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May 22, 2025

British Columbia Public Interest Advocacy Centre
Suite 803 - 470 Granville Street
Vancouver, B.C.
V6C 1V5

Attention: Leigha Worth, Executive Director

Dear Leigha Worth:

Re: FortisBC Energy Inc. (FEI)

Application for a Certificate of Public Convenience and Necessity (CPCN) for the Tilbury Liquefied Natural Gas Storage Expansion (TLSE) Project (Application)

Response to the British Columbia Public Interest Advocacy Centre representing the British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance BC, Council of Senior Citizens' Organizations of BC, and the Tenant Resource and Advisory Centre *et al.* (BCOAPO) Information Request (IR) No. 6

On December 29, 2020, FEI filed the Application referenced above and on October 24, 2024, FEI filed its Supplemental Evidence to the Application. In accordance with the regulatory timetable established in British Columbia Utilities Commission Order G-324-24 for the review of the Application, FEI respectfully submits the attached response to BCOAPO IR No. 6.

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

cc (email only): Commission Secretary
Registered Interveners

1.0 Reference: PROJECT NEED

Exhibit B-60 FEI Supplemental Evidence, pages 10 & 54 and Figure 4-20, page 161

Exhibit B-63, FEI Responses to BCUC IR 5 - 141.6 Exhibit B-64, FEI Response to BCOAPO IR 5 - 1.1 Topic: Economic Impact of Winter no-flow Event

Preamble:

FEI states that it engaged Pricewaterhouse Coopers (PwC) to undertake an independent analysis of the economic harm to the Province and that PwC conservatively estimated a winter no-flow event on the T-South to negatively impact GDP of between $1.7 billion and $3.8 billion (and may be significantly understated), well in excess of the cost of FEI's Preferred Alternative. (**Supplemental Evidence, pp. 10 & 54**)

FEI acknowledges while there are significant potential economic and social impacts associated with a winter T-South no-flow event that direct mitigation of these impacts primarily benefits FEI's customers and thus, taxpayers should not be held responsible for a portion of its costs. (**BCOAPO IR 5 – 1.1**)

FEI states that "[t]he PwC Report, which supports the 2024 Resiliency Plan and Supplemental Evidence, confirms that an outage in the Lower Mainland will result in catastrophic economic harm for British Columbians…. with FEI's existing resiliency capabilities, a winter T-South no-flow event will result in 600,000 to 640,000 customers losing service on Day 1 of the event. This finding, combined with Exponent's analysis that shows that a significant amount of the economic risk posed by a T-South no-flow event can be mitigated by the TLSE Project, demonstrates the Project's necessity from a resiliency standpoint…." (**BCUC IR 5 – 141.6**)

1.1 Please clarify whether the economic impact ranging from $1.7 billion to $3.8 billion assumes a 3-day no-flow winter event on T-south. If not, please provide the no-flow winter event duration(s) used by PwC to arrive at the $1.7 billion to $3.8 billion impact range.

<u>Response:</u>

Confirmed. The economic impact ranging from $1.7 billion to $3.8 billion assumes a 3-day no-flow winter event on T-South, which exceeds FEI's current capability to withstand, resulting in a loss of service to 600,000 to 640,000 customers on the first day of the outage and who remain without gas service for a prolonged period.

1.2 Please clarify and discuss how the expected reduction of $1.1 billion (Figure 4-20, p. 161) in negative GDP with the addition of the TLSE Project (alternative 9) over 67 years relates to the economic impact ranging from $1.7 billion to $3.8 billion. As part of the response, please explain how the $1.1 billion was calculated and provide the assumptions (including weather conditions and outage duration(s)).

Response:

The question incorrectly states that the 67-year expected GDP loss reduction from Supplemental Alternative 9 is $1.1 billion. FEI clarifies that the correct 67-year expected GDP loss reduction from the Preferred Alternative (Supplemental Alternative 9) is approximately $11.1 billion.

The $1.7 billion to $3.8 billion range is the economic impact estimated by PwC assuming a winter T-South no-flow event occurs (i.e., the negative economic consequence of a single winter T-South no-flow event). PwC's analysis does not consider the probability of the event occurring, nor does it contemplate multiple T-South no-flow events occurring over a specified time horizon.

The 67-year expected GDP loss reduction from Supplemental Alternative 9 of $11.1 billion, which was calculated by Exponent, represents the amount of risk mitigation provided by the Preferred Alternative over a 67-year time horizon. This value exceeds the $1.7 billion to $3.8 billion range as Exponent's analysis shows that, over a 67-year time horizon, multiple T-South no-flow events may occur.

The following response has also been provided by Exponent:

Exponent's analysis indicated an expected reduction of $11.1 billion CAD over 67 years (Alternative 9), not $1.1 billion CAD as suggested in the question.

Exponent understands the $1.7 billion to $3.8 billion range calculated by PwC to refer to a single winter no-flow event. This is a deterministic calculation, i.e., what happens if there is a no-flow event – with some error bounds applied. Risk reduction expressed over a time period, in contrast, considers the likelihood of multiple events and numerous uncertainties.

1.3 FEI states that "direct mitigation of these impacts by the TSLE Project primarily benefits FEI's customers". Please clarify whether it is FEI's assertion that the potential economic impact per the PwC Report is expected to be mitigated by $1.1 billion as a result of the TSLE Project.

Response:

FEI's evidence is that the TLSE Project (i.e., Supplemental Alternative 9, which is forecast to cost approximately $1.144 billion, in as spent $) will provide mitigation against the risk of a winter T-South no-flow event.

The amount of risk mitigation provided by the Preferred Alternative considering annual, 23-year, and 67-year time horizons is summarized in the Exponent Report (Table 9 of Appendix RP 2 to the 2024 Resiliency Plan), and is reproduced below. FEI notes that in Table 9, the entirety of T-South is represented by the "Combined" row.

Please refer to the response to BCOAPO IR6 1.2, which explains that the direct mitigation provided by the TLSE Project is expected to be approximately $11.1 billion over a 67-year time horizon, not $1.1 billion.

Table 9. Annual, 23-year, and 67-year expected winter-only GDP loss reductions in million CAD for AV-1, AV-2, AV-3, AV-54 individually and combined.

	Alternatives 7 and 9			Alternative 8		
AV	Annual GDP Loss Reduction	23-Year GDP Loss Reduction	67-Year GDP Loss Reduction	Annual GDP Loss Reduction	23-Year GDP Loss Reduction	67-Year GDP Loss Reduction
AV-1	96.4	2218.1	6461.5	94.1	2164.9	6306.4
AV-2	12.2	280.0	815.7	11.9	273.0	795.4
AV-3	22.8	524.9	1529.1	22.5	517.9	1508.6
AV-54	34.1	784.9	2286.3	33.8	778.1	2266.7
Combined	165.6	3808.0	11092.7	162.3	3733.9	10877.1

1.4 Please clarify whether the negative GDP of $1.7 billion to $3.8 billion is the potential economic impact associated with only FEI's customers. If not, please provide the expected economic impact associated with only FEI's customers.

Response:

The following response has been provided by PwC:

This figure of $1.7 billion to $3.8 billion represents the economic impact estimated for all BC, not just FEI customers. While the first-round effects of the disruption (direct effects) are designed to measure the impact on FEI customers, the multiplier effects (indirect and induced effects) will fall on both FEI customers and non-customers.

The scope of the PwC analysis did not include providing a disaggregated estimate of how the economic harm may be distributed between FEI customers and non-customers, but it is likely that both groups would experience significant economic disruption, alongside other health, social and welfare impacts on individuals that are not quantified in the analysis.

2.0 Reference: PROJECT NEED

Exhibit B-63, BCUC IR 5 – 124.1, 141.4 & 141.7

Topic: Economic Impact of Winter no-flow Event

Preamble:

FEI provides the following responses:

"While FEI's 2024 Resiliency Plan speaks qualitatively to the potential for electric system outages, the risk analysis does not include the impact. That is, the consequence value used to calculate the risk did not include the negative GDP impact resulting from an electric system outage caused by the pressure collapse of the gas system. To the extent that a consequential electric system outage were to occur, the GDP impacts would (all else equal) be higher than those calculated by PwC". (**BCUC IR 5 – 124.1**)

"The interviews conducted provided a range of quantitative and directional inputs for the analysis." (**BCUC IR 5 – 141.4**)

"In addition, it should be noted that the use of primary research, through interviews or surveys, is commonly used in studies that assess economic costs of utility supply outages where these studies consider a hypothetical future event. On the other hand, assessments of real-world events that have occurred in the past commonly draw upon historic economic data and statistics to inform such analysis." (**BCUC IR 5 – 141.4**)

"…PwC's Reviewed Scenarios were selected for geographic coverage of FEI's system, not on the basis that they are the most significant vulnerabilities in FEI's 2024 Resiliency Plan. Nor do they correspond with the AVs that are mitigated by the Supplemental Alternatives. PwC's analysis was not directed at assessing the mitigation provided by specific Supplemental Alternatives." (**BCUC IR 5 - 141.7**)

2.1 Please clarify if it is FEI's position that a consequential electric outage is likely to result in the case of a 3-day no-flow event on T-south assuming the conditions underpinning the TLSE Project. If not, please provide the probability that such an event would occur under the conditions assumed in the TLSE Project and discuss the assumptions.

<u>Response:</u>

Please refer to the response to CEC IR6 155.1.

2.2 Please identify the conditions provided to participants as part of the interviews conducted by PwC. For example, please explain the outage duration and weather conditions provided as part of the interviews. As part of the response, please provide: i) the detailed outage scenarios provided to participants who provided specific quantitative inputs separately from the outage scenarios provided to participants who provided directional inputs on activity reduction; and ii) the proportion of participants who provided specific quantitative inputs compared to those who provided directional inputs (based on $).

Response:

The following response has been provided by PwC:

Page 7 of the PwC report outlines the themes and topics covered in the interviews. As stated, all participants were asked to consider the impact of a “prolonged outage”, defined as a two-to-four-week period, on the ability of their business to operate. It was also stated that it should be assumed that the outage would occur during winter.

The majority of the interviewees provided specific quantitative views on the impact of the outage scenario on economic output. Furthermore, as stated in the PwC report, interviews were not the only evidence base for the output loss assumptions, they were augmented through a review of academic literature, evidence on the economic impact of past catastrophes and benchmarking.

2.3 For those stakeholders who indicated little or no impact on economic activity, please provide the types of business/industry along with their rationale, without disclosing commercially sensitive information on the public record. If commercially sensitive information is relevant, please provide that in a confidential IR response.

Response:

The following response has been provided by PwC:

As set out in Appendix 1 of the PwC report, a number of interviewees indicated that the outage was expected to have a limited impact on their ability to operate. One such example is the pulp and paper sector, where it was indicated that most facilities use biomass as their primary energy source and that gas supplies were typically only used as a backup if the biomass system were to close for maintenance or repair.

In addition, in sectors where no interviews were held, it was assumed that there would be no direct economic impact from the supply disruption. These sectors represent approximately 40% of BC’s economy and this approach was taken to build conservatism into the approach. In practice these sectors would likely also experience some level of economic disruption from a natural gas outage.

2.4 Please confirm, or otherwise explain, whether the participatory stakeholders were all FEI natural gas customers. If not, please provide the percentage of participants who were not and their percentage of GDP per the PwC report.

Response:

The following response has been provided by PwC:

Lists of FEI customers who were major natural gas users were used as the basis for identifying interview targets. At the time the interview was held, it was our understanding that all interviewees were FEI customers or had direct knowledge of the impact on FEI's customers (e.g., leaders of Industry Associations who commented on the impact on their member organisations).

As stated in the response to BCOAPO IR6 1.4, it should also be noted that the estimates for direct GDP impact were assumed to be incurred by FEI customers only. However, the inclusion of indirect and induced effects (i.e., supply chain and employee consumption effects) also includes non-FEI customers who are located in BC and would be indirectly affected by business activity reductions experienced by FEI customers.

3.0 Reference: PROJECT NEED

Exhibit B-60, page 18, Figure 1-5

Exhibit B-63, BCOAPO IR 5 – 2.1 & 2.2

Topic: Weighting of Criteria

Preamble:

FEI provides the following responses:

"In Step 2 of the expanded alternatives analysis, FEI eliminated all Supplemental Alternatives that failed to at least maintain FEI's existing on-system firm peaking gas supply capabilities. Therefore, all Supplemental Alternatives that proceeded to Step 3 of the analysis (i.e., the step where the evaluation criteria and weightings were applied) would, at a minimum, result in FEI having the same gas supply capabilities as it has today." (**BCOAPO IR 5 – 2.1**)

"…while FEI recognizes the importance of mitigating customer rate impacts, the "Rate Impact" criterion should not be weighted higher than the criteria which captures the ability of an alternative to deliver on the primary drivers for the Project. As such, FEI does not support weighting "Rate Impact" higher than "Resiliency"". (**BCOAPO IR 5 – 2.2**)

"… the "Rate Impact" criterion has been assigned the same weighting as the "Gas Supply" criterion and the "Base Plant Challenges" criterion. FEI considers it reasonable to assign these criteria the same weighting but lower than the "Resiliency" criterion." (**BCOAPO IR 5- 2.2**)

3.1 Please explain why it is necessary to weight the "Gas Supply' criterion in Step 3 given that each alternative that proceeded it would, at a minimum, result in FEI having the same gas supply capabilities as it has today.

<u>Response:</u>

FEI considered "Gas Supply" as a criterion in Step 3 to assess the differences between the Supplemental Alternatives with respect to gas supply performance.

As described in Section 3.3.4.2 of the Supplemental Evidence, in recent years, FEI has been required to augment its peaking gas supply capabilities with suboptimal measures due to a constrained market and a lack of LNG peaking supply. Therefore, the inclusion of the Gas Supply criterion enabled FEI to assess an alternative's ability to improve upon FEI's current suboptimal peaking gas supply capabilities when selecting a preferred alternative. FEI considers this assessment to be important and distinct from that of the Step 2 screen, which ensures that FEI has access to sufficient and dependable peaking supply to serve firm customers during normal operations (which is one of the needs underlying the TLSE Project).

As described in Section 4.2.2.3.3 of the Supplemental Evidence, FEI Subject Matter Leads determined the weighting of each criterion by conducting a qualitative review considering the relative importance of each criterion. The 20 percent weighting for the Gas Supply criterion was selected because, since the minimum gas supply standard was met in Step 2, it was considered appropriate to give equal weight to differences in gas supply, levelized total rate impact, and the extent to which an alternative addresses the Base Plant's inherent challenges. In other words, once it is established that the Supplemental Alternatives in Step 3 will not leave FEI worse off than it is today from a gas supply perspective, FEI considers Gas Supply, Base Plant Challenges, and Rate Impact to be equally important when selecting a preferred alternative.

3.2 Please explain FEI's justification for a 20% weighting applied to the Gas Supply criterion given that each alternative at this phase provides the same gas supply capability as FEI has today.

Response:

Please refer to the response to BCOAPO IR6 3.1.

3.3 Please explain FEI's justification for an equal weighting applied to the Rate Impact and Gas Supply criteria given the same gas supply capability as FEI has today.

Response:

Please refer to the response to BCOAPO IR6 3.1.

3.4 Please explain FEI's rationale for a total 30% combined weighting for the Gas Supply and Useful Under the Modified Diversified criteria compared to a 20% Rate Impact weighting.

Response:

The "Gas Supply" and "Useful Under the Modified Diversified" (i.e., Future Use) evaluation criteria are separate and distinct from one another. The Gas Supply criterion evaluates the impact on the availability of dependable gas supply during peak demand, whereas the Future Use criterion considers if the alternative is useful or underutilized under two adverse future load sensitivities in which FEI's Diversified Energy Planning (DEP) Scenario is modified to assume higher rates of customer and load loss (2 percent and 5 percent annually) between the in-service date and 2050. As they are distinct criteria, no meaningful conclusions can be drawn from comparing the combined weighting from adding the two criteria to the weighting of a separate criterion.

Please refer to the response to BCOAPO IR6 3.1 for discussion on why the Gas Supply and Rate Impact criteria are weighted equally.

Please also refer to Section 4.2.2.3.3 of the Supplemental Evidence and the response to BCOAPO IR5 2.2 which explains that the Future Use criterion was weighted the lowest of all criteria due to the inherent uncertainty associated with the criterion.

3.5 Please explain FEI's rationale for an equal weighting applied to the Resiliency criterion and the combined Gas Supply and Useful Under the Modified Diversified criteria.

Response:

Please refer to the response to BCOAPO IR6 3.4 for a discussion on why it is not meaningful to compare the sum of the weightings from two distinct criteria to a third criterion.

Please refer to the response to BCOAPO IR5 2.1 for discussion on why the Resiliency criterion is weighted higher than the Gas Supply criterion.

Please also refer to Section 4.2.2.3.3 of the Supplemental Evidence and the response to BCOAPO IR5 2.2 which explains that the Future Use criterion was weighted the lowest of all criteria due to the inherent uncertainty associated with the criterion.

3.6 Please provide a version of Figure 1-5 with the results based on modified weightings as follows: i) Resiliency – 35%; ii) Dependable gas during peak demand – 10%; iii) Resolves age related plant challenges – 10%; iv) Rate Impact – 35%; and v) Useful under modified planning – 10%. As part of the response, please discuss the results and conclusions that may be reasonably drawn.

Response:

FEI provides a modified version of Figure 1-5 with the requested weightings below and makes the following observations about the results:

- Supplemental Alternative 9 still scores the highest and remains the Preferred Alternative.
- While the Total Weighted Scores have changed compared to the scoring in the Supplemental Evidence, the relative ranking of each Supplemental Alternative is unchanged.
- The percentage difference in scoring between Supplemental Alternative 9 and the other Supplemental Alternatives (4, 4A and 8) increases when applying the revised weightings. This is because the revised weightings place greater importance on improving resiliency than on gas supply.
- Increasing the weighting of the Rate Impact criterion relative to the Supplemental Evidence (35 percent versus 20 percent) results in a lower Total Weighted Score for all Supplemental Alternatives.

Revised Figure 1-5: Evaluation Results with Modified Weightings

Evaluation Criterion	Criterion Weighting	Alternative 4	Alternative 4A	Alternative 8	Alternative 9
Resiliency Benefit	35%	No Impact	No Impact	Medium Positive Impact	High Positive Impact
Availability of Dependable Gas Supply During Peak Demand	10%	Medium Positive Impact	High Positive Impact	Medium Positive Impact	High Positive Impact
Resolves Age Related Base Plant Challenges	10%	High Positive Impact	High Positive Impact	High Positive Impact	High Positive Impact
Levelized Total Rate Impact	35%	Low Negative Impact	Low Negative Impact	Medium Negative Impact	Medium Negative Impact
Useful Under the Modified Diversified Energy (Planning) Scenario (mDEP 2% and 5%) Between the In-Service Date and 2050	10%	No Impact	No Impact	No Impact	No Impact
	Total Weighted Score:	0.5	0.7	0.8	1.7
					Preferred

FEI maintains that the weightings presented in the Supplemental Evidence remain reasonable and appropriate. This is because BCOAPO's proposed weightings undervalue the importance of the Gas Supply criterion, which is one of the two primary needs underlying the TLSE Project. Further, as explained in the response to BCOAPO IR5 2.2, while FEI recognizes the importance of mitigating customer rate impacts, the Rate Impact criterion should not be weighted higher than the criteria that deliver on the primary drivers for the Project. As such, FEI does not support weighting the Rate Impact criterion higher than the Gas Supply criterion. Even so, since all Supplemental Alternatives considered in Step 3 will, at a minimum, result in FEI having at least the same gas supply capabilities as it has today, the impact of undervaluing the Gas Supply criterion is less severe than the impact of undervaluing Resiliency, as demonstrated in the response to BCOAPO IR5 2.3.

3.7 Please provide a version of Figure 1-5 with the results based on modified weightings as follows: i) Resiliency – 40%; ii) Dependable gas during peak demand – 0%; iii) Resolves age related plant challenges – 20%; iv) Rate Impact – 40%; and v) Useful under modified planning – 0%. As part of the response, please discuss the results and conclusions that may be reasonably drawn to the extent they differ from the response to BCOAPO IRs 5 –2.2 and 2.3.

Response:

FEI provides a modified version of Figure 1-5 with the requested weightings below. Applying the modified weightings, Supplemental Alternative 9 scores the highest and remains the Preferred Alternative.

FEI does not consider the modified weightings to be appropriate for the same reasons provided in the response to BCOAPO IR6 3.6.

Revised Figure 1-5: Evaluation Results with Modified Weightings

Evaluation Criterion	Criterion Weighting	Alternative 4	Alternative 4A	Alternative 8	Alternative 9
Resiliency Benefit	40%	No Impact	No Impact	Medium Positive Impact	High Positive Impact
Availability of Dependable Gas Supply During Peak Demand	0%	Medium Positive Impact	High Positive Impact	Medium Positive Impact	High Positive Impact
Resolves Age Related Base Plant Challenges	20%	High Positive Impact	High Positive Impact	High Positive Impact	High Positive Impact
Levelized Total Rate Impact	40%	Low Negative Impact	Low Negative Impact	Medium Negative Impact	Medium Negative Impact
Useful Under the Modified Diversified Energy (Planning) Scenario (mDEP 2% and 5%) Between the In-Service Date and 2050	0%	No Impact	No Impact	No Impact	No Impact
	Total Weighted Score:	0.6	0.6	1.0	1.8
					Preferred

3.8 Please provide an Evaluation Scoring with Modified Weighting table that consolidates the quantitative results of the following scenarios: i) FEI's scoring as filed; ii) BCOAPO IR 5.2.3; iii) BCOAPO IR 5.2.4; iv) BCOAPO IR 6.3.6; and v) BCOAPO IR 6.3.7.

Response:

Please refer to the following table. The Supplemental Alternative with the best (highest) score in each scenario is highlighted in bold.

Table 1: Summary of Scoring Results from Supplemental Evidence and Requested Modified Weightings

Scenario	Alternative 4	Alternative 4A	Alternative 8	Alternative 9
Supplemental Evidence	1.4	1.8	1.9	**2.9**
BCOAPO IR5 2.3	1.8	**2.3**	1.6	**2.3**
BCOAPO IR5 2.4	1.3	**1.7**	1.0	1.6
BCOAPO IR6 3.6	0.5	0.7	0.8	**1.7**
BCOAPO IR6 3.7	0.6	0.6	1.0	**1.8**

4.0 Reference: PROJECT NEED

Exhibit B-63, BCUC IR 5 – 118.1

Topic: Load Change Excluding Impact of Transportation Customer Return

Preamble:

FEI provides the following response:

"FEI clarifies that the annual demand forecast presented in Figure 4-9 of the 2022 LTGRP (included in the preamble to this information request) does not, and is not intended to, represent the peak demand requirements that will be served by the TLSE Project. Figure 4-9 shows the demand that is forecast to be used by residential, commercial and industrial customers over the entire year, for each year of the forecast at the time of filing the 2022 LTGRP. It does not correlate to the demand from these customer groups during a short-term peak event (daily or hourly), nor the amount of demand that might occur during an outage on the upstream delivery system. Please refer to the response to BCUC IR5 118.5 for further discussion regarding FEI's peak day demand forecast.

FEI plans gas supply resources to meet customer demand in a design year. As shown in the figure below, over the last 10 years, ACP annual design load and peak day demand has increased by 39 Bcf and 129 MMcf/d, respectively. This load increase was primarily driven by Transportation customers returning to Core customers (i.e., RS 23 returning to RS 3). This increase has required FEI to contract additional resources from the market." (**BCUC IR 5 – 118.1**)

4.1 Please explain and provide the terms and conditions of service with respect to Transportation customers. As part of the response, please explain the terms by which FEI is obligated to serve Transportation customers under Core Service, service length, and the financial obligations.

<u>Response:</u>

The Transportation Service model has been in place for commercial and industrial customers since 1993. The Transportation Service model includes business rules, some of which were established by the BCUC in Letter L-25-03 regarding commodity unbundling, including the Essential Services Model (ESM) as the foundation. The ESM recognizes that FEI performs an essential service, is the supplier of last resort, and is also responsible for the longer-term infrastructure planning and for emergency response. Transportation Service customers are responsible to source their own gas supply, either from a shipper/shipper agent or gas marketer (shipper) and have the gas delivered directly to FEI's system at an interconnection point. FEI is required to balance the gas system as a whole, including all volumes from bundled Sales Service (Core customers) and Transportation Service customers. While Transportation Service customers (or their shipper agents) are expected to make best efforts to bring on sufficient supply to meet their customer demand, FEI must balance the system daily which includes addressing any imbalances that may occur from shippers. Many natural gas local distribution companies (LDCs) in North America have a Transportation Service offering similar to FEI's.[1]

The primary difference between bundled Sales Service and Transportation Service is that Transportation Service provides customers with the opportunity to purchase their natural gas as a commodity from parties other than FEI (i.e., a shipper). To be clear, FEI has the same obligation to serve all customers their firm load requirements regardless of which model customers elect to receive service under.

As part of implementing the Transportation Service model, parallel Transportation Service rate schedules were developed for commercial and industrial customers to facilitate the choice between bundled Sales Service (RS 2, 3, 5, 6, 7 and later RS 46[2]) and Transportation Service (RS 22, 23, 25, 26, 27 and 46). FEI's rate schedules under both models serve a variety of types of customers including, for example, businesses, schools, institutions, hospitals and public buildings.

The terms and conditions of Transportation Service are found in each rate schedule and include provisions for the length of term, automatic renewal of the term, and notice requirements when a customer elects to switch between a Transportation Service rate schedule to a bundled Sales Service rate schedule (i.e., from RS 23 to RS 3 or vice versa) or from interruptible service to firm service.

For example, the excepts below from RS 23 highlight some of the terms.

Sections 12.1 and 12.2 set out the term, automatic renewal and switching provisions:

> 12.1 **Term**
>
> The initial term of the Transportation Agreement will begin on the Commencement Date and will expire at 7:00 a.m. Pacific Standard Time on the next November 1st, provided that if the foregoing results in an initial term of less than one Year, then the initial term will instead expire at the end of one further Contract Year.
>
> 12.2 **Automatic Renewal**
>
> Except as specified in the Transportation Agreement, the term of the Transportation Agreement will continue from Year to Year after the expiry of the initial term unless cancelled by either FortisBC Energy or the Shipper,

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1 For example, as part of FEI's 2016 Rate Design Application, a jurisdictional review was done to compare FEI's Transportation Service balancing provisions with those of approximately 20 other North American local distribution companies: FEI's 2016 Rate Design Application, Appendix 10-1, Black & Veatch Transportation Service Model review, https://docs.bcuc.com/documents/proceedings/2017/doc_48545_b-1_fei-2016-rate-design-application.pdf.

2 RS 46 first became available as a bundled Sales Service rate schedule by Order G-211-13, effective December 12, 2013. By Order G-225-19, effective May 1, 2019, the Transportation Service offering was included in RS 46. Therefore, RS 46 contains both options to receive bundled Sales Service or Transportation Service through the same rate schedule.

subject to Section 3.3, (Warning if Switching from Interruptible Transportation Service or Interruptible Sales to Firm Transportation Service or Sales) upon not less than 2 months notice prior to the end of the Contract Year then in effect.

Section 3.3 addresses circumstances when an interruptible customer with significantly large volumes requests a switch to firm service. FEI must make reasonable efforts to accommodate a shipper or customer request to switch. In this circumstance it may be a necessity for FEI to incur costs to accommodate the firm load, such as system reinforcements or improvements, which FEI may be reimbursed by the customer requesting the switch, if required.

3.3 **Warning if Switching from Interruptible Transportation Service or Interruptible Sales to Firm Transportation Service or Sales**

A Shipper wishing to request a switch at the end of the term of an interruptible Transportation Agreement or an interruptible Gas Service Agreement to a firm sales Rate Schedule, or to firm transportation under this Rate Schedule, or to increase their Firm DTQ under this Rate Schedule must comply with the requirements for Firm Service set out in the applicable Rate Schedule, including the following:

(a) give 12 months prior notice to FortisBC Energy of the Shipper's desire to do so; and

(b) after receiving an estimate from FortisBC Energy of costs FortisBC Energy will reasonably incur to provide such Service, agree to reimburse FortisBC Energy for any such costs.

Notwithstanding Section 3.3(a), FortisBC Energy will make reasonable efforts to accommodate a Shipper on less than 12 months prior notice if FortisBC Energy is able, with such shorter notice, to arrange for the firm purchase and firm transportation of Gas under a firm sales Rate Schedule, or transportation under a firm transportation Rate Schedule.

For customers electing to switch from Transportation Service to bundled Sales Service, Section 26.2 of FEI's General Terms & Conditions sets out a customer's notice requirements, requires that FEI supply the customers if it is able to secure the additional supply and midstream resources to accommodate the customer and, if necessary, prescribes a mechanism for FEI to apply to the BCUC for approval to charge the customer for costs if it cannot otherwise reasonably accommodate the request to switch. Nothing in Section 26.2 relieves FEI from its obligation to serve the customer under bundled Sales Service (Core). Section 26.2 is provided below for reference:

26.2 **Direct Purchase Customers Returning to FortisBC Energy System Supply**

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

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

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

(c) FortisBC Energy may, subject to British Columbia Utilities Commission approval, charge the Customer for any costs associated with the Customer returning to system Gas supply. Such costs may include, among other things, the costs of securing additional Gas supply and transportation to accommodate the Customer. FortisBC Energy may bill the Customer for such costs as part of the regular FortisBC Energy bill for Service.

4.2 To the extent that the terms and conditions of service applicable to, please explain and provide the terms of service for remaining Transportation customers, highlighting where they differ from those applicable to the customers that elected to return to Core customers.

Response:

The terms and conditions of Transportation Service for the remaining Transportation Service customers are unaffected by customers that have elected to return to bundled Sales Service and become part of FEI's Core customers.

As discussed in the response to BCOAPO IR6 4.1, FEI provides delivery service to both Transportation Service and bundled Sales Service customers. Generally, the difference between Sales Service and Transportation Service is that Transportation Service customers must provide their own commodity and related services (i.e., gas supply and related services including storage and transport (midstream)) either themselves or through a shipper, to deliver their required supply to FEI's system. Among other things, the Transportation Service rate schedules set out the terms, conditions and obligations with respect to gas supply nomination, balancing requirements and when balancing charges are applicable (i.e., RS 23, Sections 7 to 9). Interruptible customers, whether under the Transportation Service model or the bundled Sales Service model, have the same terms, conditions and obligations as firm service customers under their respective models; however, they are subject to curtailment (interruption) if required by FEI.

In contrast, bundled Sales Service customers (Core customers), whether receiving interruptible or firm service, receive both delivery service and commodity and related services from FEI. Core customers are not responsible for any of their gas supply, storage and transport (midstream), or balancing service and are not subject to balancing charges.

4.3 Please explain what gave rise to Transportation customers returning to Core customers (without disclosing commercially sensitive information to the extent possible).

Response:

FEI provides the following subsection from the Executive Summary to FEI's 2024/2025 Annual Contracting Plan (ACP) accepted by Letter L-13-24[3] that addresses this question.

> ***Section 3.5.2.2 Customer Movement Between Bundled and Transportation Service Models[4]***
>
> Historically, customer movement between FEI's bundled service and the transportation service has been relatively minor. Many of the transportation service customers in the Lower Mainland have been able to serve their demand requirements by accessing some transportation capacity in the secondary market[5] and by purchasing gas supply at the Huntingdon/Sumas market. FEI became concerned when large-scale industrial projects proposed in the region, specifically Woodfibre LNG, began securing firm transportation capacity on the Westcoast T-South pipeline for a portion, if not all, of their supply requirements. The concern was that the incremental demand from these projects could pose a risk to any customer that relies on supply at the Huntingdon/Sumas market.
>
> FEI first became concerned with these regional transportation and storage resources constraints in 2014 and secured additional T-South capacity to allow for the potential of transportation service customers returning to bundled service, as well as for future load growth.[6] This proved to be a prudent decision because the T-South Huntingdon Delivery capacity has been fully contracted since that time. FEI began to experience an increase in transportation service customers moving back to the bundled service in 2017, but the most significant movement occurred

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[3] Letter L-13-24, pages ES-14 to ES-16. https://www.ordersdecisions.bcuc.com/bcuc/orders/en/522302/1/document.do.

[4] Transportation Service Model - customers who elect to take service under the transportation service model arrange for their own supply that is then transported by FEI to their premises. Bundled Service - customer purchases both the gas supply and delivery service from FEI. FEI's Core Customers take bundled service.

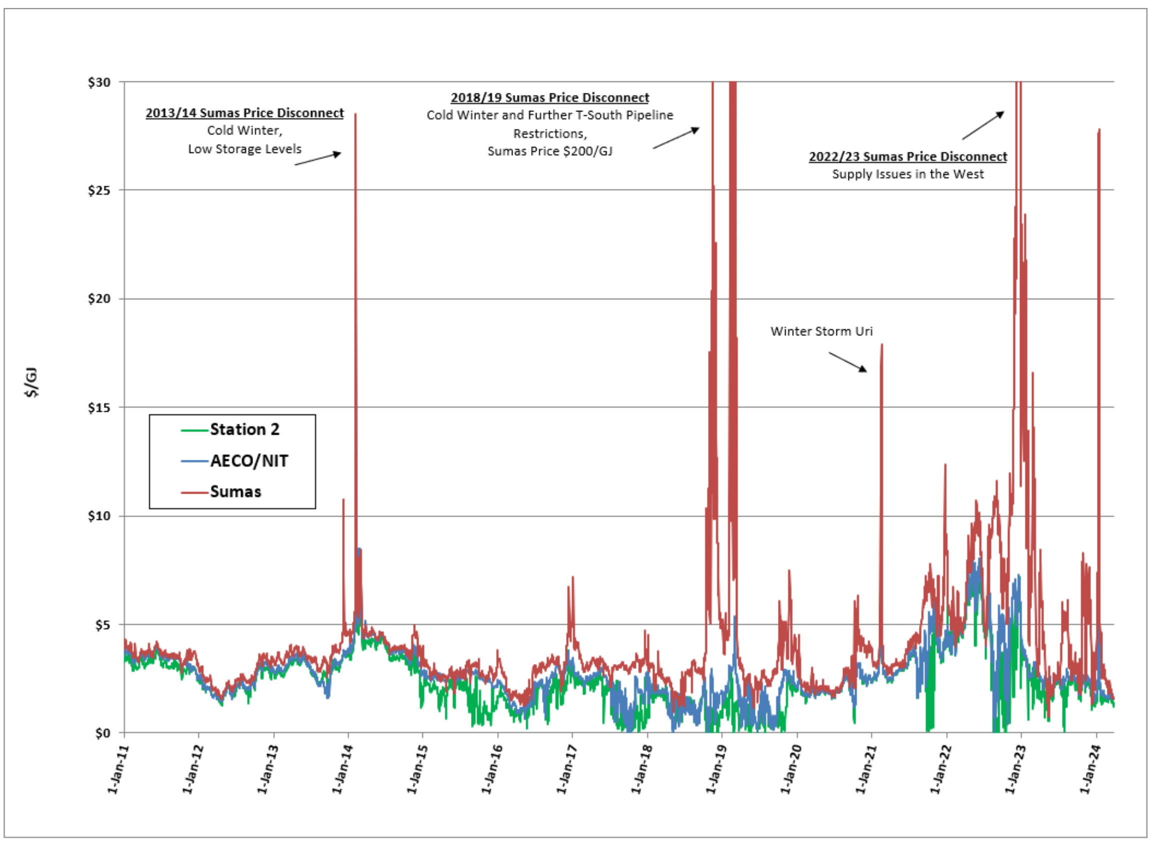
[5] Shippers on the T-South system can temporarily release pipeline capacity on an annual or seasonal basis that is not required for their own use.

[6] Approved by the BCUC on December 3, 2015 by Letter L-43-15.

after the T-South Incident[7], when 42 percent (over 900 transportation service customers) provided notice to FEI of their intention[8] to return to bundled service as of November 1, 2019. Given FEI's proactive decision to secure additional T-South capacity for this potential development, the customer movement after the T-South Incident did not have a material impact on the portfolio.

The volatility at the Huntingdon/Sumas market continued after the T-South Incident, which has led to more transportation service customers returning to the bundled service. This was exemplified during the 2022/2023 winter season, when the Huntingdon/Sumas market experienced greater pricing volatility than what occurred during the T-South Incident, as Figure ES-2 illustrates below. The average Sumas daily price between November and March was approximately $16/GJ, which was over $12/GJ higher than the Station 2 price and over $15/GJ higher than the AECO/NIT price. This development led to over 230 transportation service customers providing FEI their notice to return to the bundled service effective November 1, 2023.

Figure ES-2: Station 2, AECO/NIT and Sumas Daily Spot Prices (2010 to 2024)



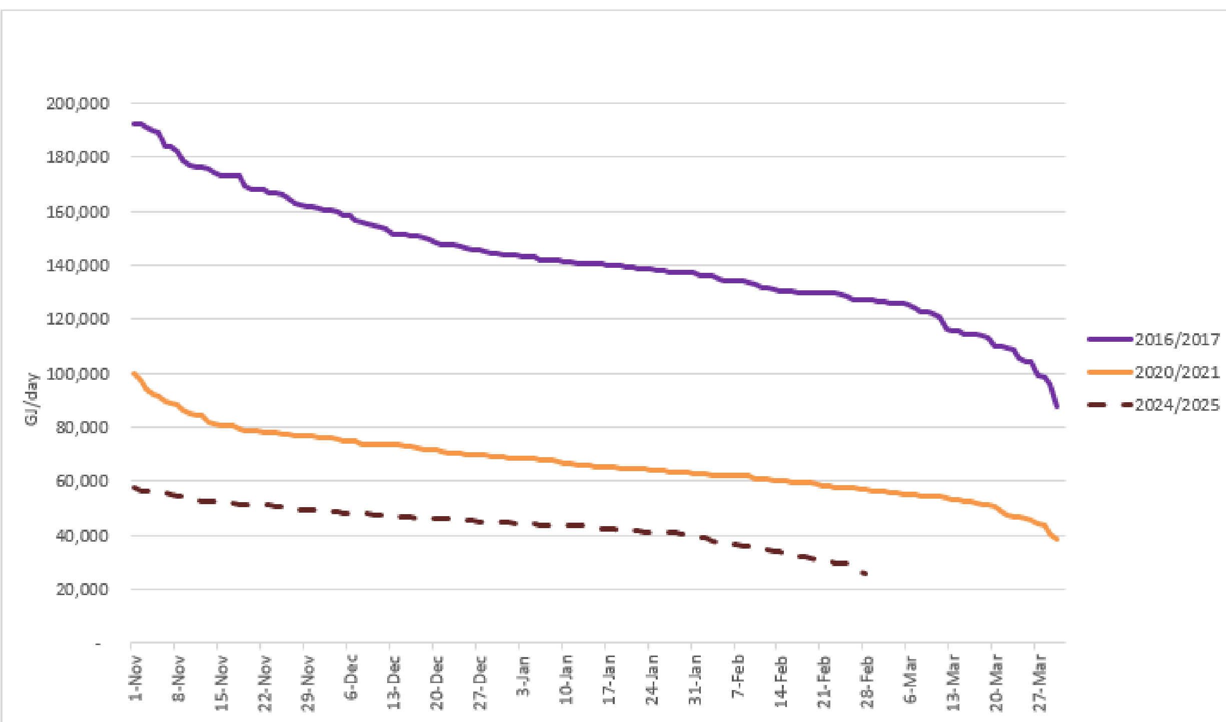
[7] T-South Incident defined in the Annual Contracting Plan as the October 9, 2018 pipeline rupture and the capacity restrictions imposed thereafter on the T-South system.

[8] This was due to the volatility at the Huntingdon/Sumas market when the average Sumas daily price for the entire 2018/19 winter was approximately $15 Cdn/GJ, which was approximately $12 Cdn/GJ higher than FEI's cost of gas.

This development has had a significant impact on FEI's ACP, as the winter design load forecast has increased by ~100 TJ/day since the 2017/2018 gas year. FEI has offset these increases by utilizing its supplemental pipeline capacity held on T-South (i.e., contingency resources). However, this comes at the expense of having less T-South capacity to help meet FEI's 15 percent planning margin for resiliency purposes, which exposes its Core customers to more risk of supply disruption. Given that FEI's excess pipeline capacity that has been serving as a contingency resource is declining, further demand increases from Core customers and/or a reduction of portfolio resources (i.e., regional storage at Mist) will result in having portfolio exposure to the Huntingdon/Sumas market until new infrastructure in the region is added. This is discussed in detail throughout the 2024/2025 ACP.

FEI expects that the Transportation Service customers in the Lower Mainland will continue to move back to the bundled service, given the risk of frequent and sustained pricing events during high demand periods will likely persist until there is some relief in the way of incremental pipeline capacity. However, there are only approximately 375 customers left on the Transportation Service model and the load associated with these customers is minor compared to what it was back in 2016, as the figure below illustrates.

Figure 1: Transportation Service Customer Winter Load Duration Curve (2016/2017 to 2024/2025)



FEI will continue to monitor such movement and could make an application to the BCUC to mitigate the impact of this scenario if needed.

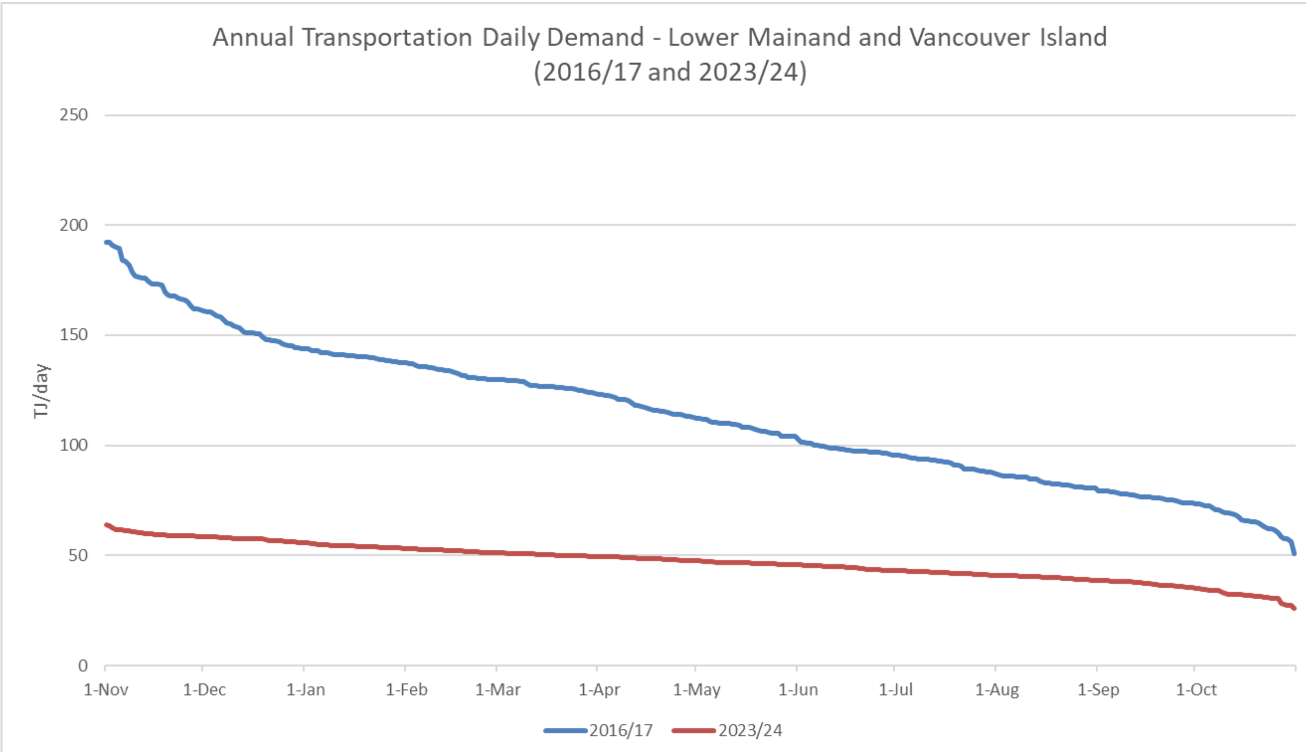
4.4 Please provide a version of Figure 1 (BCUC IR 5 – 118.1) that excludes or otherwise nullifies the increase in annual design load and peak day demand associated with Transportation customers returning to Core customers. As part of the response, please provide the increase or decrease in both the annual design load and peak day demand and discuss what (and who) is driving the change (in the absence of the impact associated with Transportation customers).

Response:

The load forecast used for FEI's gas supply planning is developed by studying the historical consumption of Core customers (RS 1 to 7 and 46) as a single group. FEI does not separate the forecast by customer group and, therefore, cannot provide a version of Figure 1 from the response to BCUC IR5 118.1 that excludes the Transportation Service customers. The increase of annual and peak demand due to Transportation Service customers returning to the bundled Sales service is embedded in the load forecast in addition to the organic growth due to the customer additions FEI has experienced in the past.

However, in order to be responsive, FEI has provided the graph below which shows a comparison of the load profiles for the Transportation Service customers in the Lower Mainland and Vancouver Island during the 2016/2017 and 2023/2024 gas years. As the graph shows, the Transportation Service customer peak demand during the 2023/2024 gas year was approximately 65 TJ/day, which was approximately 125 TJ/day less than the 2016/2017 gas year. Similarly, the annual load for the 2023/2024 gas year was approximately 45 TJ/day, which was approximately 70 TJ/day less than the 2016/2017 gas year. A significant amount of the variance between these gas years has been incorporated into FEI's load forecast, including Figure 1 from the response to BCUC IR5 118.1.[9]

[9] A portion of the variances could also be due to changing load composition, including customers that are no longer in business.


Annual Transportation Daily Demand - Lower Mainand and Vancouver Island
(2016/17 and 2023/24)
TJ/day
250
200
150
100
50
0
1-Nov
1-Dec
1-Jan
1-Feb
1-Mar
1-Apr
1-May
1-Jun
1-Jul
1-Aug
1-Sep
1-Oct
2016/17
2023/24

5.0 Reference: EXPANDED ALTERNATIVES ANALYSIS

Exhibit B-60, page 18, Figure 1-5

Exhibit B-63, BCUC IR 5 – 118.7 & 129.1

Topic: Load Decline Sensitivity

Preamble:

FEI states:

"In Figure 4-9 in the 2022 LTGRP, the Diversified Energy (Planning) Scenario shows that customer annual demand from residential, commercial, and industrial customers will decline slightly from 207 PJ in 2019 to 201 PJ in 2042. This scenario includes considerations for electrification in the residential, commercial and industrial sectors, which models the demand trajectory that reaches 25 percent electrification of residential and commercial demand and 10 percent of industrial demand by 2050….FEI clarifies that the annual demand forecast presented in Figure 4-9 in the 2022 LTGRP does not, and is not intended to, represent the peak demand requirements that will be served by the TLSE Project." (**BCUC IR 5 – 118.7.1**)

"FEI also provided a 5 percent annual load decline sensitivity (mDEP 5%) to model the potential impact of an extreme hypothetical scenario where the annual expected demolition rate more than doubled. FEI selected the 5 percent annual decline in response to the BCUC's commentary in the Adjournment Decision for FEI to further consider the potential for the transition towards a lower carbon future to affect the appropriate sizing of the TLSE Project. Unlike mDEP 2%, this sensitivity was not based on the 2022 LTGRP, but rather, was intended to represent an adverse and accelerated load decline scenario. The modelling results confirm that FEI would still be serving hundreds of thousands of customers in the Lower Mainland in 2050 and that the Lower Mainland and FEI's other service areas would still need peaking supply." (**BCUC IR 5 – 129.1**)

5.1 Please confirm, or otherwise explain, that the load forecasted as part of the 2022 LTGRP has no (or little) impact on the sizing of assets as reflected in FEI's capital project justifications, including the TLSE Project. If yes, please explain why FEI continues to invest in assets on a business-as-usual basis. If no, please clarify how the directional trends forecasted as part of the 2022 LTGRP have been reflected in the TLSE Project.

<u>Response:</u>

As explained in the response to BCUC IR5 118.1, FEI's 2022 LTGRP load forecast does not, and is not intended to, represent the peak demand requirements that will be served by the TLSE Project. As explained in Section 3 of the Supplemental Evidence, the TLSE Project, including its sizing, is driven by two distinct needs: (1) mitigating a significant resiliency risk to FEI's system;

and (2) ensuring continued access to dependable gas supply. Addressing these distinct Project drivers, and the associated evidence underlying this Application (and Supplemental Evidence), does not amount to a "business-as-usual-approach" as suggested in the question. Further, as part of the Supplemental Evidence and in response to the BCUC's commentary in the Adjournment Decision, FEI expressly considered the impact that transitioning towards a lower carbon future could have on the appropriate sizing of the TLSE Project. This analysis demonstrates that, even under the most adverse hypothetical sensitivity (mDEP 5%), FEI would still be serving hundreds of thousands of customers in the Lower Mainland in 2050. These sensitivities were derived by modifying FEI's DEP Scenario from the 2022 LTGRP.

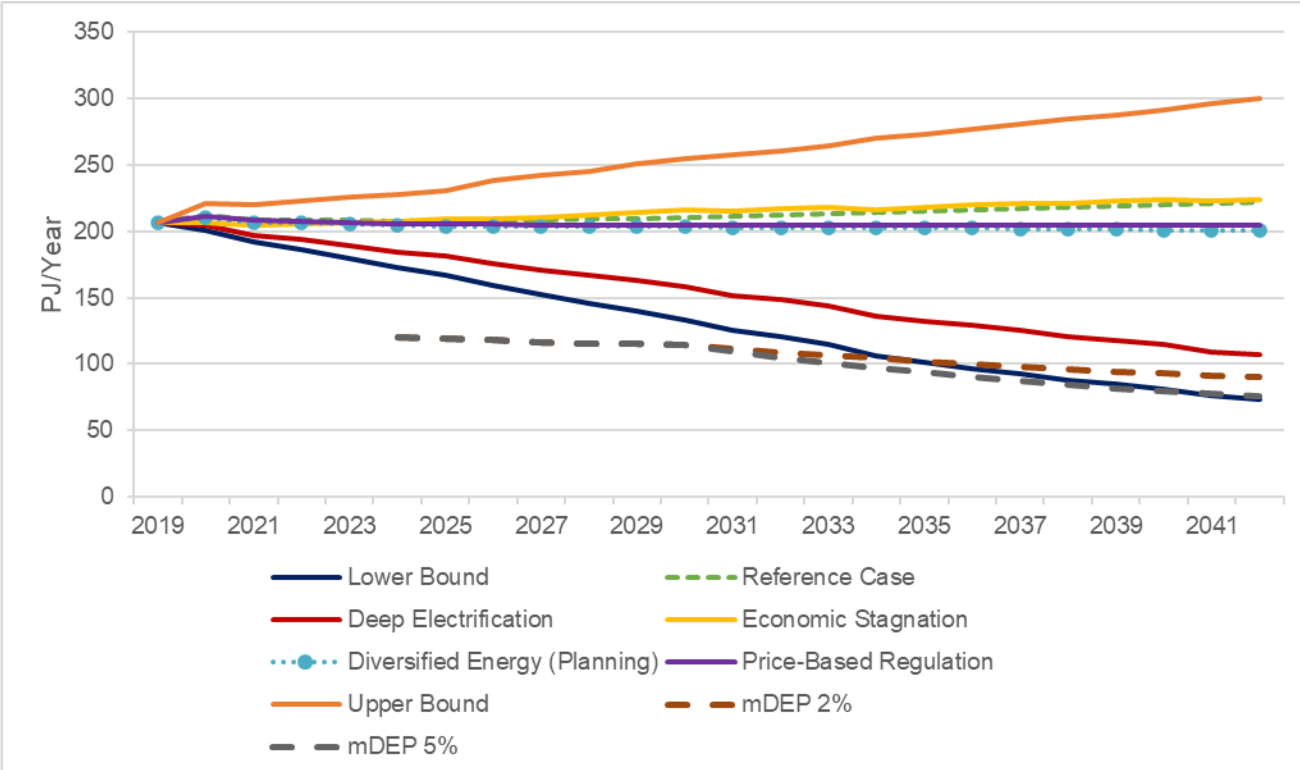
5.2 Please provide, with discussion, a version of Figure 4-9 filed as part of the FEI 2022 LTGRP (Exhibit B-1 p. 4-28) and replicated in BCUC IR 5 – 118.0 that incorporates the mDEP 2% and 5% scenarios.

Response:

Figure 4-9 from the 2022 LTGRP includes annual demand scenarios for all of FEI's residential, commercial and industrial customers, which includes Rates Schedules 1, 2, 3, 4, 5, 6, 7, 22, 23, 25 and 27. As discussed in the Supplemental Evidence, FEI began with the same Diversified Energy Planning (DEP) Scenario that was used to create Figure 4-9 in the 2022 LTGRP, and then modified the analysis to reflect which rate schedules, region and number of customers the TLSE Project would serve as a resiliency asset.[10] These modifications resulted in a different starting point for the graphed demand lines shown in the figure below. Otherwise, the primary difference in the starting year of 2024 between the mDEP scenarios and the DEP annual demand scenario from Figure 4-9 is the exclusion of non-Core rate schedules in the analysis presented in the Supplemental Evidence.

[10] Modifications are set out in Section 4.5.5.2.1 of the Supplemental Evidence, Exhibit B-60.

Revised Figure 4-9 from FEI's 2022 LTGRP Application with Hypothetical mDEP 2% and mDEP 5% Added



As shown in the figure above, the mDEP hypothetical scenarios start at approximately 84 PJ lower than the DEP Scenario due to the removal of non-Core rate schedules and the narrower region of the Lower Mainland compared to FEI's entire service area. The trajectory then follows the DEP Scenario until 2031, when customers and load start to be eliminated from the mDEP scenarios. In 2042, mDEP 2% is 110 PJ lower than the DEP Scenario and mDEP 5% is 125 PJ lower than the DEP Scenario. As a result, if the hypothetical loss of customers and load were to occur, FEI estimates that its load would be 26 to 41 PJ lower than the DEP Scenario.

Comparing the mDEP hypothetical scenarios against the Deep Electrification scenario in the Revised Figure 4-9 above would provide little value. The mDEP scenarios are based on the DEP Scenario, whereas the Deep Electrification scenario has a different starting point and assumptions that underpin the volume forecast over time. However, if FEI were to adjust the end points (2042) of the mDEP scenarios by the same load as it did for the starting (2024) point for the DEP Scenario (i.e., an mDEP adjustment of 84 PJ), the endpoints would be negative (effectively zero).

5.3 Please elaborate on FEI's statement that "the modelling results confirm that FEI would still be serving hundreds of thousands of customers in the Lower Mainland in 2050 and that the Lower Mainland and FEI's other service areas would still need peaking supply".

Response:

The sentence indicates that, even assuming an extreme hypothetical scenario (i.e., mDEP 5%), FEI's modelling supports natural gas continuing to be needed to serve the space and water heating needs of hundreds of thousands of customers in the Lower Mainland and other regions in 2050. This includes serving the peak heating portion of load in the winter months, regardless of Demand Side Management (DSM) and other energy efficiency measures, when temperatures reach their lowest. FEI's statement is conveying that, even assuming the erosion of load at an accelerated rate (where gas space and water heating load is electrified), a significant number of customers would still be exposed to the consequences of a winter T-South no-flow event in 2050 and beyond.

5.4 Further to BCOAPO IR 6.5.3 above, please provide a table that: i) identifies the peak and annual load assumed in the TLSE Project; ii) identifies the peak and annual load based on the mDEP 2% sensitivity in 2050; iii) identifies the difference (PJ and %) between the TLSE Project and the mDEP 2% sensitivity in 2050; iv) identifies the difference between the TLSE Project (with load assumptions underpinning the 3-day no-flow T-south event) compared to the mDEP 2% scenario in 2050 (please provide the difference in $ and % along with the present value of the incremental cost); and v) the TLSE alternative today, if any, that most closely meets the mDEP% 2% scenario in 2050.

Response:

While FEI provides a response to the question below, the requested analysis is not relevant to the assessment of the Project need or the assessment of Project alternatives. The TLSE Project is designed to address FEI's current resiliency risk and gas supply requirement, not hypothetical requirements in 2050.

As discussed throughout the Application and reiterated in Section 3 of the Supplemental Evidence, the TLSE Project will mitigate the significant resiliency risk that hundreds of thousands of *today's* customers in the Lower Mainland might lose service for many weeks following a winter T-South no-flow event. The Project is also required to replace the existing Tilbury Base Plant, which has been and continues to be an important on-system peaking supply resource. As discussed in Section 4.5.4.1.2 of the Supplemental Evidence, without the TLSE Project, FEI expects that there could be curtailments of up to 150 MMcf/d, as there is no available option for FEI to replace the lost peaking capacity from the existing Tilbury Base Plant until such time as there is an expansion to regional infrastructure (FEI has assumed the earliest that such an expansion could occur would be 2035). Further, there would be significant annual gas supply costs to hold the equivalent peak gas supply of 1 Bcf and 200 MMcf/d from the expanded regional infrastructure in 2035.

FEI cannot ignore the resiliency risk and the gas supply requirement between now and 2050. As such, an alternative that would meet the mDEP 2% or mDEP 5% scenario in 2050 would be the same as those alternatives already presented in the Supplemental Evidence and the preferred alternative would still be Supplemental Alternative 9.

However, in order to be responsive, Tables 1 and 2 below compare the current annual and peak demand used to assess the TLSE Project against a hypothetical annual and peak demand in 2050 assuming the mDEP 2% and mDEP 5% scenarios, respectively. While FEI has provided the annual demand as requested, FEI highlights that the Project need is based on the ability to serve <u>*peak*</u> demand, not annual load. These hypothetical scenarios show peak day demand will decrease by 283 MMcf/d and 405 MMcf/d by 2050, assuming a 2 percent and 5 percent decrease in customers per year, respectively, starting in 2031. In both hypothetical scenarios, significant peak day demand remains.

Table 1: Demand Forecast Current vs. mDEP 2% in 2050

		Current	mDEP 2% 2050 Scenario	Difference	% Difference
Annual Demand	*(Bcf/Year)*	107	75	-32	-30%
Peak Day	*(MMcf/Day)*	865	581	-283	-33%

Conversion Factor 1 Bcf = 1.05 PJ 1 MMcf = 1.05 TJ

Table 2: Demand Forecast Current vs. mDEP 5% in 2050

		Current	mDEP 5% 2050 Scenario	Difference	% Difference
Annual Demand	*(Bcf/Year)*	107	60	-48	-44%
Peak Day	*(MMcf/Day)*	865	460	-405	-47%

Conversion Factor 1 Bcf = 1.05 PJ 1 MMcf = 1.05 TJ

The Supplemental Evidence supports the need for a 2 Bcf resiliency reserve and 1 Bcf as a gas supply peaking resource. Based on the assumption that customers, and their associated peak day demand, decreases at 2 percent or 5 percent per year, the 3-day cumulative demand calculated for these two hypothetical scenarios are shown below in Figures 1 and 2, respectively. FEI notes the analysis assumes the same LNG reserve (1 Bcf) is needed for gas supply to meet peak demand.

Figure 1: LNG Reserve Needed (Current vs mDEP 2%) in 2050

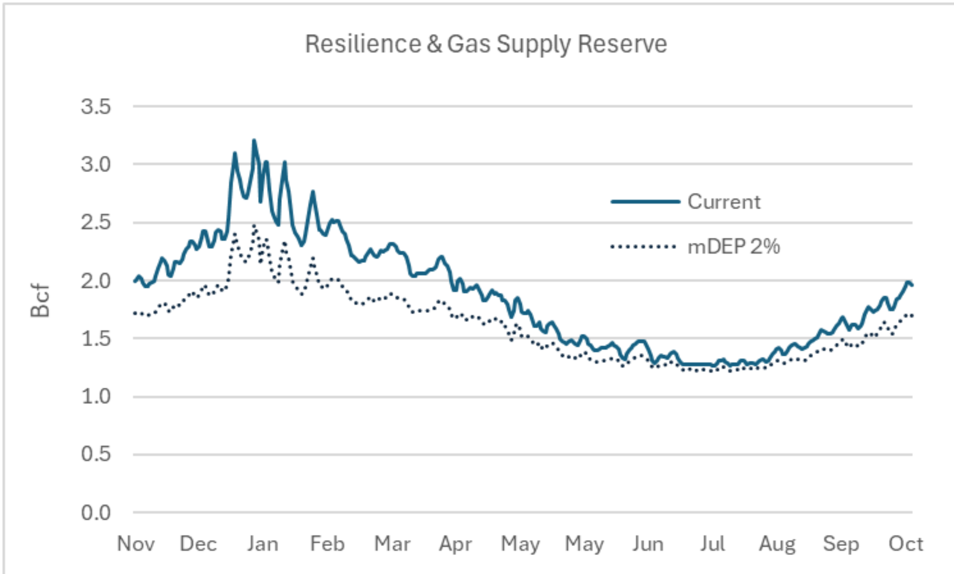
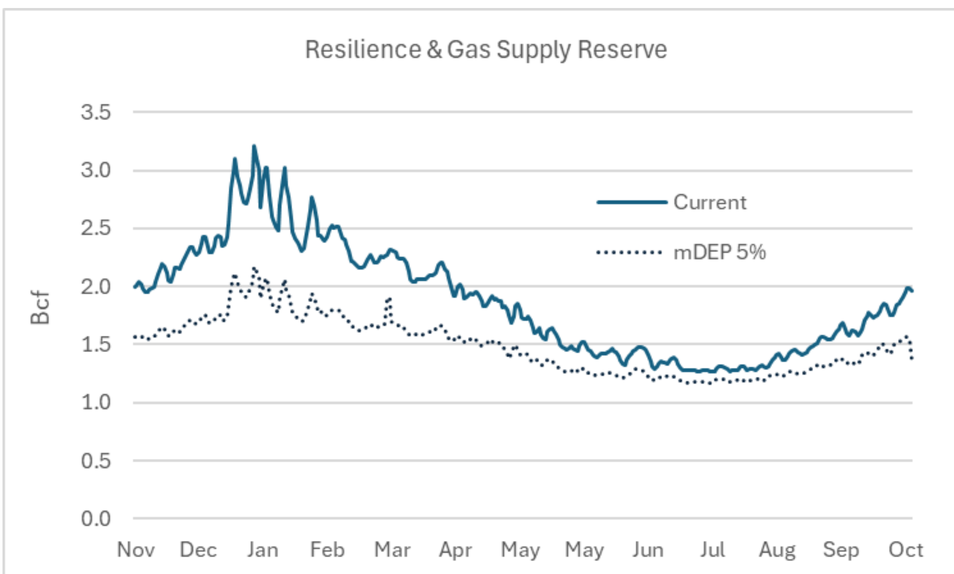


Figure 2: LNG Reserve Needed (Current vs mDEP 5%) in 2050



Figures 1 and 2 above show that FEI would still need approximately 2 to 2.5 Bcf for resiliency and gas supply purposes even under extremely adverse hypothetical load scenarios. However, as discussed in Section 4.5.5.4 of the Supplemental Evidence, even if less reserve were needed for resiliency due to a load decrease in the future, FEI could reallocate part of the resiliency reserve to gas supply, substituting LNG for other resources or generating mitigation revenue by making peaking supply available in the market. For example, with the additional LNG allocated to the gas supply portfolio, FEI would be able to de-contract some market area resources FEI currently holds and reduce the gas supply costs accordingly, ultimately benefiting customers through reduced cost of gas charges.

Finally, FEI is not able to provide an updated financial analysis under the mDEP 2% and mDEP 5% assumptions. This is because, in order to estimate the present value of the mitigation revenue, FEI would need to know the future market value of the gas supply resources. It is not possible to predict gas market conditions as far out as 2050 and to estimate the future value of the gas supply resources. However, as shown in the responses to BCUC IR6 152.1 and 156.1, even if the TLSE Project were only useful up to 2050, the present values of the total cost of service are essentially equal between Supplemental Alternative 8 (a 2 Bcf storage tank that would be similar to the hypothetical requirements under mDEP 2% and mDEP 5% shown in Figures 1 and 2 above) and Supplemental Alternative 9 (a 3 Bcf storage tank). Since FEI expects the TLSE Project will continue to operate beyond 2050, even under the adverse load scenarios of mDEP 2% and 5%, the additional 1 Bcf of tank capacity provided by Supplemental Alternative 9 will become increasingly more beneficial financially than Supplemental Alternative 8. These financial benefits fully offset the incremental capital costs for the additional 1 Bcf of LNG storage regardless of the future value of mitigation revenue in 2050 or beyond.

5.5 Further to BCOAPO IR 6.5.3 above, please provide a table that: i) identifies the peak and annual load assumed in the TLSE Project; ii) identifies the peak and annual load based on the mDEP 5% sensitivity in 2050; iii) identifies the difference (PJ and %) between the TLSE Project and the mDEP 5% sensitivity in 2050; iv) identifies the difference between the TLSE Project (with load assumptions underpinning the 3-day no-flow T-south event) compared to the mDEP 5% scenario in 2050 (please provide the difference in $ and % along with the present value of the incremental cost); and v) the TLSE alternative today, if any, that most closely meets the mDEP% 5% scenario in 2050.

<u>Response:</u>

Please refer to the response to BCOAPO IR6 5.4.

5.6 Please provide a version of Figure 1-5 assuming the weightings as proposed by FEI that assumes current load is equivalent to the mDEP 2% scenario. Please provide the assumptions and discuss the findings.

<u>Response:</u>

The TLSE Project is sized to meet resiliency and gas supply needs at the current load. FEI notes that the mDEP 2% and 5% adverse load sensitivities do not represent FEI's system load at a specific point in time, rather they represent hypothetical scenarios wherein FEI loses customers from its system over time, which was used to evaluate the usefulness of the Project under future adverse load scenarios. Section 4.5.5 of the Supplemental Evidence discusses the continued need for the Project should customers and demand decrease over time as contemplated in the mDEP scenarios.

Both the mDEP 2% and mDEP 5% scenarios start with FEI's DEP Scenario[11] current customer count and associated load and then assume hypothetical load into the future to 2050. Starting in 2031, the customer count gradually decreases by the specified rate for both the mDEP 2% and 5% scenarios. Therefore, the initial years considered in the mDEP scenarios are effectively the same as FEI's current load. As such, if FEI were to reproduce Figure 1-5 based on the load in the initial years of the mDEP scenarios (i.e., 2025 – 2030), the results would be identical to the version of Figure 1-5 provided in the Supplemental Evidence. Please refer to Section 4.5.5.2 of the Supplemental Evidence for further detail on how the mDEP 2% and 5% scenarios were created.

As described above, the mDEP analysis was designed to evaluate if a given Supplemental Alternative will be useful and not underutilized between the in-service date and into the future to 2050 based on the mDEP scenarios. The analysis has not focused on whether or not the Supplemental Alternatives would deliver on the Project objectives under the loads contemplated in the mDEP scenarios. As a result, Figure 1-5 cannot be reproduced as requested. Even if the analysis could be undertaken, FEI considers alternatives analysis scoring based on this hypothetical load scenario to be problematic for the following reasons:

1. As explained in the response to BCOAPO IR6 5.4, by conducting the alternatives analysis based on the 2050 load contemplated in the hypothetical mDEP scenarios, FEI would be ignoring the known resiliency and gas supply needs of today and in the intervening years to 2050. That is, FEI would be selecting an alternative that meets the hypothetical and uncertain needs of a year, 25 years into the future, instead of the known needs of today.
2. Even if the 2050 mDEP load materializes, selecting a Supplemental Alternative based on this future hypothetical load would likely result in the asset being undersized until the year 2050 (i.e., when the load decreases to the point contemplated in the mDEP analysis). This would result in FEI constructing an asset that could not meet the Project needs for a significant period of time (i.e., until load had declined sufficiently).

5.7 Please provide a version of Figure 1-5 assuming the weightings as proposed by FEI that assumes current load is equivalent to the mDEP 5% scenario. Please provide the assumptions and discuss the findings.

[11] The DEP Scenario from the 2022 LTGRP approximately matches FEI's current load.

Response:

Please refer to the response to BCOAPO IR6 5.6.

5.8 Please provide the rationale for not adjusting industrial load which FEI states represents 30% of its load in its mDEP 2% and 5% scenarios.

Response:

Please refer to the response to BCUC IR5 129.2.

5.9 Please provide a sensitivity that also adjusts the mDEP 2% and 5% scenarios for industrial load changes consistent with the assumptions for residential and commercial load changes. As part of the response, please provide version of Figure 1-5 assuming the weightings as proposed by FEI separately reflecting each adjusted mDEP 2% and 5% scenario.

Response:

FEI has no basis to determine which industrial customers (if any) could, for example, switch from natural gas to other energy sources or would no longer be able to operate without natural gas. For example, industrial customers that use gas to produce high intensity heat are generally considered to be hard to decarbonize and may have few suitable alternatives. However, in order to be responsive, FEI has assumed that for each industrial customer lost, the average natural gas use per industrial customer (UPC) is also lost. The table below provides the resulting peak day demand, number of customers and annual load, in 2050, assuming that FEI loses 2 or 5 percent of its residential, commercial and industrial customers each year starting in 2031.

2050	mDEP 2% (Residential, Commercial & Industrial)	mDEP 5% (Residential, Commercial & Industrial)
Customers	410,000	220,000
Annual Load (PJ)	65	35
Peak Demand (TJ/Day)	475	255

Even under these hypothetical extreme scenarios, FEI continues to serve a significant number of customers in 2050. Please refer to the response to BCOAPO IR6 5.6 for why sizing the TLSE Project based on future hypothetical needs, instead of current needs, is inappropriate.

Please also refer to the response to BCOAPO IR6 5.6 for a discussion regarding modifying Figure 1-5 to reflect the mDEP 2% and 5% scenarios.

6.0 Reference: PROJECT COSTS, ACCOUNTING TREATMENT AND RATES Exhibit B-63, BCUC IR 5 - 117.4, 140.2

Exhibit B-15, BCUC IR 1 - 14.6 Exhibit B-64, BCOAPO IR 5 - 4.2

Topic: Bill Impacts

Preamble:

As part of BCUC IR 5 – 117.4, FEI responded to how it would determine that a certain risk mitigation is too costly for customers to implement. FEI states that it did not identify a bright line investment threshold that tied risk to cost. FEI concluded it was not necessary to do so because it was self-evident based on Exponent's risk calculations for all Assessed Vulnerabilities (AVs).

FEI indicates the cost of the TLSE Project has increased by nearly 50% (As-Spent) since its 2020 Application. (**BCOAPO IR 5.4.2**)

FEI provides the following response: "...generally speaking, hydrogen blending into the CTS upstream of the Tilbury facility in the future would necessitate alterations to the sitewide upstream LNG process units to enable the separation of hydrogen from the natural gas entering the facility. These alterations may include the installation of a hydrogen extraction system, such as a standalone membrane system or a membrane combined with a pressure swing adsorption system, to ensure the gas meets the quality standards for processing in the LNG facility. The purified hydrogen could then be stored, utilized by on-site consumers, based on demand, or redirected back into the pipeline, contingent upon factors such as compliance with existing pipeline regulations, pipeline metallurgy and consumer gas quality standards." (**BCUC IR 5.140.2**)

6.1 Please confirm, or otherwise explain, that based on Exponent's risk calculations for all AVs, FEI is implicitly concluding there would be no cost threshold too high to moderate the risk on the T-south. If not confirmed, please provide the threshold by which cost to moderate the risk on the T-south would be too high for its customers.

Response:

Not confirmed. In Exponent's independent expert opinion, "…the estimated current Risks on T-South are economically very large (and thus unacceptable), and a sensitivity/cost benefit analysis shows that these very large Asset (Monetary/GDP) losses can be significantly reduced with the TLSE Project" (see the response to BCUC IR5 117.2). Further, as demonstrated in the examples below, FEI has explicitly considered cost in its assessment of the TLSE Project.

- In Table 1 of the response to BCUC IR5 117.3, FEI provided the following rationale as to why Supplemental Alternative 9 reduces the T-South risk to the ALARP zone:

> …To further reduce the risk by a substantial amount (i.e., to address the residual risk) would require a much larger on-system LNG storage tank, or a diversified pipeline supply. It is expected that these types of projects would have a significant cost.
>
> FEI finds that, due to the expected significant costs, executing these types of projects for the exclusive purpose of further reducing the T-South risk would not be practicable. That is, while FEI may pursue future projects that have an ancillary resiliency benefit, such projects would need additional project drivers, beyond T-South risk mitigation, to be viable. As such, FEI finds that, from a purely resiliency context and when considering resiliency-only projects, the TLSE Project reduces the T-South risk to the ALARP zone, and to "as low as reasonably practicable.

This assessment demonstrates that FEI does consider there to be a point at which the cost of mitigating T-South risk is too high. The TLSE Project does not meet this threshold, as confirmed by Exponent.

- In FEI's expanded alternatives analysis (Section 4 of the Supplemental Evidence), FEI explicitly considered Project cost through the "Rate Impact" criterion.
- In Table 4-12 of Section 4.5.4.2 of the Supplemental Evidence, FEI summarized the ratio of risk reduction per dollar of rate impact for Supplemental Alternatives 4, 4A, 8, and 9.
- In the response to BCUC IR5 117.3, FEI described its approach to risk evaluation as follows:

> FEI's approach to risk evaluation was to evaluate the merits of the TLSE Project based on the unmitigated risk, the amount of risk mitigation provided by the Preferred Alternative and other Supplemental Alternatives, as well as the ratio of the risk mitigation provided relative to the associated cost of service.

The following response has also been provided by Exponent:

Exponent calculated the risk and defers to FEI regarding thresholds for risk mitigation. We refer to our discussion of ALARP zones in response to BCUC IR5 117.2.

6.2 Please provide a table that reflects the bill impact to the typical residential customer in 2025 with annual consumption of 90GJ, compared to current residential rates, assuming all assets are in rate base and including the cost of fuel at the following project cost levels: i) a TLSE Project cost of $0.77 billion; ii) a TLSE Project cost of $1.14 billion; iii) a TLSE Project cost of $1.48 billion; and iv) a TLSE Project cost of $ 2.28 billion.

Response:

As discussed in the response to BCUC IR5 132.3, there is no evidence to support the hypothetical range of capital costs outside of the P10 to P90 confidence of cost distribution and escalation risk for the TLSE Project. As such, please refer to Table 1 below for the levelized total rate impact to a typical residential customer with annual consumption of 90 GJ for a P10 TLSE Project cost of $0.744 billion, a P70 TLSE Project cost of $1.144 billion (as filed), and a P90 TLSE Project cost of $1.467 billion under the Preferred Alternative (Supplemental Alternative 9).[12]

FEI notes that the P10, P70, and P90 cost estimates are similar to the i) $0.77 billion, ii) $1.14 billion, and iii) $1.48 billion Project cost scenarios requested in this question. The $2.28 billion project cost scenario requested in this question is well-above the P90 cost estimate for the TLSE Project; therefore, FEI has not included this estimate in Table 1 below.

Table 1: Levelized Total Rate Impact Per Year for an Average Residential Customer between P10 and P90 Project Cost Estimates

	Confidence Level		
	P10	P70 (As-filed)	P90
Total Project Cost Estimate - BCUC IR5 132.3 Table 4 ($ billion)	0.745	1.144	1.467
Levelized Total Rate Impact (incl. Cost of Gas) over 67 years (%)	1.25%	2.44%	3.41%
Levelized Total Rate Impact (incl. Cost of Gas) over 67 years ($/GJ)	0.117	0.228	0.318
Levelized Total Bill Impact for Avg. RS 1 Customer ($)	10.53	20.52	28.62

6.3 Please provide an updated response to BCUC IR 1.14.6 showing the cumulative rate impact, on an approved basis beginning in 2020 to current plus the rate impacts of all major projects currently planned over the next 10 years. Please provide the chart as provided in response to BCUC IR 14.6 as well as the updated version as requested and discuss the assumptions and results.

Response:

Please refer to the response to RCIA IR5 69.2 where FEI provided an update to the same figure in BCUC IR1 14.6 with updated assumptions based on current CPCNs (including all approved as well as projects currently under BCUC review) and OIC projects from 2021 to 2030.

[12] The P10, P70 (as-filed), and P90 TLSE Project cost estimates (under Supplemental Alternative 9) are shown in Table 4 of the response to BCUC IR5 132.3.

6.4 Further to BCOAPO IR 5.6.3, please provide the annual residential bill (excluding fuel costs) at 90 GJ in 2020, the estimated annual residential bill in 2030, and the difference ($ and %).

Response:

FEI assumes this question is referring to BCOAPO IR6 6.3, not BCOAPO IR5 6.3 and has responded accordingly.

As shown in the response to RCIA IR5 69.2, the estimated cumulative total rate impact from 2021 to 2030 due to FEI's current and proposed CPCN and OIC projects is approximately 12.9 percent. Please refer to Table 1 below which compares the actual residential bill (excluding commodity-related costs) based on the 2020 approved rates to the estimated residential bill (excluding commodity-related costs) based on the cumulative 12.9 percent increase by 2030 for an average residential customer consuming 90 GJ per year. In order to present a holistic view of the bill impact, FEI has included the change in the carbon tax charges between 2020 and 2030. FEI notes the cumulative rate impact of 12.9 percent, as well as the bill impact shown in Table 1 below due to current and proposed major projects, is for illustration only and does not represent FEI's actual delivery rate increases to 2030.

Table 1: Annual Residential Bill in 2020 and Estimated Bill in 2030 from Cumulative Rate Impact of All Major Projects Over 10 Years (2020-2030)

Particulars	2020 Annual $	2030 Annual $	Difference Annual $	Difference Annual %
Basic Charges	$ 153.98	$ 153.98	$ -	0.0%
Delivery Margin Related Charges	413.64	487.14	73.50	17.8%
Sub-Total	**$ 567.62**	**$ 641.12**	**$ 73.50**	**12.9%**
Carbon Tax Charges	178.78	-	(178.78)	-100.0%
Total Charges	**$ 746.40**	**$ 641.12**	**$(105.28)**	**-14.1%**
Annualized Variance			(10.53)	-1.4%

As shown in Table 1 above, the increase in the average residential bill (excluding commodity-related costs) due to current and proposed major projects to 2030 is entirely offset by the removal of the carbon tax, resulting in an overall annualized decrease of $10.53 or 1.4 percent over the 10-year period.

6.5 Of the estimated $1.1 billion cost of the TLSE Project, please provide cost associated with the Dependable Gas Supply During Peak Demand capabilities that exceeds current capabilities.

Response:

The cost associated with gas supply capabilities that exceed FEI's current capabilities (i.e., the addition of 0.4 Bcf and 250 MMcf/d for gas supply) are $66.278 million or 5.8 percent of the Project cost.[13]

6.6 Please provide a directional estimate as to the additional costs to be incurred in the event of hydrogen blending and discuss assumptions. As part of the response, please discuss whether the cost of hydrogen blending would be consistent among the Tilbury alternatives

Response:

As explained in the response to BCUC IR5 140.1, FEI continues to study the potential for hydrogen blending and no projects are imminent. Further, consistent with the response to BCUC IR1 83.5, FEI has not yet confirmed how hydrogen will be deployed in the gas system and, as such, cannot currently confirm the future requirements for hydrogen separation at its LNG facilities, including the Tilbury site.

However, FEI can confirm that the cost of hydrogen blending would be consistent regardless of the sizing of the TLSE Project. The size of a hydrogen separation facility required at the Tilbury inlet would be dependent on the maximum gas capacity entering the Tilbury facility (which correlates to the amount of liquefaction capacity at the Tilbury site) and not the TLSE tank size.

[13] Supplemental Alternative 4A provides 1 Bcf and 400 MMcf/d of regasification, with 200 MMcf/d of regasification for redundancy (as shown in Table 4-1 of the Supplemental Evidence).