Application as cited in the preamble.

If a shift in seasonality of demand results in higher peak or winter period demand, this is not expected to change FEI's supply contracting and/or price risk management principles and strategies. FEI would continue to manage the supply risk and pricing volatility in the region by maintaining access to the supply hubs (Station 2 and AECO/NIT), and evaluate future infrastructure considerations to further optimize its supply portfolio. Absent new infrastructure, FEI would also continue to hedge any supply exposure to the Huntingdon/Sumas market with financial hedging.

If a shift in demand resulted in less peak and winter demand, to the extent that FEI's portfolio should be adjusted, FEI could utilize the flexibility in its contracting resources to better fit resources to the demand shape. For additional detail on the contracting flexibility of FEI's supply portfolio, please refer to the response to BCUC IR1 53.1.

52.3 Please discuss whether and how FEI expects the general trend of the Forecast Design and Normal Loads vs. Resources graph, as shown above in Figure 6-1 from the Application for years 2021/2022, to change over the planning horizon of the LTGRP. Please discuss all changes expected (if any), with rationale.

52.3.1 Please discuss how these changes, if any, will impact FEI's current gas supply contracting strategies (if at all).

<u>Response:</u>

Please refer to the response to BCUC IR1 52.2, which explains that at this time FEI is not able to determine exactly how the seasonality of design winter and normal winter load will change over the planning horizon of the Application. While FEI has modelled annual demand and peak demand under different future scenarios, the future demand in those scenarios throughout the remainder of the winter seasons is somewhat more uncertain and subject to a number of variables. For example, it is uncertain how end-use heating equipment will change over time and how more advanced DSM will impact annual gas load shapes. However, given the expected rate of change of these factors as new construction occurs and older equipment reaches its end-of-life, FEI does not expect these uncertainties will have a material impact on the forecast until later in the planning horizon (i.e., 10 years and beyond), as these developments unfold. FEI is continuing to monitor these developments and will be studying their implications for its supply portfolio planning and management.

FEI notes that as it transitions to renewable and low-carbon gas over the planning horizon, these supplies will replace the conventional natural gas supplies that the light blue "Commodity/Energy Purchases" in Figure 6-1 is currently comprised of. These changes are discussed further in the response to BCUC IR1 52.9.

On page 6-10 of the Application, 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 Over the planning horizon, however, FEI expects to purchase or produce increasing amounts of its supplies of renewable and low-carbon gas within BC.
>
> The locations within BC where new supplies will be produced are still being developed. The identified supply volumes are very large and the potential production locations are numerous as identified by the study "Renewable and Low-Carbon Gas Potential in BC and North America", commissioned in partnership with the BC Bioenergy Network and the Province of British Columbia and included in Appendix D-2. The study has assessed the costs of these resources based on information available today, and estimates that a potential of up to 444 PJ per year could be supplied within BC by 2050. This equates to approximately twice FEI's current annual energy throughput.

52.4 Please discuss the key risks associated with FEI's plans to purchase or produce increasing amounts of renewable and low-carbon gas and how FEI intends to mitigate these risks in the context of FEI's gas supply contracting strategies.

Response:

In this response, FEI first identifies the key risks associated with FEI's plans to supply increasing amounts of renewable and low-carbon gas. Second, these risks are discussed in terms of the different renewable and low-carbon production pathways. Third, FEI discusses the strategies and actions it has identified to mitigate these risks and the opportunities that may be gained in accelerating renewable and low-carbon gas projects. Lastly, FEI summarizes the discussion within the context of gas supply contracting strategies.

1. Identification of Risks to Increasing Renewable and Low-Carbon Gas Supply

The BC Renewable and Low-Carbon Gas Supply Potential Study[57] (Study) quantitively compares various renewable and low-carbon gas pathways from a portfolio and cost perspective. The Study presents strategies and actions relating to feedstock, financial considerations, infrastructure, regulatory, climate and carbon intensity that FEI will take into consideration in scaling supply. Supply risks identified in the Study, aside from competition, include:

- The future cost allowed by the GGRR for anaerobically produced RNG;
- The availability and cost of electricity for green hydrogen;
- The availability of suitable geological features to sequester CO2; and
- The supply and distribution of woody biomass and wood residues within BC.

FEI provides an additional review of the renewable and low-carbon supply risks in Section 8.3 of Appendix A to FEI's Generic Cost of Capital Evidence in which the key risks identified include lower than expected supply volume, competition from other purchasers and gas system readiness.

2. Identification of Risks For Different Production Pathways

RNG (Biomethane) from Upgraded Biogas

RNG produced through anaerobic production pathways is the most advanced technologically and relatively easy to develop, and BC has a robust framework for the development of RNG with strong price support for deployment. As discussed in the response to BCUC IR1 77.2, although there are ample sources of renewable and low-carbon gas in North America over the planning horizon, one risk is the limited potential for on-system supply in BC to meet 2030 and potentially longer-term targets. In the near term, expanding supply from outside BC is essential for FEI to make meaningful progress toward achieving the 2030 goals of the CleanBC Roadmap.

Syngas and Lignin

Syngas and lignin production from biomass to displace natural gas in lime kilns and other natural gas-fueled industrial thermal equipment is likely the most achievable and lowest-cost option for using wood biomass resources. The key risk in this pathway is that it requires existing industrial entities such as pulp and paper mills to act as "host sites" and deploy significant capital investments to develop, own, and operate sophisticated production plant facilities under long-term commercial off-take arrangements. Given these large capital costs, industrial entities may not be positioned to accommodate long-term recovery of large investments without suitable incentives and mechanisms to de-risk investment decisions.

[57] Exhibit B1-1, 2022 LTGRP Application, Appendix D-2.

RNG from Upgraded Syngas

The technologies to produce RNG from syngas derived from wood biomass are still pre-commercial, which introduces some technology risk. Also, feedstock cost, availability, supply chain, and quality requirements are uncertain and remain a major risk to developers seeking to develop large-scale projects in BC.

Renewable and Low-Carbon Hydrogen

Renewable and low-carbon hydrogen production in BC presents the greatest opportunity for very large-scale projects to supply the requisite volumes of renewable and low-carbon gases to meet long-term decarbonization goals by 2050. However, there are several key risks that need to be considered with respect to the different renewable and low-carbon hydrogen production pathways including:

<u>Lack of industry expertise and subject matter experts</u>

FEI will need to leverage staff and external experts with relevant expertise to assist with developing hydrogen projects including production, injection/blending, dedicated hydrogen distribution systems and end use applications. The availability of qualified and experienced talent in Canada to assist FEI and other natural gas infrastructure operators to introduce hydrogen into the natural gas supply chain is currently unknown and therefore could be a challenge to hydrogen development.

<u>Cost and growth of demand and supply for hydrogen technologies</u>

Most methods of hydrogen production are energy intensive. Furthermore, producing hydrogen at a range of scales with few or no carbon emissions at acceptable cost will be a challenging economic barrier. To achieve this, some existing hydrogen production technologies require additional carbon capture technology, flexible tariffs need to be developed to provide access to green power, and new distribution and end use technologies need to be innovated and developed.

<u>Availability of hydrogen infrastructure and large-scale capital investments</u>

Domestic supply of low-carbon hydrogen is limited in many parts of Canada today and this hinders both pilot and commercial rollout. As domestic production and demand grow, there will be a need for dedicated infrastructure such as hydrogen pipelines and liquefaction plants. Ensuring that these crucial assets can be built in a coordinated and timely manner will be essential to ensuring low cost, low-carbon hydrogen can be delivered to both domestic and international markets. Existing hydrogen technologies will need to evolve to make hydrogen a sustainable energy carrier, especially for hydrogen to emerge in larger scale utility applications to displace conventional natural gas use. Long-term planning will be required to understand how much hydrogen could be injected and blended into the regional natural gas grid. Injecting renewable and low-carbon hydrogen to replace natural gas and decarbonize the gaseous energy stream will eventually compete for pipeline capacity with increasing volumes of natural gas required for LNG production.

3. Strategy and Actions FEI has Identified to Mitigate Risks

As a key stakeholder, FEI supports the Province's goal of developing BC renewable and low-carbon supply sources, including hydrogen, in building a competitive renewable and low-carbon gas industry in BC`as quickly as possible. However, a key risk mitigation strategy involves geographically diversifying FEI's supply portfolio to reduce overall portfolio risk, mitigate rate pressures and enable more rapid, cost-effective decarbonization of BC's gas supply to meet the Province's objectives and the BC Hydrogen Strategy. The Hydrogen Strategy is focused on ensuring that BC benefits from the emerging hydrogen economy, which FEI is putting significant effort into realizing. This includes developing regional hydrogen hubs, executing a comprehensive plan to blend hydrogen into the distribution system, and ensuring that, as hydrogen demand grows, FEI's existing gas infrastructure is capable and ready to deliver low-carbon hydrogen. Please refer to Section 3.3.3 of the Application for further detail.

Acquiring supply from a variety of sources and geographical areas maximizes the opportunity for GHG reductions, reduces risk and cost pressures for FEI's gas ratepayers, allows time for the expansion of BC's infrastructure and capacity, and fosters a competitive domestic industry in BC, while mitigating the longer-term risk of contracting for supply in an environment where there is growing competition for low-carbon feedstocks. With FEI being a leader in the biomethane industry, FEI has developed deep expertise and a vast network of suppliers in the industry. This is also relevant for supporting the longer-term development of hydrogen supply chains within BC to connect sources of hydrogen supply and demand. Over time, as the supply and demand for hydrogen develops, long-haul pipeline infrastructure will be built and upgraded, and it will be important for an industry in BC to be competitive to support BC's hydrogen economy.

There are also important opportunities that should be considered as part of this discussion and which FEI considers outweigh the risks noted above:

- Advancing a renewable and low-carbon gas production industry and marketplace in BC and elsewhere can create economies of scale that will ultimately lower costs for these resources;
- As production of renewable and low-carbon gas grows to capture the resources identified in BC and elsewhere, advances in production technologies and deployment at scale will improve production efficiency and lower the costs of supply;
- Both of the above opportunities have been realized in the production markets for renewable and low-carbon electricity and pursuing such market development for renewable and low-carbon gas in the province and in other parts of Canada will increase the diversity of energy resources in BC, Canada and across North America, thus improving costs, resiliency, reliability and utilization of the entire BC energy infrastructure network while distribute benefits across Canada; and
- Inherent value from diversification of low-carbon energy supply and delivery through utilization of the existing gas network in BC will help to avoid the need for extensive new electric infrastructure, particularly as required to manage peak demand, and minimize the cost of overall system infrastructure and reliability.

4. Mitigating Risks in the Context of Gas Supply Contracting Strategies

In the context of gas supply contracting strategies, FEI will continue to ensure that there are enough secure, diverse, and reliable resources in place to meet Core customers' forecast peak day, seasonal, and annual load requirements through the Annual Contracting Plan. This is one of FEI's main objectives in developing its gas supply portfolio. The issues and risks of increasing renewable and low-carbon gas supply will become an input or a consideration to FEI's overall annual assessment that ensures the objectives of the ACP are met. For example, the contractual volumes of off-system RNG have been increasing over the past few years and will continue to grow in the near future. Given the forecasted growth, FEI's gas supply team recommended having the delivery locations for future RNG contracts to be delivered at AECO/NIT and Station 2 as the preferred option, instead of Huntingdon/Sumas. This was to be consistent with FEI's existing gas supply contracting strategies for conventional gas, and to avoid any undue supply exposure at the Huntingdon/Sumas market as discussed in Section 6.2.4.2 of the Application.

52.5 Please expand on FEI's plans to produce renewable and low-carbon gas within BC. In the response, please include approximate volumes expected, locations, approximate timeframes and type of production, if known.

<u>Response:</u>

The following response provides information about FEI's current low-carbon gas supply, the evolution of FEI's low-carbon gas supply program to date and FEI's plans to expand renewable and low-carbon gas supply in BC through engaging with stakeholders, including local and regional governments and project developers, as well as Indigenous groups and communities. As BC's renewable and low-carbon gas industry is in nascent stages of development, FEI is pursuing all available near-term opportunities while continuing to develop in-BC resources and supply chains over the long term.

FEI's Current Low-Carbon Gas Supply

FEI has made significant progress in increasing contracted RNG supply for future deliveries beyond 2022. As of the third quarter of 2022, FEI has over 30 biomethane supply agreements that have been approved by the BCUC. These projects are in BC, outside BC and outside Canada and are expected to supply a total volume of RNG of approximately 20 PJ per year, with a potential maximum RNG supply volume of approximately 23 PJ annually once these biomethane facilities are fully operational in the 2025-26 timeframe.

The Evolution of FEI's Low-Carbon Gas Supply Program to Date

As discussed in Section 3.3.1 of the Application, since 2010, FEI has recognized the significant role of renewable and low-carbon gas supply as a fundamental pillar in providing low-carbon energy to its customers. Residential and commercial customers, public sector building owners, municipalities, and public transportation entities continue to express interest in purchasing significant volumes of renewable and low-carbon gas over the planning horizon.

FEI has offered an RNG Program since 2010, with cost recovery of the acquired RNG volume from voluntary program participants through the Biomethane Energy Recovery Charge (BERC), which was set to match projected supply costs. In February 2020, the BCUC accepted FEI's first acquisition of RNG outside of BC as a prescribed undertaking under the GGRR. In May 2021, the provincial government amended the GGRR, increasing the acquisition cost cap and volumes and expanding acquisition opportunities for FEI.

In December 2021, FEI filed its Comprehensive Review and Application for a Revised Renewable Gas Program (RG Program Application), which, along with other revisions, seeks to blend RNG volumes with natural gas to be sold to all sales customers as part of their gas service. As RNG supply increases to meet government emission reduction targets, FEI intends to distribute that supply to all sales customers. As shown in the Figure 1[58] below, the program has changed over the years with respect to the maximum volumes, supply projects, service offerings and pricing.

Figure 1: Overview of Key Milestones in the Development of FEI's RNG Program

Characteristic	**Phase 1** Pilot Program 2010-2013	**Phase 2** Permanent Program 2014-2016	**Phase 3** New Renewable Gas Rate (BERC) 2016-2017	**Phase 4** GGRR amended to include RG 2017-2021	**Phase 5** GGRR amended to further support RG; RG Application 2021 and future years
Volumes and Acquisition Cost Cap	0.25 PJ/Yr @ $15.28/GJ	1.5 PJ/Yr @ $15.28/GJ	1.5 PJ/Yr @$15.28/GJ	8.9 PJ/Yr @$30/GJ	>31 PJ/Yr @ $31/GJ
Supply Projects	First two projects	Added projects	Continued to add projects	Out-of-province projects added	Acquisition opportunities expanded
Offerings	Customer program initiated	Expanded customer offering	Long-term contracts available	No Change	RG Application Section 7.4
Price Mechanism	BERC = Program Costs	BERC = Program Costs	BERC = Market Price	No Change	RG Application Section 8

In addition to RNG, FEI is advancing early-stage development activities in support of hydrogen, syngas and lignin supply projects. FEI expects to begin pilot and pre-commercial stage projects using alternate forms of renewable gas allowed under the current GGRR and expects to increase supply from these alternate forms of renewable gas, which will complement growth in RNG and add to the total amount of renewable gas available to meet 2040 supply targets.

FEI is currently advancing opportunities to work with select industrial customers to trial hydrogen fuel as a replacement for natural gas in plant operations. FEI is collaborating with industrial gas

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58 Figure 3-4 in the Application.

customers in sectors including pulp and paper and minerals processing on progressing feasibility studies, pilot demonstrations, and commercial projects. The intended goal will be to demonstrate the use of renewable or low-carbon intensity hydrogen in several industrial end-use application including as a feedstock and fuel in steam boilers, kilns and smelting operations. FEI expects to successfully progress these efforts and successfully deploy hydrogen in one or more of these applications in the next two to three years, subject to establishing various agreements, permitting, funding and resourcing requirements.

FEI's Renewable and Low-Carbon Gas Supply Outlook in the Diversified Energy (Planning) Scenario plans to produce renewable and low-carbon gas within BC

FEI's outlook for future supply over the planning horizon is discussed in the responses to BCUC IR1 52.4 through 52.6 and 71.8.1. FEI assumes that RNG (biomethane) will continue to provide most of the growth opportunity in its renewable gas supply portfolio to 2030 and expects new supply, hydrogen in particular, will start to support renewable gas supply volume growth by 2030, and gain momentum beyond 2030.

In terms of volumes expected, Table 1 provides an overview for the DEP Scenario including conventional, renewable and low-carbon gas as one example of how the components of the renewable and low-carbon gas portfolio could evolve to reach the overall portfolio supply forecast. The breakdown of these components is discussed further in BCUC IR1 52.6.

Table 1: Example Outlook for Conventional, Renewable and Low-Carbon Gas Portfolio (PJ/Year) for the DEP Scenario

DEP Gas Supply Outook	2025	2030	2035	2040
	PJ/Year			
Natural Gas	177	132	107	83.6
Renewable Natural Gas	16	32	35	38
Hydrogen	5	20	34	48
Syngas and Lignin	1	7	8	8
CCS	0	1	3	5
Total	**200**	**193**	**187**	**183**

In terms of approximate timeframes and types of production, Table 2 provides an overview of BC supply potential outlined in the BC Renewable and Low-Carbon Gas Supply Potential Study, which illustrates that the potential for renewable and low-carbon gas is robust and expanding and could range from 103 PJ to as high as 444 PJ by 2050.

Table 2: Overview of BC Renewable and Low-Carbon Gas Supply Potential (PJ/Year) For 2030 and 2050

	BC Supply Potential 2030		BC Supply Potential 2050	
	Min	Max	Min	Max
RNG (Traditional)	6	6	9	10
Green and Waste Hydrogen	2	11	14	41
Wood-Based Gases (RNG, Hydrogen, Syngas, and Lignin)	2	2	19	145
Blue and Turquoise Hydrogen	16	30	62	248
Total RG and LC	**25**	**49**	**104**	**443**

FEI does not have a detailed forecast of where each type of supply originates; however, Table 7-2 in the Application provides an overview of considerations for integrating renewable and low-carbon gas in FEI systems, illustrating that there is RNG and hydrogen supply potential in all regions, and syngas and lignin supply potential in the Vancouver Island and the Interior regions.

In terms of the progress FEI is making towards these supply outlook targets, FEI plans to support development of technologies such as wood-to-RNG, in addition to supporting projects outside of BC where the technology may be transferrable, to develop BC-based renewable and low-carbon gas supply. These existing and near-term projects include RNG from landfills, anaerobic digestion, wastewater treatment plants, farm waste and wood-to-RNG. FEI is increasing contracted RNG supply for future deliveries beyond 2022. As of the third quarter in 2022, FEI has over thirty biomethane supply agreements that have been approved by the BCUC. These projects are in BC, outside BC and outside Canada and are expected to supply a total volume of RNG of approximately 20 petajoules (PJ) per year with a potential maximum RNG supply volume of approximately 23 PJ annually once these biomethane facilities are fully operational in the 2025-26 timeframe.

FEI is also actively negotiating new biomethane supply agreements and, based on current prospects by 2030, FEI expects its renewable and low-carbon gas portfolio to have more than 30 PJ of RNG based on a continued upward trajectory. As a result of increased existing supply diversity and the fact FEI continues to acquire RNG from suppliers in BC and across North America, FEI is confident that the forecast of the expected amount of RNG supply will meet targets based on continued favourable market conditions.

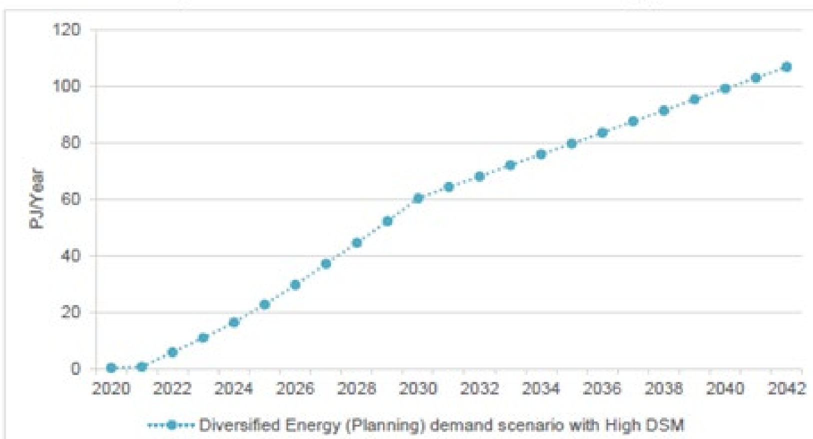
While FEI expects RNG to be an important fuel that will comprise a large share of its renewable gas portfolio, over the longer term, FEI expects to add other forms of renewable gas such as low-carbon hydrogen, which will play an increasingly significant role through its potential to be produced at scale and blended in the gas system or in dedicated infrastructure to decarbonize a range of end use applications, To that end, FEI is advancing early-stage development activities in support of hydrogen, syngas and lignin supply projects. FEI expects to begin pilot and pre-commercial stage projects using alternate forms of renewable gas allowed under the current GGRR and expects to increase supply from these alternate forms of renewable gas, which will complement growth in RNG and add to the total amount of renewable and low-carbon gas available to meet 2040 supply targets.

FEI is working on development of its hydrogen roadmap as discussed extensively in the BCUC IR1 61 series. Some examples of hydrogen development projects underway include the development of a low-carbon (turquoise) hydrogen project in the Lower Mainland that is expected to produce approximately 300,000 GJ of annual low-carbon hydrogen supply from 2025-2026. FEI continues to evaluate opportunities within BC to acquire or develop blue hydrogen and low-carbon natural gas supply. Please also refer to the responses to BCUC IR1 62.8 and 62.81 for additional discussion of blue hydrogen within BC.

Through all the different actions discussed above and further in the Application, FEI's future renewable and low-carbon gas supply potential is expected to grow, giving FEI more confidence in its total supply and the ability to make progress in reducing BC's GHG emissions while developing cost-effective renewable and low-carbon gas supply for its customers.

On page 6-12 of the Application, FEI provides Figure 6-3 as follows:

Figure 6-3: Forecast Renewable and Low-Carbon Gas Supply



52.6 Please restate Figure 6-3 to show the breakdown of forecast renewable and low carbon gas supply that underly the analysis in the Application (i.e.: volumes of RNG, hydrogen, syngas, and lignin). On the same graph, please include FEI's forecast of conventional natural gas.

52.6.1 Please explain the basis for the breakdown of forecast renewable and low carbon gas supply provided in the preceding IR.

Response:

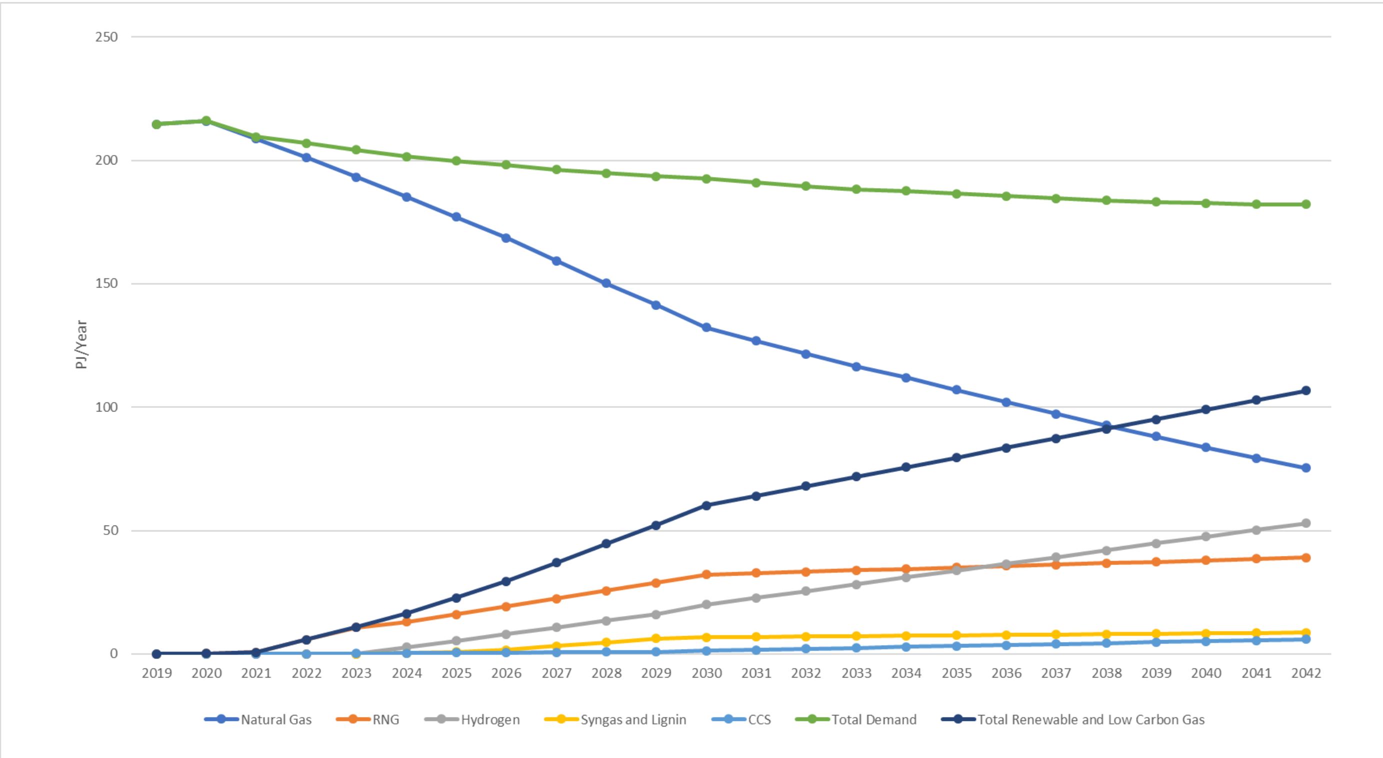
FEI provides a breakdown of its total gas supply portfolio for the DEP Scenario including conventional, renewable and low-carbon gas as one example of how the components of the renewable and low-carbon gas portfolio could evolve to reach the overall portfolio supply forecast. However, this example is not intended to provide a forecast of each individual component of the portfolio. The forecasted overall portfolio supply forecast breakdown is provided in different formats below as follows:

- Figure 1 provides a graphical representation of annual gas supply throughput to 2042 in PJ;
- Table 1 provides the numerical breakout of renewable and low-carbon gas in PJ and as a proportion of supply portfolio (percent); and
- Table 2 provides the breakout of conventional, renewable, and low-carbon gas expressed as a percentage illustrating the decline in conventional gas as requested in BCOAPA IR1 5.2.

As introduced above, FEI has developed a long-term outlook or forecast for its total supply of renewable and low-carbon gas as is shown in Figure 6-3 of the Application. However, FEI has not developed a separate 20-year forecast for each individual component of its renewable and low-carbon gas supplies (RNG, Hydrogen, Syngas and Lignin) for the Application. FEI considers that each of the individual components of that outlook will fall within a range, with the expectation that the actual amount of each component acquired will vary from year to year depending on many factors such as rate of project advancement and cost of supply.

As discussed in the response to BCUC IR1 52.5, FEI's forecast of total renewable and low-carbon gas supply considers the following market drivers. In the earlier years of the planning horizon, RNG will be the predominant resource making up a larger portion of the total renewable and low-carbon gas supply. Over the planning horizon, hydrogen supplies will be established and grow, with the expectation that hydrogen will become the predominant supply resource in later years. As syngas and lignin supplies in BC are currently limited, FEI considers that these will make up a smaller proportion of the total supply portfolio, starting in the mid to later part of the planning horizon. The use of CCUS to decarbonize FEI's gas supply is also expected to develop in the mid to late part of the planning horizon. Gas that has been decarbonized using CCUS technology is anticipated to comprise a smaller portion of the portfolio of renewable and low-carbon gases.

Figure 1: Modelled Example of Forecast of the Total Renewable and Low-Carbon Gas Supply Portfolio Showing the Component Makeup of the Portfolio, the Forecast Decline of Conventional Natural Gas Supply and Overall Forecast for Gas Demand Over the Planning Horizon[59]



[59] The demand values shown in this figure and table are post-DSM and, in keeping with the GHGRS Cap calculation to which the renewable and low-carbon gas supplies apply, does not include demand from Rate 46 Low-Carbon Transportation customers, Global LNG customers or Large New Industrial Customers (Woodfibre).

Table 1: Gas Supply Portfolio Illustrating the Proportion of Renewable and Low-Carbon Gas Over Time (in PJ)

	Natural Gas	RNG	Hydrogen	Syngas and Lignin	CCS	Total Demand	Total Renewable and Low Carbon Gas	Renewable and Low Carbon Gas as a percent of Total Demand
2019	214.7	0.0	0.0	0.0	0.0	214.7	0.0	0.0
2020	215.9	0.3	0.0	0.0	0.0	216.1	0.3	0.1
2021	208.8	0.7	0.0	0.0	0.0	209.5	0.7	0.3
2022	201.1	5.8	0.0	0.0	0.0	207.0	5.8	2.8
2023	193.2	10.7	0.0	0.0	0.2	204.2	11.0	5.4
2024	185.2	12.9	2.7	0.4	0.3	201.6	16.3	8.1
2025	177.1	16.1	5.4	0.8	0.4	199.8	22.7	11.4
2026	168.6	19.3	8.1	1.6	0.6	198.1	29.5	14.9
2027	159.3	22.5	10.7	3.2	0.7	196.3	37.0	18.9
2028	150.2	25.6	13.4	4.7	0.8	194.8	44.6	22.9
2029	141.3	28.8	16.1	6.3	0.9	193.5	52.2	27.0
2030	132.3	32.2	20.0	6.7	1.3	192.5	60.2	31.3
2031	126.9	32.8	22.8	6.9	1.7	191.0	64.1	33.6
2032	121.6	33.3	25.5	7.0	2.1	189.5	68.0	35.9
2033	116.5	33.9	28.3	7.2	2.5	188.3	71.8	38.1
2034	112.0	34.5	31.0	7.4	2.9	187.7	75.7	40.3
2035	107.0	35.1	33.8	7.5	3.2	186.5	79.6	42.7
2036	102.1	35.6	36.5	7.7	3.6	185.5	83.5	45.0
2037	97.2	36.2	39.3	7.9	4.0	184.6	87.3	47.3
2038	92.6	36.8	42.0	8.0	4.4	183.8	91.2	49.6
2039	88.1	37.4	44.8	8.2	4.8	183.2	95.1	51.9
2040	83.6	37.9	47.5	8.4	5.2	182.6	99.0	54.2
2041	79.4	38.5	50.3	8.5	5.5	182.2	102.8	56.4
2042	75.4	39.1	53.0	8.7	5.9	182.1	106.7	58.6

Table 2 shows the proportion of conventional gas and each component of the renewable and low-carbon gas supply for this modelled example as a total of the overall gas supply as a percentage, as requested in BCOAPO IR1 5.2.

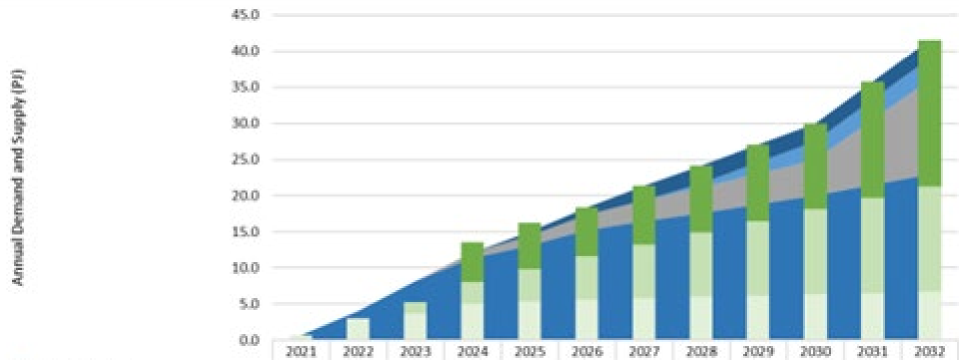
Table 2: Gas Supply Portfolio Data Illustrating Proportion of Renewable and Low-Carbon Gas Supply Over Time as a Percentage

	Natural Gas	RNG	Hydrogen	Syngas and Lignin	CCS
2019	100.0	0.0	0.0	0.0	0.0
2020	99.9	0.1	0.0	0.0	0.0
2021	99.7	0.3	0.0	0.0	0.0
2022	97.2	2.8	0.0	0.0	0.0
2023	94.6	5.3	0.0	0.0	0.1
2024	91.9	6.4	1.3	0.2	0.2
2025	88.6	8.1	2.7	0.4	0.2
2026	85.1	9.7	4.1	0.8	0.3
2027	81.1	11.4	5.5	1.6	0.3
2028	77.1	13.2	6.9	2.4	0.4
2029	73.0	14.9	8.3	3.3	0.5
2030	68.7	16.7	10.4	3.5	0.7
2031	66.4	17.1	11.9	3.6	0.9
2032	64.1	17.6	13.5	3.7	1.1
2033	61.9	18.0	15.0	3.8	1.3
2034	59.7	18.4	16.5	3.9	1.5
2035	57.3	18.8	18.1	4.0	1.7
2036	55.0	19.2	19.7	4.2	2.0
2037	52.7	19.6	21.3	4.3	2.2
2038	50.4	20.0	22.8	4.4	2.4
2039	48.1	20.4	24.4	4.5	2.6
2040	45.8	20.8	26.0	4.6	2.8
2041	43.6	21.1	27.6	4.7	3.0
2042	41.4	21.5	29.1	4.8	3.3

This above discussion illustrates one example of how the components of FEI's renewable and low-carbon gas portfolio could evolve to reach the overall portfolio supply forecast. Although the individual components of that outlook are expected to fall within a range, and the actual amount of each component acquired will vary from year to year, this example illustrates how FEI will continue to make progress towards its GHG emission reductions goals.

In Exhibit B-17 of FEI's Revised Renewable Gas Program Application – Stage 2 proceeding, in response to BCUC IR 3.1 provided on May 16, 2022, FEI provided the following figure with its forecast volumes of renewable gas supply.

Restated Figure 8-3: Breaking out Renewables by Type



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Supply - Lignin	0.0	0.0	0.0	0.0	0.5	1.0	2.0	2.5	2.5	2.5	2.5	2.5
Supply - Syngas	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.5	1.5	2.5	2.8	3.0
Supply - H2	0.0	0.0	0.0	0.7	1.4	2.1	2.9	3.6	4.3	5.0	9.0	13.0
Supply - RNG	0.7	4.0	8.1	11.4	13.1	15.3	16.5	17.6	18.8	20.0	21.5	23.0
Demand - Renewable Gas Blend	0.0	0.0	0.0	5.5	6.4	6.9	8.2	9.3	10.6	11.8	16.1	20.2
Demand - Renewable Gas Connections	0.0	0.0	1.6	3.1	4.6	6.0	7.5	8.9	10.4	11.8	13.2	14.6
Demand - Voluntary Renewabe Gas	0.7	3.0	3.7	5.0	5.3	5.5	5.7	6.0	6.2	6.4	6.5	6.6

52.7 At a high level, please reconcile, with reasons, the above restated Figure 8-3 from Exhibit B-17 in FEI's Revised Renewable Gas Program Application – Stage 2 proceeding with Figure 6-3 from the Application along with the figure provided in the preceding IR. In the response, please explain why it appears approximately 42 PJ/year of renewable supply was forecast by 2032 in the restated Figure 8-3 as compared to approximately 70 PJ/year forecast in Figure 6-3 from the Application.

Response:

The difference in the cited figures has to do with timing of the two Applications. The Revised Renewable Gas Application was prepared in 2021 and filed in December 2021. It was developed based on the CleanBC Plan target of 15 percent Renewable Gas supply. The CleanBC Roadmap, when released in October 2021, set higher emissions reduction targets than were contemplated in the original CleanBC Plan. The higher volume of renewable and low-carbon gas forecast of 68PJ in 2032 was in consideration of these more recent CleanBC Roadmap targets illustrated in the DEP Scenario to meet the proposed GHGRS emissions cap. Please also refer to BCUC IR1 71.8.1.

On page 6-13 of the Application, 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).
>
> …

Over the past several years, FEI has incorporated RNG supply into the gas supply portfolio, and expects the amount of supply will continue to grow. FEI anticipates that the majority of this supply will be secured outside of FEI's service areas (i.e., off-system supply).

52.8 Please discuss whether FEI has a forecast of percent of supply that it expects to be directly connected to FEI's system (on-system) versus delivered to FEI's system through displacement (off-system).

52.8.1 If yes, please provide this forecast and how it was developed.

52.8.2 If not, please explain why not and whether FEI expects to have this forecast in future.

Response:

In the same way there is only one forecast of conventional gas supply in the Annual Contracting Plan (ACP), FEI has developed a single forecast integrating renewable and low-carbon gas supplies produced within BC (on-system) and produced outside of BC (off-system) for the LTRGP. FEI plans to continue this practice moving forward, because the price and availability of renewable and low-carbon gas are subject to evolving market forces which introduce significant uncertainty to such a forecast.

FEI does develop a shorter-term forecast (1-5 years) that breaks out the on-system and off-system gas supply for the ACP. This has been developed so that FEI can properly manage any adjustments to the short-term contracting strategies for storage, supply, and pipeline transportation resources to meet the peak day, winter design and annual load requirements, as discussed further in the response to BCUC IR1 52.9.

The following table is the RNG supply forecast that FEI used in the 2022/2023 ACP which was filed on May 1, 2022. For the 2022/23 gas year, the forecast was based only on the BCUC-approved projects at the time of the ACP filing, whereas the remaining four years (2023/24 to 2026/27) take into account the BCUC-approved projects as well as projects that have been filed with the BCUC and projects that are currently in negotiation.

Table 1: RNG Supply Forecast (2022/2023 Annual Contracting Plan)

Gas Year	2022/23		2023/24		2024/25		2025/26		2026/27	
	Off-System	*On-System*	*Off-System*	*On-System*	*Off-System*	*On-System*	*Off-System*	*On-System*	*Off-System*	*On-System*
(TJ/day)	*13.2*	*2.6*	*30.6*	*6.3*	*42.8*	*7.5*	*47.3*	*7.7*	*47.9*	*7.7*
Total Supply (TJ/day)	**15.8**		**36.9**		**50.3**		**55**		**55.6**	

52.9 Please discuss whether FEI expects changes in the amount of on-system versus off-system supplies may affect FEI's gas supply planning processes and or gas supply contracting strategies. Please explain why or why not and at a high level, any impacts expected.

Response:

FEI's gas supply planning processes and contracting strategies are structured to plan for any changes in the amount of on-system versus off-system supplies.

As discussed in Section 6.2.3 of the Application, FEI expects these supply arrangements to be primarily off-system and delivered at the AECO/NIT or Station 2 hubs by way of displacement. As a result, FEI continues to require the equivalent level of third-party pipeline capacity contracts and infrastructure to provide the same level of service as if the supply was conventional natural gas. As off-system supplies increase, FEI will assess decreasing conventional natural gas commodity purchases at those supply hubs on an annual basis, as part of the annual contracting review that already occurs within the ACP process.

In terms of increasing on-system supply, FEI's gas supply contracting strategies would assess reducing its upstream infrastructure, which could include conventional natural gas purchases and third-party pipeline contracts. This assessment would consider the geographical location, contractual volume, and determine the firmness of the supply from the on-system production facilities, to ensure that FEI continues to contract enough secure and reliable resources to meet its customer demand requirements. In the short-term, FEI does not expect on-system supplies will be firm enough to reduce these resources in a substantial way, especially in comparison to the amount that FEI expects will come from off-system supply. As the volume of on-system supplies grow over the long term, FEI can and will adjust its portfolio through the flexibility of its existing commodity and transportation portfolio, as detailed in Section 6.2.4.3 of the Application.

On page 6-13 of the Application, FEI states:

> 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.

52.10 Please discuss whether FEI expects purchases of other renewable and low carbon gas supplies (i.e.: hydrogen, syngas, and lignin) will have the same or similar contractual obligations to that described for RNG. Please explain why or why not.

Response:

FEI expects the purchases of other renewable and low-carbon gas supplies (i.e. hydrogen, syngas, and lignin) will have similar contractual obligations to those described in the preamble for RNG purchases. It is important to note that the renewable and low-carbon gas market is still in early stages of development and is therefore smaller in size when compared to the conventional natural gas market. This translates to contractual obligations that have less flexibility and optionality than for conventional natural gas purchasing. However, FEI notes that this was also common during the early stages of commercial transactions for acquiring conventional natural gas. FEI therefore expects that as renewable and low-carbon gas markets grow and evolve for all types of renewable and low-carbon gas supplies, so will elements of the contractual obligations.

52.11 Please discuss how, if at all, the difference in contractual obligations for FEI's renewable and low carbon gas supply as compared to conventional natural gas purchases impact FEI's overall supply portfolio, FEI's contracting strategies and FEI's price risk management principles.

Response:

The three major differences in contractual obligations for FEI's RNG supply as compared to conventional natural gas purchases is the length, firmness, and optionality of the RNG supply.

With respect to length, FEI's RNG contracts are for terms typically of 10 to 25 years, whereas FEI transacts for the majority of its conventional natural gas purchases on an annual basis for winter, summer, or one-year terms. FEI can and does enter into long-term conventional supply deals for terms typically of three to ten years and, in the future, increased amounts of renewable and low-carbon gas supply would likely reduce the volume of FEI's long-term conventional purchases. This would help FEI maintain flexibility in its overall supply portfolio as longer-term renewable and low-carbon gas supply contracts replace traditional and conventional natural gas contracts.

The difference in firmness between contracts is as discussed in the preamble. FEI's RNG contracts can have an annual or monthly supply requirement or a minimum daily firm amount, whereas FEI's firm conventional natural gas purchases are for a fixed GJ/day delivery for each day of the term of the transaction. Due to the potential variability in renewable gas supply, FEI monitors any fluctuations in nominated supply to ensure that it is supplying secure and reliable firm supply service for its customers. FEI is also actively working to minimize the difference between the minimum and maximum volumes in future RNG contracts.

Lastly, RNG contracts can have contractual terms and obligations that provide optionality to the seller. For example, an RNG contract for off-system supply can have multiple nominated delivery points listed (i.e., Huntingdon or AECO/NIT). As FEI discusses in Section 6.2.3 of the Application, FEI expects that RNG supply going forward will be delivered primarily at the AECO/NIT or Station 2 hubs.

For discussion regarding the impact on price risk management principles, please refer to the response to BCUC IR1 52.18.

On page 6-15 of the Application, FEI states:

> In the past, FEI contracted pipeline capacity on third-party pipelines based on the winter design load requirements of its Core customers. Since 2019, FEI has maintained contingency resources within the ACP portfolio and FEI plans to continue this practice for the foreseeable future. Contingency resources are resources (e.g., supply, LNG, and pipeline infrastructure) above the current load forecast for Core customers that can be called on if planned resources are unexpectedly not available or insufficient to meet demand. Each year, FEI will determine a planning margin for contingency resources based on market conditions (e.g., supply risks, and fully or de-contracted regional resources).

52.12 Please discuss the volumes of contingency resources that FEI has maintained since 2019 (in PJ and % of overall supply, if possible).

Response:

The volumes of contingency resources that FEI has maintained since 2019, forecast in each Annual Contracting Plan (ACP) for the upcoming contract year, are provided in the below table. The contingency resources maintained since 2019 are not evaluated on the basis of overall commodity supply, but rather on the pipeline infrastructure required to serve Core customers from T-South to Huntingdon in the event of an incident or disruption. The contingency resources were implemented to mitigate the risk of future supply disruptions, given the market conditions in the region. FEI determined that a planning margin of approximately 15 percent was reasonable taking into consideration what occurred during the T-South incident and, specifically, the National Energy Board's orders[60] restricting the operating pressure of the T-South pipeline.

	2019/20 ACP	2020/21 ACP	2021/22 ACP	2022/23 ACP
Contingency Resources (TJ/day)	96	89	94	89
As Percent of Forecast Huntingdon Requirements (%)	17.9	14.6	15.5	14.6

FEI cannot provide a contingency resource forecast for future years, because the need for these resources is based on load forecasts that are updated annually, as well as market conditions assessed through FEI's Annual Contracting Plan.

[60] Canada Energy Regulator Oversight of Pipeline Incidents: https://www.cer-rec.gc.ca/en/safety-environment/compliance-enforcement/cer-oversight-recent-incidents/archives/index.html.

52.13 Please discuss, at a high level, how FEI forecasts its contingency resources required for future years and if possible, please provide this forecast.

Response:

Please refer to the response to BCUC IR1 52.12.

52.14 Please discuss whether FEI's forecasted increase in renewable and low carbon gas supply may impact FEI's strategy regarding contingency resources.

52.14.1 If yes, please explain how FEI's strategy may be impacted and why.

52.14.2 If not, please explain why not.

Response:

FEI does not expect future renewable and low-carbon gas supply to have a material impact to FEI's strategy regarding contingency resources. As discussed in the response to BCUC IR1 52.12, FEI's current strategy regarding contingency resources is for the forecast demand requirements for Core customers at Huntingdon served by the T-South pipeline.

In the short to medium term, FEI expects that the majority of future renewable and low-carbon gas supply will be contracted off-system and delivered at AECO/NIT and Station 2, not at Huntingdon. Over time, FEI expects more of its out-of-province renewable and low-carbon supply to be delivered to AECO/NIT.

On page 6-20 of the Application, in discussing demand uncertainties, FEI states:

> There is uncertainty tied to the Diversified Energy (Planning) Scenario and FEI expects the continued development and expansion of renewable and low-carbon gas supply to address these policies. FEI expects increased gas use in the LCT sector. Reducing conventional natural gas supply, however, will not create a major risk to FEI's medium- to long-term supply portfolio planning strategy due to the contracting flexibility of FEI's portfolio:
>
> - Commodity Purchases – Although FEI has entered into some long-term supply commitments with counterparties, a majority of the gas supply purchased for the Core customers is negotiated on an annual basis and priced off a market

index. Therefore, FEI could easily reduce or resell the amount of commodity purchases if Core demand declines or is displaced with low-carbon supply.

- Transportation Capacity – FEI's transportation portfolio has been designed so that portions of capacity on third-party pipelines are up for renewal each year. This would allow FEI to de-contract a significant amount of its transportation capacity over a five-year period if it encounters a future with lower demand than expected in its planning scenario - the Diversified Energy (Planning) Scenario.
- Storage Portfolio – FEI's approach to storage contracts is similar to the transportation portfolio; however, the contract terms may not necessarily expire on an annual basis but on a two or three-year period. Storage contracts are more difficult to manage because there are no renewal rights embedded in the contract terms, so FEI must balance term length versus the risk of losing access to storage supply. In any case, if the load duration curve changes over time such that less storage supply is needed, FEI will still have the ability to determine, as a long-term solution, an approach to de-contracting storage resources.

52.15 Please discuss whether the contracting flexibility of FEI's supply portfolio described above may be impacted due to the forecasted increase in renewable and low carbon gas supplies. Please explain why or why not.

Response:

FEI does not expect the forecasted increase in renewable and low-carbon gas supplies to materially impact the contracting flexibility of FEI's supply portfolio. As discussed in the preamble, FEI has contracting flexibility in all three elements listed (commodity purchases, transportation capacity, and its storage portfolio), which also apply to renewable and low-carbon gas supplies. For additional detail on the flexibility for commodity purchases, please refer to the responses to BCUC IR1 52.9 and 52.11.

52.16 Please discuss the current ratio of long term versus short terms commodity contracts and whether and how FEI expects this ratio to change over the planning horizon of the LTGRP.

Response:

FEI has maintained long-term supply ranging between 40 percent and 65 percent of its Station 2 Baseload supply requirements. Maintaining this range will avoid undue exposure and reliance on purchasing large quantities of Station 2 supply on the spot market and on a seasonal or annual term basis. This range also offers FEI enough flexibility to manage various changes that may occur to the portfolio over the long term, including evolving market conditions and updated load forecasts. FEI may target the lower range (i.e., 40 percent) or choose to reduce this range over the planning horizon of the LTGRP, as more renewable gas is incorporated into FEI's gas supply portfolio over the long term.

Table 1: FEI's Total Baseload Supply Portfolio Commitment to Long-Term Strategies (TJ/day)

	2017/18	2018/19	2019/20	2020/21	2021/22	2022/2023
Station 2 Supply Required - (Commodity Baseload)	254	280	309	312	308	313
Supply Commitments to Long Term Strategies	125	185	161	141	120	130
Portfolio Commitment to Long Term Strategies	**49%**	**66%**	**52%**	**45%**	**39%**	**42%**

On page 6-23 of the Application, within the section on 'Short Term Actions', FEI states: "Until new infrastructure is added in the region, FEI's contracting strategy will continue to hold more resources than the Core customers require within its portfolio of resources"

52.17 Please discuss, at a high level, what infrastructure FEI considers would be required to change its contracting strategy with regards to contingency resources.

Response:

Currently, FEI's contingency resources apply to pipeline capacity that it holds to deal with durational outages of upstream capacity. Therefore, until there is a new pipeline that follows a different path than what is available today, FEI would continue with the same strategy as it relates to pipeline contingency resources. New pipeline infrastructure like the RGSD project would reduce FEI's reliance on the T-South system, and would therefore change FEI's contracting strategy regarding contingency resources. As explained in the response to BCUC IR1 52.12, FEI maintains contingency resources to mitigate the risk of future supply disruptions due to FEI's reliance on the Westcoast T-South system.

On page 6-23 of the Application, FEI states:

> The price risk management tools discussed in this section have not yet been widely applied to renewable and low-carbon gases. However, with rapid industry growth and increasing supply availability expected over the planning horizon, FEI may seek to apply these tools and tactics to these renewable and low-carbon gas supplies as well. As renewable and low-carbon gas supply increases in its portfolio, FEI may look to use price risk management tools to help manage the costs for these supplies as well.

52.18 Please explain why FEI's price risk management tools have not yet been widely applied to its renewable and low-carbon gas supply contracts.

Response:

FEI's price risk management tools have not been applied to its renewable and low-carbon gas supply contracts because they have a long-term fixed price associated with the GJs purchased, which in itself is a form of price risk management. These contracts also have annual or monthly supply requirements or a minimum daily firm amount, as discussed in the response to BCUC IR1 52.11. This type of variability in supply can make it difficult to apply price risk management tools. However, as the renewable and low-carbon markets continue to grow, so should the liquidity of the market, which may lead to new contract/service offerings that could allow FEI to apply price risk management tools.

52.19 Please discuss what would trigger FEI to apply its price risk management tools to its renewable and low-carbon gas supply contracts.

Response:

Please refer to the response to BCUC IR1 52.18.

On page 6-24 of the Application, 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.

52.20 Please discuss FEI's view of the likelihood of a recall occurring, the expected volume of capacity that FEI currently holds that could be cut, and the timeframe this cut could be expected, if known.

Response:

FEI has a variety of storage contracts at the Mist storage facility, each with different capacities and expiry dates. As these contracts have no renewal rights, once they expire, NW Natural has the right to take back a portion, if not all, of the storage capacity for their customer load requirements. This is discussed in Section 6.6.2 of NW Natural's 2022 Integrated Resource Plan that was filed with the Public Utility Commission of Oregon on September 23, 2022:

> NW Natural has developed additional capacity in advance of core customer need. This capacity currently serves the interstate/intrastate storage (ISS) market but could be recalled for service to NW Natural's utility customers as those third-party firm storage agreements expire. [61]

NW Natural's 2022 IRP discussed customer exposure to the Sumas/Huntingdon market, and how this exposure will be "further exacerbated in 2027 when the Woodfibre LNG facility is expected to come online."[62] Their strategy to reduce this Huntingdon/Sumas supply exposure is to recall interstate/intrastate Mist storage capacity for the purposes of NW Natural's own use. Although the exact amount and timing is yet to be determined, FEI expects the recalls to cut into its existing Mist storage contracts starting in 2027 and that the cuts will be material.

The decision-making process to recall Mist capacity is somewhat similar to FEI's experience in 2019, when a portion of pipeline capacity on the Southern Crossing Pipeline (SCP) that was historically contracted out to regional parties was set to expire on October 31, 2019. FEI decided to take that capacity back in order to meet its own demand growth, and to further diversify FEI's supply portfolio. FEI and NW Natural continue to have discussions regarding this development, including preliminary discussions with NW Natural regarding the potential for NW Natural to further expand its Mist storage facility.

Further on page 6-24 of the Application, FEI states:

> In the long-term, FEI will proactively assess the need for market area storage, as impacted by future peak demand, its winter load profile, and the daily balancing requirements of the system in normal operations. FEI has had some preliminary discussions with NW Natural regarding the potential to contract for long-term non-recallable capacity. In order for this to occur, NW Natural would have to further expand its Mist storage facility.

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[61] NW Natural, 2022 NW Natural Integrated Resource Plan (September 2022) at Section 6.6.2, online at: https://edocs.puc.state.or.us/efdocs/HAA/lc79haa174551.pdf.

[62] 2022 NW Natural Integrated Resource Plan (September 2022), "Exposure to Sumas", p. 209 online at: https://edocs.puc.state.or.us/efdocs/HAA/lc79haa174551.pdf.

52.21 Please discuss whether FEI is aware of the likelihood of a Mist storage facility expansion occurring and the timeframes it may occur.

Response:

FEI is aware that a Mist storage facility expansion could be developed and in service no earlier than 2027. The completion timeline is extremely difficult to determine due to the regulatory and environmental challenges associated with developing this type of project.

On page 6-29 of the Application, is discussing recommended actions that FEI will take to manage FEI's gas supply portfolio FEI states:

> Assess the firmness of renewable and low-carbon gas supplies for year-round delivery to customers and assess the evolving marketplace for opportunities to apply traditional portfolio risk mitigation mechanisms to these renewable and low-carbon supplies.

52.22 Please expand more specifically on the actions FEI intends to undertake in the above action item.

Response:

FEI is already undertaking, and will continue to undertake, the following actions to assess the firmness of renewable and low-carbon gas supplies and assess the marketplace for opportunities:

- Monitoring daily and monthly renewable natural gas deliveries for both on- and off-system projects by delivery point (market hub) to assess variability of supply and whether adjustments of conventional natural gas purchases need to be made.
- Administering an internal quarterly update on upcoming renewable natural gas supply projects' in-service dates, to assess the impacts of acceleration or delays of supply projects within the upcoming 1-2 years.
- As part of the development of its Annual Contracting Plan, FEI will continue to refine its planning strategies to effectively manage the increasing amounts of renewable and low-carbon gas supplies into the portfolio, including options to apply traditional portfolio risk mitigation. FEI will continue to meet with BCUC staff on annual basis to discuss important areas of focus for future Annual Contracting Plans, including discussing the development of these strategies to manage the increasing amounts of renewable and low-carbon gas supplies into the portfolio.

53.0 Reference: GAS SUPPLY PORTFOLIO PLANNING

Exhibit B-1, Section 6.2.4.3, p. 6-20; Energy Scenarios – Stage 2 Submissions, Exhibit B-4, pp. 4 —5

FEI Energy Scenarios Stage 2

In FEI's Energy Scenarios Stage 2 submissions, Exhibit B-4, on pages 4 and 5, FEI provides the Total Energy Demand results (both electricity and gas) in Table 1a for residential, commercial and industrial customers as presented in each of FEI's and BC Hydro's Stage One filings.

On page 6-20 of the Application, FEI explains the contracting flexibility of its supply portfolio.

53.1 Please discuss whether FEI considers the contracting flexibility of FEI's supply portfolio described on page 6-20 of the Application can accommodate the gas demand forecasted for each of the scenarios modelled, such as BC Hydro's Reference Case and Accelerated Electrification scenarios. Please explain why or why not.

Response:

Confirmed. FEI expects that the contracting flexibility of FEI's supply portfolio can accommodate the annual gas demand shown in Table 1a of FEI's Energy Scenarios Stage 2 submissions. However, it is important to note that the BC Hydro Reference Case scenario is silent with regard to the potential for deep decarbonization of gas infrastructure through energy efficiency, transitioning to renewable and low-carbon gas to displace conventional natural gas for buildings and industry, and does not explicitly consider low-carbon gas for displacing higher carbon fuels in transportation.

Moreover, the BC Hydro Accelerated Electrification scenario did not factor in increased gas demand for LNG opportunities (both domestic and international). For these reasons, there is limited consideration within BC Hydro's scenarios of the extent to which renewable and low-carbon gases can play a role in decarbonizing BC's overall energy systems, as well as the extent to which these emission reduction initiatives could mitigate the decline in annual gas demand. Therefore, FEI does not find these scenarios appropriate to evaluate or assess when developing contracting strategies for its supply portfolio.

Nevertheless, the total annual energy demand in BC Hydro's Reference Case for Residential, Commercial, and Industrial customers grows from 209 PJ per year in 2025 to 223 PJ per year in 2040. As the BC Hydro Reference Case contains minimal forecast renewable and low-carbon gas supply (as shown in Figure 1 of FEI's Energy Scenarios Stage 2 submissions), FEI expects that it would contract additional conventional natural gas purchases on a summer, winter and annual term basis.

In BC Hydro's Accelerated Electrification scenario, the total annual energy demand declines to 91 PJ per year in 2040. FEI is able to monitor and manage any potential declines in demand or conventional commodity purchases by 2040, through the contracting flexibility of its portfolio, as discussed in Section 6.2.4.3 of the Application. For example, if the Core demand declines, FEI could reduce or resell the amount of commodity purchases. FEI's transportation portfolio has portions of capacity that are up for renewal each year, so each year FEI would assess whether it would need to de-contract any transportation capacity. FEI's flexibility in its storage portfolio is similar to the transportation portfolio, except that portions of storage are up for renewal typically on a two- or five year period. However, if significant de-contracting for third-party infrastructure occurred across the region (i.e., not just by FEI), this could have broader implications for the reliability and resiliency of the overall energy system in the Pacific Northwest.

F. SYSTEM RESOURCE NEEDS AND ALTERNATIVES

54.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Section 7.2.3.1, pp. 7-7 – 7-8; Section 7.2.3.2, p. 7-8, Section 4.4.1.2, p. 4-9

Traditional Peak Method

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

> FEI's Traditional Peak Method forecast is built from a "load gather" process that determines unique daily and hourly UPCpeak values for each customer. Values for most customers are based on a regression analysis of average consumption against local temperature using the most recent 24 months of consumption information extracted from monthly meter read data. Measured values are then extrapolated to the regional design temperature where the customer is located. The regional design temperature represents a one in 20-year value determined for each region.

54.1 Please describe, in detail, the load gather process for determining UPCpeak values and provide a sample calculation for each customer class.

Response:

FEI's load gather process for calculating the peak use per customer (UPCpeak) for Residential and Commercial rate schedules is described in detail below.

For customers with meters that are read monthly (residential and commercial customers in Rate schedules 1,2 and 3), the peak day consumption must be calculated from monthly meter readings. The process for each of these rate schedules is identical and is shown in the examples below in detail.

In the "load gather" process, FEI extracts each customer's monthly billing information for the preceding two-year period. Using a custom software application, the customer billing information and temperature information from the local weather zone index weather stations is reduced to a daily average demand and an average mean daily temperature in each billing period. This results in up to twenty-four "daily demand" versus "mean daily temperature" data points, determined based on the customers' most recent 24 months of consumption. A linear regression for each customer is performed on this data and the base load and slope (GJ/day/degree Celsius) is calculated. The peak day demand for the customer equates to the customer's demand, projected using the derived base load and slope of the linear equation to the Design Degree Day (DDD) temperature for the weather zone where the customer resides. This results in an estimate of the daily demand on the Design Degree Day.

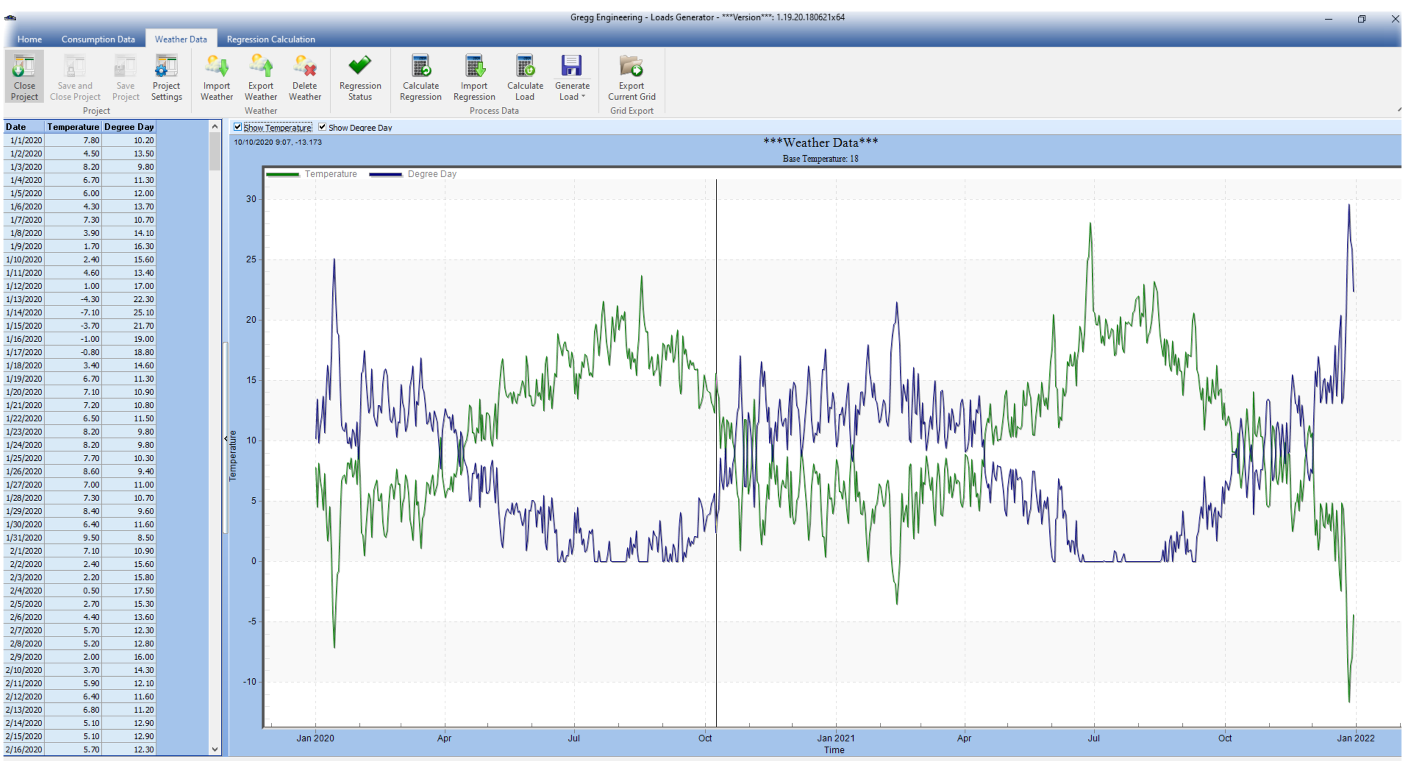
FEI's DDD temperature for any system operating within a region is the coldest day that is statistically likely to occur only once in any given 20-year period. In determining the DDD value, FEI uses an extreme value statistical method called the Gumbel Method of Moments. This method returns the expected extreme value for a given historical data set based on a specified return period. FEI uses a 1 in 20 return period on a data set that represents the coldest recorded daily mean temperature at the region's weather station each winter over a 60-year period. This method is described in more detail in the response to BCUC IR1 55.1.1

The DDD temperature values for weather zones across FEI's operating area range from a 27.8 Degree Day (DD) (corresponding to minus 9.8°C mean daily temperature) in the Comox Courtenay regions on Vancouver Island to a 60.4 DD (corresponding to minus 42.4°C mean daily temperature) in Fort Nelson. FEI calculates a design temperature in 22 different regions for the purposes of determining system capacity and peak day demand. The regional DDD values are based on up to a 60-year weather history as reported by Environment Canada at airport weather stations within each region.

The following describes the 2022 calculation process for three customers in rate schedules where only monthly consumption is available, one residential (Rate 1), one small commercial (Rate 2), and one large commercial (Rate 3) customer in the lower mainland community of North Vancouver. The process for all customer classes is the same so the explanation is more detailed for the first Rate 1 example, and the other rate schedule examples are summarized.

North Vancouver is in the Vancouver (YVR) weather zone, so the daily weather forecast for YVR from January 1, 2020, to December 31, 2021, is an input into the calculations. Figure 1 below represents the weather record at YVR for that period that was loaded into the load generating software. The data is shown as both the mean daily temperature (green) and the equivalent DD (blue).

Figure 1: YVR weather history



Residential Example:

Figure 2 below shows the monthly consumption history for a Rate 1 customer in North Vancouver. To ensuring confidentiality customer identifiers like premise numbers are obscured in the figures. The results for the selected customer (indicated with the red arrow) show monthly consumption in tabular and graphical form.

Figure 2: Monthly Consumption History Residential Example (GJ)

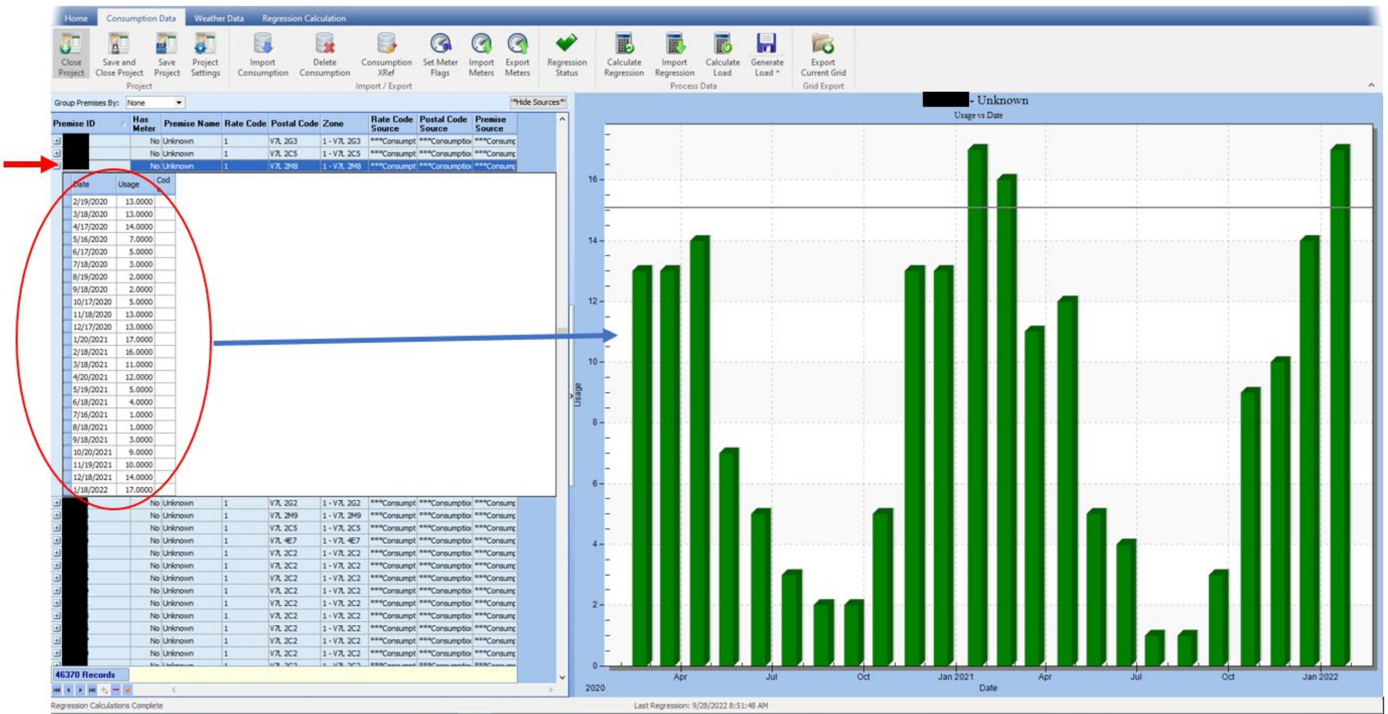
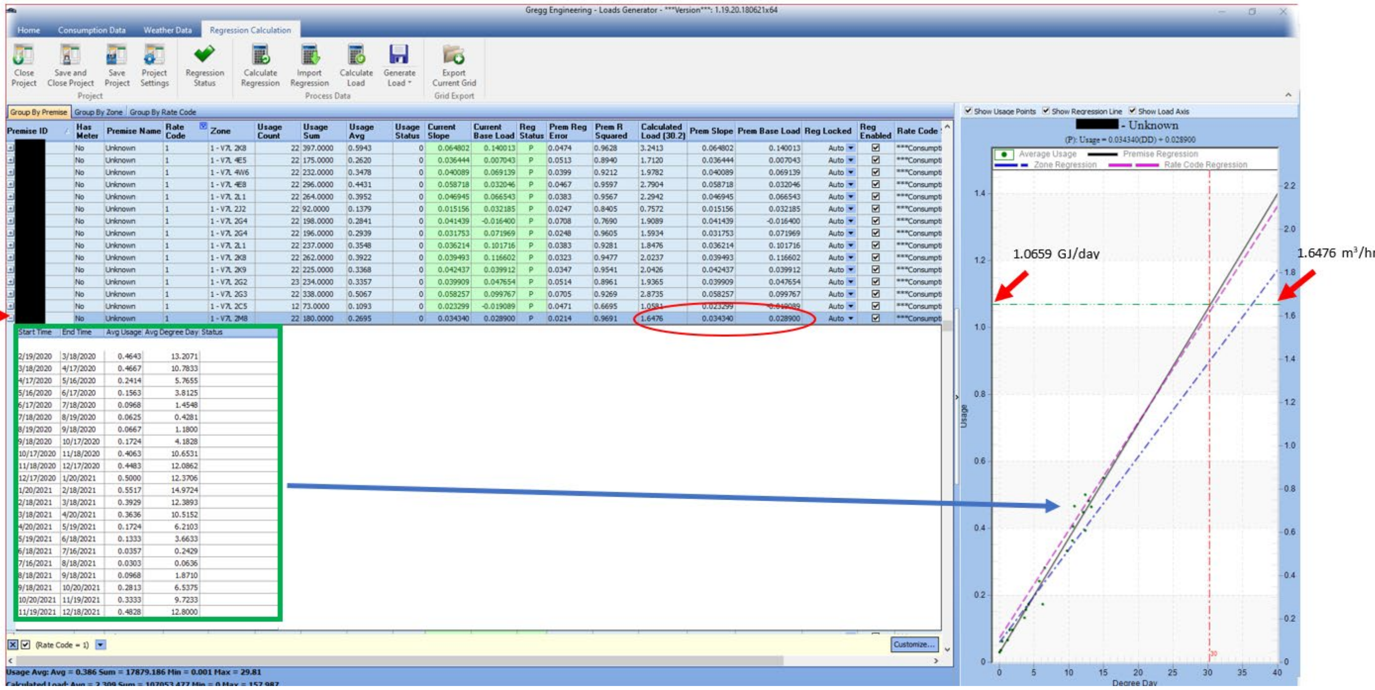


Figure 3 shows the result of combining the weather and usage information in Figure 1 and Figure 2 to establish average consumption (GJ/d) and average temperature (Ave DD) values for each billing period in the customers consumption history. The results for each billing period are shown in tabular form (highlighted by the green box) and are plotted in the graph on the right-hand side of the figure.

Figure 3: Estimating the Linear Relationship to Determine Peak Day and Peak Hour Usage



Simple linear regression is performed on the data to determine the formula of a straight line that best fits the data minimizes the deviation of the data point from the linear formula. The results of the regression analysis provide the slope of the temperature versus the demand line and the Y intercept (values circled in the columns marked “Prem Slope” and “Prem Base Load”). The linear formula takes the form:

*Usage (GJ/day) = Prem Slope (GJ/day)/DD * (DD) + Prem Base Load (GJ/day)*

This formula will provide this customer’s estimated peak day usage when the DDD (30.2 DD for YVR) and the Premise Slope and Premise Base Load from the data regression are used in the formula as follows.

*Usage (GJ/day) = 0.034340 (GJ/day)/DD * (30.2DD) + 0.0289 (GJ/day)*

Peak Day Usage =1.0659 GJ/day (identified on left Y-axis in Fig. 3)

The dashed green line in the graph in Figure 3 is located where the DDD value intersects the temperature versus demand line for the customer and illustrates the peak day and peak hour values for this customer showing the peak day values (GJ/day) on the left Y-axis and peak hour values (m^3/hr.) on the right Y-axis. The conversion from peak day to peak hour is calculated using the formula:

*Peak Hour Usage (m^3/hr.) = (Peak Day Usage (GJ/day) * Peak Hour Factor *1000)/HV (MJ/ m^3)*

The peak hour factor is derived from the relationship of peak hour observed at local gate stations and is the ratio of the peak hour flow to the total daily flow. For the coastal region a peak hour factor of 0.06 is applied. The heating value (HV) for the Coastal Region is 38.812 MJ/ m^3

Using this formula, the peak hour usage for this residential customer is:

*Peak Hour Usage (m^3/hr.) = (1.0659 GJ/day * 0.06*1000)/38.812 MJ/m^3)*

Peak Hour Usage = 1.6476 m^3/hr. (identified on right Y-axis in Fig. 3)

Small Commercial Example:

As discussed earlier the process for the small commercial and large commercial customers is the same. Figures 4 and 5 below provide results for a small commercial (Rate 2) customer in North Vancouver. Figures 6 and 7 provide the results for a large commercial (Rate 3) customers in North Vancouver.

Figure 4: Monthly Consumption History Small Comm. Example (GJ)

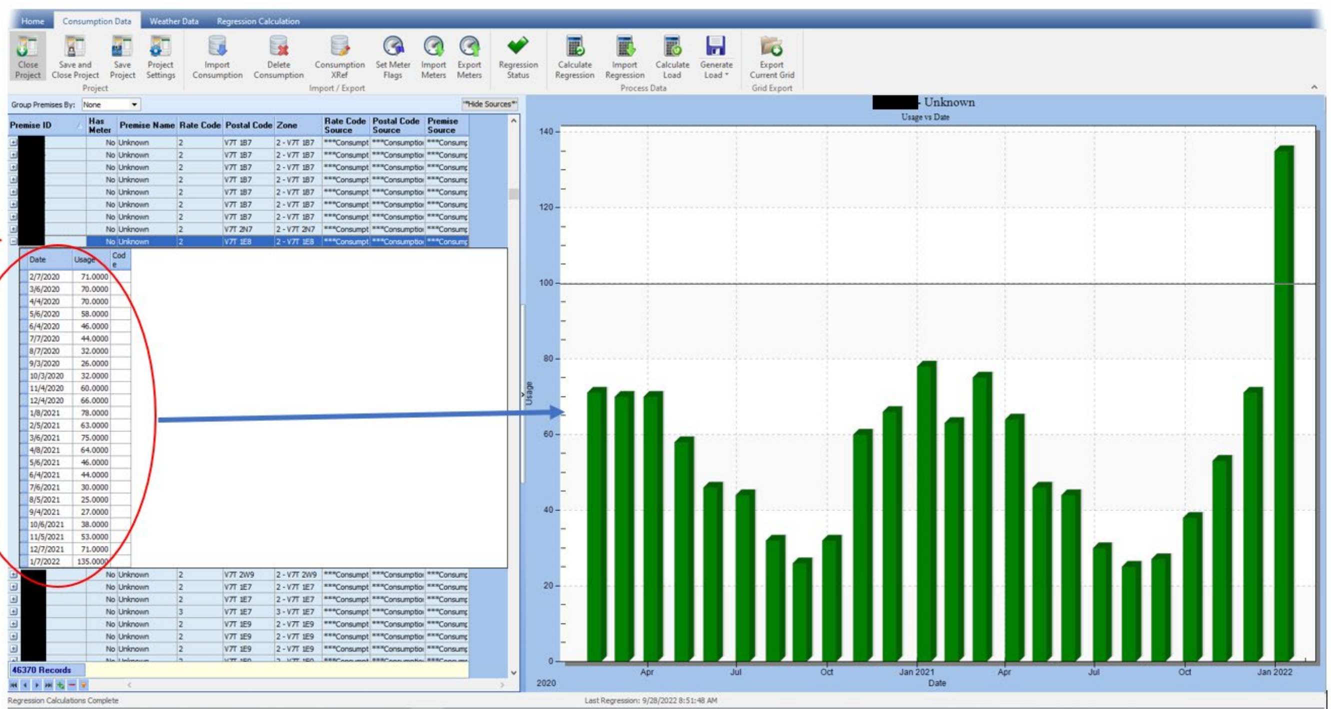
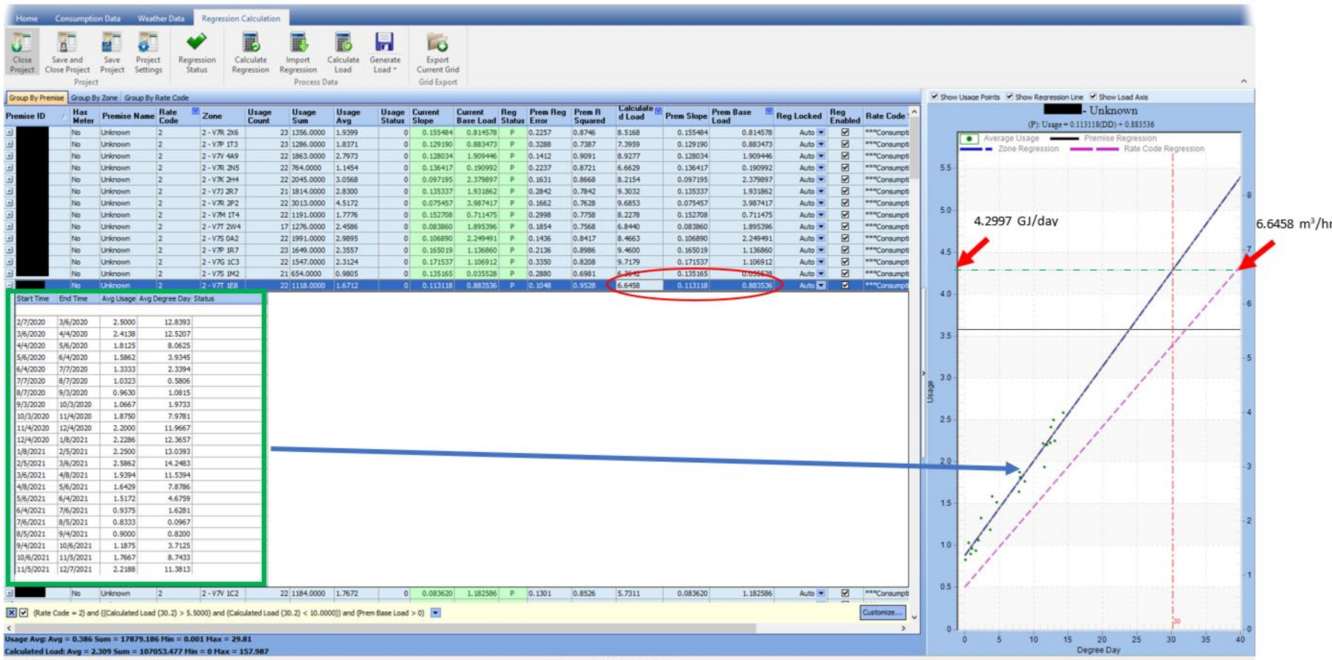


Figure 5: Estimating the Linear Relationship to Determine Peak Day and Peak Hour Usage



This small commercial customer's estimated peak day usage and peak hour usage (at a 30.2 DD) using the results of the regression and the peak day usage formula presented earlier are:

*Usage (GJ/day) = 0.113118 (GJ/day)/DD * (30.2DD) + 0.883536 (GJ/day)*

Peak Day Usage =4.2997 GJ/day (identified on left Y-axis in Fig. 5)

*Peak Hour Usage (m^3/hr.) = (4.2997 GJ/day * 0.06*1000)/38.812 MJ/m^3)*

Peak Hour Usage = 6.6458 m^3/hr. (identified on right Y-axis in Fig. 5)

Large Commercial Example:

Figure 6: Monthly Consumption History Large Comm. Example (GJ)

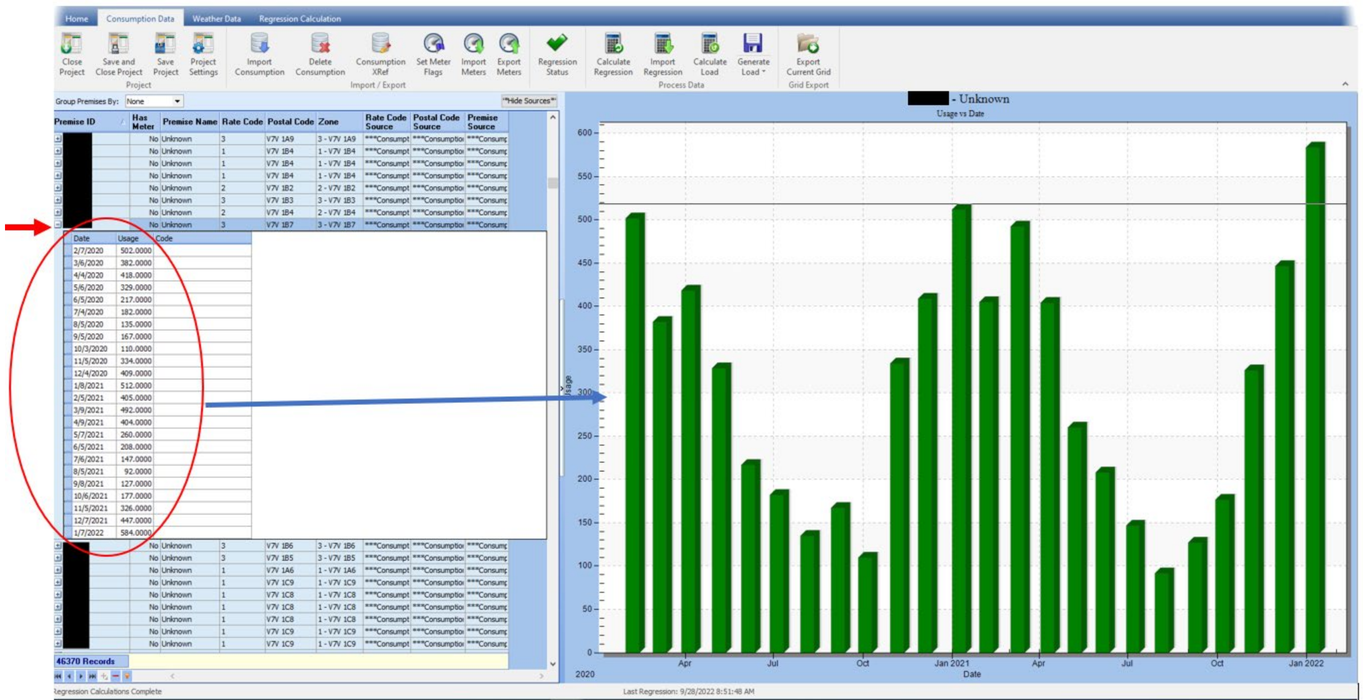
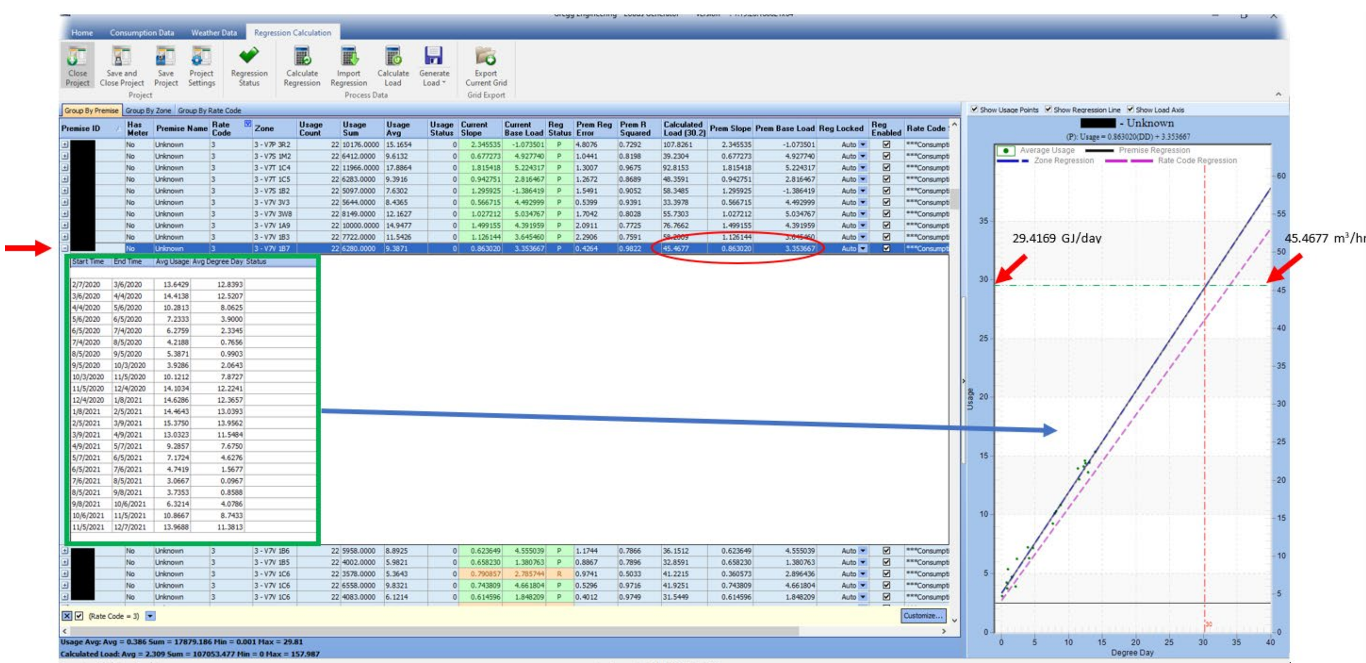


Figure 7: Estimating the Linear Relationship to Determine Peak Day and Peak Hour Usage



This large commercial customer's estimated peak day usage and peak hour usage (at a 30.2 DD) using the results of the regression and the peak day usage formula presented earlier are:

*Usage (GJ/day) = 0.863020 (GJ/day)/DD * (30.2DD) + 3.353667 (GJ/day)*

Peak Day Usage =29.4169 GJ/day (identified on left Y-axis in Fig. 7)

*Peak Hour Usage (m^3/hr.) = (29.4169 GJ/day * 0.06*1000)/38.812 MJ/m^3)*

Peak Hour Usage = 45.4677 m^3/hr. (identified on right Y-axis in Fig. 7)

On page 7-8 of the Application, FEI states:

> UPC_{peak} values used in the Traditional Peak Method forecast are determined based on current measured consumption for customers. When applied to the 20-year account forecast to determine the peak demand forecast, these values are assumed to remain unchanged over the planning horizon. As such, there is no explicit allowance for evolving customer utilization in this approach. The estimates of UPCpeak and the peak demand forecasts are "point in time" forecasts, however, and are refreshed annually. Therefore, assessments of future capacity constraints and timing upgrade projects are regularly refreshed with current customer consumption patterns and end uses that reflect the presently measured impacts of energy economics, housing renewal, and DSM programs…

For this LTGRP, FEI commissioned Posterity to develop an exploratory process linking peak demand forecasts to the end use scenarios used in the annual demand forecasts. Currently the process remains theoretical in nature and unsupported by direct measurement. Until such time as data from advanced metering becomes available, FEI's infrastructure planning continues to rely on the Traditional Peak Method which is predominantly based on current monthly consumption of FEI customers.

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

> For resources planning purposes, FEI uses the "End Use Annual Method" of demand forecasting. As described in Section 2.4, end use energy solutions and the way in which customers are using energy is changing and <u>historical trends are not robust enough</u> to provide the best basis on which to forecast the long-term potential range of FEI's future demand. [Emphasis added]

54.2 Please explain, with evidence, why historical trends are not robust enough to provide the best basis on which to forecast the long-term potential range of FEI's future energy demand.

<u>Response:</u>

The text underlined in this request, "historical trends", is referring to the Traditional Annual Method of demand forecasting. This method of forecasting based on historical trends is used in the BAU Scenario. All drivers of use rates are assumed to be intrinsic in the historical data used, and most importantly are assumed to continue to change at the trajectories captured in the historical data. As a hypothetical example, if 2 percent of customers switch from a gas furnace to a heat pump each year in the historical data, then in the BAU forecast that trend is assumed to continue, unchanged. While the BAU provides a useful baseline scenario, it is not expected to be the best basis on which to forecast long term demand when changes to the intrinsic drivers of demand are known or likely to occur. Continuing with the example above, the rate of heat pump adoption in the historical data will almost certainly be lower than the future rate. As a result, the historical data is not likely to be a good predictor of the future impact on use rates related to heat pump adoption, and as a result, an end use method with scenarios will produce a better forecast result. This is particularly true at a time when there are significant impacts from the energy transition on FEI's business.

54.3 Please confirm, or explain otherwise, that historical trends are the basis for the Traditional Peak Method forecast.

54.3.1 If confirmed, please explain whether this approach is more robust than the use of historical trends for long-term demand forecasting.

54.3.1.1 If more robust, please explain with supporting evidence.

54.3.1.2 If not more robust, please explain why this is the preferred approach and discuss in detail the risks of capacity planning based on this approach.

Response:

FEI does not use historical trends to determine the peak demand forecast. FEI uses a relatively short and most recent interval to capture a snapshot of the current relationship between consumption and the prevailing temperature and applies that current relationship throughout the forecast period without factoring in any historical trends in that relationship. In determining the traditional annual demand, historical trends are carried forward in the forecast. Further, FEI's Traditional Peak demand forecast uses historical extreme weather occurrence, but not trends in the data (warming or cooling), in determining regional design temperature (see the response to BCUC IR1 55.1). FEI considers the Traditional Peak Method of demand forecasting to be appropriately robust.

To explain further, in determining consumption (relative to prevailing temperature) FEI uses the most current available sets of metered consumption data and weather to determine the consumption versus temperature relationship customers are currently exhibiting (based on the most recent two-year period) and does not rely on historical trends to establish customers peak demand requirements (see the response to BCUC IR1 54.1). FEI, in following this process, captures the current impacts of DSM programs and energy policy and regulation that might exist in customer consumption patterns. FEI does not extrapolate that any historical trend in consumption under peak conditions can be applied to future peak demand because of the uncertainty that such trends would continue unchanged or decrease or increase in intensity in the future. FEI uses the current UPC_{peak} to reflect the demand of future customers when preparing the forecast. While the method will not fully reflect the impact of increased energy efficiency, DSM and conservation policy and regulations on UPC_{peak} in the future, the traditional approach allows FEI to minimize the risk of failing to identify and scope capacity upgrades that might be required to support future demand should conservation measures be less effective on peak demand than anticipated. FEI only begins CPCN applications and more detailed planning and design on the future upgrades when the project timing and scope (based on new assessments of UPC_{peak} prepared at that future time and reflecting future peak demand) continue to be supported by the updated peak demand forecast.

54.4 Please explain whether there are uncertainties associated with the Traditional Peak Method due to the absence of data from advanced metering.

Response:

FEI confirms there are uncertainties associated with the Traditional Peak Method due to the absence of data from advanced metering. While the Traditional Peak method is the best currently-available process to determine peak demand from monthly consumption data, it remains limited in that the daily profile of customer demand remains obscured in the monthly information. Changes that might impact peak hour consumption differently from daily consumption cannot directly be extracted from the data resulting in uncertainty as to how peak demand reduction activities can be measured. Advanced metering will allow peak hour and peak day variation to be measured directly and will improve FEI's certainty in measuring variations in peak hour and peak day consumption that might result from, for example, DSM activities, programs and/or measures directed at reducing peak demand.

54.5 Please discuss whether FEI is aware of natural gas utilities in other jurisdictions that rely on the end-use method as their primary method for capacity planning.

54.5.1 If so, please discuss whether any of these utilities are utilizing advanced metering infrastructure to implement the end-use method.

Response:

FEI is not aware of any natural gas utilities using an end use methodology in capacity planning. Appendix B-2 of the Application contains a demand forecasting methods benchmarking study in which 18 utilities were examined across multiple jurisdictions. The study includes information on how annual and peak demand forecasts are related for the utilities examined. The study identified a few cases of electric utilities utilizing an end use or hybrid end use method for peak demand forecasting, but no cases of gas utilities using an end use methodology for peak demand forecasting.

54.6 Please identify the base year used in Peak Demand Forecasting presented in the Application and provide rationale for the base year chosen.

Response:

The base year for the peak demand forecast was 2019 (referred to as the 2020 peak demand forecast). Customers attached on or before December 31, 2019 were accounted for in base demand and values for 2020, and future years included the peak demand of forecasted account additions. This base year for the peak demand forecast was used to be consistent with the base year used in annual forecasts in the Application. The base year chosen was the most recent base year and account forecast that would enable the extensive work in generating end use annual and peak demand forecast results to be completed and enable the 2022 LTGRP submission in spring of 2022.

54.6.1 If the base year is 2020 or earlier, please explain how FEI intends to account for any identified changes in customer energy usage patterns due to the COVID-19 pandemic and discuss the potential impact to Peak Demand Forecasting.

Response:

FEI has not changed its peak demand forecasting processes because of the COVID-19 pandemic. Any changes in consumption patterns due to the pandemic will be reflected in the annual renewal of the peak forecasts to the extent that pandemic-influenced changes are reflected in the monthly consumption data used to determine peak demand forecasts each year going forward. To the extent that pandemic influences on consumption are transient, their influence will appear and then subside when future forecasts are prepared. To the extent they are sustained, the impacts will remain in future forecasts.

54.6.2 If the base year is later than 2020, please explain how FEI accounted for any identified changes in customer energy usage patterns due to the COVID-19 pandemic and discuss the impact to Peak Demand Forecasting.

Response:

The base year used was before 2020. Please refer to the responses to BCUC IR1 54.6 and 54.6.1.

54.7 Please confirm, or explain otherwise, that the Peak Demand Forecasts for each of the regional transmission systems in the Application are the most recent Peak Demand Forecasts generated by FEI.

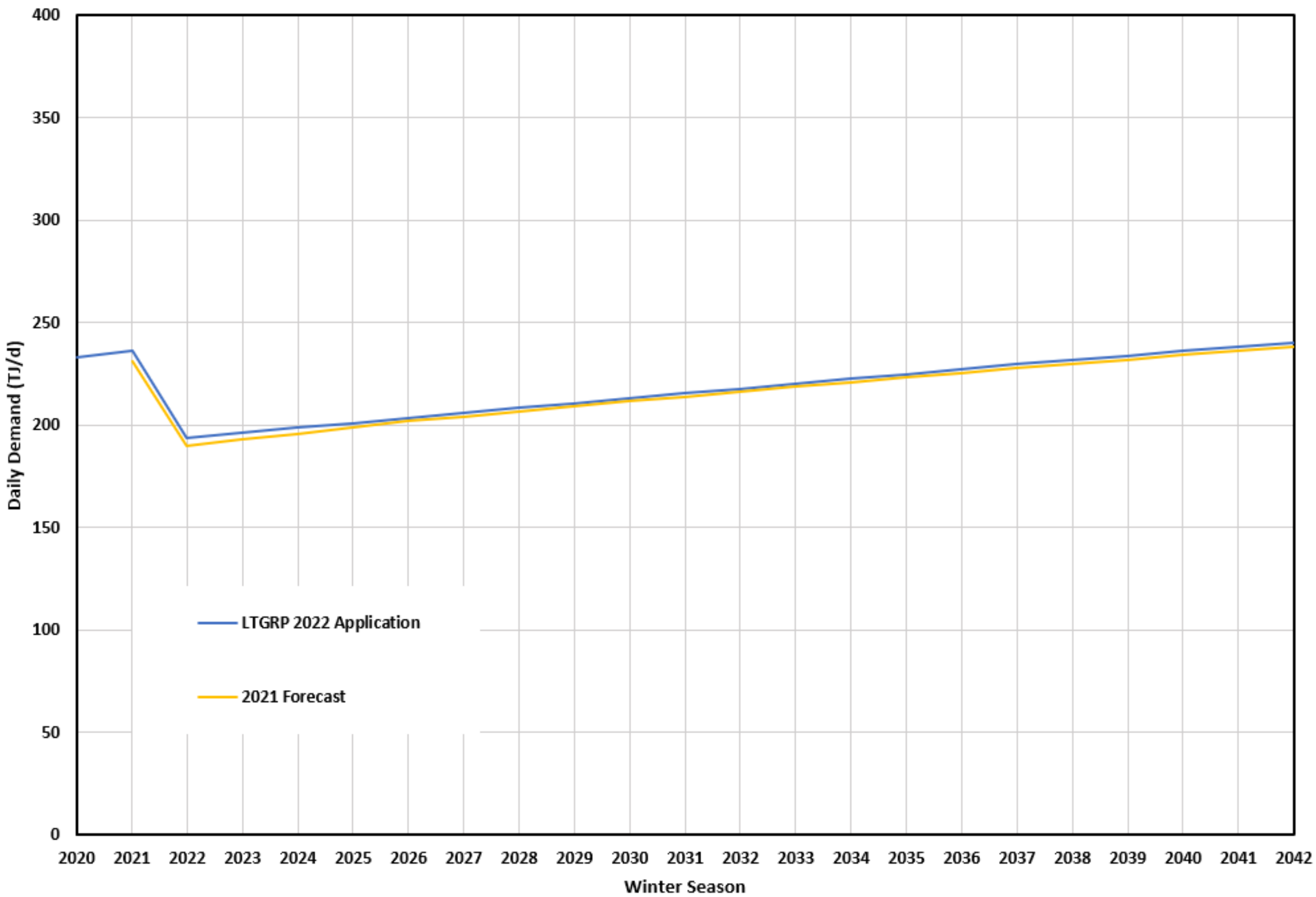
54.7.1 If yes, please identify the timing for completion and base year of the next Peak Demand Forecast for each regional transmission system.

54.7.2 If no, please provide figures for the latest Peak Demand Forecast for each regional transmission system and identify the base year. Please also identify the timing of completion for the next Peak Demand Forecast.

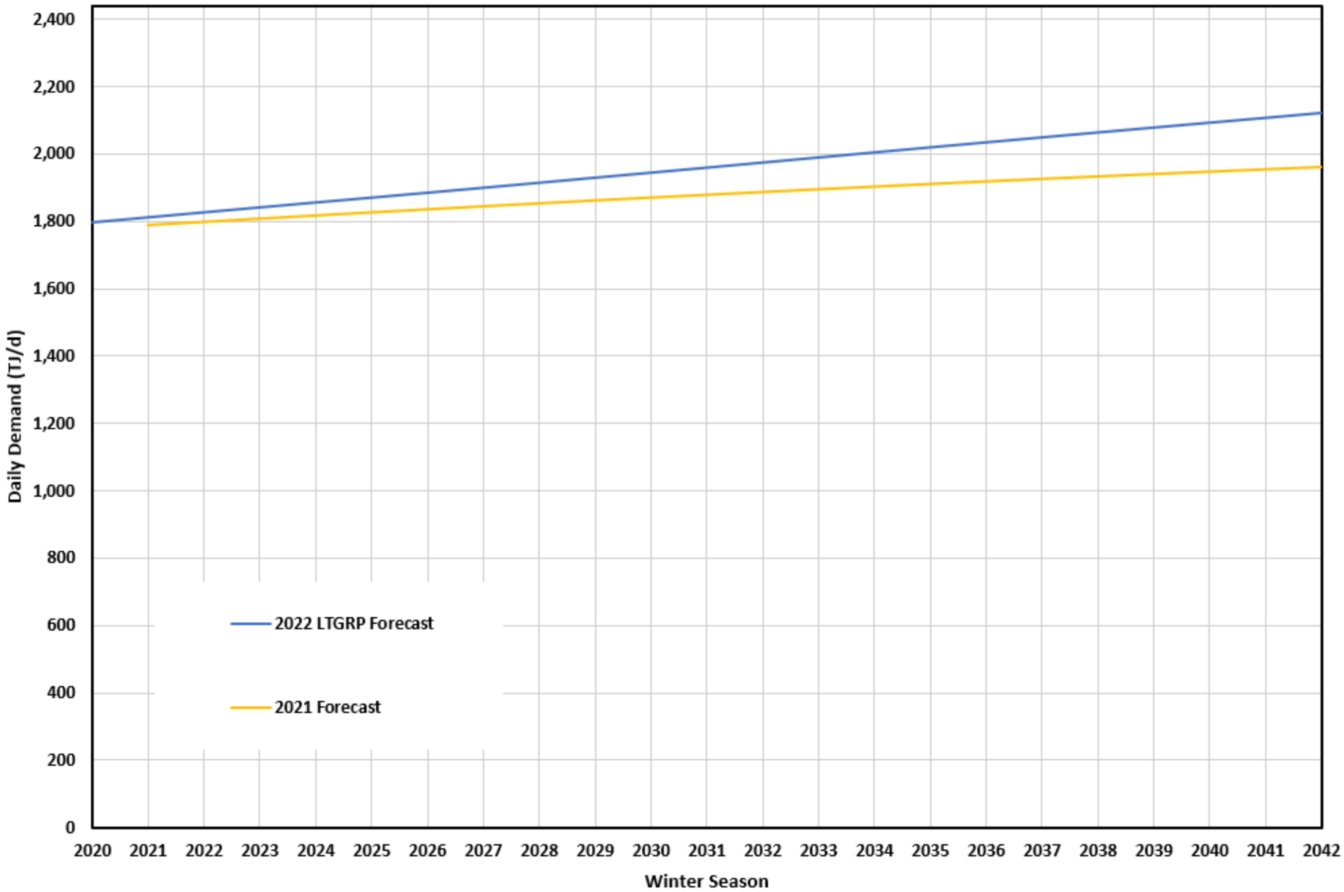
Response:

Not confirmed. FEI produces a peak demand forecast each year for each transmission system. FEI's most recent completed forecast for each system is the 2021 forecast (based on 2020 year-end customer attachments in all areas). FEI expects that the 2022 forecast (based on 2021 year-end customer attachments) will be completed by mid-December 2022. Please also refer to the response to BCUC IR1 56.6. The figures below show the most recent 2021 peak demand forecasts, compared to those used in the Application, for each transmission system.

Figure 1: VITS Traditional Peak Demand Comparison



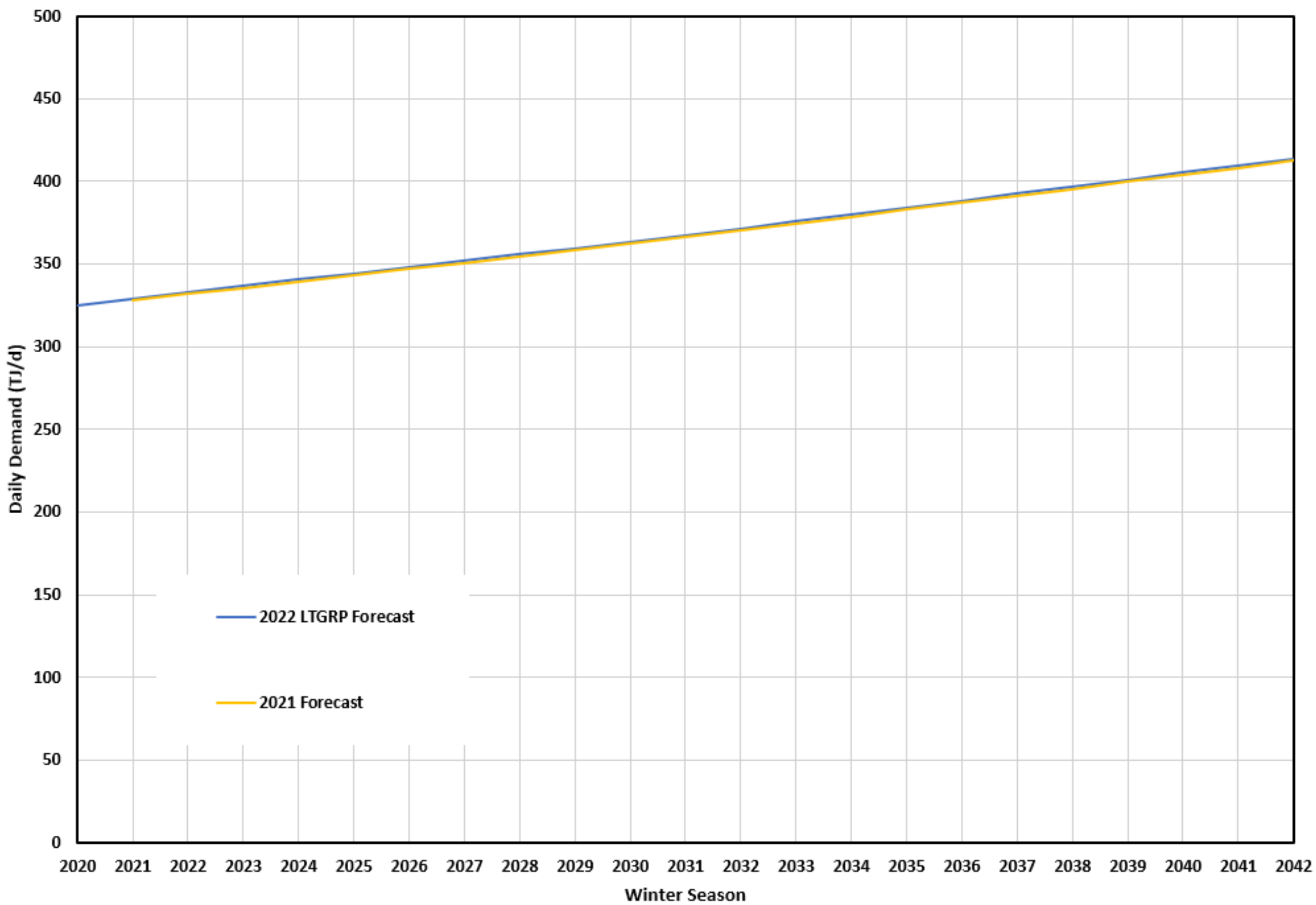
1 **Figure 2: CTS Traditional Peak Demand Comparison[63]**



2

[63] The drop in the starting point for the 2021 forecast from the forecast for the 2022 LTGRP is the result of commercial demand declining through 2020 and 2021 that is now recovering. This recovery will be reflected in the 2022 Traditional Peak forecast.

Figure 3: ITS Traditional Peak Demand Comparison



54.8 Please explain how evolving demand side measures and customer energy consumption patterns are reflected in the Peak Demand Forecast over the 20-year planning horizon.

Response:

Future evolution of DSM and customer consumption patterns are not reflected in the Traditional Peak Demand Forecasts. FEI uses the current UPC_{peak} to reflect the demand of future customers when preparing the forecast so current customer consumption patterns and DSM are reflected as continuing through the forecast. The end use forecasts, as discussed in Section 7.2.3.2 and presented in the figures in Section 7.3 of the Application, do provide a theoretical examination of the effects of DSM and anticipated changes in customer consumption on peak demand based on the inputs used in each end use scenario.

54.9 Please discuss FEI's outlook over the 20-year planning horizon on the impact of energy economics, housing renewal, and DSM Programs on capacity planning.

Response:

Over the 20-year planning horizon, FEI expects that energy economics, housing renewal increasing the proportion of energy-efficient homes, and DSM programs will all have some impact on peak demand, generally resulting in a reduction in peak demand. FEI is not certain that the impacts to peak demand will be as significant to peak demand as they will be to annual demand. Regardless, FEI expects that over time future UPC_{peak} will reflect these impacts and FEI will incorporate these changes in the peak demand forecasts. These year-over-year adjustments to peak demand, reflecting the impacts of such policy and programs, will allow capacity planning to refine the scope and timing of future projects FEI may have identified in previous 20-year forecasts.

54.9.1 Please discuss any uncertainty in this outlook and how it may impact capacity planning.

Response:

One large uncertainty in FEI's outlook on the future impacts of energy economics, housing renewal and DSM programs is related to the process of estimating the rate of change these programs and policies will produce on peak demand in the absence of hourly metering information to support these estimates. Another uncertainty is the point at which any such influence on peak demand will be exhausted. FEI's concern in applying and relying on assumptions around these estimates, particularly those that might assume more optimistic estimates of peak demand reduction, is that such reliance will result in a capacity planning process where future peak demand may be unrealistically suppressed. This could result in a circumstance where upgrade projects are not identified, scoped, and examined with sufficient lead time to implement solutions to address future capacity shortfalls.

54.10 Please explain whether the Traditional Peak Method forecast accounts for known or expected policy or regulations, on a provincial or municipal level, that are likely to impact peak demand for gas.

54.10.1 If confirmed, please discuss the policies and regulations accounted for and explain how they are considered in the Traditional Peak Method forecast.

54.10.2 If not confirmed, please explain why not, and discuss any policies or regulations that are likely to impact peak demand for gas over the planning horizon.

Response:

As with other potential future influences on peak demand discussed in the responses to BCUC IR1 54.8 through 54.9, future evolution of policy and regulation are not reflected in the Traditional Peak Demand Forecasts. The impacts of policy and regulation that are present in consumption data when the peak demand forecast is refreshed annually are represented in future traditional peak demand forecasts when they are prepared. End-use forecasts discussed in Section 7.2.3.2 and presented in the figures in Section 7.3 of the Application do provide a theoretical representation of the possible effects of regulation and policy and anticipated changes in customer consumption on peak demand based on the inputs used in each end-use scenario.

55.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Section 7.2.3.1, p. 7-7; FEI Application for a CPCN for the Okanagan Capacity Upgrade Project proceeding, Exhibit B-1-2, Section 3.3.1.1, p. 22, Exhibit B-2, BCUC IR 8.4,; Exhibit B-14, BCUC IR 43.2.1, 43.3.1

Weather and Climate Data

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

> [UPC_{peak}] Values for most customers are based on a regression analysis of average consumption against local temperature using the most recent 24 months of consumption information extracted from monthly meter read data. Measured values are then extrapolated to the regional design temperature where the customer is located. The regional design temperature represents a one in 20-year value determined for each region.

On page 22 of Exhibit B-1-2 in FEI's Application for a CPCN for the Okanagan Capacity Upgrade Project proceeding, FEI states:

> FEI's DDD [Design Degree Day] temperature for any system operating within a region is the coldest day that is statistically likely to occur only once in any given 20-year period. In determining the DDD value, FEI uses an extreme value statistical method called the Gumbel Method of Moments. This method returns the expected extreme value for a given historical data set based on a specified return period. FEI uses a 1 in 20-year return period on a data set that represents the coldest recorded daily mean temperature at the region's weather station each winter over a 60 year period.

In response to BCUC IR 8.4 in FEI's Application for a CPCN for the Okanagan Capacity Upgrade Project proceeding, FEI stated:

> FEI's peak demand forecast does not directly consider the potential impact of climate change on the DDD. FEI is not aware of a reliable method to forecast future changes in extreme weather either in severity or frequency (especially in the cold temperatures which set FEI's peak demand).
>
> However, FEI does apply trends in recent weather history (that may reflect climate change impacts) by periodically re-adjusting the DDD temperature used to estimate peak demand. FEI last updated the DDD for each of the 22 weather zones in its operating territory in 2017. These updates examined the weather history in each weather zone over the preceding 60 years. The last update resulted in a warming in the DDD temperature in most weather zones.

55.1 Please provide a table outlining the regional DDD temperature for the Interior Transmission System (ITS), Coastal Transmission System (CTS), and Vancouver

Island Transmission System (VITS) and provide evidence that each value is a one in 20-year value.

Response:

The table below outlines the regional DDDs that are used to determine the peak demand on each transmission system. Each transmission system spans more than one weather zone, each with a unique DDD as indicated in the table. Each DDD value was created using the method described in the response to BCUC IR1 55.1.1 using a return period of 20 years.

Transmission System	Regions served	Index Weather Station (Airport Code)	DDD	Mean Daily Temperature (C)
VITS	Squamish	Squamish (WSK)	32.9	-14.9
	Whistler	Whistler (WAE)	39.5	-21.5
	Powell River, Sechelt, Gibsons	Powell River (YPW)	29.0	-11
	Campbell River	Campbell River (YBL)	31.9	-13.9
	Comox, Courtenay	Comox (YQQ)	27.8	-9.8
	Nanaimo Region, Port Alberni	Nanaimo (YCD)	29.9	-11.9
	Victoria Region	Victoria (YYJ)	28.8	-10.8
CTS	Metro Vancouver	Vancouver (YVR)	30.2	-12.2
	Fraser Valley	Abbotsford (YXX)	32.5	-14.5
ITS	Kamloops	Kamloops (YKA)	46.7	-28.7
	North and Central Okanagan	Kelowna (YLW)	43.9	-25.9
	South Okanagan	Penticton (YYF)	39.1	-21.1
	West Kootenay	Castlegar (YCG)	39.7	-21.7

55.1.1 Please explain, with a sample calculation, how the regional DDD temperature is calculated for the purposes of the LTGRP.

Response:

The Design Degree Day (DDD) for each weather zone is calculated using the extreme value analysis (EVA) methodology. FEI determines the region's DDD to be equal to the 20-year return period value calculated using data from the index weather station representing the region.

The Gumbel Method of Moments is used to analyze historical information and assess or calculate what future extreme limits are probable in a specified return period. This process is used extensively to predict natural extremes and provides a basis for designing facilities to accommodate results of natural events such as earthquakes, landslides or floods in addition to designing energy systems to withstand extreme weather. The result of the analysis is referred to as the "Return Period" of an event.

The Return Period, T(t), is identified as the reciprocal of the probability of a value equaling or exceeding t (an extreme temperature), and is therefore calculated as follows:

$$T(t) = \frac{1}{(1-F(t))} \qquad \text{Eq. (1)}$$

where:

- $F(t) = e^{-e^{(\sigma(t-\mu))}}$
- σ and μ are the constants determined by regression
- $e^{(\ )}$ is the exponential function

The regression of annual extreme mean daily temperature data for a weather zone index station will determine σ and μ such that the sum of the squares of the error is minimized using the above formula. Once the equation has been solved, the Extreme Value Temperature, t, can then be solved using the following formula:

$$t = \mu + \frac{\ln\left(\ln\left(\frac{T}{T-1}\right)\right)}{\sigma} \qquad \text{Eq. (2)}$$

where:

- T is the return period as defined in Eq. (1)
- $\ln(\ )$ is the natural logarithm function

Based on Eq. (1) and (2), an iterative process for determining the optimal values of σ and μ is required. For T = 20 (return period of 20 years), the value “t” calculated above will be equivalent to the DDD temperature.

The following table presents a sample calculation process flow to derive the DDD for Metro-Vancouver (YVR) weather station based on the 60 years dataset between 1957 and 2016.

Sample Calculation Worksheet

<u>Step 1: Sort the data and assign initial value</u>

The coldest daily mean temperature of each year for each weather station between 1957 and 2016 (60 years) was collected in an Excel spreadsheet. The data was sorted from the smallest to the largest, presented in column C in the following table.

Extreme Value Analysis

Sample Calculation #1: Initial Value: σ = 0.5, μ = -15.2

σ	μ	Sum (Err^2)
0.500	-15.200	5290.523

Historic Weather			Return Period Regression			Theoretical and Actual Extreme Temperatures		
Rank	Year	Temp (°C)	Actual Return Period - R(t)	Theoretical Return - T(t)	Err^2	Actual Return Period - R(t)	Actual Temperature (°C)	Extreme Value Temperature, t (°C)
1	1968	-15.2	60.0	1.6	3412.7	60.0	-15.2	-23.4
2	1964	-12.6	30.0	1.0	839.5	30.0	-12.6	-22.0
3	1990	-11.8	20.0	1.0	360.8	20.0	-11.8	-21.1
4	1985	-11.7	15.0	1.0	195.9	15.0	-11.7	-20.5
5	1969	-11.6	12.0	1.0	120.9	12.0	-11.6	-20.1
6	2008	-10.3	10.0	1.0	81.0	10.0	-10.3	-19.7
7	1989	-9.5	8.6	1.0	57.3	8.6	-9.5	-19.4
8	1978	-9.2	7.5	1.0	42.2	7.5	-9.2	-19.1
9	1982	-9.2	6.7	1.0	32.1	6.7	-9.2	-18.8
10	1980	-9.1	6.0	1.0	25.0	6.0	-9.1	-18.6
11	1983	-9.1	5.5	1.0	19.8	5.5	-9.1	-18.4
12	1971	-8.9	5.0	1.0	16.0	5.0	-8.9	-18.2
13	1959	-8.8	4.6	1.0	13.1	4.6	-8.8	-18.0
14	1957	-8.7	4.3	1.0	10.8	4.3	-8.7	-17.9
15	1993	-8.5	4.0	1.0	9.0	4.0	-8.5	-17.7
16	1996	-8.5	3.8	1.0	7.6	3.8	-8.5	-17.5
17	2006	-8.4	3.5	1.0	6.4	3.5	-8.4	-17.4
18	1972	-7.9	3.3	1.0	5.4	3.3	-7.9	-17.3
19	1962	-7.7	3.2	1.0	4.7	3.2	-7.7	-17.1
20	2004	-7.6	3.0	1.0	4.0	3.0	-7.6	-17.0
21	1984	-7.5	2.9	1.0	3.4	2.9	-7.5	-16.9
22	1963	-7.4	2.7	1.0	3.0	2.7	-7.4	-16.8
23	1992	-6.7	2.6	1.0	2.6	2.6	-6.7	-16.7
24	2010	-6.4	2.5	1.0	2.3	2.5	-6.4	-16.5
25	1973	-6.0	2.4	1.0	2.0	2.4	-6.0	-16.4
26	2013	-5.9	2.3	1.0	1.7	2.3	-5.9	-16.3
27	1998	-5.8	2.2	1.0	1.5	2.2	-5.8	-16.2
28	2012	-5.7	2.1	1.0	1.3	2.1	-5.7	-16.1
29	2005	-5.5	2.1	1.0	1.1	2.1	-5.5	-16.0
30	1991	-5.3	2.0	1.0	1.0	2.0	-5.3	-15.9
31	2016	-5.2	1.9	1.0	0.9	1.9	-5.2	-15.8
32	1997	-4.8	1.9	1.0	0.8	1.9	-4.8	-15.7
33	2007	-4.8	1.8	1.0	0.7	1.8	-4.8	-15.7
34	1979	-4.6	1.8	1.0	0.6	1.8	-4.6	-15.6
35	1986	-4.6	1.7	1.0	0.5	1.7	-4.6	-15.5
36	2014	-4.5	1.7	1.0	0.4	1.7	-4.5	-15.4
37	2011	-4.4	1.6	1.0	0.4	1.6	-4.4	-15.3
38	1995	-4.3	1.6	1.0	0.3	1.6	-4.3	-15.2
39	1967	-4.0	1.5	1.0	0.3	1.5	-4.0	-15.1
40	1974	-3.8	1.5	1.0	0.3	1.5	-3.8	-15.0
41	1975	-3.8	1.5	1.0	0.2	1.5	-3.8	-14.9
42	1994	-3.8	1.4	1.0	0.2	1.4	-3.8	-14.8
43	1977	-3.7	1.4	1.0	0.2	1.4	-3.7	-14.7
44	1970	-3.6	1.4	1.0	0.1	1.4	-3.6	-14.6
45	1976	-3.5	1.3	1.0	0.1	1.3	-3.5	-14.5
46	1966	-3.3	1.3	1.0	0.1	1.3	-3.3	-14.4
47	1965	-3.0	1.3	1.0	0.1	1.3	-3.0	-14.4
48	1988	-3.0	1.3	1.0	0.1	1.3	-3.0	-14.2
49	2009	-2.8	1.2	1.0	0.1	1.2	-2.8	-14.1
50	1981	-2.7	1.2	1.0	0.0	1.2	-2.7	-14.0
51	2000	-2.7	1.2	1.0	0.0	1.2	-2.7	-13.9
52	1961	-2.5	1.2	1.0	0.0	1.2	-2.5	-13.8
53	2002	-2.2	1.1	1.0	0.0	1.1	-2.2	-13.7
54	1958	-2.0	1.1	1.0	0.0	1.1	-2.0	-13.5
55	1960	-1.9	1.1	1.0	0.0	1.1	-1.9	-13.4
56	2015	-1.4	1.1	1.0	0.0	1.1	-1.4	-13.2
57	1987	-1.0	1.1	1.0	0.0	1.1	-1.0	-13.0
58	2003	-0.5	1.0	1.0	0.0	1.0	-0.5	-12.8
59	2001	0.3	1.0	1.0	0.0	1.0	0.3	-12.4
60	1999	1.8	1.0	1.0	0.0	1.0	1.8	

In this 60-year dataset, the coldest day occurred in 1968 (mean daily temperature at -15.2°C). The actual return period, R(t), is 60 shown in column D. The initial values, σ = 0.5 and μ = -15.2, were input for the iteration process. The initial value for σ is generally selected between 0 and 1, whereas the initial value for μ is generally selected as the coldest temperature in the dataset.

Based on the initial value, the corresponding return period T(t) as presented in column E for each temperature can be calculated using Eq. (1).

For example, to calculate the value of cell E8 using Eq.(1) in Excel function:

= 1/(1-EXP(-EXP(0.5*(-15.2-(-15.2)))))

= 1.581977 = 1.6 (approximately, as presented in the table above).

The difference between R(t) and T(t) was then squared and summed and is shown as Err^2 in column F.

For example, to calculate the value Err^2 in cell F8:

$$Err^2 = \left(R(t) - T(t)\right)^2$$

where R(t) is the value in cell D8

= (60 – 1.581977)^2 = 3412.7 (approximately, as presented in the table above).

Based on the initial value, the extreme value temperature, t, can be calculated using Eq.(2) and the result is presented in column I.

For example, to calculate the value of cell I8 using Eq.(2) in Excel function:

= -15.2+ln(ln(60/(60-1)))/0.5

= -23.4 (approximately, as presented in the table above)

This extreme value temperature of -23.4 °C produced in the iteration is not the optimal result. -23.4°C is much colder than the coldest temperature in the dataset. The above sample calculation steps show that the initial values σ = 0.5 and μ = -15.2 generate a sum of squared errors of 5290.523, as shown in cell F4 (equal to the sum of the values in cells F8 to F67). The next step is to minimize the sum of squared errors by varying σ and μ using an iterative process.

<u>Step 2: Iterate σ and μ using Excel Solver</u>

The GRG (Generalized Reduced Gradient) nonlinear solver provided in Excel was used to find the optimal values for σ and μ by minimizing the sum of squared errors. The solver changes σ and μ multiple times until the least sum of squares of errors are reached. The solver allows the user to define a convergence criterion. The iterations will end until the difference of the cumulated sum of squares of errors (cell F4) between two iterations is less than the convergence criterion. In this calculation, the convergence criterion of 10^{-4} was used. Selecting a more stringent convergence criterion would not generate a significantly different result.

The optimal values for σ and μ in this example were found to be σ =0.384 and μ = -4.487.

Once the optimal values for σ and μ were determined, the Extreme Value Temperature, t, for each return period can then be calculated using Eq. (2).

For example, to calculate the value of cell I8 (a 60-year return value) using Eq. (2) with $\sigma = 0.384$ and $\mu = -4.487$:

$$= -4.487+\ln(\ln(60/(60-1)))/0.384$$

$$= -15.1$$ (approximately, as presented in the table below)

The result of the extreme value analysis is presented in the column I of the sample calculation worksheet below. This table shows the calculated extreme value temperature for each return period shown in column D. FEI uses a 20-year return period for design.

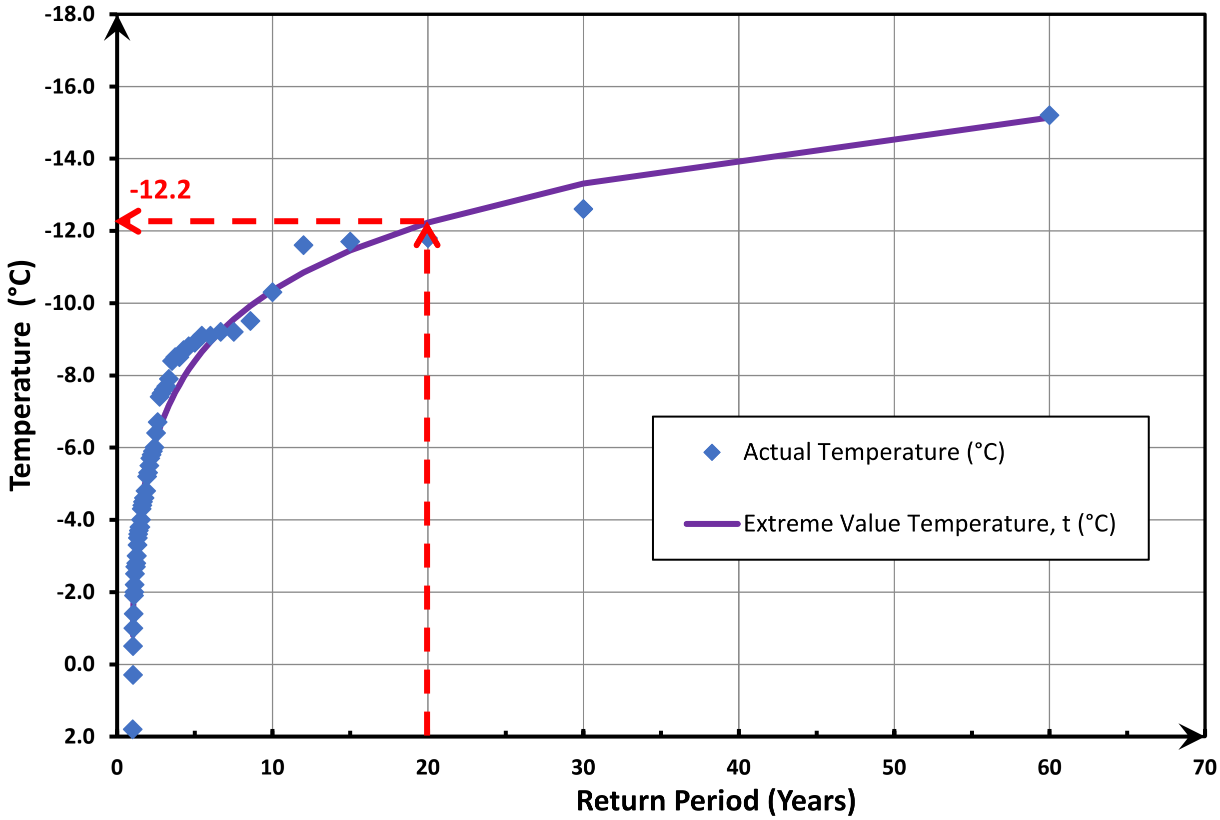
The table below shows that the calculated extreme value for a 20-year return period using this data set is -12.2 °C which is 30.2 DD, the DDD used in the Metro Vancouver (YVR) weather zone.

Extreme Value Analysis **Sample Calculation #2: Result**

σ	μ	Sum (Err²)
0.384	-4.487	93.262

Historic Weather			Return Period Regression			Theoretical and Actual Extreme Temperatures		
Rank	Year	Temp (°C)	Actual Return Period - R(t)	Theoretical Return - T(t)	Err²	Actual Return Period - R(t)	Actual Temperature (°C)	Extreme Value Temperature, t (°C)
1	1968	-15.2	60.0	61.4	2.0	60.0	-15.2	-15.1
2	1964	-12.6	30.0	23.0	49.5	30.0	-12.6	-13.3
3	1990	-11.8	20.0	17.0	8.8	20.0	-11.8	-12.2
4	1985	-11.7	15.0	16.4	2.0	15.0	-11.7	-11.5
5	1969	-11.6	12.0	15.8	14.5	12.0	-11.6	-10.9
6	2008	-10.3	10.0	9.8	0.0	10.0	-10.3	-10.4
7	1989	-9.5	8.6	7.4	1.5	8.6	-9.5	-9.9
8	1978	-9.2	7.5	6.6	0.8	7.5	-9.2	-9.6
9	1982	-9.2	6.7	6.6	0.0	6.7	-9.2	-9.2
10	1980	-9.1	6.0	6.4	0.1	6.0	-9.1	-8.9
11	1983	-9.1	5.5	6.4	0.9	5.5	-9.1	-8.7
12	1971	-8.9	5.0	5.9	0.9	5.0	-8.9	-8.4
13	1959	-8.8	4.6	5.7	1.3	4.6	-8.8	-8.2
14	1957	-8.7	4.3	5.5	1.6	4.3	-8.7	-7.9
15	1993	-8.5	4.0	5.2	1.4	4.0	-8.5	-7.7
16	1996	-8.5	3.8	5.2	2.0	3.8	-8.5	-7.5
17	2006	-8.4	3.5	5.0	2.2	3.5	-8.4	-7.4
18	1972	-7.9	3.3	4.2	0.8	3.3	-7.9	-7.2
19	1962	-7.7	3.2	4.0	0.6	3.2	-7.7	-7.0
20	2004	-7.6	3.0	3.8	0.7	3.0	-7.6	-6.8
21	1984	-7.5	2.9	3.7	0.7	2.9	-7.5	-6.7
22	1963	-7.4	2.7	3.6	0.7	2.7	-7.4	-6.5
23	1992	-6.7	2.6	2.9	0.1	2.6	-6.7	-6.4
24	2010	-6.4	2.5	2.6	0.0	2.5	-6.4	-6.2
25	1973	-6.0	2.4	2.3	0.0	2.4	-6.0	-6.1
26	2013	-5.9	2.3	2.3	0.0	2.3	-5.9	-6.0
27	1998	-5.8	2.2	2.2	0.0	2.2	-5.8	-5.8
28	2012	-5.7	2.1	2.1	0.0	2.1	-5.7	-5.7
29	2005	-5.5	2.1	2.0	0.0	2.1	-5.5	-5.6
30	1991	-5.3	2.0	1.9	0.0	2.0	-5.3	-5.4
31	2016	-5.2	1.9	1.9	0.0	1.9	-5.2	-5.3
32	1997	-4.8	1.9	1.7	0.0	1.9	-4.8	-5.2
33	2007	-4.8	1.8	1.7	0.0	1.8	-4.8	-5.1
34	1979	-4.6	1.8	1.6	0.0	1.8	-4.6	-5.0
35	1986	-4.6	1.7	1.6	0.0	1.7	-4.6	-4.8
36	2014	-4.5	1.7	1.6	0.0	1.7	-4.5	-4.7
37	2011	-4.4	1.6	1.6	0.0	1.6	-4.4	-4.6
38	1995	-4.3	1.6	1.5	0.0	1.6	-4.3	-4.5
39	1967	-4.0	1.5	1.4	0.0	1.5	-4.0	-4.4
40	1974	-3.8	1.5	1.4	0.0	1.5	-3.8	-4.2
41	1975	-3.8	1.5	1.4	0.0	1.5	-3.8	-4.1
42	1994	-3.8	1.4	1.4	0.0	1.4	-3.8	-4.0
43	1977	-3.7	1.4	1.3	0.0	1.4	-3.7	-3.9
44	1970	-3.6	1.4	1.3	0.0	1.4	-3.6	-3.8
45	1976	-3.5	1.3	1.3	0.0	1.3	-3.5	-3.6
46	1966	-3.3	1.3	1.3	0.0	1.3	-3.3	-3.5
47	1965	-3.0	1.3	1.2	0.0	1.3	-3.0	-3.4
48	1988	-3.0	1.3	1.2	0.0	1.3	-3.0	-3.2
49	2009	-2.8	1.2	1.2	0.0	1.2	-2.8	-3.1
50	1981	-2.7	1.2	1.2	0.0	1.2	-2.7	-3.0
51	2000	-2.7	1.2	1.2	0.0	1.2	-2.7	-2.8
52	1961	-2.5	1.2	1.1	0.0	1.2	-2.5	-2.7
53	2002	-2.2	1.1	1.1	0.0	1.1	-2.2	-2.5
54	1958	-2.0	1.1	1.1	0.0	1.1	-2.0	-2.3
55	1960	-1.9	1.1	1.1	0.0	1.1	-1.9	-2.1
56	2015	-1.4	1.1	1.0	0.0	1.1	-1.4	-1.9
57	1987	-1.0	1.1	1.0	0.0	1.1	-1.0	-1.6
58	2003	-0.5	1.0	1.0	0.0	1.0	-0.5	-1.3
59	2001	0.3	1.0	1.0	0.0	1.0	0.3	-0.8
60	1999	1.8	1.0	1.0	0.0	1.0	1.8	

The following figure was developed using columns G, H and I from the preceding table. The 20-year return period temperature of -12.2 °C is shown.



55.2 Please confirm that the Traditional Peak Method forecasts account for future temperature and climate uncertainties.

55.2.1 If confirmed, please explain.

55.2.2 If not confirmed, please discuss how the future temperature and climate uncertainties may impact long-term capacity planning.

Response:

Not confirmed. FEI does not explicitly project any bias related to future temperature and climate uncertainty in determining design temperature used to determine peak demand for the Traditional Peak Demand Forecast. FEI uses historical weather extremes to statistically predict (as illustrated in the response to BCUC IR1 55.1.1) the likelihood of extreme weather in various weather zones. FEI periodically refreshes its DDD calculations, bringing the most recent weather extremes into the 60-year data set used in determining the DDD temperatures.

While on average BC's climate is clearly warming, more chaotic weather patterns are also occurring. Global climate change will alter the intensity and frequency of extreme events but whether the extreme cold occurrences will be colder or warmer than currently predicted is uncertain. FEI designs the capacity of transmission and distribution systems to meet peak demand in extreme cold temperatures and not averages of colder conditions.

If climate change ultimately results in colder extreme temperature occurrences, those occurrences will be incorporated into FEI's extreme value analysis in the future and will result in colder design temperatures and higher estimates of peak demand. Identified capacity upgrade timing may advance as a result and new future capacity upgrades may be identified to address peak demand requirements. Alternatively, if the data support warmer extreme temperatures, the calculated design temperature in the future will warm, resulting in lower estimates of peak demand. The timing of identified capacity upgrades would be deferred, eliminated or reduced in scope as a result.

Please also refer to the response to BCUC IR1 55.8.1 that discusses how capacity planning is impacted by varying the extreme value analysis inputs to produce alternative system design temperatures.

55.3 Please discuss whether FEI considers there to be a need to adjust its peak demand forecasting methodology to account for climate change.

Response:

At this point in time, FEI's determination of design temperatures used to forecast peak demand is appropriate and does not need adjustment to effectively deal with and account for climate change. As discussed in the response to BCUC IR1 55.2, the process allows for observed changes in the occurrence of extreme temperatures to be incorporated periodically. This results in adjustments to the timing and scope of identified capacity upgrade projects in response to observed actual changes in the occurrence of extreme temperature used in the forecasting method. FEI continues to monitor for changes to industry practice, standards, and regulations to determine if there is a need to adjust its peak demand forecasting methodology to account for climate change.

55.4 Please discuss whether FEI is aware of any recent research or industry practice that allows for consideration of climate change and extreme weather events in peak demand forecasting.

Response:

FEI is not aware of research or established industry practice that directly considers future climate change projections in peak demand forecasting. FEI is aware of organizations like the Pacific Climate Impacts Consortium[64], and the research and studies conducted in BC like the Climate

[64] https://pacificclimate.org/.

Projections for the Okanagan Region (February 2020)[65] and Climate Projection for Metro Vancouver[66] that discuss climate change and warming of extreme temperature averages. The studies are not incompatible with FEI's current processes for determining design temperatures and, if warming trends occur, FEI's extreme value analysis will produce warmer design temperatures.

55.5 Please explain why a one in 20-year design temperature is the preferred approach and discuss any other time intervals considered, including why they were not the preferred approach.

Response:

FEI has been using a one in 20-year return period in its determination of the DDD temperature in all operations since 1994 or earlier, and extended its application to the Vancouver Island system shortly after FEI acquired it in 2005.

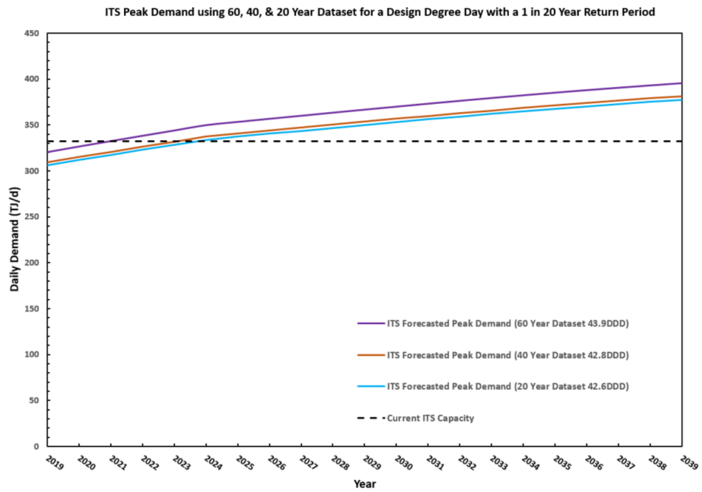
From 1992 through 1993, the interior and coastal weather zones underwent a meteorological review by a consultant retained by FEI, and updates to DDD for the interior zone were recommended. A 20-year return period was already in use for the coastal system and, based on the recommendations of the meteorological consultant and a survey of other utilities' practices, the 20-year return period was determined to be appropriate for use in the interior regions as well. FEI cannot find a record of other return periods contemplated at this time, but would expect that shorter or longer return periods would have been considered. Since this decision was made, FEI has consistently used the 20-year return period in determining design temperatures.

A one in 20-year period provides an extreme value that, on average, should occur once in that 20-year period. Each year has a five percent possibility of seeing a temperature as cold as the design value. Service outages caused by pressure collapse on systems can cause considerable safety impacts and are subject to extended timelines to address, especially because they require visits to the affected sites. FEI considers 20 years an appropriate return period to use to ensure exceeding design conditions is a very rare event.

In response to BCUC IR 43.3.1 of IR2 in FEI's Application for a CPCN for the Okanagan Capacity Upgrade Project proceeding, FEI provided the following chart and table for ITS Peak Demand using 60, 40, and 20 year dataset for a design degree day with a 1 in 20 year return period:

65 https://www.rdos.bc.ca/development-services/planning/strategic-projects/climate-projs/.

66 http://www.metrovancouver.org/services/air-quality/AirQualityPublications/ClimateProjectionsForMetroVancouver.pdf.



Year	60 Year Dataset	40 Year Dataset	20 Year Dataset
	TJ/d	TJ/d	TJ/d
2019	321	309	306
2020	327	315	312
2021	333	321	317
2022	338	326	323
2023	344	332	328
2024	350	338	334
2025	353	341	337
2026	357	344	341
2027	360	347	344
2028	363	351	347
2029	367	354	350
2030	370	357	353
2031	373	360	356
2032	376	363	359
2033	379	366	362
2034	382	369	365
2035	385	371	368
2036	388	374	370
2037	390	377	373
2038	393	379	375
2039	395	381	377

55.6 Please confirm, or explain otherwise, that for the analysis in the LTGRP the Gumbel Method of Moments was used on a 60-year data set to return a one in 20-year extreme value for the regional design temperature.

55.6.1.1 If confirmed, please explain why a 60 year dataset is the preferred approach.

Response:

Confirmed. FEI determined a return period of 20 years was preferred as described in the response to BCUC IR1 55.5. A 60-year return period was specified to produce a data set that spans multiple 20-year periods. This provides a more representative picture of 20-year weather variability in each region. Additionally, statistically this allows FEI to determine design temperature that will be less influenced by any single colder or warmer extreme event in the data set. This will provide some dampening of large swings in DDD values caused when new temperature extremes occur in the 60-year period, or when older temperature extremes disappear from the data set after periodic recalculation. FEI's objective in this regard is to ensure inputs into the planning process are not overly reactive to single events. Data sets shorter in duration would increase the sensitivity of the result to changes that roll into or roll out of the data. FEI's use of the 60-year data set balances the need to see changes in climate reflected in regional design temperatures with a process using a reasonably broad data set that reduces the reactivity of calculated design temperatures to outliers in the data.

55.7 If not confirmed, please explain the length of time included in the dataset.

Response:

Please refer to the response to BCUC IR1 55.6.

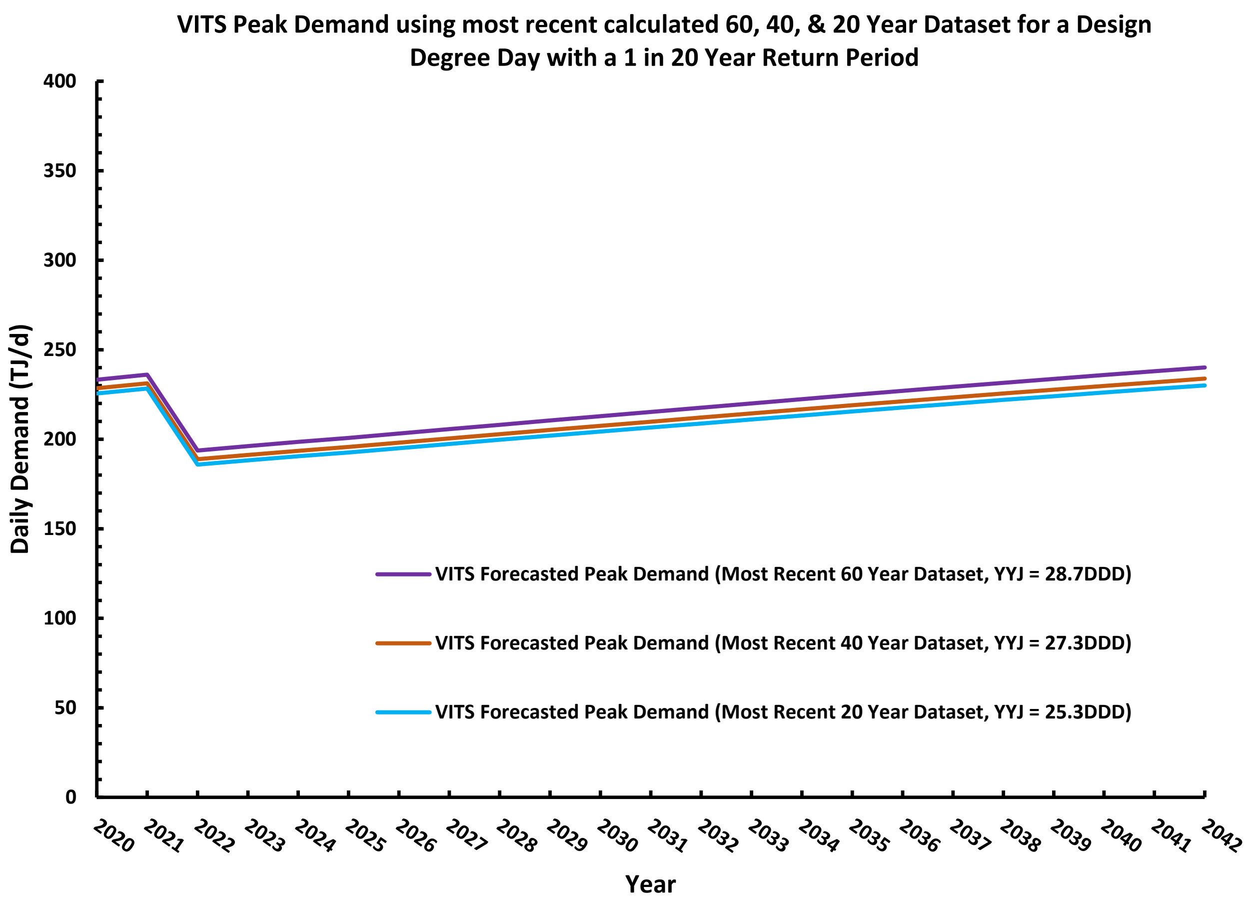
55.8 Please reproduce the preceding chart and table for the ITS, CTS, and VITS with the most recent DDD calculations over the 20-year planning horizon considered in the LTGRP Application. In your response, please identify the DDD for each of the 20, 40, and 60-year datasets.

Response:

The requested charts and tables are provided below.

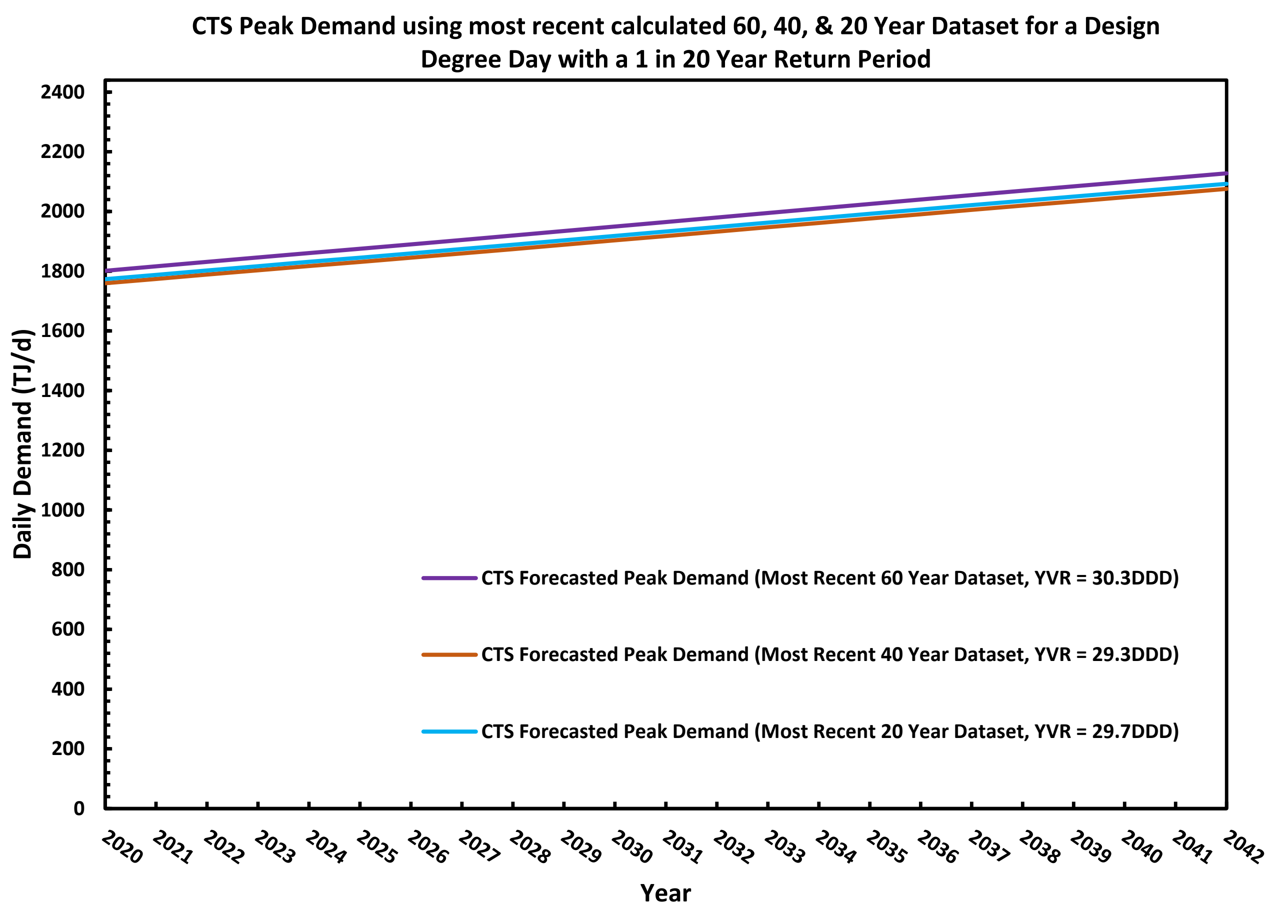
Most recent DDD calculation using 60, 40, and 20 year dataset.

Transmission System	Regions Served	Index Weather Station (Airport Code)	2022 LTGRP Application	Most Recent DDD Calculation		
			Weather: 1957 - 2016	Weather: 1962 - 2021	Weather: 1982 - 2021	Weather: 2002 - 2021
			60 Year Dataset	60 Year Dataset	40 Year Dataset	20 Year Dataset
			DDD	DDD	DDD	DDD
VITS	Squamish	Squamish (WSK)	32.9	32.7	31.5	30.9
	Whistler	Whistler (WAE)	39.5	40.0	40.1	41.8
	Powell River, Sechelt, Gibsons	Powell River (YPW)	29.0	28.8	29.1	31.0
	Campbell River	Campbell River (YBL)	31.9	31.9	31.8	29.4
	Comox, Courtenay	Comox (YQQ)	27.8	27.9	27.2	26.9
	Nanaimo Region, Port Alberni	Nanaimo (YCD)	29.9	29.8	29.1	30.0
	Victoria Region	Victoria (YYJ)	28.8	28.7	27.3	25.3
CTS	Metro Vancouver	Vancouver (YVR)	30.2	30.3	29.3	29.7
	Fraser Valley	Abbotsford (YXX)	32.5	32.6	31.8	31.7
ITS	Kamloops	Kamloops (YKA)	46.7	46.6	43.5	43.1
	North and Central Okanagan	Kelowna (YLW)	43.9	43.7	42.8	42.2
	South Okanagan	Penticton (YYF)	39.1	39.1	37.7	36.9
	West Kootenay	Castlegar (YCG)	39.7	39.3	36.2	35.9



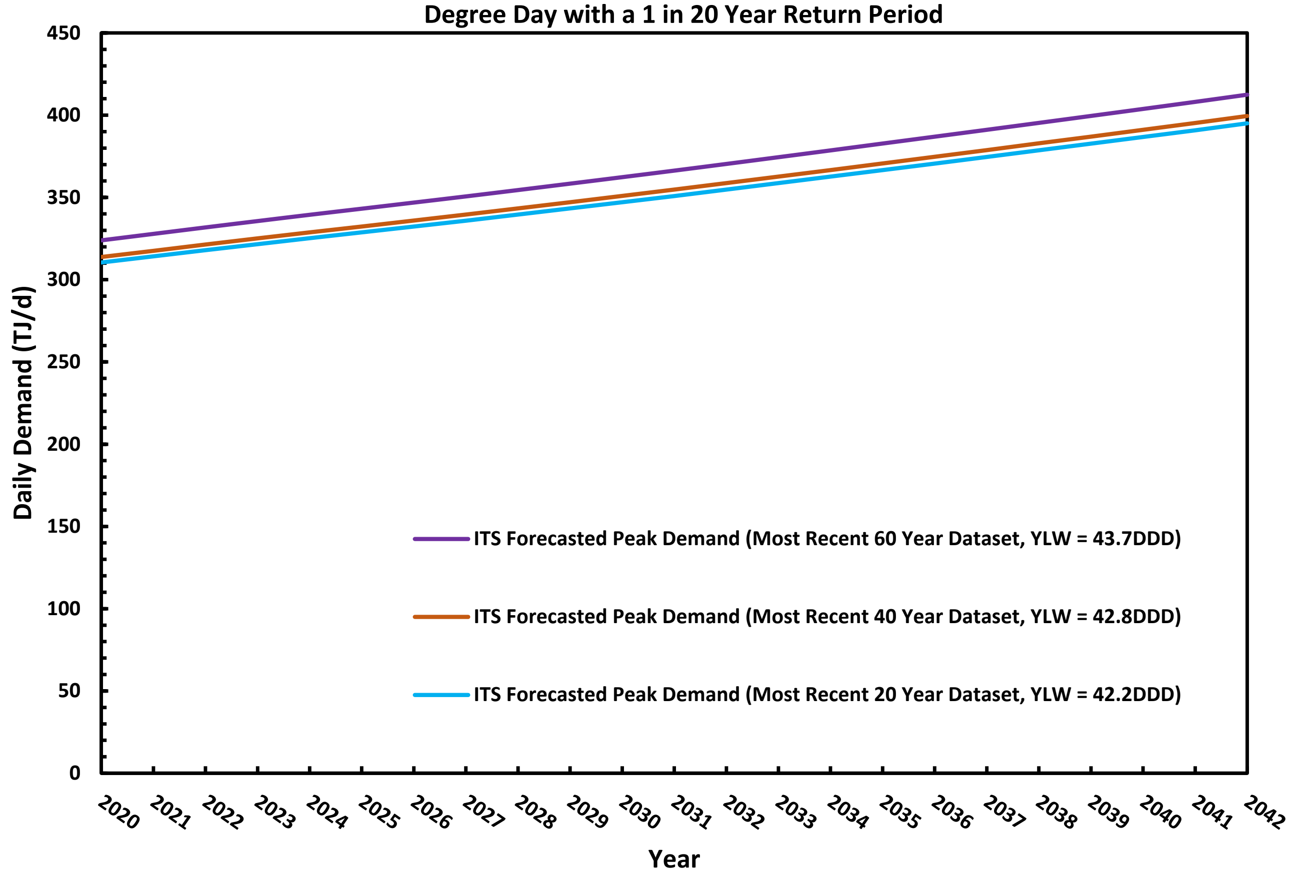
VITS				
Year	2022 LTGRP	Most Recent 60 Year Dataset	Most Recent 40 Year Dataset	Most Recent 20 Year Dataset
	TJ/d	TJ/d	TJ/d	TJ/d
2020	234	233	229	226
2021	236	236	231	228
2022	194	194	189	186
2023	196	196	191	188
2024	199	199	194	191
2025	201	201	196	193
2026	204	203	198	195
2027	206	206	200	197
2028	208	208	203	200
2029	211	211	205	202
2030	213	213	207	204
2031	216	215	210	207

VITS				
Year	2022 LTGRP	Most Recent 60 Year Dataset	Most Recent 40 Year Dataset	Most Recent 20 Year Dataset
	TJ/d	TJ/d	TJ/d	TJ/d
2032	218	218	212	209
2033	220	220	214	211
2034	223	222	217	213
2035	225	225	219	216
2036	227	227	221	218
2037	230	229	223	220
2038	232	232	226	222
2039	234	234	228	224
2040	236	236	230	226
2041	238	238	232	228
2042	241	240	234	230



CTS				
Year	2022 LTGRP	Most Recent 60 Year Dataset	Most Recent 40 Year Dataset	Most Recent 20 Year Dataset
	TJ/d	TJ/d	TJ/d	TJ/d
2020	1797	1801	1759	1773
2021	1812	1816	1774	1788
2022	1827	1831	1788	1802
2023	1842	1846	1803	1817
2024	1856	1861	1817	1831
2025	1871	1875	1831	1845
2026	1885	1890	1845	1860
2027	1900	1905	1860	1874
2028	1915	1919	1874	1889
2029	1930	1935	1889	1904
2030	1945	1950	1903	1918
2031	1960	1965	1918	1933
2032	1975	1980	1932	1948
2033	1990	1995	1947	1963
2034	2005	2010	1962	1977
2035	2020	2025	1976	1992
2036	2035	2040	1991	2007
2037	2050	2055	2005	2021
2038	2064	2069	2019	2036
2039	2079	2084	2034	2050
2040	2093	2098	2048	2064
2041	2108	2113	2062	2078
2042	2122	2128	2076	2093

ITS Peak Demand using most recent calculated 60, 40, & 20 Year Dataset for a Design Degree Day with a 1 in 20 Year Return Period



ITS				
Year	2022 LTGRP	Most Recent 60 Year Dataset	Most Recent 40 Year Dataset	Most Recent 20 Year Dataset
	TJ/d	TJ/d	TJ/d	TJ/d
2020	325	324	314	310
2021	329	328	318	314
2022	333	332	321	318
2023	337	336	325	322
2024	341	339	329	325
2025	344	343	332	329
2026	348	347	336	332
2027	352	351	340	336
2028	356	354	343	340
2029	360	358	347	343
2030	364	362	351	347

ITS				
Year	2022 LTGRP	Most Recent 60 Year Dataset	Most Recent 40 Year Dataset	Most Recent 20 Year Dataset
	TJ/d	TJ/d	TJ/d	TJ/d
2031	368	366	355	351
2032	372	370	359	355
2033	376	374	363	359
2034	380	379	367	363
2035	384	383	371	367
2036	388	387	375	371
2037	392	391	379	375
2038	397	395	383	379
2039	401	400	387	383
2040	405	404	391	387
2041	409	408	395	391
2042	414	412	399	395

55.8.1 Please discuss any implications on capacity planning for each of the ITS, CTS, and VITS if FEI were to use a 20-year or 40-year dataset for capacity planning purposes.

Response:

As was the case for the Interior Transmission System (ITS) example referenced in the preamble, the different data sets provide a variation in Design Degree Day (DDD) values. In general, the smaller and more recent data sets are returning slightly lower (warmer) DDD values. The effects on the Vancouver Island Transmission System (VITS) and ITS are similar to the previous ITS assessment example referenced in the preamble, where the calculated DDD and peak demand forecasts fall as the temperature history is shortened in the data sets. However, in the weather zones in the VITS there are exceptions to this overall gradual warming shown in the results for the Whistler, Powell River and Nanaimo weather zones, where the DDD values are progressively increasing (cooling) with a smaller data set.

In the Coastal Transmission System (CTS), the 20-year data set is returning a higher (cooler) DDD value then the 40-year data set, but a lower DDD than the 60-year data sets for the Vancouver weather zone. As a result, the CTS peak demand forecast is higher using a 20-year data set then when using a 40-year data set, a different result from the analysis on the other transmission systems. The CTS result with a 20 year data set is influenced to a larger degree by the very cold weather this past winter in late December 2021, which was included in the data set.

The implications for capacity planning are that the demand forecast associated with the lower DDD would suggest an ability to defer initiating system upgrades for up to a few years further into the future if designing to a 20-year data set rather than a 60-year data set. However, the results using the 20 year data set can be more volatile in response to a single weather event that enters or leaves the data set over time. For the VITS, the forecast spread using the various forecasts is equivalent to approximately three years of growth, meaning the lower forecast could accommodate about three years more growth before reaching capacity than the higher forecast. For the CTS, the spread is equivalent to about 2.5 years and for the ITS the spread is about 3.5 years.

In response to IR 43.2.1 of IR2 in FEI's Application for a CPCN for the Okanagan Capacity Upgrade Project, FEI stated:

For the Interior regions served by the ITS, the DDD values prior to those calculated in 2017 were last adopted in November 1992 and used from 1993 to 2016. The following table shows the changes in DDD values over time:

ITS Design Degree Day (DDD) History

Region	Prior to 1993	1993-2016	Current
Thompson	48	49	46.7
Central and North Okanagan	45	45	43.9
South Okanagan	41	40	39.1
West Kootenays	43	40	39.7

In the 1993 update, the most significant DDD change occurred in the West Kootenays; in contrast, the DDD values for major load centres in the Thompson and Okanagan regions remained relatively stable. As such, the 1993 update in DDD values had little overall impact on ITS peak demand.

55.9 Please reproduce the preceding table of ITS DDD History for the ITS, CTS, and VITS with the most recent DDD values for each region. In your response, please indicate when the most recent DDD values were calculated and discuss any trends evident in the data.

Response:

The requested information is presented in the following three tables in as much detail as FEI can find in the historical record. The information for the ITS has not changed from that provided in the OCU Proceeding, BCUC IR2 43.2.1.[67] Except for two weather zones, the trend in most areas was a slight decrease in the DDD value representing some warming of the design temperature.

67 Exhibit B-14.

Comparing the most recent DDD calculation that was completed in 2017 in all the weather zones with the previous calculation (implemented in 2005 in the VITS, 1995 in the CTS, and 1993 in the ITS), the degree of warming has ranged from 0.3 C to 2.3 C, averaging 0.9 warmer. In the Powell River (YPW) and Victoria (YYJ) regions, there was a slight increase in the design temperature, with the design temperature cooling by 0.4 C in Powell River and 0.1 C in Victoria.

Transmission System	Regions served	Index Weather Station (Airport Code)	DDD prior to 2005[68]	DDD 2005-2016	DDD since 2017
	Squamish	Squamish (WSK)	34.5	35	32.9
	Whistler	Whistler (WAE)	39.7	41.3	39.5
	Powell River, Sechelt, Gibsons	Powell River (YPW)		28.6	29.0
VITS	Campbell River	Campbell River (YBL)		32.4	31.9
	Comox, Courtenay	Comox (YQQ)	28.4	28.5	27.8
	Nanaimo Region, Port Alberni	Nanaimo (YCD)		30.4	29.9
	Victoria Region	Victoria (YYJ)		28.7	28.8

Transmission System	Regions served	Index Weather Station (Airport Code)	DDD Prior to 1995	DDD 1995-2016	DDD since 2017
CTS	Metro Vancouver	Vancouver (YVR)	33	31	30.2
	Fraser Valley	Abbotsford (YXX)		34	32.5

Transmission System	Regions served	Index Weather Station (Airport Code)	DDD prior to 1993	DDD 1993-2016	DDD since 2017
	Kamloops	Kamloops (YKA)	48	49	46.7
	North and Central Okanagan	Kelowna (YLW)	45	45	43.9
ITS	South Okanagan	Penticton (YYF)	41	40	39.1
	West Kootenay	Castlegar (YCG)	43	40	39.7

55.9.1 Please discuss how any trends in DDD history may impact capacity planning.

Response:

The DDD values presented in the response to BCUC IR1 55.9 show that the design temperatures have warmed in most regions. The impact for capacity planning of a warming design temperature

[68] With the exception of Squamish, prior to 2005 FEI did not perform capacity planning on the VITS communities (that FEI acquired from Centra Gas a few years earlier). Design temperatures for Centra were determined using the coldest day in the previous 25-year period.

is that the associated peak demand forecast would also be lower. A lower peak demand forecast can result in deferral of the need of future system upgrades by a few years.

In the response to BCUC IR1 55.8, FEI provided peak demand forecasts for each transmission system that show how peak demand varies as a result of changes in the DDD in the range of one to three degrees Celsius. Although the forecasts in that response were a result of varying the return period used in the Extreme Value analysis, given that the range of change in DDD history in various regions also results in about a one to three degree Celsius variation, the forecasts provided in that response are useful to illustrate the magnitude of the capacity planning (peak demand) impacts that such trends in DDD history might produce.

55.9.2 Please compare the most recent DDD values for each region against the coldest day observed in the last 20 years. In your response, please indicate the date of occurrence of the coldest day for each region.

Response:

The comparison of DDD versus the coldest average daily temperature recorded in the last 20 years for the weather zones served by each transmission system is summarized in the table below.

Transmission System	Regions Served	Most recent DDD values	Coldest Day Mean Daily Temperature (°C)	Date of Occurrence
VITS	Squamish	Squamish (WSK) 32.7 DDD (-14.7 °C)	-12.9	2021-12-27
	Whistler	Whistler (WAE) 40 DDD (-22 °C)	-24.0	2021-12-27
	Powell River, Sechelt, Gibsons	Powell River (YPW) 28.8 DDD (-10.8 °C)	-13.1	2013-12-21
	Campbell River	Campbell River (YBL) 31.9 DDD (-13.8 °C)	-11.5	2021-12-27
	Comox, Courtenay	Comox (YQQ) 27.9 DDD (-9.9 °C)	-8.9	2021-12-27
	Nanaimo Region, Port Alberni	Nanaimo (YCD) 29.8 DDD (-11.8 °C)	-12.0	2008-12-20
	Victoria Region	Victoria (YYJ) 28.7 DDD (-10.7 °C)	-7.3	2021-12-27
CTS	Metro Vancouver	Vancouver (YVR) 30.3 DDD (-12.3 °C)	-11.6	2021-12-27
	Fraser Valley	Abbotsford (YXX) 32.6 DDD (-14.6 °C)	-13.7	2021-12-27

Transmission System	Regions Served	Most recent DDD values	Coldest Day Mean Daily Temperature (°C)	Date of Occurrence
ITS	Thompson	Kamloops (YKA) 46.6 DDD (-28.6 °C)	-25.0	2021-12-27
	North and Central Okanagan	Kelowna (YLW) 43.7 DDD (-25.7 °C)	-24.2	2008-12-20
	South Okanagan	Penticton (YYF) 39.1 DDD (-21.1 °C)	-18.8	2021-12-27
	West Kootenays	Castlegar (YCG) 39.3 DDD (-21.3 °C)	-17.9	2004-01-05

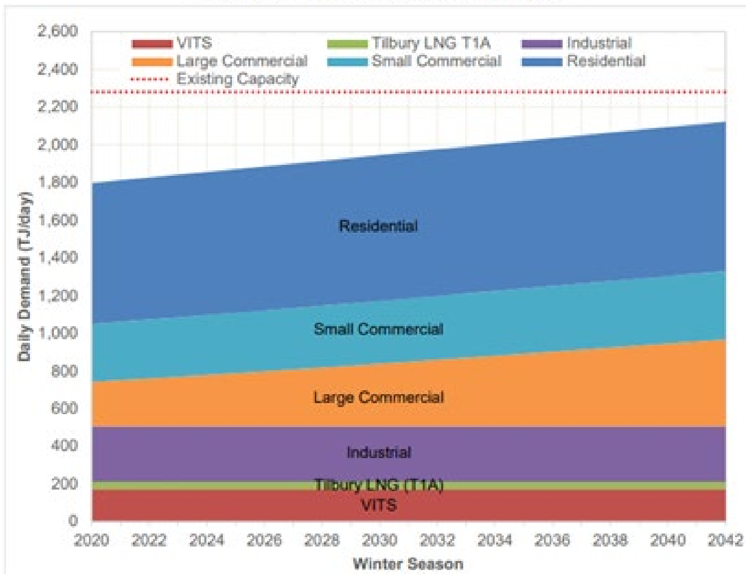
56.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Section 7.3.2.1, p. 7-20, Section 7.3.2.4, p. 7-23, Section 7.3.3.1, p. 7-27, Section 7.3.3.2, p. 7-28

ITS, CTS, and VITS Peak Demand Forecasts

In Figure 7-8 on page 7-20 of the Application, FEI presents the CTS Traditional Peak Demand Forecast:

Figure 7-8: CTS Traditional Peak Demand Forecast



56.1 Please clarify whether the daily demand for Tilbury LNG (T1A) in Figure 7-8 is interruptible.

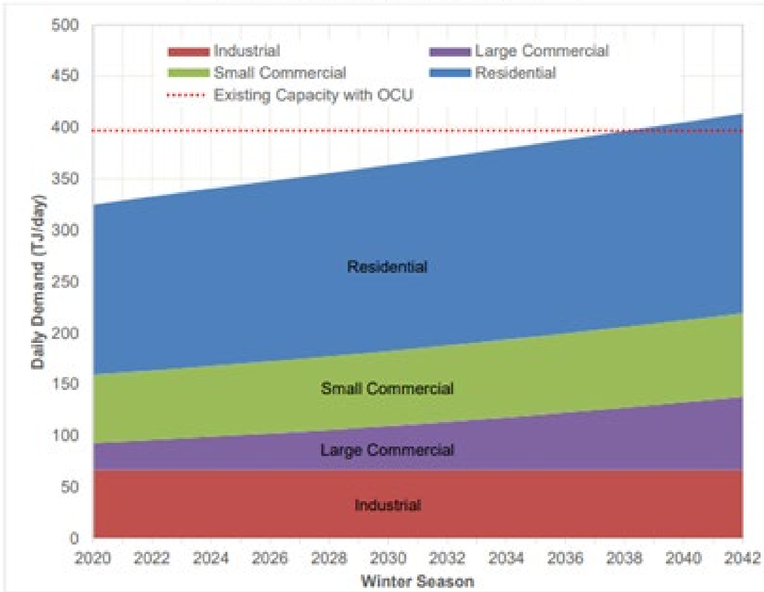
56.1.1 If interruptible, please explain why it is included in the peak demand forecast.

Response:

The demand shown in the forecast for T1A is firm demand. The load shown for the facility is equivalent to the liquefaction train at the LNG plant operating at full capacity on a peak day. FEI does not include Interruptible load in peak demand forecasts.

In Figure 7-14 on page 7-27 of the Application, FEI presents the ITS Traditional Peak Demand Forecast:

Figure 7-14: ITS Traditional Peak Demand Forecast



56.2 Please clarify which rate schedules are associated with each customer class outlined in the peak demand forecasts above.

Response:

The following table provides the rate schedules included in each classification used in the VITS, CTS, and ITS forecast figures:

Classification	Rate Schedule
Residential	1
Small Commercial	2
Large Commercial	3 23
Industrial[69]	5 25 6 22A 22B T1 (Joint Venture) T2 (BCH Island Gen.)

56.3 For the Diversified Energy scenario, please produce figures for each transmission system that clearly show the annual demand forecast by customer class, including LNG customers, similar in format to the Peak Demand Forecasts shown in Figures

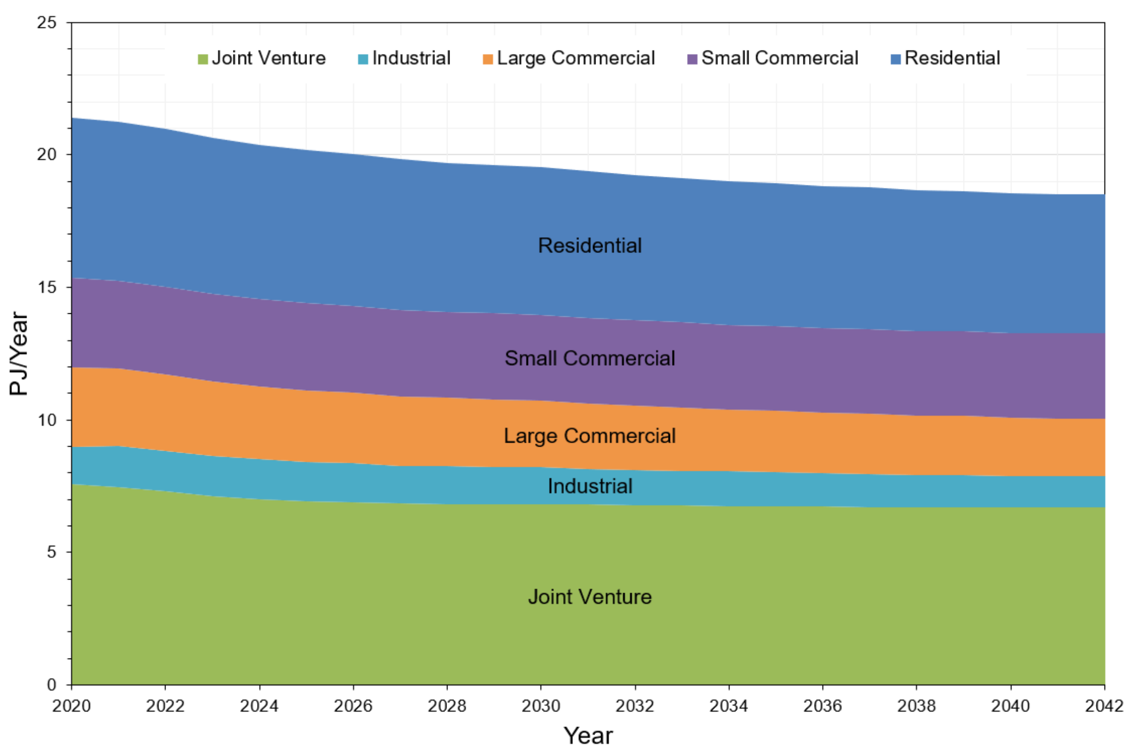
[69] Rate schedule 22 and T1 and T2 customers have some contracted firm demand included. T1 and T2 are rate schedules unique to the VITS.

7-8 and 7-14. In your response, please produce separate figures for the ITS, CTS, and VITS.

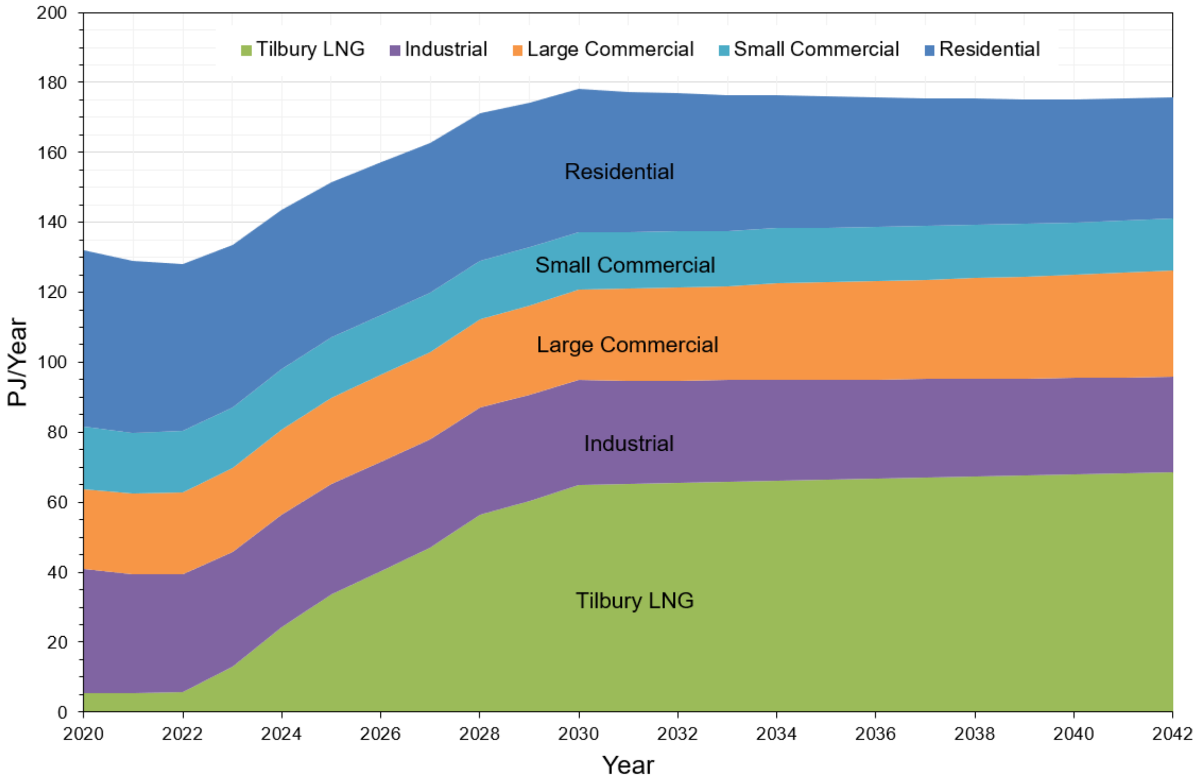
Response:

The requested figures are produced below for each transmission system. While Peak Demand forecasts are grouped by transmission systems explicitly, Annual Demand forecasts are not grouped by the transmission systems but by region. It is reasonable for the regions used in the annual demand scenarios to be grouped to approximately represent (with minor variation) the customers on each system. The Vancouver Island and Whistler region correspond generally to the VITS. The City of Vancouver and Lower Mainland regions correspond to the CTS. The Southern region corresponds to the ITS, although some east Kootenay communities outside of the ITS served by transmission laterals are included. Another difference in the annual demand forecast and peak demand forecast is that there is often a significant proportion of annual demand attributed to industrial customers in interruptible rate schedules. Interruptible industrial demand is not represented in the peak demand forecast. For the CTS, the DEP Scenario considers expansion of Tilbury for LCT and Global LNG, which is represented in the CTS annual demand below, but this annual demand does not include Woodfibre LNG. The Woodfibre LNG demand would add approximately 95 PJ/year to the forecast (modelled in the Application to be added in 2025); however, FEI considered that including this large demand step increase would obscure the view that BCUC is seeking through this IR. It should be noted that the CTS Peak Demand represented in Figure 7-8 in the Application is limited to the existing Tilbury T1A expansion. The LNG peak demand represented by LNG expansion at Tilbury beyond T1A is best represented by Figure 7-11 in the Application (which also includes peak demand for Woodfibre LNG).

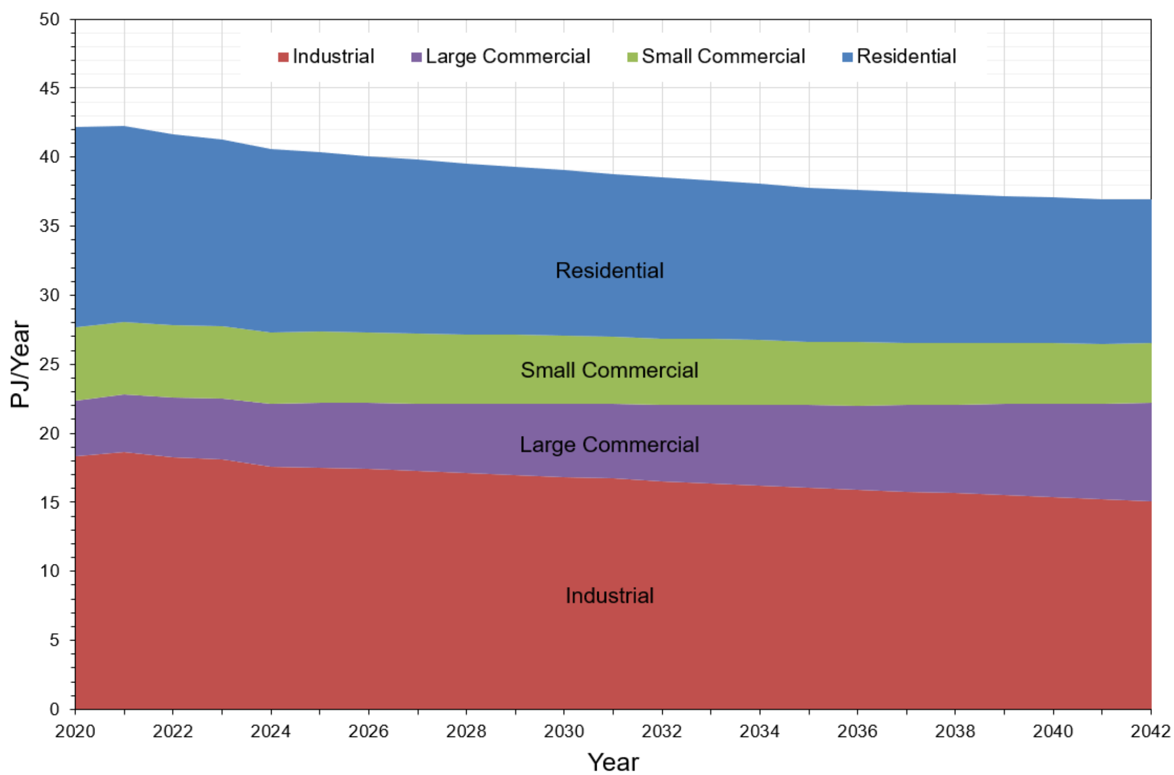
VITS Annual Demand Forecast by Customer Classification



CTS Annual Demand Forecast by Customer Classification



ITS Annual Demand Forecast by Customer Classification



56.3.1 Please discuss the relationship between the Peak Demand Forecast and the Annual Demand Forecast for each customer class within each of the ITS, CTS, and VITS. In your response, please discuss any factors which may cause this relationship to change over the 20-year planning horizon.

Response:

The relationship between the Peak Demand forecast and the Reference Case Annual Demand forecast is very similar for each of the three major transmission systems. However, there are some differences between the customer classes. The two forecasts have some differences that make them difficult to compare directly.

As described in the response to BCUC IR1 56.3, annual demand forecasts are not grouped by the transmission systems but by geographic region. It is reasonable, however, for the regions used in the annual demand scenarios to be grouped to approximately represent the customers on each system. The Vancouver Island and Whistler region correspond generally to the VITS. The City of Vancouver and Lower Mainland regions correspond to the CTS. The Southern region corresponds to the ITS, although some east Kootenay communities outside of the ITS served by transmission laterals are included.

Another difference in the annual demand forecast and peak demand forecast is that there is a proportion of annual demand attributed to industrial customers in interruptible rate schedules. Interruptible rate schedules are not represented in the peak demand forecast. At the start of the forecast period, customers in interruptible rate schedules account for approximately 28 percent of the annual demand across all FEI systems. For firm industrial rate schedules, there can be a departure in the proportion of demand associated annually and under peak demand for each system.

In the Reference Case Annual Demand Forecast over the forecast period, some end use patterns and policies in place in the base year are applied to the Reference Case forecast. The policies that provide reductions to future annual demand are not applied in the traditional peak demand forecast. The relationship between Annual Demand forecast and the Peak Demand forecast is influenced by how these factors are applied to annual demand, but not the Traditional Peak Demand. Traditional Peak Demand forecast does not apply future demand reduction for various customer classes as seen in the Reference Case Annual Demand forecast, and therefore peak demand will typically increase by a greater percentage, or will increase when annual demand is declining.

On an annual basis, FEI is now planning to the DEP Scenario forecast. When considering the DEP Scenario forecast, annual demand is the result of a wider range of end use influences being applied including, among others, electrification, substantial adoption of renewable gases, high levels of DSM, government policy and program, etc. The relationship diverges to a greater degree as is documented in the response to BCUC IR1 56.3.2. The ramping up of various end-use factors in the forecast period is the driver for the change in the relationship between annual demand and peak demand over the forecast period. FEI purposefully does not apply these moderating factors to peak demand forecasts because of the uncertainty in the ability to measure the effect on peak demand and the resulting potential for suppressing the identification of need for future infrastructure or forecasting sufficient lead time to implement if the peak reduction potential is over-represented.

As stated initially, the relationship between peak and annual demand for various customer classes (and the factors that may influence this relationship over the forecast period) are similar in all transmission systems. The variations by transmission system are driven by the variations in account growth in each system, rather than by regional variances in end use patterns. The discussion below identifies how the proportion of demand for the various customer classes changes over the forecast and relative to the overall system demand and if that is influenced by strong or weaker account growth.

VITS

At the start of the forecast period in the annual forecast, the VITS industrial rate schedules account for about 5.5 percent of the annual demand (which includes interruptible and seasonal demand) and account for approximately 20.7 percent in the peak demand forecast (which does not include interruptible and seasonal demand). Over the forecast period in both forecasts, the assumption is that industrial accounts are not forecasted and do not change. As the forecasted accounts for industrial customers are held steady, the industrial annual demand over the forecast period remains steady. The Traditional Peak Demand forecast industrial peak demand remains unchanged with no increase through the forecast.

Annual demand for residential customers at the beginning of the forecast is 28 percent of annual demand on the system, but accounts for about 44 percent of the peak demand (which excludes interruptible and seasonal demand). Strong residential account growth in the system increases the residential annual demand to amount to about 30 percent of the total annual demand and the residential peak demand grows and amounts to 46.5 percent of the system peak demand by the end of the forecast period.

Annual demand for small commercial customers at the beginning of the forecast is 16 percent of annual demand on the system but accounts for about 22.5 percent of the peak demand which excludes interruptible demand. Strong small commercial account growth in the system increases the small commercial annual demand to about 19.5 percent of the annual demand and the small commercial peak demand grows to about 26 percent of the system peak demand by the end of the forecast period.

Annual demand for large commercial customers at the beginning of the forecast is 14 percent of annual demand on the system but accounts for about 13 percent of the peak (demand which excludes interruptible and seasonal demand). Low large commercial account growth in the system decreases the large commercial annual demand to about 13.5 percent of the annual demand and the large commercial peak demand decreases to about 11 percent of the system peak demand by the end of the forecast period.

CTS

In the annual forecast of the CTS, industrial rate schedules account for about 9.5 percent of the annual demand (which includes interruptible demand) and accounts for approximately 20.5 percent in the peak demand forecast (that does not include interruptible demand). Over the forecast period in both forecasts, the assumption is that industrial accounts do not change. However, over the forecast period some end use patterns and policies in place in the base year are applied to the reference case forecast and for industrial accounts this amounts to about a 1.5 percent decrease in reference case annual demand over the forecast. The Traditional Peak Demand forecast does not apply these future effects and as a result industrial peak demand remains unchanged, showing no decrease through the forecast.

Annual demand for residential customers at the beginning of the forecast is 41 percent of annual demand on the system, but accounts for about 46 percent of the peak demand (which excludes interruptible demand). Low residential account growth in the system reduces the residential annual demand to about 31 percent of the annual demand and the residential peak demand reduces and amounts to 40.5 percent of the system peak demand by the end of the forecast period.

Annual demand for small commercial customers at the beginning of the forecast is 14 percent of annual demand on the system but accounts for about 19 percent of the peak demand (which excludes interruptible demand). Moderate small commercial account growth in the system sustains the small commercial annual demand at about 14 percent of the annual demand and the small commercial peak demand reduces slightly to about 18.5 percent of the system peak demand by the end of the forecast period.

Annual demand for large commercial customers at the beginning of the forecast is 17 percent of annual demand on the system but accounts for about 14.5 percent of the peak demand, which excludes interruptible demand. Strong large commercial account growth in the system increases the large commercial annual demand to about 28.5 percent of the annual demand and the large commercial peak demand grows amounts to about 23.5 percent of the system peak demand by the end of the forecast period.

ITS

In the annual ITS forecast, industrial rate schedules account for about 8.5 percent of the annual demand (which includes interruptible demand) and accounts for approximately 20.5 percent in the peak demand forecast (which does not include interruptible demand). Over the forecast period in both forecasts, the assumption is that industrial accounts do not change. As the forecasted account increases for industrial customers are held steady, the industrial annual demand over the forecast period remains steady. The Traditional Peak Demand forecast industrial peak demand remains unchanged with no increase through the forecast.

Annual demand for residential customers at the beginning of the forecast is 34 percent of annual demand on the system but accounts for about 50.5 percent of the peak demand (which excludes interruptible demand). Moderate residential account growth in the system reduces the residential annual demand to about 28 percent of the annual demand and the residential peak demand amounts to 43.5 percent of the system peak demand by the end of the forecast period.

Annual demand for small commercial customers at the beginning of the forecast is 12.5 percent of annual demand on the system but accounts for about 20.5 percent of the peak demand (which excludes interruptible demand). Moderate small commercial account growth in the system sustains the annual demand to about 12.5 percent of the annual demand and the small commercial peak demand amounts to about 18.5 percent of the system peak demand by the end of the forecast period.

Annual demand for large commercial customers at the beginning of the forecast is 9 percent of annual demand on the system but accounts for about 8.5 percent of the peak demand which excludes interruptible demand. Strong large commercial account growth in the system increases the annual demand to about 19.5 percent of the annual demand and the large commercial peak demand grows to about 22.5 percent of the system peak demand by the end of the forecast period.

56.3.2 For the Diversified Energy scenario (for annual demand) and the Traditional Peak Demand forecast, please identify any occurrence where the Annual Demand decreases and the Peak Demand increases over the 20-year planning horizon for a specific customer class within an individual transmission system.

56.3.2.1 Please provide a detailed explanation with rationale for each occurrence.

Response:

In this response, FEI is comparing the DEP Annual forecast with DSM to the Traditional Peak Demand forecast. As the annual demand is not organized by individual transmission systems, FEI is grouping various regions that closely approximate the areas covered by the transmission system as described in the response the BCUC IR1 56.3 and 56.3.1.

Region / Transmission System	Customer Class	DEP Annual Forecast	Traditional Peak Demand Forecast
VITS	Residential	14 percent decrease	35 percent increase
	Small Commercial	6.5 percent decrease	48 percent increase
	Large Commercial	30 percent decrease	10 percent increase
	Industrial	16 percent decrease	No change
	Combined	16 percent decrease	27.5 percent increase
CTS	Residential	33 percent decrease	6 percent increase
	Small Commercial	17 percent decrease	17 percent increase
	Large Commercial	40 percent increase	96 percent increase
	Industrial	28.5 percent decrease	No change
	Combined	13 percent decrease	18 percent increase

Region / Transmission System	Customer Class	DEP Annual Forecast	Traditional Peak Demand Forecast
ITS	Residential	30 percent decrease	14 percent increase
	Small Commercial	20 percent decrease	20.5 percent increase
	Large Commercial	82.5 percent increase	250 percent increase
	Industrial	14 percent decrease	No change
	Combined	13.5 percent decrease	32 percent increase

VITS

For the VITS over the forecast period, the annual demand for residential customers declines by 14 percent while the traditional peak demand increases by 35 percent. For small commercial customers, the annual demand declines by 6.5 percent while the peak demand increases by 48 percent. For large commercial customers, annual demand declines by 30 percent while peak demand grows by 10 percent. For industrial customers, annual demand decreases by 16 percent while the peak demand holds steady with no growth or decline over the forecast period. Across all customer classes, the VITS annual demand declines by approximately 16 percent while peak demand grows by about 27.5 percent.

CTS

For the CTS over the forecast period, the annual demand for residential customers declines by 33 percent while the traditional peak demand increases by 6 percent. For small commercial customers, the annual demand declines by 17 percent while the peak demand increases by 17 percent. For large commercial customers, the annual demand and peak demand both increase with annual demand increasing by 40 percent and peak demand increasing by 96 percent. For industrial customers, annual demand decreases by 28.5 percent while the peak demand holds steady with no growth or decline over the forecast period. Across all customer classes, the CTS annual demand declines by approximately 13 percent while peak demand grows by about 18 percent.

ITS

For the ITS over the forecast period, the annual demand for residential customers declines by 30 percent while the traditional peak demand increases by 14 percent. For small commercial customers, the annual demand declines by 20 percent while the peak demand increases by 20.5 percent. For large commercial customers, the annual demand and peak demand both increase with annual demand increasing by 82.5 percent and peak demand increasing by 250 percent. For other industrial customers, annual demand decreases by 14 percent while the peak demand holds steady with no growth or decline over the forecast period. Across all customer classes, the ITS annual demand declines by approximately 13.5 percent while peak demand grows by about 32 percent.

56.3.3 For the Diversified Energy scenario (for annual demand) and the Traditional Peak Demand forecast, please identify any occurrence where the Annual Demand increases and the Peak Demand decreases over the 20-year planning horizon for a specific customer class within an individual transmission system.

56.3.3.1 Please provide a detailed explanation with rationale for each occurrence.

Response:

In comparing the DEP Annual Demand forecast with DSM and the Traditional Peak Demand forecast, there are no customer classes in any FEI transmission systems where the annual demand increases and the peak demand decreases.

56.4 Please provide a detailed explanation for the projected growth or decline in daily demand over the planning horizon for each customer class, on each of the ITS, CTS and VTS, as presented in the Traditional Peak Demand Forecast.

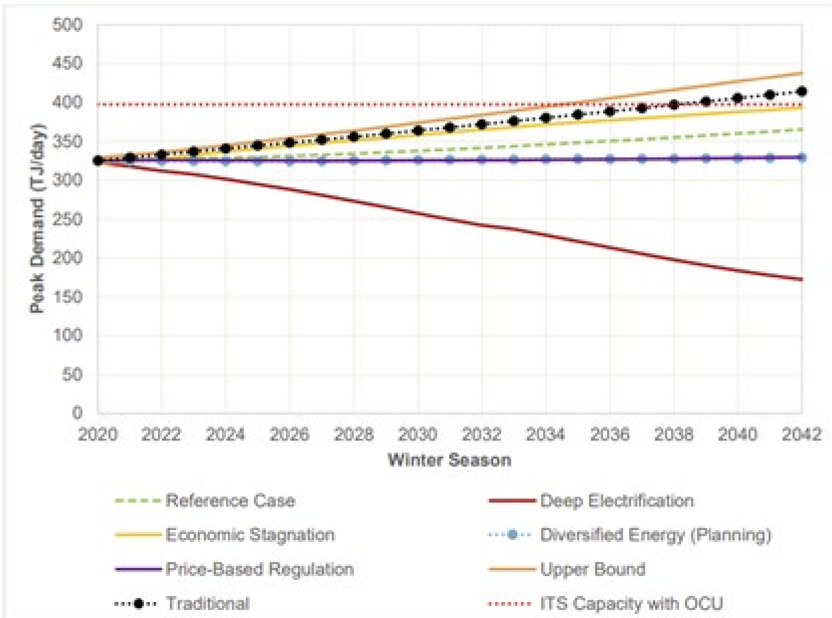
Response:

In the process that creates Traditional Peak Demand forecast, the peak use per customer (UPC_{peak}) for residential and small and large commercial rate classes is determined from recently-measured customer consumption, using the load gather process described in detail in the response to BCUC IR1 54.1. To determine the forecasted peak demand, regional averages for UPC_{peak} for each rate class are identified and multiplied by the numbers of forecasted accounts in each region provided by the Reference Case account forecast. As the UPC_{peak} values in the Traditional Peak Demand forecast process are fixed and do not vary over the forecast period, the projected growth or decline in the peak demand forecast for each system is directly related to the account forecast growth or decline. As the Reference Case account forecast process in each region is projecting account growth in each rate class in each of the VITS, CTS and ITS, the traditional peak demand forecast follows those projections proportionally. The account forecasting process for residential and commercial customers is described in detail in Appendix B-1, Section 1.1 of the Application.

In the Reference Case account forecasts used in the Traditional Peak Demand forecast, residential small and large commercial rate schedules are forecasted but industrial accounts are not. Therefore, the number of accounts in these rate schedules remains fixed at current level. This results in the Traditional Peak Demand forecast showing industrial peak demand as unchanged as well throughout the forecast period in each of the VITS, CTS and ITS.

On page 7-28 of the Application, FEI presents Figure 7-15: ITS Demand-Capacity Balance Using End Use Peak Demand Forecasts:

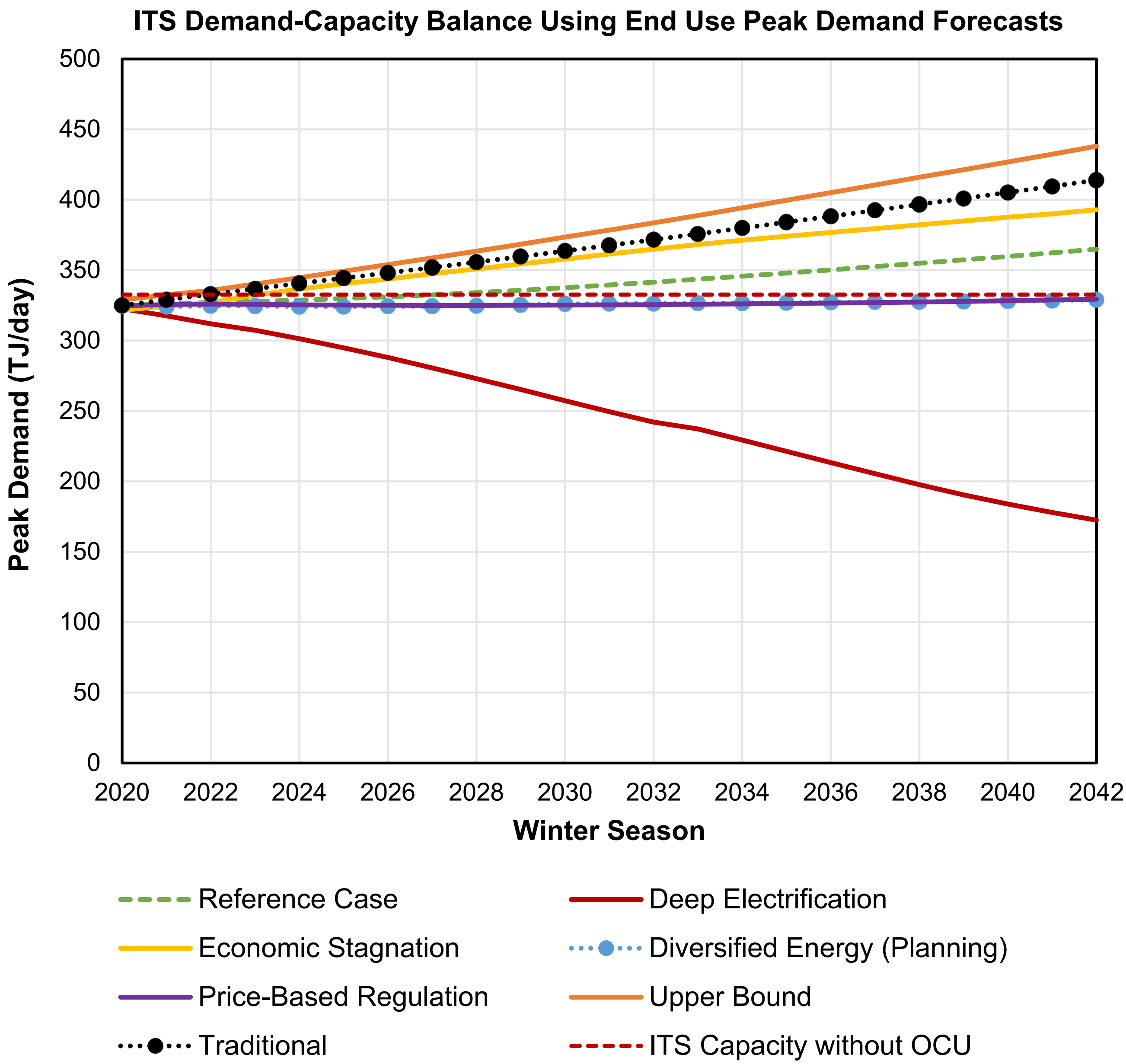
Figure 7-15: ITS Demand-Capacity Balance Using End Use Peak Demand Forecasts



56.5 Please reproduce Figure 7-15 showing ITS Capacity without the Okanagan Capacity Upgrade (OCU) Project.

Response:

The requested figure is reproduced below.



ITS Demand-Capacity Balance Using End Use Peak Demand Forecasts
Peak Demand (TJ/day)
0
50
100
150
200
250
300
350
400
450
500
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
2042
Winter Season
Reference Case
Deep Electrification
Economic Stagnation
Diversified Energy (Planning)
Price-Based Regulation
Upper Bound
Traditional
ITS Capacity without OCU

57.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Section 7.2, p. 7-4, Section 7.5, p. 7-42,Section 7.5.1, pp. 7-42 to 7-43; Appendix E (Gas System Resiliency Plan), pp. 4, 29, 30

Resiliency, and Integrity

On pages 7-42 and 7-43 of the Application, with respect to resiliency of the CTS, FEI states:

> To enhance resiliency in the CTS, as discussed in Section 6.3.2 and 6.3.3, since the T-South incident, FEI has filed an application with the BCUC for the TLSE [Tilbury Liquefied Natural Gas Storage] project to address resiliency for FEI's Lower Mainland systems. FEI is also considering new regional pipeline infrastructure to build on the resiliency provided by the TLSE project and add pipeline diversity to the CTS and broader region. The RGSD [Regional Gas Supply Diversity] project would expand the SCP from Oliver to the Lower Mainland to increase the CTS's supply diversity. In the medium term, FEI's AMI project will be beneficial in enhancing FEI's CTS load management capabilities. These projects will add key components to FEI's portfolio approach to resiliency while providing other benefits for customers.

On page 29 of the Gas System Resiliency Plan (Appendix E), FEI states:

> From a resiliency perspective, on-system storage and new pipeline infrastructure are complementary assets to the supply portfolio as each separately addresses short-duration and long-duration supply issues in a cost-effective manner. Neither is a substitute for the other. For instance, the TLSE project will be the most cost-effective resource to respond immediately to withstand a short-term critical emergency that disrupts supply to FEI's Lower Mainland system such as in phase 1 of the T-South Incident. While FEI's ability to rely on the TLSE project in the event of a supply disruption does not depend on the physical or contractual availability of alternate pipeline capacity upstream of FEI's system, the TLSE project has limitations in addressing long-term capacity shortfalls or duration issues, as experienced during phases 2 and 3 of the T-South Incident. The RGSD project would help manage a long-duration supply disruption while also meeting the commercial needs of the region.

On page 30 of the Gas System Resiliency Plan (Appendix E,) FEI states:

> …the optimal solution is to balance the benefits and costs of additional strategically located pipeline capacity with the benefits and costs of on-system storage located near the load centre. The optimal solution is therefore combining the benefits of the RGSD project with those of the TLSE project to cost-effectively provide broader resiliency benefits and improved flexibility to meet a range of potential supply disruptions and growing demand while also enabling the transition to renewable and low-carbon gas supplies.

57.1 Please explain how FEI's AMI project will be beneficial in enhancing FEI's CTS load management capabilities.

Response:

AMI will provide information and understanding of actual customer demand in near real time and provide a means of remotely isolating load, enhancing FEI's load management capabilities.

FEI currently monitors data from its Supervisory Control and Data Acquisition (SCADA) system to gain an overall understanding of daily and hourly load on the system. However, FEI does not have data available to inform how specific portions or groups of customers are contributing to the overall load. When considering load management, FEI is currently basing decisions on broad assumptions. In circumstances that would require FEI to consider curtailing demand on the system, this lack of detail in the data creates uncertainty in projecting the effectiveness of curtailing certain customer groups or portions of the system to meet any forecasted supply shortage. This impedes FEI's ability to make informed decisions on how to isolate portions of the system in time to effectively address shortages. This data shortfall generally results in decisions on curtailing load that are more impactful to customers than might be necessary to meet any supply shortfall

FEI's proposed AMI project will provide the ability to collect system supply and demand information, identifying where in the system the most significant loads are occurring, and perform remote disconnects if necessary.

AMI provides FEI with a technology platform that will allow the economic installation of additional mid-point pressure and flow sensors, and tail-end pressure sensors. With this technology, FEI will be able to monitor, in near-real time, the performance of all stations throughout FEI's system. To support monitoring and forecasting the total system demand, AMI will provide FEI with the ability to monitor, in near real-time, all customer consumption. This means all meters[70], no matter the size, will be connected to the AMI network. As customer consumption information is collected throughout each hour, FEI will aggregate the total system demand and will be able to determine the granular demand in specific parts of the system. This near-real-time aggregated total demand on the system of interest, and supply performance, will be used by FEI to determine which parts of FEI's system are vulnerable to a pressure collapse during a gas supply emergency.

AMI will also provide the ability to remotely disconnect residential and small commercial customers, in order to decrease the possibility of a pressure collapse. Large commercial and industrial customer meters will not be equipped with remote shutoff valves, and so FEI will continue to rely on slower, manual processes to curtail these customers.

57.2 Please briefly discuss the benefits of the TLSE and RGSD projects identified as part of the portfolio approach to resiliency. In your response, please identify any benefits that overlap between projects.

[70] Except for a small number of non-communicating meters as explained in the AMI CPCN Application.

Response:

As discussed in Sections 5.2 and 5.3 of Appendix E to the Application, the TLSE and RGSD projects provide complementary but distinct benefits. As discussed below, the resiliency benefits associated with each resource are especially important should an outage occur on the T-South pipeline (which currently supplies the majority of the gas to FEI's system) during the winter.

Benefits of the TLSE Project

The TLSE project will significantly improve FEI's ability to maintain short-term continuity of service to the Lower Mainland in the event of a disruption in the supply of natural gas to FEI's system, following a major incident on the T-South pipeline (e.g., Phase 1 of the 2018 T-South Incident, as described in Appendix E, Section 4.4.1 of the Application). In particular, as the only practical and effective solution to withstand and recover from a three-day "no-flow" event on the T-South system, the immediate on-system gas supply provided by the TLSE project will avoid the need to shut down significant portions of FEI's distribution system or otherwise cause firm customers to lose service in the Lower Mainland (FEI's largest service region with hundreds of thousands of customers).

Short-term continuity of this kind cannot be provided in a cost-effective manner by a pipeline solution such as the RGSD project. In particular, without the TLSE Project, FEI would have to increase the size of the RGSD pipeline to enable it to serve as a full replacement for the T-South pipeline and contract significantly more pipeline capacity in order to replicate the resiliency benefits of on-system storage. FEI is not proposing such a solution, as increasing pipeline capacity on the RGSD project beyond an optimal amount would leave a significant portion of pipeline capacity reserved for resiliency with FEI's customers paying higher annual costs due to the additional pipeline demand charges.

Benefits of the RGSD Project

The RGSD project will provide FEI with long-duration continuous piped gas supply from a secondary pipeline source in the event the T-South pipeline is constrained over a long period of time due to another major incident. The RGSD project would be located in a separate corridor, thus reducing FEI's existing dependence on a single upstream pipeline and significantly reducing the risk of a major incident impacting it and the T-South pipeline at the same time (i.e., system redundancy). In particular, the RGSD project addresses one limitation of the TLSE project; namely, that on-system storage cannot be used to address long-term capacity shortfalls or long-duration issues (like those experienced during Phases 2 and 3 of the T-South Incident, as described in Appendix E, Section 4.4.1 of the Application), due to the finite amount of available storage.

Moreover, with a significant portion of FEI's load served through the RGSD project, as partial service resumes on the T-South pipeline following a major incident, FEI would also be able to reduce the required gas supply from the TLSE project and preserve LNG inventory for future needs or use it as supplementary supply when needed during cold weather conditions for load balancing in the Lower Mainland. However, without the RGSD project, FEI's customers would remain vulnerable to a prolonged disruption to supply and without resources to deal with other weather conditions in the same winter once the 2 Bcf inventory reserved for resiliency in the TLSE tank is depleted (e.g., extreme cold weather or peak day conditions when the 3rd Bcf of LNG from the TLSE project is also needed to provide "needle peaking" services to supplement the distribution system).

In addition to providing another avenue of continuous gas supply, the RGSD project is intended to support FEI's decarbonization initiatives by providing an avenue to access renewable gases from new supply sources over time. FEI expects to access renewable methane and hydrogen from new sources within BC and Alberta over the long term. Furthermore, the project will provide FEI's customers access to a large and robust supply basin, namely the AECO/NIT hub, with significant pricing stability and competitive storage contracting optionality.

Ultimately, the combination of the TLSE and RGSD projects will significantly enhance the resiliency of FEI's system by enabling the utility to continue serving the Lower Mainland during periods of high demand to mitigate the risk posed by a low-probability, high-consequence event on the T-South system.

57.3 Please explain whether approval of the proposed RGSD project would impact the design or sizing requirements of the TLSE project.

57.3.1 If yes, please provide a detailed explanation of the impact, and identify the required design and sizing of the TLSE project.

57.3.2 If not, please explain why not.

Response:

FEI confirms that approval of the RGSD project would not impact the design or sizing requirements of the TLSE project. As explained in the response to BCUC IR1 57.2, the 2 Bcf of storage reserved for resiliency in the TLSE tank is optimally sized to enable FEI's system to withstand a three-day no-flow event on the T-South system, while the RGSD project will address longer duration no-flow events or capacity shortfalls.

57.4 Please explain whether there would be an impact to the proposed TLSE project if the RGSD project were to not proceed.

57.4.1 If yes, please provide a detailed explanation of the impact, and identify the required design and sizing of the TLSE project.

57.4.2 If not, please explain why not.

Response:

For the reasons set out in the response to BCUC IR1 57.3, there would be no impact to the TLSE project if the RGSD project were to not proceed.

57.5 Please explain whether there would be an impact to the proposed RGSD project if the TLSE project were to not proceed.

57.5.1 If yes, please provide a detailed explanation of the impact, and identify the required design and sizing of the RGSD project.

57.5.2 If no, please explain why not.

Response:

FEI does not anticipate that the development of the RGSD project will be impacted whether the TLSE project is developed or not. As explained on page 29 of Appendix E to the Application, FEI does not propose to increase the size of the RGSD project to 800 MMcf per day if the TLSE project is not built. Rather, the portfolio approach proposed by FEI that includes both RGSD and TLSE is the most practical solution. Both resources are complementary and provide distinct gas supply functions to FEI's customers as stated in the preamble above.

57.6 Please explain how FEI approaches resiliency planning to identify, prioritize and consider cost impacts of proposed projects, including potential interdependencies between projects.

Response:

FEI approaches resiliency planning to identify and consider cost impacts of proposed projects using the same design principles that FEI applies to its gas supply portfolio through its Annual Contracting Plan (ACP). Section 6.2.1 of the Application details the fundamental principle of constructing an efficient gas supply portfolio of resources, which is to match the resource characteristics to the demand characteristics. In broad terms, an efficient supply portfolio consists of:

- Purchasing firm natural gas commodity volumes and contracting third-party pipeline capacity to address seasonal and base load requirements (i.e., consistent demand for the 151-day winter season and annual demand);

- Using shorter-duration market area storage to provide short- to medium-duration seasonal supply; and
- Using on-system storage resources for short-duration supply to cover events such as winter demand peaks.

Just as FEI's ACP combines assets with distinct attributes to meet the shape of FEI's load profile, a portfolio approach to resiliency incorporates enhancements with distinct attributes that, together, provide a cost-effective approach to resiliency. As the preamble notes, expansions to on-system LNG storage is the most effective way to immediately respond to a critical emergency to ensure the integrity of FEI's system, and aligns well with FEI's efficient supply portfolio and load profile. The addition of new regional pipeline infrastructure, constructed in a corridor different from the T-South system, would help ensure that some supply is available during an event that involves a sustained loss of pipeline capacity. Figure E-8 of the Application illustrates how diverse pipeline capacity can be used efficiently in combination with expanded peaking resources like on-system LNG storage, to build resiliency.

FEI evaluated whether it makes sense to pursue either a pipeline or on-system LNG solution exclusively; however, the analysis indicated that employing only one measure to address all resiliency needs was either too costly or not feasible. Therefore, FEI evaluated multiple solutions and identified a portfolio of investments as the most cost-effective and optimal solution to address its resiliency needs. FEI is unable to specifically prioritize the individual components of these investment decisions because they are complementary and may involve different design and approval timelines impacting in-service time frames.

On page 7-4 of the Application, FEI states:

> In addition to load growth, other factors can also affect system capacity. For example, increased urban density close to existing pipeline assets can lead to a class location designation change and may result in a subsequent reduction in allowable operating pressure for that pipeline. Class location designations are defined in the Canadian Standards Association (CSA) Z662:19 *Oil and Gas Pipeline Systems* standard and used as a protective measure in pipeline design to address population density and other criteria in the vicinity of a pipeline.

On page 7-42 of the Application, FEI states: "To provide reliable service, FEI has maintained the integrity of its assets, and ensured the adequacy and security of gas supply."

On page 4 of the Gas System Resiliency Plan (Appendix E), FEI states:

> In the context of reliability and resiliency, integrity management is concerned with avoiding incidents, such as leaks or ruptures, that would undermine the ability of the assets to deliver service to customers. <u>FEI uses tools and technology to detect</u>

> <u>and mitigate threats to system assets, such as corrosion, third-party damage, and external forces such as landslides, floods, and seismic events.</u> Consistent with industry practice, FEI is continually seeking improved methods to address these threats, including increased use of electro-magnetic acoustic transducer in-line inspection (EMAT ILI). By reducing the likelihood of these threats resulting in incidents, integrity management ensures that it is highly likely that FEI's gas assets will be available to serve customers. Ultimately, ensuring FEI's gas assets remain fit for service is foundational to delivering safe and reliable service to customers. [Emphasis added]

57.7 Please explain generally how the pipeline integrity threats noted above, and the mitigation of these threats, may impact transmission system capacity and capacity planning.

<u>Response:</u>

FEI's integrity management activities work to identify and address integrity threats to ensure safe and reliable operation of its transmission systems. When integrity threats are identified, one mitigation strategy is to temporarily reduce the operating pressure of the pipeline until the threats are investigated and addressed. During this period of reduced pressure operations, which would be in effect until the integrity issue is resolved, there would be an associated reduction in capacity as a result. This is a temporary situation and, once the integrity threat is addressed, pressure restrictions would be lifted to restore the original transmission capacity. As these capacity impacts would be temporary, FEI does not reflect such impacts in capacity planning or in the capacity of transmission system to support the peak demand forecasts.

57.8 Please discuss whether FEI is aware of any updates in the next edition of the CSA Z662 Oil and Gas Pipeline Systems standard that could affect system capacity.

57.8.1 If so, please discuss any potential impact to capacity planning and how it has been considered over the 20-year planning horizon.

<u>Response:</u>

FEI is not aware of any updates to the upcoming 2023 revision of the CSA Z662 standard that would impact pipeline capacity. Therefore, FEI has not included any impacts in the 20-year planning horizon associated with changes to the standard.

58.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Section 7.4, pp. 7-35 – 7-36, Appendix D-2, pp. 6 — 7; B.C. Hydrogen Strategy, pp. 5-6[71]

Off-System Supply of Renewable and Low-carbon Gases

On page 7-35 of the Application, FEI states:

> 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…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.

Further on page 7-36 of the Application, FEI states:

> Although FEI is securing about as many contracts for supply within BC as outside of BC, the larger producers, in the near term, are outside of the province. <u>Therefore, in the early years of the planning horizon, FEI's supply will predominantly be acquired and used outside of FEI's service territory</u>. [Emphasis added]

58.1 Please clarify whether FEI is referring specifically to the off-system supply of RNG or the off-system supply of hydrogen, or both, in the preamble above.

<u>Response:</u>

FEI is referring to both RNG and hydrogen in the references included in the preamble.

58.2 In the near term, please elaborate on the basis on which FEI will select between securing the supply of on-system or off-system renewable and low-carbon gases. For example, on the basis of lowest cost, availability, location of supply, etc.

<u>Response:</u>

FEI selects projects based on a variety of factors such as price, expected volume, price per tonne of carbon reduction, annual GHG savings, feedstock reliability, and community and provincial impact. FEI weighs projects in BC more favourably in terms of community and provincial impact in order to account for non-financial benefits such as partnerships with Indigenous groups or other financial benefits flowing to BC suppliers paid by FEI ratepayers.

[71] https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc-hydro-review/bc_hydrogen_strategy_final.pdf#page=5.

On page 6 of Appendix D-2 to the Application, FEI states:

> Purchasing low-carbon and renewable gases outside of B.C. at low costs can hedge against higher gas costs while offering the option to sell any surplus gas later if sufficient gas can be sourced inside B.C. This could lower the cost for B.C. ratepayers but may at the same time reduce the impetus to develop projects inside B.C. On the other hand, B.C. public natural gas utilities are unlikely to secure as much of this gas as they wish to due to competition. In the U.S., several jurisdictions have implemented renewable gas policies and have created lucrative markets for RNG certificates. Quebec has also enacted a RNG mandate. To take advantage of low-cost renewable gas supply from outside of the province, utilities will need to move quickly as competition for low-cost and low-carbon and renewable gas is likely to intensify.

Further on page 7 of Appendix D-2 to the Application, FEI states:

> The critical next step is for governments, indigenous communities, utilities, and other industry participants to work collectively on policies and investments that will unlock and enable this potential [renewable and low-carbon gas production sector in B.C.]. The report [Appendix D-2] discusses several policy instruments to attract the required investment. These include R&D and demonstration support, policies favouring gas production inside B.C., the monetisation of social and environmental co-benefits, and low interest financing and joint ventures between gas utilities and industry.

Page 5 of the B.C. Hydrogen Strategy states:

> The strategy includes 63 actions to undertake over the short term (2020-2025), medium term (2025-2030) and long term (2030-beyond). These include:
>
> - incentivizing the production of renewable and low-carbon hydrogen;
> - developing regional hydrogen hubs where production and demand are co-located…

Further on page 6, the B.C. Hydrogen Strategy states:

> To reduce emissions and decarbonize the economy, the B.C. Hydrogen Strategy must focus on advancing and providing support only for renewable and low-carbon hydrogen pathways, with long-term targets for declining carbon intensity consistent with net-zero emissions by 2050. Our immediate priorities will be to:
>
> - scale-up green hydrogen production using B.C.'s abundant supply of clean, renewable electricity; and

- establish a regulatory framework for CCS to enable blue hydrogen production while ensuring it has similar or lower emissions.

58.3 Please explain how FEI's strategy to predominantly acquire its supply of renewable and low-carbon gases outside of its service territory aligns with B.C. Government's objectives, in particular, as they are outlined in the B.C. Hydrogen Strategy.

Response:

FEI's strategy to acquire renewable natural gas (RNG) from sources both outside and inside BC is consistent with the objectives of the provincial government and the goals of the BC Hydrogen Strategy. In the near term, expanding supply from outside BC is essential for FEI to make meaningful progress toward achieving the 2030 goals of the CleanBC Roadmap. Over the long term, FEI supports the Province's goal of developing BC supply sources, including hydrogen, as a quickly as possible. FEI's strategy to acquire renewable natural gas (RNG) from sources both outside and inside BC is consistent with the objectives of the provincial government and the goals of the BC Hydrogen Strategy.

As highlighted in the question preamble, the Hydrogen Strategy is focused on ensuring that BC benefits from the emerging hydrogen economy, which FEI is putting significant effort into realizing. This includes developing regional hydrogen hubs, executing a comprehensive plan to blend hydrogen into the distribution system, and ensuring that, as hydrogen demand grows, FEI's existing gas infrastructure is capable and ready to deliver low-carbon hydrogen. Please refer to Section 3.3.3 of the Application for further detail.

59.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES
Exhibit B-1, Section 7.4, p. 7-35
On-System Hubs

On page 7-35 of the Application, FEI states:

> On-System Hubs: Local production and supply of renewable low-carbon gas will be developed. These local hubs, whether they produce RNG, or hydrogen or syngas and lignin will have some ability to free up pipeline capacity as the local demand served by this production no longer needs to be transported through the upstream transmission pipeline.

59.1 Please elaborate on the definition of an On-System Hub. For example, does FEI consider On-System Hubs to be large single customers or clusters of small individual customers? Do On-System Hubs produce and consume renewable low-carbon gas at one site?

59.1.1 Please elaborate on the identified locations of potential hubs of renewable low-carbon gas within FEI's service territory which may be established by 2030. Please include the type of renewable or low-carbon gas (i.e. RNG, hydrogen, lignin, etc.) for each identified hub, as well as the amount (in PJ) of demand and supply of low-carbon gas at each identified hub.

Response:

FEI defines the term "On-System Hub" as a network of one or more facilities producing renewable or low-carbon fuels, and one or more customers that use the renewable and low-carbon fuels to displace conventional natural gas, with connective infrastructure all located in proximity. As FEI continues to grow future renewable and low-carbon gas supply in BC by developing on-system hydrogen, syngas and lignin projects, it is likely that the production facilities will be situated in proximity to available resources and gas consumers that can use the renewable and low-carbon gas to partially or fully displace their conventional natural gas to balance demand. FEI anticipates that there will be opportunities to develop On-System Hubs in its different service territories by 2030; however, the precise resource availability, production location and facility production capacity within each service area, as well as forecast supply volume and demand potential, is not certain at this time.

59.2 Please discuss any differences in the development of On-System Hubs within FEI's three transmission systems (i.e. VITS, CTS, ITS).

Response:

The available resources for On-System Hubs will vary by region and location and are not dependent on which transmission system a potential hub is located within. On-System Hubs at different locations within the same transmission system could develop differently from one another because of local resource availability and the capability of gas consumers in the location to use the renewable and low-carbon gas (RNG, hydrogen, syngas, lignin, or other low-carbon fuels) to displace conventional natural gas in the system. FEI is not anticipating the transmission system will be a factor that would differentiate On-System Hub development.

59.3 Please explain whether FEI anticipates seeking approval of capital expenditures related to On-System Hubs within the next five years.

Response:

Yes, FEI anticipates seeking approval of capital expenditures related to On-System Hubs within the next five years. FEI is currently progressing development activities to better understand the opportunity and requirements to develop On-System Hubs, including enabling activities, resource availability, project size, economics and development timescale and will submit an application when projects are sufficiently developed to meet application submission requirements.

60.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Section 7.4.1.2, p. 7-39

VITS Syngas and Lignin Production

On page 7-39 of the Application, FEI states:

> There are also several existing industrial locations where syngas and lignin production could meet local needs and displace the need for pipeline delivery (and capacity) of conventional gas to those locations.

60.1 Please describe the existing industrial locations within the VITS where syngas and lignin production could meet local needs.

60.1.1 Please provide the syngas and lignin supply potential at each of these existing industrial locations.

60.1.2 Please provide FEI's current estimated timing of developing syngas and lignin supply from these existing industrial locations.

Response:

The BC Renewable and Low-Carbon Gas Supply Potential Study[72] states that syngas could likely be produced at most BC pulp and paper mills to displace conventional natural gas use in lime kilns (pages 48-49). Table 16 (page 63) of that report lists the potential industrial sites, including those on Vancouver Island, where lignin could also be used as a replacement for conventional natural gas.

60.2 Please explain whether FEI anticipates seeking approval of capital expenditures related to the integration of syngas and/or lignin within the next five years.

Response:

Please refer to the response to BCUC IR1 59.2 and 59.3 with regard to the development of syngas/lignin supply (along with other renewable and low-carbon gases) as an on-system hub.

[72] Exhibit B-1, Appendix D-2.

61.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Section 7.4.1.2, pp. 7-39 – 7-40; FEI TLSE CPCN proceeding, Exhibit B-15, BCUC IR 21.1 FEI Coastal Transmission System Transmission Integrity Management Capabilities Project (TIMC) CPCN proceeding, Exhibit B-19, Panel IR 1.1, 1.3[73]; FEI Revised Renewable Gas Program Application – Stage 2 proceeding, Exhibit B-17, BCUC IR 3.9, 3.10.1[74]

Hydrogen Blending

On page 7-39 of the Application, FEI states:

> To integrate hydrogen into the VITS, with the possibility of the Woodfibre LNG project entering service within the next few years and given the impacts of hydrogen blends on pipeline capacity and larger scale LNG production, FEI is not currently considering allowing hydrogen blends into the system at Eagle Mountain (the start of the VITS).

Further on page 7-40 of the Application, 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.
>
> Hydrogen at locations like Tilbury and Eagle Mountain, and possibly other industrial locations using methane as a feedstock would require hydrogen to be removed to accommodate production… [Emphasis added]

61.1 Please clarify whether FEI's current designs of the Eagle Mountain to Woodfibre Gas Pipeline Project, including the designs of the Eagle Mountain and Squamish compressor stations, are based on a feed gas composition which includes a hydrogen component of up to 20 percent by volume.

Response:

The current design of the Eagle Mountain to Woodfibre Gas Pipeline Project, including the designs of the Eagle Mountain and Squamish compressor stations, is not based on a gas supply composition that contains 20 percent hydrogen by volume. Although a solution could be engineered if needed, as discussed on p. 7-39 of the Application, FEI is not currently considering hydrogen blends into the VITS at Eagle Mountain, due to the impact of hydrogen blends on pipeline capacity and consequent LNG production at Woodfibre.

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[73] https://docs.bcuc.com/Documents/Proceedings/2022/DOC_65718_B-19-FEI-responses-to-Panel-IR-No1.pdf.

[74] https://docs.bcuc.com/Documents/Proceedings/2022/DOC_66560_B-17-FEI-response-to-BCUC-IR1.pdf.

This does not preclude hydrogen from being introduced downstream of the Woodfibre site. The compatibility and tolerable blend percentages for existing downstream infrastructure has yet to be fully determined.

61.2 Has FEI identified any industrial locations within the CTS currently using methane as a feedstock, and which would require the removal of any blended hydrogen? If so, please explain.

Response:

FEI is aware of industrial locations within the CTS that use natural gas as a feedstock and that could be sensitive to the inclusion of hydrogen in the gas supply. These include locations where LNG is produced through liquefaction of methane, where hydrogen is produced through reforming of methane, or where commercial production requires the combustion of methane (such as cement production). FEI intends to engage with all industrial customers within the CTS prior to introducing hydrogen to the gas supply in order to identify their supply requirements, including any impact mitigation measures or the removal of any blended hydrogen, if necessary.

In response to BCUC IR 21.1 in FEI's TLSE CPCN proceeding, FEI stated:

> FEI does not anticipate impacts on the TLSE Project, nor on its liquefaction process, as a result of increasing hydrogen content in the gas stream as hydrogen can be separated if introduced upstream of the Tilbury facility.
>
> There are two potential options available to mitigate the impact on LNG operations from increasing hydrogen content in the gas system:
>
> - hydrogen would be removed by separating it from the gas supply upstream of the LNG facility and then redirected to a different part of the gas network; or
> - hydrogen would enter the LNG facility but would be extracted prior to liquefaction and stored separately onsite for use in gaseous or liquid form (e.g., for fuel cell electric vehicle refueling).
>
> This would mitigate:
>
> - Impacts on the rate of boil-off gas generation from the LNG storage tank;
> - The risk of stratification within the LNG storage tank; and
> - The impact on FEI's long-term LNG storage operations.

> Both options would remove the hydrogen from the gas stream prior to liquefaction and hence the LNG tank would continue to only store liquid natural gas. As such, there are no increased capital or operating costs included in the TLSE Project associated with the future use of hydrogen in FEI's gas supply network

In response to Panel IR 1.3 in FEI's TIMC CPCN proceeding, FEI stated:

> All of the pipeline segments modified by <u>the CTS TIMC Project will be used and useful following the blending of increasing concentrations of hydrogen into the CTS</u>. As explained in Section 5.4.2 of the Application, replacement of some pipeline segments is included within the scope of the CTS TIMC Project. During their design and construction, FEI will consider the potential for future use of these pipeline segments to transport increasing percentages of hydrogen. For clarity, these limited replacements may not make the overall pipeline capable of transporting high concentrations of hydrogen, but they may eliminate possible future bottlenecks and allow FEI to increase hydrogen blending concentrations in certain pipelines for little to no cost…

> The only prudent course of action at this time is to modify the existing CTS pipelines to allow them to be inspected using EMAT ILI. This will allow any existing cracking issues to be identified and addressed. <u>Given that the CTS pipelines can carry a blend of hydrogen today, and replacement of the CTS to accommodate hydrogen is not reasonably contemplated, FEI's CTS pipelines will continue to be used and useful</u>. As FEI has an obligation to provide safe service to its customers, FEI cannot defer the CTS TIMC Project due to the potential for hydrogen-related developments on its system. The information gathered by EMAT ILI will also directly factor into FEI's analysis of determining what concentration of hydrogen each pipeline can safely accommodate in the future. [Emphasis added]

Further on page 7-40 of the Application, FEI states:

> The hydrogen "backbone" described earlier is a likely and flexible way that the system can be expanded later in the forecast period considering the number of factors, yet be fully determined, that may need to be defined and managed.

61.3 Please describe the analysis that FEI has undertaken to identify their current preferred approach for the delivery of hydrogen to the CTS customers. Please include in the discussion the strategy drivers considered; the volumes of hydrogen analyzed, alternatives considered, operational and cost impacts and all assumptions made.

<u>Response:</u>

In this response, FEI discusses past and ongoing analysis that FEI has undertaken to identify its overall hydrogen deployment strategy, including the preferred approach for the delivery of hydrogen to CTS customers. FEI also discusses assumptions made and conclusions drawn from this analysis. A discussion of the strategy drivers considered, the volumes of hydrogen analyzed, alternatives considered, and operational impacts is provided in the IRs referenced in the preamble, which are provided in Appendix D, and Section 7.4.1.3 of the Application. At this stage, FEI does not have sufficient information to address in more detail the potential cost impacts of the delivery of hydrogen to CTS customers.

Analysis, Assumptions, Conclusions:

FEI has developed a preliminary hydrogen development roadmap that integrates our ongoing and planned activities to verify that hydrogen is safe to transport in the existing CTS gas system and confirm any changes that would be required to FEI's system to integrate hydrogen at higher blend levels in the future. FEI also continues to utilize available resources including our Clean Growth Innovation Fund (CGIF) to build our knowledge base and business innovation portfolio by supporting hydrogen technology development and other research initiatives in BC and Canada.

FEI's preliminary analysis indicates potential availability of renewable and low-carbon hydrogen ("hydrogen") to supply CTS customers

FEI is engaging with potential hydrogen producers and collaborating to investigate feasible opportunities to offtake, self-develop, and co-develop hydrogen production for supply to CTS customers. Analysis to date includes technical and economic feasibility and preliminary business case analysis to acquire hydrogen via different production pathways. Based on this analysis, FEI's 10 year supply outlook includes:

- On-system industrial by-product hydrogen upgraded to pipeline quality – supply potential up to 0.5 PJ per year;
- On-system turquoise hydrogen derived from pyrolysis of natural gas feedstock with solid carbon removal – supply potential up to 3 PJ per year;
- On-system green hydrogen derived from electrolysis of water using clean grid electricity – supply potential up to 3 PJ per year; and
- Off-system low-carbon intensity hydrogen delivered by displacement – significant supply potential, however, regulatory approval requirements are currently uncertain.

FEI's research, testing, development, and innovation indicates hydrogen-natural gas blends will be safe to distribute in the CTS gas system for use by CTS customers

FEI's analysis is based on ongoing engagement with research institutions and participation in BC- and Canadian-based research and development initiatives. FEI is partnering with UBC School of Engineering to develop a scalable and automated laboratory, the "H2Lab", to conduct an integrated experimental study on the performance and feasibility of distributing hydrogen-natural gas mixtures in the BC gas system for a range of 5 – 20 percent hydrogen blend concentration level by volume. UBC has completed the experimental first phase of the program. The results of this phase provide guidance on the requirements to inject hydrogen into the gas system, including with respect to achieving mixing quality, managing the flammability of accidental releases, understanding material exposure and managing the integrity of steel distribution lines, separating hydrogen from blended gas supply for dedicated hydrogen customers, maintaining stable combustion, and developing innovative leak detection technology.

The H2Lab is now entering phase 2 that will progress the experimental study to full-scale lab demonstrations in 2023. FEI expects the results will support the practical deployment of hydrogen by informing FEI's first hydrogen blending trials in the gas distribution system and the longer-term hydrogen roll out.

Since 2018, FEI and other Canadian utilities have individually completed testing on a representative subset of in-service gas appliances to validate safe operation on a range of hydrogen-natural gas blends. The results and conclusions of this work have informed regulatory approval for the first two hydrogen blending pilots in Ontario and Alberta. Hy4Home is a recently-initiated joint industry project comprising a consortium of Canadian gas utility companies with a common goal to combine results from completed appliance testing programs and blending pilots and progress further testing on a wider representative sample of all in-service appliances in Canada to verify the safe operation on hydrogen blends. FEI is closely monitoring the progress of this project.

FEI's engagement and participation in international efforts informs our plans to safely deploy and operationalize hydrogen at increasing blend levels in the CTS gas system

FEI's analysis is based on active and ongoing participation in international efforts to pioneer the safe use of blended hydrogen in gas networks to reduce emissions. FEI is engaged at various levels in multiple international joint industry initiatives that aim to rapidly develop a hydrogen ecosystem that can produce and distribute hydrogen as a clean energy supply. The conclusions from this work continue to play a significant part in transforming the mindset of industry towards a hydrogen future

Since 2018, FEI has been a member of HYREADY which is an international consortium that is preparing engineering guidelines to deploy hydrogen in the gas system. The guidelines would be targeted to multiple work packages, including blending hydrogen with natural gas and converting distribution systems to 100 percent hydrogen service. Over the last three years, FEI has also participated in a range of additional joint industry projects focusing on topics including advanced composite pipelines, integrity management for hydrogen pipelines, and investigation of best practices to perform planned and unplanned maintenance on hydrogen pipelines.

FEI continues to learn best practices from industry-leading hydrogen projects and international programs that it hopes to apply in BC to advance innovation in deploying hydrogen as a mass market fuel. HyDeploy[75] is a UK program pioneering the safe use of blended hydrogen in gas networks to reduce carbon emissions; it has been in operation since 2017 and continues to provide the results from its various research phases and public trials. In addition, there are numerous UK projects to identify the technical barriers to 100 percent hydrogen service, including the impact to domestic appliances such as boilers, and industrial and commercial applications.

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[75] HyDeploy, "Pioneering the safe use of blended hydrogen in gas networks to reduce carbon emissions" (2022) online at: https://hydeploy.co.uk/.

The Hy4Heat[76] program, established by the UK government, conducted the first holistic safety assessment which demonstrated that the use of 100 percent hydrogen for heating and cooking can be made as safe as the use of natural gas in the most common domestic UK buildings. The evidence and technical conclusions from the program work packages are fully available.

FEI is also engaged through international collaboration forums with European gas system operators such as Gasunie,[77] which are advancing accelerated plans to convert segments of the existing natural gas transmission system to 100 percent hydrogen service by 2026, with the goal of developing a national transportation network by 2030. FEI expects these advances will inform global industry advances and inform FEI's long-term plans to convert segments of the CTS to hydrogen service.

FEI has prepared engineering guidelines that indicate safe blending concentration limits for hydrogen in the gas system

FEI engaged industry specialists to prepare Hydrogen Blending Engineering Guidelines (Hydrogen Blending Guidelines) based on a review of FEI's gas system assets. This analysis was informed by a literature review, leading industry research, and subject matter experts, with the goal of understanding the admissible limits for hydrogen blending. A significant portion of the gas distribution systems served by the CTS are constructed of polyethylene and steel, which both have properties that are less susceptible to degradation concerns. Our current research indicates that gas distribution assets that were not designed and constructed from the outset for hydrogen service can still transport meaningful quantities of hydrogen and will be subject to further technical review and validation.

FEI has ongoing and planned transmission and distribution gas asset and end-use technical assessments to investigate methods to mitigate risks of higher hydrogen blends

Based on pre-feasibility work completed over the last number of years, FEI plans to undertake a comprehensive technical review and hydrogen readiness assessment of all gas system assets and customer end-use equipment and systems referred to as the BC Gas System Hydrogen Blending Study and Technical Assessment project. This technical review and assessment will include safety, system integrity, and performance considerations, and will analyze the implications of adding hydrogen to FEI's network operations. FEI will develop measures to mitigate any consequences of adding hydrogen in order to ensure gas networks and customer end-use systems, processes and appliances are hydrogen-ready. This program of work will include asset-specific engineering assessments, field testing, and technical verification, with governance and oversight from the Province of BC, the soon-to-be BC Energy Regulator (formally the BC Oil and Gas Commission), and Technical Safety BC, to investigate hydrogen blending targets across the entire gas system.

In addition, FEI's ongoing program of hydrogen research and development activities, including, for example, the data collected by FEI's proposed CTS TIMC Project and other in-line inspection

[76] Hy4Heat, News Page, online at: https://www.hy4heat.info/.

[77] Gasunie, "Gasunie starts construction of national hydrogen network in the Netherlands", June 29, 2022 Press Release, online at: https://www.gasunie.nl/en/news/gasunie-starts-construction-of-national-hydrogen-network-in-the-netherlands.

(ILI) activities, will allow FEI to identify and address integrity on the CTS pipelines. This work will help FEI evaluate the safe operation of the CTS pipelines under various hydrogen blending scenarios in the future. FEI is also investigating emerging industry solutions to inhibit and mitigate issues such as hydrogen embrittlement. Further research and technical assessment is ongoing to analyze if the levels at which the oxygen is present in the gas system would be sufficient to mitigate the risk of embrittlement if high concentrations of hydrogen were added to the CTS pipelines.

This body of work is expected to reinforce FEI's conclusions as to the optimum hydrogen blend concentration levels in the current gas system and prepare plans to increase the blend concentration levels over time. Further, FEI expects that achieving this goal will be managed effectively through the development of codes and standards, regulatory amendments, and ongoing sustainment upgrades as the gas network continually evolves.

FEI continues to explore infrastructure repurposing for future 100 percent hydrogen distribution networks to integrate higher levels of hydrogen into the CTS

FEI's analysis is based on already-completed preliminary technical reviews of select segments of the existing high-pressure and low-pressure gas system pipeline network in BC. These reviews indicate it may be feasible to transport up to 100 percent hydrogen in FEI's existing pipes; however, further work will be required to confirm any upgrades to pipeline station facilities and to establish other suitable mitigations to ensure the safety and security of gas supply and system which would also apply to the CTS. FEI has also completed desktop analysis on recently deactivated CTS gas distribution system assets, which indicates it is potentially feasibly to repurpose them to 100 percent hydrogen service.

The distribution of 100 percent hydrogen may be pursued by FEI in the future either through retrofitting existing infrastructure, investing in new infrastructure, or by producing hydrogen closer to the point of use. However, at this time, FEI does not know which, if any, of the segments of the CTS might need to be replaced or repurposed, nor the timing of this work. FEI does not envision CTS pipelines being removed and replaced with new hydrogen-ready pipelines, as this would not be a cost-effective method to potentially support 100 percent hydrogen distribution.

FEI is preparing to deploy community trials to blend hydrogen in the gas distribution system

As our understanding on hydrogen production, distribution, and end-use applications develops, FEI is also currently planning pilot demonstration projects that will test the use of hydrogen in controlled sections of our gas networks prior to more widespread roll-out of hydrogen. Given the technical research and testing completed to date, FEI has identified a segment of the CTS gas distribution system that in its current form can distribute hydrogen as a blend in the natural gas stream. FEI anticipates that successful blending pilot results will allow FEI to move from the requirement to survey, test, and trial all parts of a network prior to injection, to the ability to inject into an untested CTS network. This will be achieved through development of the evidence base through blending in this multi-year project.

FEI's hydrogen deployment roadmap assumes necessary updates to Regulations, Codes and Standards

FEI recognizes that because hydrogen is not currently present in the gas supply, the development of codes, standards, and clear regulatory requirements will be critical to market development and ensuring the ongoing safety and reliability of the energy delivery system. FEI's analysis is based on participation and collaboration with NRCan codes and standards working groups, research and development institutions, gas industry peers, technical regulators, and standards organizations to identify knowledge gaps and develop standards, procedures, and approval pathways to integrate hydrogen into the gaseous energy supply. FEI continues to work with governing bodies and authorities having jurisdiction to develop a deployment strategy to manage change and address safety, training, and education for supply chain stakeholders and wider societal perceptions and considerations as outlined below. This work will also address gaps in codes, standards, and regulations and inform the regulatory pathway in BC for the implementation of hydrogen throughout the BC gas system with residential, commercial, and industrial customers.

The Hydrogen Codes and Standards Working Group (H2CSWG) was established in April 2021 to support the implementation of the Hydrogen Strategy for Canada. The H2CSWG is co-chaired by Natural Resources Canada (NRCan) and the Standards Council of Canada (SCC) and is comprised of over 100 experts and representatives from various industries, governments, academia, and non-governmental sectors. Updating existing codes and standards for natural gas transmission and distribution systems and customer end-use equipment is ongoing, for example, under the direction and leadership of various NRCan program initiatives. This work will take time and involve many stakeholder consultations, and alignment with national and international standards and Original Equipment Manufacturer capacities.

The H2CSWG is charged with:

- Promoting coordination and strengthening collaboration amongst its diverse interested parties; and
- Formulating recommendations on hydrogen-related codes and standardization matters in support of the implementation of the Hydrogen Strategy for Canada.

The Canadian Standards Association (CSA) Oil and Gas Pipeline Systems Code (CSA Z662) and Steel Pipe Code (CSA Z245.1) does not currently support the blending of hydrogen natural gas. A CSA Z662 Task Force has been set up to review and recommend requirements for the 2023 edition of the CSA Z662 standard, specifically for hydrogen or blended hydrogen service. The purpose of the Task Force is to review and update the requirements for gas pipelines to ensure that pipelines containing pure hydrogen, hydrogen blends or renewable natural gas are fully aligned with or incorporated into the CSA Z662 and CSA Z245 Standards with a target to have all necessary changes in place no later than the planned 2027 edition of Z662. The task force will leverage previous work including standards from other jurisdictions, as applicable, to help guide the process for CSA. This may include referencing entire standards, aligning technical requirements, using similar approaches from existing documents or creating new standalone documents.

FEI is working with the CSA Task Force on a conformance strategy for transmission system pipelines to be developed that includes participation in the CSA pipeline standards development process and other industry organizations engaging with the Canadian Energy Regulator (CER), BC Oil and Gas Commission (OGC), Technical Safety BC, as well as other provincial regulators as applicable, to be able to anticipate and influence future regulations. FEI intends to leverage this interaction with regulators to understand their expectations in the form of pilot and demonstration facilities and any advanced notifications required.

Hydrogen blending in existing gas equipment and appliances is not currently supported because gas equipment and appliances standards lack test gas specifications to support testing. The H2CSWG has recommended the establishment of a Task Force under CSA, with input from other key industry stakeholders like manufacturers, research labs, utilities, and certification bodies. The goal will be to establish an official maximum blend limit to be published by a technical authority such as CSA. This will require changes to the following standards:

- CSA B149 family of standards – Gas Installation Codes
- CSA Z21/Z83 family of standards – Gas Appliance & Components Safety Standards
- CSA JB121 family of standards – Fuels & Appliances – Energy Performance Standards

As discussed above, FEI will continue to work with governing bodies and authorities having jurisdiction to develop its hydrogen deployment strategy.

FEI is developing an optimum approach to deploy hydrogen to CTS customers

FEI's market engagement to confirm the expected availability of renewable and low-carbon hydrogen supply in terms of production location, production volume, and offtake price is ongoing. FEI expects hydrogen blending in the gas system will be a key near-term offtake strategy to build hydrogen demand, reduce emissions, and stimulate the hydrogen market in BC. Therefore, FEI continues to advance a range of activities to study, test, and verify that hydrogen will be safe to use and scale in the existing gas system and to identify any changes that may be required to ensure ongoing safe operation of the gas system. FEI has not yet determined the overall cost impacts as further analysis will be required to map out the consequences of hydrogen addition for FEI's network operations and mitigation measures. FEI expects the transition to hydrogen would not reduce the use and usefulness of the CTS. Based on its analysis to-date, FEI expects the CTS will continue to supply natural gas (both conventional and renewable) as the transition to integrating hydrogen supplies progresses:

- Within the next three years, FEI expects to execute a hydrogen blending demonstration pilot project for the CTS, which will be a precursor to pursuing additional projects in the near term to establish the use of hydrogen in FEI's gas system.
- After successful demonstration and validation, FEI expects to blend hydrogen into the CTS lower-pressure distribution system network, or subsections of the lower-pressure distribution system served by the CTS, at blend concentrations of up to 5 percent hydrogen by volume.

- Over time, FEI expects to expand hydrogen blended service across more of the distribution system network served by the CTS, at higher blend concentrations of between 20 and 30 percent hydrogen by volume, with the potential for segments within the system to expand to include hydrogen networks that can distribute higher shares of hydrogen. This will include expanded local hydrogen production facilities interconnected to the distribution system.
- Further out in the forecasting period, as hydrogen begins to support more of the core demand, load will be displaced from the CTS and a backbone pipeline network would likely be required to support increasing hydrogen supply into the Lower Mainland and to directly connect supply to demand nodes. These demand nodes may include larger single-point customers that can convert to hydrogen or involve FEI gate stations that connect the distribution networks to the CTS.
- Beyond that point, FEI expects it may become necessary to expand, upgrade or repurpose some components of the CTS to support and enhance the capacity of the blended systems, while still supporting the remaining dedicated natural gas requirements. Over the longer term and as supply and demand for hydrogen grows, FEI expects to transition the CTS higher pressure transmission system pipeline corridors through retrofitting, upgrading and expansion to transport an increasing share of hydrogen and RNG, which will include supply delivered from outside the CTS. This will include import of hydrogen by pipeline into the CTS.

61.4 Please clarify whether FEI's strategy with respect to the integration of hydrogen has changed from the time FEI responded to IR's in the TIMC CPCN proceeding to the time FEI filed its LTGRP Application.

Response:

FEI continues to develop its hydrogen deployment strategy which has not materially changed from the time FEI responded to the IRs in the TIMC CPCN proceeding.

61.4.1 Please explain when the hydrogen "backbone" approach to integrating the supply of hydrogen was first contemplated by FEI.

Response:

FEI first contemplated the hydrogen "backbone" concept to integrating the supply of hydrogen in 2019, when the BC Bioenergy Network released its British Columbia Hydrogen Study.[78] This

[78] Exhibit B-1, Application, Appendix A-6.

concept further evolved after the subsequent release of the Federal Government's Hydrogen Strategy for Canada[79] in 2020, and the BC Renewable and Low-Carbon Gas Supply Potential Study[80] and the Province's BC Hydrogen Study[81] in 2022. These policy documents were instrumental in guiding FEI's vision for the potential role that hydrogen could play in decarbonizing the province's gas system.

61.5 Please confirm, or explain otherwise, that the driver for pursuing a hydrogen "backbone" approach to supply hydrogen to customers within the CTS is the requirement for hydrogen separation facilities at Tilbury and Woodfibre LNG facilities, due to the inability to accommodate hydrogen as a component within the gas supplied to those LNG facilities.

Response:

Not confirmed. The driver for pursuing a "backbone" network of pipelines to transport hydrogen is to efficiently connect hydrogen producers and consumers and integrate hydrogen supply as On-System Hydrogen Hubs evolve, and then later in the forecast period efficiently inter-connect On-System Hubs in different regions with abundant renewable and low-carbon hydrogen supply potential with centres of demand. FEI has yet to determine the optimum strategy to integrate hydrogen supply to customers served by the CTS. Depending on the location, size, and timing of hydrogen production, and whether production is interconnected to blend into the transmission system, the downstream distribution system, or through dedicated infrastructure to connect production directly to customers, some of the hydrogen could flow towards the referenced LNG facilities, in which case there would be a need to separate the hydrogen from the feed supply to those facilities. Please refer to the response to the BCUC IR1 61.4.1 for further details.

61.6 Please discuss whether pursuit of the hydrogen "backbone" approach would reduce the use and usefulness of the CTS in the long term.

Response:

Even with the transition to hydrogen, the CTS will continue to supply natural gas (both conventional and renewable), including to the Tilbury LNG facilities and the VITS, as the transition to integrating hydrogen supply progresses.

[79] Exhibit B-1, Application, Appendix A-3.
[80] Exhibit B-1, Application, Appendix D-2.
[81] Exhibit B-1, Application, Appendix A-4.

On page 7-39 of the Application, FEI states:

> FEI is not currently considering allowing hydrogen blends into the system at Eagle Mountain (the start of the VITS). FEI would achieve this by controlling the flow of hydrogen in the upstream CTS. However, downstream of the Woodfibre LNG plant there is potential to produce hydrogen in local hubs to be used locally or to be blended into the transmission or distribution system. <u>This integration of hydrogen would require some means of removing hydrogen at FEI's Mount Hayes LNG facility when the plant in liquefying</u>. [Emphasis added]

61.7 Please clarify whether hydrogen "backbone" approach to integrating hydrogen is likely for the VITS, due to the need to remove hydrogen from the feed gas entering into FEI's Mount Hayes LNG facility.

Response:

As discussed in the response to BCUC IR1 61.5, FEI does not consider the need to remove hydrogen from the gas supply entering the Mount Hayes LNG facility as a driver of whether the "backbone" approach to integrating hydrogen is appropriate for the VITS. The rate of LNG production on the VITS downstream of the Woodfibre LNG facility is relatively small compared to the LNG production that currently exists and that is projected to develop on the CTS at Tilbury and on the VITS at Woodfibre LNG. The scale of facilities that would be required to separate hydrogen at the Mt. Hayes LNG facility is also relatively minor, making blending hydrogen into the VITS downstream of Woodfibre LNG facility more feasible.

61.7.1 If FEI considers future hydrogen blending within the VITS (downstream of Woodfibre LNG plant) to be more likely than future hydrogen blending within CTS, please explain why.

Response:

At this time, FEI does not consider future hydrogen blending within the VITS downstream of the Woodfibre LNG plant to be more likely than future hydrogen blending within the CTS.

In response to Panel IR 1.1 in FEI's TIMC CPCN proceeding, FEI stated:

> In 2021, FEI completed the scope definition and budget and schedule planning for a project to confirm the admissible limits for hydrogen blending for its existing natural gas infrastructure and end-use customer equipment and applications in

British Columbia. This project will start in 2022 and focus on the following key objectives to be completed by 2024:

- o Determine longer-term increases to the hydrogen blend targets that would be feasible with continuing research, regulatory amendments and codes and standards development, mitigation measures, and network upgrades…
- o Develop a <u>hydrogen deployment roadmap</u> to address the technical uncertainties, overlapping project requirements, and any limitations on system capacity to optimize for larger-scale hydrogen production, distribution and use… [Emphasis added]

61.8 Please provide an update regarding the development of FEI's hydrogen deployment roadmap.

<u>Response:</u>

FEI has issued a Request for Proposal and expects to engage external professional service providers to assist FEI in further developing its hydrogen roadmap plan through the BC Gas System Hydrogen Blending Study and Technical Assessment project. This is part of an integrated program of work to evaluate all of FEI's gas system assets and gas customers' installations, in order to establish the requirements and overall strategy to blend hydrogen throughout FEI's service territories. FEI expects to advance its hydrogen roadmap throughout 2023 and 2024 as part of the broader program of work that will also include developing a hydrogen deployment strategy to guide FEI's roll out of hydrogen in the near-term and also the longer-term.

61.8.1 Please provide a summary of the key objectives of FEI's hydrogen blending project that will be completed in 2022.

<u>Response:</u>

FEI is currently in the process of planning a hydrogen blending pilot project with the following objectives, all of which have been initiated but none will be completed in 2022 or before the pilot is established:

1. As a first mover project, it will demonstrate to gas customers the practical use of hydrogen in FEI's gas system and support conversation, education, advocacy and present a forum to dispel concerns and lay the groundwork for wider customer comfort with the adoption of hydrogen as a new sustainable fuel.
2. Enable FEI to gain practical insight into hydrogen's compatibility in the natural gas distribution network.
3. Support the potential to unlock growth of the renewable gas portfolio in BC through more extensive use of hydrogen in FEI's natural gas network. This project will help further the

overarching goal of allowing hydrogen suppliers to be able to apply to inject hydrogen into FEI's network, just as renewable natural gas producers can today.

4. Engage the relevant safety and regulatory authorities to establish the necessary regulatory framework and inform of any changes needed to enable the safe blending of hydrogen on a commercial basis into natural gas infrastructure.
5. Based on evidence gathered and results obtained, the project will help inform the requirements of an internal hydrogen standard to enable the use of hydrogen as a utility gas.

61.9 Please describe the next steps required (e.g. continuing research, pilot studies, regulatory amendments) prior to FEI beginning to deliver on-system hydrogen to its customers.

Response:

FEI is designing a hydrogen development roadmap plan (Hydrogen Roadmap) and has issued a Request for Proposal (BC Gas System Hydrogen Blending Study and Technical Assessment project) for external services providers to assist FEI in progressing the next major steps that are outlined below.

Confirmation of hydrogen blending targets and ambitions

FEI currently aims to confirm that a 5 percent by volume blend of hydrogen by 2025 and up to a 30 percent volume blend of hydrogen is feasible by 2030. FEI will continue to validate these targets as part of the strategy to efficiently manage the gas portfolio change and hydrogen roll-out.

Annually Updated State of the Art Analysis (SOTA)

A SOTA analysis will be required to leverage work already completed by other entities and jurisdictions regarding end-users' use and adoption of hydrogen blends, and to inform the Hydrogen Roadmap.

Feasibility Study Technical Evaluation

Through implementation of a series of technical and safety evaluations, FEI will determine the compatibility of hydrogen with the existing transmission and distribution systems and customers' end use equipment, processes, systems, and applications. Specific upgrades and other activities required for the gas system to continue to operate safely and reliably with the targeted hydrogen blend will be identified. The technical assessment will also identify gaps in knowledge which will inform the design of research and innovation activities, as well as modifications to existing codes and standards.

Field surveys and material compatibility testing

Based on the results of a Hydrogen Feasibility Study, field surveys and material compatibility testing will need to be completed to further assess the hydrogen compatibility of the existing transmission and distribution systems and customers' end use equipment.

Research and innovation

Research and innovation programs will fill gaps in knowledge identified by the Hydrogen Feasibility Study and technical assessments. For example, research may focus on the hydrogen compatibility of specific end-user appliances, or material compatibility tests could be performed in a research environment. If new end-user appliances or other components are required as part of the transition to hydrogen-natural gas, innovation projects with local partners can be defined to develop these components. For example, FEI currently has an ongoing project with UBCO's School of Engineering to develop a H2 Lab across three phases of development to operate a scalable and automated hydrogen-enriched natural gas (HENG) laboratory testbed.

Identify Hydrogen availability to supply hydrogen blending and other end-use demand scenarios

There are scenarios in which hydrogen blending levels could be limited by hydrogen gas supply. To inform the Hydrogen Roadmap, FEI will evaluate potential locations to blend hydrogen or for direct industrial displacement and sources of renewable and low-carbon hydrogen supply. This will determine if these sources are sufficient to meet the hydrogen ambitions and targets.

End-user equipment plan

FEI will define an overall plan to increase the maximum amount of hydrogen acceptable for existing installed equipment. The plan will inform the Hydrogen Roadmap and include details for:

- Certifying existing equipment and infrastructure that can handle various hydrogen concentrations as hydrogen-compatible, if cost-effective;
- Developing and rolling out the mitigation measures identified in the Feasibility Study to maximize the amount of hydrogen which can be accommodated by the currently-installed equipment and infrastructure;
- Replacing equipment parts (e.g., burners, injectors) or components which cannot be retrofitted and are sensitive to the presence of hydrogen;
- Defining routes for developing new test gases (reference and limit gases) to test new equipment for targeted blend levels;
- Defining strategies with regards to appliance approval (product certification) for targeted blend levels;
- Investigating routes to develop permissible technical properties for hydrogen gas (e.g., Wobbe range, density, calorific value); and
- Defining a replacement program for the roll-out of new hydrogen-ready end-use equipment and gas infrastructure.

Pilot and demonstration projects

FEI intends to develop hydrogen blending pilot projects to demonstrate the ability of the system to accommodate hydrogen-natural gas blends. These projects will verify the findings from the Feasibility Study technical assessments and inform regulatory pathways to support efficient deployment of hydrogen to meet the hydrogen blending targets.

Codes, standards, and regulations

Updating existing codes and standards for natural gas transmission and distribution systems and customer end-use equipment is ongoing (for example, under the direction and leadership of various NRCan program initiatives) but will take time and involve stakeholder consultation, as well as alignment with national and international standards. A plan for these activities, including identification of all codes, standards, and stakeholders, will be developed as part of the Hydrogen Roadmap.

Enabling policies

For a large-scale roll-out, enabling policies may be required. For example, policies which encourage industries and other end-users to accommodate hydrogen-natural gas blends, such as an incentive system for residential users who purchase hydrogen-certified appliances. A plan for these efforts is to be developed as part of the Hydrogen Roadmap.

Training and education

FEI workforce training will be required to support the roll-out of hydrogen blends in accordance with relevant codes and standards, internal and external practices and procedures, and public safety requirements. Existing training programs for maintenance and inspection personnel will be reviewed and required modifications will be identified and provided in the form of a proposed outline framework, including guidance and recommendations on any new requirements for hydrogen.

Roll-out

With all the previously described activities in place, the roll-out of hydrogen-natural gas blends can be initiated, including activities for systematic roll-out of initial and increasing hydrogen blends.

61.9.1 In what year does FEI anticipate it will begin delivering on-system hydrogen?

<u>Response:</u>

If FEI is successful in executing the Hydrogen Roadmap tasks as outlined in response to BCUC IR1 61.9, the first project to pilot and demonstrate on-system hydrogen could be in operation prior to 2025. Subject to successful pilot demonstrations, FEI expects to bring larger hydrogen supply projects online between 2025 and 2030.

In response to BCUC IR 3.9 in FEI's Revised Renewable Gas Program Application – Stage 2 proceeding, FEI stated:

> FEI anticipates that its existing natural gas network will deliver hydrogen blends of between 5 percent and 20 percent by volume to meet the 2030 supply mix forecast. In addition, FEI expects segments of the network may be repurposed for 100 percent hydrogen delivery to select industrial, commercial and residential customers where feasible.

Further in response to BCUC IR 3.10.1 in FEI's Revised Renewable Gas Program Application – Stage 2 proceeding, FEI stated:

> FEI expects to have enough information based on existing industry literature, third party studies, ongoing research and development, internal technical guidance, and further planned hydrogen feasibility research, field-testing and pilot deployment to begin blending hydrogen into its existing gas system by 2024.

61.10 Please clarify whether, in the above IR responses, FEI contemplates hydrogen blends by 2030 of between 5 percent and 20 percent in its existing distribution or transmission natural gas network, or both.

Response:

Please refer to FEI's response to BCUC IR1 61.3.

61.11 Under the hydrogen "backbone" approach to integrating hydrogen, please provide a map of the CTS, VITS and ITS illustrating which transmission lines FEI anticipates will deliver a blend of hydrogen and natural gas, and which transmission lines FEI is considering not allowing blends of hydrogen and natural gas.

Response:

FEI's hydrogen deployment strategy is currently not sufficiently developed to identify the hydrogen backbone requirements or to support providing a map of the CTS, VITS, and ITS illustrating the future backbone infrastructure and whether it would include existing or new pipelines. FEI needs to complete further system planning analysis considering existing transmission system infrastructure, ongoing transmission projects, and planned transmission infrastructure projects to determine which transmission lines FEI will need to consider to support hydrogen development.

61.12 Please explain what approvals, if any, FEI requires from the BCUC prior to blending hydrogen into its existing natural gas transmission or distribution networks.

Response:

FEI expects to seek acceptance from the BCUC under 44.2 (1)(c) of the UCA for the expenditures to acquire hydrogen, which may qualify as a prescribed undertaking under the Greenhouse Gas Reduction (Clean Energy) Regulation (GGRR). FEI expects that it would also apply for approval of tariff amendments to allow for the sale of the hydrogen, and approval of any related treatment of the costs and revenues that may be required for rate setting purposes. FEI anticipates that its application would include discussion about the percentage of, and mechanism by which, FEI would blend hydrogen into its system and request any other approvals that may be required to blend hydrogen on its system.

FEI also expects that regulatory approvals will be required from Technical Safety BC and the BC Oil and Gas Commission prior to blending hydrogen into its existing natural gas transmission or distribution system networks.

The Province has recently proposed changes to legislation that would expand the responsibilities of the BC Oil and Gas Commission to include hydrogen.[82] The Province's intention is to create a one-stop place for hydrogen permitting and regulation, in order to simplify and accelerate the regulatory approvals process to bring hydrogen technology to the market. Once the enabling legislation is enacted, FEI expects to have more certainty respecting the regulatory approvals necessary to blend hydrogen into its system.

61.12.1 If FEI considers that BCUC approvals are required prior to FEI blending hydrogen into its existing natural gas transmission or distribution networks, please explain when FEI anticipates filing applications seeking these approvals.

Response:

FEI anticipates submitting its first application for the acquisition of hydrogen to the BCUC in 2023.

[82] 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.

61.13 Please explain whether FEI will require the construction of any new pipelines before it can begin integrating hydrogen into the VITS, CTS or ITS.

61.13.1 If so, please describe what pipeline infrastructure is required and when FEI anticipates submitting applications to the BCUC related to new pipeline expenditures.

Response:

FEI does not expect to require the construction of any new pipelines, except perhaps interconnection pipelines, before it begins integrating hydrogen into the VITS, CTS or ITS.

62.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Appendix D-2, pp. 92, 93, 98; Exhibit B-4, Section 2.1.1, pp. 8, 9

Hydrogen Production

On page 8 of FEI's Energy Scenario – Stage 2 submissions, FEI states:

> FEI did not present a specific forecast of each component of its forecast renewable and low-carbon gas supply within the total amounts of this supply as it considers these individual types of gases to be subject to a greater range of uncertainty than the overall supply of renewable and low-carbon gases. However, as a modelling exercise, FEI has examined potential trajectories for growth in the amount of hydrogen in each of its scenarios. Figure 2 and Table 3 below display linear hydrogen growth trajectories starting in 2023 for each of the five scenarios modelled by FEI over the planning horizon.

> On page 9 of FEI's Energy Scenario – Stage 2 submission, FEI provides Figure 2 and Table 3 which display linear hydrogen growth trajectories starting in 2023. FEI "acknowledges that actual growth in hydrogen supply is unlikely to be linear as depicted…the linear trajectories were modelled as simplifying assumption for the LTGRP."

Figure 2: Forecast of Hydrogen Supply by Scenario

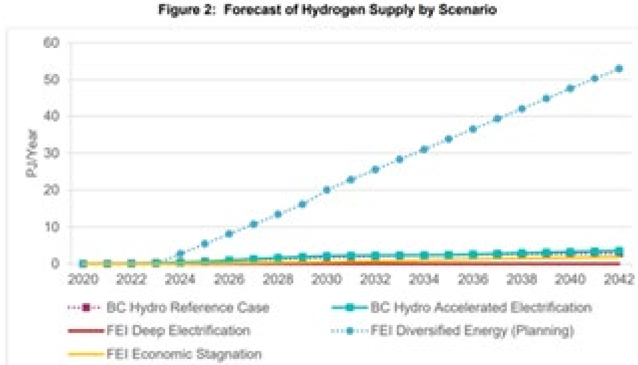

Table 3: Forecast of Hydrogen Supply by Scenario (PJ/Year)

	2025	2030	2035	2040	2042
FEI Diversified Energy (Planning)	5.4	20.0	33.8	47.5	53.0
BC Hydro Accelerated Electrification	0.5	2.1	2.4	3.2	3.5
BC Hydro Reference Case	0.7	1.7	2.4	2.7	2.9
FEI Economic Stagnation	0.1	0.5	1.1	1.7	1.9
FEI Deep Electrification	0.0	0.0	0.0	0.0	0.0

Further on page 9, FEI states:

> As shown above, the only scenario presented by either utility that considers a meaningful role for hydrogen in a low-carbon energy future is FEI's Diversified Energy (Planning) Scenario. In this scenario, hydrogen from off-system supply sources will be relied on in the early stages of FEI's carbon reduction transition. Physical hydrogen flows on FEI's gas infrastructure are expected to rise, but be

limited to smaller amounts and portions of FEI's system early in the transition as the technologies and infrastructure needed to manage larger volumes are refined and implemented. From 2030 to 2042, while the development of on-system resources will have grown, FEI anticipates there will still be some reliance on off-system supplies

62.1 Please clarify whether the forecasted hydrogen supply depicted in Figure 2 above represents the supply of hydrogen available to FEI (on-system and off-system), or if it represents the amount of hydrogen delivered (actual and notional) to FEI customers.

Response:

The hydrogen supply depicted in Figure 2 represents the amount of hydrogen supply to be delivered to FEI customers from both on-system and off-system sources. FEI expects this volume of hydrogen to be delivered through blending into the distribution network as well as through industrial gas displacement. However, as noted on page 9 of FEI's Energy Scenario – Stage 2 submission, actual growth in hydrogen supply is unlikely to be linear as depicted, so the timing associated with volumes shown in Figure 2 should be viewed as estimates.

62.2 Please confirm the first year that FEI anticipates purchasing off-system and on-system hydrogen.

Response:

FEI anticipates the first off-system and on-system hydrogen contracts could be executed in the next 12 to 24 months, and expects the first supply to be delivered in the 2025-2030 timeframe. Since initial off-system hydrogen purchases would most likely be delivered by displacement, the timing would be dependent on the development schedule of off-system projects. With respect to on-system hydrogen, FEI is currently undertaking extensive analysis to advance to final investment decisions for on-system hydrogen production and is engaging with potential third-party hydrogen producers to procure on-system hydrogen supply.

62.3 If the off-system hydrogen is not delivered to FEI customers, please explain how the purchase of off-system hydrogen would contribute to FEI's carbon reduction transition. Please include a discussion of how the GHG reduction will be determined with a sample calculation and assumptions made.

Response:

If low-carbon hydrogen is injected into a distribution network in Canada or the US and delivered by displacement, the off-system hydrogen would contribute to FEI's carbon reductions in the same way that off-system RNG currently contributes to FEI's carbon reductions. Off-system hydrogen can displace natural gas consumption directly at an industrial host site or by injecting hydrogen into a natural gas pipeline that can accept hydrogen. For example, assuming natural gas carbon intensity of 60 kgCO2e per GJ and hydrogen carbon intensity of 36 kgCO2e per GJ, the GHG reduction would amount to 24 kgCO2e per GJ. The carbon intensity of hydrogen is expected to vary by project and calculations would be made using government-approved emission factors. As a result, FEI requires clarity from the BC government on emission reduction calculations for hydrogen, in addition to recognition for off-system hydrogen purchases to count toward FEI's GHG emission reduction obligations.

62.3.1 Would the entity consuming the off-system hydrogen need to be using it to displace natural gas consumption for FEI to recognise the GHG reduction?

Response:

Although FEI has not yet procured off-system hydrogen by displacement, under the existing energy policy and regulatory framework, FEI believes the answer is yes. However, when FEI becomes subject to the GHG emissions cap identified in the CleanBC Roadmap, FEI believes there may be opportunity to claim the GHG emission reductions associated with replacing natural gas and other higher carbon emitting fuels like coal or diesel in other jurisdictions, if best practice carbon accounting and protocols are followed.

62.4 If actual growth in hydrogen supply is not likely to be linear, please confirm the first year that FEI anticipates delivering hydrogen to its customers.

Response:

As discussed in the response to BCUC IR1 62.2, FEI may not acquire hydrogen supply until 2025-2030. As a result, FEI does not anticipate delivering any significant amounts of hydrogen to its customers until that timeframe. However, FEI may pilot small-scale innovative technologies that could generate and deliver small amounts of hydrogen to FEI's customers prior to the 2025-2030 timeframe.

62.5 If actual growth in hydrogen supply is not likely to be linear, please provide FEI's current estimate of the on-system and off-system delivery of hydrogen to its customers in 2025.

Response:

As discussed in the responses to BCUC IR1 62.2 and BCUC IR1 62.4, FEI is progressing various activities to develop on-system renewable and low-carbon hydrogen supply volumes. FEI currently anticipates that on-system delivery of hydrogen by 2025 could be in the range 0.1 to 0.5 petajoules per year. FEI is in discussions to acquire off-system hydrogen supply; however, FEI does not expect any of the large off-system hydrogen projects to come into service before 2025. Therefore, the current estimate for hydrogen supply does not include any off-system hydrogen supply in 2025.

62.5.1 Please provide an estimated breakdown of hydrogen FEI anticipates delivering to VITS, ITS and CTS customers in 2025.

Response:

In the Application (including the Stage 2 Submission), FEI has not allocated its estimated supplies of renewable and low-carbon fuels to specific customers, customer groups or service regions, and, therefore, cannot provide the requested breakdown.

62.6 Please elaborate on FEI's current strategy with respect to hydrogen production; does FEI envision owning and/or operating hydrogen production facilities in B.C. over the 20-year planning horizon, either independently or through joint ventures with industry partners?

Response:

Yes, FEI envisions owning and/or operating low-carbon hydrogen production facilities in BC over the 20-year planning horizon, either independently or through collaboration with industry partners. Investing in the entire value chain of low-carbon hydrogen development, including hydrogen production, is critical to securing low-carbon hydrogen supply and supporting BC's GHG reduction goals. FEI is also interested in purchasing supplies of hydrogen and other forms of renewable and low-carbon gas from independent producers when the opportunity to do so emerges.

62.6.1 If FEI anticipates relying solely on third-party hydrogen suppliers, please discuss FEI's assessment of the risk of hydrogen supply not being available in the amounts forecasted over the 20-year planning horizon, and any mitigation measures available to FEI to address this risk.

Response:

As stated in the response to BCUC IR1 62.6, FEI does not intend to rely solely on third-party hydrogen suppliers. Relying solely on third-party hydrogen suppliers would increase the risk of not meeting the hydrogen supply quantity that is forecasted over the 20-year planning horizon. To mitigate the hydrogen supply-related risk, FEI expects to be proactively involved in the low-carbon hydrogen development value chain and collaborate with industry partners to develop, own and/or operate hydrogen production facilities.

62.7 Please describe any identified FEI and/or third party led capital projects that may be required to enable FEI's delivery of on-system hydrogen within the next five years.

Response:

FEI is collaborating with third parties to potentially partner on the development of capital projects to develop on-system renewable and low-carbon hydrogen supply. To enable delivery of on-system hydrogen within the next five years, FEI, Suncor Energy and Australia-based Hazer Group are collaborating on a pilot commercial demonstration project[83] to produce low-carbon hydrogen through a methane pyrolysis process from natural gas, which stores the carbon byproduct as solid synthetic graphite. The project is expected to produce up to 2,500 tonnes of low-carbon hydrogen per year, which equates to roughly 300,000 GJ annually of low-carbon hydrogen supply.

On page 92 of Appendix D-2 to the Application, FEI provides Tables 29 and 30 which summarize assumptions for B.C. based renewable and low-carbon gas production in 2030 and 2050, respectively:

[83] https://vancouversun.com/business/local-business/fortisbc-suncor-port-moody-hydrogen-pilot-project.

Table 29 Assumptions for Gas Production in 2030 and 2050, in PJ/yr (Minimum Scenario)

Gas Type	2030	2050	Rationale
Green hydrogen (large on-grid)	0.0	8.3	Slower ramp-up than Maximum scenario
Green hydrogen (small on-grid)	0.8	1.9	Slower ramp-up than Maximum scenario
Green hydrogen (large off-grid)	0.0	2.4	A single 300 MW off-grid wind farm after 2030
Blue hydrogen	14.2	46.8	Limited by permitting and regulatory restraints
Turquoise hydrogen	1.5	15.4	Slower ramp-up than Maximum scenario
Waste hydrogen	0.9	0.9	Identical to Maximum scenario
Syngas in lime kilns	1.4	5.9	Identical to Maximum scenario
Lignin in lime kilns	0.0	0.0	Lignin a more expensive fuel than syngas
Syngas to hydrogen	0.3	13.4	No change to forestry practices. BC Hydro PPAs are extended. No use of wood pellet feedstock. Only low-cost residue used.
Syngas to RNG	0.0	0.0	Technology not advancing as expected
Agricultural RNG	0.9	1.2	Potential for production cost below $31/GJ; 70% of 2030 technical potential (90% of 2050 potential).
Municipal RNG	2.3	4.0	
Waste water treatment gas	0.4	0.6	
Landfill gas	2.1	2.7	
TOTAL	24.7	103.8	

Table 30 Assumptions for Gas Production in 2030 and 2050, in PJ/yr (Maximum Scenario)

Gas Type	2030	2050	Rationale
Green hydrogen (large on-grid)	8.4	21.0	Converted to petajoules from Table 18
Green hydrogen (small on-grid)	0.8	6.3	Converted to petajoules from Table 18
Green hydrogen (large off-grid)	1.7	12.6	Converted to petajoules from Table 18
Blue hydrogen	14.2	156	From ZEN (2019) report, Figure 28 (in 2050)
Turquoise hydrogen	15.4	92.2	From ZEN (2019) report, Figure 28 (in 2050)
Waste hydrogen	0.9	0.9	From ZEN (2019) report, Figure 28
Syngas in lime kilns	1.4	5.9	100% of lime kilns are converted to syngas by 2050. BC Hydro contracts are not extended.
Lignin in lime kilns	0.0	0.0	Lignin a more expensive fuel than syngas
Syngas to hydrogen	0.3	64.9	Increased forest residue recovery. BC Hydro contracts are not extended. Pellet feedstock transitions towards gas production. 36 plants (or less if larger plant size), also using standing trees
Syngas to RNG	0.3	74.2	One demo by 2030. 26 full-size plants by 2050. Use of some roundwood
Agricultural RNG	1.4	2.0	Potential for production cost below $50/GJ. 70% of 2030 technical potential (90% of 2050 potential).
Municipal RNG	2.4	4.2	
Waste water treatment gas	0.4	0.6	
Landfill gas	2.1	2.8	
TOTAL	49.7	444	

Regarding Tables 29 and 30, FEI states on page 93 of Appendix D-2 to the Application:

> **Maximum scenario:** the 2030 target of 15% renewable gas can be reached using only in-province resources if low-carbon gas becomes eligible.
>
> **Minimum scenario:** compared to the Maximum scenario, the 2030 target cannot be reached with provincial resources. If low-carbon gases are eligible and if action is taken now to implement blue hydrogen production, only 24 out of 30 petajoules per year required are produced in province. B.C: gas utilities would have to purchase 6 gigajoules a year of RNG from out-of-province resources.

Further on page 98 of Appendix D-2 to the Application, FEI provides table 32 which summarizes the potential supply portfolios of renewable and low-carbon gases in 2030 and 2050:

Table 32 Potential Supply Portfolios of Renewable and Low-Carbon Gases

	2030	2050
Primary sources	Waste hydrogen Anaerobically produced RNG Syngas in lime kilns Blue hydrogen	Turquoise hydrogen Syngas in lime kilns Hydrogen (or RNG) from wood Anaerobically produced RNG Waste hydrogen
Secondary sources	Turquoise hydrogen Hydrogen from wood (demonstration)	Blue hydrogen Green hydrogen

62.8 Please elaborate on FEI's assessment of the supply of on-system and off-system blue hydrogen over the next five years.

Response:

FEI is in the early stages of evaluating the feasibility and potential for on-system blue hydrogen supply. This will include hydrogen production, carbon capture, carbon transport, and sequestration. The facilities being considered are large, complex and are not anticipated to be online within the next five years. FEI is aware of several proposed off-system blue hydrogen production projects that could provide significant low-carbon hydrogen supply to FEI over the next five years.

62.8.1 Has FEI identified any opportunities for on-system blue hydrogen production within its service territory?

Response:

FEI has begun to explore blue hydrogen production in BC which may be suitable for deployment within FEI's service territory. Early feasibility work to be conducted in 2022-2023 is intended to prove the concept and identify potential locations, though no specific locations have been identified to date.

62.8.2 Does FEI anticipate seeking approval of any capital expenditures related to blue hydrogen production over the next five years?

Response:

As FEI considers that blue hydrogen will be required to achieve the Province's GHG reduction goals, FEI expects to seek approval of at least some elements of blue hydrogen development funding over the next five years.

62.8.3 Please describe any off-system blue hydrogen production projects FEI is currently considering as a potential supply of hydrogen.

Response:

FEI continuously monitors renewable and low-carbon gas supply opportunities located outside of BC and is aware of several proposed low-carbon (blue) hydrogen production projects in Alberta that could potentially provide off-system hydrogen supply to FEI. Please also refer to the response to BCUC IR1 62.2.

62.9 Please elaborate on FEI's assessment of the supply of on-system green hydrogen over the next five years.

Response:

FEI does not anticipate a meaningful supply of on-system green hydrogen to be developed over the next five years. In order to be competitive with other sources of renewable and low-carbon gas including RNG and blue and turquoise hydrogen, green hydrogen will need to be developed at large scale with access to low-cost clean electricity. Further, improvements to electrolyzer efficiency and cost are expected to occur over time, but not in the short term. Over the next five years, however, FEI will be actively pursuing this low-carbon fuel supply through significant pre-feasibility, technology, business development, and policy efforts to realize the green hydrogen opportunity. FEI notes that this is a rapidly evolving area, and factors such as federal and provincial policy could accelerate opportunities for project development through support from grant funding and tax incentives, such as the tax credits recently announced by the federal government.[84]

62.10 Please discuss whether FEI anticipates that the amount of on-system green hydrogen will exceed the 2.9 PJ to 3.5 PJ amount that BC Hydro has forecasted as part of the scenarios modeled in BC Hydro's IRP. If so, by how much does FEI anticipate on-system green hydrogen will exceed BC Hydro's forecasted amounts.

Response:

FEI anticipates that it is possible that the volume of on-system green hydrogen could exceed the amount that BC Hydro has forecast. However, in the Application, FEI is not forecasting the amount of each individual type of hydrogen that it will acquire and deliver to customers over the 20-year planning horizon and therefore is unable to provide the requested information.

62.10.1 Please clarify how many MW of electricity capacity is required to produce 1 PJ of green hydrogen annually.

[84] Financial Post, "Ottawa announces tax credits of 30% for investment in clean technology", Nov. 3, 2022. Online: https://financialpost.com/news/economy/freeland-unveils-tax-credits-of-30-40-for-investment-in-clean-technology-and-hydrogen.

Response:

FEI estimates that approximately 42 to 50 megawatts (MW) of electrical capacity would be required to produce 1 PJ of green hydrogen annually. Precisely how many MW of electricity capacity would be required to produce 1 PJ of green hydrogen annually would be project- and technology-specific.

62.11 Please explain whether FEI considers there will be adequate on-system supply of hydrogen by 2030 to support FEI achieving the proposed 2030 GHGRS emission reduction cap.

62.11.1 If not, please explain whether FEI considers there will be adequate on-system and off-system supply of hydrogen by 2030 to support FEI achieving the proposed 2030 GHGRS emission reduction cap.

Response:

FEI considers that there will be adequate low-carbon and renewable gas supplies, including hydrogen, to support FEI achieving the 2030 GHGRS emissions cap. These supplies are anticipated to include larger amounts of RNG than hydrogen by 2030; however, the actual amounts of each type of renewable and low-carbon gas could vary from that modelled in the Application in order to achieve the total amounts of low-carbon and renewable gas required. In the Application, FEI modelled that RNG would be supplied from a mix of sources from inside and outside BC, based on proportions suggested in the BC Renewable and Low-Carbon Gas Supply Potential Study[85] and that hydrogen would be supplied predominantly from within BC. Please refer to the responses to BCUC IR1 52.4 through 52.6 for further discussion on renewable and low-carbon supply potential.

[85] Exhibit B1-1, 2022 LTGRP Application, Appendix D-2

63.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Section 7.4.1.3, p. 7-40; FEI TLSE CPCN Application proceeding, Exhibit B-26, BCUC IR 83.1

Hydrogen Separation

On page 7-40 of the Application, FEI states:

> An alternate approach would be to accept increasingly higher blends at Huntingdon into the CTS directly as the supply increases and install multiple separation facilities throughout the CTS at locations like Tilbury LNG where it is necessary to separate the hydrogen.

63.1 In the alternate approach to integrating hydrogen described above, please explain where FEI considers hydrogen separation facilities may be required on the CTS other than at the Tilbury LNG facility.

Response:

In addition to separation facilities at the Tilbury LNG facility, it is possible separation facilities could be required at other key nodes on the gas system, such as compressor station facilities or at locations where customers operate plant facilities that would not be compatible with receiving hydrogen in their gas supply. However, the details of any specific system modifications will depend on various factors to be considered during feasibility and engineering design (i.e., hydrogen concentration, location of injection, metallurgical properties, etc.).

63.1.1 Please explain who would be responsible for the operation of hydrogen separation facilities located throughout the CTS.

Response:

FEI would be responsible for operating these facilities if they are installed on the FEI gas system. If a customer elected to separate the hydrogen from the gas supply by installing separation facilities within their business or plant operations and behind their meter, then they would be responsible for the operation of the separation facilities.

In response to BCUC IR 83.1 in FEI's TLSE CPCN Application proceeding, FEI stated:

> FEI and the University of British Columbia (Okanagan Campus) have completed a desktop study on the use of commercial membrane technology for the separation

of mixed natural gas and hydrogen steams. The study suggests that the separation process is technically feasible.

63.2 Please provide an update regarding the studies into the separation of mixed natural gas and hydrogen streams being conducted by FEI.

Response:

FEI continues to work with the University of British Columbia (Okanagan Campus) (UBCO) team on phase two of the H2Lab that includes the sub-project to advance process feasibility and practical applications of commercial membrane technologies to separate blended hydrogen and natural gas.

63.3 Is FEI aware of any natural gas pipeline operators currently separating hydrogen from mixed natural gas and hydrogen streams? If so, please provide further information regarding how and why the pipeline operator is separating hydrogen from mixed natural gas and hydrogen streams.

Response:

FEI is not aware of any natural gas pipeline operators currently separating hydrogen from mixed natural gas and hydrogen streams. FEI is aware of a pilot demonstration project in Germany by Linde and Evonik Industries, to showcase their hydrogen separation technology to extract hydrogen from mixed hydrogen and natural gas streams[86] and a proposed demonstration project by SoCal Gas called "[H2]PureComp" that includes the development, installation, and demonstration of an Electrochemical Hydrogen Purification and Compression (EHPC) skid developed by the Netherlands-based company HyET Hydrogen.[87]

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86 Evonik Industries AG, "Extracting hydrogen from natural gas networks" (November 12, 2020) online at: https://www.membrane-separation.com/en/media/press-releases/extracting-hydrogen-from-natural-gas-networks-147522.html.

87 https://www.socalgas.com/sustainability/hydrogen/h2purecomp.

64.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Section 7.4.1.1, p. 7-36

CCUS

On page 7-36 of the Application, FEI states:

> From now until 2030, FEI expects a larger share of on-system renewable and low-carbon gas contribution will come from on-system RNG, syngas and lignin production, and CCUS. By 2042, as technology advances to produce hydrogen electrolytically, by pyrolysis or reformation, hydrogen is expected to be a larger share of FEI's fuel mix.

64.1 Please elaborate on the extent that CCUS will contribute to FEI's on-system low-carbon gas supply from now until 2030.

Response:

FEI sees potential for different CCS and CCUS[88] technologies and applications to support FEI's GHG emission reductions goals and contribute to on-system low-carbon gas supply by 2030 and beyond. The BC Renewable and Low-Carbon Gas Supply Potential Study[89] of the Application outlines in detail some of these CCUS technologies that FEI is interested in accelerating to produce low-carbon gas. FEI is in the early stages of investigating and supporting some projects that involve carbon capture through the Clean Growth Innovation Fund. These projects are at a relatively early stage of development and are therefore low on the Technical Readiness Level scale.[90] Some projects are progressing to small-scale pilot demonstrations, after which commercialization planning can proceed based on an established baseline of successful performance.

FEI is also interested in accelerating CCUS technologies in other applications, such as capturing and sequestering post-combustion point source carbon at industrial emitters, capturing carbon emissions from biomethane upgrader facilities to produce deeply negative RNG, and the direct capture of carbon dioxide from air. At present, commercialization timelines, forecasted costs, service offerings, rate design and other relevant considerations are unavailable. FEI also sees a role for CCS in developing low-carbon conventional gas and is in the early stages of investigating an opportunity to invest in CCS with low-carbon gas offtake. However, FEI would require low-carbon conventional gas to be recognized within the regulatory framework in order to execute on this opportunity. These initiatives will be initiated once FEI determines the types of CCUS projects that would support the Company's emissions reduction goals.

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[88] As described in Table 1-2 of the Application, FEI defines CCUS as "Applying the carbon reduction benefits of CCUS to the delivery of natural gas on FEI's gas network."

[89] Exhibit B1-1, 2022 LTGRP Application, Appendix D-2.

[90] The Technical Readiness Scale Level is used by Industry Canada to identify the stage of development of new technologies from infancy to market readiness. More information is available at: https://ised-isde.canada.ca/site/industrial-technologies-office/en/technology-demonstration-program-tdp/application-guides/annex-2-technology-readiness-level-trl-scale.

With regard to the contribution of CCUS within the overall renewable and low-carbon gas portfolio outlook in the LTGRP, FEI has not forecast specific amounts of each type of renewable and low-carbon gas (including CCUS). Please see the response to BCUC IR1 71.8.1 for the amounts of each type that were modelled over the next 20 years. These component amounts are high-level estimates and should not be considered forecasts. Rather, FEI expects that the amount of each type of gas acquired will fall within a range, the total of which will meet the overall renewable and low-carbon gas forecast presented in Figure 6-3 of the Application. The actual amounts of each type of gas acquired will depend on many factors, such as rate of project advancement and cost of supply.

64.1.1 Please describe what amount (in PJ and tCO2e) of on-system low-carbon gas will be supplied by CCUS by 2030.

Response:

Please refer to the response to BCUC IR1 52.6 regarding the amounts of the various components that have been modelled within the overall forecast of renewable and low-carbon gas supply. FEI currently has insufficient data to forecast what amount (in PJ and tCO2e) of on-system low-carbon gas utilizing CCUS will be supplied by 2030. Please also refer to the response to BCUC IR1 64.1.

64.1.2 Please describe the location and timing of any CCUS Projects FEI is currently monitoring or supporting.

Response:

FEI tracks market developments and monitors proposed low-carbon hydrogen and CCUS feasibility studies, pilot scale and commercial scale developments in British Columbia, Alberta and across Canada, but does not, at this time, have definitive details on location, timing or other details further to publicly-available information.

64.2 Please explain whether FEI anticipates it will seek approval of any CCUS related capital expenditures over the 20-year planning horizon.

Response:

FEI may seek approval of CCUS related capital expenditures as part of developing on-system, low-carbon gas supply acquisition over the 20-year planning horizon. This will be contingent on the successful deployment of CCUS technologies and their industrial application which, as recognized in the CleanBC Roadmap to 2030,[91] are still in the emergent phase in British Columbia and will require a coordinated, comprehensive provincial approach to guide their deployment.

[91] Exhibit B-1, Application, Appendix A-5.

65.0 Reference: SYSTEM RESOURCE NEEDS AND ALTERNATIVES

Exhibit B-1, Section 3.6.2, p. 3-24 Section 7.3.1.5, p. 7-17, Section 7.3.2.2, p. 7-20, Section 7.3.2.4, p. 7-24

Impact of LNG Facilities on System Planning

On page 7-17 of the Application, FEI states: "Woodfibre LNG Limited has presently indicated that it expects to require Firm Transportation service from FEI of up to 237 MMscf/day on the VITS."

Further on page 7-17 of the Application, FEI states:

> To accommodate this load addition, there is a need to reinforce the existing VITS with pipeline looping and added compression near Squamish. This infrastructure expansion would match the Firm Transportation capacity contracted by Woodfibre LNG Limited under peak demand, preserving available capacity for existing customers, but would allow large volumes of interruptible capacity to be available for much of the year. <u>The Woodfibre LNG project will help reduce costs for firm service on FEI systems providing benefits to FEI's existing customers</u>. Woodfibre LNG project's toll will recover the cost of the Woodfibre LNG project and provide an additional contribution to FEI's other customers over time. [Emphasis added]

On page 7-20 of the Application, FEI states:

> The CTS [coastal transmission system] currently has sufficient capacity to support peak demand throughout the 20-year planning horizon with additional capacity to support some LNG liquefaction expansion at locations like Tilbury LNG in Delta and the Woodfibre LNG project in Howe Sound. For the foreseeable future, additional expansion requirements for the CTS will be driven by LNG additions or other large industrial demand in the Lower Mainland or VITS, rather than by Core customer growth.

On page 3-24 of the Application, FEI states:

> FEI will continue to advance its interests in the LNG marine bunkering market as an LNG fuel. FEI's early progress in this market, coupled with recent supportive market conditions, <u>creates a favourable opportunity for further helping to reduce customer rate pressures</u> and reducing GHG emissions. [Emphasis added]

65.1 Please elaborate on the specific cost benefits offered to FEI's existing ratepayers by the addition of (i) Woodfibre LNG and (ii) expansion of LNG projects for the marine bunkering market.

<u>Response:</u>

When Woodfibre LNG commences operations, FEI will provide gas transportation to their facility under FEI's Rate Schedule 50 (RS 50). The RS 50 toll-setting mechanism is such that the toll recovers the incremental cost to serve the RS 50 customers, plus a system contribution of $0.10

per GJ which ensures RS 50 customers pay to use FEI's existing transmission system.[92] The year one toll will escalate each year by FEI's annual rate increase, as approved by the BCUC, bound between 0 and 3 percent. Currently, all of FEI's other non-bypass customers are providing for the cost recovery of FEI's existing transmission system, so when Woodfibre LNG commences service and starts paying the $0.10 per GJ embedded in the RS 50 toll, that amount will lessen the costs of the existing transmission system that is recovered from all other customers, resulting in a rate decrease, all else equal. In the scenario where the $0.10 toll escalates at 1.5 percent[93] per year, the system contribution benefit that will accrue to FEI's other customers is expected to be approximately $600 million over the 40-year term of the agreement.

LNG marine bunkering benefits will be dependent on the size of facilities required to serve that market and the annual demand of the sector. FEI will serve the LNG marine bunkering market under Rate Schedule 46 (RS 46), which will be used to recover the costs of the infrastructure required to serve that market and also provide benefits to customers when the revenues from RS 46 either utilize existing capacity at Tilbury or exceed the incremental cost of new infrastructure. FEI is currently assessing the market and facilities required and estimates the RS 46 revenue from this market to be approximately $4 billion over the 20-year planning horizon, assuming approximately $1 billion of liquefaction capacity is constructed and that all LNG production capacity is fully sold.

On page 7-24 of the Application, FEI provides Table 7-1 which summarizes potential CTS expansion requirements in order to supply potential LNG expansion:

Table 7-1: CTS Expansion Scenarios for LNG

CTS Upgrades	LNG Expansion	Timeframe
2 km NPS 30 from Tilbury Plant and up to 15,000 HP Added (up to 30,000 HP total) or 35 km NPS 42 Pipeline Loop	Incremental 100 MMscf/day addition to Liquefaction at Tilbury Plant (up to 135 MMscf/day total) Woodfibre LNG project at 237 MMscf/day	2025 or later
Up to an Additional 10,000 HP Added (up to 40,000 HP total) or additional 13 km NPS 42 Pipeline Loop (48 km total)	Incremental 150 MMscf/day additional Liquefaction at Tilbury Plant (up to 285 MMscf/day total) Woodfibre LNG project at 237 MMscf/day	2027 or later
Up to an Additional 10,000 HP Added (up to 50,000 HP total) or additional 6 km Pipeline Loop (54 km total)	Up to 400 MMscfd additional Liquefaction at Tilbury Plant (up to 435 MMscf/day total) Woodfibre LNG project at 237 MMscf/day	2029 or later

65.2 Please clarify whether FEI currently has sufficient capacity on the CTS to accommodate the Woodfibre LNG project at 237 MMscf/day.

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92 The Eagle Mountain – Woodfibre Gas Pipeline project starts at FEI's V1 compressor station in Coquitlam and ends at the Woodfibre LNG facility in Squamish. FEI must transport gas across its existing transmission system from its interconnection point with the T-South upstream transmission system at Huntingdon to the V1 compressor station in Coquitlam.

93 1.5 percent is halfway between the lower and upper bounds of 0 percent and 3 percent, respectively.

65.2.1 If yes, please confirm, or explain otherwise, that future CTS upgrades will be triggered by expansion at the Tilbury Plant.

Response:

Confirmed. FEI currently has sufficient capacity on the CTS to accommodate Woodfibre LNG at 237 MMscf/day and the upgrades set out in Table 7-1 would be triggered by Tilbury LNG expansions.

65.3 Please discuss whether FEI considers there is any possibility that the Woodfibre LNG project would be expanded beyond demand of 237 MMscf/day.

Response:

FEI cannot speculate on the possibility of expansions to Woodfibre LNG facilities beyond the 237 MMscf/day.

65.4 Please provide the approximate cost estimates for the compressor and pipeline expansions FEI lists in Table 7-1.

Response:

FEI estimates that the cost of the CTS expansions required to provide service to Tilbury as set out in Table 7-1 would be between $200 and $600 million. While a detailed level of assessment has not been undertaken to split the estimate between the three line items in Table 7-1, FEI estimates that the last two line items, which are required to serve non-regulated Tilbury LNG expansions, would account for approximately $400 million of the $600 million total.

FEI's CTS upgrades are included in FEI's rate base and recovered from all customers. If a CTS upgrade exceeds FEI's CPCN threshold of $15 million, as would likely be the case with the CTS upgrades required for LNG expansion at Tilbury, then FEI would file an application with the BCUC where questions of cost recovery for any particular upgrade could be explored.

As noted above, the last two line items in Table 7-1 referenced in the preamble to this question are for CTS upgrades required to serve non-regulated Tilbury LNG expansions. It is expected that FEI would serve this customer under RS 50.[94] RS 50's toll-setting mechanism is such that system upgrades required to serve a new RS 50 customer are included in the calculation of the RS 50

[94] Rate Schedule 50 is FEI's Large Volume Industrial Transportation tariff. This is also the rate schedule that will be used to serve Woodfibre LNG.

toll. Accordingly, the incremental CTS expansions related to the last two line items in Table 7-1 would be recovered from RS 50 customers.

65.4.1 Please compare the approximate costs of the compressor and pipeline expansions FEI lists in Table 7-1, to the potential cost benefits offered to FEI's existing ratepayers resulting from LNG expansion outlined in BCUC IR 65.1.

<u>Response:</u>

The benefits described in the response to BCUC IR1 65.1 and the costs described in the response to BCUC IR1 65.4 are not directly comparable.

The benefits discussed in the response to BCUC IR1 65.1 are referring to the Woodfibre LNG and Tilbury expansion to serve the <u>marine bunkering market</u> (as requested), but exclude the benefits associated with the last two line items in Table 7-1, referenced in the preamble to this question, which would be needed for non-regulated Tilbury LNG expansions to serve an LNG export market. The benefits flowing to FEI's customers through RS 50 associated with a non-regulated Tilbury LNG expansion would be approximately $300 million to $1 billion over 40 years.

The costs discussed in the response to BCUC IR1 65.4 are for compressor and pipeline expansions (as requested) and do not include capital costs to expand liquefaction at Tilbury to serve a marine bunkering market, which are approximately $1 billion as set out in the response to BCUC IR1 65.1.

65.4.2 Please explain how FEI currently intends to recover the costs of the potential CTS upgrades noted in Table 7-1.

<u>Response:</u>

Please refer to the response BCUC IR1 65.4.

65.5 Please discuss whether FEI currently considers the CTS would require the construction of a dedicated hydrogen "backbone" pipeline from Huntingdon control station, regardless of whether the in the event that the liquefaction capacity at Tilbury and Woodfibre expand.

65.5.1 Please clarify whether, in the event that the liquefaction capacity at Tilbury and Woodfibre expand within the timeframe noted in Table 7-1, FEI would require the construction of a dedicated hydrogen “backbone” pipeline from Huntingdon control station in the same timeframe.

Response:

The requirement for a “backbone” hydrogen pipeline system would be required to efficiently integrate hydrogen supply to CTS customers and would therefore be independent of whether the liquefaction capacity at Tilbury and/or Woodfibre expand. However, FEI has not yet established the requirements for such a backbone infrastructure and further to BCUC IR1 61.5, is not in a position to clarify whether, in the event that the liquefaction capacity at Tilbury and/or Woodfibre expand within the timeframe noted in Table 7-1, FEI would require the construction of a dedicated hydrogen “backbone” pipeline from the Huntingdon control station in the same timeframe.

G. CONSULTATION AND ENGAGEMENT

66.0 Reference: CONSULTATION AND ENGAGEMENT
Exhibit B-13, p. 8-13
Indigenous Engagement Workshops

On page 8-13 of the Application, FEI states:

> Throughout 2021 and into early 2022, FEI planned five virtual engagement workshops directly with First Nations community representatives and Indigenous groups across the FEI service area. This included two workshops within the shared service territory, which focused on both FBC's LTERP process and a high-level overview of FEI's LTGRP process. These workshops were held on February 4, 2021 and March 3, 2021 and were attended by community representatives from the Ktunaxa Nation and the Okanagan Nation Alliance. Two additional virtual engagement workshops were held with First Nations located in the Lower Mainland and Fraser Valley regions of the province on January 13, 2022 and January 18, 2022… During the February 4, 2021 and March 3, 2021 workshop sessions, FEI provided an overview of the Pathways Report and key aspects of FBC's LTERP and FEI's LTGRP. Given the timing of the engagement, aspects of the FEI LTGRP were discussed at a high level during these engagement workshops as further work was required by FEI to complete key aspects of the LTGRP, such as a final analysis of demand scenarios, resource options, and system needs.

66.1 Please explain the rationale for the timing of the workshops held in the shared service territory with FortisBC Inc. (FBC), and those in Lower Mainland and Fraser Valley regions.

Response:

FEI worked closely with the FBC resource planning team to align engagement activities for both the FBC LTERP and the FEI LTGRP, where possible. This approach was implemented to address capacity constraints for communities participating in the engagement process and for FBC and FEI. The FBC LTERP was submitted to the BCUC in July of 2021, and to meet the LTERP submission timetable, engagement in the FEI-FBC shared service territory was prioritized from a scheduling perspective in comparison to FEI service territory engagement workshops.

After completion of the FBC LTERP submission, FEI continued engagement on the LTGRP through regional community and Indigenous engagement workshops in the FEI-only service territory, which included two more engagement workshops in the Lower Mainland and Fraser Valley regions. FEI initially planned to host Lower Mainland-focused Indigenous community engagement workshops in the fall of 2021; however, unprecedented flooding throughout the region became a significant priority for communities and for FEI to address during this time. FEI deferred the proposed engagement sessions into early 2022 to provide communities with a greater opportunity to participate in recognition of the unique circumstances and capacity constraints posed by the flooding emergency. Finally, while FEI prepared its engagement session schedule to maximize opportunities for engagement, the availability of community members to attend required some adjustment to the final timing of events.

66.2 Please explain whether participants in the February 4, 2021 and March 3, 2021 workshops were provided additional engagement opportunities when analysis for the key aspects LTGRP was complete.

Response:

FEI provided multiple follow-up opportunities throughout the engagement process with participants at community and Indigenous engagement workshops. Upon completion of the February 4, 2021 and March 3, 2021 sessions, FEI provided contact information for its Resource Planning and Indigenous Relations team members to promote ongoing discussions for any participants who still had outstanding questions, comments, or interest in the development of the LTGRP. In the weeks following each session, FEI provided a copy of the session notes to all of those who participated, so participants could review the notes, provide edits, and have the opportunity to provide additional input or feedback on the LTGRP. FEI received no further correspondence from participants regarding the workshop session notes or inquiries about opportunities for future engagement.

FEI provided notice of the LTGRP filing to all participants of these and all engagement sessions which included a link to the filing and a copy of the executive summary of the LTGRP. This notice was completed in alignment with directives stated in BCUC Order G-146-22. Through this notice, FEI also offered participants an opportunity to hold a follow up meeting to review key elements of the LTGRP such as a final analysis of demand scenarios, resource options, and energy system needs.

As identified in Section 10 of the LTGRP, FEI is working to continuously improve its engagement processes for ongoing LTGRP development. This includes assessment and implementation of the resources needed to improve engagement with Indigenous communities in FEI's resource planning activities, including securing additional sources of capacity funding to increase participation. FEI will continue to evaluate various engagement methods and technology platforms to create opportunity for Indigenous communities to provide meaningful input into the LTGRP and other business priorities on an ongoing basis. FEI views its engagement with Indigenous communities on long-term resource planning as ongoing and not limited to taking place only within the timing of one LTGRP. Feedback that FEI may continue to receive even after the 2022 LTGRP was submitted will continue to inform future LTGRPs and their associated engagement activities.

66.3 Please discuss how the input from the participants in the February 4, 2021 and March 3, 2021 workshops was incorporated into the development of the key aspects of the LGTRP.

Response:

FEI integrated feedback from Indigenous community representatives into the LTGRP in a number of ways. General themes across workshops included affordability, decarbonization, environmental protection, energy efficiency programs, and clean energy projects. FEI sees these general themes raised by participants as directly related to the LTGRP development process, and integrated this feedback throughout various parts of the LTGRP. Within Section 1.4 of the Application, FEI identifies the following LTGRP objectives which are aligned with community participant feedback:

- Ensure cost-effective, secure and reliable energy for customers;
- Provide cost-effective DSM and lower carbon solutions; and
- Ensure consistency with provincial energy objectives.

Key areas of feedback from the February 4, 2021 and March 3, 2021 workshop participants are described in Table 1, along with how this feedback was incorporated into the LTGRP.

Table 1: Feedback received from February 4, 2021 and March 3, 2021 workshops and how the LTGRP addresses the feedback

Feedback Received	How Feedback was Addressed in the 2022 LTGRP
Ensuring the UN Declaration and energy priorities of Indigenous groups are considered in the development of the LTGRP.	• Section 1.5.1 summarizes how the 2022 LTGRP aligns with the United Nations Declaration on the Rights of Indigenous Peoples. • Section 2.3 provides an overview of legislative and policy developments with respect to engagement with Indigenous groups that have impacts on FEI's long-term planning. • Section 8.3.2 discusses FEI's support for the United Nations Declaration on the Rights of Indigenous Peoples.
An understanding of how the LTGRP informs the planning process for specific capital projects and interest in expanding gas service to communities not currently served by FEI.	Section 7 of the LTGRP describes system planning and projects that are under consideration across regional transmission systems. Section 7.4 describes the integration of renewable and low-carbon gas as a foundation for future clean energy projects.
Opportunities for additional energy efficiency collaboration with local communities as a means to reduce high energy bills, support local housing improvements, and community development projects	Section 5.2.1.2 describes FEI's DSM programs and the High DSM setting to ensure adequate funding for extensive programs.
Recognition that cost and affordability are key priorities, as many community members deal with high electricity and gas bills	Section 9.4 describes rate impacts for the DEP Scenario and other scenarios, recognizing that rate impact discussions are an ongoing challenge in the clean energy transition and further discussion will need to be undertaken with regards to serving low-income customers.

Feedback Received	How Feedback was Addressed in the 2022 LTGRP
The need for FEI to improve its engagement process for ongoing LTGRP development	Section 10, Action Item 4 highlights FEI's intention to continually improve engagement processes, including to assess and implement the resources needed to improve engagement with Indigenous groups in FEI's resource planning activities, including securing additional sources of capacity funding to increase participation.

FEI recognizes the need to enhance and improve its engagement process for ongoing and future LTGRP development processes. Feedback was provided to FEI on the importance of integrating Indigenous energy priorities and the key principles of UNDRIP into its utility planning process. This was a common theme from the February 4, 2021 and March 3, 2021 workshops sessions, as well as from engagement sessions in the FEI-only service territory. In Section 2.3 of the Application, FEI acknowledges the need to continually review its engagement process and monitor policy developments to ensure key principles of UNDRIP and feedback from Indigenous communities on energy opportunities and issues is effectively integrated into the LTGRP development process. FEI has also developed Action Item 4 in the Action Plan (Section 10 of the Application), to outline steps it will take to continue to improve Indigenous engagement activities for future LTGRPs.

Through Indigenous engagement workshops, FEI also received feedback on its broader business operations, FEI's major projects, and actions for FEI to consider in its operations within the context of Truth and Reconciliation. FEI has integrated this feedback into different business processes, such as FEI's Progressive Aboriginal Relations (PAR) certification process, and has engaged participants directly to follow up on specific energy project opportunities or initiatives raised during the LTGRP engagement process.

66.4 Given the timing of the Lower Mainland and Fraser Valley workshops relative to the filing of the LTGRP, please, please discuss how the input from the participants was incorporated into the development of the LTGRP.

Response:

Please refer to the responses to BCUC IR1 66.2 and 66.3.

67.0 Reference: CONSULTATION AND ENGAGEMENT

Exhibit B-1, pp. 8-1 to 8-4, 8-8, 8-11; FBC 2021 Long Term Electric Resource Plan (LTERP) and Long-Term (LT) DSM Plan proceeding, Exhibit B-1 – Volume 1 - 2021 LTERP, p. 107

Resource Planning Advisory Group

On page 8-1 of the Application, FEI states:

> FEI has an external website for its resource planning and stakeholder engagement, which includes all of FEI's presentation materials and meeting notes from its engagement sessions: https://www.fortisbc.com/about-us/projects22planning/natural-gas-projects-planning/natural-gas-planning-stakeholder-engagement.

On page 8-2 of the Application, FEI states:

> The RPAG [Resource Planning Advisory Group] is a technical working group that engages representatives of municipalities, provincial government, customers, public interest associations, environmental organizations and intervener groups in the development of the LTGRP. RPAG members bring significant knowledge and experience to the process and provide key insight and feedback to FEI.

On pages 8-3 to 8-4 of the Application, FEI states:

> The first two RPAG sessions were held in early 2021. Members of the RPAG and the Energy Efficiency and Conservation Advisory Group (EECAG), FEI's consultant Guidehouse, and FEI staff attended the sessions…
>
> RPAG members expressed a strong commitment to reducing GHG emissions and in that context, there was general support for ensuring a long life for gas infrastructure, addressing the costs of decarbonization and impacts of climate change, and providing affordable energy and a resilient energy system for all customers. There was also general support for FEI to use the Diversified Energy (Planning) Scenario as FEI's planning scenario for the 2022 LTGRP.

67.1 Please discuss whether FEI considers there are any potential gaps in the RPAG membership.

<u>Response:</u>

The RPAG for the 2022 LTGRP represents a broad cross section of stakeholders and interest groups, and had higher membership and experienced higher attendance at the engagement sessions than in past resource planning processes. Nonetheless, FEI considers that there may be potential gaps in its membership. These gaps may be in terms of interested parties who are unaware of the resource planning process, interest groups who are underrepresented, or stakeholders that FEI would like to engage with but who do not wish to or are unable to participate. It is also possible that the RPAG can become overrepresented by certain stakeholder interests, resulting in the positions of special interest groups being put forward in the planning process that are not necessarily representative of the customers FEI serves or the general public.

While the membership of the RPAG for the 2022 LTGRP was quite balanced, groups that FEI considers to be typically underrepresented on the RPAG are Indigenous groups and individual residential, commercial, and industrial customers as representatives of their sector. Accordingly, FEI continues to improve its engagement with Indigenous groups outside of the RPAG and to seek other avenues of gauging customer interests, such as through the work of FEI's customer relations managers, customer service representatives, and the customer research group. FEI appreciates the significant knowledge and experience RPAG members contributed to the development of the 2022 LTGRP.

67.2 Please outline the information in the RPAG meeting notes that indicates the general support for FEI to use the Diversified Energy (Planning) Scenario as FEI's planning scenario for the 2022 LTGRP.

Response:

Meeting notes for the RPAG sessions are publicly available at the following link: https://www.fortisbc.com/about-us/projects-planning/natural-gas-projects-planning/natural-gas-planning-stakeholder-engagement.

Results of RPAG meeting discussions are summarized in Section 8.2 and specifically Table 8-3 in the Application. FEI clarifies that RPAG notes are not formal minutes, but rather notes of the general discussions that took place during the sessions. These notes were circulated in draft form to all attendees after each meeting with a request from FEI that members review and advise if they felt there were any errors or omissions. The conclusion that there was "general support for FEI to use the DEP Scenario as FEI's planning scenario for the 2022 LTGRP" was based on the general tone and discussions that occurred over the six RPAG Sessions. No specific question was posed seeking support for the DEP Scenario as the planning scenario. Rather, the conclusion of general support was a culmination of discussions that took place from January 2021 through February 2022. During this time, FEI's response to the provincial GHG emission targets announced October 25, 2021 became a key consideration for the planning environment in which FEI is to conduct its business over the next 20 years.

Examples of discussion points brought forward in RPAG sessions regarding the DEP Scenario and pillars of the Clean Growth Pathway are described in Table 1. FEI acknowledges that some comments questioned aspects of FEI's Clean Growth Pathway, as can be seen below, but overall these discussions provided a strong indication that members generally supported the selection of the DEP Scenario as FEI's planning scenario. Any comments made by FEI staff within this dialogue are noted, otherwise the dated and numbered discussion points in this table were provided by RPAG members and attendees.

Table 1: Overview of RPAG Notes Highlighting Discussions Supportive of the DEP Scenario and FEI's Decarbonization Initiatives

Meeting Date / Number	Discussion Point Number	Comment
Topic: Support for the Clean Growth Pathway and FEI's decarbonization initiatives. FEI observations were: • All members were aligned on the need for urgent climate action in BC with a general understanding that FEI needs to meet requirements and GHG emission reduction targets of government policy. • Since affordability considerations and the need for a province-wide approach to energy system planning were raised frequently, FEI summarized this feedback below.		
Related discussion points captured at RPAG sessions were:		
January 25, 2021 - #1	1.a.i	Member interest in climate action including provincial decarbonization goals, such as those outlined in CleanBC, and the transition to clean energy. Multiple members highlighted a particular interest in electrification as well as renewable gasses.
January 25, 2021 - #1	1.a.ii	Member interest in learning and providing support to the utility during this exciting and dynamic time of transition. Invested in ensuring a long life for the utility in order to meet the future needs of customers.
February 12, 2021 - #2	Breakout Group 1	Members were encouraged to see natural gas being explored as part of the solution and following in the steps of other jurisdictions by assessing a diverse energy future.
February 12, 2021 - #2	Breakout Group 4	Members agreed with the approach to utilizing the energy systems available to us in order to reduce risk and increase resiliency.
February 12, 2021 - #2	Breakout Group 5	We have to do everything; cannot focus on just one area. We need to look at diversification. It's exciting to see FortisBC undertaking this study. Municipalities are looking at reducing GHG emissions and it would be useful to see how the plan intersects with the municipality plans.
November 3, 2021- #4	3.g	RPAG Member expressed appreciation for the cautionary responses to comments and acknowledges the critical role of the gas infrastructure in providing more cost effective ways to decarbonize through displacement of conventional gas. Electrification is not the only answer. The costs associated with new electric supply are difficult to predict. It is easy for senior governments to promise to keep energy costs low, but we all need to understand the reality of the costs that will be incurred through this energy transition although through energy efficiency and building retrofits we should be consuming far less energy in future years.
December 1, 2021 - #5	2.g	What I see is that FEI is complementary to the electrification plan. I admire FortisBC's efforts in this space and we need all pieces working together. As we spread the cost over all ratepayers, a lower rate spread out over customers may change the cost competitiveness of electrification. Since we are tackling all solutions together, we need to know how this impacts new builds in particular.

<table>
<tr><th>Meeting Date / Number</th><th>Discussion Point Number</th><th>Comment</th></tr>
<tr><td colspan="3">Topic: Pillar 1 - Transitioning to renewable and low-carbon gases to decarbonize the gas supply.

FEI observations were:
General support for bringing on renewable and low-carbon gas sourced both within and outside of BC, with an understanding that FEI has challenges in procuring supply at a reasonable cost and is faced with uncertainties in long-term forecasts of supply and costs.
Some concerns raised about the best uses for the renewable resource given end-use equipment technologies available for decarbonizing different sectors of the economy.
Some concerns raised about the role of new connections to the gas system's decarbonization plans</td></tr>
<tr><td colspan="3">Related discussion points captured at RPAG sessions were:</td></tr>
<tr><td>February 12, 2021- #2</td><td>Breakout Group 5</td><td>Model depends on technological innovation to keep costs down to ensure this is a cost-effective resource. Government 15% RNG contribution in the CleanBC plan seems very ambitious, a large amount of reliance on this source. Doesn't seem that this amount of fuel is available at a cost-effective price. Look forward to more analysis and contribution to discussion.</td></tr>
<tr><td>June 17, 2021- #3</td><td>5.p.</td><td>FortisBC's supply of RNG from outside BC is entirely within the applicable GHG accounting framework for BC. Those GHG emissions reductions belong to FortisBC and not to anyone else. The emissions reductions then get purchased with the RNG sold to FortisBC customers. This is fundamentally different from FortisBC taking public relations credit for displacing non-BC fossil fuels.</td></tr>
<tr><td>February 10, 2022 - #5</td><td>3.1.1</td><td>In terms of best use for the renewable resource – in light of heat pumps being effective for residential use, why not focus renewables on industrial use and electrify residential?
FortisBC: The BC Hydro IRP suggests that we will be in a capacity shortfall before 2030. So the highest and best use of clean energy goes both ways. Do we preserve precious clean electricity? Or do we preserve renewable and low-carbon gas? This is the question facing long range energy planning in BC.</td></tr>
</table>

Meeting Date / Number	Discussion Point Number	Comment
Topic: Pillar 2 - Investing in DSM programs in support of energy efficiency and conservation measures to reduce energy use among residential, commercial and industrial customers. FEI observations were: • General support for scaling FEI's DSM activities with the need for accelerated building retrofit activities and supporting commercial and industrial processes.		
Related discussion points captured at RPAG sessions were:		
February 12, 2021 - #2	Breakout Group 2	Dual fuel systems are preferred because of three imperatives to maintain: building/facilities resilience, the comfort of tenants and affordability. Furthermore, dual fuel systems can provide housing providers flexibility to respond to energy price fluctuations over time and mitigate the risks associated with switching the way fuel system of a building, particularly when it comes to the heating system.
February 12, 2021 - #2	Breakout Group 3	The longevity of DSM and energy efficiency programs is going to be critical.
November 3, 2021 - #4	3.b.	I support continuing DSM with renewables as energy efficiency helps reduce costs to customers over time. In addition, there are significant non-energy benefits such as comfort, air quality and more. Over time will the price of RG have a more significant impact on cost effectiveness and the investment in DSM?
Topic: Pillars 3 and 4 - Support for low-carbon transportation infrastructure and investing in LNG to lower GHG emissions in marine fueling and global markets FEI observations were: • FEI received some questions regarding how low-carbon transportation infrastructure was taken into account but generally supportive discussion of emission reduction initiatives. • There was discussion regarding how international GHG emissions should be captured into FEI's emission reductions estimates. This discussion will likely continue into the next LTGRP.		
Related discussion points captured at RPAG sessions were:		
Jan 25, 2021 - #1	3.e	Regarding the marine market share (domestic and international), I assume this refers to LNG marine bunkering? If so, this starts getting into reducing carbon emissions internationally. How will this be addressed in the 2022 LTGRP?
Jan 25, 2021 - #1	3.e.ii	In previous BC Utilities Commission proceedings, the international marine bunkering was justified as decreasing rates for customers due to the overall increase in throughput for the system. However, the contribution to reducing international GHG emissions was not mentioned. It would be really beneficial to include this as it's an important factor that should be discussed.

Meeting Date / Number	Discussion Point Number	Comment
Topic: Balancing Affordability with Decarbonization Objectives. FEI observations were: • Recognition of the need for transformational change and members acknowledged that balancing costs for decarbonization with the need to maintain affordability is going to be an issue for the province's infrastructure as a whole and will need to be monitored carefully. • Some members highlighted the financial hardship imposed on low-income households and the need for addressing differential scales of hardship across the population. An adequate response will require significant changes to the regulatory framework and the regulator's mandate, as well as initiatives from government. FEI's investigations have shown a diversified energy future to be more cost-effective than a single utility approach to decarbonization.		
Related discussion points captured at RPAG sessions were:		
January 25, 2021 - #1	1.a.iii	Ensuring affordability and accessibility of energy for residential and commercial customers.
January 25, 2021 - #1	3.d	We need to contend with the cost implications, especially energy rates, that the transition will bring about and the impact this will have on individuals. It would be prudent to start adjusting the messaging that rates will likely go up in the future and shift the focus to ways we can help customers keep total costs down by reducing consumption through demand side management. The historical message of keeping rates low doesn't help us move forward.
February 12, 2021 - #2	N/A	I think we are facing a huge challenge; a transformation. How do we finance this?
February 12, 2021 - #2	Breakout Group 1	The issue around risk and variability of supply should be kept top of mind and we should not lose sight of affordability when we talk about pathways forward.
February 12, 2021 - #2	Breakout Group 3	Social equity and affordability needs to be at the forefront. Rate design is important for either pathway.
February 12, 2021 - #2	Breakout Group 4	Energy poverty and cost of energy to residential customers is important as electrification can be costly.
February 12, 2021 - #2	Breakout Group 5	We are in a transformation and not a transition period. Enormity of the budgets necessary to make these changes. How are we going to pull out a $100 billion to make this transformation happen? Need working teams (residential, commercial, industrial groups) to understand how we can make this plan work.
June 17, 2021 - #3	3.f	Is there a discussion within FortisBC and potentially with BC Government and BC Hydro about how to manage the inevitability of rising energy prices as social and environmental costs are integrated into new prices, and how conservation can offset these price increases? This is very important for consumers and getting buy in.

Meeting Date / Number	Discussion Point Number	Comment
December 1, 2021 - #5	2.h.ii.	In relation to the member's point, decarbonizing our economy will impose serious financial hardship on low-income households, and this is one of the ways that will play out. Addressing differential scales of hardship across the population is an element of the larger "just transition" strategy that labour and progressive environmental groups have been advocating for some time. An adequate response will require significant changes to the regulatory framework and the regulator's mandate, as well as initiatives from government.
Topic: Support for utilities and government to collaborate on province-wide resource planning. FEI observations were: • Members recognized the high degree of coordination needed between various key players, including the government (with regards to policies), the electric and natural gas utilities, municipalities and other sectors, during this time of transition. This speaks to a diversified approach rather than a single utility approach. • There were many instances where members raised the need for FEI, BC Hydro, FBC and the province to collaborate on long-term resource planning to provide a province-wide perspective on energy needs. Again, this speaks to a diversified approach rather than a single utility approach.		
Related discussion points captured at RPAG sessions were:		
January 25, 2021 - #1	3.c	There is a high degree of coordination needed between various key players, including the government (with regards to policies), the electric and natural gas utilities, municipalities and other sectors, during this time of transition.
January 25, 2021 - #1	4.a	Is there a process for sharing information and aligning efforts between FortisBC's LTGRP and BC Hydro's Integrated Resource Plan (IRP)? For example, the assumptions used.
February 12, 2021- #2	N/A	Attendee expressed need to examine resilience of both gas and electric systems province-wide.
February 12, 2021- #2	N/A	The resiliency of the natural gas system mitigates the risk of the energy system as a whole.
February 12, 2021- #2	Breakout Group 3	Would like to see more collaboration between FortisBC, BC Hydro and the Province's plans. It would be valuable to review and understand what assumptions are being used in plans and how these assumptions align.
February 12, 2021- #2	Breakout Group 4	Need better understanding and reconciliation of the differences between the Pathways assumptions and BC Hydro's electrification impact report.
February 12, 2021- #2	Breakout Group 5	Capacity factor to meet demand particularly on the coldest days and relevance of line pack in the gas system would be helpful to understand the known problems of capacity potential from BC Hydro. Would be good to see a similar work done by BC Hydro; maybe a collaborative review on this front.

Meeting Date / Number	Discussion Point Number	Comment
February 12, 2021- #2	Breakout Group 5	More coordination is needed between BC Hydro and FortisBC. Perhaps exploring a joint resource plan to ensure alignment between the main utilities in the province.
June 17, 2021- #3	5.j	It would be very insightful to have BC Government, BC Hydro, FortisBC and BCUC speak to the synergies, tensions, and risks associated with "integrated" resource/energy planning either as part of this process or an independent forum. There is a real need to strengthen alignment, appreciating there will be competing perspectives. We need extraordinary policy and governance to navigate our challenge. Existing policy making and governance systems are inadequate.
December 1, 2021 - #5	2.a	BCH is filing IRP in December, LTERP is still in process, the RG filing will be soon, FEI LGTRP will be in March. This is an important time for these regulatory pieces to fit together. We need a reasonable process to ensure that this all works together for the good of the province overall.
February 10, 2022 - #6	5.5	Good to see the collaboration efforts with BC Hydro through the BCUC scenarios request.

In the final RPAG meeting on February 10, 2022, FEI summarized the feedback received throughout the 2022 LTGRP consultation process in presentation slides 14 through 18. At that session, Slide 16 (text is reproduced below) was reviewed with RPAG members:

> General agreement for the DEP as the planning scenario and comparisons to the Deep Electrification scenario are of interest. Discussions included:
>
> - Clarification of aspects of the demand and supply critical uncertainties;
> - Location of emission reductions and carbon accounting approach;
> - Approaches to decarbonizing various sectors;
> - Breakout of transportation sector demand;
> - Illustrated demand and carbon reductions by end use;
> - Costs of decarbonization approaches; and
> - Slider tool for exploring and discussing demand/supply critical uncertainties.

When FEI highlighted that the Diversified Energy Pathway was selected as the planning scenario, there was general agreement at the meeting and there were no opinions expressed to the contrary. One member wanted further information about how FEI consolidated the summary of feedback, and if the feedback was based on quantitative or qualitative analysis. FEI responded that the summary of feedback was based on reviewing prior session notes, while combining some feedback from other engagement sessions. FEI explained to the member that notes were distributed after each session, and participants could provide their comments or corrections to FEI for updates prior to posting the final notes on FortisBC.com. Furthermore, no contrary feedback was received regarding the above statement after the February 10, 2022 notes were distributed. FEI interpreted this as general agreement.

Taking all of these discussions and actions into consideration has led FEI to conclude that there was general support among RPAG members for FEI to select the DEP Scenario as its planning scenario for the 2022 LTGRP.

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

> At the June 21, 2021 RPAG meeting, FEI introduced the Expert (Crowd) Opinion Forecast and "Slider" forecasting tool (Expert Opinion Tool). Stakeholders were given an introduction to the exercise and a website link via email after the session. Stakeholders were invited to use the tool to develop their own forecast scenario and to then submit the results to FEI. The exercise was anonymous, but an option was made available for participants to identify their affiliation. The invitation was sent to 31 stakeholders. FEI received responses from 14 RPAG members.

On page 8-11 of the Application, FEI states:

> For the 2022 LTGRP, the sample size (i.e., the number of crowd participants) was small and so likely contains a level of bias. Therefore, FEI did not create a crowd opinion forecast scenario for analysis in the demand forecast Section 4. However, the results clearly indicate that the stakeholders who responded shared the view that decarbonization is of great importance to them. Support from some RPAG members and FEI's experience suggests the exercise is worth continuing and building upon for the next LTGRP as a means of engaging those outside of FEI in these important discussions.

On page 107 of FBC's 2021 LTERP in FBC's 2021 LTERP and LT DSM Plan proceeding, FBC summarizes a crowdsource load scenario as follows:

> FBC also provided RPAG stakeholders with a crowdsource load scenarios tool to give them the opportunity to model their own load driver penetration levels and scenario impacts. The tool allowed stakeholders to adjust the growth rate of the load drivers based on their own views of the driver growth and penetration levels over time. Ten stakeholders used the tool provided and submitted their results to FBC.

67.3 Please confirm, or explain otherwise, that FBC included a crowdsource load scenario in its LTERP, including for the purposes of undertaking portfolio analysis.

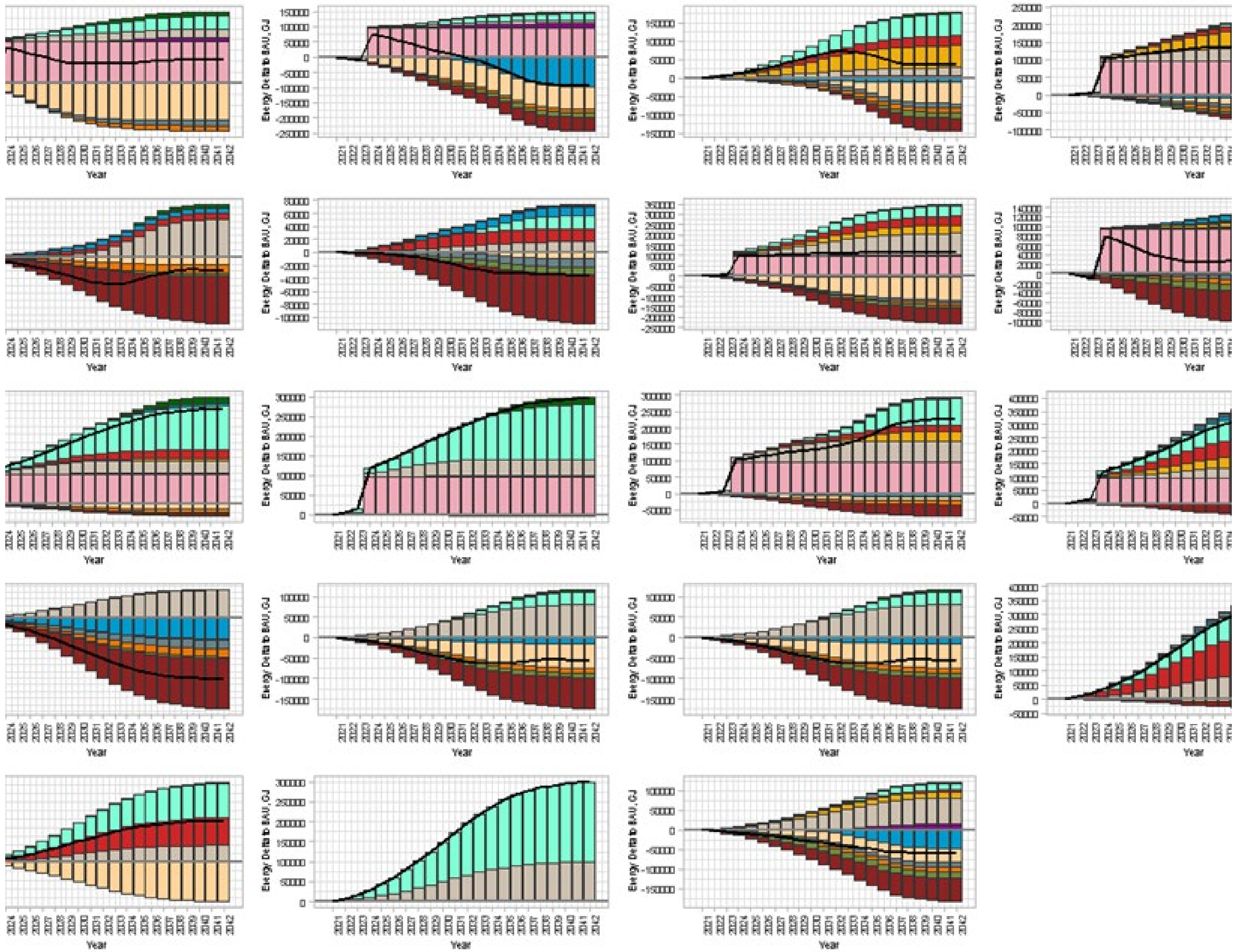
67.3.1 If confirmed, please further explain the rationale for FEI excluding the crowdsource scenario, given the higher number of responses than the FBC crowdsource scenario.

Response:

Confirmed. FBC included a crowdsource load scenario in its 2021 LTERP.

For FEI, although 14 out of 31 participants invited to the crowdsource exercise responded, the sample size was deemed to be too small for FEI to include a crowdsource scenario in the LTGRP. The responses received represented a smaller proportion of the FEI RPAG than FBC experienced during its crowdsource forecast exercise and exhibited a wide range of variability. For example, eight responders did not factor in demand for the Woodfibre LNG project. The crowdsource dataset represented a wide range of responses for key drivers as illustrated in Figure 8-2 of the Application and in the figure below. The LTGRP team was therefore concerned that distilling the results into a single crowdsource forecast would not represent a statistically meaningful demand scenario and would not appropriately represent overall stakeholders' views in the results. The end-use forecasting method used for the LTGRP makes the LTGRP crowdsource tool more complex than the LTERP tool, which may explain some of the variability in the responses, which detracted from a meaningful outcome.

Figure 1: Overview of Individual Responses for Key Drivers in the Crowdsource Exercise



Nevertheless, responses from the crowdsource tool clearly indicated that the stakeholders who responded shared the view that decarbonization is of great importance to them. Support from some RPAG members and FEI's experience suggests the exercise is worth continuing and building upon for the next LTGRP as a means of engaging stakeholders in these important discussions. FEI will consider adding a crowdsource scenario in the next LTGRP.

67.4 Please provide a comparison of the median demand and supply drivers in the crowdsource scenario to those in the FEI LTGRP load forecast scenarios and supply forecasts.

Response:

Table 1 provides a comparison of the median demand and supply drivers in the external crowdsource scenario based on 2042 demand incremental to the Business As Usual baseline and corresponding demand impacts from the forecast scenarios where possible. Although the information from which to make comparisons is limited, the crowdsource forecast does correspond with the DEP Scenario for impacts of fuel switching and renewable and low-carbon gas supply forecasts. It is difficult to make any further comparisons between the crowdsource slider tool and the LTGRP model outputs.

Table 1: Key Driver Outputs from the External Crowdsource Scenario in Comparison to Select Scenarios from 2022 LTGRP Modeling

	Scenario Comparison for 2042 Demand			
Driver	Crowdsource External (PJ/Yr)	Reference Case (PJ/Yr)	DEP (PJ/Yr)	Deep Electrification (PJ/Yr)
Demand		**229**	**208**	**116**
Carbon Price	-41	N/A*	N/A*	N/A*
Climate	-7	N/A*	N/A*	N/A*
Customers	0	N/A*	N/A*	N/A*
Codes and Standards[95]	-12	0	-21	-113
Gas to Electric Fuel Switch	-28			
Gas Price	-9	N/A*	N/A*	N/A*

[95] The cells were merged as these demand reductions can be compared to Pre-DSM GHG emission reductions. These reductions result from a combination of natural efficiency and fuel switching to electricity. The changes in demand are from price- and policy- driven fuel switching, building codes and equipment standards, and customer account forecasts.

Driver	Scenario Comparison for 2042 Demand			
	Crowdsource External (PJ/Yr)	Reference Case (PJ/Yr)	DEP (PJ/Yr)	Deep Electrification (PJ/Yr)
Renewable and Low-Carbon Supply				
CCS	5	0	6	2
Hydrogen	30	2	53	0
RNG	58	11	39	5
Syngas and Lignin	4	0	9	0
Total	**97**	**13**	**107**	**7**

* *Data for these cells is not available (N/A) because the end-use annual demand forecasting method used in the LTGRP addresses cross-effects from these different critical uncertainties being modelled. This makes it difficult to quantify the influence of a single demand driver in the way that the crowd source tool models the preferences of the participants in the crowdsource exercise.*

67.5 Please further explain what factors or circumstances would contribute to FEI including a crowdsource scenario in a future LTGRP.

Response:

FEI believes the slider tool is a valuable method for obtaining feedback on long-term resource planning issues and can be insightful for those who participate. FEI expects to include the crowdsource scenario in future LTGRPs and will explore ways to improve participation in the crowdsource scenario exercise. The tool will be available early enough in the next resource planning cycle to allow broad-based consultation, increasing the likelihood that a large enough sample size will provide meaningful results. Achieving at least 30 complete responses would improve the ability to distill the data received into a single crowdsource result by generating a statistically normal distribution to enable a valid statistical comparison and a meaningful outcome. As such, FEI will consider both improving the way it delivers the crowdsource exercise and increasing the number of participants in the exercise.

68.0 Reference: CONSULTATION AND ENGAGEMENT

Exhibit B-1, Section 8.4, p. 8-18

Community Engagement

On page 8-18 of the Application, FEI provides the following table:

Table 8-4 below provides an overview of the variety of organizations that were invited to participate in these events for the 2022 LTGRP development.

Table 8-4: Community Engagement Participants Represented a Variety of Organizations

Types of Organizations Represented at Community Engagement Sessions
Community planners/developers/operations managers
Energy and sustainability managers and professionals
First Nations community representatives
Municipal community leaders and elected officials
Energy and sustainability non-profit organizations
Real estate builders and developers
Large businesses/manufacturers
Industrial customers
Local businesses and business associations
Economic development representatives, including Chamber of Commerce and Board of Trade members

68.1 Please confirm, or explain otherwise, that residential customers were not invited to participate in community engagement sessions. If confirmed, please explain why not.

Response:

FEI confirms that it did not appoint specific residential customer designates in community engagement sessions. Rather, FEI considered the participation by representatives from community organizations, municipal governments, non-government organizations, and Indigenous communities can meaningfully represent residential customer interests. Real estate builders and developers and others are also largely focused on the energy needs of the residential building sector.

68.2 Please explain whether residential customers were provided any other opportunities to engage and provide input during the development of the LTGRP.

Response:

Residential customers are also represented on the RPAG by Midgard Consulting (representing RCIA) and the BC Public Interest Advocacy Centre (representing BCOAPO). The RCIA is an active RPAG member. As part of its mandate, the RCIA advocates for the energy needs of residential energy consumers in BC.[96] BCOAPO also represents a large group of residential customers.[97]

68.3 Please discuss whether FEI considers there are any significant gaps in the commercial customer base, not otherwise covered by the types of organization outlined in Table 8-4, that were not invited to participate in community engagement sessions.

Response:

Commercial customers such as hospitality, restaurants, small businesses, and other smaller organizations that represent de-centralized sectors of the economy are challenging to engage in consultation efforts. These customer types represent a large and diverse group, whose focus on managing daily business operations leaves little capacity to participate in consultation sessions. However, FEI's team of commercial account managers actively reach out to these customers regarding their current and future energy needs on an ongoing basis. As discussed in Section 8.5, commercial customers were consulted on the Clean Growth Pathway and low-carbon transition, decarbonizing the built environment, the Comprehensive Review and Revised Renewable Gas Program Application, the Conservation Potential Review, and actively engage in FEI's Conservation and Energy Management programs. In addition, these customers are advised on quarterly gas rate change applications and decisions. FEI also notes that the Commercial Energy Consumers Association[98] is both a member of the RPAG for the 2022 LTGRP and an intervener in the LTGRP and numerous other regulatory proceedings. As stated in Action Item 4 of the Action Plan, FEI is committed to continually improving its engagement processes and activities for the next resource plan in recognition of the critical decision-making required to meet BC's growing needs for energy.

[96] As stated on its website (https://www.residentialintervener.com): "The Residential Consumer Intervener Association (RCIA) acts in a transparent and non-discriminatory manner to represent the varied interests of residential energy consumers in the BC Utilities Commission's (BCUC) public proceedings and hearings. The RCIA's primary goal is to ensure the safety and reliability of energy utility services, and that the residential ratepayers and the public interest are adequately represented in BCUC proceedings because BCUC decisions will affect the rates residential consumers pay."

[97] Exhibit C-18-1.

[98] As indicated in the CEC's Request to Intervene (Exhibit C8-1), the CEC is composed of members which are commercial class customers of FEI.

H. OUTCOMES OF THE CLEAN GROWTH PATHWAY

69.0 Reference: GHG EMISSION REDUCTIONS IN THE DIVERSIFIED ENERGY (PLANNING) SCENARIO

Exhibit B-1, Section 9.2.1.1, p. 9-2

Demand Reduction (pre-DSM)

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

> The impact of natural efficiency and some electrification of end use demand in the Diversified Energy (Planning) Scenario results in slightly reduced overall demand in these customer groups over the planning horizon as shown in Figure 4-9. This demand reduction corresponds to GHG emission reductions of 0.3 Mt CO2e per year in 2030 and 0.4 Mt CO2e per year in 2040.

69.1 Please provide for all of FEI's scenarios, a breakdown of the reductions in demand due to natural efficiency and electrification, in volume (PJ) and GHG emission reductions (Mt CO2e).

Response:

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

Please refer to FEI's response to the BCUC IR1 72 series for a general discussion of how FEI determined the appropriate level of planned emission reductions from different actions for the DEP Scenario.

Table 1 provides a breakdown of the demand reductions due to natural efficiency and electrification, in volume (PJ) and GHG emission reductions (Mt CO_2e) for all of FEI's scenarios for the milestone years 2019, 2030, 2040 and 2042. In the LTGRP modeling, FEI refers to this as Demand Reduction Pre-DSM. This represents the demand reduction due to the impact of natural efficiency combined with a degree of fuel switching to electricity. The changes in demand are from price- and policy-driven fuel switching, building codes and equipment standards, and customer account forecasts. Further details about the methodology and assumptions are discussed in BCUC IR1 69.2.

Table 1: Pre-DSM Demand Reductions Due to Natural Efficiency and Electrification (End Use Emission Factors) for Residential, Commercial and Industrial Customers for the Reference Case and Alternate Scenarios in the 2022 LTGRP

Pre- DSM Demand Reduction (Fuel Switching Setting)	Reference Case				Diversified Energy (Planning)				Deep Electrification			
	2019	2030	2040	2042	2019	2030	2040	2042	2019	2030	2040	2042
Demand Reduction (PJ)	0.0	0.0	0.0	0.0	0.0	7.3	18.6	20.9	0.0	50.9	103.7	113.2
GHG Emission Reductions (Mt CO2e)	0.0	0.0	0.0	0.0	0.0	0.4	0.9	1.0	0.0	2.5	5.2	5.6

Pre- DSM Demand Reduction (Fuel Switching Setting)	Upper Bound				Price Based Regulation				Economic Stagnation			
	2019	2030	2040	2042	2019	2030	2040	2042	2019	2030	2040	2042
Demand Reduction (PJ)	0.0	-44.1	-72.8	-79.2	0.0	6.3	15.4	17.4	0.0	-5.6	-4.8	-3.1
GHG Emission Reductions (Mt CO2e)	0.0	-2.2	-3.6	-3.9	0.0	0.3	0.8	0.9	0.0	-0.3	-0.2	-0.2

69.2 Please explain the methodologies, assumptions and emission factors used to calculate emission reductions from natural efficiency and electrification of end use demand.

Response:

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

The methodology and assumptions used in modeling the scenarios in the LTRGP and used to calculate pre-DSM demand reductions illustrated in Table 1 in the response to BCUC IR1 69.1, are discussed below. The scenario values for Demand Reduction Pre -DSM were calculated by subtracting total demand for each scenario from the Reference Case demand, and applying emission factors by fuel that make up the change in demand. The Reference Case demonstrates the demand that would have occurred over the planning horizon based on the expectation of what would happen if conditions for critical uncertainties remained as they were for the base year (2019). Therefore, the difference in demand reflects levels of natural efficiency and electrification caused by policy and price signals beyond the reference settings. Each scenario was assigned a “Fuel Switching Setting” as inputs to the model (illustrated in Table 4-1 in the Application) as follows:

- DEP – Moderate Electrification Setting;
- Deep Electrification – Accelerated Electrification Setting; and
- Upper Bound, Price Based Regulation and Economic Stagnation – Reference Setting.

Pre-DSM demand reduction emission factors were based on the assumption of reducing the need to purchase conventional natural gas. The analysis used the end use emission factor for natural gas of 0.0499 tCO_2e/GJ. Electrification causes an increase in electricity use, and therefore also uses the emission factor for electricity. For all GHG emission calculations reported in Section 9 of the Application, and for all emission reductions presented in BCUC IR1 series, FEI assumed the emission factor for electricity was zero.

1. Calculating Emissions/Emission Reductions from Natural Efficiency

The following methodology and assumptions were used to estimate the reduction in energy consumption due to natural energy conservation, by sector.

Residential

Estimated changes to tertiary load (and hence Average Unit Energy Consumption (UEC)) for space heating in existing dwellings based on the estimated renovation rates combined with the estimated improvement in the building envelope for an average renovation.

- As part of another project, PG estimated that the rate of a renovation that alters the home's envelope occurs at approximately twice the rate of new construction. This estimate was based on the relative market share of windows used in renovations versus new builds.

- PG also estimated that a renovation without added floor area reduces space heating load by approximately 2 per cent.
- Landcor NC Data provided an estimate of the rate of permitted renovations by region. PG assumed that the average renovation for which a permit is required adds livable space to the house. The estimate used was an average of 10 percent additional floor area.

Further changes to the space heating UEC were estimated based on the evolving efficiency of heating equipment. Furnaces and boilers were assumed to be replaced at the natural rate at which they reach end of life, with whatever equipment will be standard in that year.

The trends in Domestic Hot Water (DHW) tertiary loads were assumed to come from the natural replacement of clothes washers and dishwashers at end of life, with new ones at the current standard. DHW use in showers and other fixtures was not assumed to change in the Reference Case.

Further changes to the UEC of DHW were estimated based on the natural replacement of existing water heating equipment at its end of life with new equipment that meets the equipment standard for that year.

Tertiary loads in new dwellings are based on the current version of the BC Building Code. Step Code regulations that are expected to be adopted in future years were not taken into account.

Commercial

Changes to space heating due to improved codes in new commercial construction, are based on the current version of the BC Building Code. Step Code regulations that are expected to be adopted in future years were not taken into account.

Further changes to space heating UEC were estimated based on the evolving efficiency of heating equipment. Boilers and other heating equipment were assumed to be replaced at the natural rate at which they reach end of life, with whatever equipment will be standard in that year.

Changes to the UEC of Service Water Heating (SWH) were based on the natural replacement of existing water heating equipment at its end of life with new equipment that meets the equipment standard for that year.

Industrial

Natural conservation in industry is assumed to be minimal.

2. Calculating Emission Reductions from Electrification

The following methodology and assumptions were used for electrification in the three sectors. As detailed below, these included typical lifetimes of equipment associated with each end use, and if an end use can fuel switch, the next likely substitute fuel. The assumptions are provided for each sector. Please also see the response to BCUC IR1 25.3.

The PG Navigator model calculates annual changes to fuel shares of end-uses in response to price changes or policy-driven fuel-switching. In all cases, the change in fuel share towards or away from natural gas is limited by the estimated lifetime of appliance. For example, if the average water heater lasts 13 years, no one year should see a change in fuel share of existing buildings of more than 1/13 for water heating. The following tables provide the fuel switching assumptions by end-use for each sector including the assumed equipment life, if fuel switching away from natural gas is possible and if so, the alternate fuel, and the information source for the assumption.

Exhibit 1: Residential End Use Lifetimes and Fuel Switching Assumptions

End Use Name	Assumed Life (years)	Fuel Switching Possible?	Alternate Fuel	Information Source
Other Gas Uses	15	No	NA	FortisBC Model Improvements Project (measure life)
Cooking	12	No[99]	NA	2021 CPR (measure life)
Clothes Dryer	12	Yes	Electricity	2021 CPR (measure life)
Dishwasher DHW	13	Yes	Electricity	2021 CPR (measure life)
Washer DHW	13	Yes	Electricity	2021 CPR (measure life)
Shower DHW	13	Yes	Electricity	2021 CPR (measure life)
Other DHW	13	Yes	Electricity	2021 CPR (measure life)
Fireplace	15	Yes	Electricity	2021 CPR (measure life)
Pool & Spa Heaters	7	Yes	Electricity	2021 CPR (measure life)
Space Heating	18	Yes	Electricity	2021 CPR (measure life)

Exhibit 2: Commercial End Use Lifetimes and Fuel Switching Assumptions

End Use Name	Assumed Life (years)	Fuel Switching Possible?	Alternate Fuel	Information Source
Food Services (FS)	15	No	N/A	2017 LTGRP
Other	14	No	N/A	2017 LTGRP
Space Heating (SH)	15	Yes	Electricity	2017 LTGRP
Service Water Heating (SHW)	12	Yes	Electricity	2017 LTGRP
Pool	8	Yes	Electricity	2021 CPR (Pool Heater Measure Life)

Exhibit 3: Industrial End Use Lifetimes and Fuel Switching Assumptions

End Use Name	Segment	Assumed Life (years)	Fuel Switching Possible?	Alternative Fuel	Info Source
Direct Gas Use	All	0	No	NA	2017 LTGRP
On-Site Generation	All	0	No	NA	2017 LTGRP
Other	All	0	No	NA	2017 LTGRP

[99] Fuel switching is physically possible for cooking end-uses, but this end use was modelled to be completely insensitive to price due to the fact that variable energy costs are a very small portion of total cooking appliance costs, and the fact that consumers are often insensitive to fuel cost because they have strong preferences for one cooking fuel over another.

End Use Name	Segment	Assumed Life (years)	Fuel Switching Possible?	Alternative Fuel	Info Source
Petrochem Refining	All	15	No	NA	PG engineering knowledge
Direct-fired Heating	All	20	Yes	Electricity	2017 LTGRP
Heat Treating	All	15	Yes	Electricity	2017 LTGRP
Kilns	Non-metallic Mineral	25	Yes	Other Fossil Fuels[100]	PG engineering knowledge
Kilns	Pulp & Paper - Kraft	25	Yes	Electricity	PG engineering knowledge
Ovens	All	15	Yes	Electricity	2017 LTGRP
Product Drying	Mining	25	Yes	Electricity	PG engineering knowledge
Product Drying	Pulp & Paper - Kraft	25	Yes	Renewable Energy	PG engineering knowledge
Product Drying	Pulp & Paper - TMP	25	Yes	Renewable Energy	PG engineering knowledge
Product Drying	Wood Products	25	Yes	Renewable Energy	PG engineering knowledge
Process Boilers	All	25	Yes	Other Fossil Fuels	PG engineering knowledge
Space Heating	All	20	Yes	Electricity	2017 LTGRP
Water Heaters	All	15	Yes	Electricity	2017 LTGRP

Price Elasticity of Demand Values

The price elasticity of demand reflects how demand for a good changes in response to a change in the price of that good, all else being equal. For the LTGRP modelling, only "own-price" elasticity – how demand changes in response to changes in price of that good only – was used.

Price elasticity is represented numerically and calculated as the percent change in quantity demand divided by the percent change in price.

The following simplifying assumptions were made for the LTGRP:

- Price elasticities will not vary by year; the same value will be used throughout the study period
- Price elasticities vary by sector, but not by region, segment, rate class, end use, etc.
- The same price elasticity value will be applied to changes in commodity price and carbon price.

[100] "Other Fossil Fuels" are a fuel with a higher emissions factor than traditional natural gas.

Exhibit 4 provides the price elasticity values used for each sector. Price elasticity values were not required for the LCT sector, as prices applicable to the sector were not varied.

Exhibit 4: Price Elasticity of Demand by Sectors

	Residential	Commercial	Industrial
Long Run Price Elasticity Value	-0.380	-0.350	-0.700

These values are from the long-run elasticity values for natural gas by sector provided by The State of Washington's Department of Commerce Carbon Tax Assessment Model.[101] These values are "the product of an extensive literature search of fuel and sector specific price elasticity of demand values." For details on the research method and data sources reviewed in the literature review on the subject, please see the report titled "Price Elasticity of Demand for Natural Gas: Considerations for Load Forecasting", February 14, 2019 written by Posterity Group for FEI, included as Attachment 69.2.

Please also refer to the response to BCUC IR1 25.3 for assumptions and further details related to the fuel switching setting used in modeling the alternate demand scenarios in the LTGRP.

[101] Washington State Department of Commerce, "Carbon Tax Assessment Model," 2017. [Online]. Available: https://www.commerce.wa.gov/growing-the-economy/energy/washington-state-energy-office/carbon-tax/ [Accessed 14 01 2019].

70.0 Reference: GHG EMISSION REDUCTIONS IN THE DIVERSIFIED ENERGY (PLANNING) SCENARIO

Exhibit B-1, Section 9.2.1.2, p. 9-2

DSM

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

> Section 5 of the 2022 LTGRP recommends that FEI pursue the High DSM Setting with the resulting gas savings presented in Figure 5-5. In the Diversified Energy (Planning) Scenario, this high level of energy savings results in 0.9 Mt CO2e reductions in 2030 and 1.3 Mt CO2e reductions in 2040.

70.1 Please provide, for each of FEI's scenarios the assumptions regarding the choice of DSM setting, the gas savings expressed in PJ and the GHG emission savings in MTCO2e for the planning horizon.

Response:

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

Table 1 illustrates for each of FEI's scenarios the choice of DSM setting, the gas savings expressed in PJ and the GHG end-use emission savings in $MtCO_2e$ for the milestone years 2019, 2030, 2040 and 2042.

Table 1: DSM Demand Reductions (End Use Emission Factors) for Residential, Commercial and Industrial Customers for the Reference Case and Alternate Scenarios

DSM Demand Reduction	Reference Case Medium DSM Setting				Diversified Energy (Planning) Scenario High DSM Setting				Deep Electrification Taper Off DSM Setting			
	2019	2030	2040	2042	2019	2030	2040	2042	2019	2030	2040	2042
Demand Reduction Volume (PJ)	0.0	13.0	23.0	24.0	0.0	18.2	25.8	26.0	0.0	12.6	15.1	14.5
GHG Emission Reductions (MtCO2e)	0.0	0.6	1.1	1.2	0.0	0.9	1.3	1.3	0.0	0.6	0.8	0.7

DSM Demand Reduction	Upper Bound No DSM				Price Based Regulation Medium UCT Setting				Economic Stagnation Medium DSM Setting			
	2019	2030	2040	2042	2019	2030	2040	2042	2019	2030	2040	2042
Demand Reduction Volume (PJ)	0.0	0.0	0.0	0.0	0.0	9.4	8.5	7.0	0.0	13.2	21.0	21.9
GHG Emission Reductions (MtCO2e)	0.0	0.0	0.0	0.0	0.0	0.5	0.4	0.3	0.0	0.7	1.0	1.1

The choice of DSM setting applied to each scenario is aligned with the scenario narrative described in Table 4-1 in the Application. The DSM analysis then estimates the potential impact of DSM programs by tailoring the results of the 2021 CPR to the economic and policy considerations reflected in each scenario. The assumptions regarding the choice of DSM setting that were applied to each scenario are described in Table 2 below.

Table 2: Assumptions Regarding the Choice of DSM Setting Applied to LTGRP Scenarios

Scenario	DSM Setting	Assumptions Regarding the Choice of DSM Setting
Reference Case	Medium	• The Reference Case demonstrates the DSM activity that is assumed to occur over the planning horizon based on the continuation of expected trends and implementation of known policies.
DEP	High	• Consistent with the Clean Growth Pathway, the High DSM Setting maximizes energy savings potential and therefore the potential to reduce GHG emissions by accelerating building retrofits, high performance new construction, and energy efficiency in commercial and industrial processes.
Deep Electrification	Taper Off	• As electrification is the primary avenue utilized by the BC government for decarbonization in this scenario, FEI's DSM budgets are constrained. This analysis required an additional iterative process to find the optimal solutions of measures to meet the program budget based on an economic screening threshold in each year that allowed just enough measures to pass the screen based on a specified limit for that year. Budget is limited to 50 percent of 2022 spending in 2023, declining to 25 percent of 2022 spending by 2042.
Price-Based Regulation	Medium UCT	• Use of price signals instead of carbon regulation within the planning environment creates favourable conditions for FEI's Clean Growth Pathway as represented by the Medium UCT setting where no budget limit is applied, but efficient budget spending is undertaken.
Economic Stagnation	Medium	• As the BC economy tightens, investments in decarbonization are more limited and FEI continues to pursue DSM.
Upper Bound	N/A – no DSM	• This scenario combines all outcomes that would increase demand and therefore no DSM is applied.

70.2 Please explain the methodology and emission factors used to calculate DSM GHG emission reductions.

Response:

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

When DSM measures are applied to a scenario, they are assumed to reduce the consumption of conventional natural gas, even if the customer may be using a mix of fuel types. The logic for this is that reductions in energy used by customers will not change the amount of renewable gasses FEI acquires over the planning horizon, but will instead be used to reduce the volume of conventional gas purchased. The emission reductions from DSM are calculated using the emission factor for natural gas. The end use emission factor for natural gas is 0.0499 and the life cycle emission factor is 0.0598 tCO_2e/GJ.

Table 1-2 on page 1-6 of the Application provides emission factors used in the Application. Note that some results are based on life cycle emission factors while others use end use emission factors. The factor which is used is described in the text accompanying the table or figure.

71.0 Reference: GHG EMISSION REDUCTIONS IN THE DIVERSIFIED ENERGY (PLANNING) SCENARIO

Exhibit B-1, Section 9.2.1.3, pp. 9-2, 9-10, 9-11; Section 1.3, pp. 1-6 – 1-7; FEI BERC Rate proceeding, Exhibit B-17, BCUC IR 5.1 , 5.1.1

2020 B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions[102], p. 1

Renewable and Low-Carbon Gas Supply

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

> In this section, FEI presents emission reductions using the end use emission factor in order to align with the GHGRS [Greenhouse Gas Reduction Standard]. Section 9.2.2.3 presents emission reductions for all four pillars of FEI's Clean Growth Pathway using life cycle emission factors. A complete listing and explanation of the emission factors used is presented in Table 1-2 of this LTGRP.

On the same page, with respect to renewable and low-carbon gas supply, FEI states:

> FEI's transition to renewable and low-carbon gas supplies has the largest impact on GHG emission reductions for residential, commercial and industrial customers. Acquiring and allocating 60.2 PJ of renewable and low-carbon gas supply by 2030 to these customer groups results in emission reductions of 3.0 Mt CO2e. In 2040, the allocation of 99 PJ of renewable and low-carbon gas to these customer groups results in 4.9 Mt CO2e of GHG emission reductions.

On pages 27 and 28, in response to BCUC IR 5.1 and 5.1.1 in the BERC Rate proceeding, FEI stated:

> The ramp-up time to reach expected volumes of a given Renewable Gas supply project varies widely depending on the complexity of the system, the nature of the feedstock and the weather conditions. However, on average, FEI expects that most facilities will operate below expected volumes for the first year, with increased volumes in the second year of production, before reaching maximum expected volumes in the third year of operation…
>
> Since 2010, FEI has developed a network of Renewable Gas suppliers which has enabled the most significant and longest running Renewable Gas program in North America. FEI relies on, and benefits from, its own experience in developing existing supply to determine expected annual volume projections.
>
> For projects that are operating, FEI relies on historical production data to project future volume. For example, one of FEI's current RNG suppliers, Fraser Valley

[102] B.C. Ministry of Environment and Climate Change Strategy (2021), 2020 B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions, https://www2.gov.bc.ca/assets/gov/environment/climate-change/cng/methodology/2020-pso-methodology.pdf.

Biogas, has been producing 80 TJ of RNG annually since 2014 and FEI thus projects these volumes to continue.

For projects that are not yet built or operational, FEI typically uses a projected volume that is 75 percent of the facility's maximum annual volume. FEI selected this percentage based on its experience with the 10 operating projects in its supply portfolio as of 2021.

In some cases, a projected volume that is 75 percent of the facility's maximum production volume is not appropriate. For example, the Columbia-Shuswap Regional District Landfill produces approximately 16 TJ per year (about 40 percent of max). In this case, the maximum annual volume allows for increased production as a result of population growth or improvements in landfill collection over the life of the contract. As such, FEI has chosen to use a more conservative approach for this project and uses the actual current RNG production, even though over the life of the project there may be future higher volumes. As FEI gains more experience and can draw on historical data from a greater number of projects, it expects to continue to improve its forecast accuracy.

Pages 1-6 to 1-7 of the Application include the following table:

Table 1-2: Fuel Types and Decarbonization Technologies Used in the 2022 LTGRP

Fuel Type	Description	Life cycle Emission Factor (tCO_2e/GJ)	End use cycle Emission Factor (tCO_2e/GJ)
Natural gas	Natural gas is a naturally occurring hydrocarbon. Hydrocarbons are a class of organic compounds consisting of carbon and hydrogen. Raw natural gas (before processing) is composed primarily of methane.	0.0598	0.04987
Renewable natural gas (RNG)	Upgraded biogas produced from farm or municipal organic biomass. Upgraded synthesis gas (syngas) produced from wood biomass at pulp mills and some municipal organic biomass.	0.0100	0.0003
Syngas	Produced from wood to displace natural gas used in lime kilns at pulp mills. Can also be upgraded to green hydrogen.	0.0100	0.0000
Lignin	Produced from black liquor to displace natural gas used in lime kilns at pulp mills.	0.0100	0.0000
Green Hydrogen	Produced via water electrolysis using renewable electricity feedstock.	0.0000	0.0000
Blue Hydrogen	Reformed from hydrocarbon feedstock with up to 90 percent carbon sequestered.	0.0200	0.0000
Natural Gas with Associated Carbon Capture, Utilization and Storage (CCUS)	Applying the carbon reduction benefits of CCUS to the delivery of natural gas on FEI's gas network.	0.0148	0.0148

The 2020 B.C. Best Practices Methodology for Quantifying Greenhouse Gas Emissions sets out the current best practices for quantifying and reporting greenhouse gas (GHG) emissions from B.C.'s provincial public sector organizations, local governments and communities. This document has been included as reference in the Application, for example in the report included in Appendix D-2.

71.1 Please explain the difference between end-use and life cycle methodologies.

Response:

Lifecycle emission factors represent the GHG emissions from upstream fuel production to fuel consumption at the end use appliance. The end use emission factor is a subset of the lifecycle emission factor and is the GHG emissions associated with the consumption of the fuel at the end use appliance. As an example, the lifecycle emission factor for natural gas would include the GHG emissions associated upstream production at the well head all the way to (and including) the consumption at a residential furnace. The end use emission factor for natural gas would include only the GHG emissions associated with the consumption at a residential furnace.

71.1.1 In the case of life cycle emission factors, please describe the boundaries of the analysis, including whether the analysis considers all upstream activities, new infrastructure construction, and out-of-province emissions.

Response:

As discussed in the response to BCUC IR1 71.1, the life cycle emission factor includes upstream related activities. The life cycle emission factor provided in Table 1-2 of the Application is an estimate of GHG intensity associated with various fuels. For renewable and low-carbon gas such as RNG, syngas, lignin, etc., the life cycle intensities would be quantified as supply is acquired. This process would include quantifying GHG intensity estimates for out-of-province and new infrastructure construction.

71.2 Please discuss how fugitive emissions associated with FEI's transmission system are taken into account.

Response:

Fugitive emissions associated with FEI's transmission system are taken into account in the life cycle emission factors described in the response to BCUC IR1 71.1. These emission factors include all related GHG emissions from fuel production to fuel consumption at the customer appliance, including all related fugitive GHG emissions from the transmission system.

71.2.1 Please provide the total GHG emissions (tCO2e/year) which resulted from FEI's fugitive emissions in each of the past three years.

Response:

FEI provides its total fugitive emissions in the table below, alongside total energy delivered and fugitive emissions per unit of energy delivered, which can be compared to the units in Table 1-2 quoted in the preamble above.

	Fugitive Emissions as reported to the BC Ministry of Environment (tCO2e)	Total Energy Delivered (PJ)	FEI Fugitive GHG Emissions per Unit of Energy Delivered (tCO2e/GJ)
2021	52,801	228	0.0002
2020	44,620	219	0.0002
2019	47,968	227	0.0002

71.2.2 Please discuss whether FEI envisions the need for a capital project in the 20-year planning horizon that is driven by the need to reduce addresses fugitive emissions on its system.

Response:

FEI does envision the need for capital projects in the 20-year planning horizon to reduce GHG emissions, and plans to include capital replacement projects for non-end of life assets to reduce operational GHG emissions (including fugitive methane emissions) in the next rate application (subsequent to the 2020-2024 MRP term). To date, a number of capital upgrades have been identified with the potential of reducing approximately 65,000 tCO2e between 2025 and 2050. This is in addition to the currently identified methane emission reduction projects that are forecast in the 2023 Annual Review, and are intended to reduce methane emission by 200,000 tCO2e.

71.3 Please clarify the treatment of embodied carbon from new infrastructure that FEI would deem critical for gas supply, whether they are associated with FEI or third party investments.

Response:

For the purposes of this question, FEI defines "embodied carbon" as GHG emissions related to the manufacturing, transportation, installation, maintenance and disposal of building materials. Embodied carbon from new infrastructure is not accounted for in existing GHG emissions calculations in the Application.

71.4 Please clarify the source of information for each emission factor provided in Table 1-2.

Response:

The source of each emission factor in Table 1-2 is described in the table below.

Table 1: Sources of Emission Factors

Fuel Type	Lifecycle Emission Factor (tCO2e/GJ)	End use Emission Factor (tCO2e/GJ)	Source
Natural Gas	0.0598	0.04987	The lifecycle emission factor for natural gas is based upon GHGenius modeling results. The end use emission factor is based on the BC government's 2020 Best Practices Methodology for Quantifying Greenhouse Gas Emissions.
Renewable natural gas (RNG)	0.0100	0.0003	End use emission factor is based on the BC government's 2020 Best Practices Methodology for Quantifying Greenhouse Gas Emissions.
Syngas	0.0100	0	Syngas and lignin are both forms of energy derived from organic material. As such it is assumed that their lifecycle emissions are roughly similar to RNG, which is similarly derived from valorizing organic materials. See RNG explanation in row above.
Lignin	0.0100	0	
Green Hydrogen	0	0	Green hydrogen is assumed to be made from a low-carbon source of electricity (hydro, wind or solar) and therefore to have a lifecycle emission factor close to zero.
Blue Hydrogen	0.02	0	Blue hydrogen's lifecycle emissions are based on the emissions from producing natural gas, the efficiency of conversion to hydrogen, and energy inputs required to run the facility and sequester carbon. The lifecycle emission factor is based on generic assumptions and actual lifecycle emissions may ultimately vary by facility.
Natural Gas with associated CCUS	0.0148	0.0148	Calculated based on end use emission factor and IEAGHG, "Towards Zero Emissions CCS from Power Stations using Higher Capture Rates or Biomass", 2019/02,March,2019.[Online]. Available at: http://documents.ieaghg.org/index.php/s/CLIZIvBI6OdMFnf/download.

FEI acknowledges that there is considerable uncertainty associated with analysis of fuels that are not yet produced within BC and as such, educated assumptions about the emission factors for hydrogen, syngas and lignin have been made.

71.5 Please further explain why FEI considers the end-use emission factors will align with the proposed GHG Reduction Standards.

Response:

The provincial GHG emissions inventory as well as the CleanBC Roadmap accounts for GHG emissions on a sector-by-sector basis using end-use emissions factors. The GHGRS is described in the Roadmap as a tool to reduce emissions in the buildings and industry sectors (net of upstream oil and gas extraction). Emissions in these sectors are accounted for using end-use emissions factors. The sector-by-sector inventory negates the need to adopt a life cycle emission factor, as the life cycle emission factor would result in double counting of GHG emissions or include emissions from out-of-province. As a result, the application of an end-use factor would best align with the proposed GHG Reduction Standards.

As an example, the BC Government will have BC data for upstream, gas processing plant, pipeline transmission, and pipeline distribution GHG emissions. If FEI were to apply a life cycle emission factor to energy sold to end-users, double counting of GHG emissions upstream of the end-user would result.

71.6 If FEI's emission factors are different to those currently outlined by the BC Best Practices Methodology, please explain the reasons for the differences.

Response:

Where available, emission factors from BC Best Practices were adopted in Table 1-2 (i.e., end use combustion emission factors for natural gas and renewable natural gas). In the other cases where no emission factors are published for a given fuel (e.g., green hydrogen), other government source data was applied.

71.7 Please provide, for the Diversified Energy (Planning) Scenario, the supporting assumptions and calculations used to arrive at the forecast 60 PJ and 99 PJ of renewable and low-carbon gas supply by 2030 and 2040, respectively.

Response:

Arriving at the forecast of renewable and low-carbon gas for the DEP Scenario presented in the 2022 LTGRP involved a series of iterative steps that are described throughout the LTGRP and can be summarized as follows:

- Identifying the amount of carbon emission reductions needed to meet the proposed GHGRS 2030 Emissions Cap (the Cap);
- Determining the amount of emission reductions that other actions such as DSM activities could contribute to meeting the Cap;
- Calculating the remaining emission reductions required by FEI to meet the Cap after the actions from the preceding step were assumed to have been taken;
- Assessing the availability of renewable and low-carbon gas over the planning horizon;
- Assessing the ability of FEI to acquire the available quantities of renewable and low-carbon gas over the planning horizon; and
- Applying FEI's collective expertise and knowledge gained over years of acquiring, transporting and delivering energy, to continue undertaking Clean Growth Pathway initiatives such as DSM and developing a renewable and low-carbon gas marketplace in BC. This foundation enables FEI to undertake the carbon reduction activities identified in the 2022 LTGRP and to finalize the forecasted contribution of each of the actions, including the acquisition and delivery of renewable and low-carbon gas to customers, in meeting the required carbon reductions.

The relative contributions of each of the carbon reducing activities and associated sections in the 2022 LTGRP are summarized in the following table.

Table 1: Steps Taken in LTGRP Process to Calculate Emission Reductions Required to Meet Proposed GHGRS and Provincial Targets

Steps Taken to Calculate Emission Reduction Initiatives in the DEP		LTGRP Section for Assumptions and Methodology	DEP Annual Demand (PJ/Yr)		DEP Emissions (Mt CO_2e/Yr)	
			2030	2040	2030	2040
	Provincial GHG Reduction Targets (FEI Share)				5.7	4.3
1	Total Demand	Section 4	210.7	208.4	10.5	10.4
2	Less DSM Savings	Section 5	(18.2)	(25.8)	(0.9)	(1.3)
	Post-DSM Demand and Emissions		192.5	182.6	9.6	9.1
3	Renewable and Low-Carbon Gas Supply Transition	Sections 6 and 7	60.2	99.0	(3.0)	(4.9)
	Post-Transition Emissions		-	-	6.6	4.3

	Steps Taken to Calculate Emission Reduction Initiatives in the DEP	LTGRP Section for Assumptions and Methodology	DEP Annual Demand (PJ/Yr)		DEP Emissions (Mt CO_2e/Yr)	
			2030	2040	2030	2040
	Provincial GHG Reduction Targets (FEI Share)				5.7	4.3
4	Additional Actions	Section 9	18.0[103]	Not Required	(0.9)	Not Required
5	**FEI Total Remaining Emissions**				**5.7**	**4.3**

Specifically, regarding the GHG reductions from the 60 PJ and 99 PJ supply of renewable and low-carbon gas, the calculation of emission reductions for each type of fuel is as follows:

*Fuel (PJ) * Emission factor (Mt Co_2e/PJ for each fuel type) = Total Emissions (Mt Co_2e).*

For the amounts of each type of fuel modelled in the DEP and alternate future scenarios, please refer to BCUC IR1 71.8.1.

71.8 Please discuss whether FEI considers 60 PJ of renewable and low-carbon gas supply represents the maximum volume it could secure by 2030.

<u>Response:</u>

As discussed in the response to BCUC IR1 77.2, research demonstrates that available resources to produce RNG far exceed the 60 PJ target of renewable and low-carbon gas by 2030. Therefore, in theory, 60 PJ does not represent the maximum volume FEI could secure by 2030. By 2030, FEI expects its renewable and low-carbon gas portfolio to have more than 30 PJ of renewable gas based on a continued upward trajectory. While FEI expects RNG to be an important fuel and to make up a large amount of its renewable gas mix, over the longer term, FEI expects other forms of renewable gas, such as low-carbon hydrogen, to play an increasingly significant role. These different forms of renewable gas have the potential to be produced at scale and blended in the gas system or in dedicated infrastructure to decarbonize a range of end-use applications. While future renewable and low-carbon gas supply potential is expected to grow, it remains to be seen if technological advances and market conditions will support increasing supply diversity beyond the 60 PJ target by 2030.

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[103] Emission reduction equivalent to 18 PJ natural gas demand reduction through additional initiatives described in BCUC IR1 74.2.

71.8.1 For each year in the planning horizon, please provide a forecast of the following information:

- a breakdown of the different types of gas supplies (e.g. renewable natural gas, syngas, lignin, hydrogen by production type, etc.) in PJ;
- breakdown of the origin of each type of supply (e.g. BC, other in Canada, out of Canada);
- average cost ($/GJ) by type of gas, and total renewable and low-carbon gasses; and
- total annual cost of renewable and low carbon gasses.

Response:

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

In the tables below, FEI provides the renewable and low-carbon portfolio supply outlook for the DEP Scenario, Reference Case and all alternate scenarios to serve residential, commercial and industrial customers. This supply outlook represents an example of how components of the scenarios could evolve, including different types of gas supply, their average cost and total annual cost. The origin of supply is discussed below the tables.

It is important to emphasize that FEI has not developed a separate 20-year forecast for each individual component of its renewable and low-carbon gas supplies (i.e. RNG, hydrogen, syngas and lignin) for its 2022 LTGRP. The data for the individual components of the renewable and low-carbon portfolios presented in the tables below is an outlook and not a forecast per se. The individual component volumes could change and new forms of renewable and low-carbon gas or other gas decarbonization pathways could come into play in the future. FEI considers that each of the individual components of the outlook will fall within a range, with the expectation that the actual amount of component acquired will vary from year to year depending on many factors, such as rate of project advancement and cost of supply.

In terms of costs, for expediency, syngas, lignin and CCUS, which are included in smaller amounts, were assumed to be available at the same or lower cost than that of hydrogen and/or RNG. It is assumed that if these fuels were substantially more expensive, then FEI would acquire additional RNG or hydrogen instead. Only one cost outlook was developed for hydrogen. It is important to note that this is a long-range outlook with uncertainty remaining for costs into the future. FEI has attempted to be reasonably accurate in these early cost outlooks based on FEI's experience in sourcing gas supply, the B.C. Renewable and Low-Carbon Gas Supply Potential Study[104], and other industry research available at the time. The costs may vary per scenario as indicated in the tables below.

[104] Exhibit B1-1, 2022 LTGRP Application, Appendix D-2.

Table 1: DEP Forecast of Renewable and Low-Carbon Gas Supply and Costs

Year	Renewable and Low-Carbon Gas Supply					Estimated Cost / GJ		Estimated Cost of Renewable and Low Carbon Gas Supply				
	RNG	Hydrogen	Syngas and Lignin	CCUS	Total Renewable and Low-Carbon	RNG / Syngas and Lignin / CCUS	Hydrogen	RNG	Hydrogen	Syngas and Lignin	CCUS	Total Cost
	(PJ)					($/GJ)		($ Million)				
2019	0.0	0.0	0.0	0.0	**0.0**	21.4	30.5	0.0	0.0	0.0	0.0	**0.0**
2020	0.3	0.0	0.0	0.0	**0.3**	21.7	30.5	5.9	0.0	0.0	0.0	**5.9**
2021	0.7	0.0	0.0	0.0	**0.7**	22.1	30.5	15.5	0.0	0.0	0.0	**15.5**
2022	5.8	0.0	0.0	0.0	**5.8**	22.6	30.5	131.1	0.0	0.0	0.3	**131.3**
2023	10.7	0.0	0.0	0.2	**11.0**	23.1	30.5	247.7	0.0	0.0	5.1	**252.9**
2024	12.9	2.7	0.4	0.3	**16.3**	23.6	30.5	304.3	82.0	9.3	7.8	**403.5**
2025	16.1	5.4	0.8	0.4	**22.7**	24.0	30.5	387.2	163.9	19.0	10.7	**580.8**
2026	19.3	8.1	1.6	0.6	**29.5**	24.6	30.5	473.5	245.7	38.9	13.6	**771.7**
2027	22.5	10.7	3.2	0.7	**37.0**	25.1	30.5	563.2	327.5	79.4	16.7	**986.8**
2028	25.6	13.4	4.7	0.8	**44.6**	25.6	15.0	656.5	201.3	121.5	19.9	**999.2**
2029	28.8	16.1	6.3	0.9	**52.2**	26.1	15.0	753.4	241.6	165.5	23.2	**1,183.7**
2030	32.2	20.0	6.7	1.3	**60.2**	26.7	15.0	858.5	300.0	178.8	35.6	**1,372.9**
2031	32.8	22.8	6.9	1.7	**64.1**	27.2	15.0	892.2	341.3	187.1	46.7	**1,467.3**
2032	33.3	25.5	7.0	2.1	**68.0**	27.8	15.0	927.0	382.5	195.6	58.4	**1,563.5**
2033	33.9	28.3	7.2	2.5	**71.8**	28.4	15.0	962.8	423.8	204.5	70.5	**1,661.5**
2034	34.5	31.0	7.4	2.9	**75.7**	29.0	15.0	999.7	465.0	213.6	83.0	**1,761.3**
2035	35.1	33.8	7.5	3.2	**79.6**	29.6	15.0	1,037.7	506.3	223.0	96.1	**1,863.1**
2036	35.6	36.5	7.7	3.6	**83.5**	30.2	15.0	1,077.0	547.5	232.8	109.7	**1,967.0**
2037	36.2	39.3	7.9	4.0	**87.3**	30.9	15.0	1,117.2	588.8	242.8	123.8	**2,072.6**
2038	36.8	42.0	8.0	4.4	**91.2**	31.0	15.0	1,140.1	630.0	249.0	136.2	**2,155.4**
2039	37.4	44.8	8.2	4.8	**95.1**	31.0	15.0	1,158.0	671.3	254.2	148.1	**2,231.5**
2040	37.9	47.5	8.4	5.2	**99.0**	31.0	15.0	1,175.8	712.5	259.4	159.9	**2,307.6**
2041	38.5	50.3	8.5	5.5	**102.8**	31.0	15.0	1,193.7	753.8	264.5	171.8	**2,383.8**
2042	39.1	53.0	8.7	5.9	**106.7**	31.0	15.0	1,211.5	795.0	269.7	183.7	**2,459.9**

Table 2: Reference Case Forecast of Renewable and Low-Carbon Gas Supply and Costs

Year	Renewable and Low-Carbon Gas Supply					Estimated Cost / GJ		Estimated Cost of Renewable and Low Carbon Gas Supply				
	RNG	Hydrogen	Syngas and Lignin	CCUS	Total Renewable and Low-Carbon	RNG / Syngas and Lignin / CCUS	Hydrogen	RNG	Hydrogen	Syngas and Lignin	CCUS	Total Cost
	(PJ)					($/GJ)		($ Million)				
2019	0.0	0.0	0.0	0.0	**0.0**	21.4	30.5	0.0	0.0	0.0	0.0	**0.0**
2020	0.3	0.0	0.0	0.0	**0.3**	21.7	30.5	5.9	0.0	0.0	0.0	**5.9**
2021	0.9	0.0	0.0	0.0	**0.9**	22.1	30.5	19.8	0.0	0.0	0.0	**19.8**
2022	3.4	0.0	0.0	0.0	**3.4**	22.6	30.5	76.3	0.0	0.0	0.0	**76.3**
2023	6.1	0.0	0.0	0.0	**6.1**	23.1	30.5	139.7	0.3	0.0	0.0	**140.0**
2024	7.9	0.1	0.0	0.0	**8.0**	23.6	30.5	186.4	2.3	0.0	0.0	**188.7**
2025	8.7	0.1	0.0	0.0	**8.9**	24.0	30.5	210.3	4.3	0.0	0.0	**214.6**
2026	9.6	0.2	0.0	0.0	**9.8**	24.6	30.5	236.5	6.3	0.0	0.0	**242.8**
2027	10.6	0.3	0.0	0.0	**10.9**	25.1	30.5	266.7	8.3	0.0	0.0	**274.9**
2028	10.8	0.3	0.0	0.0	**11.1**	25.6	15.0	275.2	5.1	0.0	0.0	**280.3**
2029	10.7	0.4	0.0	0.0	**11.1**	26.1	15.0	280.6	6.0	0.0	0.0	**286.7**
2030	10.7	0.5	0.0	0.0	**11.2**	26.7	15.0	286.4	7.0	0.0	0.0	**293.4**
2031	10.7	0.6	0.0	0.0	**11.3**	27.2	15.0	292.4	8.8	0.0	0.0	**301.2**
2032	10.7	0.7	0.0	0.0	**11.4**	27.8	15.0	298.6	10.5	0.0	0.0	**309.2**
2033	10.7	0.8	0.0	0.0	**11.6**	28.4	15.0	305.0	12.3	0.0	0.0	**317.3**
2034	10.7	0.9	0.0	0.0	**11.7**	29.0	15.0	311.6	14.0	0.0	0.0	**325.6**
2035	10.7	1.1	0.0	0.0	**11.8**	29.6	15.0	318.2	15.8	0.0	0.0	**334.0**
2036	10.8	1.2	0.0	0.0	**11.9**	30.2	15.0	325.0	17.5	0.0	0.0	**342.5**
2037	10.8	1.3	0.0	0.0	**12.0**	30.9	15.0	331.8	19.3	0.0	0.0	**351.1**
2038	10.8	1.4	0.0	0.0	**12.2**	31.0	15.0	333.4	21.1	0.0	0.0	**354.5**
2039	10.8	1.5	0.0	0.0	**12.3**	31.0	15.0	333.5	22.8	0.0	0.0	**356.3**
2040	10.8	1.6	0.0	0.0	**12.4**	31.0	15.0	333.6	24.6	0.0	0.0	**358.2**
2041	10.8	1.8	0.0	0.0	**12.5**	31.0	15.0	333.6	26.3	0.0	0.0	**360.0**
2042	10.8	1.9	0.0	0.0	**12.6**	31.0	15.0	333.7	28.1	0.0	0.0	**361.9**

Table 3: Price-Based Regulation Scenario Forecast of Renewable and Low-Carbon Gas Supply and Costs

Year	Renewable and Low-Carbon Gas Supply					Estimated Cost / GJ		Estimated Cost of Renewable and Low Carbon Gas Supply				
	RNG	Hydrogen	Syngas and Lignin	CCUS	Total Renewable and Low-Carbon	RNG / Syngas and Lignin / CCUS	Hydrogen	RNG	Hydrogen	Syngas and Lignin	CCUS	Total Cost
	(PJ)					($/GJ)		($ Million)				
2019	0.0	0.0	0.0	0.0	**0.0**	21.4	30.5	0.0	0.0	0.0	0.0	**0.0**
2020	0.3	0.0	0.0	0.0	**0.3**	21.7	30.5	5.9	0.0	0.0	0.0	**5.9**
2021	4.8	0.0	0.0	0.0	**4.8**	22.1	30.5	105.8	0.0	0.0	0.0	**105.8**
2022	9.3	0.0	0.0	0.2	**9.5**	22.6	30.5	209.5	0.0	0.0	5.0	**214.4**
2023	13.2	0.0	0.0	0.4	**13.7**	23.1	30.5	305.0	0.0	0.0	10.2	**315.1**
2024	16.4	3.6	0.5	0.7	**21.3**	23.6	30.5	387.2	111.0	11.8	15.8	**525.8**
2025	19.5	6.9	1.0	0.9	**28.3**	24.0	30.5	468.5	210.8	24.0	21.4	**724.7**
2026	22.6	10.0	2.0	1.1	**35.7**	24.6	30.5	553.9	305.9	49.1	27.3	**936.2**
2027	25.4	12.9	4.0	1.3	**43.7**	25.1	30.5	637.5	394.7	100.3	33.3	**1,165.8**
2028	27.8	15.5	6.0	1.6	**50.8**	25.6	15.0	711.1	232.1	153.6	39.9	**1,136.6**
2029	30.7	18.2	8.0	1.8	**58.7**	26.1	15.0	802.1	273.6	209.1	46.5	**1,331.2**
2030	33.5	20.9	10.0	2.0	**66.4**	26.7	15.0	894.1	314.0	266.8	53.4	**1,528.3**
2031	36.8	25.0	10.5	2.7	**75.0**	27.2	15.0	1,002.6	374.7	286.1	72.7	**1,736.0**
2032	40.1	29.0	11.0	3.3	**83.4**	27.8	15.0	1,114.6	434.9	306.0	92.6	**1,948.0**
2033	43.4	33.0	11.5	4.0	**91.9**	28.4	15.0	1,231.1	495.3	326.6	113.6	**2,166.6**
2034	46.6	37.1	12.0	4.7	**100.4**	29.0	15.0	1,352.4	555.9	348.0	135.4	**2,391.6**
2035	49.9	41.1	12.5	5.3	**108.8**	29.6	15.0	1,477.3	615.9	370.1	157.8	**2,621.0**
2036	53.1	45.0	13.0	5.9	**117.1**	30.2	15.0	1,605.8	675.5	393.0	179.3	**2,853.5**
2037	56.3	49.0	13.5	5.9	**124.8**	30.9	15.0	1,738.3	734.7	416.6	183.3	**3,073.0**
2038	59.5	52.9	14.0	6.0	**132.5**	31.0	15.0	1,845.4	794.0	434.0	186.0	**3,259.4**
2039	62.7	56.9	14.5	6.0	**140.1**	31.0	15.0	1,943.7	852.8	449.5	186.3	**3,432.3**
2040	65.9	60.7	15.0	6.0	**147.6**	31.0	15.0	2,041.4	911.1	465.0	186.9	**3,604.4**
2041	69.0	64.6	15.5	6.1	**155.1**	31.0	15.0	2,138.1	968.7	480.5	187.6	**3,774.8**
2042	72.1	68.5	16.0	6.1	**162.7**	31.0	15.0	2,235.4	1,026.9	496.0	188.8	**3,947.1**

Table 4: Deep Electrification Scenario Forecast of Renewable and Low-Carbon Gas Supply and Costs

Year	Renewable and Low-Carbon Gas Supply					Estimated Cost / GJ		Estimated Cost of Renewable and Low Carbon Gas Supply				
	RNG	Hydrogen	Syngas and Lignin	CCUS	Total Renewable and Low-Carbon	RNG / Syngas and Lignin / CCUS	Hydrogen	RNG	Hydrogen	Syngas and Lignin	CCUS	Total Cost
	(PJ)					($/GJ)		($ Million)				
2019	0.0	0.0	0.0	0.0	**0.0**	21.4	30.5	0.0	0.0	0.0	0.0	**0.0**
2020	0.3	0.0	0.0	0.0	**0.3**	21.7	30.5	5.6	0.0	0.0	0.0	**5.6**
2021	0.8	0.0	0.0	0.0	**0.8**	22.1	30.5	18.1	0.0	0.0	0.0	**18.1**
2022	3.1	0.0	0.0	0.2	**3.3**	22.6	30.5	70.5	0.0	0.0	5.0	**75.5**
2023	5.1	0.0	0.0	0.4	**5.5**	23.1	30.5	116.5	0.0	0.0	10.2	**126.7**
2024	5.3	0.0	0.0	0.7	**5.9**	23.6	30.5	124.1	0.0	0.0	15.8	**139.9**
2025	5.6	0.0	0.0	0.9	**6.4**	24.0	30.5	133.5	0.0	0.0	21.4	**154.9**
2026	5.5	0.0	0.0	1.1	**6.6**	24.6	30.5	135.5	0.0	0.0	27.3	**162.8**
2027	5.5	0.0	0.0	1.3	**6.9**	25.1	30.5	138.6	0.0	0.0	33.3	**172.0**
2028	5.5	0.0	0.0	1.6	**7.1**	25.6	15.0	141.3	0.0	0.0	39.9	**181.2**
2029	5.5	0.0	0.0	1.8	**7.3**	26.1	15.0	144.3	0.0	0.0	46.5	**190.8**
2030	5.5	0.0	0.0	2.0	**7.5**	26.7	15.0	147.0	0.0	0.0	53.4	**200.4**
2031	5.5	0.0	0.0	2.7	**8.2**	27.2	15.0	149.8	0.0	0.0	72.7	**222.6**
2032	5.5	0.0	0.0	3.3	**8.8**	27.8	15.0	153.0	0.0	0.0	92.6	**245.6**
2033	5.5	0.0	0.0	3.4	**8.9**	28.4	15.0	155.9	0.0	0.0	95.4	**251.3**
2034	5.5	0.0	0.0	2.4	**7.9**	29.0	15.0	158.6	0.0	0.0	70.5	**229.1**
2035	5.5	0.0	0.0	2.4	**7.9**	29.6	15.0	161.9	0.0	0.0	72.2	**234.2**
2036	5.5	0.0	0.0	2.5	**7.9**	30.2	15.0	165.1	0.0	0.0	75.0	**240.0**
2037	5.5	0.0	0.0	2.5	**8.0**	30.9	15.0	168.5	0.0	0.0	76.8	**245.3**
2038	5.5	0.0	0.0	2.5	**8.0**	31.0	15.0	169.0	0.0	0.0	77.5	**246.5**
2039	5.5	0.0	0.0	2.5	**8.0**	31.0	15.0	169.0	0.0	0.0	77.5	**246.5**
2040	5.4	0.0	0.0	2.5	**8.0**	31.0	15.0	168.6	0.0	0.0	78.4	**247.1**
2041	5.4	0.0	0.0	1.6	**7.0**	31.0	15.0	168.0	0.0	0.0	50.2	**218.2**
2042	5.4	0.0	0.0	1.6	**7.1**	31.0	15.0	168.3	0.0	0.0	50.2	**218.6**

Table 5: Economic Stagnation Scenario Forecast of Renewable and Low-Carbon Gas Supply and Costs

Year	Renewable and Low-Carbon Gas Supply					Estimated Cost / GJ		Estimated Cost of Renewable and Low Carbon Gas Supply				
	RNG	Hydrogen	Syngas and Lignin	CCUS	Total Renewable and Low-Carbon	RNG / Syngas and Lignin / CCUS	Hydrogen	RNG	Hydrogen	Syngas and Lignin	CCUS	Total Cost
	(PJ)					($/GJ)		($ Million)				
2019	0.0	0.0	0.0	0.0	**0.0**	21.4	30.5	0.0	0.0	0.0	0.0	**0.0**
2020	0.3	0.0	0.0	0.0	**0.3**	21.7	30.5	6.1	0.0	0.0	0.0	**6.1**
2021	0.9	0.0	0.0	0.0	**0.9**	22.1	30.5	19.7	0.0	0.0	0.0	**19.7**
2022	3.4	0.0	0.0	0.0	**3.4**	22.6	30.5	76.1	0.0	0.0	0.0	**76.1**
2023	6.1	0.0	0.0	0.0	**6.1**	23.1	30.5	140.0	0.0	0.0	0.0	**140.0**
2024	7.9	0.1	0.0	0.0	**8.0**	23.6	30.5	187.0	2.4	0.0	0.0	**189.5**
2025	8.8	0.1	0.0	0.0	**8.9**	24.0	30.5	211.2	4.3	0.0	0.0	**215.4**
2026	9.7	0.2	0.0	0.0	**9.9**	24.6	30.5	237.2	6.4	0.0	0.0	**243.6**
2027	10.7	0.3	0.0	0.0	**11.0**	25.1	30.5	268.3	8.2	0.0	0.0	**276.5**
2028	10.8	0.3	0.0	0.0	**11.2**	25.6	15.0	277.2	5.1	0.0	0.0	**282.3**
2029	10.8	0.4	0.0	0.0	**11.2**	26.1	15.0	283.3	6.0	0.0	0.0	**289.3**
2030	10.8	0.5	0.0	0.0	**11.3**	26.7	15.0	289.2	6.9	0.0	0.0	**296.1**
2031	10.8	0.6	0.0	0.0	**11.4**	27.2	15.0	295.0	8.9	0.0	0.0	**303.9**
2032	10.9	0.7	0.0	0.0	**11.6**	27.8	15.0	301.8	10.5	0.0	0.0	**312.3**
2033	10.9	0.8	0.0	0.0	**11.7**	28.4	15.0	308.1	12.5	0.0	0.0	**320.6**
2034	10.9	0.9	0.0	0.0	**11.8**	29.0	15.0	314.6	14.1	0.0	0.0	**328.7**
2035	10.9	1.1	0.0	0.0	**11.9**	29.6	15.0	321.2	15.9	0.0	0.0	**337.1**
2036	10.9	1.2	0.0	0.0	**12.0**	30.2	15.0	328.0	17.7	0.0	0.0	**345.7**
2037	10.9	1.3	0.0	0.0	**12.2**	30.9	15.0	335.1	19.5	0.0	0.0	**354.6**
2038	10.9	1.4	0.0	0.0	**12.3**	31.0	15.0	336.7	21.3	0.0	0.0	**358.0**
2039	10.9	1.5	0.0	0.0	**12.4**	31.0	15.0	337.3	23.0	0.0	0.0	**360.2**
2040	10.9	1.7	0.0	0.0	**12.5**	31.0	15.0	337.0	24.8	0.0	0.0	**361.7**
2041	10.9	1.8	0.0	0.0	**12.7**	31.0	15.0	337.3	26.6	0.0	0.0	**363.8**
2042	10.9	1.9	0.0	0.0	**12.8**	31.0	15.0	337.0	28.5	0.0	0.0	**365.5**

Table 6: Upper Bound Scenario Forecast of Renewable and Low-Carbon Gas Supply and Costs

Year	Renewable and Low-Carbon Gas Supply					Estimated Cost / GJ		Estimated Cost of Renewable and Low Carbon Gas Supply				
	RNG	Hydrogen	Syngas and Lignin	CCUS	Total Renewable and Low-Carbon	RNG / Syngas and Lignin / CCUS	Hydrogen	RNG	Hydrogen	Syngas and Lignin	CCUS	Total Cost
	(PJ)					($/GJ)		($ Million)				
2019	0.0	0.0	0.0	0.0	**0.0**	21.4	30.5	0.0	0.0	0.0	0.0	**0.0**
2020	0.3	0.0	0.0	0.0	**0.3**	21.7	30.5	6.1	0.0	0.0	0.0	**6.1**
2021	4.8	0.0	0.0	0.0	**4.8**	22.1	30.5	106.5	0.0	0.0	0.0	**106.5**
2022	9.3	0.0	0.0	0.2	**9.6**	22.6	30.5	211.0	0.0	0.0	5.0	**216.0**
2023	13.4	0.0	0.0	0.4	**13.9**	23.1	30.5	309.4	0.0	0.0	10.2	**319.5**
2024	16.8	3.7	0.5	0.7	**21.7**	23.6	30.5	396.0	113.5	11.8	15.8	**537.0**
2025	20.1	7.1	1.0	0.9	**29.1**	24.0	30.5	483.2	217.5	24.0	21.4	**746.1**
2026	23.5	10.5	2.0	1.1	**37.1**	24.6	30.5	577.8	319.0	49.1	27.3	**973.2**
2027	26.8	13.6	4.0	1.3	**45.7**	25.1	30.5	670.6	414.8	100.3	33.3	**1,219.0**
2028	29.5	16.4	6.0	1.6	**53.5**	25.6	15.0	755.1	246.3	153.6	39.9	**1,194.9**
2029	32.9	19.5	8.0	1.8	**62.2**	26.1	15.0	859.0	293.1	209.1	46.5	**1,407.7**
2030	36.2	22.6	10.0	2.0	**70.7**	26.7	15.0	964.9	338.7	266.8	53.4	**1,623.7**
2031	39.8	27.0	10.5	2.7	**80.0**	27.2	15.0	1,084.8	405.5	286.1	72.7	**1,849.1**
2032	43.5	31.5	11.0	3.3	**89.3**	27.8	15.0	1,210.5	472.4	306.0	92.6	**2,081.5**
2033	47.3	36.0	11.5	4.0	**98.7**	28.4	15.0	1,341.9	539.9	326.6	113.6	**2,321.9**
2034	51.1	40.6	12.0	4.7	**108.3**	29.0	15.0	1,480.8	608.7	348.0	135.4	**2,572.9**
2035	54.8	45.1	12.5	5.3	**117.7**	29.6	15.0	1,622.0	676.2	370.1	157.8	**2,826.1**
2036	58.5	49.6	13.0	6.0	**127.1**	30.2	15.0	1,768.8	743.9	393.0	181.4	**3,087.0**
2037	62.3	54.2	13.5	6.7	**136.6**	30.9	15.0	1,921.7	812.3	416.6	205.8	**3,356.3**
2038	66.0	58.7	14.0	7.3	**146.0**	31.0	15.0	2,046.6	880.4	434.0	227.2	**3,588.2**
2039	69.8	63.3	14.5	8.0	**155.5**	31.0	15.0	2,162.9	948.8	449.5	248.0	**3,809.1**
2040	73.6	67.8	15.0	8.7	**165.1**	31.0	15.0	2,280.1	1,017.5	465.0	268.8	**4,031.3**
2041	77.4	72.5	15.5	9.3	**174.7**	31.0	15.0	2,399.4	1,087.2	480.5	289.2	**4,256.3**
2042	81.2	77.1	16.0	10.0	**184.3**	31.0	15.0	2,516.6	1,156.2	496.0	310.0	**4,478.8**

In terms of the region where the supply will originate, please refer to the response to BCUC IR1 52.5 for a discussion about FEI's initiatives to source renewable and low-carbon gas supply. Although FEI does not have a detailed forecast of where each type of supply originates, Table 7-2 in the Application provides an overview of considerations for integrating renewable and low-carbon gas in FEI systems. The table demonstrates that there is RNG and hydrogen supply potential in all regions, and syngas and lignin supply potential in the Vancouver Island and the Interior regions. FEI aims to support the BC renewable gas industry where possible, but ratepayer impacts are also a priority in ensuring FEI reaches its decarbonization objectives at the lowest cost possible for customers. Please refer to FEI's responses to BCUC IR1 52.4 to 52.6 for a discussion of risks and opportunities related to acquiring and producing the forecasted amounts of renewable and low-carbon gas and BCUC IR1 77.2 for further discussion about supply potential.

71.8.2 Please confirm if these commodity costs and volumes were applied in the rate impact analysis in Section 9.4 of the Application.

71.8.2.1 If not, please discuss the reason for using different commodity costs and volumes and the assumptions used in the rate impact analysis.

Response:

Confirmed. FEI's estimated costs of renewable and low-carbon gas were taken into consideration in the rate impact analysis discussed in Section 9.4 of the Application. As discussed, commodity costs were based on a mix of supply of conventional natural gas and renewable and low-carbon gas, and midstream (i.e., storage and transport charges) costs which were assumed to escalate over time by inflation.

The supporting materials from which FEI derived the forecast for renewable and low-carbon gas cost (i.e., market analysis, studies, etc.) included:

- RNG price assumptions based on executed supply agreements, supply agreements in advanced stages of negotiation, and potential opportunities in the form of supply prospects.
- RNG forward price outlook based on experience and market pricing signals from active engagement as a buyer in the biogas marketplace.
- RNG, renewable and low-carbon hydrogen, syngas, and lignin forecast volume and price scenarios researched by qualified third-party experts over the past decade to complete longer-term supply potential outlooks; most recently FEI worked with the BC Bioenergy Network to complete the BC Renewable and Low-Carbon Gas Supply Potential study to assess BC, Canada, and North America RNG supply. This latest body of work integrates numerous previous renewable and low-carbon potential studies and estimates for BC's

and the broader North American marketplace for feedstock availability and price outlook.[105]

- Publicly-available market information on emerging low-carbon hydrogen supply in western Canada, such as published by The Transition Accelerator in Alberta.[106]
- Commissioned market studies by HIS Markit, Goobie Tulk Inc. and Fluor Canada analyzing the emerging low-carbon hydrogen supply in western Canada, including technology and industry readiness to develop large scale production of low-carbon hydrogen supply incorporating very high carbon capture rates, production cost drivers and market pricing considerations.

To the extent this information is publicly available, it has been included in Appendices A and D of the Application or is identified in the footnotes associated with this response.

71.9 For the Reference Case, Upper Bound, Economic Stagnation, Deep Electrification and Price-Based Regulation scenarios, please provide the forecast volumes of renewable and low-carbon gas supply for the planning horizon, with supporting assumptions and calculations.

Response:

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

Please refer to the response to BCUC IR1 71.8.1 for the forecast volumes of renewable and low-carbon gas supply for the planning horizon for the Reference Case and alternate scenarios. FEI provides high-level supporting assumptions for how renewable and low-carbon gas allocations were modelled in the table below.

Table 1: Assumptions Regarding the Scenarios' Renewable and Low-Carbon Gas Supply Allocation

Scenario	Assumptions Regarding the Allocation of Renewable and Low-Carbon Gas Supply to Total Demand
Reference Case	The Reference Case demonstrates the level of activity assumed to occur over the planning horizon based on the expected continuation of current trends and implementation of known policies as at the time the allocations were determined.
DEP	Consistent with FEI's Clean Growth Pathway, renewable and low-carbon energy solutions are prioritized. Targets are developed to be in line with the proposed GHGRS emissions cap.

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105 Exhibit B1-1, 2022 LTGRP Application, Appendix D-2.

106 D. Layzell, C. Young, J. Lof, J. Leary and S. Sit, Towards Net-Zero Energy Systems in Canada: A Key Role for Hydrogen (September 2020) Transition Accelerator Reports: Vol 2, Issue 3, online at: https://transitionaccelerator.ca/towards-net-zero-energy-systems-in-canada-a-key-role-for-hydrogen/.

Scenario	Assumptions Regarding the Allocation of Renewable and Low-Carbon Gas Supply to Total Demand
Deep Electrification	As electrification is the primary avenue utilized by the BC government for decarbonization, FEI's budgets to acquire renewable and low-carbon gases are constrained in order to minimize customer rate impacts.
Price-Based Regulation	Use of price signals instead of carbon regulation within the planning environment creates favourable conditions for FEI's Clean Growth Pathway. Price signals boost development of renewable and low-carbon gases including CCUS.
Economic Stagnation	As the BC economy tightens, investments in decarbonization are limited.
Upper Bound	A combination of settings such that all outcomes would increase gas demand, for all fuels in this scenario.

71.9.1 For each year in the planning horizon, please also provide, for each scenario, the following information:

- a breakdown of the different types of gas supplies (e.g. renewable natural gas, syngas, lignin, hydrogen, etc.) in PJ;
- breakdown of the origin of each type of supply (e.g. BC, other in Canada, out of Canada);
- average cost per ($/GJ) by type of gas, and total renewable and low-carbon gasses; and
- total annual cost of renewable and low carbon gasses.

Response:

Please refer to the response to BCUC IR1 71.8.1.

71.9.2 Please clarify if these commodity costs and volumes were applied in the rate impact analysis in section 9.4 of the Application.

71.9.2.1 If not, please discuss the reason for using different commodity costs and volumes and the assumptions used in the rate impact analysis.

Response:

Confirmed, as stated in the response to BCUC IR1 71.8.2.

71.10 Please explain, for all of FEI's scenarios, if FEI used the emission factors indicated in Table 1-2 in the Application for the modelling of GHG emissions. If the calculation included other emission factors, please indicate the values and the source of such emission factors.

Response:

FEI confirms that the emission factors for renewable and low-carbon gases listed in Table 1-2 were adopted in the modelling of GHG emissions under all scenarios described in the Application.

71.11 Please explain, for all scenarios, if the modelling of GHG emissions considered emissions associated with FEI's infrastructure investments (i.e. embodied carbon) required by each of the scenarios.

71.11.1 If yes, please indicate, for each scenario, the assumed infrastructure investments contemplated, the embodied carbon and the assumptions or sources of information used for these calculations.

Response:

Please refer to the response to BCUC IR1 71.3.

71.12 Please indicate the anticipated lead times needed to ramp up supply for renewable and low-carbon projects, including but not limited to the duration to construct and ramp up projects following the establishment of a supply agreement.

Response:

FEI anticipates lead times to ramp up supply for on-system and off-system renewable and low-carbon projects will vary significantly between jurisdictions and production pathways; for example, the recently announced Inflation Reduction Act will likely reduce the lead times to ramp up clean energy supply in the United States by incentivizing domestic production in clean energy technologies like solar, wind, carbon capture, and clean hydrogen[107]. For on-system supply in British Columbia (BC), the BC Renewable and Low-Carbon Gas Supply Potential Study[108] (the Study) presents scenarios and cost curves for supply to ramp up by 2030 and 2050 based on project development cycles, learning curves and build-out rates for commercialized and new or emerging technologies. The Study outlook concludes that by 2030, mature and lower-cost on-

[107] https://www.whitehouse.gov/briefing-room/statements-releases/2022/08/19/fact-sheet-the-inflation-reduction-act-supports-workers-and-families/.
[108] Exhibit B1-1, 2022 LTGRP Application, Appendix D-2.

system RNG (biomethane) anaerobic digestion projects, as well as some syngas, lignin, and hydrogen projects, will be developed first and will need to be supplemented by off-system acquisitions to sufficiently ramp up supply to meet 2030 targets. The Study outlook also concludes that by 2050, renewable and low-carbon hydrogen supply and wood-based supply pathways (wood to syngas and wood to RNG) could represent a larger share of the on-system supply ramp up potential, subject to key considerations including technology status, readiness and resource availability, and policy support; for example, to develop large-scale low-carbon hydrogen production in BC, it will require projects with high rates of carbon capture and suitable access to geology to securely store large volumes of sequestered carbon.

In terms of the speed to develop individual projects, as discussed above, some types of projects may require longer lead times depending on project requirements such as technology scale up, infrastructure interconnections, regulatory approvals and permits, social acceptance, and investment needs. FEI's experience in BC as an RNG purchaser and project developer indicates that anaerobic digestion RNG projects up to 0.3 PJ per year production, which is currently representative of the largest proposed project capacity of this type in BC, could on average require three to five years of lead time to bring to commercial operation after final investment approval. FEI is also engaging with potential suppliers and completing in-house early-stage technical and economic feasibility assessments for larger scale renewable and low-carbon supply, including green hydrogen projects up to 5 PJ per year and blue hydrogen projects with significantly greater annual production capacity that would require much longer than five years to achieve commercial operation after establishment of a supply agreement and final investment approval. Off-system projects, depending on the jurisdictional requirements and supporting policy and incentives in place, may require less time to construct similar-sized projects; therefore, FEI's approach of seeking supply from a broader marketplace, including a portfolio of on-system and off-system projects, mitigates some of the risk associated with longer lead time needed to ramp up supply for renewable and low-carbon projects.

71.13 Please describe in detail the key risks associated with FEI's acquisition of the necessary volumes of renewable and low carbon gasses by 2030, and in the longer term. Please elaborate on the risks for each type of renewable and low carbon gas, and in the case of hydrogen, the different forms of production.

71.13.1 Please describe the strategies and actions FEI has identified to mitigate such risks.

Response:

Please refer to the response to BCUC IR1 52.4.

71.14 Please elaborate on the likelihood of FEI achieving the required volumes of renewable and low-carbon supply forecast by 2030 for each of FEI's scenarios.

Response:

Please refer to FEI's response to BCUC IR1 52.4 to 52.6 for a discussion of risks and opportunities related to acquiring and producing the forecasted amounts of renewable and low-carbon gas and 77.2 for further discussion about supply potential.

71.14.1 Please explain FEI's alternative options to meet the proposed GHGRS emission cap if the contracted supply of renewable and low-carbon gasses is lower than forecast.

Response:

The BC Government has not yet established alternative options for FEI to meet the proposed GHGRS emission cap. However, please refer to FEI's response to BCUC IR1 74.2 for a comprehensive discussion on FEI's emission reduction initiatives. If contracted supply of renewable and low-carbon gasses is lower than forecast, FEI expect to use the other initiatives discussed in response to BCUC IR1 74.2 to meet the GHGRS.

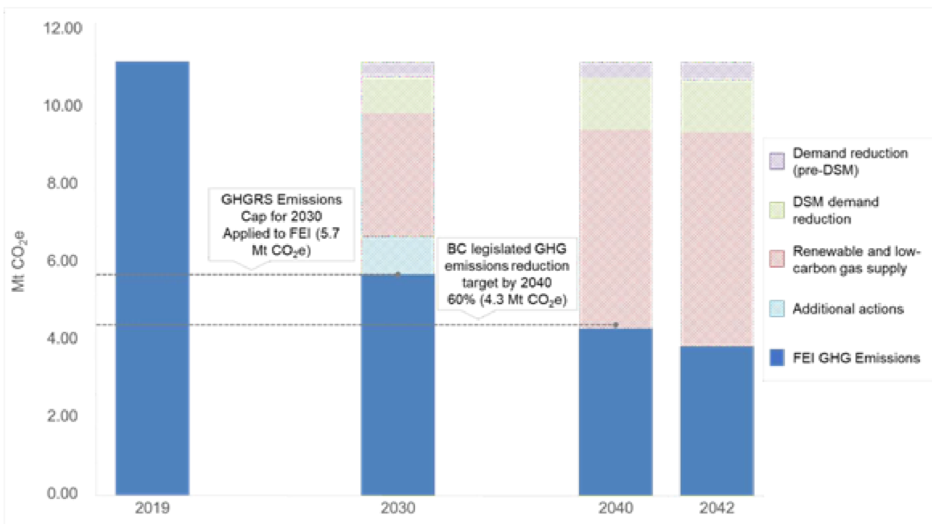
72.0 Reference: GHG EMISSION REDUCTIONS IN THE DIVERSIFIED ENERGY (PLANNING) SCENARIO

Exhibit B-1, Section 9.2.1.5, pp. 9-4 — 9.5, 9-10 – 9-11

Emission Reduction Scenarios

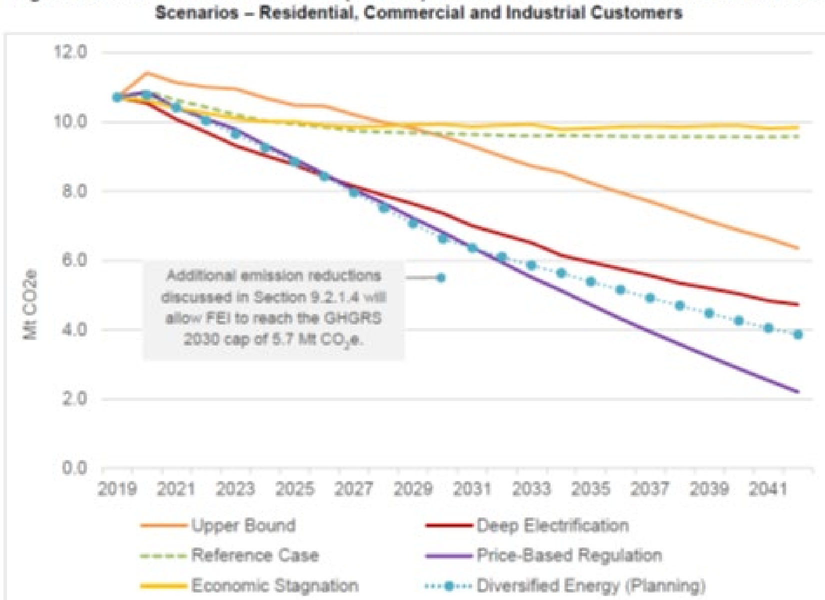
In section 9-2 of the Application, FEI outlines its approach to GHG emission reductions in the Diversified Energy (Planning) scenario. On page 9-4 of the Application, FEI includes the following graph:

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



On page 9-5 of the Application, FEI presents the following figure:

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



On pages 9-10 and 9-11 of the Application, FEI includes Table 9-1: FEI's Investments in Decarbonization Initiatives Support Market Transformation Over the 20-Year Planning Horizon.

72.1 Please provide an overview of FEI's process to determine the appropriate level of planned emission reductions from different actions for the Diversified Energy (Planning) scenario, as outlined in Figure 9-1. Please include an explanation of any analysis of trade-offs or alternative pathways considered.

Response:

FEI's process to determine the appropriate level of planned emission reductions from different actions for the DEP Scenario is based on FEI's initiatives detailed in Section 3, which describes FEI's Clean Growth Pathway and the four pillars that are being undertaken to achieve a low-carbon energy future. Through workshops and collaboration across business units, the decarbonization targets illustrated in Figure 9-1 represent what FEI is implementing through the Action Plan in the short term, and other company initiatives in the longer term to support decarbonization through the four pillars of the Clean Growth Pathway. Please refer to the responses to BCUC IR1 71.7 for assumptions and calculations used in developing FEI's planned emission reductions and BCUC IR1 74.2 for further discussion on FEI's initiatives to meet the proposed GHGRS.

72.2 Please provide the information included in Figure 9-1 in table format, for all of FEI's load forecast scenarios.

Response:

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

Table 1 provides the information included in Figure 9-1 in table format, for all of FEI's load forecast scenarios. The GHG emission reduction categories (rows in the table) consist of the following:

- **GHG Reduction from Demand Reduction (Pre-DSM)** – This represents the demand reduction due to the impact of natural efficiency[109] combined with a degree of fuel switching to electricity. The changes in demand are from price- and policy-driven fuel switching, building codes and equipment standards, and customer account forecasts. The Reference Case demonstrates the forecasted demand based on continuation of current economic conditions and implementation of known policies (as of 2019). The values presented in Table 1 for Demand Reduction Pre -DSM were calculated by subtracting total demand from the Reference Case demand thus reflecting levels of natural efficiency and electrification caused by policy and price signals beyond the reference settings.[110]

[109] Efficiency improvements that occur through the natural replacement of older, less efficient equipment with newer, more efficient equipment as influenced by market transformation by DSM programs, regulations, and other factors.
[110] In preparing IRs regarding Figure 9-1 in the Application, FEI determined that the pre-DSM calculations were

- **GHG Reduction from DSM Activities –** This represents the demand reduction developed in the DSM analysis discussed in Section 5 of the Application.
- **GHG Reductions from the Transition to Renewable and Low-Carbon Gas Supply –** This represents the emissions reduction achieved by substituting conventional natural gas demand with renewable and low-carbon gas supply.
- **GHG Reductions from Additional Actions -** In Section 9.2.1.4 of the Application, FEI discusses the additional actions it plans to take by 2030 to meet the proposed GHGRS cap.
- **Total GHG Reductions –** The sum of all GHG reduction activities listed above.
- **FEI Remaining Emissions –** This represents FEI's total GHG emissions after the emission reductions discussed above are taken into account.
- **Further Emissions Reductions Required To Meet Provincial Targets –** This represents the difference between FEI's total emissions and in 2030, the proposed GHGRS emissions cap of 5.7 Mt CO2e and in 2040, the BC legislated GHG emissions reduction target (60 percent reduction of FEI's 2007 customer emissions) to meet 4.3 Mt CO2e[111]. These steps were developed outside of the LTGRP modelling process and are not accounted for as "actions" (or Critical Uncertainties) in the scenario forecasts.

incorrect. FEI subtracted demand from 2007 demand and GHG emission levels rather than using the Reference Case as the baseline for each year in each scenario. The sentence in Section 9.2.1.1 stating: "This demand reduction corresponds to GHG emission reductions of **0.3 Mt CO_2e per** year in 2030 and **0.4 Mt CO_2e** per year in 2040." should be stated as "This demand reduction corresponds to GHG emission reductions of **0.4 Mt CO_2e** per year in 2030 and **0.9 Mt CO_2e** per year in 2040." There were no other impacts to calculations in the Application as a result of this oversight except where this analysis was presented in the Executive Summary, Section 9 and Figure ES-8.

[111] BC *Climate Change Accountability Act*, Part 1 - BC Greenhouse Gas Emission Targets, sub-section 2(1)(a.2).

Table 1: GHG Emission Reductions (End Use Emission Factors) for Residential, Commercial and Industrial Customers for the Reference Case and Alternate Scenarios in the 2022 LTGRP

Clean Growth Pathway Emission Reduction Categories	Reference Case (Mt CO2e)				Diversified Energy (Planning) (Mt CO2e)				Deep Electrification (Mt CO2e)			
	2019	2030	2040	2042	2019	2030	2040	2042	2019	2030	2040	2042
GHG Reductions from Demand Reduction (Pre-DSM)	0.0	0.0	0.0	0.0	0.0	0.4	0.9	1.0	0.0	2.5	5.2	5.6
GHG Reductions from DSM Activities	0.0	0.6	1.1	1.2	0.0	0.9	1.3	1.3	0.0	0.6	0.8	0.7
GHG Reductions from Transition to Renewable and Low-Carbon Gas	0.0	0.5	0.6	0.6	0.0	3.0	4.8	5.2	0.0	0.3	0.4	0.3
GHG Reductions from Additional Actions						0.9						
Total GHG Reductions	0.0	1.2	1.7	1.8	0.0	5.2	7.1	7.6	0.0	3.5	6.3	6.7
FEI Remaining Emissions	10.7	9.7	9.6	9.6	10.7	5.7	4.3	3.9	10.7	7.4	5.0	4.7
Further Emissions Reductions Needed to Meet GHGRS Cap	5.0	4.0	5.3	5.3	5.0	0.0	0.0	-0.4	5.0	1.7	0.7	0.4

Clean Growth Pathway Emission Reduction Categories	Upper Bound (Mt CO2e)				Price-Based Regulation (Mt CO2e)				Economic Stagnation (Mt CO2e)			
	2019	2030	2040	2042	2019	2030	2040	2042	2019	2030	2040	2042
GHG Reductions from Demand Reduction (Pre-DSM)	0.0	-2.2	-3.6	-3.9	0.0	0.3	0.8	0.9	0.0	-0.3	-0.2	-0.2
GHG Reductions from DSM Activities	0.0	0.0	0.0	0.0	0.0	0.5	0.4	0.3	0.0	0.7	1.0	1.1
GHG Reductions from Transition to Renewable and Low-Carbon Gas	0.0	3.5	8.1	9.0	0.0	3.3	7.3	8.0	0.0	0.6	0.6	0.6
GHG Reductions from Additional Actions												
Total GHG Reductions	0.0	1.3	4.5	5.1	0.0	4.1	8.4	9.2	0.0	0.9	1.4	1.6
FEI Remaining Emissions	10.7	9.6	6.9	6.4	10.7	6.8	2.9	2.2	10.7	9.9	9.9	9.8
Further Emissions Reductions Needed to Meet GHGRS Cap	5.0	3.9	2.6	2.1	5.0	1.1	-1.4	-2.1	5.0	4.2	5.6	5.5

72.2.1 For each of FEI's scenarios, please also provide a breakdown of GHG emissions (MTCO2e) by customer class for the years 2019, 2030, 2040 and 2042. Please also separately outline the emissions associated with low carbon transportation and LNG customers.

Response:

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

First, FEI illustrates GHG end use emissions (Mt CO_2e) by customer type for the years 2019, 2030, 2040 and 2042 for each of FEI's scenarios in Table 1 below.

Second, FEI illustrates the life cycle emission reductions in Table 2, and the emissions in Table 3, that are associated with low-carbon transportation (LCT) and LNG customers for the years 2019, 2030, 2040 and 2042 for each of FEI's scenarios. By providing emission reductions, FEI recognizes that the gaseous fuels supplied by FEI in this sector are assumed to displace fuels with higher carbon emissions. Therefore, illustrating emission reductions is key.

1. End Use Emissions (Mt CO_2e) by Customer Type

The breakdown of end use emissions (Mt CO_2e) by customer type is illustrated in Table 1 below for the years 2019, 2030, 2040 and 2042 for each of FEI's scenarios. FEI interprets the term 'customer class' in this request to refer broadly to customer type (residential, commercial and industrial) and not to 'customer rate class'. End use emission factors are used to be consistent with the data illustrated in BCUC IR1 72.2.

Table 1: GHG Emissions (End Use Emissions) (Mt CO_2e) for Residential, Commercial and Industrial Customers for the Reference Case and Alternate Scenarios in the 2022 LTGRP by Customer Type

Customer Type	Reference Case (Mt CO2e)				Diversified Energy (Planning) (Mt CO2e)				Deep Electrification (Mt CO2e)			
	2019	2030	2040	2042	2019	2030	2040	2042	2019	2030	2040	2042
Residential	3.8	3.1	2.8	2.8	3.8	1.9	1.4	1.3	3.8	2.5	1.4	1.2
Commercial	3.1	3.2	3.4	3.5	3.1	1.9	1.5	1.4	3.1	1.8	1.1	1.0
Industrial	3.7	3.3	3.3	3.3	3.7	1.9	1.4	1.2	3.7	3.1	2.6	2.5
FEI Total GHG's	10.7	9.7	9.6	9.6	10.7	5.7	4.3	3.9	10.7	7.4	5.1	4.8

Customer Type	Upper Bound (Mt CO2e)				Price Based Regulation (Mt CO2e)				Economic Stagnation (Mt CO2e)			
	2019	2030	2040	2042	2019	2030	2040	2042	2019	2030	2040	2042
Residential	3.8	3.1	2.2	2.0	3.8	2.5	1.2	1.0	3.8	3.7	3.6	3.6
Commercial	3.1	3.4	3.0	2.9	3.1	2.4	1.2	1.0	3.1	3.2	3.6	3.7
Industrial	3.7	3.1	1.7	1.5	3.7	2.0	0.5	0.2	3.7	3.1	2.7	2.6
FEI Total GHG's	10.7	9.6	6.9	6.4	10.7	6.8	2.9	2.2	10.7	9.9	9.9	9.9

2. Life Cycle Emission Reductions (Mt CO2e) and Emissions (Mt CO2e) for LCT Customers and Global LNG

FEI provides both the emission reductions and emissions that result from FEI serving low-carbon transportation fuel and global LNG customers, in order to provide the complete picture of emissions related to these sectors (as discussed in Section 9.2.2 in the Application). Table 2, below, provides a breakdown of GHG emission reductions (life cycle) (Mt CO2e) associated with the demand for serving low-carbon transportation and LNG export customers for the years 2019, 2030, 2040 and 2042 for each of FEI's scenarios. Table 3 illustrates the life cycle emissions that occur as a result of serving low-carbon transportation and global LNG customers. Life cycle emission factors are used to be consistent with data illustrated in Figures 9-3, 9-4, and 9-5 in the Application.

Table 2: GHG Emission Reductions (Life Cycle) (Mt CO_2e) for LCT and Global LNG Initiatives for the Reference Case and Alternate Scenarios in the 2022 LTGRP

Year	LCT and LNG Export Emission Reductions (Life Cycle) by Scenario					
	Reference Case	Diversified Energy (Planning)	Deep Electrification	Upper Bound	Price-Based Regulation	Economic Stagnation
	(MtCO2e)	(MtCO2e)	(MtCO2e)	(MtCO2e)	(MtCO2e)	(MtCO2e)
2019	0.00	0.00	0.00	0.00	0.00	0.00
2030	-0.07	-1.61	-0.34	-2.26	-1.99	-0.06
2040	-0.03	-1.98	-0.31	-3.54	-3.34	-0.03
2042	-0.03	-2.07	-0.32	-3.78	-3.64	-0.03

Note: a negative sign indicates a reduction from current state.

Modelled changes to the planning environment conditions present in the Upper Bound and Price-Based Regulation Scenarios encourage higher investment in low-carbon transportation infrastructure, logistics and gas delivered by FEI than is expected to occur in the DEP Scenario, and therefore more emission reduction opportunities are noted in these scenarios. On the other hand, the conditions present in the Deep Electrification and Economic Stagnation Scenarios do not encourage diversified energy solutions, hindering such investments and resulting in minimal carbon reductions for these high energy, difficult-to-decarbonize users.

Table 3: GHG Emissions (Life Cycle) (Mt CO_2e) for LCT and LNG Export Initiatives for the Reference Case and Alternate Scenarios in the 2022 LTGRP

Year	LCT and LNG Export Emissions (Life Cycle) by Scenario					
	Reference Case	Diversified Energy (Planning)	Deep Electrification	Upper Bound	Price-Based Regulation	Economic Stagnation
	(MtCO2e)	(MtCO2e)	(MtCO2e)	(MtCO2e)	(MtCO2e)	(MtCO2e)
2019	0.17	0.17	0.17	0.17	0.17	0.17
2030	0.26	3.60	0.62	4.83	3.98	0.18
2040	0.26	3.43	0.61	4.57	2.81	0.17
2042	0.26	3.39	0.61	4.53	2.56	0.17

72.3 Please explain the reason why GHG emissions in the Deep Electrification scenario are higher than those in the Diversified Energy (Planning) scenario.

Response:

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

The DEP Scenario contains a higher amount of low-carbon and renewable gas supply, which is assumed to displace conventional natural gas, thereby resulting in more GHG emission reductions than the Deep Electrification scenario. The Deep Electrification scenario contains a lower amount of low-carbon and renewable gases, and more conventional natural gas, than the DEP Scenario. This assumption was made because meeting the GHGRS was not a condition applied to all scenarios. If a Deep Electrification scenario results in fewer gas customers to support the cost to operate the gas system, it would likely be unrealistic for these customers to additionally bear the costs of higher-priced renewable and low-carbon gas to gain further GHG reductions beyond those resulting from electrification, especially considering these same customers would likely also have to bear the anticipated increased costs of electricity associated with Deep Electrification.

72.3.1 Please clarify whether FEI's assumptions include that under the Deep Electrification scenario, FEI would meet the proposed GHGRS cap.

Response:

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

No, the Deep Electrification scenario is not expected to meet the proposed GHGRS cap by 2030, nor the provincially-legislated GHG emissions target of 60 percent reduction of 2007 emissions by 2040. Please refer to the response to BCUC IR1 72.3 for further discussion.

72.4 Please provide a table similar to Table 9-1 of the Application which summarizes FEI's investments in decarbonization initiatives to support market transformation over the planning horizon for FEI's other scenarios (Reference Case, Upper Bound, Economic Stagnation, Deep Electrification and Price-Based Regulation scenarios).

Response:

The table below illustrates the investments in decarbonization in FEI's other scenarios. Each investment is ranked as either low, medium or high based on each scenario in relation to the DEP Scenario. Investments are based on the scenario descriptions and input settings described in

Table 4-1 on page 4-21 of the Application. A brief description of the scenario provides the background as to why the investment level was chosen as follows:

- DEP Scenario builds upon a diversified approach to energy delivery and emission reductions to British Columbians. Growth is shown for both gas and electric utilities and existing infrastructure is used to deliver low-carbon energy solutions to customers.
- The Upper Bound Scenario would see medium investments through each of the areas under the assumption that the BC economy experiences higher-than-average growth, which would keep regional gas supply abundant, among other things.
- The Reference Case Scenario is not described in Table 4-1 in the Application but was developed as the baseline for scenario analysis in which the Reference setting is used for all critical uncertainties. This scenario demonstrates low and medium investments across the decarbonization areas.
- The Economic Stagnation Scenario shows low investment in all four decarbonization areas as FEI assumes the BC economy is tightened, leaving fewer dollars available to the government and utility customers in BC to aggressively pursue decarbonization initiatives.
- The Deep Electrification Scenario assumes a mixture of low investments in most of the decarbonization areas with an increase in investments such as Carbon Capture Utilization and Storage (CCUS) for areas that are difficult to decarbonize through electrification. This scenario assumes the BC government does not increase the carbon tax, but uses all other policy levers to electrify the economy to achieve domestic carbon abatement.
- The Price-Based Regulation Scenario shows a mixture of high and medium investment across the decarbonization areas since this scenario assumes the BC government concludes that price signals and more ambitious upstream emissions reductions provide the best solution for decarbonization and carbon abatement. These price signals boost development of renewable gases, CCUS and LCT.

Table 1: FEI's Anticipated Investment in Decarbonization to Support Market Transformation to 2042 Relative to the DEP Scenario

FEI's Anticipated Investment in Decarbonization to Support Market Transformation to 2042						
Decarbonization Initiative	2022 LTGRP Scenario					
	DEP	Upper Bound	Reference Case	Economic Stagnation	Deep Electrification	Price-Based Regulation
Decarbonization of fuel types through transitioning to renewable and low-carbon gases – Pillar 1						
Renewable and low-carbon gases transition	High	Medium	Low	Low	Low	High
Hydrogen production and distribution	High	Medium	Low	Low	Low	High
Industrial decarbonization	Medium	Medium	Low	Low	High	Medium

FEI's Anticipated Investment in Decarbonization to Support Market Transformation to 2042						
Decarbonization Initiative	2022 LTGRP Scenario					
	DEP	Upper Bound	Reference Case	Economic Stagnation	Deep Electrification	Price-Based Regulation
Carbon Capture, Utilization and Storage (CCUS)	High	Medium	Low	Low	High	High
Electrification	Medium	Medium	Low	Low	High	Low
Low-Carbon Transportation and LNG – Pillars 3 and 4						
Low-Carbon Transportation	High	Medium	Low	Low	Low	Medium
DSM and Other Initiatives Reduce Energy Consumption in Residential, Commercial and Industrial Sectors – Pillar 2						
Demand-side Management and high efficiency equipment	High	Medium	Medium	Low	High	High
Decarbonization in Commercial and Industrial Processes	High	Medium	Medium	Low	High	High
Enabling Activities to Support Market Transformation[112]						
Clean energy workforce capacity	High	Medium	Low	Low	Low	Medium
Utility, government, rightsholder and stakeholder collaboration on climate action	High	Medium	Low	Low	Low	High
Policy and regulatory environment supportive of decarbonization	High	Medium	Medium	Low	Low	High

72.5 Please explain, for each of FEI's scenarios, the assumptions regarding investments by third parties necessary to achieve the decarbonization market transformations.

72.5.1 If the modelling included no explicit assumptions, please discuss the nature and magnitude of investments in decarbonization markets by third parties, that would potentially be necessary in each of FEI's scenarios.

Response:

FEI has not conducted a detailed assessment of the third-party investments as part of the Application. However, FEI has calculated the total system-wide costs[113] for decarbonization,

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112 Enabling Activities to Support Market Transformation include FEI's investments in workforce capacity and training as well as climate action programs and research to support decarbonization efforts.

113 Costs calculations included initiatives such as energy efficiency (residential & commercial envelope improvements, heat pumps, other end user costs, industrial process improvements and fuel switching, etc.) vehicle electrification

which were presented in the Pathways Report released in 2020,[114] which the Diversified Energy Pathway is based upon.

In the Pathways Report, Guidehouse provides total systems cost estimates for decarbonizing BC's energy system. These costs would include costs borne by all parties in BC, including third parties. The total cost estimates to 2050, which should be noted as outside the scope of the LTGRP which only projects to 2042, for BC include the following:

- Total System Costs associated with the Diversified Pathway as:
    - $64 billion by 2030; and
    - $356 billion by 2050.
- Total System Costs associated with the Electrification Pathway as:
    - $86 billion by 2030; and
    - $454 billion by 2050.

The Pathways Report breaks down total investment costs by i) initiatives (costs borne by end-users for low-carbon end-use technologies, ii) gas system costs, and iii) electric system costs. Gas system costs are those costs related to the sustainment, infrastructure and low-carbon gaseous fuels required to align with the pathways. We can assume that the infrastructure and sustainment costs will be borne by FEI and that a portion of the low-carbon fuels will be invested in directly by FEI, with the remainder invested in by third party developers.

Beyond gas system costs, FEI cannot project or speculate on how much investment will be borne by FEI or other third parties; however, given the scale of the challenge of reducing emissions and the expected costs as discussed above, it is likely that a significant amount of investment will be needed by third parties in any decarbonization scenario.

(light duty, medium & high duty vehicles), fuel switching (agriculture fuel switching, smelting, CCS, etc.), transportation (marine, buses, & jet fuels) and renewable gases.

[114] Application, Appendix A-2.

73.0 Reference: GHG EMISSION REDUCTIONS IN THE DIVERSIFIED ENERGY (PLANNING) SCENARIO

Exhibit B-1, Section 9.2.1.5, p. 9-4; FEI BERC Rate proceeding, Exhibit B-24, City of Vancouver IR 1.3

Offsets

In response to City of Vancouver IR 1.3 in the FEI BERC Rate proceeding, FEI stated:

> FEI has historically used carbon offsets in a limited way to balance supply and demand of RNG as the program developed. When FEI uses carbon offsets, it ensures they are from reputable BC sources first. If not available, FEI has used carbon offsets from Canadian sources. These offsets are used to ensure that an equivalent amount of carbon reduction to RNG use occurs. Despite using carbon offsets in the past, RNG supply is increasing significantly, and FEI does not expect to use offsets in a significant way in the future.

73.1 Please discuss FEI's perspective on the use of offsets to address GHG emission reductions in the LTGRP.

Response:

As discussed in the preamble above, FEI has regulatory approval to use offsets as a limited way to manage supply-demand imbalance in the RNG program. To date, FEI has not contemplated broader use of offsets to address GHG emission reductions. However, FEI believes that offsets will likely be one of many important tools that governments and corporate entities will use to achieve net-zero emissions targets. While the BC government has indicated that gas distribution utilities will be subject to a GHG emissions cap, the government has yet to specify whether offsets will play a role in meeting any such GHG reduction obligations and any potential offset protocols that may apply.

73.2 Please explain FEI's historic use of GHG offsets in the last five years, the amounts purchased per year (TJ equivalent, and tCO2e), average cost, purpose, sources of offsets (suppliers, location issued: BC, out of province, out of country), total renewable or low carbon gas on that year (volume in TJ), total sales on that year in volume (renewable or not).

Response:

As discussed in Section 9.2.1.5 of the Application and the response to BCUC IR1 73.1, FEI has used carbon offsets in a limited way to balance supply and demand associated with the RNG program. FEI's RNG program has maintained a positive biomethane balance except for the years 2017-2021, when FEI purchased high quality offsets through Ostrom (formerly Offsetters), a BC-based vendor, to balance biomethane supply. Please refer to the table below for the total gas sales and RNG in each year, offsets purchased per year (approximate TJ equivalent and tCO2e), average offset cost and source. No offsets are anticipated to be purchased in 2022.

	Total gas sales (PJ)	Total RNG (TJ)	Offsets (approx. TJ or CO_2e)	Avg. offset cost	Offset source
2017	221 PJ	233 TJ	48 TJ or 2,400 tCO2e	$16/tCO2e	Great Bear Forest Carbon Project (BC), Quadra Island Forestland Conservation Project (BC)
2018	212 PJ	276 TJ	112 TJ or 5,600 tCO2e	$16/tCO2e	Great Bear Forest Carbon Project (BC), Quadra Island Forestland Conservation Project (BC)
2019	227 PJ	315 TJ	91 TJ or 4,600 tCO2e	$14/tCO2e	Great Bear Forest Carbon Project (BC), LFG Project (US)
2020	219 PJ	306 TJ	58 TJ or 2,900 tCO2e	$20/tCO2e	Great Bear Forest Carbon Project (BC)
2021	230 PJ	250 TJ	76 TJ or 3,800 tCO2e	$20/tCO2e	Great Bear Forest Carbon Project (BC)

73.3 Please elaborate on FEI's understanding of whether offsets would be permitted as pathway towards meeting the anticipated GHGRS emissions cap.

Response:

Please refer to the response to BCUC IR1 73.1.

73.4 Please discuss the price forecast of carbon offsets in the planning horizon and the drivers of change in price and availability of offsets.

Response:

As discussed in Section 9.2.1.5 of the Application, FEI has only used carbon offsets in a limited application to balance supply and demand associated with the RNG program. No scenarios developed under the LTGRP consider offsets as a GHG emission reduction strategy. As a result, price and supply forecasting of offsets was not completed.

73.5 Please explain whether the modelling of any of FEI's scenarios contemplated the use of offsets.

73.5.1 If yes, please provide the annual amount of offsets in volume (tCO2e) and the average cost in each scenario.

Response:

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

None of the scenarios in the 2022 LTGRP modelled the use of market-purchased carbon emission offsets to achieve GHG emission reductions. While offsets are not modeled at this time, nor part of FEI's core strategy, it is possible they may be considered in the future.

74.0 Reference: GHG EMISSION REDUCTIONS IN THE DIVERSIFIED ENERGY (PLANNING) SCENARIO

Exhibit B-1, Section 9.2.1.4, pp. 9-2, 9-3; Section 9.2.1.5, p. 9-4; FEI BERC Rate proceeding, Exhibit B-17, BCUC IR 1.1

Additional Reductions

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

> After completing the demand and supply modelling for the 2022 LTGRP, FEI identified further opportunities for additional emission reductions which FEI expects to incorporate into its Clean Growth Pathway. These additional emission reduction opportunities, which have not yet been modelled, consist of:
>
> Additional demand-side measures not modelled in the 2021 CPR….
>
> Additional reductions from FEI's transition to renewable and low-carbon gas supplies – particularly from higher than modelled CCUS implementation…
>
> FEI expects these opportunities to result in a further 0.9 Mt CO2e reductions or more by 2030. FEI is still considering how these additional opportunities feed into the emissions reductions later in the planning horizon and so has not included them in its assessment of 2040 emission reductions at this time.

In response to BCUC IR 1.1 in the FEI BERC Rate proceeding, FEI stated:

> Carbon capture and sequestration (CCS): For CCS, Guidehouse estimated potential GHG reductions for end-use gas consumption such as in the cement sector. It was assumed that this could accomplish 0.6 Mt of GHG reductions.

74.1 Please clarify if FEI considers additional emission reductions are necessary under the Diversified Energy (Planning) Scenario, and FEI's other scenarios, in order to meet the expected requirements of the GHGRS emissions cap.

Response:

Yes. In Table 1 of the response to BCUC IR1 72.2, FEI illustrates the results of emission reduction initiatives and total remaining emissions modeled for the DEP Scenario and all alternate scenarios. Table 1 below summarizes the emission reductions needed to meet the GHGRS cap in 2030 and the legislated target in 2040. The DEP Scenario was designed specifically to undertake all available and reasonable GHG emission activities to meet the 2030 proposed GHGRS cap and the 2040 legislated targets. This scenario includes taking "additional actions" resulting in 0.9 Mt CO2e emission reductions as described in Section 9.2 of the Application. The other alternate scenarios did not set the GHGRS cap as a limitation and so further emission reductions would be required to meet the cap in those scenarios. Forcing all scenarios to meet the cap as a default setting would reduce the value of conducting the scenario exercise in identifying the ability of various scenarios to reach the cap.

Table 1: Overview of the Further Emission Reduction Requirements to meet the GHGRS target for the Reference Case and Alternate Scenarios

Scenario	2030 (Mt CO2e)	2040 (Mt CO2e)
Reference Case	4.0	5.3
DEP	0.0	0.0
Deep Electrification	1.7	0.7
Upper Bound	3.9	2.6
Price-Based Regulation	1.1	-1.4
Economic Stagnation	4.2	5.6

FEI distinguishes two approaches for describing emission reductions required to meet the proposed GHGRS emissions cap by 2030 and legislated targets for 2040 for alternate scenarios.

1. **Additional Emission Reduction Actions** – These actions only apply to the DEP Scenario as described in Section 9.2 of the Application. Additional actions will be taken by 2030 to further reduce emissions by 0.9 Mt CO2e to meet the proposed GHGRS cap of 5.7 Mt CO2e. There are no additional actions required to meet the BC legislated GHG emissions target of 4.3 Mt CO2e (60 percent reduction of FEI's 2007 emissions) by 2040.

2. **Further Emission Reduction Requirements** – This approach pertains to all other scenarios as they will not meet the 2030 proposed GHGRS emissions cap of 5.7 Mt CO2e. A few may meet the 2040 BC legislated GHG emissions target. These alternate scenarios were developed to represent different future outcomes for the purposes of resource planning. Undertaking further emission reduction initiatives is simply applying Clean Growth Pathway initiatives, and in essence moving towards the DEP Scenario.

Only two scenarios (in addition to DEP) are close to meeting the proposed GHGRS cap as follows:

- The Price-Based Regulation Scenario involves settings that are beneficial to FEI's implementation of the Clean Growth Pathway. These settings assume the BC government determines that price signals and more ambitious upstream emissions reductions provide the best solution for decarbonization and carbon abatement. Additional actions could be taken in this scenario as price signals boost development of renewable gases, CCUS and LCT.

- The Deep Electrification Scenario does not meet the GHGRS because FEI considers that it would not be economically feasible to incorporate higher amounts of higher-priced low-carbon and renewable gases where there are fewer customers to bear the costs to operate the gas system. These same customers would likely have to bear the anticipated increased costs of electrification. Under these conditions, energy affordability would be even more challenged.

For the reasons discussed above the DEP Scenario is the only scenario that will be discussed further in terms of additional actions or alternatives to meet the GHGRS.

74.1.1 If yes, please indicate FEI's alternative options to meet the requirements of the proposed GHGRS emissions, should these "additional emission reductions" be unavailable in a timely fashion and/or in the magnitudes estimated. Please also discuss the pros and cons of each of the alternative options.

Response:

It is important to note that the BC Government has not yet established alternative options for FEI to meet the proposed GHGRS emission cap; therefore, FEI is unable to discuss any alternative options. Nevertheless, FEI will continue to undertake all available and reasonable GHG emission activities to meet the 2030 proposed GHGRS cap and the 2040 legislated targets, while exploring other potential opportunities. Achieving these targets will require collaboration by all stakeholders in BC, including all levels of government and electric utilities for the DEP Scenario. These additional actions and opportunities are discussed for the DEP Scenario in BCUC IR1 74.2. As discussed in BCUC IR1 74.1, further emission reductions in the context of the other alternate scenarios will not be discussed further.

74.2 Please provide for each of FEI's scenarios the assumptions used for calculating additional emission reductions, including a breakdown of the emission reductions that stem from additional DSM measures not modelled in the 2021 CPR and additional reductions from FEI's transition to renewable and low-carbon gasses.

Response:

FEI breaks down this response into a number of steps.

1. The first step is to provide an overview of emission reduction initiatives being undertaken by FEI in the DEP Scenario in Table 1. As noted in the response to BCUC IR1 74.1, it is not useful to discuss further emission reduction initiatives for any other scenarios as they are not designed nor intended to meet the GHGRS.
2. The second step is to provide a discussion of the opportunities that are being explored to achieve the emission reductions from the additional actions for the DEP Scenario.
3. For the third step, FEI has not developed a detailed breakdown of additional emissions reductions for the individual emission reduction activities. Nevertheless, Table 2 below describes a range of emission reduction potentials for a number of opportunities. These are high-level estimates only at this time for the purposes of this response. FEI will continue to define the additional emission reduction initiatives as more information is gathered in the coming years and will be available for the next LTGRP submission.

Step 1 - Overview of FEI's Emission Reduction Activities in the DEP Scenario

Table 1 provides an overview of FEI's emission reduction initiatives including additional actions required to meet the GHGRS. The additional actions represent 0.9/4.2 Mt CO2e, or an additional 21 percent[115] GHG emission reductions over those modeled in the DEP Scenario. This is equivalent to a demand reduction of 18 PJ.

Table 1: Overview of FEI's Emission Reduction Activities Including Additional Actions in the DEP

FEI Emission Reduction Initiatives	Diversified Energy (Planning) (Mt CO2e)			
	2019	2030	2040	2042
Demand Reduction (pre-DSM)	0.0	0.4	0.9	1.0
DSM Demand Reduction	0.0	0.9	1.3	1.3
Renewable and Low-Carbon Gas Supply	0.0	3.0	4.8	5.2
FEI Additional Actions		0.9		
Total GHG Emission Reductions		5.2	7.1	7.6
FEI Total GHG Emissions	**10.7**	**5.7**	**4.3**	**3.9**

Step 2 - Overview of Additional Emission Reduction Activities Being Evaluated

Additional emission reductions beyond those modelled for the DEP Scenario will be undertaken through a combination of two approaches. The first approach will involve expanding and accelerating initiatives that are currently under way. The second approach will involve exploring new opportunities that are in the early development stages and are not yet identified in the resource plan.

1. Expanding and accelerating emission reduction initiatives that are currently under way:

    - **Renewable and low-carbon gas:** Accelerate the investment in renewable and low-carbon gas supply beyond 60 PJ of supply;
    - **DSM:** Accelerate DSM initiatives and expand Advanced DSM activities beyond 18.2 PJ of cumulative energy savings. Opportunities to expand Advanced DSM measures are discussed in BCUC IR1 46.1. These initiatives include dual fuel heating systems, gas heat pumps and Deep Energy Retrofits; and
    - **Behaviour and Conservation:** Natural efficiency initiatives and behaviour change programs may reduce use per customer. If the application is approved, FEI's Advanced Metering Infrastructure project may provide benefits to support these programs in educating customers about their energy use. Energy conservation messaging to all customer sectors could enable further demand reductions.

[115] The 21 percent GHG reduction required over the modeled reductions represents 0.9/4.2 Mt CO2e resulting from Pre-DSM Demand Reduction, DSM Demand Reduction and Renewable and Low-Carbon Gas Supply by 2030 in the DEP Scenario.

2. Exploring new and evolving emission reduction opportunities that are at the early development stage and cannot be quantified but will be described in further detail in the next LTGRP:

- **Negative emissions**: Negative emissions technologies like bioenergy with carbon capture (BECCS) and sequestration;
- **Carbon Negative Supply**: Much of FEI's recent RNG supply acquisition has a negative carbon intensity, and FEI will continue to monitor opportunities to lower the carbon intensity of its portfolio moving forward (particularly with RNG). Directionally, this could translate to lower actual volumes being needed to meet emissions targets with carbon negative supply;
- **Direct carbon removals and offsets:** Depending on the stringency of the policy and cost declines, FEI may consider technologies like direct air capture with carbon capture and storage or carbon capture on end use natural gas combustion as a means to abate GHG emissions to meet the requirements of the cap;
- **Certified gas:** For its purchases of conventional natural gas, FEI could acquire gas that is certified to have lower carbon emissions associated with its production such as GHG abatement using negative emissions technologies or practices;
- **Non-pipe solutions:** Explore and identify opportunities for demand and capacity reduction through Non-Pipe Solutions such as Enhanced Targeted Energy Efficiency (ETEE) and Natural Gas Demand Response (NGDR);
- **Networked geothermal heating:** Gas utilities in the northeastern United States are piloting networked geothermal heating solutions which could provide heating using existing gas system pipelines or new pipelines to deliver heat (and potentially other energy services) at a community scale;
- **Offsets:** FEI's use of offsets has been given regulatory approval in a limited way to manage supply-demand imbalance in the RNG program. To date, FEI has not contemplated broader use of offsets to address GHG emission reductions. However, FEI believes that offsets will likely be one of many important tools that governments and corporate entities will use to achieve net-zero emissions targets. While the BC government has indicated that gas distribution utilities will be subject to a GHG emissions cap, the government has yet to specify whether offsets will play a role in meeting any such GHG reduction obligations and any potential offset protocols that may apply;
- **Nature-based solutions:** Solutions such as reforestation and international transferred mitigation outcomes (ITMOs) as identified in Article 6 the Paris Agreement could also reduce GHG emissions and potentially be considered by the BC Government as alternative options; and
- **Emission Reductions in Hard to Decarbonize Sectors:** FEI will continue to examine additional emission reduction opportunities in hard to decarbonize sectors such as industrial applications and transportation. Currently, the 2030

combined emissions reduction forecast for FEI's LCT and global LNG initiatives would result in 1.6 Mt CO2e (life cycle emission factor). Within the CleanBC Roadmap to 2030, the Province has said it intends to develop marine credits under the BC – Low Carbon Fuel Standard framework. The use of new carbon emission trading policies, such as internationally traded mitigations outcomes (ITMOs) allowable under article 6 of the Paris Treaty, could allow FEI to acquire further emission reductions. FEI will continue to explore other emission reduction opportunities in these sectors.

There are a number of additional demand reduction influences that may or may not be within FEI's control. These include the impact of natural efficiency, customer behaviour change, and other factors that could reduce use per customer. Electrification impacts are accounted for within the DEP Scenario, but the outcome of these impacts by 2030 still remains to be seen. Proposed policy that prohibits choice for new customers to connect to the gas system could result in fewer customers over time.

FEI will continue to explore and identify additional emission reduction initiatives as more information is gathered in the coming years.

Step 3 - High Level Breakdown of Emission Reduction Potential for Additional Actions to Meet the GHGRS

The GHG Reduction Standard is expected to be one of the cornerstone policies impacting FEI and it is still under development by the Province. Consequently, FEI has not yet developed a detailed breakdown of additional emissions reductions for the individual activities. Nevertheless, Table 2 below describes the emission reduction potential of a number of actions FEI is exploring to meet the GHGRS. These are high level, indicative estimates only at this time for the purposes of this response. FEI will continue to define the additional emission reduction initiatives for the next LTGRP submission.

Table 2: High Level Overview of Potential Additional Emission Reduction Actions to Meet GHGRS by 2030 Identified to Date

Description	Lower	Upper	Lower	Upper	Likelihood and Risks Discussed in Following Key IR Responses
	(Mt CO2e)		(PJ)		
Expand and accelerate initiatives currently under way					
Acquire Additional Renewable and Low-Carbon Gas Supply – 5% and 10%	0.15	0.3	3.0	6.0	**Renewable and Low-Carbon Gas:** • BCUC IR1: 52.4, 52.5, 52.6, 71.7, 71.8, 77 series **Hydrogen Specifically:** • BCUC IR1: 61 series, 62 series • BCSEA IR1: 18.2 • CEC IR1: 21 and 22 series • RCIA IR1: 4.1, 24 through 29 series • MS2S IR1: 6 series, 8 series

Description	Lower (Mt CO2e)	Upper (Mt CO2e)	Lower (PJ)	Upper (PJ)	Likelihood and Risks Discussed in Following Key IR Responses
DSM • Accelerate Advanced DSM Measures[116] • A combination of Non-pipe Solutions, Behaviour Change, Natural Efficiency, Targeted EE, AMI and Demand Response (DR) Opportunities (for peak demand reduction)[117]	0.05	0.1	0.9	1.8	**General:** • BCUC IR1: 45.series, 46.series, 70 series **Gas heat pumps:** • BCUC IR1: 42 series • CEC IR1: 23.1, 23.2, 34.2 **Deep Retrofits:** • BCSEA IR1: 15.1 • CEC IR1: 34.1, 35.1 **Dual fuel hybrid heating:** • BCUC IR1: 9.2 series, 9.3 series • CEC IR1: 23.3 **Non-Pipe Solutions, Behaviour, and DR:** • BCUC IR1: 47–51 series • RCIA IR1: 11 series
Expansion of current initiatives - Total	**0.20**	**0.4**	**3.9**	**7.8**	
New and evolving technologies and other emission reduction opportunities					
• CCUS[118] • Low-Carbon conventional gas purchase119 • Negative Emissions Technologies (Direct Air Capture) • Offsets • Demand reduction through electrification / decreased customer accounts					**CCUS:** • BCUC IR1: 9.1 series, 64 series • MS2S IR1: 9 series **Low-Carbon Conventional gas:** • BCUC IR1: 76 series **Offsets:** • BCUC IR1: 73 series • MoveUp IR1: 2.4.1 **Demand Reduction through Electrification:** • BCUC IR1: 25 series, 69 series • BC Hydro IR1: 4 series
New and evolving opportunities - Total	**0.70**	**1.0**	**NA**	**NA**	
Total Opportunities Identified to Date	**0.90**	**1.4**	**NA**	**NA**	**General considerations:** • BCUC IR1: 78 series • BCOAPA IR1: 8.1 • MoveUp IR1: 2.7

[116] FEI acknowledges that estimates of DSM potential by 2030 is uncertain due to anticipated DSM regulatory amendments and other market factors.

[117] FEI continues to evaluate these initiatives to validate their potential energy savings and acknowledges that some of these individual initiatives may need to be conducted concurrently, not independently, in order to achieve potential energy savings.

[118] Not yet confirmed if these emission reduction initiatives can be claimed under the GHGRS.

[119] Not yet confirmed if these emission reduction initiatives can be claimed under the GHGRS.

74.2.1 Please elaborate on the likelihood and risks of each source of "additional emission reduction" identified in the filing of being implemented and able to achieve additional reductions by 2030 and later in the planning horizon.

Response:

In providing a lower and upper range of emission reduction potential in Table 2 of the response to BCUC IR1 74.2, FEI illustrates that there is a range of possible outcomes associated with each of the additional actions FEI is currently considering for meeting the GHGRS cap. In the last column of Table 2, FEI provides a list of IR responses that include discussions about the risks and risk mitigation measures FEI is undertaking on emission reduction initiatives. FEI acknowledges there are risks associated with these initiatives just as there are risks associated with new programs or the development and adoption of any kind of technology or business process. An important aspect of reducing these risks is the continued support and investment in the technology by FEI and external parties. Investment is required for proof of concept and feasibility studies that will prove out the technology, market acceptance and economics of individual approaches. Early stage investment is critical in fostering market transformation that will accelerate the adoption of new technologies and initiatives. Further, support from the provincial and federal governments is also needed to lower the risks and increase the likelihood of providing emission reductions.

74.3 Please indicate if there have been additional measures relevant to the category "Additional Reductions" identified after the filing of the LTGRP. If there are, please describe them and their potential importance.

Response:

Please refer to the response to BCUC IR1 74.2 for an overview of additional measures continually being explored by FEI and other stakeholders that are relevant to the "Additional Reductions" category. Several of the items were not discussed in detail in the Application and have been included in the response since investigation into their potential is continuing.

74.4 Please discuss FEI's outlook for carbon capture, utilization and storage (CCUS), including but not limited to the different technologies and applications that would potentially support FEI's GHG emission reductions, commercialization timelines, forecasted costs, and any other relevant considerations.

Response:

Please refer to the responses to BCUC IR1 64 series for discussion on FEI's CCUS support for on-system low-carbon gas supply and BCUC IR1 9 series for discussion on small-scale residential and commercial carbon capture projects.

75.0 RATE IMPACT OF THE DIVERSIFIED ENERGY (PLANNING) SCENARIO

Exhibit B-1, Section 9.4, pp. 9-11 – 9-13, 9-15; Section 10, p. 10-4, Exhibit B-4, Section 2.3, p. 18

Rate Impact Scenarios

On pages 9-11 to 9-12 of the Application, FEI lists the assumptions used in the modeling of rate impacts of the different scenarios:

> The analysis on effective rate impacts compares the changes in rates to the current 2022 approved rates with the following assumptions:
>
> - The 20-year annual demand for each scenario includes DSM and low-carbon transportation;
> - The long-term DSM expenditures for each scenario are 1 under the High DSM setting discussed in Section 5.4.1;
> - Commodity costs are based on a mix of supply of conventional natural gas and renewable gas, and midstream (i.e., storage and transport charges) costs assumed an escalation of by inflation;
> - Carbon tax under the Diversified Energy (Planning) and Deep Electrification scenarios assumes annual escalation until it reaches $170 per tonne in 2030 as discussed in Section 2.2.1.4.2. For the Reference scenario, carbon tax is assumed to remain at $50 per tonne while for the Upper Bound scenario, carbon tax is assumed to be eliminated. For all scenarios, the bill impact analysis includes the avoided carbon tax resulting from the mix of renewable and low-carbon gas in the commodity costs. For example, assuming FEI's gas supply includes 5 percent mix of renewable and low-carbon gas in 2023, then the carbon tax is applied to the 95 percent of conventional natural gas only with no carbon tax on the remaining 5 percent;
> - 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;
> - 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.

- The effective rate impacts are based on the average use per customer (UPC) between 2022 and 2042 under the Diversified Energy (Planning) Scenario:
  - Residential (RS 1): 60 GJ per year
  - Small Commercial (RS 2): 293 GJ per year
  - Large Commercial (RS 3): 3,253 GJ per year
  - Industrial General Firm Service (RS 5): 18,542 GJ per year

On page 9-15 of the Application, FEI includes the following table and figure:

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%

On pages 9-13 to 9-14 of the Application, FEI includes the Figures:

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

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

Figure 9-9: Cumulative Effective Rate Impact (2022 – 2042) – Large Commercial RS 3, Avg. UPC 3,253 GJ; and Figure 9-10: Cumulative Effective Rate Impact (2022 – 2042) – General Firm Service RS 5, Avg. UPC 18,542 GJ.

On page 10-4 of the Application, FEI states:

> The RGSD project is a critical infrastructure investment necessary for implementing FEI's Clean Growth Pathway, resiliency improvements, and gas supply risk management. The RGSD project is the preferred and recommended solution to meet the need for new regional pipeline infrastructure driven by three market conditions which are outside of FEI's control…

On page 18 of the FEI and BC Hydro Energy Scenarios, FEI Stage 2 Submission, FEI states:

> To provide context for FEI's long-term volume forecasts, Figures 6 through 9 provide a 20-year directional view of the potential impact on customer rates under BC Hydro's Reference Case and Accelerated Electrification and FEI's Diversified Energy (Planning), Deep Electrification, and Economic Stagnation scenarios for Residential (RS 1), Small Commercial (RS 2), Large Commercial (RS 3), and Industrial General Firm Service (RS 5) customers, respectively.

75.1 Please, explain the reasons Table 9-2 did not include information for the Price-Based Regulation and Economic Stagnation scenarios.

Response:

FEI did not include the Price Based Regulation and Economic Stagnation scenarios in Table 9-2 in the Application, as FEI intended to be thoughtful about the volume of information presented in the Application. FEI provided results for the four select scenarios that were considered to provide the most representative overview of the implications for rates that different futures will have.

75.2 Please provide an update to Table 9-2 that includes rate impact information for the Price-Based regulation and Economic Stagnation scenarios.

Response:

Please refer to Table 1 below for an update to Table 9-2 that includes rate impact information for the Price-Based Regulation and Economic Stagnation scenarios.

Table 1: Summary and Comparison of Average Projected Delivery Rate Changes for Alternate Scenarios

	Effective Rate Change (2022 - 2042, %)												
	Average UPC (2022 - 2042)	Reference		Upper Bound		Diversified Energy (Planning)		Deep Electrification		Economic Stagnation		Price Based Regulation	
		Cumulative	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative	Annual
Residential (RS 1)	60	73%	2.8%	77%	2.9%	118%	4.0%	235%	6.2%	20%	0.9%	130%	4.3%
Small Commercial (RS 2)	293	41%	1.7%	64%	2.5%	102%	3.6%	207%	5.8%	1%	0.0%	121%	4.0%
Large Commercial (RS 3)	3,253	40%	1.7%	69%	2.6%	107%	3.7%	206%	5.7%	-3%	-0.2%	130%	4.2%
General Firm Service (RS 5)	18,542	44%	1.9%	80%	3.0%	114%	3.9%	150%	4.7%	10%	0.5%	146%	4.6%

75.2.1 Please clarify whether the assumptions used for the analysis of effective rate impacts would apply to the Price-base regulation and Economic Stagnation scenarios. If not, please explain the reasons and describe the assumptions pertinent to those scenarios.

Response:

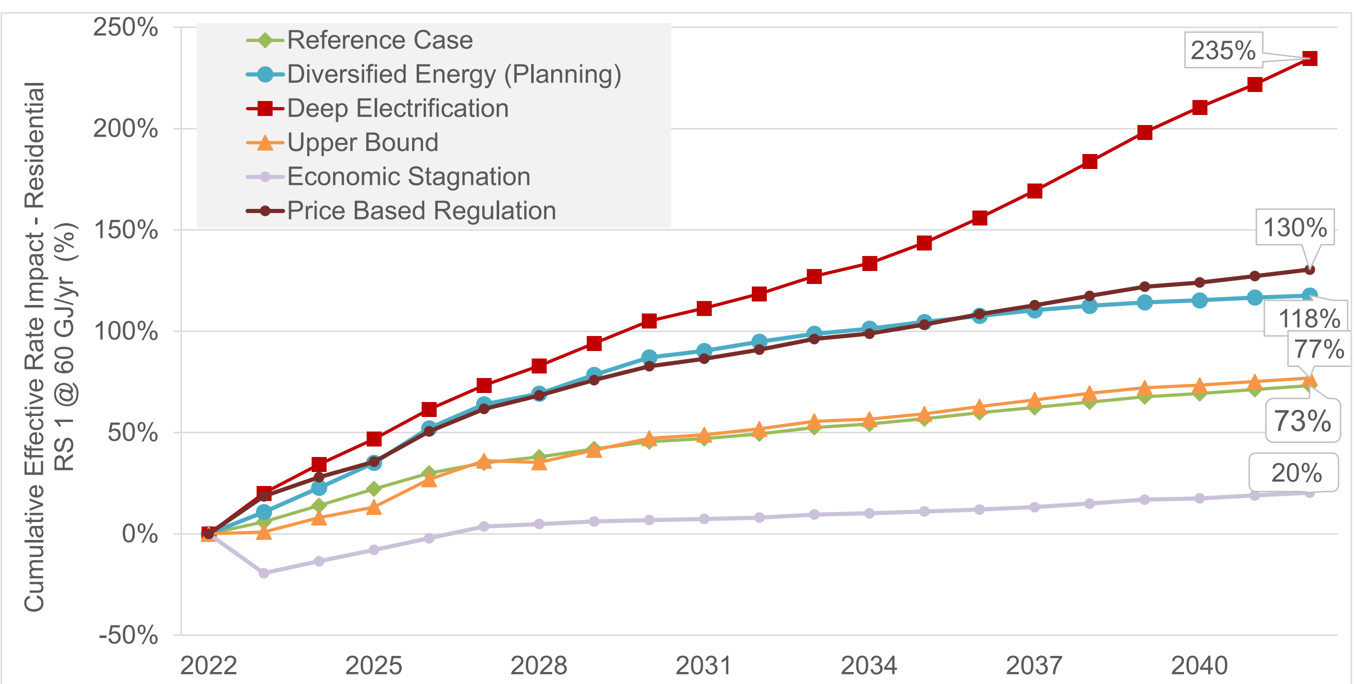
Confirmed. The assumptions used for the analysis of effective rate impacts would apply to the Price- Based Regulation and Economic Stagnation scenarios with the exception of the Carbon Tax. For the FEI Economic Stagnation Scenario, carbon tax is assumed to be eliminated. For the Price-Based Regulation scenario, carbon tax is assumed to escalate annually until it reaches $227 per tonne in 2042.

75.3 Please provide updated versions of Figures 9-7, 9-8, 9-9 and 9-10 that also include information for the Price-Based Regulation and Economic Stagnation scenarios.

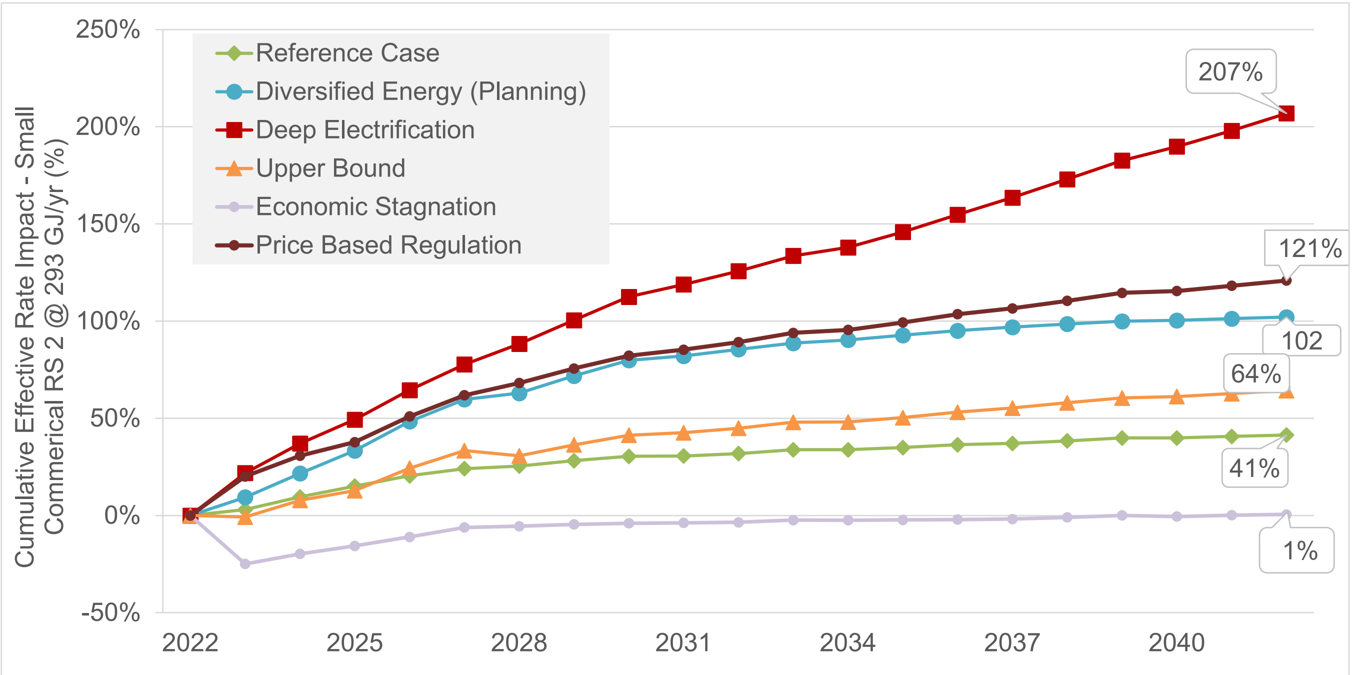
Response:

Please refer to Figures 1 to 4 below for the updated versions of Figures 9-7, 9-8, 9-9 and 9-10 in the Application that also include information for the Price-Based Regulation and Economic Stagnation scenarios.

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



1 2 **Figure 2: Cumulative Effective Rate Impact (2022 – 2042) – Small Commercial RS 2, Avg. UPC 293 GJ**

3


4 5 **Figure 3: Cumulative Effective Rate Impact (2022 – 2042) – Large Commercial RS 3, Avg. UPC 3,253 GJ**

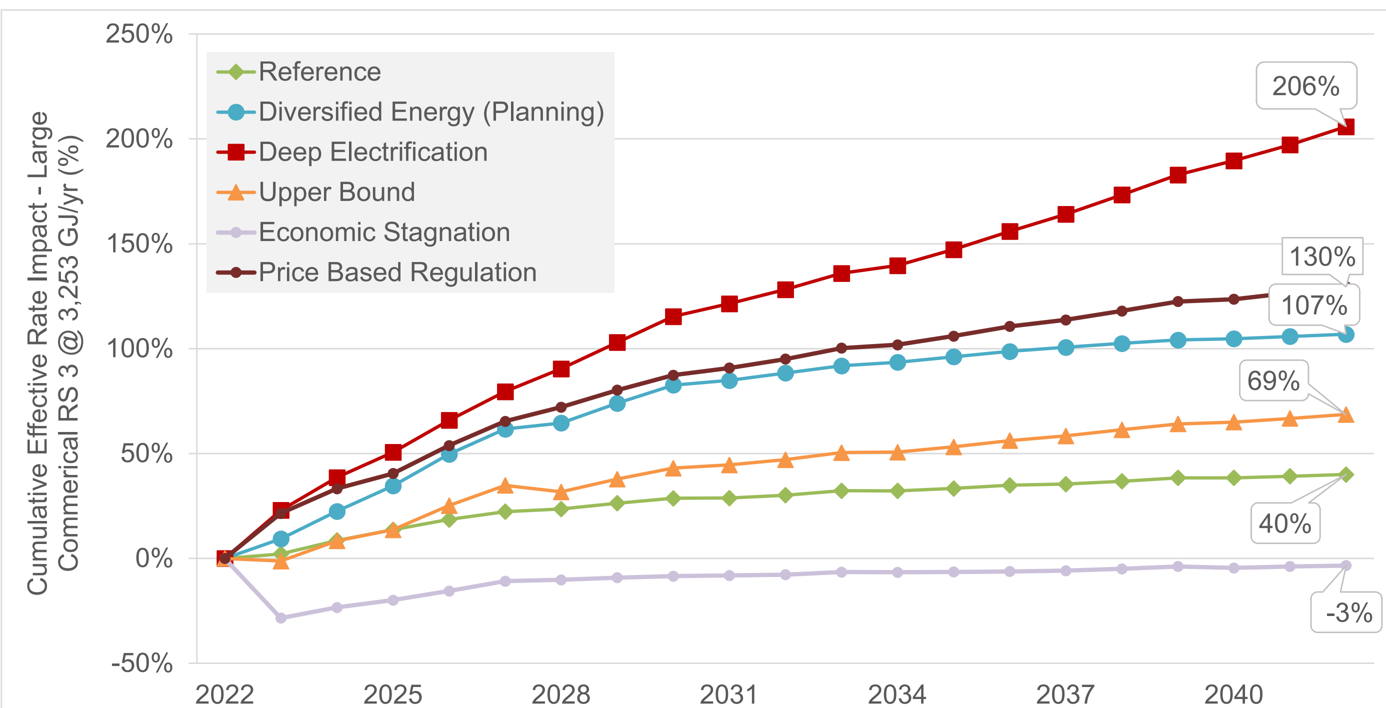
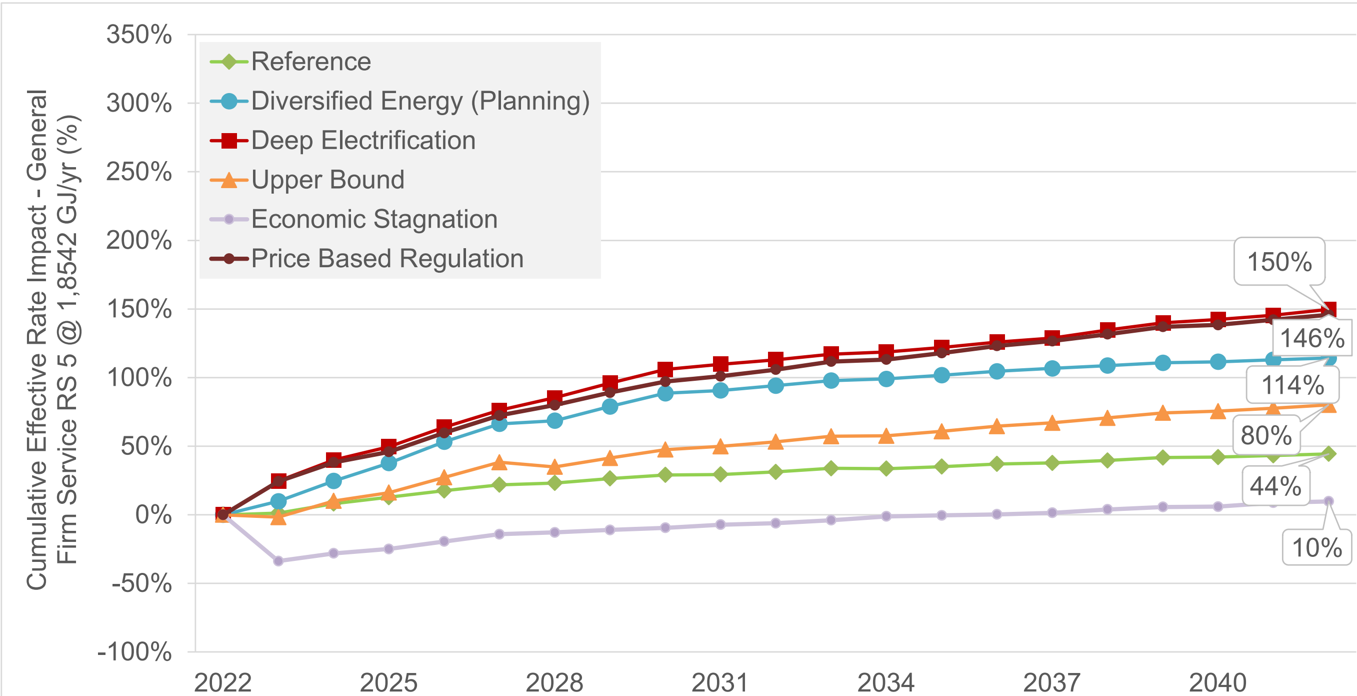
6


Figure 4: Cumulative Effective Rate Impact (2022 – 2042) – General Firm Service RS 5, Avg. UPC 18,542 GJ



75.4 Please provide a table comparing the assumptions used for the modeling of rate impacts for the following scenarios: FEI's scenarios outlined in Table 9-2, FEI's Price-Based Regulation and Economic Stagnation scenarios, as well as the BC Hydro's Reference Case and Accelerated Electrification.

<u>Response:</u>

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

The table below provides a comparison of assumptions used for modeling rate impacts for FEI's LTGRP alternate scenarios and BC Hydro's Reference Case and Accelerated Electrification scenarios. The assumptions were based on the scenario description and input settings for each one of the scenarios as outlined in Table 4-1 of the Application. Please refer to Attachments 75.4 and 75.4.1 for the 20-year annual demand and the cost of energy summary.

Table 1: Summary of Assumptions Used for Modeling Rate Impacts for FEI LTGRP Reference Case and Alternate Scenarios and BC Hydro's Reference Case and Accelerated Electrification Scenario

Assumptions	FEI Reference Case and Alternate Scenarios						BC Hydro	
	Reference Case	DEP	Deep Electrification	Upper Bound	Price-Based Regulation	Economic Stagnation	Reference Case	Accelerated Electrification
Appliance Standards	Reference	Reference	Accelerated	Reference	Reference	Reference	FEI Reference	FEI Accelerated
Carbon Price	Reference	Reference	Reference	Low	High	Low	Navius Data	Navius Data
Customer Growth	Reference	Reference	Low	High	Reference	Low	BCH Data	BCH Data
Fuel Switching	Reference	Moderate Electrification	Accelerated Electrification	Reference	Reference	Reference	BCH Data	BCH Data
Natural Gas Price	Reference	Reference	Low	Low	High	Low	FEI Reference	FEI Reference
New Construction Code	Reference	Reference	Accelerated	Delayed	Reference	Delayed	FEI Accelerated	FEI Accelerated
Retrofit Code	Reference	Reference	Accelerated	Reference	Reference	Reference	FEI Reference	FEI Accelerated
LCT Demand	Planning	Planning	Low	High	High	Low	FEI Reference	FEI Reference
Global LNG Demand	Planning	Planning	Planning	High	Reference	Reference	FEI Reference	FEI Reference
New Large Industrial	Planning	Planning	Reference	High	Reference	Reference	FEI Planning	FEI Planning
DSM Setting	Medium	High	Taper Off	No DSM	Medium UCT	Medium	Medium	Medium
20-year annual demand	Attachment 75.4	"	"	"	"	"	"	"
Cost of Energy	Attachment 75.4.1	"	"	"	"	"	"	"

75.5 Please elaborate on the variables and assumptions that have the most significant impact on the rate impact analysis.

Response:

Using the DEP Scenario as an example, please refer to Table 1 below for a breakdown of the cumulative rate increase (i.e., 118 percent) for the residential customers. The biggest driver of the rate impact is the commodity related charges, which included the mix of conventional natural gas costs and renewable gas costs. This is followed by inflation and demand forecasts. Under the DEP Scenario, demand is forecast to reduce by approximately 12 percent over the 20-year planning period, with residential demand forecast to decrease by approximately 25 percent by 2042.

Table 1: Breakdown of the Cumulative Rate Increase by 2042 (RS 1) shown in Figure 9-7

Component	Cumulative Rate Impact by 2042 (%)	Proportion (%)
Demand Forecast	18%	15%
Low Carbon Transportation (LCT)	-12%	-10%
CPCNs (Approved/Filed)	12%	10%
Regular Capital (VITS, CTS and ITS)	14%	12%
Demand Side Management (DSM)	3%	3%
Inflation[1]	25%	21%
Delivery	60%	50%
Commodity Related Charges	48%	41%
Carbon Tax	10%	9%
Total	118%	100%

Note to table:

1) Inflation is based on 3 percent per year from 2022 to 2026 (5 years) and 2 percent per year from 2027 to 2042 (16 years). Total impact due to inflation shown in the table is the cumulative and compounded impact from 2022 to 2042.

75.6 Please indicate the estimated cost and incremental rate impact of the RGSD project.

75.6.1 Please indicate if there are any other major capital projects, including but not limited to projects related to low-carbon transportation and LNG, that FEI considers are likely to be required in the planning horizon and are not otherwise outlined in the rate impact analysis. If so, please provide a list of projects, estimated cost, in-service date, and overall rate impact.

Please discuss if there is a change in the need for such projects depending on the scenario.

Response:

FEI notes that while responding to this information request, FEI realized the list of major capital projects shown on page 9-12 of the Application did not include the Okanagan Capacity Upgrade (OCU) CPCN project. FEI confirms the incremental cost of service due to the OCU project was included in every scenario of the rate impact analysis presented in Section 9.4 of the Application. It was only inadvertently excluded to the list on page 9-12. FEI also notes that, as explained on page 9-12 of the Application, other than the capital expenditures already identified for FEI's major transmission system (i.e., VITS, CTS, and ITS) and the recently approved/filed CPCNs, FEI also used the total 2022 approved delivery margin (which includes the 2022 approved capital expenditure level) as the baseline plus annual escalation to forecast other major capital that FEI expects to occur annually over the 20-year planning period. Although FEI does not know the specific project or the level of capital required for future projects related to but not limited to LCT, LNG, renewable gas and hydrogen, FEI did include a certain level of capital as a proxy over the 20-year planning period to reflect the potential of these investments.

As such, the only major capital project that has been identified but not included in the rate impact analysis is the Regional Gas Supply Diversity (RGSD) Project. FEI's preliminary evaluation suggests that the RGSD Project is the most beneficial option for addressing regional market conditions and reducing risk for FEI customers and merits further assessment and development work.[120] FEI is currently conducting development work to assess the technical and financial feasibility of the project including a detailed analyses of RGSD versus other regional supply options.

Based on AACE[121] methodology for Class 5 cost estimates, FEI anticipates the RGSD project will cost approximately $4 Billion. Currently, FEI believes that the RGSD project could have an estimated in-service date of late 2029. The RGSD project offers a number of strategic benefits, such as:

- the opportunity for FEI to release Westcoast T-South capacity to existing or new parties;
- increased access to cost-effective blue hydrogen;
- reduced market price exposure at Station 2;
- increased access to cost-effective storage contracting options in Alberta;
- improved liquidity by purchasing supply from the AECO/NIT hub (increasing the number of counter parties to transact with); and
- reduced potential for excess gas supply at Huntingdon during the summer months.

[120] Application for Approval of the Regional Gas Supply Diversity Project Development Account, Exhibit B-1, Section 8 (2022) online at: https://docs.bcuc.com/Documents/Proceedings/2022/DOC_66904_B-1-FEI-RegionalGasSupplyDiversity-DevelopmentAccount.pdf.

[121] Association for the Advancement of Cost Engineering.

As a result, FEI believes that cost mitigation activities will significantly offset the project's annual cost of service. At this point in time, FEI has not completed its analysis of the potential cost savings associated with RGSD. Due to RGSD being in the early development stages and this information not being available, FEI is not able to provide estimated rate impacts for the RGSD project at this time.

76.0 Reference: GHG EMISSION REDUCTIONS IN THE DIVERSIFIED ENERGY (PLANNING) SCENARIO

Article: What is Certified Gas[122], Article: The Rise of Differentiated Gas and What Certification Methods Exist[123]

Certified Natural Gas

The article *The Rise of Differentiated Gas and What Certification Methods Exist* states:

> Growing awareness of methane's potential as a greenhouse gas (GHG) has spurred the creation of several programs helping companies differentiate natural gas through certification. The goal of these programs is to help oil and gas operators and distributors establish practices and procedures that indicate their natural gas is produced and delivered through low-emissions processes or is being sourced responsibly…
>
> The fundamental goal of natural gas certification is to reduce methane emissions while providing companies with measurable proof that they are making impactful changes in their operations.

The article *What is Certified Gas* indicates that gas that is "certified" has been deemed to be responsibly produced according to criteria determined by an independent third party.

76.1 Please discuss FEI's perspective on certified natural gas, for example as a source of lower GHG emission supplies or as a tool to demonstrate lower GHG emissions in FEI's operations.

Response:

FEI sees certified gas as a potentially cost-effective means of lowering the carbon footprint of conventional gas supply and assuring various environmental, social and governance practices associated with natural gas production. However, each certified gas standard currently sets its own criteria; not all standards include a methane emissions measurement component. To be used as a source of lower carbon gas, the carbon intensity of certified gas must be verified to be less than the carbon intensity of conventional gas. While FEI has considered using certified gas as a means of lowering GHG emissions for its customers and own operations, the BC government has not yet determined the details of the Greenhouse Gas Reduction Standard, including the range of potential compliance pathways such as certified gas.

76.2 Please explain whether FEI has considered the use of certified natural gas as an option to reduce FEI's GHG emissions.

[122] https://www.naturalgasintel.com/what-is-certified-gas/
[123] https://www.bridgerphotonics.com/blog/what-is-certified-natural-gas.

Response:

Please refer to the response to BCUC IR1 76.1.

77.0 Reference: ENERGY SUPPLY PORTFOLIO

Exhibit B-1, Section 6.2.2.2, pp. 6-10 to 6-11, Section 6.2.3, pp. 6-12 to 6-13, Section 9.2.1.3, p. 9-2, Appendix D-2 (B.C. Renewable and Low-Carbon Gas Supply Potential Study Report), pp. 3, 7

Renewable and Low-Carbon Gas Supply Potential

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

> FEI's transition to renewable and low-carbon gas supplies has the largest impact on GHG emission reductions for residential, commercial and industrial customers. Acquiring and allocating 60.2 PJ of renewable and low-carbon gas supply by 2030 to these customer groups results in emission reductions of 3.0 Mt CO2e. In 2040, the allocation of 99 PJ of renewable and low-carbon gas to these customer groups results in 4.9 Mt CO2e of GHG emission reductions.

On pages 6-10 and 6-11 of the Application, FEI states:

> At this time, the key resources that FEI anticipates acquiring over the next 20 years and beyond to increasingly displace conventional natural gas supplies are RNG, hydrogen, syngas and lignin…
>
> The locations within BC where new supplies will be produced are still being developed. The identified supply volumes are very large and the potential production locations are numerous as identified by the study "Renewable and Low-Carbon Gas Potential in BC and North America", commissioned in partnership with the BC Bioenergy Network and the Province of British Columbia and included in Appendix D-2. The study has assessed the costs of these resources based on information available today, and estimates that a potential of up to 444 PJ per year could be supplied within BC by 2050. This equates to approximately twice FEI's current annual energy throughput.

On pages 6-12 and 6-13 of the Application, FEI states:

> FEI's modelling of supply resources over the next 20 years has identified the following gas supply resource mix observations for annual demand for the Diversified Energy (Planning) Scenario over the planning horizon and beyond:
>
> **To 2030:**
>
> - RNG and hydrogen from off-system supply sources will be relied on more heavily in the early stages of FEI's carbon reduction transition. Conventional natural gas and RNG will continue to make up the majority of physical deliveries to customers during this period and will be delivered to FEI by displacement as with conventional natural gas purchases184. Physical flows of hydrogen on FEI's gas infrastructure are expected to rise but be limited to smaller amounts and portions of FEI's system until around 2030 as the

technologies and infrastructure needed to manage larger volumes are refined and implemented.

- One or more syngas and lignin projects will displace some industrial load, though natural gas may continue to provide firm back-up service for periods when syngas or lignin production is unavailable.
- CCUS is expected to still be in development stages, perhaps available in small amounts through pilot projects, in 2030.

From 2030 to 2042:

- This is the latter part of the planning horizon for the 2022 LTGRP and as such is subject to greater uncertainty. The proportion of FEI customers using conventional methane for space and water heating as opposed to other renewable and low-carbon gas supplies will have decreased, but will still make up a majority of customers. While the development of on-system resources will have grown in the intervening years, FEI anticipates there will still be reliance on off-system supplies.

Beyond 2042:

- The steps taken earlier in the planning horizon will set FEI on a pathway to deep decarbonization by 2050 and well on its way to achieving carbon neutrality on an annual basis. RNG and hydrogen will both be an important part of FEI's resource mix.

On page 3 of the B.C. Renewable and Low-Carbon Gas Supply Potential Study Report (Appendix D-2) states:

> The resource potential represents the theoretical availability of various biomass feedstock types, electricity, and fossil natural gas to produce renewable and low-carbon gases. The technical potential constrains the resource potential as it estimates the capacity for each pathway after accounting for geographic limitations, transport constraints, conversion efficiency and various system assumptions. This also includes technological readiness and realistically achievable implementation rates. The resulting potentials in the Maximum and Minimum scenarios for each pathway are further lowered as they consider timelines, harvesting practices and different outcomes with respect to resource availability and the speed of deployment. They represent the upper and lower bounds of renewable and low-carbon gas supply potential that can likely be achieved in B.C. by 2030 and by 2050, as shown in Figure 4. Some economic constraints, such as competing uses, price, or market developments, have not been considered in the estimation of these bounds.

On page 7 of the same report (Appendix D-2) states:

The cost of building a renewable and low-carbon gas production sector to replace fossil gas use in B.C. could range between $5 billion and $20 billion for the 2050 Minimum and Maximum scenario, respectively.

77.1 Please explain if FEI considered economic constraints when calculating renewable and low-carbon gas supply for its scenarios. If yes, please elaborate on the considerations for each type of gas.

Response:

Yes. For example, the BC Renewable and Low-Carbon Gas Supply Potential Study[124] (Study) developed 'Minimum' and 'Maximum' supply scenarios for 2030 and 2050, which considered economic factors such as restrictive carbon intensity policy, higher feedstock prices, resource competition and capital costs as inputs into the 2030 and 2050 supply scenarios.[125] These factors and associated risk mitigation strategies (e.g. long-term offtake agreements) were considered in the planning of low-carbon and renewable gas supply for the LTGRP.

77.2 Please compare FEI's forecast of renewable and low-carbon gas supply (PJ) and cost ($/GJ) in the different scenarios and the information provided in the Renewable and Low-Carbon Gas Potential in BC and North America.

Response:

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

FEI's forecast of renewable and low-carbon gas supply (PJ) in the different scenarios in relation to the BC Renewable and Low-Carbon Gas Supply Potential Study[126] and additional research[127], is described in Table 1 for the year 2030 and Table 2 below for the year 2040 (note that the study provides its resource potential view as at 2050, beyond the planning period for the LTGRP). These years were chosen for this response to align with provincial emission reduction target years within

---

[124] Exhibit B1-1, 2022 LTGRP Application, Appendix D-2.
[125] The assumptions are discussed in detail at pp. 91-93 of the Study.
[126] Exhibit B1-1, 2022 LTGRP Application, Appendix D-2.
[127] BC Supply Potential - Figures 3-7 and 3-8 in the Application (based on the Study)
Canada supply potential additional research:
- Salim Abboud et al., *Potential Production of Methane from Canadian Wastes,* 2010.
- Canadian Biogas Association, *Canadian Biogas Study: Benefits to the Economy, Environment and Energy - Technical Document*, 2013.
- TorchLight Bioresources Inc., *Renewable Natural Gas (Biomethane) Feedstock Potential in Canada*, 2020.

US supply potential additional research:
- American Gas Foundation, The Potential for Renewable Gas: Biogas Derived from Biomass Feedstocks and Upgraded to Pipeline Quality, September 2011.
- National Research Energy Laboratory, Energy Analysis: Biogas Potential in the United States, October 2013.
- American Gas Foundation, Renewable Sources of Natural Gas: Supply and Emissions Reduction Assessment, December 2019.

the planning horizon of the Application. The supply forecast and cost per unit of renewable and low-carbon gas for individual years in different scenarios is discussed further in BCUC IR1 71.8.1.

Table 1: 2030 Renewable and Low-Carbon Gas Supply Outlook Examples for FEI Reference Case and Alternate Scenarios and Supply Potential

Renewable and Low-Carbon Fuel Type	Reference Case	DEP	Deep Electri-fication	Upper Bound	Price-Based Regulation	Economic Stagnation
FEI Renewable and Low-Carbon Gas Supply Outlook Examples in 2030 (PJ/Yr)						
Renewable Natural Gas	11	32	6	36	34	11
Hydrogen	1	20	0	23	21	1
Syngas and Lignin	0	7	0	10	10	0
CCS	0	1	2	2	2	0
Total RG and LC	**11**	**60**	**8**	**71**	**66**	**11**
Renewable and Low-Carbon Gas Supply Potential Study in 2030 (PJ/Yr)						
	BC Supply Potential		**Canadian Supply Potential**		**US Supply Potential**	
	Min	**Max**	**Min**	**Max**	**Min**	**Max**
RNG (Traditional)	6	6	61	82	350	460
Green and Waste Hydrogen	2	11				
Wood-Based Gases (RNG, Hydrogen, Syngas, and Lignin)	2	2				
Blue and Turquoise Hydrogen	16	30				
Total RG and LC	**25**	**49**				

Table 2: 2040 Renewable and Low-Carbon Gas Supply Outlook Examples for FEI Reference Case and Alternate Scenarios and 2050 Supply Potential

Renewable and Low-Carbon Fuel Type	Reference Case	DEP	Deep Electri-fication	Upper Bound	Price-Based Regulation	Economic Stagnation
FEI Renewable and Low-Carbon Gas Supply Outlook Examples in 2040 (PJ/Yr)						
Renewable Natural Gas	11	38	5	74	66	11
Hydrogen	2	48	0	68	61	2
Syngas and Lignin	0	8	0	15	15	0
CCS	0	5	3	9	6	0
Total RG and LC	**12**	**99**	**8**	**165**	**148**	**13**
Renewable and Low-Carbon Gas Supply Potential Study in 2050 (PJ/Yr)						
	BC Supply Potential		**Canadian Supply Potential**		**US Supply Potential**	
	Min	**Max**	**Min**	**Max**	**Min**	**Max**
RNG (Traditional)	9	10	N/A	N/A	630	857
Green and Waste Hydrogen	14	41				
Wood-Based Gases (RNG, Hydrogen, Syngas, and Lignin)	19	145				
Blue and Turquoise Hydrogen	62	248				
Total RG and LC	**104**	**443**				

The analysis suggests that there is adequate supply of renewable and low-carbon gas to serve FEI's demand well beyond FEI's targets for all alternate future scenarios. However, FEI will need to rely on out-of-province sources up to approximately 2030. Beyond 2030, FEI anticipates that the BC marketplace will evolve, and FEI will increasingly invest in local projects where reasonable and cost-effective to do so. Therefore, regardless of increasing demand from neighboring jurisdictions, FEI expects there to be sufficient renewable and low carbon gas available to meet FEI's needs.

77.3 Please describe the conditions that would promote a faster development of the renewable and low-carbon gas production in B.C.

<u>Response:</u>

Faster development of renewable and low-carbon gas production in BC could be achieved through updates to the policy and regulatory framework that governs FEI's acquisition and development of renewable and low-carbon gases. Such updates could include:

- An expanded supply cap to support flexibility in achieving the proposed GHGRS and to allow for the acquisition of renewable gas beyond 2030 given that development of larger projects spans multiple years;
- A higher price cap to allow for the development and implementation of projects requiring a higher price, such as small BC-based projects and hydrogen. Alternatively, the price limit could be defined as an average price, allowing for a mix of low and high-cost gas production;
- Allowing utilities to provide capital incentives for renewable and low-carbon gas project development;
- Expanding the definition of hydrogen based on lifecycle GHG emissions intensity;
- Developing alternative electricity rate designs and retail access to BC's electricity grid;
- Accelerated regulatory development activities and capital incentives to make the gas system hydrogen-ready;
- Policy direction, incentives and financial support for industrial low-carbon gas displacement;
- Developing a mechanism and incentives to recognize new clean fuel pathways including low-carbon hydrogen acquired from within or outside BC, carbon capture utilization and storage, negative emissions technologies, and abated or certified natural gas; and
- Updates to BC's Carbon Tax Legislation to recognize lower carbon intensity of renewable and low-carbon gases in addition to RNG.

77.4 Please indicate if the statement in the report included in Appendix D-2 regarding the cost to build a renewable and low-carbon gas production sector includes any consideration of necessary infrastructure upgrades to integrate such gases in the transmission and distribution systems. If not, please indicate what would be the range of potential investments required to support the integration of renewable and low-carbon gases in B.C.

Response:

The BC Renewable and Low Carbon Gas Supply Potential Study[128] (Study) focuses on the displacement of natural gas in the BC pipeline system with renewable and low-carbon gases. The projected $5 billion to $20 billion of investment required to achieve the production of the “Minimum” and “Maximum” scenarios identified in the Study include high-level assumptions around infrastructure upgrades to integrate such gases in the transmission and distribution systems. However, these assumptions are not a detailed assessment of infrastructure upgrades or modifications needed. The focus of the investment requirement was on producing the volumes of renewable and low-carbon carbon gases.

As discussed in the response to BCUC IR1 61.3, identifying the infrastructure needs of a renewable gas system is one of the next steps in FEI’s development framework for renewable and low-carbon gases. Based on pre-feasibility work completed over the last number of years, FEI plans to undertake a comprehensive technical review and hydrogen readiness assessment of all gas system assets and customer end-use equipment and systems. The project, referred to as the BC Gas System Hydrogen Blending Study and Technical Assessment project, will provide more information regarding hydrogen considerations, including potential modifications to the system and an assessment of costs.

77.4.1 Please explain the extent to which the rate impact analysis in section 9.4 of the Application includes costs associated with integrating renewable and low-carbon gases in FEI’s transmission and distribution system.

77.4.1.1 If not included in the rate impact analysis, to the extent FEI is able to, please provide an estimated rate impact associated with the costs to integrate renewable and low-carbon gases in FEI’s transmission and distribution system. Please discuss how such costs would vary depending on the scenario.

[128] Exhibit B1-1, 2022 LTGRP Application, Appendix D-2.

Response:

The rate impact analysis in Section 9.4 of the Application includes some of the costs associated with integrating renewable and low-carbon gases in FEI's transmission and distribution system. The following considerations are included in the rate impact analysis:

- As highlighted on page 9-12 of the Application, FEI has included the supply costs of both conventional natural gas and the supply costs of renewable and low-carbon gases in the rate impact analysis in Section 9.4 of the Application in all scenarios. The difference of the cost of gas between the different scenarios depends on the forecast percentage of fuel mix over the 20-year planning period.
- There will be no additional costs associated with the integration of renewable gas such as RNG in FEI's transmission and distribution system, since RNG is interchangeable[129] with conventional natural gas. RNG has wider availability and is forecast to make up a greater proportion of the resource mix in the near term.
- With respect to off-system supply where FEI achieves carbon reduction and credit for FEI's customers with environmental attributes associated with renewable and low-carbon gas, since the transportation and consumption is conducted completely outside of FEI systems, there will not be additional costs to FEI's gas system except for the supply cost of the off-system renewable gas, which is included in the cost of gas calculation as indicated in the first bullet point above.
- With respect to integrating hydrogen into FEI's system, development in this area is still at a preliminary stage. As discussed in the response to BCUC IR1 61.9, there are still significant development steps to be undertaken before there would be sufficient knowledge and information to determine the level of capital investment required to blend hydrogen into FEI's gas system, including any dedicated hydrogen pipeline or hydrogen separation facilities within FEI's gas system. Furthermore, as discussed in the response to BCUC IR1 63.2, FEI is still working with UBCO on commercializing hydrogen separation and therefore currently does not have any information regarding the level of capital required for separation facilities. Given the reasons above, FEI did not develop any capital estimates that are specific for hydrogen infrastructure for inclusion in the effective rate impact analysis shown in Section 9.4 of the Application.
- Although FEI did not develop capital expenditure estimates that are specific for hydrogen, FEI factored in, to a certain extent, the potential of future capital expenditures and commodity costs of blending hydrogen into FEI's gas system into the effective rate impact analysis shown in Section 9.4 of the Application. As explained on page 9-12 of the Application and also in response to BCUC IR1 75.6, other than the capital expenditures already identified for FEI's major transmission system (i.e., VITS, CTS, and ITS) and the recently approved/filed CPCNs, FEI also used the total 2022 approved delivery margin

[129] The physical properties of renewable natural gas, such as specific gravity, viscosity and heating value, etc., falls within the range of the physical properties of FEI's conventional sources of natural gas. The capacity impacts and gas supply resource needs are comparable, and both sources of methane can utilize the same upstream and on-system infrastructure.

(which includes the 2022 approved capital expenditure level) as the baseline plus annual escalation to forecast other major capital that FEI expects to occur annually over the 20-year planning period. As such, although FEI does not know the specific level of capital required for hydrogen, FEI did include a certain level of capital as a proxy over the 20-year planning period to reflect the potential of these investments. While FEI is unable to determine if these capital expenditures, especially those that are included in the later years of the 20-year planning period (i.e., 2027 and beyond), would be for conventional natural gas infrastructure, or for dedicated hydrogen infrastructure, or both, FEI expects these capital expenditures will be needed and would be different depending on the various scenarios.

- As for the commodity-related costs, FEI also includes the supply costs of hydrogen in all scenarios, depending on the percentage of the fuel mix over the 20-year planning period. For example, the Deep Electrification scenario assumed there would be no hydrogen blend in the renewable gas portfolio while the DEP Scenario includes a much larger blend of hydrogen in the renewable gas portfolio.

As such, based on the information currently available, FEI has reasonably considered the costs and impact of integrating renewable and low-carbon gas to FEI's system (both capital and commodity related costs) over the 20-year planning period, including the potential of facilitating hydrogen blending into FEI's gas system.

77.5 Please discuss the drivers of changes in the price of renewable and low carbon gas supplies, for each type of gas being considered by FEI.

Response:

Possible drivers of change in the price of renewable and low-carbon gas supplies in British Columbia include the following:

- Feedstock price escalation:
  - Feedstock costs for renewable and low-carbon gas production from clean electricity and wood biomass may increase with inflation. In some cases, woody biomass feedstock costs may increase as the lowest cost feedstocks become contracted. These impacts would increase the price of green hydrogen produced from clean electricity, as well as syngas and lignin produced from wood biomass.
- Exempting fossil resources used as a feedstock to generate low-carbon hydrogen with carbon capture and storage:
  - The BC carbon tax does not apply to natural gas used as a feedstock, as opposed to as fuel. This means that for turquoise and blue hydrogen production where natural gas is a feedstock, no carbon tax currently applies on any volumes of CO_2 emitted at the production stage. This may or may not change in the future.

- Investments in advancing the readiness of commercialization technologies:
  - Pre-commercial pathways need to be supported with further research, development and demonstration projects. This means the deployment of near-commercial technologies such as RNG (biomethane) produced from wood biomass feedstock and low-carbon (turquoise) hydrogen production will see initially higher productions costs until the technology can advance to lever economies of scale and reduce production costs.
- Availability of resources and cost of capital to scale production capacity:
  - Some pathways, such as low-carbon (blue) hydrogen production using carbon capture and storage, require substantial investments for project development and production capacity to scale up and reduce production costs.
- Increasing competition for renewable gas supply:
  - Increasing competition for renewable gas supply may drive prices higher as more entrants to market compete for renewable and low-carbon gas resources.
- Importing lower-cost off-system renewable gas supply:
  - Other jurisdictions with surplus low-cost resources, such as biogas from large-scale landfill operations, would deliver renewable gas to BC at lower cost compared to on-system biomethane production from landfill gas. Importing off-system supply is a key strategy to reducing costs to consumers in the near-term until on-system supply ramps up in BC.

78.0 Reference: ENERGY SUPPLY PORTFOLIO

Exhibit B-1, Section 9.3, pp. 9-10 – 9-11, Section 10, pp. 10-1, 10-6

GHG Emissions Reduction Monitoring

On page 10-1 and 10-6 of the Application respectively, FEI identified the following activities as part of its action plan:

1. Accelerate the development and acquisition of renewable and low-carbon gas supplies to meet customer energy needs and contribute to provincial emission reduction targets; …

8. Continue monitoring, analysing and contributing to the energy planning environment while working with government on policy framework for deep decarbonization.

On pages 9-10 and 9-11 of the Application, FEI includes Table 9-1: FEI's Investments in Decarbonization Initiatives to Support Market Transformation Over the 20-Year Planning Horizon.

78.1 Please discuss whether FEI has identified interim targets for its decarbonization initiatives, prior to 2030.

Response:

FEI has not identified interim targets for decarbonization initiatives prior to 2030. Future policy direction from the Province such as the GHGRS could include interim compliance targets. If this occurs, FEI will abide by any provincial policy directive for GHG reductions.

78.2 Please describe the key parameters FEI will monitor to evaluate the progress and performance its decarbonization initiatives.

Response:

Activities and FEIs investments in decarbonization initiatives listed in the Application on pages 10-1, 10-6 and in Table 9-1 are in alignment and supported through the FortisBC Clean Growth Pathway's four key pillars. Progress and performance on key activities under the pillars are disclosed in FortisBC's annual Corporate and Sustainability Reports.[130] Below is a description of some of the activities monitored under the pillars:

- Pillar 1: Transitioning to renewable and low-carbon gases to decarbonize the gas supply: Number of suppliers and supply volume of renewable and low-carbon gases, number of contracts signed/ approved by BCUC, among others;

[130] Corporate and Sustainability Reports page: https://www.fortisbc.com/sustainabilityreport.

- Pillar 2: Investing in DSM programs in support of energy efficiency and conservation measures to reduce energy use among residential, commercial, and industrial customers: Investments in energy efficiency programs, natural gas efficiency programs, electricity programs, among others;
- Pillar 3: Support for low-carbon transportation infrastructure to reduce emissions in this sector: Number of medium and heavy-duty vehicles and short sea vessels using CNG or LNG, among others; and
- Pillar 4: Investing in LNG to lower GHG emissions in marine fueling and global markets: Number of containers of LNG delivered to marine customers, among others.

To see additional metrics that FEI measures and reports on, please refer to the 2021 Sustainability Report.[131] FEI will also incorporate any reporting requirements that might result from legislation implementing the CleanBC Roadmap to 2030.

78.3 Please explain what factors might lead FEI to modify its plans for investments in decarbonization initiatives prior to 2030.

Response:

Factors that would lead to a modification in FEI's plans for investments in decarbonization initiatives include, but are not limited to, changes in:

- Federal, provincial, municipal and Indigenous government policy direction and the corresponding regulatory outcomes;
- Market conditions and customer adoption of low-carbon energy;
- Technological innovation; and
- Economic and population growth.

Please refer to the response to BCUC IR1 72.4 to see the level of investment for each decarbonization initiative under the DEP Scenario.

78.4 Please elaborate on the key uncertainties associated with the proposed GHGRS emissions cap that might affect FEI's planned investments in decarbonization initiatives.

[131] 2021 Corporate and Sustainability Report: https://www.cdn.fortisbc.com/libraries/docs/wwwfortisbccomsustainabilityreportnewlibraries/default-document-library/22-030-7_sustain-corp_report2021_booklet_press.pdf.

Response:

Key uncertainties associated with the proposed GHGRS emissions cap that might affect FEI's planned investments in decarbonization initiatives under the DEP Scenario are the categories listed below and illustrated in Figure ES-8 in the Application:

- Timeline when GHGRS will be enacted;
- Interplay between GHGRS, GGRR, the carbon tax and other regulations and policies;
- The total GHG reduction obligation required for FEI;
- The nature of the obligation of FEI's customers that only access transportation services;
- Allowed abatement pathways;
- Roles of other parties that could contribute to abatement;
- Scope of the GHG emissions covered under the GHGRS;
- Reporting and compliance requirements; and
- The nature of financial support from the Province to ensure affordability for customers in the pursuit of abatement pathways. For example, incentives for renewable and low-carbon gases.

Attachment 11.1

FEI 20 Year Customer Forecast Method

Contents

Introduction

The FEI forecast for residential and commercial customers is prepared each year. The forecast is based on internal billing data and external third party forecasts, and extends out 20 years. The first two years of the forecast are used each year in the annual rate-setting filing. The forecast is also used by several internal users as well as filings that require a longer term forecast such as the Okanagan Capacity Upgrade project and the Long Term Gas Resource Plan.

The residential and commercial forecasts both start with actual billing system data and each incorporates a third party forecast in a slightly different way. In both cases the forecast methods result in both regional and branch (municipal) forecasts.

Timeframes

The 20-year customer forecast serves multiple purposes and with two time horizons:

- Short Term: The first two to five years of the forecast considers the short term. The first two years of the short-term forecast are used in the annual rate setting applications.
- Long Term: The full 20-year forecast is used by System Planning and the Long Term Gas Resource plan
- There are currently no medium-term regular users of the forecast, but all 20 years of the forecast are prepared according to the methods described in this document so should medium-term requirements emerge the forecast will be ready to serve them.

Customers and Customer Additions

The FEI customer forecast is developed using the last known actual customer totals by region and rate class from the prior year, along with a forecast of customer additions.

$$Customer\ Forecast_t = Year\ End\ Customer\ Total_{t-1} + Forecast\ Customer\ Additions$$

It is important to note that many different customer additions forecast methods likely exist but most will provide similar customer forecasts because the existing base of customers is large and customer additions are always orders of magnitude smaller.

Regional, LHA and Branch Forecasts

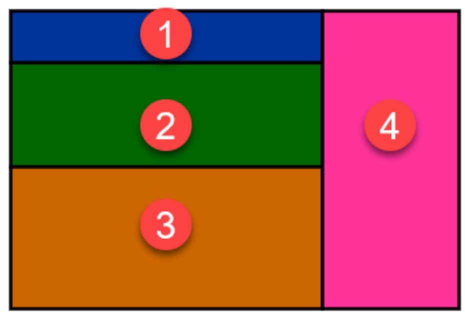
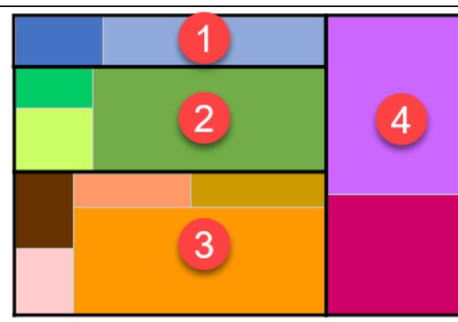
The customer forecast is required at various levels of geographic granularity. The highest level is the complete FEI service territory, followed by the BC STATS Local Health Area (LHA) and finally the FEI municipal (or branch) level.

Top Down and Bottom Up

It is important to understand that the levels of granularity do not change the forecast and are only a method for proportioning and aggregating the customer additions. In the following table the boxes represent the customer totals at the three different levels of granularity. Please note that in all cases the boxes are the same size.

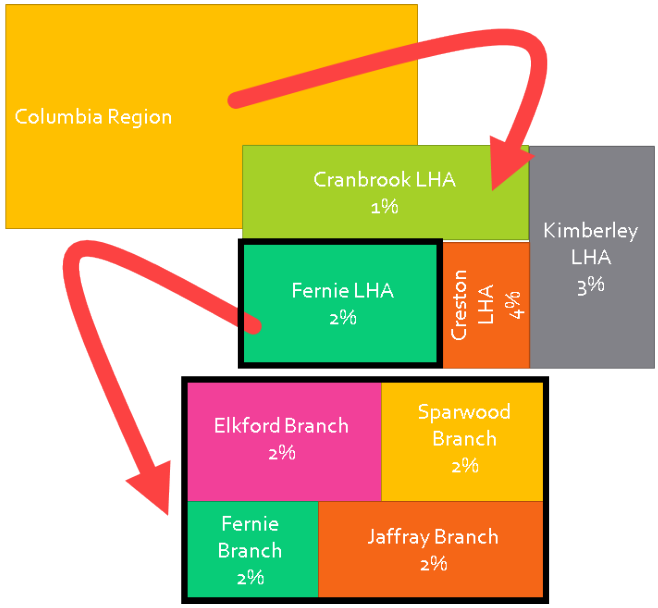
<table>
<tr><th>Level</th><th>Diagram</th></tr>
<tr><td><u>FEI Region</u>
The FEI service territory is broken into regions including the Lower Mainland, Inland, Columbia, Vancouver Island and Whistler. All customer forecasting starts at the regional level.

The regional forecast is the official forecast. Subsequent levels of granularity must always sum back up to the regional forecast. Demand forecasting is completed at the regional level due to differing temperature patterns that impact use rate calculations.</td><td></td></tr>
<tr><td><u>Local Health Area (LHA)</u>
Local health areas are used by BC STATS to provide granular forecasts of many things in the Province. FEI makes use of the household formation forecast at this level of granularity. The LHA-level forecast is a necessary step to get to the branch forecast, below.

In the example, the region contains four LHAs. Please note the following:
A region can contain one or more LHAs.
An LHA can only belong to one region.
The sum of LHA customers equals the regional total.</td><td></td></tr>
<tr><td><u>Municipality (branch)</u>
A branch is a municipality or city where FEI offers gas service. The four LHAs above are now shown at the branch level. For example, LHA #2 contains three branches. Please note the following:
An LHA can contain one or more branches.
A branch can only belong to one LHA.
All branches in an LHA are assumed to grow at the same rate as the LHA.
The sum of branch customers in an LHA equals the LHA total.</td><td></td></tr>
</table>

Columbia Example

In the following example the Columbia region contains four LHAs (Cranbrook, Kimberley, Fernie and Creston). The Fernie LHA contains the Elkford, Sparwood, Fernie and Jaffray branches. The percentages shown in the boxes are the HHF growth rates from BC STATS. Notice how the Fernie LHA growth rate of 2 percent is carried over to the four branches that are situated inside the Fernie LHA.



The Regional Customer Additions Forecasts

The regional forecasts are the official forecasts and are developed as the first step. The following examples show how the CBOC method (for residential customers) and the three-year average method (for commercial customers) work.

Residential

The regional residential net customer additions forecast is developed based on housing starts data from the CBOC Provincial Outlook Long-Term Economic Forecast. The following example uses 2021 data. The housing starts data was as follows:

BC Housing Starts Data

Housing Type	2019	2020	2021	2022
Housing Starts, Singles, British Columbia	8,792	8,519	6,823	6,099
Housing Starts, Multiples, British Columbia	36,140	29,215	25,565	25,466
Total	44,932	37,734	32,388	31,566

From the above housing starts forecast, the 2022F single family dwelling (SFD) growth rate is calculated as follows:

$$2022F\ SFD\ Growth\ Rate = \left(\frac{6{,}099}{6{,}823}\right) - 1 = -10.6\%$$

The remainder of the growth rates are calculated the same way and the results are shown in the following table:

Growth Rates

Housing Type	2021	2022
SFD Forecast Percent Change	**-19.9%**	**-10.6%**
MFD Forecast Percent Change	**-12.5%**	**-0.4%**

The following table incorporates the FEI proportions of the actual account additions by SFD and multi-family dwelling (MFD) based on percentages from internal data in columns A and B. The 2020 actual total additions are shown in column C, followed by the SFD and MFD proportions in columns D and E. Finally, the CBOC growth rates for 2021 are applied to the SFD and MFD proportions for 2021 in columns F and G and for 2022 in columns I and J.

FEI Proportions of Actual Account Additions by SFD and MFD

	Internal Split		Actual Adds 2020			2021S			2022F		
	SFD	MFD	Total	SFD	MFD	SFD	MFD	Total	SFD	MFD	Total
	A	B	C	D	E	F	G	H	I	J	K
Mainland											
Lower Mainland	35%	65%	4,831	1,693	3,138	1,356	2,746	4,102	1,212	2,735	3,947
Inland	68%	32%	3,183	2,158	1,025	1,728	897	2,625	1,545	894	2,439
Columbia	67%	33%	249	168	81	134	71	205	120	71	191
Revelstoke	99%	1%	62	61	1	49	1	50	44	1	45
Whistler	76%	24%	41	31	10	25	9	34	22	9	31
Vancouver Island	82%	18%	4,629	3,803	826	3,045	723	3,768	2,723	720	3,443
Total			**12,995**	**7,913**	**5,082**	**6,337**	**4,447**	**10,784**	**5,666**	**4,430**	**10,096**

For example, the Columbia 2021S SFD value of 134 (column F) is derived as follows:

- Columbia 2020 Internal Split – SFD percentage = 67% (column A)
- Columbia 2020 Actual additions = 249 (column C)

$$COL\ 2020 Actual\ SFD = 67\%\ \times 249 = 168\ (column\ D)$$

$$COL\ 2021\ Seed\ SFD =\ -19.9\% \times 168 = 134\ (column\ F)$$

The MFD forecast of 71 in column G is calculated the same way. The combined residential forecast for 2021S in column H is the sum of 134 + 71 = 205.

Commercial

The regional commercial customer additions are calculated as an average of the net customer additions by region and rate class from the prior three years.

The following table shows the customer additions for Lower Mainland RS 2.

Customer Additions for Lower Mainland RS 2

	Year	Customers	Customer Additions	Average 2018-2020
		A	B	C
1	2017	53,320		
2	2018	54,055	735	
3	2019	54,211	156	
4	2020	54,619	408	433
5	2021S	55,052		
6	2022F	55,485		

Customer additions are calculated in column B. The three-year average of additions is shown in C4 and is 433. 433 additions are forecast in each of 2021 and 2022.

$$2021S\ Customers = 2020\ Customers\ + 3\ Yr\ Avg\ Additions$$

Using the data above:

$$2021S = 55{,}052 = 54{,}619 + 433$$

Identical calculations are completed for all regions and all small commercial rate schedules.

However, due to rate switching between the large commercial rate schedules (specifically RS 3 and RS 23), forecasting for these two classes was done as a group and then proportioned per 2020 customers distribution.

The following table shows how the Lower Mainland large commercial customer additions forecast was developed. Other regions are similar.

Lower Mainland Large Commercial Customer Additions Forecast Development

		Customers					Proportion	
		RS 3	RS 23	Total	Total	3 Yr. Average	RS 3	RS 23
		A	B	C	D	E	F	G
1	2017	4,111	1,225	5,336				
2	2018	4,575	1,144	5,719	383			
3	2019	5,347	505	5,852	133			
4	2020	5,075	430	5,505	- 347	56	52	4
5	2021S	5,127	434				52	4
6	2022F	5,179	439				52	4

For each actual year (rows 1-4) the rate class customers from columns A and B are summed in column C.

Aggregate customer additions are shown in column D.

The three-year average customer additions is 56 and shown in column E, row 4.

The 2020 proportion is calculated from columns A-C on row 4.

For example, the RS 3 proportion is:

$$RS\ 3\ Proportion = \frac{5{,}075}{5{,}505} = 0.92$$

The proportion of the aggregate customer additions (56) assigned to RS 3 is then:

$$RS\ 3\ Customer\ Additions = 0.92\ \times 56 = 52$$

A similar calculation is performed for RS 23 to arrive at 4 customer additions.

On row 5 the 2021S customer additions for RS 3 are shown in column A and calculated as:

$$2021S = 5{,}127 = 5{,}075 + 52$$

The remaining calculations are similar.

LHA and Branch Forecasts

Once the regional forecasts are developed, they are proportioned into the various BC STATS Local Health Area (LHA) and the FEI municipal (or branch) levels.

While the computer script used to develop the forecast works from the "bottom up", presenting the forecast "top down" makes it easier to describe how it works.

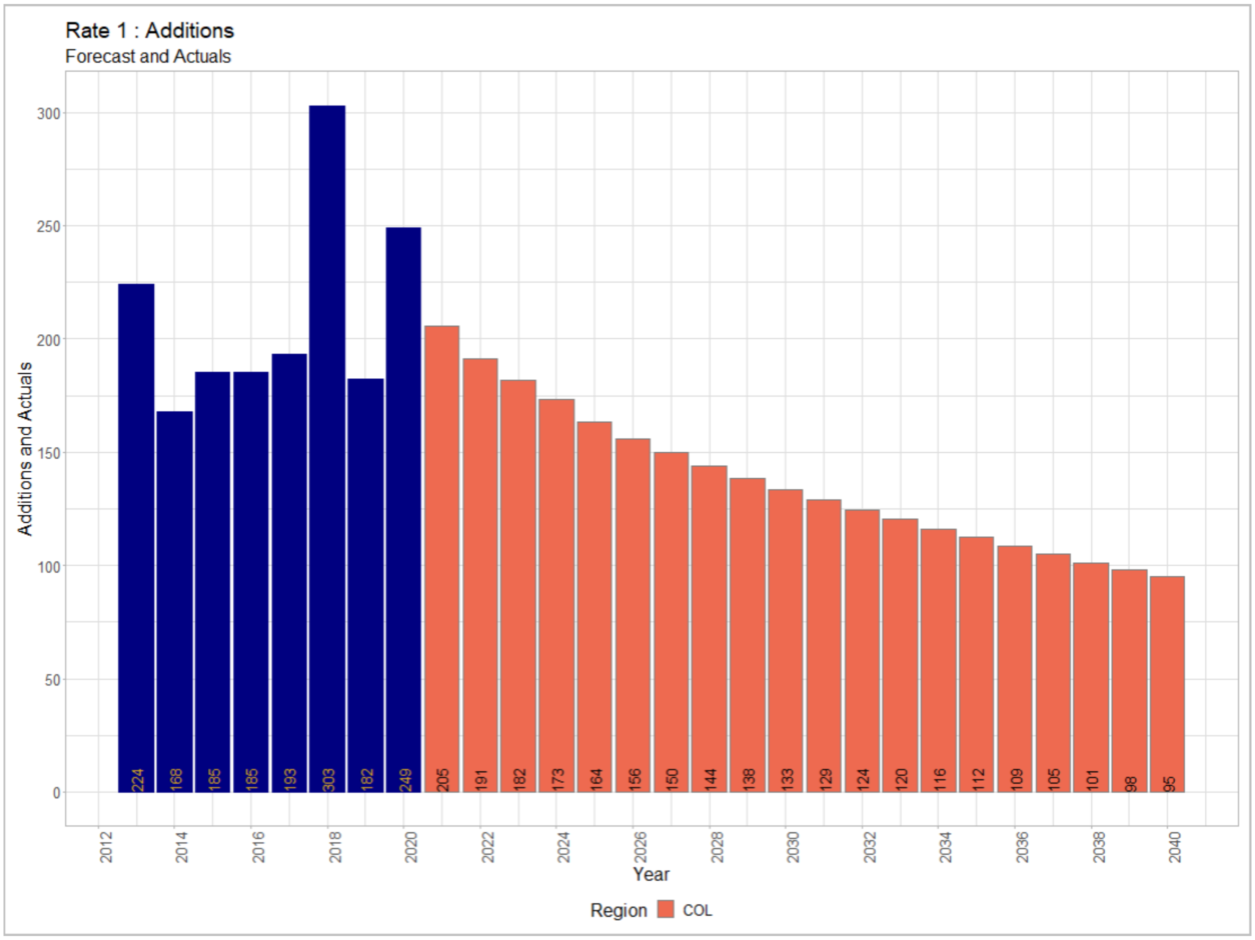
The following screen shots and examples demonstrate the residential forecast for the Columbia region.

2021 Actual Residential Additions

In Columbia the 2021 residential customer additions were forecast to be 205 (see yellow highlighted cell in the below table).

	Internal Split		Actual Adds 2020			2021S			2022F		
	SFD	MFD	Total	SFD	MFD	SFD	MFD	Total	SFD	MFD	Total
	A	B	C	D	E	F	G	H	I	J	K
Mainland											
Lower Mainland	35%	65%	4,831	1,693	3,138	1,356	2,746	4,102	1,212	2,735	3,947
Inland	68%	32%	3,183	2,158	1,025	1,728	897	2,625	1,545	894	2,439
Columbia	67%	33%	249	168	81	134	71	205	120	71	191
Revelstoke	99%	1%	62	61	1	49	1	50	44	1	45
Whistler	76%	24%	41	31	10	25	9	34	22	9	31
Vancouver Island	82%	18%	4,629	3,803	826	3,045	723	3,768	2,723	720	3,443
Total			**12,995**	**7,913**	**5,082**	**6,337**	**4,447**	**10,784**	**5,666**	**4,430**	**10,096**

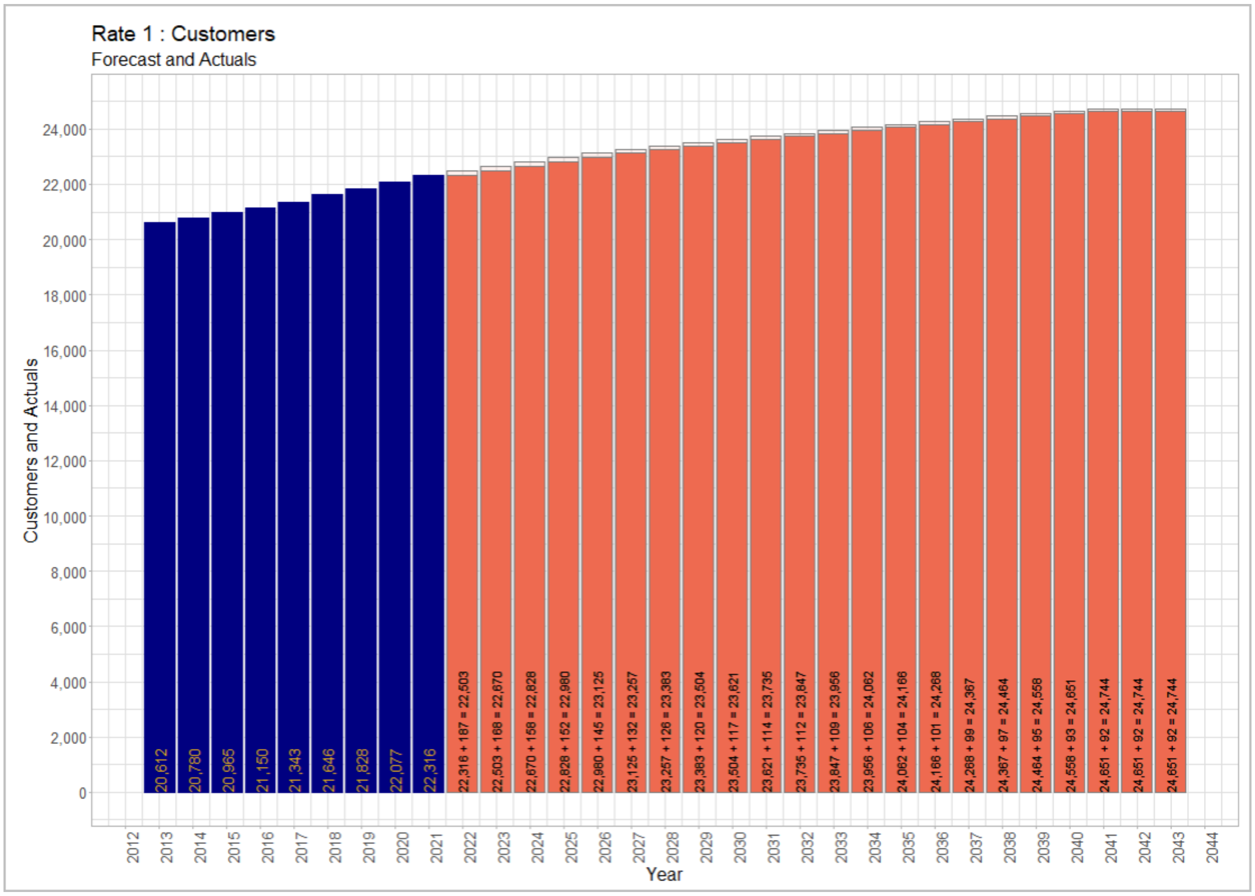
The CBOC growth rates for single and multi-family dwellings were negative, so the red bars in the figure below show the declining additions forecast. Note the 2021S residential customer additions forecast of 205 in the below figure.



The Official Customer Forecast

The customer additions forecast (e.g., 205 for 2021) is then added to the actual customers as shown in the following figure. This is the "official" RS 1 forecast for the Columbia region. The trajectory looks reasonable.

In the following plot a "stacked column chart" is used. The additions are stacked on top of the prior year customer total and appear as the small shaded rectangles. This serves as a reminder that the customer additions forecast is very small relative to the customer totals each year.



For the purpose of System Planning, the regional forecast is not granular enough. System Planning needs this forecast broken down to the municipal (branch) level. Further, FEI is unable to take the simplistic approach of applying a ratio to the forecast based on something like current customer totals because different branches are expected to grow at different rates. This is because System Planning cannot assume homogenous growth for all branches.

The CBOC does not have a branch level forecast, so it is necessary to split up the official regional forecast in such a way that it represents the expected growth trajectory for each branch. To do this FEI uses the more granular growth trajectories from the BC STATS LHA (local health area) forecast to split the regional forecast. It is important to note that once split, the sum of both the branch-level and LHA forecasts must still roll up to the official regional forecast as shown above. The LHA forecast growth rates are only used for obtaining the correct growth trajectory for the branches and LHAs. The LHA forecast is for household formations, not SFD and MFD housing starts and therefore cannot be used to develop the official regional customer forecast.

The LHA Step

The following example illustrates how the 205 additions forecast for 2021S above is distributed to the four Local Health Areas (LHAs) and associated branches in the Columbia region. The remaining years, regions, LHAs and branches of the forecast are calculated the same way.

FEI first starts with the LHAs as follows:

- The 2020 and 2021 household formation (HHF) data is downloaded from BC STATS.
- The HHF data is used to calculate the annual growth rate (column D) as column C divided by Column B.

Note that there are unique growth rates for each LHA, and the growth rate can be 0 percent (e.g., Creston).

	A	B	C	D	E	F	G	H	I	J
	LHA	2020 HHF	2021 HHF	HHF Growth Rate	Branch	2020 YE Customers	BC Stats Adds	Reconciled Adds	Reconciled Forecast	Check
1	Fernie	8,116	8,223	1.32%	Elkford	1,017	13	21	1,038	
2					Fernie	3,592	47	75	3,667	
3					Jaffray	3	0	0	3	
4					Sparwood	1,761	23	37	1,798	
5	Cranbrook	12,173	12,217	0.36%	Cranbrook	8,705	31	50	8,755	
6	Kimberley	4,832	4,848	0.33%	Kimberley	4,083	14	22	4,105	
7	Creston	5,949	5,949	0.00%	Arrow Creek	1	-	-	1	
8					Creston	2,857	-	-	2,857	
9					Elko	2	-	-	2	
10					Galloway	4	-	-	4	
11					Kitchener	10	-	-	10	
12					Wynndel	41	-	-	41	
13	Sum					22,076	129	205	22,281	205
14	Regional forecast						205			
15	Reconciliation Factor						1.59			

Each branch (municipality) in the FEI service territory is assigned to one and only one LHA. The FEI billing system has the year end actual customer counts by rate and branch for the prior year. These counts are shown in column F for 2020. Note that (for example) Elkford, Fernie, Jaffray and Sparwood are all assigned to the Fernie LHA (column A).

	A	B	C	D	E	F	G	H	I	J
	LHA	2020 HHF	2021 HHF	HHF Growth Rate	Branch	2020 YE Customers	BC Stats Adds	Reconciled Adds	Reconciled Forecast	Check
1	Fernie	8,116	8,223	1.32%	Elkford	1,017	13	21	1,038	
2					Fernie	3,592	47	75	3,667	
3					Jaffray	3	0	0	3	
4					Sparwood	1,761	23	37	1,798	
5	Cranbrook	12,173	12,217	0.36%	Cranbrook	8,705	31	50	8,755	
6	Kimberley	4,832	4,848	0.33%	Kimberley	4,083	14	22	4,105	
7	Creston	5,949	5,949	0.00%	Arrow Creek	1	-	-	1	
8					Creston	2,857	-	-	2,857	
9					Elko	2	-	-	2	
10					Galloway	4	-	-	4	
11					Kitchener	10	-	-	10	
12					Wynndel	41	-	-	41	
13	Sum					22,076	129	205	22,281	205
14	Regional forecast						205			
15	Reconciliation Factor						1.59			

The HHF growth rates calculated earlier for each LHA are applied to the year end actuals of each branch contained in the LHA. For example, the growth rates for Elkford, Fernie, Jaffray and Sparwood are all set to the growth rate for the Fernie LHA (1.32%).

Next, column G is calculated as the growth rates (column D) multiplied by the 2020 year-end customers (column F).

However, the sum of the branch forecast calculated this way will not normally match the CBOC-based regional forecast. Since the CBOC forecast is the official forecast for the region and the LHA step is only used to proportion the additions to the branches the two forecasts must be reconciled.

As shown in cell G13 of the below table, the sum of the additions from the LHA method is 129 customers, as compared to Cell G14 which is the official CBOC based regional forecast (205).

This means that the LHA forecast is lower than the CBOC forecast, so a reconciliation factor is established. The reconciliation factor ensures that the regional total is correct while also preserving the LHA proportions.

In this case the reconciliation factor is:

$$Reconciliation\ Factor = \frac{Official\ Regional\ Forecast}{LHA\ based\ forecast} = \frac{205}{129} = 1.59$$

	A	B	C	D	E	F	G	H	I	J
	LHA	2020 HHF	2021 HHF	HHF Growth Rate	Branch	2020 YE Customers	BC Stats Adds	Reconciled Adds	Reconciled Forecast	Check
1	Fernie	8,116	8,223	1.32%	Elkford	1,017	13	21	1,038	
2				1.32%	Fernie	3,592	47	75	3,667	
3				1.32%	Jaffray	3	0	0	3	
4				1.32%	Sparwood	1,761	23	37	1,798	
5	Cranbrook	12,173	12,217	0.36%	Cranbrook	8,705	31	50	8,755	
6	Kimberley	4,832	4,848	0.33%	Kimberley	4,083	14	22	4,105	
7	Creston	5,949	5,949	0.00%	Arrow Creek	1	-	-	1	
8				0.00%	Creston	2,857	-	-	2,857	
9				0.00%	Elko	2	-	-	2	
10				0.00%	Galloway	4	-	-	4	
11				0.00%	Kitchener	10	-	-	10	
12				0.00%	Wynndel	41	-	-	41	
13	Sum					22,076	129	205	22,281	205
14	Regional forecast						205			
15	Reconciliation Factor						1.59			

Column H is now calculated as column G multiplied by the reconciliation factor calculated above and shown in cell G15. The sum of the reconciled additions in column H is now correct at 205.

	A	B	C	D	E	F	G	H	I	J
	LHA	2020 HHF	2021 HHF	HHF Growth Rate	Branch	2020 YE Customers	BC Stats Adds	Reconciled Adds	Reconciled Forecast	Check
1	Fernie	8,116	8,223	1.32%	Elkford	1,017	13	21	1,038	
2				1.32%	Fernie	3,592	47	75	3,667	
3				1.32%	Jaffray	3	0	0	3	
4				1.32%	Sparwood	1,761	23	37	1,798	
5	Cranbrook	12,173	12,217	0.36%	Cranbrook	8,705	31	50	8,755	
6	Kimberley	4,832	4,848	0.33%	Kimberley	4,083	14	22	4,105	
7	Creston	5,949	5,949	0.00%	Arrow Creek	1	-	-	1	
8				0.00%	Creston	2,857	-	-	2,857	
9				0.00%	Elko	2	-	-	2	
10				0.00%	Galloway	4	-	-	4	
11				0.00%	Kitchener	10	-	-	10	
12				0.00%	Wynndel	41	-	-	41	
13	Sum					22,076	129	205	22,281	205
14	Regional forecast						205			
15	Reconciliation Factor						1.59			

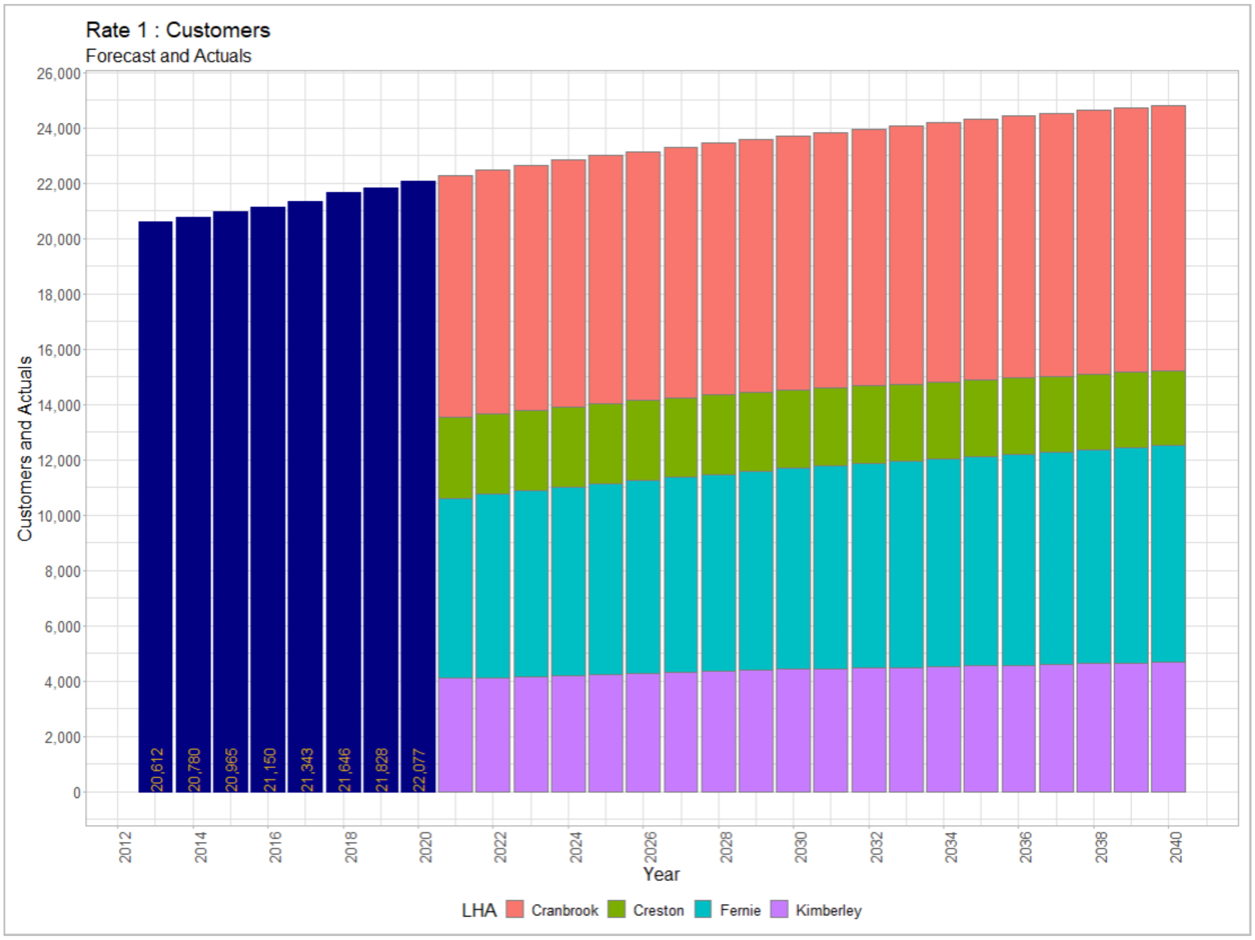
Finally, the branch customer forecast (column I) is calculated as the 2020 year-end customers total in column F plus the reconciled addition forecast in column H.

The check in J13 matches the regional forecast in G14.

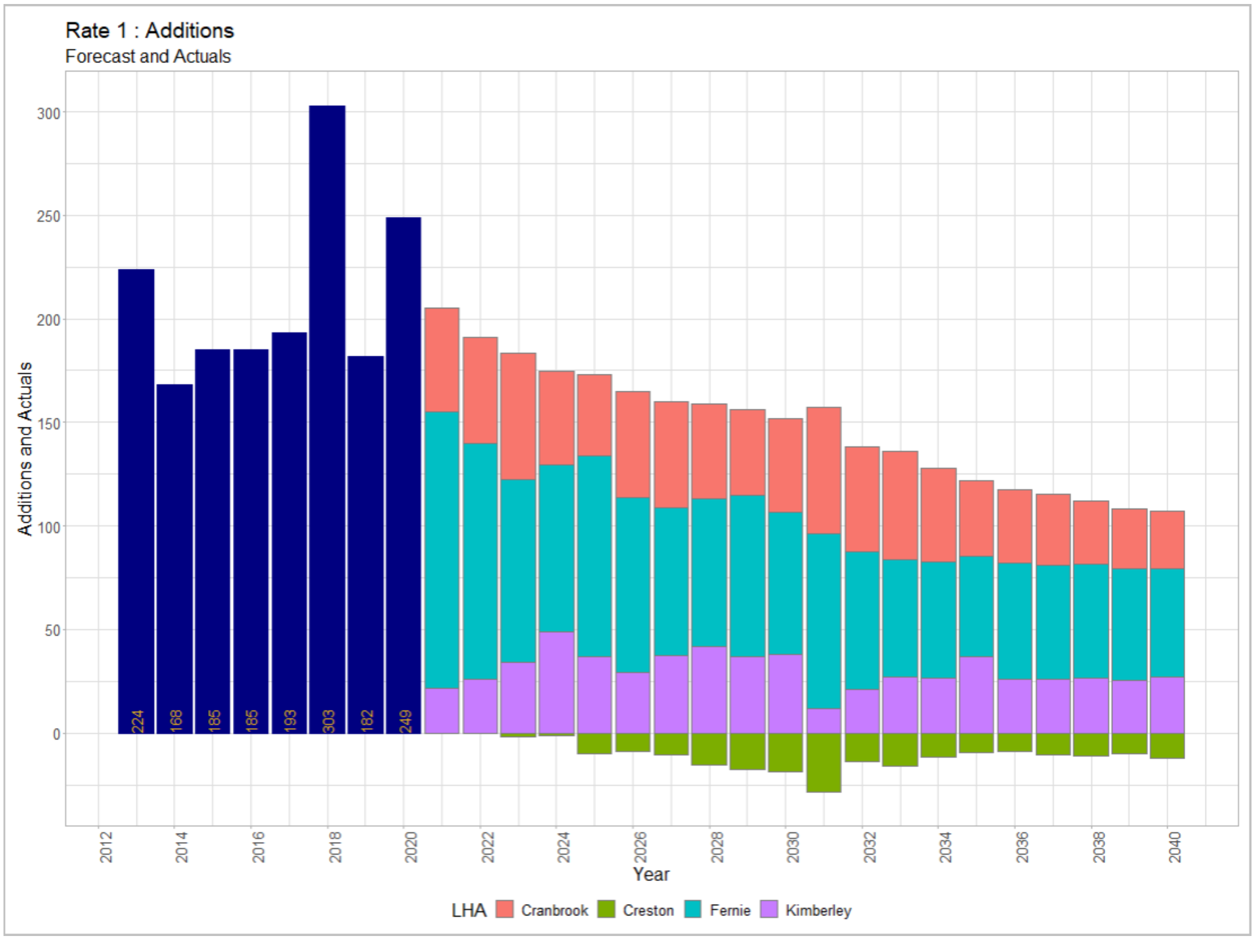
	A	B	C	D	E	F	G	H	I	J
	LHA	2020 HHF	2021 HHF	HHF Growth Rate	Branch	2020 YE Customers	BC Stats Adds	Reconciled Adds	Reconciled Forecast	Check
1	Fernie	8,116	8,223	1.32%	Elkford	1,017	13	21	1,038	
2				1.32%	Fernie	3,592	47	75	3,667	
3				1.32%	Jaffray	3	0	0	3	
4				1.32%	Sparwood	1,761	23	37	1,798	
5	Cranbrook	12,173	12,217	0.36%	Cranbrook	8,705	31	50	8,755	
6	Kimberley	4,832	4,848	0.33%	Kimberley	4,083	14	22	4,105	
7	Creston	5,949	5,949	0.00%	Arrow Creek	1	-	-	1	
8				0.00%	Creston	2,857	-	-	2,857	
9				0.00%	Elko	2	-	-	2	
10				0.00%	Galloway	4	-	-	4	
11				0.00%	Kitchener	10	-	-	10	
12				0.00%	Wynndel	41	-	-	41	
13	Sum					22,076	129	205	22,281	205
14	Regional forecast						205			
15	Reconciliation Factor						1.59			

Columbia LHA Forecast

The following figure shows the complete Columbia customer forecast split into each of the four LHAs that comprise the Columbia region, following the method described above. Note that the aggregation of the forecasts matches the official forecast. The sum does not change after it is proportioned.

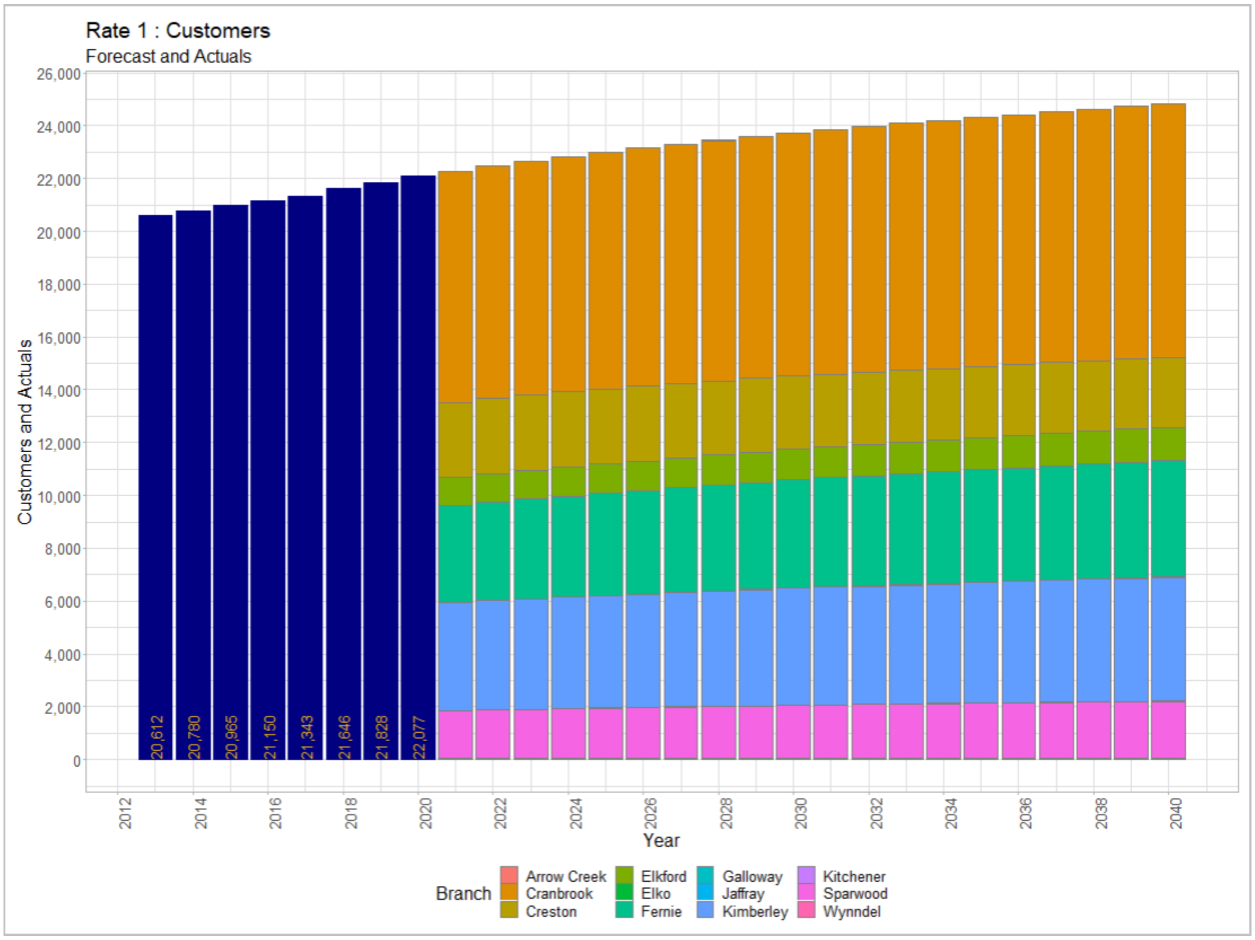


The customer additions forecast is computed by subtracting the previous year from the current year.

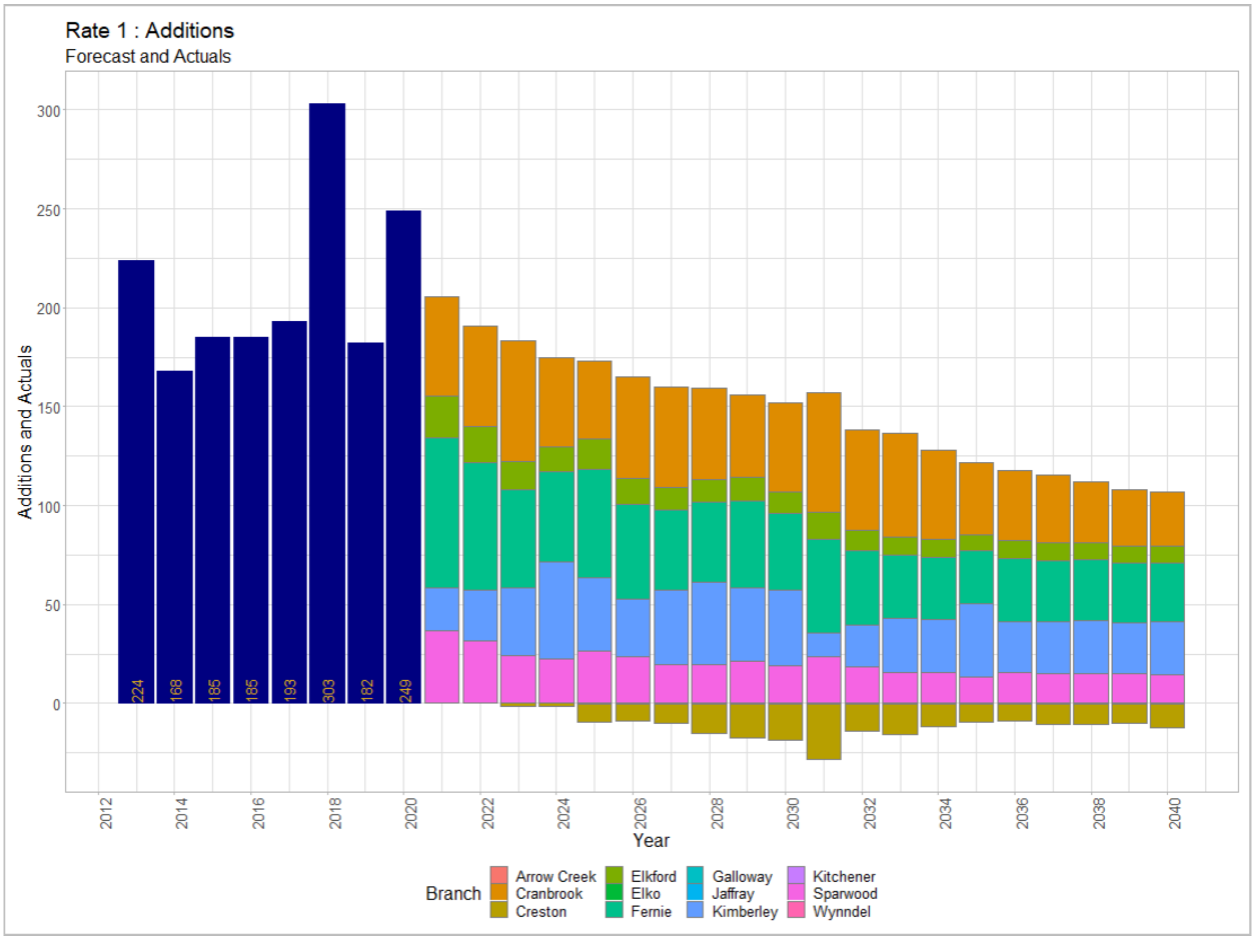

Rate 1 : Additions
Forecast and Actuals
Additions and Actuals
300
250
200
150
100
50
0
224
168
185
185
193
303
182
249
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
2032
2034
2036
2038
2040
Year
LHA
Cranbrook
Creston
Fernie
Kimberley

Columbia Branch Forecast

Next the growth rates and reconciliation factors for each LHA are applied to the branches within each LHA. Again, note that the aggregate total ("top edge" of the forecast) does not change.



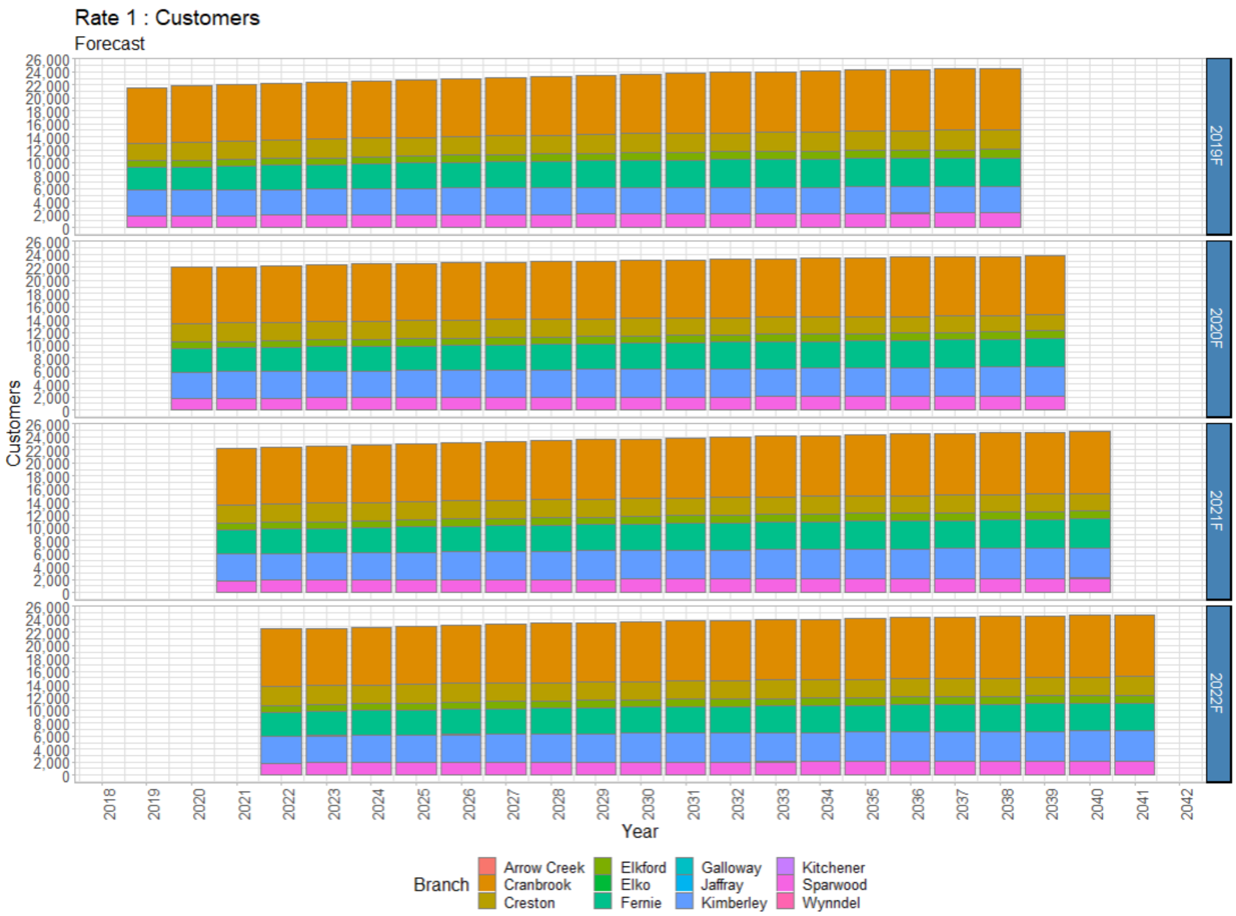
The branch level customer additions forecast is computed by subtracting the previous year from the current year.



Rate 1 : Additions
Forecast and Actuals
Additions and Actuals
Year
224
168
185
185
193
303
182
249
Branch
Arrow Creek
Cranbrook
Creston
Elkford
Elko
Fernie
Galloway
Jaffray
Kimberley
Kitchener
Sparwood
Wynndel

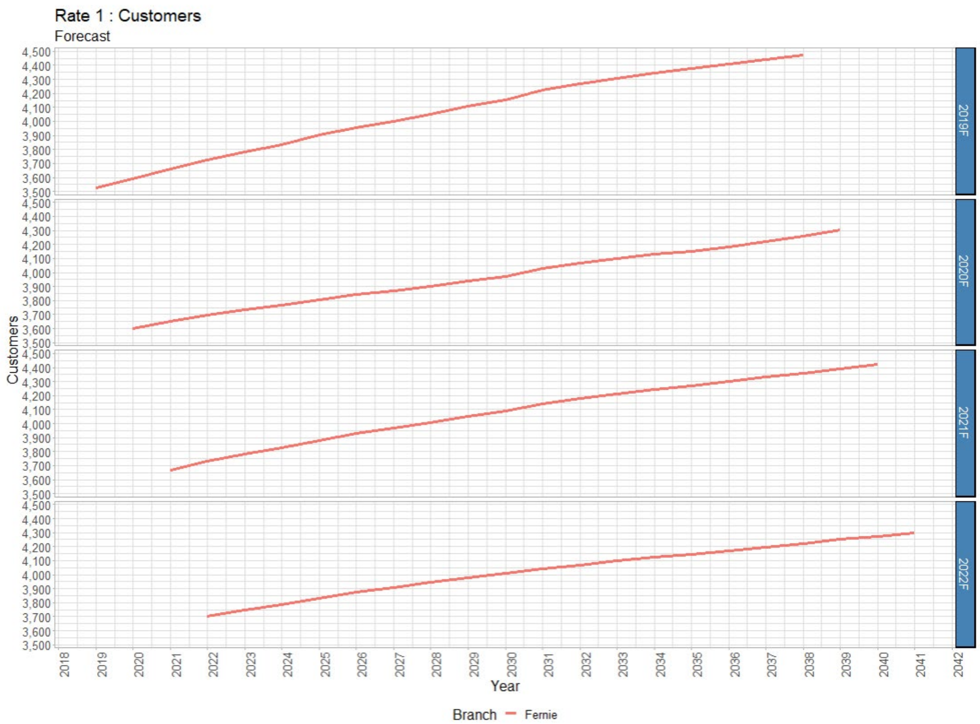
Annual Updates

The BC STATS and CBOC forecasts are refreshed each year and are applied the same way to FEI's actual customer data. The following figure shows the most recent four years by branch. Note from this figure that the different trajectories of each branch are not apparent, however they do exist.

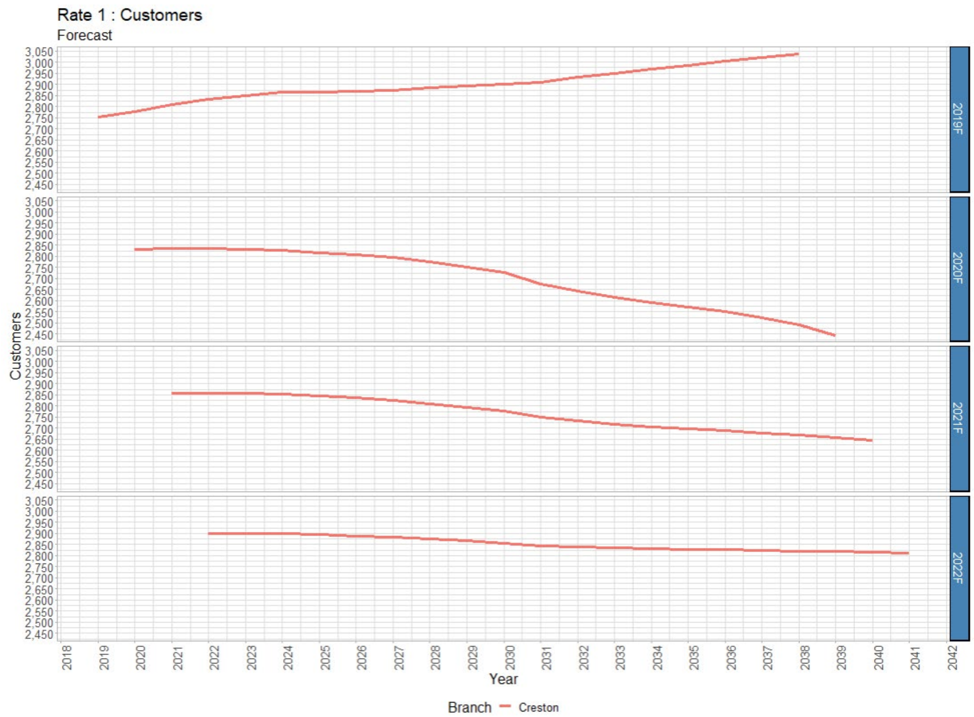


Branch Trajectories

The following figure shows the same data but as a line graph for Fernie. The figure shows that the BC STATS outlook for Fernie has not changed appreciably for four years. Positive growth is forecast.



On the other hand, the trajectory for Creston has changed as shown in the following figure. These are the branch level changes that System Planning needs for their work.



Rate 1 : Customers
Forecast
Customers
Year
2019F
2020F
2021F
2022F
Branch
Creston

Commercial LHA and Branch Worked Example

Once the regional commercial forecasts are developed, they must also be proportioned into branch level forecasts using the LHA data. While the regional forecast is easily calculated in Excel, this step is more complex. The LHA and branch forecasts can be completed using Excel, but the method is well suited to a data analytics programming script. FEI now uses a custom R script to complete this portion of the forecast.

This section mimics two iterations (years) of the R script and presents the results in a tabular fashion to explain the calculations.

Commercial calculations are completed for Rates 2/3/23 with the following differences:

- Rate 2: The basic forecast uses a 3-year average of the prior regional customer additions.
- Rate 3/23: Large commercial is forecast together to avoid extreme trajectories that could result from rate switching. Once the rates are combined, the calculations are identical to those for Rate 2.

This following worked example is for Columbia Rate 2 using the 2021 actual data.

Step 1

1) Based on BC STATS, there are four LHAs in the Columbia region.
2) In the Mapping section of the source file, the FEI branches are associated with the applicable LHAs. This mapping is exclusive to FEI and maintained by FEI. This analysis is completed at the branch level and will roll up to the regional totals.
3) The prior year customers are needed for each iteration. There are 20 iterations for the 20-year forecast. The first iteration starts with the branch customers at year end provided by Finance.
4) The commercial basic method is a 3-year average. The 3-year average customer additions for the Columbia region has been calculated and is 2. The 2 is repeated in each cell for convenience but this does not mean that each branch is going to grow by 2. It is necessary for the R script only.
5) The LHA data is available from BC STATS and is added to the input file. From the HHF data FEI uses the lag function to calculate the HHF growth and then the HHF growth rate. Note that the growth rate is the same for all branches in an LHA. In the case of Columbia, there are four LHAs, so there are four different growth rates. Growth rates appear more than once when there are multiple branches in an LHA.
6) The total of the prior year (YE) customers is 2,149. Since the additions is known to be 2, FEI expects the YE customers at the end of this iteration (i.e., 2022 YE) would be 2,151.

Branch	LHA_Name	Prior YE Customers	Basic Additions	HHF Prior	HHF	HHF Growth	HHF Growth Rate
Elkford	Fernie	77	2	7,616	7,733	117	0.0154
Fernie	Fernie	375	2	7,616	7,733	117	0.0154
Jaffray	Fernie	1	2	7,616	7,733	117	0.0154
Sparwood	Fernie	209	2	7,616	7,733	117	0.0154
Cranbrook	Cranbrook	906	2	12,261	12,330	69	0.0056
Kimberley	Kimberley	251	2	4,733	4,763	30	0.0063
Creston	Creston	322	2	5,824	5,829	5	0.0009
Elko	Creston	2	2	5,824	5,829	5	0.0009
Wynndel	Creston	6	2	5,824	5,829	5	0.0009
		2,149					

Step 2

1) FEI calculates the branch level additions based on the LHA growth rates. This indicates which branches are growing faster and which are slower.
    a. Multiply the YE branch level customers by the respective growth rate to get the BC STATS based branch additions.
2) The sum of all the branch level additions is 17.1. Note that this is bigger than the forecast additions of "2" calculated in Step 1. The BC STATS additions are therefore too big.

Branch	LHA_Name	Prior YE Customers	Basic Additions	HHF Prior	HHF	HHF Growth	HHF Growth Rate	BC Stats Branch Adds	
Elkford	Fernie	77.00	2	7,616	7,733	117	0.0154	1.1829	
Fernie	Fernie	375.00	2	7,616	7,733	117	0.0154	5.7609	
Jaffray	Fernie	1.00	2	7,616	7,733	117	0.0154	0.0154	
Sparwood	Fernie	209.00	2	7,616	7,733	117	0.0154	3.2107	
Cranbrook	Cranbrook	906.00	2	12,261	12,330	69	0.0056	5.0986	
Kimberley	Kimberley	251.00	2	4,733	4,763	30	0.0063	1.5910	
Creston	Creston	322.00	2	5,824	5,829	5	0.0009	0.2764	
Elko	Creston	2.00	2	5,824	5,829	5	0.0009	0.0017	
Wynndel	Creston	6.00	2	5,824	5,829	5	0.0009	0.0052	
		2,149.00						17.1428	BC Stats Regional Adds

Step 3

1) The total regional additions from Step 2 (17.14) are added to each row for convenience.
2) The reconciliation factor is the ratio of the basic additions (2) to the BC STATS additions (17.14). The reconciliation factor is the same for all rows because this calculation is at the regional level. Recall that the "2" additions were the basic 3-year average regional calculation.
3) The Reconciled Additions are the BC STATS additions scaled down so that the regional total remains at 2. FEI then uses the BC STATS branch additions calculated in Step 2 and multiplies by the Reconciliation Factor.
4) The branch YE customers is then the prior YE customers plus the reconciled additions.

5) The sum of the reconciled additions for the region is 2, as expected.
6) The new sum of the YE customers for the region is 2,151.
7) The prior YE customer total was 2,149; therefore, 2,149 + 2 = 2,151.

At this point the regional total of 2 customer additions has been distributed to the branches in the region via the projected growth for the LHAs in the region.

This completes the calculation for the first year and provides the YE customer total. While FEI knew the YE total would be 2,151, this method distributes the growth of 2 customers amongst the branches.

FEI now uses the 2,151 as the starting point for the next iteration, which is Year 2.

Branch	LHA_Name	Prior YE Customers	Basic Additions	HHF Prior	HHF	HHF Growth	HHF Growth Rate	BC Stats Branch Adds	BC Stats Regional Adds	Reconciliation Factor	Reconciled Additions	YE Customers
Elkford	Fernie	77.00	2	7,616	7,733	117	0.0154	1.1829	17.1428	0.11667	0.1380	77.138
Fernie	Fernie	375.00	2	7,616	7,733	117	0.0154	5.7609	17.1428	0.11667	0.6721	375.672
Jaffray	Fernie	1.00	2	7,616	7,733	117	0.0154	0.0154	17.1428	0.11667	0.0018	1.002
Sparwood	Fernie	209.00	2	7,616	7,733	117	0.0154	3.2107	17.1428	0.11667	0.3746	209.375
Cranbrook	Cranbrook	906.00	2	12,261	12,330	69	0.0056	5.0986	17.1428	0.11667	0.5948	906.595
Kimberley	Kimberley	251.00	2	4,733	4,763	30	0.0063	1.5910	17.1428	0.11667	0.1856	251.186
Creston	Creston	322.00	2	5,824	5,829	5	0.0009	0.2764	17.1428	0.11667	0.0323	322.032
Elko	Creston	2.00	2	5,824	5,829	5	0.0009	0.0017	17.1428	0.11667	[illegible]	2.000
Wynndel	Creston	6.00	2	5,824	5,829	5	0.0009	0.0052	17.1428	0.11667	[illegible]	6.001
		2,149.00									2.0000	2,151.000

Step 4

In Step 4 FEI repeats the process but instead of starting with the branch level customers from Finance, FEI starts with the result from Step 3.

1) The YE customers from the end of Step 3 is copied down.
2) The basic additions from the 3-year average method apply to all 20 years of the forecast. The “2” is entered on each row for convenience.
3) The LHA data is contained in the BC STATS file for 2023 and shown here for the four LHAs that make up Columbia. The HHF growth is calculated using the lag function and the growth rate is the growth divided by the prior year HHF.
4) Finally, the branch level additions from BC STATS are calculated using the HHF growth rates (0.0144) and the Prior YE Customers.
   a. The sum of the branch level additions from the BC STATS method is 18.6. This is much greater than the 2 customer additions forecast using the basic 3-year average method so this must be reconciled.

Branch	LHA_Name	Prior YE Customers	Basic Additions	HHF Prior	HHF	HHF Growth	HHF Growth Rate	BC Stats Branch Adds
Elkford	Fernie	77.138	2	7,733	7,844	111	0.0144	1.1072
Fernie	Fernie	375.672	2	7,733	7,844	111	0.0144	5.3924
Jaffray	Fernie	1.002	2	7,733	7,844	111	0.0144	0.0144
Sparwood	Fernie	209.375	2	7,733	7,844	111	0.0144	3.0054
Cranbrook	Cranbrook	906.595	2	12,330	12,422	92	0.0075	6.7645
Kimberley	Kimberley	251.186	2	4,763	4,806	43	0.0090	2.2677
Creston	Creston	322.032	2	5,829	5,830	1	0.0002	0.0552
Elko	Creston	2.000	2	5,829	5,830	1	0.0002	0.0003
Wynndel	Creston	6.001	2	5,829	5,830	1	0.0002	0.0010
		2,151.00						18.6083

Step 5

Similar to Step 3, Step 5 calculates the reconciled additions for the year.

1) The BC STATS regional additions from Step 4 are added to each row for convenience.
2) The new reconciliation factor is calculated as the Basic Additions (2) divided by the BC STATS regional additions and added to each row for convenience.
3) The reconciled additions are calculated as the BC STATS branch additions multiplied by the reconciliation factor.
4) Finally, the YE branch customers for the second year are the sum of the Prior YE branch customer totals plus the reconciled branch additions.
5) The regional sum of the reconciled additions is again 2 to match the basic regional additions.
6) The YE customer total has increased by 2 to 2,153 as expected.

Branch	LHA_Name	Prior YE Customers	Basic Additions	HHF Prior	HHF	HHF Growth	HHF Growth Rate	BC Stats Branch Adds	BC Stats Regional Adds	Reconciliation Factor	Reconciled Additions	YE Customers
Elkford	Fernie	77.138	2	7,733	7,844	111	0.0144	1.1072	18.6083	0.10748	0.1190	77.257
Fernie	Fernie	375.672	2	7,733	7,844	111	0.0144	5.3924	18.6083	0.10748	0.5796	376.252
Jaffray	Fernie	1.002	2	7,733	7,844	111	0.0144	0.0144	18.6083	0.10748	0.0015	1.003
Sparwood	Fernie	209.375	2	7,733	7,844	111	0.0144	3.0054	18.6083	0.10748	0.3230	209.698
Cranbrook	Cranbrook	906.595	2	12,330	12,422	92	0.0075	6.7645	18.6083	0.10748	0.7270	907.322
Kimberley	Kimberley	251.186	2	4,763	4,806	43	0.0090	2.2677	18.6083	0.10748	0.2437	251.429
Creston	Creston	322.032	2	5,829	5,830	1	0.0002	0.0552	18.6083	0.10748	0.0059	322.038
Elko	Creston	2.000	2	5,829	5,830	1	0.0002	0.0003	18.6083	0.10748	0.0000	2.000
Wynndel	Creston	6.001	2	5,829	5,830	1	0.0002	0.0010	18.6083	0.10748	0.0001	6.001
		2,151.00									2.0000	2,153.000

Step 6

This process continues for the duration of the forecast.

Commercial after Year 6

The reconciliation factor ensures that the sum of the branch additions will always equal the regional total. In the case of the commercial forecast this means that the 3-year average of additions was used for all 20 years of the forecast. In an effort to capture the BC STATS third party forecast projections in the commercial forecast, the reconciliation factor calculated for Yyear 6 is frozen for the remainder of the forecast. This means that the ratio between the 3-year average additions and the sum of the branch additions calculated in the year is assumed to remain constant. In this case any changes in the trajectory of the BC STATS forecast will now manifest in the commercial forecast. If the sum of the branch additions drops because the LHA HHF forecasts are declining, then with a fixed reconciliation factor the commercial sum will also drop. The change imparted by BC STATS is muted because of the reconciliation factor. There will always be more households formed than commercial customers added.

Attachment 69.2

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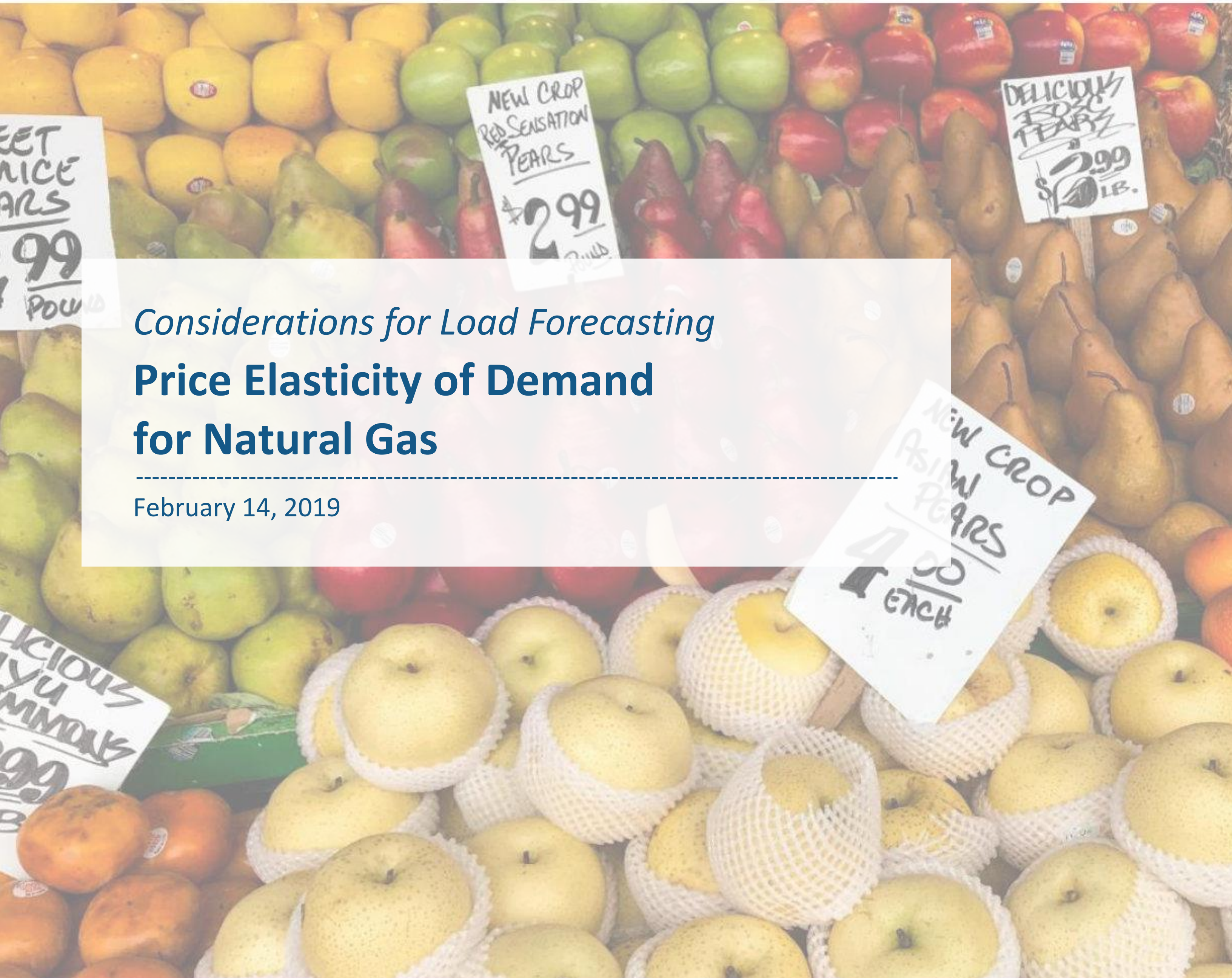

Considerations for Load Forecasting

Price Elasticity of Demand for Natural Gas

February 14, 2019

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Contents

Summary

The purpose is to advise FortisBC on the values to use for price elasticity for natural gas demand in the next load forecast. To do so, this memo provides:

- A summary of the economic theory of price elasticity of demand with specific notes on how it applies to natural gas, and key findings from the literature;
- Recommended minimum and maximum elasticities to bound the scenarios on the load forecast;
- Recommended reference case values (short-run and long-run) for the load forecast; and,
- Suggestions for how to incorporate temporal considerations of price elasticity in the load forecasting model.

The memo also includes considerations related to price elasticity that FortisBC may wish to further explore.

As explained in this document, Posterity Group recommends that FortisBC use price elasticities from the literature for minimum and maximum values, and reference case values from specific sources. These values are displayed in the table below:

	Short Run (SR) Values			Long Run (LR) Values		
	SR Min	SR Reference Case	SR Max	LR Min	LR Reference Case	LR Max
Residential	-0.030	-0.278	-0.670	-0.100	-0.380	-0.880
Commercial	-0.055	-0.205	-0.530	-0.125	-0.350	-0.990
Industrial	-0.067	-0.709	-3.680	-0.142	-0.700	-0.700

We recommend FortisBC incorporate price elasticities into the load-forecasting model in the following ways:

- *Vary elasticity by sector*, as per the suggested values in Exhibit 5.
- *Incorporate temporal considerations* to the model.
    - Short run response: change UEC by end-use, prior to the equipment's end of life
    - Long run response: change fuel share by end-use, when the equipment reaches end of life
- *Use the same elasticity for commodity price and carbon price* until there is enough literature on the subject to have a different elasticity value for carbon price.

1 The Task

Task 5 of the Navigator Model Enhancement project is to “add a price sensitivity scenario driver” to the Navigator load forecasting model. As price elasticity is used in the input development workbooks, this memo provides Posterity Group’s advice on what price elasticity values to use and how to incorporate changes from this driver into the model. The memo also discusses considerations related to price elasticity of demand that FortisBC may wish to further explore.

1.1 Context

During the 2017 LTGRP IR process, FortisBC was asked to justify the price elasticity value for the residential sector used in the 2016 load forecast. As part of the response, research was conducted on what the price elasticity should be and why. While the research for this IR was not exhaustive, it did show that:

- There are a wide range of elasticities in the literature.
- Price elasticity changes over time.
- Price elasticity varies by sector.

As price elasticity is an important input in the load forecast, FortisBC needs to understand the values used, their appropriateness and potential range, and how they are incorporated in the model.

1.1.1 2016 LTGRP Price Elasticities

The 2016 load forecast used the following price elasticities as inputs:

- Residential: - 0.2
- Commercial: - 0.5
- Industrial: - 0.5

The 2016 forecast used static price elasticities. Elasticities did not vary over time; they remained constant throughout the 20-year forecast period, and did not vary by end-use, for those end-uses that responded to price.[1] The same elasticities were used for both commodity and carbon price.

The elasticities were incorporated into the model by changing fuel share. When commodity and/or carbon price changed, the percentage the natural gas provided for an end use changed based on the elasticity value for the sector. For example, if the price of natural gas increased by 50%, then demand from the Residential sector fell by 10% and demand from the Commercial and Industrial sectors decreased by 25%, ceteris paribus.

[1] Some end-uses, such as cooking or a variety of industrial end-uses, were assumed to be unlikely to respond to normal pricing signals, because their users choose fuels based on criteria other than price.

2 Price Elasticity of Demand: Theoretical Context

The price elasticity of demand reflects how demand for a good changes in response to a change in the price of that good, ceteris paribus. Note that this memo only discusses "own-price" elasticity – how demand changes in response to changes in price of that good only (natural gas in this case)[2]. Other types of elasticity include:

- *Price elasticity of supply:* the *change in supply* in response to a *change in price* (e.g. change in supply for natural gas in response to a change in price).
- *Cross-price elasticity:* the *change in demand* in response to a *change in price of another good* (e.g. change in demand for natural gas in response to change in the price of electricity).
- *Income elasticity:* the *change in demand* in response to a *change in income* (e.g. change in demand for natural gas in response to a change in income).

The decisions a consumer makes in response to a change in price are influenced by several factors including [1]:

- The ease to switch to substitutes
- The prices of substitutes
- The expected future price of the good and substitutes
- Changes in income

The effects of these factors are difficult to tease apart.

Price elasticity is represented numerically and calculated as the percent change in quantity demand divided by the percent change in price. A value of >1 is considered 'elastic', as the change in quantity demanded is greater than the change in price. A value of <1 is considered 'inelastic', as the change in quantity demanded is less than the change in price [1]. Price elasticity of demand is typically negative, as an increase in price causes a decrease in demand, and vice versa.

Demand for energy, including natural gas, tends to be inelastic because it is required to provide necessary services such as heating and fuel [1].

When the price of a fuel increases, a consumer typically responds in one of two ways [2]:

- Use the fuel more efficiently
- Switch to another fuel

The following sub-sections briefly discuss some of the key considerations for price elasticity of demand, with a focus on natural gas.

[2] Note that in the load forecast, the commodity price of natural gas is used as the input for natural gas price. As discussed in Section 5.1, we recognize that the commodity price is a portion of a customer's natural gas bill. For the purposes of this memo, "natural gas price" is the price used as an input to the load forecast.

2.1 Variation over Time

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

Economic theory defines two time periods:

- *Short run:* the quantity of at least one input is fixed (i.e., capital) and the quantities of other inputs can vary (i.e., labour).
- *Long run:* The quantities of all inputs can vary.

In the context of natural gas demand, it would be likely that operations could vary in the short run (i.e. a homeowner changing thermostat setting) while capital is fixed (i.e. the natural gas furnace remains the main heating source) [2]. In the long run, operations and capital can both vary. When a furnace reaches its end of life, for example, the consumer could respond to pricing signals by replacing it with a more efficient furnace or another type of heating equipment that does not use natural gas. Short run responses tend to be temporary in nature.

In the long run, people can change more inputs and behaviour in response to prices, therefore price elasticity of demand tends to be more elastic in the long run compared to the short run (i.e., long run elasticities are larger absolute values). Long run responses tend to be more permanent changes, compared to short run responses.

2.2 Sectoral Differences

Sectors are likely to respond differently to changes in the price of natural gas. Some of these key differences are listed below:

Residential

- Residential consumers typically use natural gas for cooking, and space and water heating.
- Residential buildings typically cannot easily switch fuels.

Commercial

- Similar to the Residential sector, the Commercial sector mainly uses natural gas for space and water heating.
- Some Commercial buildings (typically larger ones) can switch fuels relatively easily.

Industrial[3]

- The industrial sector tends to be a large energy consumer, therefore has more to gain from substituting to alternative fuels in response to changes in price.
- Many industrial facilities can switch between gas, oil and electricity relatively easily.
- Large businesses tend to have more resources dedicated to energy management at facilities and are keen to maximize profits [1].

[3] Note that for the purposes of this memo, we do not consider natural gas used to generate electricity.

2.3 B.C Carbon Tax

The effect on demand by a change in the commodity price may differ from the effect on demand from the change in tax. Studies suggest that people react differently to changes in tax compared to changes in other components of prices that are determined by markets [3] (a concept known as "tax salience"). In a 2014 paper, Rivers and Schaufele found that the effect of an increase in B.C carbon tax on gasoline demand was 7.1 times larger than the effect from the identical increase in the market price of gasoline [4].

Research on tax saliency shows that consumers are more responsive to taxes that are visible. In the case of B.C, the future value of the carbon tax is known, unlike the future price of natural gas. Rivers and Schaufele suggest that consumers' concern about the environment may also contribute to their responsiveness to the carbon tax [4].

At this time, the literature on elasticity to a change in carbon price is limited. We suggested that FortisBC keep abreast of future work on this subject in case future forecasts want to differentiate responses to a change in carbon price compared to a change in commodity price.

3 Price Elasticity Values

There is significant literature on price elasticity for demand for energy and various fuels, including natural gas, with a wide range of estimates[4] [5] [6].

For this memo, Posterity Group conducted a light literature review and collected estimates for price elasticities for natural gas demand, and when possible, differentiated by sector and short/long run. We focused on studies that used data from Canada or the Pacific Northwest (i.e. similar climates), from economically developed countries, and that had been completed since 1990. The collection of estimates is included in Appendix A. Please note that this is by no means an exhaustive list of estimates available.

The following sections summarize our findings.

Survey of Price Elasticities used by Utilities in Sales Forecasts

In 2006, Itron Inc. conducted a survey of gas and electric utilities in Canada and the U.S to determine how they account for commodity prices in their sales forecasts [12]. They found the following average price elasticity values were used in sales forecasts:

	SR	*LR*
Residential	*-0.096*	*-0.173*
Commercial	*-0.080*	*-0.125*
Industrial	*-0.068*	*-0.142*

Note that only 4 Canadian gas utilities were included in the survey.

3.1 Directional Conditions

Theory and the literature provide the following directional conditions for price elasticity of demand for natural gas:

- *Energy demand is typically inelastic with respect to price* (i.e. >1). This means that consumers are not very responsive to price signals, as consumers tend to rely on natural gas for essential services, such as space and water heating.
- *Short-run elasticities are typically less than long-run elasticities*, as it is difficult for consumers to change the efficiency of equipment or fuel source in the short run. Over time, consumers can change more (i.e., operations and capital). Note that some Industrial consumers can be highly sensitive to prices in the short run (thus more elastic) as they can quickly and easily switch fuels.
- *The Industrial sector tends to be more elastic* compared to the Residential and Commercial sectors. This is because the Industrial sector tends to use natural gas for more end-uses compared to the other sectors and can more easily fuel switch in the short run.

3.2 Minimum, Maximum and Average Values

In 2017, Labandeira et al conducted a meta-analysis on the price elasticity of energy demand and confirmed that the literature offered a wide range of price elasticity estimates. The authors analyzed 428 papers produced between 1990 and 2016 and found the average elasticity for natural gas to be -0.180 in

[4] Professor Dalh with the Colorado School of Mines developed an online Energy Demand Database [13]. The database includes a bibliography of the Energy Demand Elasticity Database which is a 142-page Word document listing academic papers on the subject. This list is a great resource and demonstrates the volume of literature on the subject.

the short term and -0.684 in the long term [5, p. 554]. While these estimates do not differentiate by sector, they help to bound the range of values one can expect.

Exhibit 1 presents the minimum, maximum and average price elasticity values from the literature sources reviewed. Note that the average values align with the directional conditions from the literature: Industrial is more elastic than Residential and Commercial, and long-run elasticities are larger than short-run elasticities (except for the long-run average for Industrial).

Exhibit 1 – Summary of Price Elasticities from the Literature

	Short Run (SR) Values			Long Run (LR) Values		
	SR Min	SR Average	SR Max	LR Min	LR Average	LR Max
Residential	-0.030	-0.157	-0.670	-0.100	-0.349	-0.880
Commercial	-0.055	-0.206	-0.530	-0.125	-0.429	-0.990
Industrial	-0.067	-0.826	-3.680[5]	-0.142	-0.414	-0.700

Exhibit 2 presents key statistics of the price elasticities estimates aggregated via a high-level literature review.

Exhibit 2 – Summary Statistics on Price Elasticities

	Short Run			Long Run		
	SR Stand Dev	# of SR Data Points	SR Variance	LR Stand Dev	# of LR Data Points	LR Variance
Residential	0.146	17	0.021	0.206	20	0.042
Commercial	0.151	7	0.023	0.301	5	0.091
Industrial	1.295	6	1.677	0.229	4	0.052

Due to small number of data points and range of estimates in this dataset, we do not recommend using average SR or LR values directly. However, FortisBC should consider using the minimum and maximum values as bounds for the elasticity values used in scenario analysis.

[5] Note that -3.860 is an outlier in the values collected, as it is the only elastic (>1) value. It was included in range of estimates as the value is from a relatively recent study and used B.C data, which suggests that although it is an outlier, it may be indicative of the maximum elasticity for the Industrial sector.

3.3 Estimates Most Applicable to FortisBC

The price elasticity estimates provided to the literature use a variety of approaches to generate estimates and a variety of types of data, we wanted to identify the sources and estimates that may be most applicable to FortisBC to use as "reference case" values.

Short-Run Values

Davis and Muehlegger (2010) is one of few sources included in our literature review that provides short-run estimates for all sectors. [7]. Their estimates are based on a seventeen-year panel dataset of natural gas sales and prices from the U.S Department of Energy, are statistically significant, and the authors state that the values are conservative.

Exhibit 3 – Short-Run Estimates Price Elasticities for Natural Gas from David and Muehlegger

	Estimated Short-Run Price Elasticities of Demand
Residential sector	-0.278
Commercial sector	-0.205
Industrial sector	-0.709

Although these values are estimated using U.S data, it is from a relatively robust dataset using relatively recent data. They also align with the directional conditions from the literature.

Long-Run Values

The State of Washington's Department of Commerce publishes the long-term price elasticities of demand for various fuels used in their Carbon Tax Assessment Model. These values are "the product of an extensive literature search of fuel and sector specific price elasticity of demand values [8]." Their default values for natural gas by sector are presented in Exhibit 4.

Exhibit 4 – Long-Run Price Elasticities for Natural Gas used by Washington State [9]

	Long-Run Price Elasticities of Demand
Residential sector	-0.380
Commercial sector	-0.350
Industrial sector	-0.700

The state of Washington uses these elasticities in their modelling of GHG and fiscal impacts of a carbon tax to help inform policy for the State, which suggests they have likely been subject to scrutiny. These values also align with the directional conditionals provided in Section 3.1.

4 Recommendations

Based on this memo, Posterity Group recommends the following price elasticity values and how to incorporate price elasticity in the model.

4.1 Elasticity Values

The literature on price elasticity of demand for energy, including natural gas, provide a range of estimates. There is no "right" answer for what the price elasticity for natural gas is, especially specific to B.C and the FortisBC service territory. With this in mind, we recommend FortisBC consider using the following price elasticity values for the reference case, and minimum/maximum values to bound a scenario analysis:

Exhibit 5 – Suggested Elasticity Values

	Short Run (SR) Values			Long Run (LR) Values		
	SR Min	SR Reference Case	SR Max	LR Min	LR Reference Case	LR Max
Residential	-0.030	-0.278	-0.670	-0.100	-0.380	-0.880
Commercial	-0.055	-0.205	-0.530	-0.125	-0.350	-0.990
Industrial	-0.067	-0.709	-3.680	-0.142	-0.700	-0.700

Note that these values diverge from the directional conditions in the following ways:

- Industrial sector: Short run maximum and reference case values are larger than long run values.
- Industrial sector: short run maximum is elastic.

4.2 Modelling Price Elasticity

We recommend FortisBC incorporate price elasticities into the load-forecasting model in the following ways:

- *Vary elasticity by sector*, as per the suggested values in Exhibit 5. (Note that the previous load-forecast differentiated elasticity by sector.)
- *Incorporate temporal considerations* to the model:
    - Short run response: change UEC by end-use, prior to the equipment's end of life. This will be combined with the changes from codes and standards.
    - Long run response: change fuel share by end-use, when the equipment reaches end of life using the existing fuel-share solver approach. We currently do not have sufficient information to vary elasticity by year or by the delta in price change.
- *Use the same elasticity for commodity price and carbon price* until there is enough literature on the subject to have a different elasticity value for carbon price. FortisBC may wish to explore the differences in elasticity to commodity versus carbon price in more depth, which we have not done for this memo.

5 Other Considerations

FortisBC may wish to consider the following items in future load forecasts and planning exercises. We have not incorporated these items at this time, as they are either too complex or we do not have enough information at this time to make a recommendation on how to incorporate the item into the forecast.

5.1 Retail Rates versus Commodity Price of Natural Gas

In this memo and for the load forecast, we discuss price of natural gas as a “good” people buy. However, when consumers buy gas from a utility such as FortisBC, they are not paying the commodity price. Customers pay a retail rate which vary depending on rate class.

FortisBC purchases natural gas from producers and sells it to customers at cost.[6] The rate shown on a customer’s utility bill is a combination of the commodity price, delivery charges, storage and transportation, and taxes, including the B.C carbon tax.[7] The rates FortisBC charges to customers must be approved by the British Columbia Utilities Commission (BCUC) and are reviewed quarterly [10]. Rates for the upcoming 12 months are based on forecasted commodity prices. Midstream cost and distribution costs are determined via rate-setting proceedings between FortisBC and the BCUC.

Due to the structure of a customer’s bill and the process to set rates, a change in the commodity price will only be reflected on a customer’s bill in the following quarter. This results in a time lag between an increase in the commodity price and an increase in a customer’s bill [1, p. 4].

While the difference between retail rates and commodity price for natural gas is worth noting, we do not suggest at this time that FortisBC use retail rates instead of commodity price as a driver of demand in the LTGRP. Based on discussions with FortisBC integrated resource planning staff, we came to this conclusion for the following key reasons:

- The literature review on price elasticity of demand suggests that a change in commodity price drives changes in demand
- Commodity price is a direct flow through for FortisBC as natural gas is cold at cost therefore the company does not profit from commodity sales
- Forecasted long-run retail rate changes are outputs from the LTGRP analysis, therefore including them as inputs to the LTGRP would create a feedback loop, which would create significant and undesirable complexity to the forecasting model.

5.2 Cross-price elasticity

Recall that cross-price elasticity is how demand for a good changes in response to a change in price of other goods. FortisBC may wish to consider cross-price elasticity when modelling fuel switching, as the

[6] Note that customers can sign a consumer agreement with a gas marketer to purchase natural gas at a fixed rate for a 1-5 year contract. For the purposes of selected price elasticities, we will assume all FortisBC customers buy natural gas from FortisBC.

[7] Using rates from FortisBC’s website, the percentage of a customer’s bill that reflects the cost of gas ranges from 23% for Rate 1 customers to 54% for Rate 5 customers.

cost of other fuels impacts demand for natural gas. Note that cross-price elasticity is discussed in more detail in a separate document.

5.1 Asymmetrical Demand Responses

Studies suggest that there may be asymmetrical demand responses. This means that there can be a difference in the magnitude of a change in demand depending if a price increases or decreases [11]. This means that, for example, a 10% increase in price may result in a 20% decrease in demand while a 10% decrease in price may lead to a 5% increase in demand.

A short run example is if natural gas prices fall, Residential consumers are unlikely to increase the temperature setting on their thermostats. However, if natural gas prices increase, Residential consumers are likely to decrease the temperatures setting on their thermostat. In this example, Residential customers are less sensitive to a decrease in price compared to an increase in price. A long run example is if higher natural gas prices induce investment in energy efficiency equipment such that demand is reduced, a drop in natural gas prices is not going to cause customers to revert to older vintages of equipment.

At this time, we have not researched this topic in sufficient depth to vary elasticity depending on if the price of natural gas increased or decreased.

5.2 Elasticity Change over Time

Note that price elasticities may change over time (please see Ryan and Razek's 2012 paper that examines how elasticities evolve in response to changes in prices over time in Canada. They suggest energy consumers are becoming less sensitive to changes in price). However, we do not have enough information to forecast what elasticities will be in the future and thus have not included it at this time.

5.3 Income-elasticity

Income-elasticity is how changes in income effect demand for a good. As economic growth is already a drive in the model, FortisBC may wish to look at how income (or revenue for Commercial and Industrial) affect demand.

5.4 Interactive effects between codes & standards and elasticity

Consumers have less choice in efficiency when equipment standards and building codes create minimum standards for the market. Long-run elasticities should decrease with less choice in the market [12].

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Appendix A Price Elasticity Estimates from the Literature

The following table is a collection of price elasticity estimates from the literature. Note that we focused on studies that used data from Canada or the Pacific Northwest (i.e. similar climates), from economically developed countries, and that had been completed since 1990. The table is organized by sector (Residential, Commercial then Industrial)

Short Run	Long Run	Sector	Source (Year)	Data Location	Data Type and/or Years	Notes
-0.670		Residential	Ryan and Razek (2012)	BC, Canada	Estimated (1960-2006)	
-0.240	-0.510	Residential	Bernstein & Madlener (2011)	12 OECD Countries	1980-2008 (annual)	
-0.190	-0.260	Residential	Payne et al (2011)	Illinois, US	1970-2007 (annual)	
-0.180	-0.500	Residential	NREL (2006)	Pacific Coast, US	1977-2004	
-0.170	-0.280	Residential	U.S Energy Information Administration (2014)	US	NEMS modelled 2015-2040	Own-price elasticity for residential demand in the US building sectors when fuel price is doubled between 2015 and 2040
-0.150	-0.210	Residential	U.S Energy Information Administration (2014)	US	NEMS modelled 2015-2040	Own-price elasticity for residential demand in the US building sectors when fuel price is cut in half between 2015 and 2040
-0.130	-0.680	Residential	Dalh (1993)	US	aggregated data from 9 studies post 1980	

Short Run	Long Run	Sector	Source (Year)	Data Location	Data Type and/or Years	Notes
-0.120	-0.360	Residential	Bernstein & Griffin (2006)	US	1977-2004 (annual)	
-0.102	-0.365	Residential	Liu (2004)	OECD	1978 - 1999	
-0.096	-0.173	Residential	Itron (2006)	US and Canada	Survey Data from utilities	These are the elasticities utilities use in their sales forecasting. This is the average from the survey data
-0.090	-0.180	Residential	Joutz et al (2008)	US	1980-2006 (monthly)	
-0.042		Residential	Costello (2006)	US	RSTEM derived average values in response to Henry Hub spot prices	
-0.040	-0.160	Residential	Bernstein & Madlener (2011)	United States	1980-2008 (annual)	
-0.030	-0.100	Residential	Nilsen et al (2008)	12 European Countries	1978-2002 (annual)	
-0.030	-0.260	Residential	Bohi and Zimmerman (1984)			
	-0.500	Residential	Maruejols et al (2009)	Canada	1960-2007 (annual)	
	-0.880	Residential	Gholami (2014)	BC, Canada		

Short Run	Long Run	Sector	Source (Year)	Data Location	Data Type and/or Years	Notes
	-0.380	Residential	Washington State CTAM (2015)	various	from literature review	Washington State's CTAM model provides price elasticities for various fuels from the literature that are used in the CTAM model. This is the 'default' value.
	-0.100	Residential	UK Department of Energy & Climate Change (2016)	UK	2005-2012	
	-0.647	Residential	Alberinia et al (2011)	US	1997–2007	
-0.11	-0.20	Residential	Hausman and Kellogg (2015)	US	estimated using EIA data (2001-2015)	
-0.278		Residential	Davis and Muehlegger (2010)	US	estimated using data from 1989 to 2007	
	-0.24	Residential	Arora (2014)	US	Modelled (1993-2013)	The elasticity calculations are based on series of weekly, monthly, and quarterly frequencies whose sample periods both exclude and include shale.
-0.260	-0.990	Commercial	Dalh (1993)	US	aggregated data from 9 studies post 1980	

Short Run	Long Run	Sector	Source (Year)	Data Location	Data Type and/or Years	Notes
-0.223	-0.450	Commercial	U.S Energy Information Administration (2014)	US	modelled	
-0.080	-0.125	Commercial	Itron (2006)	US and Canada	survey data from utilities	These are the elasticities utilities use in their sales forecasting. This is the average from the survey data
-0.055		Commercial	Costello (2006)	US	RSTEM derived average values in response to Henry Hub spot prices	
	-0.350	Commercial	Washington State CTAM (2015)	various	from literature review	Washington State's CTAM model provides price elasticities for various fuels from the literature that are used in the CTAM model. This is the 'default' value.
-0.530		Commercial	Ryan and Razek (2012)	BC, Canada	Estimated (1960-2006)	
-0.09	-0.23	Commercial	Hausman and Kellogg (2015)	US	estimated using EIA data (2001-2015)	
-0.205		Commercial	Davis and Muehlegger (2010)	US	estimated using data from 1989 to 2007	
-0.269		Industrial	Costello (2006)	US	RSTEM derived average values in	

Short Run	Long Run	Sector	Source (Year)	Data Location	Data Type and/or Years	Notes
					response to Henry Hub spot prices	
-0.068	-0.142	Industrial	Itron (2006)	US and Canada	survey data from utilities	These are the elasticities utilities use in their sales forecasting. This is the average from the survey data
-0.067	-0.243	Industrial	Liu (2005)	OECD	1978 - 1999	
	-0.700	Industrial	Washington State CTAM (2015)	various	from literature review	Washington State's CTAM model provides price elasticities for various fuels from the literature that are used in the CTAM model. This is the 'default' value.
-3.680		Industrial	Ryan and Razek (2012)	BC, Canada	Estimated (1960-2006)	
-0.16	-0.57	Industrial	Hausman and Kellogg (2015)	US	estimated using EIA data (2001-2015)	
-0.709		Industrial	Davis and Muehlegger (2010)	US	estimated using data from 2001 to 2007	

Attachment 75.4

2022 LTGRP Volumes Summary (TJ's)

Reference Volume

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Residential	73,759	72,670	71,555	70,617	69,739	68,887	68,054	67,293	66,545	65,812	65,090	64,379	63,674	63,042	62,474	61,922	61,404	60,918	60,446	60,007	59,597
Commercial	64,297	64,717	65,073	65,359	65,733	66,072	66,436	66,836	67,223	67,661	68,155	68,641	69,140	69,650	70,209	70,758	71,332	71,892	72,497	73,100	73,728
Industrial	66,880	65,986	65,139	64,931	64,683	64,300	64,236	64,194	64,209	64,175	64,142	64,175	64,778	64,751	64,713	64,678	64,735	64,723	64,689	64,696	64,788
Total	204,936	203,373	201,767	200,908	200,154	199,258	198,725	198,322	197,978	197,647	197,387	197,194	197,593	197,443	197,396	197,358	197,471	197,533	197,633	197,802	198,114
Percentage Change Year Ov	-0.65%	-0.76%	-0.79%	-0.43%	-0.37%	-0.45%	-0.27%	-0.20%	-0.17%	-0.17%	-0.13%	-0.10%	0.20%	-0.08%	-0.02%	-0.02%	0.06%	0.03%	0.05%	0.09%	0.16%

Upper Bound Volume

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Residential	77,203	77,648	78,104	78,537	78,950	79,353	79,745	80,123	80,469	80,787	81,095	81,397	81,700	82,002	82,301	82,591	82,869	83,133	83,396	83,655	83,906
Commercial	69,834	71,572	73,361	75,112	77,386	79,491	81,477	83,338	85,546	87,722	89,880	91,990	94,494	96,619	98,808	100,891	103,076	105,314	107,684	109,987	112,203
Industrial	75,353	76,212	76,452	77,380	82,253	83,226	84,024	87,089	88,170	89,003	89,689	90,960	93,717	94,468	95,372	97,096	98,225	99,221	100,577	102,791	103,919
Total	222,391	225,432	227,917	231,028	238,589	242,070	245,245	250,551	254,184	257,512	260,664	264,347	269,910	273,088	276,481	280,578	284,170	287,668	291,657	296,433	300,028
Percentage Change Year Ov	0.97%	1.37%	1.10%	1.36%	3.27%	1.46%	1.31%	2.16%	1.45%	1.31%	1.22%	1.41%	2.10%	1.18%	1.24%	1.48%	1.28%	1.23%	1.39%	1.64%	1.21%

Diversified Energy Planning Volume

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Residential	71,366	69,752	68,319	67,077	65,896	64,762	63,675	62,673	61,746	60,769	59,831	58,953	58,105	57,280	56,545	55,827	55,160	54,560	54,014	53,519	53,182
Commercial	62,455	62,561	62,455	62,294	62,158	61,919	61,618	61,448	61,426	61,040	60,707	60,436	60,133	59,931	59,754	59,659	59,587	59,545	59,536	59,611	59,702
Industrial	65,777	64,691	63,705	63,402	63,099	62,733	62,581	62,467	62,453	62,311	62,174	62,135	62,652	62,543	62,440	62,317	62,342	62,339	62,315	62,341	62,516
Total	199,598	197,004	194,479	192,773	191,153	189,414	187,873	186,589	185,625	184,120	182,712	181,523	180,890	179,753	178,738	177,804	177,090	176,444	175,865	175,471	175,401
Percentage Change Year Ov	-1.15%	-1.30%	-1.28%	-0.88%	-0.84%	-0.91%	-0.81%	-0.68%	-0.52%	-0.81%	-0.76%	-0.65%	-0.35%	-0.63%	-0.56%	-0.52%	-0.40%	-0.36%	-0.33%	-0.22%	-0.04%

Deep Electrification Volume

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Residential	70,269	67,960	65,612	63,265	60,970	58,485	56,013	53,609	51,128	48,672	46,232	43,689	41,195	38,746	36,351	34,022	31,853	29,944	28,295	26,874	25,675
Commercial	54,251	52,163	49,988	47,902	45,724	43,440	41,318	39,275	37,185	35,245	33,520	31,848	30,263	28,878	27,644	26,486	25,457	24,504	23,638	22,527	21,764
Industrial	64,815	63,295	62,605	62,295	60,119	59,598	59,027	58,721	58,092	55,721	55,508	54,874	51,007	50,902	50,804	50,467	49,354	49,244	48,607	46,488	46,216
Total	189,336	183,418	178,204	173,462	166,812	161,523	156,358	151,605	146,406	139,639	135,260	130,411	122,465	118,525	114,799	110,975	106,665	103,692	100,540	95,888	93,655
Percentage Change Year Ov	-2.47%	-3.13%	-2.84%	-2.66%	-3.83%	-3.17%	-3.20%	-3.04%	-3.43%	-4.62%	-3.14%	-3.58%	-6.09%	-3.22%	-3.14%	-3.33%	-3.88%	-2.79%	-3.04%	-4.63%	-2.33%

BCH Deep Electrification

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Residential	72,361	70,733	69,145	67,871	65,341	62,633	59,989	57,421	54,765	51,902	49,086	46,101	43,112	40,233	37,771	35,788	33,933	32,194	30,516	28,884	27,311
Commercial	51,666	47,954	43,901	39,782	35,458	31,042	26,632	22,178	17,579	13,716	10,630	7,505	6,034	5,798	6,113	6,292	6,329	6,235	6,006	5,654	5,184
Industrial	62,574	60,753	59,130	57,664	57,026	56,272	55,518	54,648	53,717	53,787	53,855	53,922	54,006	54,077	54,012	53,973	54,095	54,285	54,485	54,687	54,833
Total	186,601	179,441	172,176	165,317	157,826	149,948	142,139	134,248	126,062	119,406	113,571	107,528	103,151	100,108	97,896	96,053	94,357	92,715	91,007	89,225	87,328
Percentage Change Year Ov	-3.72%	-3.84%	-4.05%	-3.98%	-4.53%	-4.99%	-5.21%	-5.55%	-6.10%	-5.28%	-4.89%	-5.32%	-4.07%	-2.95%	-2.21%	-1.88%	-1.77%	-1.74%	-1.84%	-1.96%	-2.13%

Price Based Volume

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Residential	73,585	72,372	71,193	70,030	68,885	67,741	66,595	65,503	64,437	63,446	62,506	61,677	60,942	60,216	59,517	58,834	58,198	57,617	57,120	56,685	56,328
Commercial	64,057	64,341	64,525	64,606	64,722	64,755	64,767	64,800	64,813	64,910	65,088	65,279	65,499	65,760	66,099	66,480	66,905	67,376	67,900	68,433	69,001
Industrial	67,659	66,953	66,307	66,319	66,301	66,161	66,272	66,390	66,563	66,691	66,821	67,069	67,819	67,956	68,083	68,213	68,433	68,590	68,729	68,867	69,083
Total	205,301	203,666	202,024	200,955	199,908	198,657	197,634	196,693	195,813	195,046	194,416	194,025	194,260	193,932	193,699	193,526	193,536	193,583	193,750	193,985	194,412
Percentage Change Year Ov	-0.62%	-0.80%	-0.81%	-0.53%	-0.52%	-0.63%	-0.51%	-0.48%	-0.45%	-0.39%	-0.32%	-0.20%	0.12%	-0.17%	-0.12%	-0.09%	0.01%	0.02%	0.09%	0.12%	0.22%

BCH Reference

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Residential	76,468	76,187	75,882	75,770	75,736	75,327	74,914	74,605	74,303	73,794	73,283	72,462	71,706	70,928	70,526	70,078	69,632	69,159	68,682	68,221	67,777
Commercial	64,036	64,704	65,040	65,381	65,731	65,780	66,020	66,129	66,491	66,677	66,855	67,080	68,053	68,226	68,635	69,052	69,508	69,887	70,234	70,798	71,241
Industrial	67,291	67,482	67,713	67,969	69,448	70,933	72,420	73,909	75,405	76,567	77,749	78,945	80,137	81,305	81,813	82,305	82,823	83,335	83,720	84,121	84,431
Total	207,795	208,373	208,635	209,121	210,915	212,039	213,355	214,643	216,199	217,038	217,887	218,487	219,896	220,459	220,974	221,435	221,963	222,382	222,636	223,141	223,450
Percentage Change Year Ov	0.15%	0.28%	0.13%	0.23%	0.86%	0.53%	0.62%	0.60%	0.72%	0.39%	0.39%	0.28%	0.65%	0.26%	0.23%	0.21%	0.24%	0.19%	0.11%	0.23%	0.14%

Economic Stagnation

	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Residential	76,902	77,164	77,241	77,311	77,435	77,534	77,639	77,847	78,067	78,270	78,437	78,537	78,573	78,483	78,268	77,950	77,580	77,242	76,922	76,624	76,353
Commercial	60,912	61,783	62,526	63,375	64,084	64,707	65,495	66,344	67,006	67,722	68,641	69,429	70,126	71,089	72,117	73,124	74,160	75,208	76,296	76,920	77,928
Industrial	63,637	62,095	61,428	61,262	59,302	58,906	58,534	58,431	57,999	55,787	55,739	55,293	51,888	51,963	52,033	51,856	50,895	50,967	50,440	48,663	48,725
Total	201,451	201,042	201,196	201,947	200,821	201,146	201,668	202,623	203,072	201,779	202,817	203,260	200,587	201,534	202,419	202,930	202,634	203,416	203,658	202,207	203,006
Percentage Change Year Ov	-0.11%	-0.20%	0.08%	0.37%	-0.56%	0.16%	0.26%	0.47%	0.22%	-0.64%	0.51%	0.22%	-1.31%	0.47%	0.44%	0.25%	-0.15%	0.39%	0.12%	-0.71%	0.40%

Attachment 75.4.1

2022 LTGRP Cost of Energy Forecast ($/GJ) Per Scenario

Reference Case	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
Cost of Energy	3.979	4.210	4.637	4.744	4.921	5.202	5.220	5.450	5.630	5.605	5.749	5.958	5.901	5.978	6.083	6.055	6.173	6.334	6.298	6.369	6.439

Upper Bound	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
Cost of Energy	6.108	6.596	7.761	8.270	9.095	10.059	9.652	10.257	10.766	10.985	11.270	11.623	11.682	11.974	12.278	12.464	12.781	13.124	13.242	13.477	13.717

Diversified Energy	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
Cost of Energy	4.203	4.627	5.363	5.951	6.614	7.354	7.040	7.699	8.370	8.623	9.001	9.447	9.681	10.034	10.403	10.697	11.025	11.367	11.559	11.824	12.077

Deep Electrification	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
Cost of Energy	5.702	6.091	6.753	6.818	7.266	7.862	8.161	8.670	9.107	9.325	9.655	9.980	9.709	9.957	10.268	10.424	10.838	11.310	11.424	11.381	11.719

BCH Deep Electrification	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
Cost of Energy	3.912	4.485	4.989	5.732	6.342	6.837	7.548	8.243	8.815	9.022	9.285	9.316	9.446	9.602	11.631	13.939	16.211	18.333	20.552	22.749	24.936

Price Based Volume	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
Cost of Energy	5.683	6.091	6.815	6.842	7.269	7.846	8.015	8.389	8.676	8.615	8.650	8.802	8.569	8.653	8.783	8.747	8.921	9.167	9.018	9.140	9.261

BCH Reference Case	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
Cost of Energy	3.979	4.210	4.637	4.744	4.921	5.202	5.220	5.450	5.630	5.605	5.749	5.958	5.901	5.978	6.083	6.055	6.173	6.334	6.298	6.369	6.439

Economic Stagnation	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**	**2041**	**2042**
Cost of Energy	2.999	3.188	3.499	3.473	3.648	3.892	3.935	4.068	4.170	4.216	4.292	4.416	4.373	4.388	4.423	4.461	4.561	4.679	4.572	4.613	4.640