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March 20, 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. 5**

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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. 5.

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: Exhibit B-60 FEI Supplemental Evidence, page 10, Figure 1-2,**

**Exhibit A-49, BCUC IR 124**

**Topic: Economic Impact of Winter no-flow Event**

**Preamble:**

FEI states that if the risk on T-South is left unmitigated, British Columbians will be exposed to serious health and mortality risk and significant social and economic consequences….It will cause billions of dollars of economic harm, and can be expected to result in adverse health impacts and death for vulnerable populations. (**Supplemental Evidence, p. 32**)

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

FEI is very cognizant that this Project involves significant capital costs and will increase customer bills. However, as demonstrated in Texas, the implications of not making an investment in a new facility to serve load in normal operations and a likely supply emergency are too significant to ignore. (**Supplemental Evidence, p. 5)**

FEI states that the economic impacts of a loss or disruption of gas supply may result in permanent business closures and loss of jobs. **(Supplemental Evidence, p. 207)**

1.1 Given the economic loss potential to the Province of British Columbia associated with a winter no-flow event on the T-South that is well in excess of the cost of FEI's Preferred Alternative, please provide FEI's views as to why it is reasonable that natural gas ratepayers of FEI be solely responsible to fund the expenditures of the TLSE Expansion Project rather than taxpayers also funding a portion of the expenditures.

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

FEI acknowledges the significant economic and social impacts associated with a winter T-South no-flow event, as detailed in the Supplemental Evidence. While the broader economic impacts of a no-flow event are significant, the direct mitigation of these impacts by the TLSE Project primarily benefits FEI's customers by mitigating the significant resiliency risk of a no-flow event and by ensuring that FEI continues to have access to sufficient dependable peaking supply to be able to serve firm customers during normal operations.

1.2 Please explain what discussions FEI has had with the Province of British Columbia specifically as it relates to the potential economic and societal costs of a winter no-flow event on the T-South and what, if any, contingency plans (including funding) the Province has, or is, putting in place.

1.2.1 If no discussions have occurred, please explain why not.

**Response:**

FEI briefed both ministry staff and elected officials when the 2018 T-South Incident occurred and continued to do so through the full restoration of the pipeline to normal operating capacity (over one year later). These briefings involved identifying the immediate impacts, mitigation efforts, and contingency plans.

After normal operations resumed, FEI continued to engage with the Province to inform staff and officials of the broad economic and societal risks associated with the reoccurrence of a no-flow event, as well as FEI's plans to mitigate against this risk, including the need to invest in the resilience of the gas system through on-system storage, load management capabilities and diverse pipelines.

The Province did not share any information with FEI regarding contingency funding that it has, or will put in place to avoid or recover from such an incident in the future. FEI believes that the Province is generally supportive of FEI's efforts to enhance the resiliency of its system through investments that address this risk. The Province recognized the key role of the gas system and its contribution towards the resilience of BC's energy system in its recent climate and energy strategy, *Powering our Future* (pp. 19 and 28):[1]

> BC's gas system will also continue to play an important role for many years to come in order to maintain system resiliency, meet peak energy demand, and provide home heating in colder climates.
>
> …
>
> Part of what makes BC's energy system resilient is the diversity of its energy sources. For example, a record-breaking cold snap in January 2024 drove BC's hourly peak demand to new highs. BC Hydro was able not only to meet that peak demand at home in BC, but also to export much-needed power to our neighbours in Alberta. Natural gas was also critical in meeting peak demand, delivering about twice as much energy for home heating as the electricity system during this time – highlighting the importance of BC's existing gas system.

1 https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/community-energy-solutions/powering_our_future_-_bcs_clean_energy_strategy_2024.pdf.

**2.0 Reference: Exhibit B-60 FEI Supplemental Evidence, pages 13, 17, 18, Figure 1-5**

**Topic: Weighting of Evaluation Criterion**

**Preamble:**

In Figure 1-5, FEI provides the weighting of five evaluation criterion in order numerically score Supplemental Alternatives and concludes that Alternative 9 scored materially higher than other Supplemental Alternatives. (**Supplemental Evidence, p. 17**)

FEI states that based on additional engineering analysis, the Base Plant is experiencing deteriorating performance despite further investment indicating that the Base Plant has reached end-of-life. FEI goes on to state that there is no feasible option to extend the life of the Base Plant or replace its peaking supply in the market and thus requires a sizable capital investment regardless of resiliency considerations, to ensure firm load can continue to be served in normal operating conditions. (**Supplemental Evidence, p. 13**)

2.1 Given Base Plant performance deterioration since FEI's initial Tilbury LNG Expansion Project such that existing plant has reached end-of-life, please explain with rationale whether the urgency for sizable capital investment just to ensure firm load can be served in normal operating conditions suggests that the objective of the TLSE has shifted placing a greater level of importance, and therefore higher weighting, to Dependable gas during peak demand compared to the 20% ascribed by FEI in Figure 1-5 and that the Resiliency criteria weighting of 30% should be downgraded. As part of the response, please explain the reasonableness of weighting the Resiliency criteria greater than providing Dependable gas during peak demand.

**Response:**

The selected weightings in the expanded alternatives analysis correctly represent the following two needs of the TLSE Project:[2]

- To mitigate the significant resiliency risk that hundreds of thousands of customers in the Lower Mainland will lose service for many weeks following a winter no-flow event on T-South; and
- To ensure that FEI continues to have access to sufficient dependable peaking supply to be able to serve firm customers during normal operations.

Since filing the Application, the findings from FEI's continued operation of the Base Plant and from engineering studies have made it clear that the Base Plant has reached end-of-life. As a result, the Supplemental Evidence places more emphasis on ensuring FEI's gas supply needs are met than was done in the Application. This is evident, for instance, from: (1) FEI including

[2] Exhibit B-60, Supplemental Evidence, Section 3.1.

"Availability of Dependable Gas Supply During Peak Demand" and "Resolves Age Related Base Plant Challenges" as evaluation criteria in the expanded alternatives analysis; and (2) the inclusion of having access to dependable peaking gas supply in FEI's stated need for the TLSE Project.

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.[3] 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. As a result, since none of the Supplemental Alternatives considered in the scoring step would result in FEI not being able to serve firm customers during peaking events, FEI decided to weight "Availability of Dependable Gas Supply During Peak Demand" lower than "Resiliency". Further, FEI considers it reasonable to weight "Resiliency" as the highest individual evaluation criterion due to the significant customer outage risk that FEI is currently exposed to from a winter T-South no-flow event.

2.2 Given the significant rate impacts associated with the Proposed Tilbury LNG Expansion Project in an environment of significant rate increases already being experienced by FEI's ratepayers, the potential for loss of load from environmental policy and potential catastrophic impacts to the long-term viability of the natural gas utility, please explain the reasonableness of FEI's lower total rate impact weighting of 20% compared to the Resiliency criteria weighting of 30% as reflected in Figure 1-5.

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

FEI considers its weighting in the expanded alternatives analysis to be reasonable for the reasons below.

First, the purpose of the "Resiliency" criterion is to assess a given Supplemental Alternative's ability to support FEI's system in the event of a winter T-South no-flow event. One of the two primary drivers supporting the need for the TLSE Project is to mitigate the significant resiliency risk that hundreds of thousands of customers in the Lower Mainland will lose service for many weeks following a winter no-flow event on T-South. As demonstrated in Figure 4-2, as well as Table 4-12 of the Supplemental Evidence, the potential GDP loss following a winter T-South no-flow event, which will have a significant impact on FEI's customers, significantly exceeds the cost and associated rate impact associated with the TLSE Project.

While minimizing the rate impact associated with capital investments is an important consideration, and was included as a criterion in the expanded alternatives analysis, FEI does

[3] Exhibit B-60, Supplemental Evidence, Section 4.4.

not consider it reasonable or appropriate for it to be weighted higher than the “Resiliency” criterion that represents a primary driver of the Project need. As discussed in the response to BCOAPO IR5 2.1, the “Resiliency” criterion is assigned the highest individual weighting due to the significant customer outage risk that FEI is currently exposed to from a winter T-South no-flow event.

Second, as discussed on page 112 of the Supplemental Evidence, 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. Please refer to the response to BCOAPO IR5 2.1 for a discussion on why “Resiliency” is weighted higher than the “Gas Supply” criterion.

Finally, FEI notes that the question’s reference to “…the potential for loss of load from environmental policy and potential catastrophic impacts to the long-term viability of the natural gas utility…” is properly accounted for in the “Future Use” criterion, which assesses whether the alternative will be useful for resiliency and/or FEI’s gas supply purposes, and the potential for underutilized assets resulting from each alternative in the future. As discussed in Section 4.5.5.4 of the Supplemental Evidence, in the event of extreme load declines, for those alternatives that include larger tank sizes, FEI could elect to allocate more of the tank for gas supply purposes which would create opportunities to use the additional peak demand supply from Tilbury to substitute other more expensive supply resources or generate more mitigation revenue, both of which will ultimately benefit customers in rates through reduced gas costs. Given the inherent uncertainty in forecasting future potential load loss scenarios, FEI reasonably assigned the “Future Use” criterion a lower weighting than the “Resiliency” and “Rate Impact” criteria.[4]

2.3 Please provide a version of Figure 1-5 with the results based on modified weightings as follows: i) Resiliency - 10%; ii) Dependable gas during peak demand – 25%; iii) Resolves age related plant challenges – 25%; iv) Total Rate Impact – 25%; and v) Useful under modified planning – 15%. As part of the response, please discuss the results and the conclusions that may be reasonably drawn.

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

FEI has provided a modified version of Figure 1-5 with the requested weightings below. With the modified weightings, Supplemental Alternatives 9 and 4A are equal, both scoring the highest. However, FEI does not consider the modified weightings to be appropriate for the following reasons.

- The modified weightings only reflect a portion of the Project need described in Section 3.1 of the Supplemental Evidence; the Project need is to mitigate the significant resiliency risk posed by a winter T-South no-flow event <u>and</u> continue to have access to sufficient

[4] Exhibit B-60, Supplemental Evidence, Section 4.2.2.3.3.

dependable peaking gas supply. In particular, significantly reducing the "Resiliency" weighting places much greater emphasis on continued access to sufficient dependable gas supply, and much less weight on mitigating the known catastrophic risk associated with hundreds of thousands of Lower Mainland customers losing gas service during the winter for many weeks. Reducing the "Resiliency" weighting in this way drastically underrepresents the need to mitigate the risk of a T-South no-flow event.

- As discussed 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 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".
- Increasing the weighting of "Useful Under the Modified Diversified Energy (Planning) Scenario (mDEP 2% and 5%) Between the In-Service Date and 2050" criterion, while decreasing the weighting of the "Resiliency" criterion, results in placing more weight on something that has less certainty (i.e., FEI's future load), and less weight on something that is certain (i.e., the significant risk facing FEI today due to a T-South no-flow event).

**Revised Figure 1-5: Evaluation Results with Modified Weightings**

| Evaluation Criterion | Criterion Weighting | Alternative 4 | Alternative 4A | Alternative 8 | Alternative 9 |
|---|---|---|---|---|---|
| Resiliency Benefit | 10% | No Impact | No Impact | Medium Positive Impact | High Positive Impact |
| Availability of Dependable Gas Supply During Peak Demand | 25% | Medium Positive Impact | High Positive Impact | Medium Positive Impact | High Positive Impact |
| Resolves Age Related Base Plant Challenges | 25% | High Positive Impact | High Positive Impact | High Positive Impact | High Positive Impact |
| Levelized Total Rate Impact | 25% | 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 | 15% | No Impact | No Impact | No Impact | No Impact |
| | Total Weighted Score: | 1.8 | 2.3 | 1.6 | 2.3 |

2.4 Please provide a version of Figure 1-5 with the results based on modified weightings as follows: i) Resiliency - 10%; ii) Dependable gas during peak demand – 20%; iii) Resolves age related plant challenges – 20%; iv) Total Rate Impact – 30%; and v) Useful under modified planning – 20%. As part of the response, please discuss the results and the conclusions that may be reasonably drawn.

**Response:**

FEI provides a modified version of Figure 1-5 below with the requested weightings. Applying the modified weightings, Supplemental Alternative 4A now scores the highest, but only differs from Supplemental Alternative 9 by a score of 0.1. For the same reasons set out in the response to BCOAPO IR5 2.3, FEI does not support the modified weightings proposed in this question.

It is to be expected that modifying the weightings so as to place little weight on resiliency and a high weight on the rate impact will have the effect of making the Supplemental Alternatives that provide resiliency appear unfavourable relative to the Supplemental Alternatives that provide little or no resiliency. This is because there is a cost to resiliency. Applying the approach in the question results in higher ratings for the Supplemental Alternatives with zero resiliency benefit, but with costs that are nearly as high as the Supplemental Alternatives with resiliency benefits, as Figure 4-6 from the Supplemental Evidence illustrates.

**Revised Figure 5-1: Evaluation Scoring with Modified Weighting**

| Evaluation Criterion | Criterion Weighting | Alternative 4 | Alternative 4A | Alternative 8 | Alternative 9 |
|---|---|---|---|---|---|
| Resiliency Benefit | 10% | No Impact | No Impact | Medium Positive Impact | High Positive Impact |
| Availability of Dependable Gas Supply During Peak Demand | 20% | 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 | 30% | 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 | 20% | No Impact | No Impact | No Impact | No Impact |
| | **Total Weighted Score:** | 1.3 | 1.7 | 1.0 | 1.6 |

**3.0 Reference: Exhibit B-60 Supplemental Application, page 132,**

**Exhibit A-49, BCUC IRs 118.3 & 121**

**Topic: Additional Base Load Requirements of TLSE**

Preamble:

FEI states that its current peaking supply requirements are 1.0 Bcf paired with 200 MMcf/d. A supplemental alternative must achieve this level of peaking supply to avoid curtailments of firm customers under normal operations. **(Supplemental Evidence, p. 132)**

FEI states that Regional Gas Supply Diversity (RGSD), Advanced Metering Infrastructure (AMI) and the TLSE Project in combination are required to meet FEI's long term resiliency needs; however, the TLSE Project is the most cost-effective and optimal solution to address the risk of a no-flow event underlying the Minimum Resiliency Planning Objective (MRPO). **(Response to BCUC IR 10.6).**

3.1 Further to BCUC IR 118.3, please explain how long current peaking requirements have exceeded the Base Load capability of Tilbury. As part of the response, please also discuss how FEI has met these firm requirements under normal operating conditions.

**Response:**

Please refer to the responses to BCUC IR5 118.1 and 118.3.

3.2 Further to BCUC IR 121, please discuss what impact, if any, the cancellation of the RGSD has to the TLSE Project and how those impacts have been reflected in the: i) TLSE Project need; ii) the 2024 Resiliency Plan; and iii) the financial and economic analysis underpinning the TLSE Project. If there is no impact to the TLSE Project, please explain why.

**Response:**

As explained below, neither the RGSD Project nor its cancellation has an impact on the TLSE Project need, the 2024 Resiliency Plan, or the financial and/or economic analysis underpinning the TLSE Project.

***TLSE Project Need***

As explained in Section 3.1 of the Supplemental Evidence, the TLSE Project is needed to:

- Mitigate the significant resiliency risk that hundreds of thousands of customers in the Lower Mainland will lose service for many weeks following a winter no-flow event on T-South; and
- Ensure that FEI continues to have access to sufficient dependable peaking supply to be able to serve firm customers during normal operations.

The RGSD Project would not have prevented customer outages from occurring. As explained in Section 5.6 of Appendix C to the Supplemental Evidence, and further discussed in FEI's RGSD Project Development Account Cost Recovery Application[5], FEI ceased further investigation of its own regional pipeline solution in Q1 of 2024 because the development work indicated that the RGSD Project's timeline would extend beyond short-term market needs and that it would be more beneficial for FEI's customers to collaborate with other regional market participants on an integrated solution. FEI is now seeking approval in the RGSD Project Development Account Cost Recovery Application to recover the costs in the RGSD Development Account and to close the account.

FEI confirms that the conclusion of the RGSD Project has no implications for FEI's analysis of the TLSE Project. As discussed in Section 5.6 of Appendix C to the Supplemental Evidence, the RGSD Project or any regional pipeline infrastructure solution involving the expansion of the Southern Crossing Pipeline (SCP) would be complementary to, but not a replacement for, the proposed TLSE Project from a resiliency perspective.

The RGSD Project would not have been a replacement for the TLSE Project because it would not prevent a widespread customer outage in the Lower Mainland on the first day following a winter T-South no-flow event. This is because, firstly, a pipeline from Oliver to Kingsvale would not eliminate the single point of failure risk on T-South between Kingsvale and the Lower Mainland.

Secondly, even if an outage occurred upstream of an expanded SCP, gas deliveries to the Lower Mainland from the SCP would not occur in time to maintain pressure following a T-South no-flow event. Therefore, avoiding a widespread outage on the first day of a winter T-South no-flow event would require new on-system LNG in the Lower Mainland (i.e., the TLSE Project) to bridge that initial period until FEI can obtain more gas from the SCP. As a result, FEI determined that an expanded SCP would only assist in FEI's efforts to recover from a supply disruption and reduce the consequences (and hence overall risk) of a winter T-South no-flow event when sufficient on-system LNG is in place to bridge the initial no-flow period.

In the case of the peaking gas supply need, the RGSD Project would not have been utilized to provide peaking supply. Pipeline capacity fills a different role than on-system LNG. It would have been uneconomical to hold year-round capacity for this purpose.

The RGSD Project was thus not an alternative to the TLSE Project.

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5 https://docs.bcuc.com/documents/proceedings/2024/doc_79760_b-1-fei-rgsd-development-account-cost-recovery.pdf

***2024 Resiliency Plan***

The 2024 Resiliency Plan's assessment of current risk accounts for FEI's resiliency capabilities. FEI determined its resiliency capabilities by considering those that currently exist and can be utilized by FEI, plus those that are forthcoming via an approved project (i.e., FEI's approved AMI project). The RGSD Project is neither in place, nor approved; therefore, the RGSD Project was not considered to be an existing resiliency capability in the 2024 Resiliency Plan. As such, the decision to no longer pursue the RGSD Project on its own had no bearing on the analysis.

Please refer to the response to BCUC IR5 121.4 for a discussion on how the inclusion of an integrated pipeline solution in collaboration with other regional market participants would impact the conclusions of the 2024 Resiliency Plan.

***Financial and Economic Analysis Underpinning the TLSE Project***

There is no impact to the financial and economic analysis of the TLSE Project. The capital cost estimates developed for the TLSE Project are specific to the LNG facility at Tilbury, thus the RGSD Project has no impact on the cost estimates. Further, the annual gas supply costs used for the financial and economic analysis are not based on pipeline expansion costs; rather, they are based on the cost of a Mist storage expansion project and the cost of obtaining pipeline capacity on Northwest Pipeline (NWP). As such, FEI did not use any cost estimate related to the RGSD Project for the financial and economic analysis that underpins the TLSE Project.

**4.0 Reference: Exhibit B-60, Supplemental Evidence, page 195, Table 6-1, page 203, Table 6-5 and page 204**

**Topic: Project Cost Estimate and Rate Impacts**

Preamble:

FEI states that the current base price forecast shows a trend of low prices through 2026 likely reflecting a combination of reduced steel prices and reduced industry capital spending in BC. **(Supplemental Evidence, p. 194)**

4.1 Please provide the actual total costs incurred to December 31, 2024 (or as current as possible) relating to the TLSE project.

**Response:**

Please refer to Table 1 below for the actual costs incurred for the TLSE Project up to December 31, 2024.

**Table 1: Actual Costs Incurred for TLSE Project as of December 31, 2024 ($ millions)**

| Particulars ($ millions) | Total |
|---|---|
| Application Costs | $ 4.287 |
| Preliminary Stage Development Costs | 1.546 |
| Pre-Construction Capitalized Development Costs | 32.738 |
| **Total** | $ 38.571 |

Section 6.1.2 of the Supplemental Evidence describes each of the three categories of costs in more detail. The difference in the Application costs and the Preliminary Stage Development costs provided in the above table compared to the amounts provided in the Supplemental Evidence is that the above table includes only actual costs up to December 31, 2024 (as requested in the question), whereas the amounts in the Supplemental Evidence include both actual costs as well as the forecast costs through to the end of the regulatory process.

4.2 Please provide an expanded version of Table 6-1 that includes: i) additional columns with the 2020$ and As Spent (2020) by category consistent with Table 6-1 for comparison purposes; ii) additional columns with the difference (%) between 2020 and 2023; and iii) a column with the top 3 drivers of the difference by category between 2020 and 2023. As part of the response, please exclude gas supply savings reflected in the Supplemental Evidence.

**Response:**

Please refer to Table 1 below (in the same format as Table 6-1 of the Supplemental Evidence) for a comparison of the TLSE Project cost estimate (excluding gas supply costs/savings) between the Application filed in December 2020 and the Supplemental Evidence filed in October 2024.

**Table 1: Comparison of the TLSE Project Cost Estimate between Application (2020) and Supplemental Evidence (2024) ($ millions)**

| | TLSE Supplemental Evidence filed 2024 | | TLSE CPCN Application filed 2020 | | Difference in As-Spent $ | |
|---|---|---|---|---|---|---|
| | 2023 $ | As-Spent $ | 2020 $ | As-Spent $ | ($) | (%) |
| LNG Tank (3 BCF) | 359.749 | 423.480 | 268.622 | 296.653 | 126.827 | 42.8% |
| Regasification Equipment | 141.483 | 166.547 | 104.253 | 113.279 | 53.268 | 47.0% |
| Ground Improvement | 60.944 | 71.740 | 35.086 | 39.133 | 32.607 | 83.3% |
| Auxiliary System | 153.964 | 181.239 | 108.846 | 118.422 | 62.817 | 53.0% |
| Base Plant Demolition | 14.927 | 17.571 | 12.297 | 13.824 | 3.747 | 27.1% |
| Subtotal Capital Cost | 731.067 | 860.578 | 529.103 | 581.312 | 279.266 | 48.0% |
| Contingency | 135.800 | 160.749 | 108.200 | 118.384 | 42.365 | 35.8% |
| Subtotal Project Capital Costs w/ Contingency | 866.867 | 1,021.327 | 637.303 | 699.696 | 321.631 | 46.0% |
| CPCN Application | 4.945 | 4.945 | 0.600 | 0.600 | 4.345 | 724.2% |
| CPCN Preliminary Stage Development | 1.546 | 1.546 | 1.546 | 1.546 | - | 0.0% |
| Subtotal w/ Deferral Costs | 873.358 | 1,027.818 | 639.449 | 701.842 | 325.976 | 46.4% |
| AFUDC | - | 120.096 | - | 69.796 | 50.300 | 72.1% |
| Tax Offset | - | (4.025) | - | (2.640) | (1.384) | 52.4% |
| ***TOTAL Project Cost ($millions)*** | ***873.358*** | ***1,143.889*** | ***639.449*** | ***768.998*** | ***374.892*** | ***48.8%*** |

The following is a summary of the primary differences between the cost estimates (in as-spent dollars) provided in the 2020 Application and the 2024 Supplemental Evidence:

- **Base Capital Cost:** The increase in the Base Capital Cost (i.e., $860.578 million in as-spent dollars for the Supplemental Evidence and $581.312 million in as-spent dollars for the Application) is primarily due to:
  - As discussed on page 194 of the Supplemental Evidence, there have been significant inflationary increases in material and equipment costs as well as increased labour costs between 2020 and 2024. This is expected and consistent with the increases experienced across the industry during a period of time that included the COVID-19 pandemic and the subsequent significant global inflationary increases experienced by many industries; and
  - As discussed on page 189 of the Supplemental Evidence, the geotechnical requirements have changed due to seismic design standard changes since the Application was filed in 2020. The geotechnical costs in the Application filed in 2020 were based on an earlier version of the CSA Z276 code, which has been updated in April 2023 (CSA Z276:2022) with significant changes in seismic hazard and design criteria. As such, in addition to the inflationary increase of costs as noted above, the ground improvement costs in the Supplemental Evidence are also updated to reflect the latest design requirements.
- **Contingency:** FEI engaged Validation Estimating to provide a recommendation on the contingency for the TLSE Project for both the Application and the Supplemental Evidence.

The level of contingency is similar, i.e., approximately 20 percent of the Base Cost estimate in the Application compared to approximately 18 percent of the Base Cost estimate in the Supplemental Evidence. As such, the primary reason for the increase in the total amount of contingency is due to the increase in the Base Capital Cost as discussed above.

- **CPCN Application Costs:** The Supplemental Evidence includes actual regulatory proceeding costs (i.e., CPCN Application costs) since 2020 as well as a forecast of the remaining regulatory proceeding costs through 2025. In the original Application (filed in 2020), the CPCN Application costs were based on the expected regulatory process at that time, which did not include an adjournment of the regulatory proceeding and the requirement to develop a comprehensive resiliency plan and supplemental evidence (including preparing cost estimates for various additional Supplemental Alternatives). Thus, the CPCN Application costs have increased since the filing of the Application in 2020.
- **AFUDC:** The drivers of the increased AFUDC are:
  - The higher Base Cost estimate plus contingency;
  - The Project cost estimate filed as part of the Supplemental Evidence included actual pre-construction development costs since 2020, which continue to attract AFUDC; and
  - The change in FEI's weighted average cost of capital (WACC), which the AFUDC rate is equivalent to, between 2020 and 2024. This is primarily due to the BCUC Stage 1 Generic Cost of Capital Decision and Order G-236-23 which approved an increase to FEI's common equity from 38.5 percent to 45 percent and an increase in the return on equity (ROE) from 8.75 percent to 9.65 percent.

4.3 Please provide an expanded version of Table 6-5 that adds columns to include: i) the Summary Delivery Rate Impacts filed as part of the initial application December 29, 2020, which were compared to FEI's 2021 approved revenue requirement (excluding bypass) at the time; and ii) the difference ($ and %) between the current Application and the initial application. Please assume that the initial application is advanced four years to 2026 from 2022 and exclude gas cost savings.

**Response:**

Please refer to Table 1 below for the comparison of the cumulative incremental delivery rate impact as well as the year-over-year increase from 2026 to 2031 between the Project cost estimate from the Application filed in 2020 and the updated cost estimate from the Supplemental Evidence filed in 2024.

FEI notes that in order to be comparable with the delivery rate impact for the updated cost estimate from the Supplemental Evidence, the cumulative incremental delivery rate impact as well as the year-over-year increase shown in Table 1 below for the cost estimate from the Application were calculated to compare to FEI's 2024 approved revenue requirement. FEI also notes that the cumulative delivery rate impact and year-over-year increases from 2026 to 2031 are without annual gas cost savings.

Please also refer to the response to BCOAPO IR5 4.2 for discussion on the primary differences in the cost estimates between 2020 and 2024.

**Table 1: Comparison of the Cumulative Delivery Rate Impact and Year-Over-Year Increase from 2026 to 2031 (Compared to 2024 Approved Rates) between the Project Cost Estimates from the Application in 2020 and the Supplemental Evidence in 2024**

| | | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|
| TLSE Supplemental Evidence filed 2024 | Annual Delivery Margin, Incremental to 2026 Approved, Non-Bypass ($ millions) | 1.328 | 1.456 | 13.834 | 33.280 | 54.792 | 125.920 |
| | *% Increase to 2026 Approved Delivery Margin, Non-bypass* | *0.12%* | *0.13%* | *1.21%* | *2.92%* | *4.80%* | *11.03%* |
| | *Incremental % Delivery Rate Impact (Year-over-Year)* | *0.12%* | *0.01%* | *1.08%* | *1.68%* | *1.83%* | *5.95%* |
| TLSE Application filed 2020 | Annual Delivery Margin, Incremental to 2026 Approved, Non-Bypass ($ millions) | (0.162) | 0.361 | 1.274 | 22.909 | 36.651 | 79.799 |
| | *% Increase to 2026 Approved Delivery Margin, Non-bypass* | *(0.01%)* | *0.03%* | *0.11%* | *2.01%* | *3.21%* | *6.99%* |
| | *Incremental % Delivery Rate Impact (Year-over-Year)* | *(0.01%)* | *0.05%* | *0.08%* | *1.89%* | *1.18%* | *3.66%* |
| Difference | Annual Delivery Margin, Incremental to 2026 Approved, Non-Bypass ($ millions) | 1.489 | 1.096 | 12.560 | 10.371 | 18.141 | 46.121 |
| | *% Increase to 2026 Approved Delivery Margin, Non-bypass* | *0.13%* | *0.10%* | *1.10%* | *0.91%* | *1.59%* | *4.04%* |
| | *Incremental % Delivery Rate Impact (Year-over-Year)* | *0.13%* | *(0.03%)* | *1.00%* | *(0.21%)* | *0.65%* | *2.28%* |

*Note to Table:*

The delivery rate impact in the first year of the cost estimate from the 2020 Application is a credit in rates because, as discussed in Section 6.4.4 of the Application, the amortization of the TLSE Application and Preliminary Stage Development Costs deferral account at that time was a credit due to the tax offset on the capitalized development costs. In the 2024 Supplemental Evidence, the delivery rate impact in the first year of the cost estimate is no longer a credit. This is because, as discussed in the response to BCOAPO IR5 4.2, the Application costs are now higher due to the additional regulatory process and the costs related to preparing the 2024 Resiliency Plan, the other external expert reports, and the updated and additional cost estimates. The increase in the Application costs exceeds the tax offset on the capitalized development costs in the Supplemental Evidence.

4.4 Please provide an expanded version of Table 6-5 that adds columns to include: i) the Summary Delivery Rate Impacts filed as part of the initial application December 29, 2020, which were compared to FEI's 2021 approved revenue requirement (excluding bypass) at the time; and ii) the Summary Delivery Rate Impacts reflecting the shorter 20 year expected service life. Please assume that the initial application is advanced four years to 2026 from 2022 and exclude gas cost savings.

**Response:**

Please refer to Table 1 below for the cumulative incremental delivery rate impact, as well as the year-over-year increase from 2026 to 2031 (when compared to 2024 Approved rates) for:

i) The cost estimate from the Application filed in 2020 based on a 67-year analysis period (60 years of expected asset life); and

ii) The cost estimate from the Application filed in 2020 based on a 31-year analysis period (24 years of expected asset life).

FEI notes that a financial analysis with a 20-year amortization period on the 2020 cost estimate was not completed as part of the Application or the regulatory proceeding at that time. However, in response to BCUC Panel IR1 7.1,[6] FEI provided a financial analysis with a 24-year amortization period assuming a useful life of the assets up to 2050 (i.e., 24 years from 2027 to 2050 plus 7 years of construction period for a total analysis period of 31 years). FEI has therefore provided the requested analysis over a 24-year period instead of a 20-year period. Given the relatively small difference in the number of years, the results of the analysis would be similar. FEI considers this reasonable given the time that would be required to re-create the financial model for the 2020 cost estimate using a 20-year amortization period.

**Table 1: Summary of Delivery Rate Impact from 2026 to 2031 (Compared to 2024 Approved Rates) for the Project Cost Estimates from (1) the 2024 Supplemental Evidence with a 60-year Expected Life, (2) the 2020 Application with a 60-year Expected Life and (3) 2020 Application with a 24-year Expected Life**

| | | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|
| TLSE Supplemental Evidence filed 2024 | Annual Delivery Margin, Incremental to 2026 Approved, Non-Bypass ($ millions) | 1.328 | 1.456 | 13.834 | 33.280 | 54.792 | 125.920 |
| | *% Increase to 2026 Approved Delivery Margin, Non-bypass* | *0.12%* | *0.13%* | *1.21%* | *2.92%* | *4.80%* | *11.03%* |
| | *Incremental % Delivery Rate Impact (Year-over-Year)* | *0.12%* | *0.01%* | *1.08%* | *1.68%* | *1.83%* | *5.95%* |
| | | | | | | | |
| TLSE Application filed 2020 | Annual Delivery Margin, Incremental to 2026 Approved, Non-Bypass ($ millions) | (0.162) | 0.361 | 1.274 | 22.909 | 36.651 | 79.799 |
| | *% Increase to 2026 Approved Delivery Margin, Non-bypass* | *(0.01%)* | *0.03%* | *0.11%* | *2.01%* | *3.21%* | *6.99%* |
| | *Incremental % Delivery Rate Impact (Year-over-Year)* | *(0.01%)* | *0.05%* | *0.08%* | *1.89%* | *1.18%* | *3.66%* |
| | | | | | | | |
| TLSE Application filed 2020 (24-year Useful Life; BCUC Panel IR1 7.1) | Annual Delivery Margin, Incremental to 2026 Approved, Non-Bypass ($ millions) | (0.162) | 0.361 | 1.274 | 26.667 | 41.249 | 104.683 |
| | *% Increase to 2026 Approved Delivery Margin, Non-bypass* | *(0.01%)* | *0.03%* | *0.11%* | *2.34%* | *3.61%* | *9.17%* |
| | *Incremental % Delivery Rate Impact (Year-over-Year)* | *(0.01%)* | *0.05%* | *0.08%* | *2.22%* | *1.25%* | *5.36%* |

As expected, due to the shorter amortization period, the cumulative delivery rate impact for the analysis with an expected life of 24 years (i.e., 9.17 percent in 2031) is higher than the analysis with an expected life of 60 years (i.e., 6.99 percent in 2031) for the same cost estimate in 2020.

4.5 Please provide FEI's views regarding the potential cost implications to the TLSE Project that will or may occur as a result of U.S.-imposed and threatened tariffs.

[6] Exhibit B-39.

1 **Response:**

2 Please refer to the response to BCSEA IR5 23.1.

3

**5.0 Reference: Exhibit B-60, Supplemental Evidence, pages 5, 6, 68, 199, Table 6-2, page 196, Table 6-5, page 203, Appendix C, Table C-5**

**Topic: 67-Year Average Service Life Assumption**

Preamble: FEI states:

Although the TLSE Project is properly characterized as a resiliency project, it would be incorrect to conceptualize the full project cost as the cost of increasing resiliency given that the TLSE Project also replaces the existing Tilbury Base Plant tank, which is now over 50 years old – well-beyond its expected service life. (**Supplemental Evidence pp. 5, 6)**

The Base Plant houses the only regasification capacity at Tilbury (there is no regasification equipment in Tilbury 1A). It is connected to the Base Plant storage tank and FEI's transmission system through interconnection piping. The Base Plant equipment is critically important to avoid curtailment of firm load but despite investment in recent years, the Base Plant equipment has been experiencing unpredictable failures consistent with equipment that is end of life. The regasification equipment is obsolete, has been experiencing increasing rates of failure and reliability issues, and is difficult to maintain or repair. Its deteriorating condition is compromising both existing peaking gas supply and resiliency. **(Supplemental Evidence, p. 68)**

The 60-year post-Project analysis period was chosen based on the average service life for a new 3 Bcf LNG tank, as recommended by Concentric who completed FEI's most recent Depreciation Study. **(Supplemental Evidence, p. 199)**

5.1 Please clarify and explain whether the rate impacts of the TLSE Project, as proposed, assumes a 67-year analysis period for the entirety of the TLSE Project. If yes, please explain why given that at least a portion of the existing infrastructure which is 50 years old but well beyond its expected service life.

**Response:**

The delivery rate impacts are calculated based on the depreciation rates of the TLSE assets. For the proposed new TLSE tank, the depreciation rate is derived from the expected service life of 60 years. As discussed in Section 6.2.2 of the Supplemental Evidence, FEI applied a 67-year analysis period based on the expected service life of the LNG storage tank (which is the component of the TLSE Project with the highest capital cost) plus a 7-year construction period.

The 60-year expected service life of the new TLSE storage tank, as discussed in Section 6.2.2 of the Supplemental Evidence, was recommended by Concentric Advisors, ULC (Concentric). Concentric is an industry expert in depreciation studies and also completed FEI's most recent depreciation study (2022) filed as part of FortisBC's 2025-2027 Rate Setting Framework Application.

The expected service life of the new TLSE LNG storage tank cannot be compared to the existing Base Plant tank. The design and safety requirements for an LNG storage tank in the early 1970s is quite different than today's design and safety requirements, thus the expected service life of the proposed LNG tank is not comparable to the actual service life of the Base Plant that was built nearly 55 years ago. As discussed in Section 3.3 of the Supplemental Evidence, the Base Plant, built in 1971, has reached its end of life. For the purposes of the financial analysis for all Supplemental Alternatives, FEI assumed the end date for the Base Plant is 2030 and has accordingly assumed that it is retired from FEI's rate base at that time.

5.2 Further to BCOAPO 5.1 above, please clarify if all Alternatives (for example, Alternatives 2 and 4) cost and rate impact analysis assumed a 67-year analysis.

5.2.1 If yes, please provide the cost and rate impact analysis as reflected in Table C-5 and Table 6-5 that identifies and incorporates an average service life of the Base Plant (that is, 50 years or less) currently beyond its expected service life.

5.2.2 If not, please explain the assumptions.

**Response:**

As explained in the response to BCOAPO IR5 5.1, the 67-year analysis period is based on an expected life of 60 years for the *new* TLSE storage tank, plus a 7-year construction period. The 67-year analysis period is applied to all Supplemental Alternatives 1 to 9 as presented in Table C-5 because:

- Supplemental Alternatives 4, 4A, 5, 6, 7, 8, and 9 all involve a new LNG storage tank, thus the 67-year analysis period cover one lifecycle of the new tank (i.e., 60 years) plus the 7-year construction period; and
- Although Supplemental Alternatives 1, 2, and 3 do not involve a new LNG storage tank, in order to provide an appropriate comparison of present values and rate impacts between all alternatives, the 67-year analysis period is also used.

For clarity, and as explained in the response to BCOAPO IR5 5.1, FEI does not assume any component of the existing Base Plant will continue to be in-service beyond 2030 within the financial analysis for the Supplemental Alternatives. Further, the expected service life of a new LNG storage tank built today should not be compared to an LNG storage tank that was built nearly 55 years ago with a different design and different safety requirements. As such, FEI considers it appropriate to use the 60-year expected life of a new LNG storage tank (or 67 years including the construction period) for the financial analysis of all the Supplemental Alternatives.

However, in order to be responsive, please refer to Table 1 below for a summary of the costs and rate impacts for all the Supplemental Alternatives assuming an expected service life of 50 years (57-year analysis period including 7 years of construction) presented in the same format as Table C-5 of Appendix C to the Supplemental Evidence. As shown in Table 1 below, using a 50-year expected service life for the new LNG storage tank does not change the selection of the Preferred

Alternative. Supplemental Alternative 9 (i.e., 3 Bcf tank) will allow FEI to optimize the gas portfolio and mitigate the risk of a winter T-South no-flow event, while having a smaller levelized total rate impact than Supplemental Alternative 8 (i.e., 2 Bcf tank).

**Table 1: Costs and Rate Impacts of all Alternatives Over 57-year Analysis Period (Assuming the Expected Life of LNG Storage Tank is 50 years)**

| Alternative | Construction Capital Cost ($MM) | Total Capital Cost incl. Sustainment ($MM) | PV Cost of Service ($MM) | PV Cost of Gas ($MM) | Total PV of Revenue Requirement ($MM) | PV of 2024 Revenue Requirement ($MM) | Levelized Total Rate Impact (%) | Incremental to Alt 1 - Base Case (%) | Payback Period (Years) |
|---|---|---|---|---|---|---|---|---|---|
| | (A) | (B) | (C) | (D) | (E) = (C) + (D) | (F) | (G) = (E) / (F) | (H) = (G) - Base Case(G) | (I) |
| Alt 1 (Base Case) | - | - | - | 505.0 | 505.0 | 29,077.0 | 1.7% | 0.00% | - |
| Alt 1 (Contingent) | - | - | - | 505.0 | 505.0 | 29,077.0 | 1.7% | 0.00% | - |
| Alt 1 (Contingent w/T1A) | - | - | - | 505.0 | 505.0 | 29,077.0 | 1.7% | 0.00% | - |
| Alt 2 | 391.5 | 1,277.5 | 447.3 | 505.0 | 952.3 | 29,077.0 | 3.3% | 1.54% | - |
| Alt 2 (Contingent) | 391.5 | 1,277.5 | 447.3 | 505.0 | 952.3 | 29,077.0 | 3.3% | 1.54% | - |
| Alt 2 (Contingent w/T1A) | 391.5 | 1,277.5 | 447.3 | 505.0 | 952.3 | 29,077.0 | 3.3% | 1.54% | - |
| Alt 3 | 435.0 | 1,453.3 | 470.3 | 505.0 | 975.3 | 29,077.0 | 3.4% | 1.62% | - |
| Alt 3 (Contingent) | 435.0 | 1,453.3 | 470.3 | 505.0 | 975.3 | 29,077.0 | 3.4% | 1.62% | - |
| Alt 3 (Contingent w/T1A) | 435.0 | 1,453.3 | 470.3 | 505.0 | 975.3 | 29,077.0 | 3.4% | 1.62% | - |
| Alt 4 | 826.9 | 1,873.1 | 769.5 | 149.3 | 918.8 | 29,077.0 | 3.2% | 1.42% | 22 |
| Alt 4A | 893.2 | 2,006.4 | 868.8 | - | 868.8 | 29,077.0 | 3.0% | 1.25% | 18 |
| Alt 4 (Contingent) | 826.9 | 1,873.1 | 769.5 | 149.3 | 918.8 | 29,077.0 | 3.2% | 1.42% | - |
| Alt 5 | 826.9 | 1,873.1 | 769.5 | 505.0 | 1,274.5 | 29,077.0 | 4.4% | 2.65% | - |
| Alt 5 (Contingent w/T1A) | 826.9 | 1,873.1 | 769.5 | 505.0 | 1,274.5 | 29,077.0 | 4.4% | 2.65% | - |
| Alt 6 | 933.5 | 2,205.0 | 916.6 | 505.0 | 1,421.6 | 29,077.0 | 4.9% | 3.15% | - |
| Alt 7 | 1,030.3 | 2,257.9 | 1,103.6 | 505.0 | 1,608.6 | 29,077.0 | 5.5% | 3.80% | - |
| Alt 8 | 1,030.3 | 2,257.9 | 1,103.6 | 149.3 | 1,252.9 | 29,077.0 | 4.3% | 2.57% | 27 |
| Alt 9 (Preferred) | 1,141.0 | 2,350.9 | 1,210.6 | - | 1,210.6 | 29,077.0 | 4.2% | 2.43% | 22 |

Please also refer to Table 2 below for the delivery rate impacts of all Supplemental Alternatives from 2026 to 2031 presented in the same format as Table 6-5 of the Supplemental Evidence.

**Table 2: Delivery Rate Impact for all Supplemental Alternatives from 2026 to 2031 (Incremental to Supplemental Alternative 1) Based on a 57-year Analysis Period (Assuming the Expected Life of LNG Storage Tank is 50 Years)**

| | | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 |
|---|---|---|---|---|---|---|---|
| Alt 2 | Annual Delivery Margin, Incremental to 2026 Approved, Non-Bypass ($ millions) | 2.102 | 2.234 | 8.992 | 45.294 | 40.600 | 40.941 |
| | ***% Increase to 2026 Approved Delivery Margin, Non-bypass*** | ***0.18%*** | ***0.20%*** | ***0.79%*** | ***3.97%*** | ***3.56%*** | ***3.59%*** |
| | ***Incremental % Delivery Rate Impact (Year-over-Year)*** | ***0.18%*** | ***0.20%*** | ***0.59%*** | ***3.16%*** | ***(0.40%)*** | ***0.03%*** |
| Alt 3 | Annual Delivery Margin, Incremental to 2026 Approved, Non-Bypass ($ millions) | 2.102 | 2.227 | 8.564 | 8.005 | 50.462 | 45.287 |
| | ***% Increase to 2026 Approved Delivery Margin, Non-bypass*** | ***0.18%*** | ***0.20%*** | ***0.75%*** | ***0.70%*** | ***4.42%*** | ***3.97%*** |
| | ***Incremental % Delivery Rate Impact (Year-over-Year)*** | ***0.18%*** | ***0.20%*** | ***0.55%*** | ***(0.05%)*** | ***3.69%*** | ***(0.43%)*** |
| Alt 4 | Annual Delivery Margin, Incremental to 2026 Approved, Non-Bypass ($ millions) | 1.394 | 2.115 | 8.716 | 1.792 | 27.205 | 88.512 |
| | ***% Increase to 2026 Approved Delivery Margin, Non-bypass*** | ***0.12%*** | ***0.19%*** | ***0.76%*** | ***0.16%*** | ***2.38%*** | ***7.76%*** |
| | ***Incremental % Delivery Rate Impact (Year-over-Year)*** | ***0.12%*** | ***0.06%*** | ***0.58%*** | ***(0.60%)*** | ***2.22%*** | ***5.25%*** |
| Alt 4A | Annual Delivery Margin, Incremental to 2026 Approved, Non-Bypass ($ millions) | 1.394 | 2.147 | 10.382 | 1.412 | 30.731 | 98.173 |
| | ***% Increase to 2026 Approved Delivery Margin, Non-bypass*** | ***0.12%*** | ***0.19%*** | ***0.91%*** | ***0.12%*** | ***2.69%*** | ***8.60%*** |
| | ***Incremental % Delivery Rate Impact (Year-over-Year)*** | ***0.12%*** | ***0.07%*** | ***0.72%*** | ***(0.78%)*** | ***2.57%*** | ***5.75%*** |
| Alt 5 | Annual Delivery Margin, Incremental to 2026 Approved, Non-Bypass ($ millions) | 1.394 | 2.115 | 8.716 | 1.792 | 27.205 | 88.512 |
| | ***% Increase to 2026 Approved Delivery Margin, Non-bypass*** | ***0.12%*** | ***0.19%*** | ***0.76%*** | ***0.16%*** | ***2.38%*** | ***7.76%*** |
| | ***Incremental % Delivery Rate Impact (Year-over-Year)*** | ***0.12%*** | ***0.06%*** | ***0.58%*** | ***(0.60%)*** | ***2.22%*** | ***5.25%*** |
| Alt 6 | Annual Delivery Margin, Incremental to 2026 Approved, Non-Bypass ($ millions) | 1.500 | 2.148 | 10.362 | 6.895 | 32.394 | 102.719 |
| | ***% Increase to 2026 Approved Delivery Margin, Non-bypass*** | ***0.13%*** | ***0.19%*** | ***0.91%*** | ***0.60%*** | ***2.84%*** | ***9.00%*** |
| | ***Incremental % Delivery Rate Impact (Year-over-Year)*** | ***0.13%*** | ***0.06%*** | ***0.72%*** | ***(0.30%)*** | ***2.22%*** | ***5.99%*** |
| Alt 7 | Annual Delivery Margin, Incremental to 2026 Approved, Non-Bypass ($ millions) | 1.355 | 1.405 | 10.935 | 30.738 | 52.139 | 116.274 |
| | ***% Increase to 2026 Approved Delivery Margin, Non-bypass*** | ***0.12%*** | ***0.12%*** | ***0.96%*** | ***2.69%*** | ***4.57%*** | ***10.19%*** |
| | ***Incremental % Delivery Rate Impact (Year-over-Year)*** | ***0.12%*** | ***0.00%*** | ***0.83%*** | ***1.72%*** | ***1.83%*** | ***5.37%*** |
| Alt 8 | Annual Delivery Margin, Incremental to 2026 Approved, Non-Bypass ($ millions) | 1.355 | 1.405 | 10.935 | 30.738 | 52.139 | 116.274 |
| | ***% Increase to 2026 Approved Delivery Margin, Non-bypass*** | ***0.12%*** | ***0.12%*** | ***0.96%*** | ***2.69%*** | ***4.57%*** | ***10.19%*** |
| | ***Incremental % Delivery Rate Impact (Year-over-Year)*** | ***0.12%*** | ***0.00%*** | ***0.83%*** | ***1.72%*** | ***1.83%*** | ***5.37%*** |
| Alt 9 | Annual Delivery Margin, Incremental to 2026 Approved, Non-Bypass ($ millions) | 1.328 | 1.456 | 13.834 | 33.280 | 54.688 | 129.366 |
| | ***% Increase to 2026 Approved Delivery Margin, Non-bypass*** | ***0.12%*** | ***0.13%*** | ***1.21%*** | ***2.92%*** | ***4.79%*** | ***11.33%*** |
| | ***Incremental % Delivery Rate Impact (Year-over-Year)*** | ***0.12%*** | ***0.01%*** | ***1.08%*** | ***1.68%*** | ***1.82%*** | ***6.24%*** |

**6.0 Reference: Exhibit A-49, BCUC IRs 116.1, 116.3, 117.1, 117.4, 118.4, 118.5.1, 118.7.2, 121.4**

**Order G-62-23, Executive Summary, pages. 12, 21, 25, 29**

**Topic: Holistic review of Resiliency Objectives**

Preamble:

In Order G-62-23, the BCUC found that Resiliency objectives must be looked at holistically and that strengthening portions of a system shouldn't happen in a vacuum…. that there is uncertainty how the RGSD project may or may not impact the need for the TLSE Project and further supports the need for a more holistic resilience plan. The BCUC also finds, among other things, that FEI's resiliency plan should:

- Consider what assets currently provide resiliency and what and where are the gaps;
- Give consideration to how other planned projects address or mitigate these gaps and the extent of overlap with the TLSE Project;
- Identify steps that can be taken to fill the gaps in the short, medium and long term;
- Consider the significant probability that demand for natural gas will be reduced, reducing the size of the tank and amount of regasification required; and
- Result in a higher level of confidence in terms of the risk assessed and the expected life of the assets.

6.1 Further to BCUC IR 121.4, if an integrated solution in collaboration with other regional market participants was not considered as a capability in the Resiliency Plan, please explain why not.

**Response:**

Please refer to the response to BCUC IR5 121.4.

6.2 In the context of BCUC IRs such as 116.1, 116.3, 117.1, 117.4, 118.4, 118.5.1, 118.7.2, 121.4, please provide FEI's views as to whether its Supplemental Evidence meets the overall spirit and intent of Order G-62-23, excerpts of which are provided in the preamble.

**Response:**

FEI considers that the Supplemental Evidence, which incorporates the underlying analysis from FEI's 2024 Resiliency Plan and the expertise of multiple independent experts, is consistent with the overall spirit and intent of the BCUC's Adjournment Decision (Order G-62-23). FEI developed the 2024 Resiliency Plan over the course of many months with significant input from independent experts. The 2024 Resiliency Plan represents a holistic vulnerability assessment encompassing FEI's own system and regional infrastructure.

Please refer to Section 2.3 and Appendix B to the Supplemental Evidence which explains where and how the Supplemental Evidence and the 2024 Resiliency Plan address each of the BCUC's findings and commentary in the Adjournment Decision.