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May 3, 2023

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

Attention: Peter Helland, Director

Dear Peter Helland:

Re: FortisBC Energy Inc. (FEI)

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

Response to the Residential Consumer Intervener Association (RCIA) Information Request (IR) No. 2

On May 9, 2022, FEI filed the LTGRP referenced above. In accordance with the amended regulatory timetable established in British Columbia Utilities Commission Order G-99-23 for the review of the LTGRP, FEI respectfully submits the attached response to RCIA IR No. 2.

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

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

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Commission Secretary
Registered Parties

37. Reference: Exhibit B-6, FEI Response to BCUC IR1, IR 61.9

Hydrogen Development Roadmap

In the response to BCUC IR1 61.9, FEI describes the next steps prior to delivering on-system hydrogen to its customers.

37.1 Please confirm which, if any, of the actions and undertakings in the response to BCUC IR1 61.9 are considered prescribed undertakings under any legislation applicable to FEI.

<u>Response:</u>

FEI's progress at integrating hydrogen into its gas system is still at a preliminary stage. The actions and activities included in the response to BCUC IR1 61.9 (copied in the below list) are proposed components of an integrated hydrogen development action plan aimed at advancing the initial integration steps.

At present, the prescribed undertakings in the *Greenhouse Gas Reduction Regulation* (GGRR) related to hydrogen enable the utility to acquire, by way of production or purchase, hydrogen derived from water using electricity that is generated primarily from clean or renewable resources or is waste hydrogen. This hydrogen may be distributed through the natural gas distribution system to customers or provided to an FEI customer directly and will replace, at least in part, natural gas derived from fossil fuels used by that customer, with both a capped price and volume limit.

Some of the following activities may fall within a prescribed undertaking if the scope of a particular activity is considered part of a hydrogen production project or hydrogen offtake supply agreement. Also, the GGRR may be amended to include the proposed activities as a prescribed undertaking. As discussed in the response to CEC IR1 46.2, absent provincial or federal funding or grants, FEI expects that it will apply to the BCUC for recovery of system expenditures related to enabling hydrogen as an energy source, whether the system expenditures are considered a prescribed undertaking or not.

Actions and Undertakings:

1. Confirmation of hydrogen blending targets and ambitions
2. Annually Updated State of the Art Analysis (SOTA)
3. Feasibility Study Technical Evaluation
4. Field surveys and material compatibility testing
5. Research and innovation
6. Identify Hydrogen availability to supply hydrogen blending and other end-use demand scenarios

7. End-User Equipment Plan
8. Pilot and demonstration projects
9. Codes, Standards, and Regulations
10. Enabling policies
11. Training and education
12. Roll out

37.2 Will FEI's expenditures related to hydrogen infrastructure ("backbone", dedicated pipelines, blending facilities, etc.) be considered prescribed undertakings?

Response:

FEI's expenditures related to hydrogen infrastructure such as "backbone, dedicated pipelines, blending facilities, etc." may be considered a prescribed undertaking to the extent that such activities meet the requirements of a prescribed undertaking in the GGRR as may be amended from time to time.

37.3 Please confirm whether Fortis or FEI expects to own, or partly own, facilities which will produce hydrogen.

37.3.1 If confirmed, please confirm whether these facilities will form part of FEI's rate base.

Response:

Confirmed. In the response to BCUC IR1 62.6, FEI stated that it 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. If FEI were to construct facilities for the purposes of low-carbon hydrogen production, the approved capital costs associated with these facilities would be included in FEI's rate base.

37.4 Please provide a table of specific expenditures (or expenditure categories) related to the incorporation of hydrogen in FEI's system, including expenditures related to the development of hydrogen infrastructure by year over the next five years. Some example expenditures or categories may include pilot projects, expenditures for obtaining regulatory approval to blend hydrogen into the transmission or distribution systems, upgrades to the transmission or distribution systems, investments in hydrogen production facilities or separation facilities, or investments in dedicated hydrogen infrastructure.

Response:

FEI's ongoing efforts at integrating hydrogen into its gas systems are still at a preliminary stage. FEI has not yet developed specific expenditures (or expenditure categories) related to the incorporation of hydrogen into its system, including expenditures related to the development of hydrogen infrastructure by year over the next five years. FEI described the actions it foresees undertaking in the responses to BCUC IR1 61.9 and RCIA IR2 37.1, including how these actions and undertakings are proposed components of an integrated hydrogen development action plan aimed at advancing the initial integration steps. As FEI progresses this broad-based suite of hydrogen development and integration activities, including advancing specific projects or opportunities to produce or procure low-carbon hydrogen, FEI expects to submit applications to the BCUC as required.

38. Reference: Exhibit B-17, FEI Response to RCIA IR1, IR 36.2.2 Attachment; Exhibit B-1, Application, p.4-28

GHGRS Cap and No New Customers

The attachment to FEI's response to RCIA IR1 36.2.2 lists capital expenditures by year.

38.1 Please explain, in general terms, how capital expenditures in the Diversified Energy (Planning) scenario would change if FEI ceased or was otherwise precluded from attaching any new customers across its territory beginning in 2030, due to the GHGRS cap.

Response:

FEI notes that a scenario in which it ceased adding customers would not be a Diversified Energy (Planning) Scenario, but would instead be some other scenario for which many other assumptions would also need to be determined to allow a more complete examination. This clarification applies to all of the RCIA IR2 38 series responses that follow. However, FEI provides the following discussion for each to be responsive.

FEI's growth capital, which is the capital required to add new customers, is only one component of its total capital expenditures. Using FEI's 2023 Approved growth capital[1] as an example, it is approximately 20 percent of FEI's total approved capital expenditures.[2] The majority of FEI's capital is related to sustainment capital, which would still be required in a case where FEI was precluded from adding customers. Further, all of the CPCNs or major projects listed in Section 9.4 of the Application[3] and included as part of the rate impact analysis for the LTGRP are required even if FEI could not add customers after 2030.

Further, if FEI ceased or was otherwise precluded from attaching any new customers starting in 2030, FEI would also lose the incremental revenues from these new customers which in most cases would offset the rate impact of the growth capital expenditures. Therefore, the resulting rate impacts to FEI's customers would actually be similar to those rate impacts shown in Section 9.4 of the Application.

Please refer to Table 1 below which shows that the difference in cumulative rate impacts for residential customers by 2042 is small with and without growth capital starting from 2030 (also with and without the incremental revenue due to demand from new customers as discussed in the response to RCIA IR2 38.3). Please also see Attachment 38.1 for the capital expenditures by year, less growth capital, in the same format as provided in the response to RCIA IR1 36.2.2. For clarity, FEI's growth capital is part of Regular Capital, and as explained in BCUC IR1 75.6, FEI's rate impact analysis for the LTGRP included an escalation of its regular capital to 2042 as a proxy

[1] Approved as part of FEI's Annual Review for 2023 Delivery Rates Decision and Order G-352-22.

[2] 2023 Approved growth capital of $87.531 million divided by FEI's 2023 total approved capital of $435.056 million is approximately 20 percent.

[3] Per discussion in RCIA IR1 35.4, the OCU CPCN project was included in every scenario in the rate impact analysis of the LTGRP. It was only inadvertently excluded from the major project list in Section 9.4 of the Application.

over the 20-year planning period. As such, for the purpose of this information request, FEI had taken out the portion of the escalated growth capital from 2030 onward.

Table 1: Comparison of Cumulative Rate Impact for Residential Customers by 2042 with and without New Customer Additions and Growth Capital starting from 2030

	Cumulative Rate Impact by 2042 (%)							
	Reference		Upper Bound		Diversified Energy (Planning)		Deep Electrification	
Component	With Growth Capital (%)	Without Growth Capital (%)	With Growth Capital (%)	Without Growth Capital (%)	With Growth Capital (%)	Without Growth Capital (%)	With Growth Capital (%)	Without Growth Capital (%)
Delivery	58%	55%	32%	31%	60%	56%	164%	168%
Commodity Related Charges	16%	16%	59%	60%	48%	48%	46%	46%
Carbon Tax	0%	0%	-14%	-14%	10%	10%	24%	24%
Total	73%	70%	77%	76%	118%	114%	235%	239%

38.2 Please re-file the attachment to RCIA IR1 36.2.2 to eliminate capital expenditures related to attaching new customers.

Response:

Please refer to the response to RCIA IR2 38.1.

38.3 Please explain, in general terms, how customer volumes in the Diversified Energy (Planning) scenario would change if FEI ceased or was otherwise precluded from attaching any new customers across its territory beginning in 2030, due to the GHGRS cap.

Response:

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

To respond to this request, the following assumptions were made:

- No change to the DEP Scenario demand up to 2030;
- No changes to the modeled numbers or characteristics of existing customers after 2030;
- After 2030, the total number of customers is frozen at the 2030 number. This means that any demolition of existing customers is added to the number of new customers, but no net customer growth occurs. The characteristics of the new customers in the model were not changed – only their number; and

- The analysis only includes residential, commercial and industrial customers, consistent with the request in RCIA IR2 38.4.

With these assumptions, if FEI ceased to attach new customers, the total customer demand in the DEP Scenario would be expected to decrease by approximately 8 PJ relative to the DEP Scenario as modeled. This is approximately a 4 percent decrease of the total annual demand in 2042.

FEI notes that in this analysis it has modelled no new customers beyond 2030, whereas if the reason for the moratorium was the GHGRS Cap, it may be that FEI could add customers as long as it remained at or under the Cap. Also, since the basis of this hypothetical moratorium is the Cap, the analysis is very different from the analysis conducted for BCUC IR2 93.1 and 93.2, which examines a "worst-case scenario" resulting in a moratorium on new customers beginning in 2023 as a result of the RG Program Application not being approved. In this analysis for RCIA, it is assumed that rebuilds (new buildings that replace demolitions) could be reconnected to the gas system. In the analysis for BCUC IR2 93.1, demolitions are assumed to leave the gas system permanently.

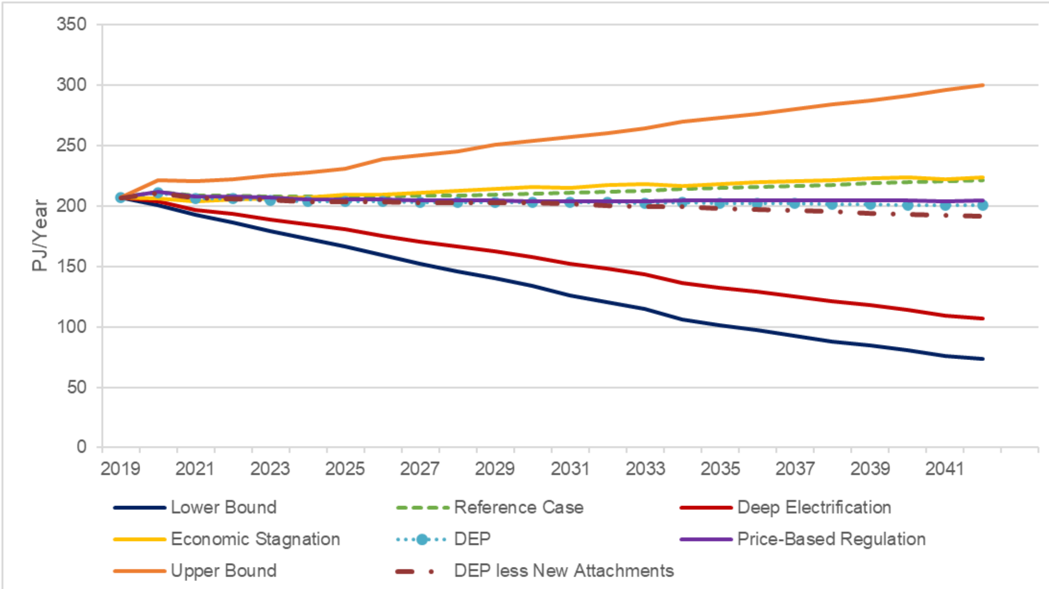
38.4 Please re-file Figure 4-9 on page 4-28 from the Application showing the change in annual demand if FEI ceased or was otherwise precluded from attaching any new customers across its territory beginning in 2030.

<u>Response:</u>

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

Figure 1 below provides an updated version of Figure 4-9. The original DEP dataset is shown alongside the DEP dataset after the demand for new customers is excluded. The updated data is based on the calculations provided in the response to RCIA IR2 38.3.

Figure 1: Annual Demand Scenarios – Residential, Commercial, and Industrial Customers after the Exclusion of New Customers (Pre-DSM Demand)



38.5 Please confirm or otherwise explain whether no longer attaching customers would result in FEI avoiding the need for any capacity upgrade projects.

Response:

Not confirmed. Capacity driven projects, such as those listed in the attachment to RCIA IR1 36.2.2 referenced above (Capacity Upgrades (VITS, CTS, ITS)) are driven by the peak day energy demand of the various components of the system. Regardless of whether new customers continue to be attached, that peak day energy demand could change, requiring additional capacity upgrade projects. Reasons for a change in the peak day energy demand include, but are not limited to:

1. An increase in peak day energy requirements of existing customers, whether a single large customer or in aggregate for a large number of smaller customers;
2. A decrease in the peak day temperature, wherein the extreme cold temperatures experienced throughout FEI's service territory become even colder; or
3. A material decrease in the energy density of the gaseous fuel that FEI is delivering to its customers, such as would be the case if and when large amounts of hydrogen are blended into the natural gas stream.

39. Reference: Exhibit B-6, FEI Response to BCUC IR1, IR 61.3

Dedicated Hydrogen Distribution Infrastructure

In the response to BCUC IR1 61.3, FEI states:

> 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.

39.1 Please confirm whether FEI has been granted franchises or exclusive rights by municipal or other authorities to distribute hydrogen through hydrogen-dedicated pipelines.

39.1.1 If not confirmed, please explain the steps FEI will take to obtain these franchises or rights.

<u>Response:</u>

FEI is in the early days of evaluating blending and integration of hydrogen in distribution pipelines and at this time FEI's efforts with municipalities have been focused on discussing the decarbonization of the gas distribution system, including opportunities for 100 percent hydrogen delivery where suitable. At the appropriate time, FEI will determine which regulatory and other approvals are required, and will engage with municipalities and all other relevant authorities to obtain appropriate approvals.

39.2 Please explain why FEI is the appropriate entity to distribute hydrogen through dedicated infrastructure, as opposed to an unregulated Fortis affiliate or an unrelated entity who obtains a franchise or rights.

<u>Response:</u>

Given FEI's extensive experience as a regulated gas distribution utility, FEI is well placed to distribute hydrogen through dedicated infrastructure.

Any entity distributing hydrogen through dedicated infrastructure would likely be a public utility that is regulated by the BCUC. The *Utilities Commission Act* (UCA) defines a "public utility" as a person who owns or operates in BC, equipment or facilities for

> (a) the production, generation, storage, transmission, sale, delivery or provision of electricity, natural gas, steam or **any other agent for the production of light, heat, cold or power** to or for the public or a corporation for compensation, [Emphasis added]

Since hydrogen will likely be used for heat or power, any entity producing, generating, storing, transmitting or selling it will fall into the definition of a public utility, and will therefore be regulated by the BCUC, subject to any exemption that may be granted by the BCUC.

40. Reference: Exhibit B-9, FEI Response to BCOAPO IR1, IR 4.3; Exhibit B-6, FEI Response to BCUC IR1, IR 35.3; Exhibit B-12, FEI Response to BCSEA IR1, IR 14.3

Cost of DSM Compared to Acquiring RNG and Hydrogen

In the response to BCOAPO IR1 4.3, FEI states:

> The MTRC test uses an avoided cost based on a Zero-Emissions Energy Alternative (ZEEA) that is defined in the DSM Regulation as the long run marginal cost of clean electricity in BC. Throughout the forecast period, the assumed cost of the ZEEA is higher than either the avoided cost of natural gas or the avoided cost of renewable and low-carbon gas used in the TRC test. Using the MTRC test as one of the screens in the OR function allows measures to be included in the potential early in the forecast period, therefore ensuring that the cost of low-carbon energy is considered in identifying those DSM measures that are cost-effective. Since these tests compare the cost of DSM against the cost of acquiring resources, they effectively optimize the resource mix.

In the response to BCUC IR1 35.3, FEI states:

> 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.

In the response to BCSEA IR1 14.3, FEI states:

> There were no scenarios in which the marginal cost of renewable or low-carbon gases rose to the point where their avoided cost was greater than the ZEEA. In summary, the MTRC was the dominant determination of whether a measure was cost-effective. In the scenarios considered, therefore, the RNG cost did not affect the cost-effectiveness of individual measures.

40.1 Please explain why FEI would pursue DSM expenditures which pass the MTRC test but not the TRC, if there is the alternative to achieve the same GHG emissions reductions through the acquisition of low-carbon gases (RNG or hydrogen, on-system or off-system), considering RNG and hydrogen are projected to be lower cost than any DSM expenditures which are only cost effective when considering the zero-emissions energy alternative. Please respond from FEI's perspective as well as the customer's perspective.

<u>Response:</u>

Please refer to the response to BCUC IR1 74.2 which summarizes FEI's emission reduction initiatives needed to meet the proposed GHGRS cap in 2030 and the legislated target in 2040 as part of its Clean Growth Pathway. As discussed, the DEP Scenario was designed specifically to undertake all available and reasonable GHG emission reduction activities to meet the 2030 proposed GHGRS cap and the 2040 legislated targets. Choosing to pursue DSM (including measures that pass both the MTRC and TRC) or renewable and low-carbon gases is not a binary or a mutually exclusive decision given both resources are necessary to meet targets.

In a hypothetical scenario where there was a clear excess in potential of both DSM and renewables and low-carbon gases obtainable, FEI would prioritize acquisition of resources that had the lowest greenhouse gas reduction cost to customers, while considering the principle of equity amongst rate classes. Those low-cost DSM measures would typically be correlated with a high TRC cost-effectiveness. In addition, FEI's acquisition of DSM resources would have to continue to comply with the DSM Regulation (e.g., meeting adequacy requirements by offering programs such as energy efficiency education, programs for low-income customers and Indigenous customers) regardless of their greenhouse gas reduction cost.

40.1.1 Please elaborate on the factors which FEI would consider when deciding whether to pursue DSM measures versus achieving the same GHG reductions by acquiring low-carbon gas supplies.

Response:

Please refer to the response to RCIA IR2 40.1 for additional context on why both DSM and renewable and low-carbon gases will be required to meet the GHG reduction targets. In a hypothetical scenario where there was excess potential of both DSM and renewable and low-carbon gases, the following potential factors would be considered:

- Resource with the lowest greenhouse gas reduction cost to the customer;
- Customer acceptance and preference;
- Ease of resource acquisition; and/or
- Shortest schedule to acquire.

40.2 If the MTRC test was amended to use the avoided cost of RNG or hydrogen instead of ZEEA, how would this affect the DSM expenditure plan and expected GHG reductions from DSM programs?

Response:

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

If the MTRC test was amended to use the avoided cost of RNG or hydrogen instead of ZEEA, there would be a modest difference in the results as the avoided cost of “the next GJ of the cheapest low-carbon gas” was assumed to be only approximately 15 percent lower than the ZEEA in most years. As a result, measures currently with marginal MTRC values,[4] may not pass. Therefore, the savings would be somewhat reduced, as would planned DSM expenditures and anticipated GHG emission reductions. The effect would be most pronounced in the Residential Program Area.

40.3 Provide FEI’s views whether the MTRC test should be amended to use the avoided costs of RNG and hydrogen once these low-carbon gases become more widely available.

Response:

FEI would not be opposed to such an amendment. However, the components of the MTRC calculation outlined in the DSM Regulation are determined by the Province, not FEI.

40.4 Could FEI achieve the GHG reductions projected in the Diversified Energy Planning scenario by reducing DSM expenditures (for example, by reducing incentives to 50% of the incremental cost of the measure), while increasing the amounts of low-carbon gas purchased? Please explain why or why not.

Response:

Please refer to the response to RCIA IR2 40.1.

[4] Please refer to the response to BCSEA IR1 14.1 for the list of measures in the DEP that pass the MTRC only or both the TRC and MTRC.

41. Reference: Exhibit B-9, FEI Response to BCOAPO IR1, IR 5.6;

FEI CPCN FOR THE TILBURY LNG STORAGE EXPANSION PROJECT, Exhibit B-15, FEI Response to BCUC IR1, IR 8.1;

FEI CPCN FOR THE TILBURY LNG STORAGE EXPANSION PROJECT, Exhibit B-17, FEI Response to BCOAPO IR1, IR 5.1

Interior Transmission System LNG Resiliency Project

In the response to BCOAPO IR1 5.6, FEI states:

> In addition to these two major projects, FEI is also considering a number of additional on-system resiliency projects over the 20-year horizon, as discussed in Section 7.5.2 of the Application… These potential investments consist of:
>
> 1) Interior Transmission System Resiliency Solution – Currently envisioned as an LNG liquefaction, storage, and regassification facility in the Vernon area of the Okanagan region.

In the response to BCUC IR1 8.1 from the Tilbury LNG Storage Expansion CPCN proceeding, FEI explains why the Minimum Resiliency Planning Objective ("MRPO") does not apply to the Interior:

> The Lower Mainland system configuration, load and geography are unique; therefore, the resiliency considerations for the Lower Mainland associated with a no-flow event on the T-South system do not necessarily apply to the Vancouver Island and the Interior service areas. The Lower Mainland customer load, which makes up the largest share (approximately 60 percent) of the demand on FEI's system, has the least amount of resiliency to upstream supply disruptions. In contrast,
>
> - Interior customers have access to greater pipeline connectivity (i.e., multiple pipeline interconnections to T-South and TC Energy) compared to the Lower Mainland and Vancouver Island, which greatly increases system resiliency for the Interior region.

41.1 Considering the response to BCUC IR1 8.1 from the TLSE CPCN, proceeding, please explain why FEI has included a resiliency project for the Okanagan region.

Response:

FEI's response to BCUC IR1 8.1 was intended to highlight why the MRPO as defined in the TLSE Project CPCN Application for the CTS is not applicable to FEI's other service regions.

The North Okanagan region of the ITS has more inherent resiliency than the CTS due to it having multiple sources of supply (i.e., upstream interconnections with the Westcoast T-South and TC Energy Foothills systems). As stated in the response to BCOAPO IR1 5.1, the TLSE project would improve resiliency by supplementing these sources of supply should there be a reduced flow or a no-flow event on the TC Energy pipeline.

However, supply into the North Okanagan region of the ITS is delivered through two pipelines (i.e., pipeline connections from Savona to Kamloops and/or from Oliver to Vernon). Neither of these pipeline connections on their own can supply the total needs for the ITS region during colder weather. Consequently, the ITS has full resiliency for short timeframes during the year when system loads are lower (i.e., the summer months), but outages would result should one of the sources be disrupted during the winter. The ITS Resiliency Solution, as currently envisioned, would address this existing gap in resiliency.

In the response to BCOAPO IR1 5.1 from the Tilbury LNG Storage Expansion CPCN proceeding, FEI states:

> While the MRPO targets the needs of the Lower Mainland, the TLSE Project will also improve resiliency for the Interior service area. As FEI discussed in the TLSE Workshop, the storage provided by the TLSE facility would also allow FEI to meet customer demand for the vast majority of the year even if one of the gas transmission lines in the Interior was disrupted.[6] For example, if there was reduced capacity or a no-flow event on the TC Energy pipeline that provides supply for the FEI Interior Transmission System (ITS) at Yahk, the TLSE Project could also help FEI manage such an event. FEI could divert supply from the T-South system into the ITS to replace the lost capacity from TC Energy, and then use the TLSE storage and regasification to back-fill the reduced supply into the Lower Mainland which would have previously been supplied from the T-South system.

41.2 If the TLSE project is constructed and contributes the resiliency improvements to the Interior Transmission System described in the response to BCOAPO IR1 5.6 in the TLSE CPCN, proceeding, please explain why a separate LNG facility near Vernon is required and why it would be a cost-effective alternative to other pipeline-based resiliency upgrades.

<u>Response:</u>

Please refer to the response to RCIA IR2 41.1 which explains that neither of the two pipelines into the ITS region on its own is able to support the load during colder weather, which is a supply risk that the TLSE project cannot address. The contemplated Interior Transmission System Resiliency Solution would help mitigate these supply risks in a cost-effective manner and complements the TLSE resiliency by further reducing the amount of gas from the TC Energy system that would need to flow all the way to Kelowna. An alternative solution to address a T-South outage would be to continue the proposed OCU pipeline north of Kelowna to the Vernon area, allowing gas from TC Energy to flow north past Kelowna to supply Kamloops.

42. Reference: Exhibit B-6, FEI Response to BCUC IR1, IR 30.3

BC Hydro Accelerated Electrification Scenario

In its response to BCUC IR1 30.3, FEI states:

> 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.

42.1 What proportion of the 1 million gas customers does the BC Hydro Accelerated Electrification scenario anticipate would be electrified by 2030? By 2042?

Response:

FEI and Posterity Group collaborated on this response.

In FEI's modelling of the BC Hydro scenarios, electrification was modelled as the replacement of specific end-use equipment at the end of its useful life. It was not modelled as the departure of the account, with all its end uses leaving the gas system at the same time – and therefore FEI's model did not determine whether customers were either completely or partially electrified. However, in FEI's modelling of the scenarios, when compared to the BC Hydro Reference Case, the BC Hydro Accelerated Electrification scenario shows a reduction in natural gas demand of approximately 42 percent in 2030 and 61 percent in 2042. FEI does not have sufficient knowledge of BC Hydro's modelling assumptions or results for these scenarios to be able to answer this question in regard to the scenario modelling undertaken by BC Hydro.

42.2 What proportion of the gas demand (peak) and annual energy does the Accelerated Electrification scenario anticipate would be electrified by 2030? 2042?

42.2.1 Please show how these proportions compare to the electrification of gas demand and energy in the Diversified Energy Planning and Deep Electrification scenarios

Response:

FEI and Posterity Group collaborated on this response.

FEI provides the following table to compare how the BC Hydro Accelerated Electrification, Diversified Energy Planning, and Deep Electrification scenarios would reduce gas demand (peak) and annual energy by 2030 and by 2042. In this analysis, peak demand was modelled using the exploratory end-use peak demand forecast method. Additional discussion is provided in Exhibit B-4.

Scenario	Peak Hour Gas Demand Reduction		Annual Energy Reduction	
	2030	2042	2030	2042
BCH Accelerated Electrification	42%	65%	42%	61%
Diversified Energy Planning	13%	22%	14%	22%
Deep Electrification	35%	63%	32%	58%

43. Reference: Exhibit B-12, FEI Response to BCSEA IR1, IRs 21.13, 21.14;

Exhibit B-6, FEI Response to BCUC IR1, IR 61.3

Okanagan Capacity Upgrade and ITS Capacity

In the response to BCSEA IR1 21.14, FEI states:

> The current capacity lines shown in these figures only reflect capacity to move natural gas. Because specific details of where renewable gases will enter the ITS are still in early stages of development, there is insufficient information presently available to quantify how the ITS capacity may change over time with the level of renewable gases incorporated in each forecast. Upgrades of the existing system to facilitate moving higher volumes of low-carbon gases while delivering less energy may be required to meet the DEP Scenario forecast or the Reference forecast. Therefore, the improvement in capacity that the OCU Project will provide for the ITS, and that is required to meet current peak demand, will enhance FEI's ability to supply renewable gases like hydrogen in the region, even with a decline in peak demand such as the decline represented in the DEP Scenario or Reference forecasts.

In the response to BCUC IR1 61.3, FEI states:

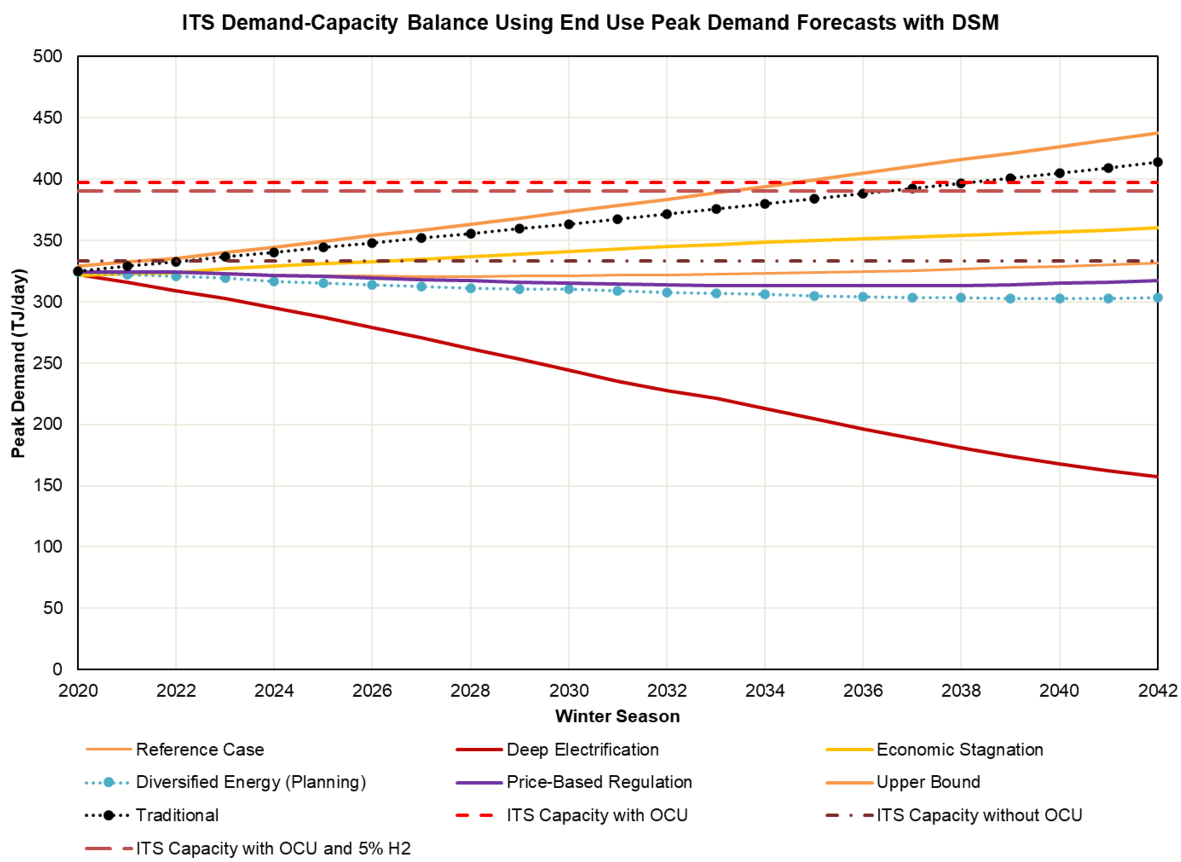
- After successful demonstration and validation, FEI expects to blend hydrogen into the CTS lower-pressure distribution system network, or subsections of the lower-pressure distribution system served by the CTS, at blend concentrations of up to 5 percent hydrogen by volume.
- Over time, FEI expects to 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.

43.1 Please file versions of the figure from BCSEA 21.13 showing the ITS capacity with and without OCU assuming i) a 5% blend of hydrogen and ii) a 30% blend of hydrogen.

<u>Response:</u>

To prepare a version of the requested figure with 5 percent and 30 percent blends of hydrogen, FEI assumes both Westcoast and TC Energy have the capability of transporting and delivering those levels of hydrogen to FEI's transmission system taps at both Savona and Yahk. This would also imply that the Southern Crossing Pipeline (SCP) will flow the blended gas mixtures and send a portion of the gas towards the Okanagan, and the remaining gas to Kingsvale to be injected into the Westcoast system.

The figure below shows the ITS capacity with a 5 percent blend of hydrogen with the OCU project in service. The hydraulic model presents that, without the OCU project, the ITS does not have the capacity to receive a 5 percent blend of hydrogen from Savona and Yahk, hence the capacity line for this scenario is not shown on the figure. FEI also simulated a 30 percent blend of hydrogen and found that even at existing levels of demand, substantial upgrades at the Kitchener and Kingsvale compressor stations would be required and as such, the capacity line for the 30 percent blend of hydrogen is also not shown on the figure below.



44. Reference: Exhibit B-17, FEI Response to RCIA IR1, IR 20.1, 25.1; Exhibit B-1, Application, 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 <u>will have some ability to free up pipeline capacity as the local demand</u> served by this production no longer needs to be transported through the upstream transmission pipeline.

In the response to RCIA IR1 20.1, FEI states:

> In any case, FEI will manage the risk of outages of the RNG or hydrogen production in the same manner as FEI currently mitigates the risk of forced outages with the production and delivery of conventional gas under most operating conditions. This is done through maintaining a diverse portfolio of resources (commodity, pipeline capacity, and storage resources) that considers the following measures:
>
> • Holding contingency resources within the portfolio, as discussed in Section 6.2.4 of the Application, to mitigate the risk of future supply disruptions (pipeline and storage) during the winter season;
>
> • Procuring market area and seasonal storage resources to mitigate disruptions associated with well freeze-offs and upsets in processing plants; and
>
> • Utilizing Mt. Hayes and Tilbury LNG storage facilities to provide high-volume gas supply to FEI on very short notice. This can mitigate several short-term outages, as well as third party pipeline or storage capacity disruptions given their on-system location near major load centres.

In the response to RCIA IR1 25.1, FEI states:

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

44.1 Please explain whether and how local hubs will be able to "free up pipeline capacity" on FEI's system (as opposed to upstream pipelines), considering the risk of interruption of local low-carbon gas production during peak demand events.

Response:

As noted in the preamble, all sources of supply and demand are subject to risk of interruption and can correspondingly impact the system during peak demand events. When considering a new local hub's ability to provide peak day capacity, FEI would need to establish confidence that it could meet an acceptable level of reliability, or, that an interruption to its supply could be overcome through other sources or mitigation strategies. If that confidence is achieved, local hubs as described could be used to free up pipeline capacity as noted in the preamble.

44.1.1 If FEI must hold redundant resources to address the possibility that local low-carbon gas production is not available on the peak day, does that effectively mean that local hubs do not provide any benefit toward addressing FEI's local peak day demands?

Response:

The principal benefit of low-carbon gas that FEI is working to capture is the reduction in GHG emissions associated with its use. If interruptions to low-carbon supply are assumed to be infrequent and brief, then maintaining access to alternate, conventional gas supply to act as temporary replacement of a loss of low-carbon production would not negate that benefit overall. Every quantity of low-carbon gas used instead of conventional gas helps FEI meet its GHG emission targets so the infrequent use of conventional gas as a replacement may still enable FEI to achieve those targets.

From a peak day capacity point of view, if alternate supply needs to be transported an appreciable distance further than the low-carbon supply it is meant to replace, it would diminish the capacity-related benefits of a local, low-carbon supply hub. As discussed in the response to RCIA IR2 44.1, FEI would need to assess the likelihood and impact of an interruption before deciding whether there was a need to retain that capacity and supply.

45. Reference: Exhibit B-6, FEI Response to BCUC IR1, IR 61.3

Hydrogen Blending and CSA Standards

In the response to BCUC IR1 61.3, FEI states:

> 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.
>
> …
>
> 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

45.1 Please discuss whether FEI is aware of any updates in the 2023 edition of the CSA Z662 Oil and Gas Pipeline Systems standard that will address blending of hydrogen into gas transmission or distribution systems, or whether these updates will be held until the 2027 edition.

<u>Response:</u>

Yes, FEI is aware that a new section will be included in the 2023 edition of CSA Z662 Oil and Gas Pipeline Systems standard that will address blending of hydrogen into the gas transmission and distribution systems. FEI expects that these new requirements will be further enhanced in subsequent editions of the standard in 2027 and later editions.

45.2 Please discuss whether FEI is aware of any updates in the next editions of related standards for pipeline transmission and distribution systems, such as CSA B137 Thermoplastic Pressure Piping standards or CSA Z245.1 Steel Pipe standard that will address the ability of these piping systems to transport hydrogen-natural gas blends.

Response:

FEI is aware that the updates to CSA Z662 Oil and Gas Pipeline Systems standard also include CSA Z245.1 Steel Pipe standard and the CSA B137 Thermoplastic Pressure Piping standards.

45.3 Please confirm whether there are timelines established to update the gas equipment and appliance standards CSA B149, Z21/Z83, and JB121. If confirmed, please provide the dates when these updates are targeted.

Response:

FEI is aware that CSA is in the process of establishing a Task Force working group that will consider the updates necessary to integrate hydrogen into these standards. FEI is not currently aware of the timeline associated with these proposed updates.

46. Reference: Exhibit B-6, FEI Response to BCUC IR1, IR 33.13, 61.2

Impact of Hydrogen Blends on CNG Operations

In the response to BCUC IR1 61.2, FEI states:

> 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…

In the response to BCUC IR1 33.13, FEI states:

> 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.

46.1 Please explain whether and how hydrogen blends may affect FEI's CNG operations and whether there is a risk of increased costs associated with hydrogen blends, such as a requirement to add hydrogen separation equipment

.

Response:

Prior to delivering hydrogen as a blend in the natural gas supply to CNG refueling stations, whether CNG stations are operated by FEI or by a gas customer of FEI, there are potential effects that will need to be assessed and analyzed to determine the safe hydrogen blend concentration which include:

- The effect of hydrogen addition on CNG refueling stations;
- The effect of hydrogen addition on CNG vehicles onboard fuel storage tank and fuel delivery and management systems; and
- The effect of hydrogen addition on engine performance.

FEI will work with its CNG fueling customers to determine the optimal path forward to ensure that the energy it provides is compatible with how customers use that energy. FEI has not yet determined whether customers can refuse a hydrogen blended gaseous energy while maintaining a natural gas service.

46.1.1 Please explain how the proposed Gibson CNG peaking facility will accommodate any hydrogen in the gas stream.

Response:

The facility has not been specifically designed to accommodate a percentage of hydrogen. Instead, FEI has included in the engineering scope to be performed by an engineering consultant, a technical assessment and recommendation of the acceptable upper bounds of hydrogen for each major component. If FEI chooses to blend hydrogen into the Gibson's distribution pressure system in the future, FEI may need to upgrade the necessary equipment to meet the blending requirements at that point in time.

46.2 Please confirm whether FEI has customers with their own CNG facilities. For example, does FEI have customers who compress CNG for use in their vehicle fleets?

46.2.1 If confirmed, please explain how these customers will be affected when FEI begins blending hydrogen into the gas stream.

46.2.2 Please explain whether these customers have the right to refuse hydrogen blends while maintaining their natural gas service, or whether they have any recourse if FEI supplies them a hydrogen-natural gas blend that may be incompatible with their equipment.

Response:

Confirmed. Please refer to the response to RCIA IR2 46.1.

47. Reference: Exhibit B-6, FEI Response to BCUC IR1, IR 59.3

On-System Hydrogen Hubs

In the response to BCUC IR1 61.3, FEI states:

> 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.

47.1 Please confirm whether the on-system hubs for which FEI will seek approval of capital expenditures in the next five years will include hydrogen-specific hubs or other dedicated hydrogen infrastructure.

<u>Response:</u>

Confirmed. FEI will apply for approval of capital expenditures when the projects are sufficiently developed such that FEI is able to provide the details necessary to support a capital cost forecast.

48. Reference: Exhibit B-9, FEI Response to BCOAPO IR1, IR 9.1; Exhibit B-6, FEI Response to BCUC IR1, IR 75.5

Bill Impacts Due to Climate Policy

In the response to BCOAPO IR1 9.1, FEI states:

> Since affordability is relative and is defined differently by different customer segments, and even by customers within each segment, FEI views affordability and affordable rates through the lens of FEI's ability to transition to low carbon fuels at the lowest reasonable cost. For example, as discussed in the response to CEC IR1 14.3, FEI seeks to acquire renewable and low carbon gas at the lowest reasonable cost. Given this context, FEI notes that climate policy accounts for approximately 60 percent of the change in the annual bill.

In the response to BCUC IR1 75.5, FEI provides Table 1:

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%

48.1 Please confirm whether the 60 percent figure in the above quotation includes the costs identified on page 9-12 of the Application, and therefore exclude any costs related to hydrogen-specific infrastructure. If not confirmed, please explain.

<u>Response:</u>

Not confirmed. The 60 percent figure referenced in the response to BCOAPO IR1 9.1 (please also see the response to BCOAPO IR2 18.1 which explains that the 60 percent figure was a rounded-up number from 56 percent) includes the costs identified on page 9-12 of the Application and *does* include potential costs related to future infrastructure for hydrogen. The integration of hydrogen into FEI's system is still at a preliminary stage and FEI has not developed any capital estimates that are specific to hydrogen infrastructure for the purpose of estimating the effective rate impact analysis in Section 9.4 of the Application. However, as explained in the response to

BCUC IR1 77.4.1, FEI did include a proxy of future capital over the 20-year planning period to reflect these potential investments.

48.2 Please confirm that climate policy accounts for a cumulative bill impact of approximately 71% (60% of 118%) by 2042. If not confirmed, please explain.

Response:

Not confirmed. Please refer to the response to BCOAPO IR2 18.1.

49. Reference: Exhibit B-6, FEI Response to BCUC IR1, IR 75.5; Exhibit B-1, Application, p.7-22, 9-13 to 9-15

Bill Impacts Due to Low Carbon Transportation

In the response to BCUC IR1 75.5, FEI provides Table 1, showing the cumulative rate (or bill) impact by component:

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%

On page 7-22 of the Application, FEI states:

> The demand for conventional gas from transportation sector fuel customers is forecast to continue growing over the next 20 years (as discussed in Section 4.6), and increased use of LNG as a lower intensity fuel for road and marine transport in the Lower Mainland area will likely drive LNG demand growth. The potential demand and the point-source nature of additional LNG liquefaction production in peak conditions at Tilbury may create system impacts <u>and could trigger the need for system reinforcements of the CTS</u>. [emphasis added]

49.1 Please identify any projects in the planning period and their corresponding expenditures that relate to development of Low Carbon Transportation beyond FEI's current (or currently in development) capabilities to serve this segment. Alternatively, provide the estimated annual expenditures contemplated in the LTGRP for expanding FEI's sales in the LCT market compared to the status quo.

<u>Response:</u>

The only project in the 20-year planning period associated with the development of new LCT demand beyond FEI's current capabilities is the Tilbury Phase 1B Project as identified on page 9-12 of the Application, and further discussed in the response to BCUC IR2 109.3.

Please refer to Table 1 below which shows the current, preliminary estimate of the Tilbury Phase 1B Project capital costs. FEI notes the capital expenditures for the Tilbury Phase 1B Project were also included in the list of capital expenditures provided in the response to RCIA IR1 36.2.2. The preliminary estimate set out in Table 1 below includes additional liquefaction at the Tilbury facility and CTS capacity upgrades, both approved under OIC No. 749/2014 and amended under OIC No. 162/2017, as well as additional infrastructure such as on-shore pipeline and compression upgrades expected to be required to support the forecast LCT demand growth under the Diversified Energy Planning (DEP) Scenario.

Table 1: Preliminary Capital Cost Estimate of Tilbury Phase 1B Project ($ million)

	2023	2024	2025	Total
T1B	$ 451	$ 365	$ 260	$ 1,076

FEI confirms the impact from the Tilbury Phase 1B Project has been included in the rate impact analysis shown in Section 9.4 of the Application and is also reflected in Table 1 of the response to BCUC IR1 75.5 as referenced in the preamble above. As discussed throughout the Application and also demonstrated in Table 1 of the response to BCUC IR1 75.5, the offsetting revenue resulting from new LCT sales will provide an overall benefit to all of FEI's customers. It can be seen from Figures 1 to 4 below, which are re-creations of Figures 9-7 to 9-10 of the Application and include the scenarios without new LCT developments and sales (dotted line), and also from Table 2 below, which is a re-creation of Table 9-2 of the Application, if FEI did not pursue the Tilbury Phase 1B Project, the cumulative rate impacts to FEI's customers would have been higher.

FEI notes there is no change to the rate impacts associated with the Deep Electrification Scenario and Reference Case Scenario. This is because the Tilbury Phase 1B Project (costs and revenues) was only included in the DEP Scenario and the Upper Bound Scenario for the rate impact analysis shown in Section 9.4 of the Application. For the Deep Electrification and Reference Case Scenarios, only the current level of LCT sales were included, thus there is no additional infrastructure and LCT sales beyond FEI's current capability.

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

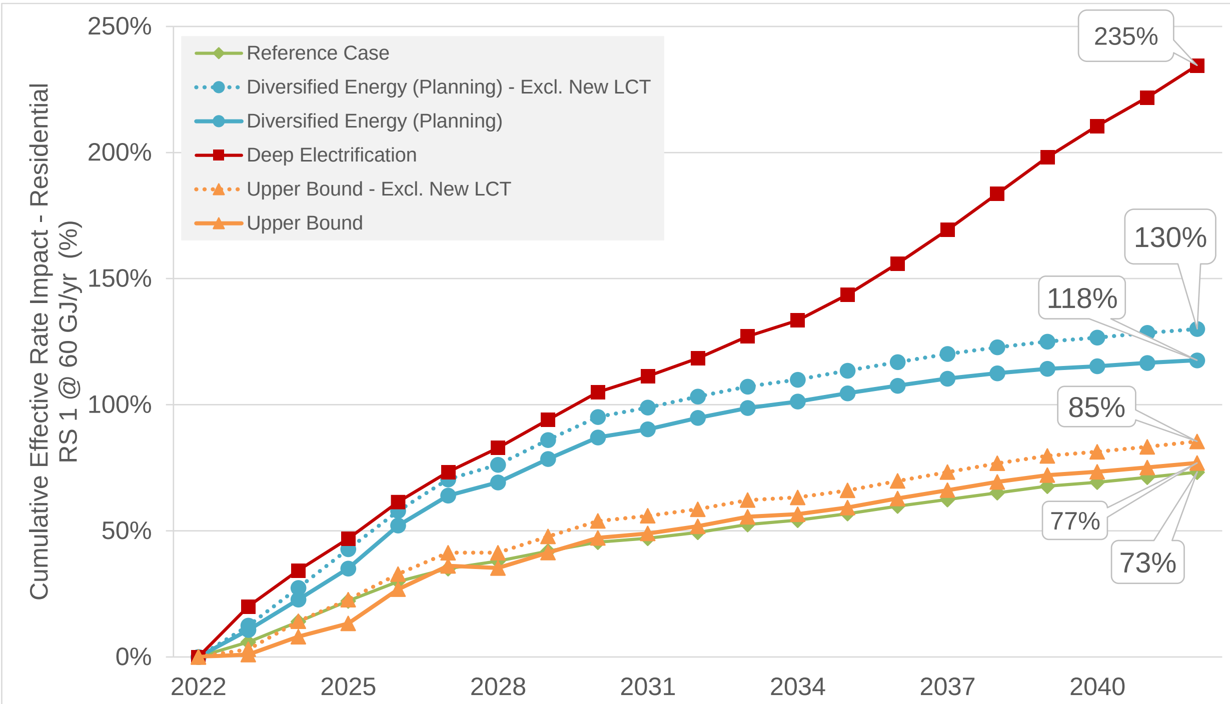


Figure 2: Updated Figure 9-8 for Cumulative Effective Rate Impact (2022 – 2042) – Small Commercial RS 2, Average UPC 293 GJ

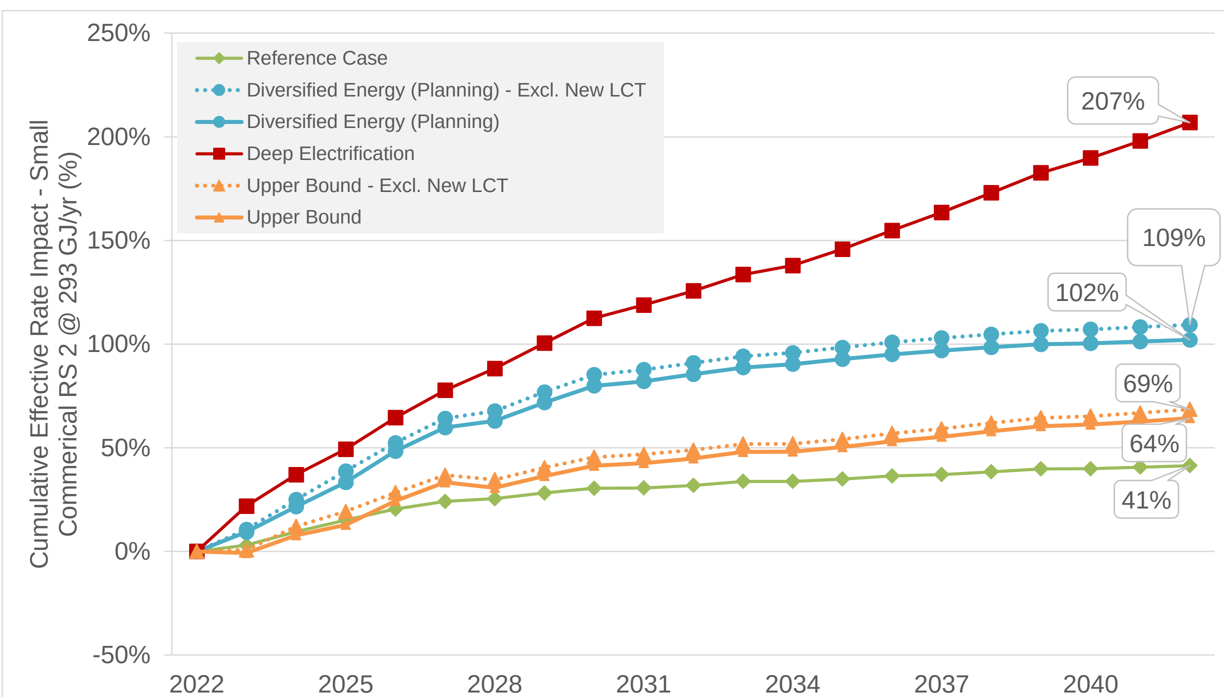


Figure 3: Updated Figure 9-9 for Cumulative Effective Rate Impact (2022 – 2042) – Large Commercial RS 3, Average UPC 3,253 GJ

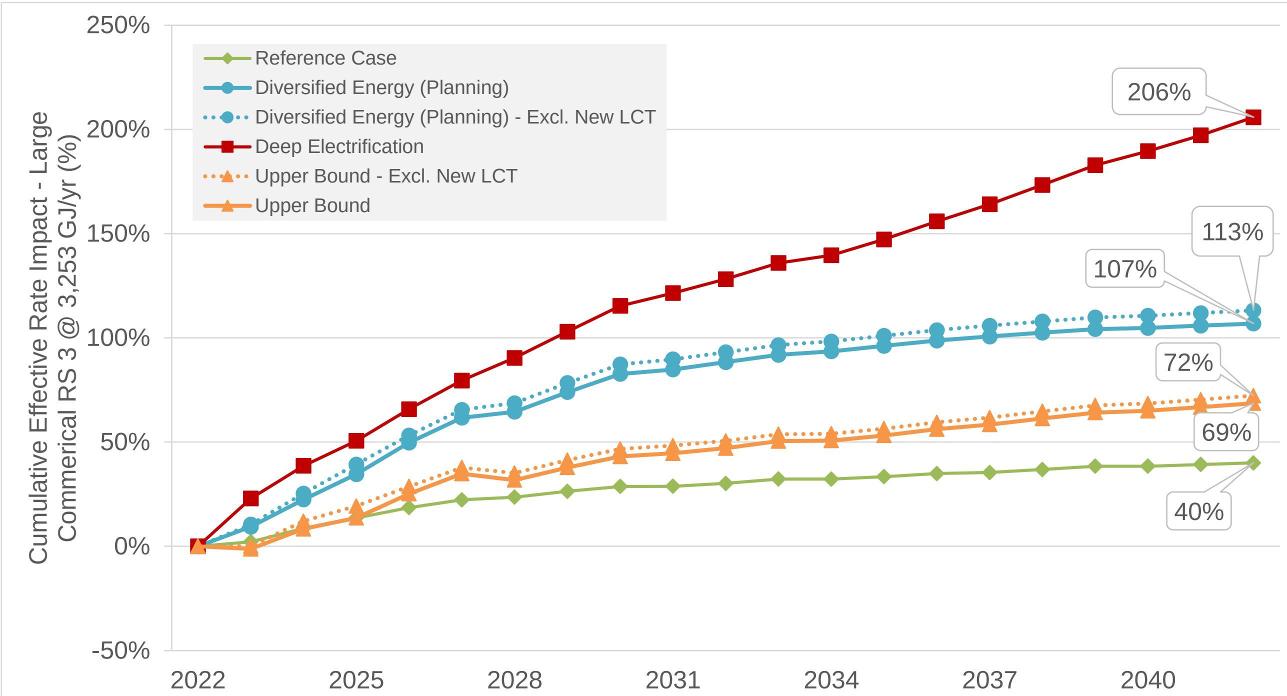


Figure 4: Updated Figure 9-10 for Cumulative Effective Rate Impact (2022 – 2042) – General Firm Service RS 5, Average UPC 18,542 GJ

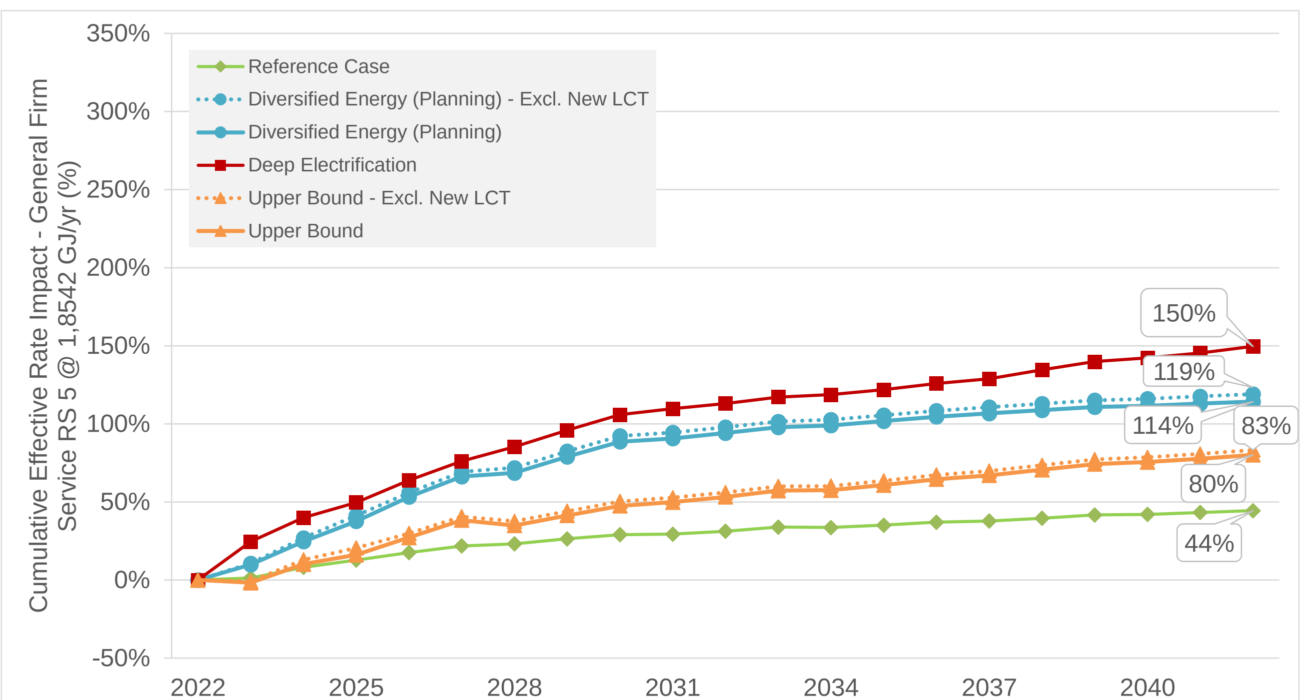


Table 2: Summary and Comparison of Average Projected Rate Changes

	Effective Rate Change (2022 - 2042, %)												
	Average UPC (GJ) (2022 - 2042)	**Reference**		**Upper Bound - Excl. New LCT**		**Upper Bound**		**Diversified Energy (Planning) - Excl. New LCT**		**Diversified Energy (Planning)**		**Deep Electrification**	
		Cumulative	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative	Annual	Cumulative	Annual
Residential (RS 1)	60	73%	2.8%	85%	3.1%	77%	2.9%	135%	4.4%	118%	4.0%	243%	6.4%
Small Commercial (RS 2)	293	41%	1.7%	69%	2.6%	64%	2.5%	116%	3.9%	102%	3.6%	217%	5.9%
Large Commercial (RS 3)	3,253	40%	1.7%	72%	2.8%	69%	2.6%	121%	4.0%	107%	3.7%	217%	5.9%
General Firm Service (RS 5)	18,542	44%	1.9%	83%	3.1%	80%	3.0%	128%	4.2%	114%	3.9%	163%	5.0%

49.2 Please confirm whether the rate impact from LCT shown in the above table includes the additional costs related to infrastructure (e.g., CTS capacity upgrades, LNG facilities, filling/bunkering equipment) necessary to realize the projected LCT sales.

Response:

Please refer to the response to RCIA IR2 49.1.

49.3 If FEI did not pursue these projects related to increasing LCT sales, it would not incur these expenditures but would also not realize the additional revenues from LCT customers. Please describe the directional impact this would have on delivery rates and resulting bill impacts.

49.3.1 Please show how the bill impacts would change by plotting additional curves on Figures 9-7 to 9-10 and adding a column to Table 9-2 to show the Diversified Energy Planning scenario but without the expenditures and corresponding revenues from additional LCT sales.

Response:

Please refer to the response to RCIA IR2 49.1.

50. Reference: Exhibit B-6, FEI Response to BCUC IR1, IR 62.7

FEI Collaboration on Methane Pyrolysis Project

In the response to BCUC IR1 62.7, FEI states:

> 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.

50.1 When does FEI plan to file a CPCN Application for this project?

<u>Response:</u>

FEI is currently completing early-stage project development activities and other due diligence work on this project. After the ongoing project development work is completed, and if the outcomes from the ongoing project development confirm that the project is technically and commercially viable, then FEI will apply for the necessary approvals from the BCUC, whether through a CPCN, expenditure schedule or other method.

50.2 Please confirm whether FEI has received approval to incur development expenses for this project.

<u>Response:</u>

The current project scope only includes early-stage project development feasibility work and FEI's expenditures related to this work will be relatively minor. FEI has received and is using funds from the CleanBC Innovation Accelerator for 75 percent of the costs for this stage of the project development feasibility work, and the balance of the funding costs for this stage of the project development will be shared equally by FEI, Suncor, and Hazer Group. FEI expects to record its expenditures as a flow-through O&M expense as part of its Clean Growth Initiatives under its 2020-2024 Multi-Year Ratemaking Plan or, subject to BCUC approval, in a project development deferral account.

50.3 Please explain the objectives of this project. Is this project to serve a single customer, or to create hydrogen for blending in FEI's transmission or distribution systems?

Response:

The project has the potential to serve several different customers including Suncor, to displace natural gas and for use as a feedstock to manufacture sustainable liquid fuels, to other customers for transport refueling applications, as well as for blending into the local FEI gas distribution system.

50.4 Please explain whether FEI will be investing capital in this project, and whether FEI will incorporate this project into its rate base.

50.4.1 If FEI intends to invest capital in this project, please explain why FEI is the party doing this as opposed to contracting for the output, similar to how FEI contracts for the supply of its conventional gas resources

50.4.2 Please explain whether FEI could provide the necessary purchase guarantee to Suncor and Hazer Group for the plant's output by way of contract as opposed to FEI investing in the plant

Response:

FEI's potential investment in this project will be subject to the findings from ongoing early-stage project development and due diligence work. As stated in the response to BCUC IR1 62.6, 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 from independent producers when the opportunity to do so emerges. FEI expects to provide the necessary purchase guarantee to Suncor and Hazer Group for the plant's output by way of contract irrespective of whether FEI invests in the plant.

51. Reference: Exhibit B-20, FEI Evidentiary Update (Kelowna Electrification Study), p.4

Heat Pump Efficiency

On page 4 of the Kelowna Electrification Study, FEI states:

> Heat pumps, and their efficiencies as currently represented in the BC Cold Climate Field Study, essentially provide the same efficiency as electric resistive heating at temperatures below approximately -18 C, while the average daily temperature for Kelowna during the winter can be -26 C or lower (with nighttime temperatures well below -30 C). Accordingly, at temperatures colder than -18 C for the 25 percent and 50 percent electrification cases, and at temperatures colder than -20 C for the 100 percent electrification case,[11] it is assumed that heating load is served through the auxiliary / resistive heating mode on the heat pump or by less-efficient electric heating appliances.[12] The thermal efficiency gain for heat pumps discussed in the above bullet reduces the gas-to-electric conversion only up until those points; after that, the efficiency improvement is lost.

51.1 Please confirm whether FEI's model adjusts the efficiency of the heat pumps as the temperature approaches -18 C to reflect the corresponding decline in efficiency.

51.1.1 If not confirmed, please explain why not.

Response:

FEI confirms that the model accounts for the declining heat pump performance based on Figure 3-16 from the Cold Climate Heat Pump study, reproduced below:

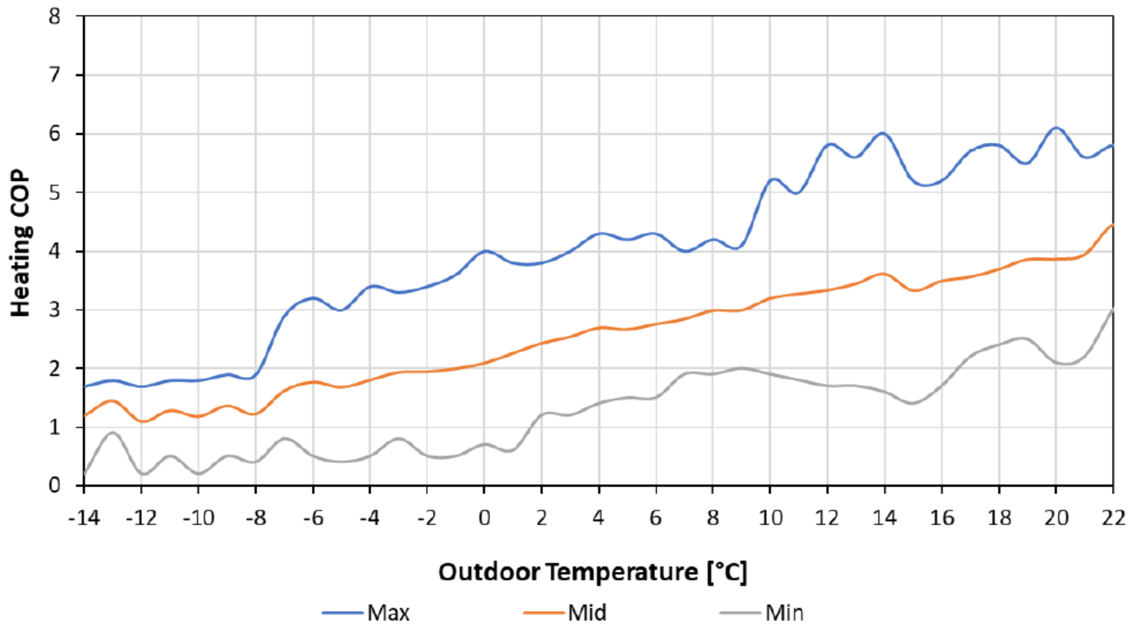


Figure 3.16 – average heating COP range of all heat pumps vs. outdoor temperature.

For example, the "Max" efficiency heat pump setting used in the 100 percent electrification case has a heating COP of approximately 3.0 at -5 C, declining below a COP of 2.0 beginning at -8 C.

51.1.2 Please directionally indicate the impact, if any, that including adjustments to the hearing efficiency as the outside air temperature approaches -18C would have on the results of the Kelowna Electrification Study conclusions.

<u>Response:</u>

Please refer to the response to RCIA IR2 51.1. Declining heating efficiencies were modelled in the Kelowna Electrification Case Study so there would be no additional impact on the conclusions.

52. Reference: Exhibit B-20, FEI Evidentiary Update (Kelowna Electrification Study), p.5; Exhibit B-1, Application, p.4-21

LTGRP Scenarios

On page 5 of the Kelowna Electrification Study, FEI provides Table 3-2:

Table 3-2: City of Kelowna - Electricity Peak Winter Load in 2040 at Cold Temperatures Based on 25 Percent Increments of Electrification

	Electrification Case				
	0%	25%	50%	75%	100%
Mean Daily Temperature (C)	Peak (MW)				
0	354	415	477	539	555
-5	377	463	548	634	660
-10	400	516	632	748	790
-15	423	581	739	897	984
-20	446	657	867	1,078	1,289
-26	472	711	950	1,190	1,429

Section 4.5 of the Application identifies alternate future scenarios such as Reference, Diversified Energy (Planning), Upper Bound, Lower Bound, Price-Based Regulation, Economic Stagnation, and Deep Electrification.

52.1 Please identify the scenarios in FEI's LTGRP that align with each electrification case shown in Table 3-2.

Response:

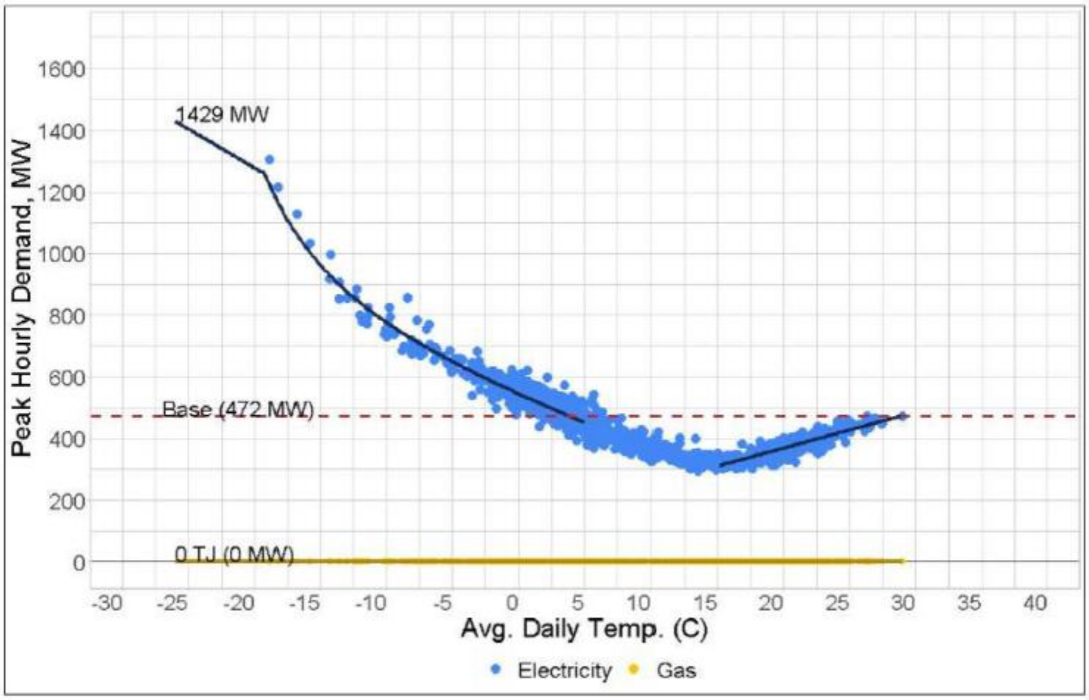
Please refer to the response to BCSEA IR2 55.7.

53. Reference: Exhibit B-20, FEI Evidentiary Update (Kelowna Electrification Study), p.9

Peak Demand Extrapolation

On page 9 of the Kelowna Electrification Study, FEI provides Figure 3-5:

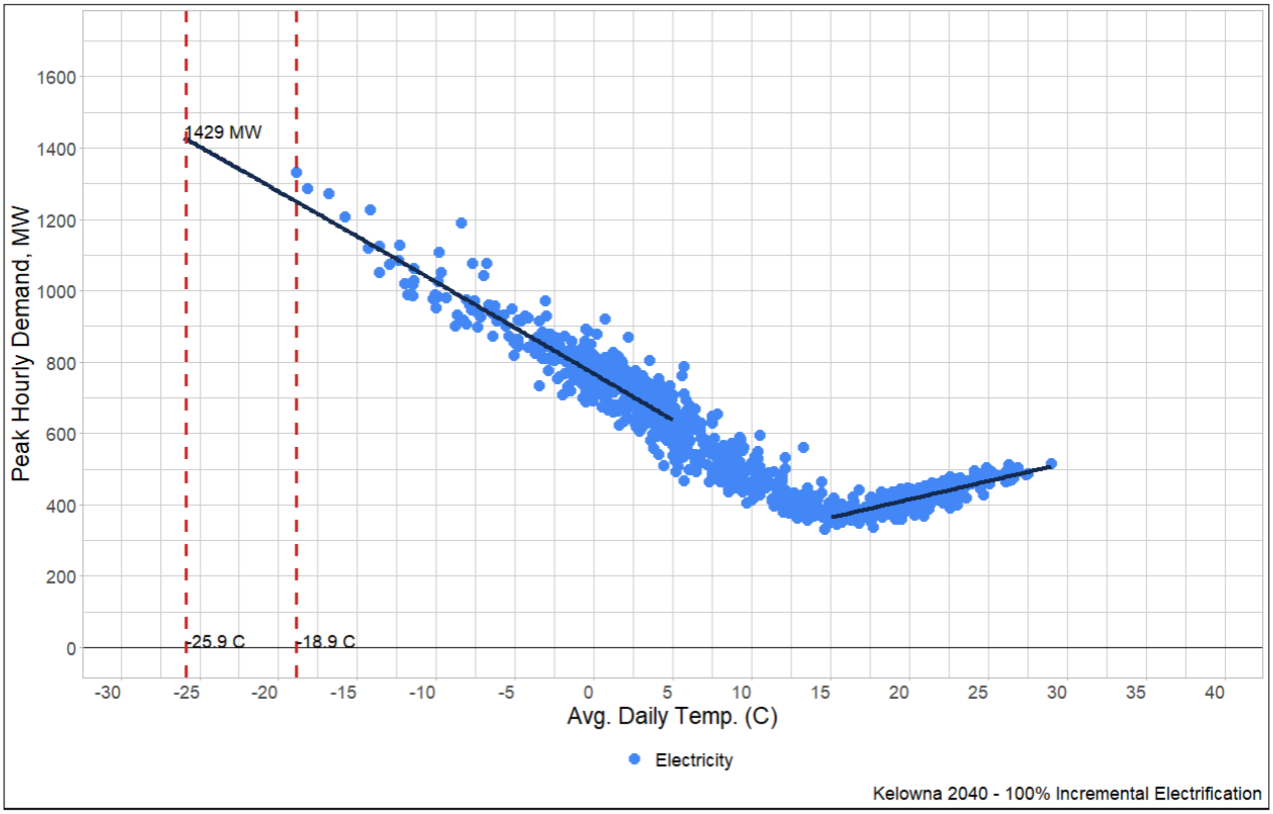
Figure 3-5: City of Kelowna - Electricity and Gas Demand by Temperature in 2040 with 100 Percent Electrification[17]



53.1 Please explain how FEI extrapolated the peak hourly demand curve to a temperature less than -18 C, which appears to be the lowest temperature data point in Figure 3-5.

<u>Response:</u>

In the model used for the Kelowna Electrification Case Study, FEI applied a linear regression to the observed load data versus temperature points from 2018 to 2020. As shown in the figure below, the coldest mean daily temperature recorded between 2018 and 2020 was -18.9 C. The design temperature for Kelowna is -25.9 C, and therefore, FEI extended the regression line to -25.9 C. FEI notes that the mean daily temperature recorded at the Kelowna Airport on December 22, 2022, was -26.2 C.



Peak Hourly Demand, MW
1600
1400
1200
1000
800
600
400
200
0
1429 MW
-25.9 C
-18.9 C
-30
-25
-20
-15
-10
-5
0
5
10
15
20
25
30
35
40
Avg. Daily Temp. (C)
Electricity
Kelowna 2040 - 100% Incremental Electrification

54. Reference: Exhibit B-20, FEI Evidentiary Update (Kelowna Electrification Study), p.10

Local Generation Resources

On page 10 of the Kelowna Electrification Study, FEI states:

> 100 percent of the new generation resources required to meet the added loaded would be from outside the Kelowna area via existing or new FBC-BC Hydro and Power Authority (BC Hydro) interconnections (to identify the transmission impacts without including generation within the Kelowna area);

On page 14 of the Kelowna Electrification Study, FEI states:

> FBC preferred portfolio C3 (clean resource portfolio with renewable natural gas (RNG)-fueled generation) from the 2021 LTERP contains some capacity generation resources that are assumed to be located in the Kelowna region, namely two RNG-SCGT (simple-cycle gas turbine) units and a 25 MW utility-scale battery. These resources would provide a combined 173 MW of dependable winter capacity at an estimated cost of approximately $350 million[29] which is exclusive of land acquisition costs. Locating generation in the Kelowna area would reduce a portion of the peak demand on the transmission system, thereby potentially deferring some transmission requirements and providing locational value.[30]

On page 15 of the Kelowna Electrification Study, FEI provides Table 4-4:

Table 4-4: Summary of System Impacts and Land Acquisition Costs Required for Electrification Cases by 2040[32]

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

54.1 Please quantify the reduction in Project Costs that would result from the installation of the two RNG-SCGT units and utility-scale battery as explained on page 14 of the Kelowna Electrification Study. Please provide the Project Costs with transmission investments deferred as well as the Project Costs with the transmission investments deferred plus the cost of the RNG-SCGT units and battery.

Response:

The Kelowna Electrification Case Study investigated the potential instantaneous peak demand in the year 2040. The Study does not include a forecast over a planning horizon to be able to calculate a deferral credit.

In the context of the Study, the installation of the two RNG-SCGT units and the utility-scale battery contained in FBC's LTERP preferred portfolio would provide 173 MW of local dispatchable generation, thereby reducing the transmission load on the peak hour by 173 MW. Any additional generation in the Kelowna area could only eliminate or defer the need for the 500 kV bulk transmission lines and associated station. For clarity, other system upgrades aside from bulk transmission into the Kelowna area, such as distribution stations and feeders, would still be required to serve the peak load.

In the 100 percent electrification case (with peak demand of 1,429 MW), peak demand net of 173 MW of local dependable capacity would reduce the transmission load into Kelowna down to 1,256 MW. A load level of 1,256 MW would still require both 500 kV lines, associated station and land, and would not impact any project costs of other system upgrades under this case. In the 50 percent electrification case, the transmission load requirements would be reduced to 777 MW. A load level of 777 MW would eliminate the need for the second Ashton Creek to Vaseux Lake (ACK-VAS) 500 kV line and associated land requirements, thereby reducing the estimated system upgrade to the range of $658 million to $917 million. In the 25 percent electrification case, transmission load requirements are reduced to a 538 MW load level. From a planning perspective, 538 MW is close enough to the 550 MW threshold to still trigger the need for one of the two 500 kV lines and, therefore, there is no further project cost reduction. In summary, 173 MW of local dispatchable generation may be able to defer one of the 500 kV transmission line projects, depending on the level of electrification realized by the year 2040.

54.2 Please explain whether solar photovoltaic or other renewable generation, either behind-the-meter or utility-scale, could assist in meeting the winter peak demand.

Response:

Yes, renewable generation can make contributions to meeting winter peak demand. For example, if wind power is generating during the peak hour, it is then contributing to meeting the peak winter demand. However, if it is not generating, then it is not directly contributing. As such, the peak contribution that an intermittent renewable resource like wind or solar makes will be much smaller on a planning basis and much more variable on an operating basis than the contribution a firm renewable resource such as geothermal will make. Therefore, it is likely that a wind resource will be matched with some form of storage (hydro or batteries), while a geothermal resource will not require storage.

However, the inclusion of storage does not necessarily mean that the intermittent renewable resource gains capacity. Any additional capacity must come from the underlying storage mechanism. In the case of hydro storage, zero additional capacity is added since the hydro capacity already existed and likely would have been used at peak capacity times. In the case of batteries, if the battery is part of the wind project, then new capacity is created, but if it is a general utility battery, not tied to any one resource, then again, no new capacity can be attributed to the intermittent renewable resource.

For a discussion on behind-the-meter generation, with a focus on rooftop solar, please refer to the response to BCUC IR2 120.3.

54.2.1 What time of day does FEI expect the winter peak or peaks? Is solar PV generation able to contribute to meeting these winter peaks?

Response:

Please refer to the response to BCUC IR2 120.3.

55. Reference: Exhibit B-20, FEI Evidentiary Update (Kelowna Electrification Study), p.17

Extrapolation Beyond Kelowna

On page 17 of the Kelowna Electrification Study, FEI states:

> FortisBC is in a unique position to use the City of Kelowna as a case study to demonstrate the impacts of electrification on peak demand and system upgrade costs, illustrating at a high-level the challenges associated with meeting winter heating demand through one energy system. The examination of the Kelowna Electrification Case Study demonstrates that the transfer of peak demand from the gas system to the electric system creates a significant requirement for additional electric infrastructure and associated land to address the incremental winter electric peak demand. This Study provides a starting point for further analysis to understand the holistic impacts of electrification, including the current state of the electric system's ability to accommodate electrified load, as well as in other regions that include a higher number of customers as well as a lower load factor (i.e. higher weighting to winter heating demand), highlighting the importance of collaboration and coordination between the gas and electric systems in the province.

55.1 Please provide FEI's extrapolations of the Kelowna Electrification Study to the remainder of its service territories and any conclusions drawn by FEI that apply to those territories.

<u>Response:</u>

FEI is unable to provide extrapolations of the Study to the remainder of its service territory at this time. FEI does not currently have the necessary electric load and system information for the rest of its service territory similar to what is currently available for the FEI/FBC shared service territory. Further, as mentioned in the Study, its results are preliminary, directional, and indicative, and are subject to on-going refinement and more in-depth analysis. Please also refer to the responses to BCUC IR2 121.1 and 121.4 regarding opportunities to further extend the Study.

Attachment 38.1

Capital Expenditure (Reference)	Cumulative (2023-2042)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Regular Capital	1,498	383	367	369	380	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IS Upgrade	42	-	20	21	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Capacity Upgrades (VITS, CTS, ITS)	280	2	4	4	60	120	12	6	32	-	-	-	-	-	-	-	-	40	-	-	-
Resiliency Upgrades (Distribution)	1,130	-	-	5	10	10	150	300	25	1	6	11	41	177	278	109	8	-	-	-	-
Integrity Upgrades	144	3	13	16	19	18	3	2	23	45	4	-	-	-	-	-	-	-	-	-	-
CPCNs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
T1B	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TLSE	739	166	252	210	111	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AMI	473	91	168	150	64	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TIMC-CTS	100	5	93	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TIMC-ITS	82	4	11	33	33	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PGR	17	17	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OCU	253	113	139	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGU	104	69	33	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Regular/Major Capital, Escalated (2027-2042)	8,846	-	-	-	-	546	564	575	480	492	500	511	519	542	554	571	574	584	597	616	622
Total ($000s)	**13,708**	**854**	**1,099**	**812**	**679**	**694**	**728**	**883**	**559**	**538**	**510**	**522**	**559**	**719**	**832**	**680**	**582**	**624**	**597**	**616**	**622**

Capital Expenditure (Upper)	Cumulative (2023-2042)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Regular Capital	1,499	384	367	369	380	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IS Upgrade	42	-	20	21	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Capacity Upgrades (VITS, CTS, ITS)	779	6	12	12	180	360	34	20	75	-	-	-	-	-	-	-	-	80	-	-	-
Resiliency Upgrades (Distribution)	3,479	-	-	15	30	30	455	910	85	153	311	46	96	325	495	334	60	44	10	41	41
Integrity Upgrades	289	3	33	38	44	22	4	3	45	90	8	-	-	-	-	-	-	-	-	-	-
CPCNs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
T1B	1,076	451	365	260	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TLSE	739	166	252	210	111	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AMI	473	91	168	150	64	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TIMC-CTS	100	5	93	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TIMC-ITS	82	4	11	33	33	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PGR	17	17	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OCU	253	113	139	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGU	104	69	33	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Regular/Major Capital, Escalated (2027-2042)	9,028	-	-	-	-	546	564	575	480	494	505	518	528	553	568	587	593	606	620	642	651
Total ($000s)	**17,960**	**1,309**	**1,493**	**1,112**	**844**	**957**	**1,057**	**1,508**	**685**	**736**	**823**	**564**	**624**	**878**	**1,062**	**921**	**653**	**730**	**631**	**683**	**691**

Capital Expenditure (Diversified Energy Planning)	Cumulative (2023-2042)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Regular Capital	1,498	383	367	369	380	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IS Upgrade	42	-	20	21	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Capacity Upgrades (VITS, CTS, ITS)	679	6	12	12	180	360	31	6	32	-	-	-	-	-	-	-	-	40	-	-	-
Resiliency Upgrades (Distribution)	1,130	-	-	5	10	10	150	300	25	1	6	11	41	177	278	109	8	-	-	-	-
Integrity Upgrades	144	3	13	16	19	18	3	2	23	45	4	-	-	-	-	-	-	-	-	-	-
CPCNs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
T1B	1,076	451	365	260	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TLSE	739	166	252	210	111	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AMI	473	91	168	150	64	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TIMC-CTS	100	5	93	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TIMC-ITS	82	4	11	33	33	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PGR	17	17	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OCU	253	113	139	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGU	104	69	33	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Regular/Major Capital, Escalated (2027-2042)	8,846	-	-	-	-	546	564	575	480	492	500	511	519	542	554	571	574	584	597	616	622
Total ($000s)	**15,183**	**1,308**	**1,472**	**1,080**	**799**	**934**	**748**	**883**	**559**	**538**	**510**	**522**	**559**	**719**	**832**	**680**	**582**	**624**	**597**	**616**	**622**

Capital Expenditure (Deep Electrification)	Cumulative (2023-2042)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Regular Capital	1,498	383	367	369	380	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IS Upgrade	42	-	20	21	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Capacity Upgrades (VITS, CTS, ITS)	80	-	-	-	-	-	2	6	32	-	-	-	-	-	-	-	-	40	-	-	-
Resiliency Upgrades (Distribution)	1,130	-	-	5	10	10	150	300	25	1	6	11	41	177	278	109	8	-	-	-	-
Integrity Upgrades	144	3	13	16	19	18	3	2	23	45	4	-	-	-	-	-	-	-	-	-	-
CPCNs	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
T1B	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TLSE	739	166	252	210	111	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
AMI	473	91	168	150	64	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TIMC-CTS	100	5	93	3	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
TIMC-ITS	82	4	11	33	33	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
PGR	17	17	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
OCU	253	113	139	0	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
IGU	104	69	33	1	1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Regular/Major Capital, Escalated (2027-2042)	10,039	-	-	-	-	546	564	575	561	575	585	598	607	632	646	664	669	682	696	717	725
Total ($000s)	**14,701**	**852**	**1,095**	**808**	**619**	**574**	**718**	**883**	**641**	**621**	**594**	**609**	**647**	**809**	**924**	**773**	**677**	**722**	**696**	**717**	**725**