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March 20, 2025

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

Attention: Patrick Wruck, Commission Secretary

Dear Patrick Wruck:

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 Utilities Commission (BCUC) Information Request (IR) No. 5

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 BCUC Order G-324-24 for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 5.

Treatment of Confidential Material

FEI has filed a portion of the responses to BCUC IR5 116.9, 116.12, 116.13, 120.1, 121.3, and 124.2, and Attachments 132.1 and 135.1.1 on a confidential basis as identified in each response and has provided a redacted version for the public record of this proceeding. With regard to the responses to BCUC IR5 116.9, 116.12, 116.13, 121.3, and 124.2, FEI requests that the unredacted portion of these responses only be accessible to the BCUC, consistent with BCUC Order G-19-25 and for the reasons discussed in the responses.

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

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Registered Interveners

Table of Contents **Page No.**

A. PROJECT NEED

116.0 Reference: PROJECT NEED

Exhibit B-60 (Supplemental Evidence), pp. 35, 41, Exhibit B-15, BCUC IR 1.3.1, 1.4, 1.6.1, 1.9, Exhibit B-61 (2024 Resiliency Plan), pp. 43 – 44, Appendix RP 2 (Exponent Report), Table 3 p. 30, p. 33 para. 82, p. 66, para. 157, p. 67, para. 160, p. 76 para. 176; Appendix R, para. 2 & Table R.1; Exhibit B-15, Attachment 1.5C, p. 2, Figures 2, 3; FEI Interior Transmission System (ITS) Transmission Integrity Management Capabilities (TIMC) CPCN proceeding, Exhibit B-1, p. 43

AV-1, AV-2, AV-3 and AV-54 Probability of Failure

On page 35 of Exhibit B-60, FortisBC Energy Inc. (FEI) states: "…the 2024 Resiliency Plan, with its probability x consequence analysis that reflects actual location-specific causes of supply disruptions, confirms that a total loss of T-South supply during winter is FEI's single greatest customer outage risk by a large margin."

On page 41 of Exhibit B-60, FEI states: "The 2024 Resiliency Plan evaluates T-South in four segments, which are anonymized as AV-1, AV-2, AV-3 and AV-54, recognizing that the impacts can differ depending on where on T-South the disruption occurs."

In response to BCUC Information Request (IR) 1.3.1, FEI stated:

> FEI is aware that Westcoast [Westcoast Energy Inc, owner and operater of the T-South pipeline and subsidiary of Enbridge Inc. (Enbridge)] has completed a comprehensive review of its integrity management program for the T-South system

> and identified several improvements to enhance pipeline safety, including additional in-line inspection assessments and shortening re-inspection intervals. This review also resulted in the completion of additional integrity digs on many segments of the T-South system. FEI is of the view that while Westcoast's integrity management program is important for reducing the likelihood of integrity-related incidents occurring, it does not address all potential sources of disruption and is unlikely to reduce the time needed to re-establish supply in the event of a future rupture or other supply disruption for the reasons set out above.

On March 4, 2020, with respect to the T-South Incident, the Transportation Safety Board of Canada (TSB) released "Pipeline transportation safety investigation P18H0088" (TSB Report).

In response to BCUC IR 1.4, FEI stated:

> FEI has analyzed the TSB findings and actions taken by Westcoast as outlined in the TSB Report, both as part of its management review process for its Integrity Management Program for Pipelines (IMP-P) and in considering the need for the TLSE [Tilbury Liquefied Natural Gas Storage Expansion] Project…The TSB findings and actions taken by Westcoast reinforce FEI's assertion that the risk of pipeline failures on the Westcoast T-South system cannot be reduced to zero, that no-flow events can occur if both pipelines are shut-in following a failure incident, and that an extended period of reduced pipeline flows may occur following pipeline repairs.

116.1 Please summarize the actions taken by Westcoast since the issuance of the TSB Report to mitigate the risk of rupture on the T-South system.

<u>Response:</u>

FEI notes that Enbridge (Westcoast) is under no obligation to share information with FEI regarding their risk of rupture. If information is shared by a pipeline operator, it is undertaken at the operator's discretion.

FEI engages regularly with Enbridge on a range of matters affecting the T-South system, including understanding progress made managing assets and system integrity. For example, FEI met with Enbridge senior representatives in May 2021, including the senior executive responsible for Integrity Management for North America assets, to obtain an update on improvements to its asset and integrity management systems. FEI is aware that Enbridge has evolved its integrity program, like many pipeline operators, in such areas as inline inspection technology and upgrades to its valve infrastructure.

FEI's interaction with Enbridge on asset integrity is in the context of FEI being a shipper or customer on T-South, and FEI has never had a role in Westcoast's integrity planning. The level of information that FEI received as a shipper is relatively high-level, not unlike the level of detail provided in the public paper discussed below. FEI has not been made privy to detailed information about overall quantification of risk, specific hazards facing T-South, the probability of rupture or ignited rupture or other hazards. This type of information is highly sensitive to an energy company, and FEI would not expect to see that information in the normal course (FEI similarly regards its own system information in the 2024 Resiliency Plan as confidential). FEI thus retained Exponent to perform its own risk analysis.

Other technical information sharing between FEI and Westcoast occurs periodically and has occurred since April 19, 2021, related to the following matters:

- Control room-related information sharing, for the purpose of understanding operation challenges and coordination (especially related to the Huntingdon site), timed both weekly and annually;
- Pipeline operation-related information sharing, for the purpose of aligning operational work schedules and reducing impacts to shippers, timed approximately monthly; and
- Gas supply-related information sharing, for the purpose of discussing operational balancing agreement (OBA) levels and changes in WEI's operating status and conditions, timed weekly or more frequently.

In addition to the TSB Report, which was issued in March 2020, FEI is aware of one additional publicly available reference containing actions taken by Westcoast regarding the mitigation of risk of rupture on the T-South system since 2018. This is a high-level paper[1] presented by Enbridge Gas Transmission & Midstream (operator) and NDT Global (ILI service provider) at the 2024 ASME International Pipeline Conference. The paper indicates that Enbridge and NDT Global formed a partnership to develop a new crack management technology/tool, driven by a realization that crack management actions taken by Westcoast following the 2018 incident resulted in an "effective yet inefficient" program. The paper does not include a timeline for development and implementation of the new technology on T-South or the Westcoast system generally.

As demonstrated in the analysis undertaken by Exponent, there a number of other hazards, including non-earthquake-induced landslide and earthquake-induced landslide, that along with internal failures (e.g., cracking) contribute to T-South being FEI's single largest customer outage risk. The efforts described in the paper above would not mitigate the risk posed by these other hazards, or other hazards such as the risk of a cyber attack that would introduce risk over and above what was set out in Exponent's analysis. Please refer to Appendix U to the Exponent Report (Appendix RP 2 to the 2024 Resiliency Plan) for a breakdown of the expected loss associated with each hazard on T-South.

[1] The paper is entitled, "Closing the Gap on Crack Detection for Gas Transmission Pipeline", and is available for purchase here: https://asmedigitalcollection.asme.org/IPC/proceedings-abstract/IPC2024/88551/V02BT03A001/1210602

In response to BCUC IR 1.6.1, FEI stated:

> Integrity-related personnel from both FEI and Enbridge (Westcoast) have met to facilitate high level technical information sharing (for example, most recently through a discussion on April 19, 2021). However, the information shared between operators was on a confidential basis, and as such, FEI is unable to provide specific information regarding Westcoast's integrity management processes on the T-South system.

116.2 Please provide an update regarding any further technical information sharing between FEI and Westcoast that have occurred since April 19, 2021, including the timing and purpose of any discussions.

<u>Response:</u>

Please refer to the response to BCUC IR5 116.1.

116.3 Please provide any feedback FEI has received from Westcoast regarding the 2024 Resiliency Plan, including the assumptions made within the 2024 Resiliency Plan with respect to the probability of failure of the T-South system.

116.3.1 If FEI has not sought any feedback from Westcoast with respect to FEI's 2024 Resiliency Plan or the assumptions made within that plan with respect to the probability of failure of the T-South system, please explain why not.

<u>Response:</u>

FEI did not seek feedback from Westcoast with respect to the 2024 Resiliency Plan or the assumptions made within the plan with respect to the probability of failure of the T-South system. The 2024 Resiliency Plan highlights vulnerabilities across FEI's system operations, and only a subset are directly related to Westcoast (AVs 1, 2, 3, and 54). FEI is in the best position to assess the consequences of a loss of supply on the T-South system to FEI's customers. To FEI's knowledge, Westcoast has not publicly disclosed the probability of failure of its T-South system, and FEI would not expect Westcoast to share that information given its operational and security sensitivity (FEI notes that any de-anonymized information about specific AVs in the 2024 Resiliency Plan was made available to the BCUC only). FEI also saw value in using Exponent's probability analysis as a consistent basis for assessing all of the AVs. Exponent's approach to calculating the probability of failure of the T-South system is explained in Section 4.2 of the Exponent Report (Appendix RP2 to the 2024 Resiliency Plan).

In response to BCUC IR 1.9, FEI stated:

> FEI would expect that the threats that could potentially cause a supply disruption of Westcoast's T-South system are similar to those managed by FEI. This would include cyber-attacks, as well as disruption of physical infrastructure. However, FEI is unable to comment on the extent to which threats are mitigated by Westcoast's integrity management processes or other processes as FEI does not have access to the information required to make this assessment.

On page 43 of Exhibit B-61, FEI states:

> Exponent calculated failure rates for third-party owned infrastructure (Westcoast T-South and the TC Energy Foothills Pipeline) based on the following approach:
>
> o <u>Failures caused by internal hazards and failure mechanisms unrelated to natural hazards (collectively referred to as internal hazards):</u> For the majority of pipeline AVs, Exponent used the failure rates from a Qualitative Safety Risk Assessment Report prepared by JANA in February 2021 as part of FEI's ordinary course of business (2021 JANA Pipeline QRA). However, the 2021 JANA Pipeline QRA did not include off-system supply pipelines. Therefore, for the supply-related AVs (AVs 1, 2, 3, 4, and 54), rates of failure due to internal hazards were assigned from the most closely comparable AV with an internal failure rate available from JANA's analysis. The basis of comparison between AVs were diameter and year of construction, both of which are correlated with the rate of internal failures. Refer to Exponent's Report Appendix R for a more in-depth discussion. [Emphasis included]

Appendix RP 2 of Exhibit B-61 provides the Exponent Report. On page R-1 in paragraph 2 of Appendix R of the Exponent Report, Exponent states:

> Therefore, for AV-xx -xx -xx -xx -xx -xx and -xx rates of failure due to internal hazards were assigned from the most closely comparable AV with an internal failure rate available from JANA's analysis. The basis of comparison between AVs were diameter and year of construction, both of which are correlated with the rate of internal failures. Table R.1 specifies for each pipeline in an AV the internal rate of failure that was assigned from a source AV, as well as the diameter and year of construction of the source AV.

Table R.1 in Appendix R provides a selected internal failure rate of 6.51e-5 /km/year for nine of eleven AVs without internal failure rates and provides a selected internal failure rate of 6.83e-6 /km/year for the remaining two of eleven AVs without internal failure rates.

116.4 Please confirm, or explain otherwise, that the internal failure rate of 6.51e-5 /km/year from the 2021 JANA Pipeline QRA is the internal failure rate of a pipeline for which integrity management mitigations have not been implemented (i.e. unmitigated internal failure rate).

116.4.1 If confirmed, please explain why assuming an internal failure rate of 6.51e-5 /km/year for AVs 1, 2, 3 and 54 is appropriate, given the integrity management mitigations implemented by Westcoast on the T-South system, in particular the additional integrity management mitigations implemented following the TSB report (e.g. EMAT ILI).

Response:

FEI provides the following response:

Not confirmed. While the 2021 JANA Pipeline QRA was completed before EMAT ILI was in place on FEI's system, it would be incorrect to characterize the internal failure rate as "unmitigated".

The 2021 JANA Pipeline QRA assessed the general failure potential of the lines based on their specific characteristics and historical industry failure rates of comparable lines. As such, the internal failure rate of 6.51e-5 /km/year includes consideration of FEI's integrity management mitigations for the relevant threats. FEI recognizes that this failure rate estimate was developed prior to the adoption of an EMAT ILI program, and that the cracking failure rate estimate could not be informed by data on the actual cracks present on the line such as their location and sizing (i.e., depth and length). However, in the absence of EMAT ILI data on FEI's system, the JANA QRA leveraged other data such as historical industry failure rates. Historical industry failure rates are derived from pipelines with a range of hazard management (mitigation) practices applied to them, and therefore do not represent an "unmitigated internal failure rate" as part of the JANA QRA or as part of Exponent's analysis.

FEI notes that even with EMAT ILI in place, cracking threats will not be eliminated entirely, as demonstrated by the 2018 T-South Incident which the TSB concluded was caused by stress corrosion cracking.[2] Even if a pipeline operator incorporates EMAT ILI into its integrity management program like Enbridge had done on T-South by 2018,[3] there will still be a residual risk of failure due to cracking. FEI explained this in response to BCOAPO IR1 5.2 in the Coastal Transmission System (CTS) Transmission Integrity Management Capabilities (TIMC) Project CPCN proceeding:[4]

> FEI, in alignment with industry best practices, endeavours to implement integrity management activities that mitigate threats to its transmission pipelines. Even so, FEI recognizes that residual risk cannot be reduced to zero.

JANA confirmed in the same BCOAPO IR response that, in its opinion, "it is not possible to reduce risk to zero for any activity or pipeline operation."[5]

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[2] Pipeline transportation safety investigation report P18H0088, Section 1.9, para 4.

[3] Pipeline transportation safety investigation report P18H0088, Section 1.13.1, para 1 .

[4] Exhibit B-6: https://docs.bcuc.com/documents/proceedings/2021/doc_63628_b-6-fei-response-to-bcoapo-ir1.pdf.

[5] Exhibit B-6, BCOAPO IR1 5.2: https://docs.bcuc.com/documents/proceedings/2021/doc_63628_b-6-fei-response-to-bcoapo-ir1.pdf.

Further, the use of EMAT ILI itself is not the only factor that is required to reduce failure rates due to cracking. Applying the findings from the EMAT ILI tool in an effective manner is also required (e.g., conducting integrity digs, pipeline replacement, etc.).

Exponent also provides the following response regarding the appropriateness of an internal failure rate of 6.51e-5 /km/year for AVs 1, 2, 3 and 54:

Exponent understands that JANA's analysis considers application of FEI's integrity management program in determining internal failure rates. Exponent based internal failure rates for T-South on the most similar of FEI's pipelines for which JANA calculated internal failure rates. Exponent does not respond to BCUC IR5 116.4.1 in light of the answer to BCUC IR5 116.4.

Exponent considers its values to be appropriate. For this analysis, there were two relevant datasets: JANA's analysis of FEI's pipelines with similar ages and diameters; and JANA's analysis of generic pipelines using the PHMSA and TSB data representing pipelines with current integrity management practices. The mean rupture rate using the PHMSA data (a much larger dataset than the TSB data) was 3.1e-5/km/year, which is similar to the value used by Exponent.

Nevertheless, to assess the sensitivity of the expected annual GDP loss reduction at average winter temperature of the combined AV-1, -2, -3, and -54 to the internal failure rate, Exponent performed a sensitivity study in which the internal failure rate used in its report was reduced by 20% (Figure 1). The values can be compared with those shown in Figure 41 of Exponent's report (reproduced as Figure 2 here). It is seen that the expected annual GDP loss reduction for Supplemental Alternatives 7 and 9 (Preferred) decreases from $166 million CAD to $151 million CAD (a 9% reduction) when the internal failure rate is reduced by 20%. Based on these sensitivity study results, reducing the internal failure rate can modestly decrease the expected GDP loss reduction on T-South; however, because the majority of GDP losses stem from other failures (e.g., non-earthquake induced landslides), there is still substantial expected GDP loss reduction when Alternative 9 is implemented.

Figure 1: Total Expected Annual GDP Loss Reduction for the Combination of AV-1, -2, -3, and -54 when the Internal Failure Rate Used in Exponent's Report is Reduced by 20%

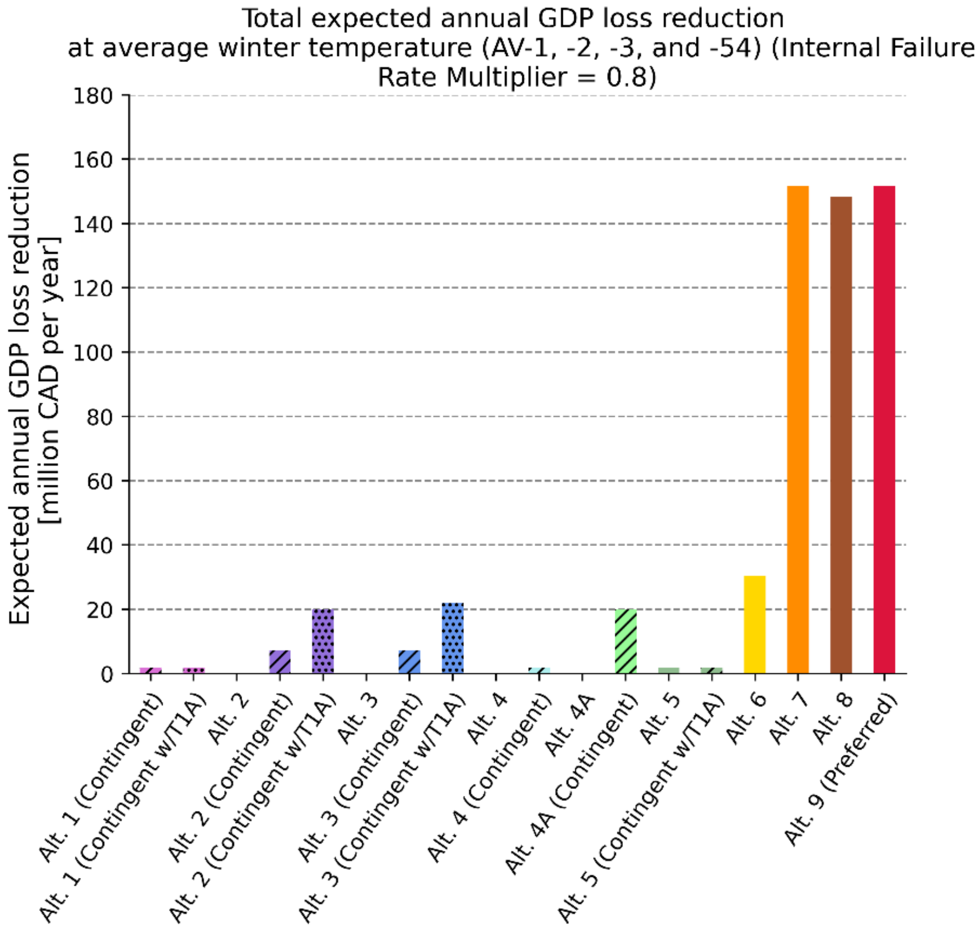
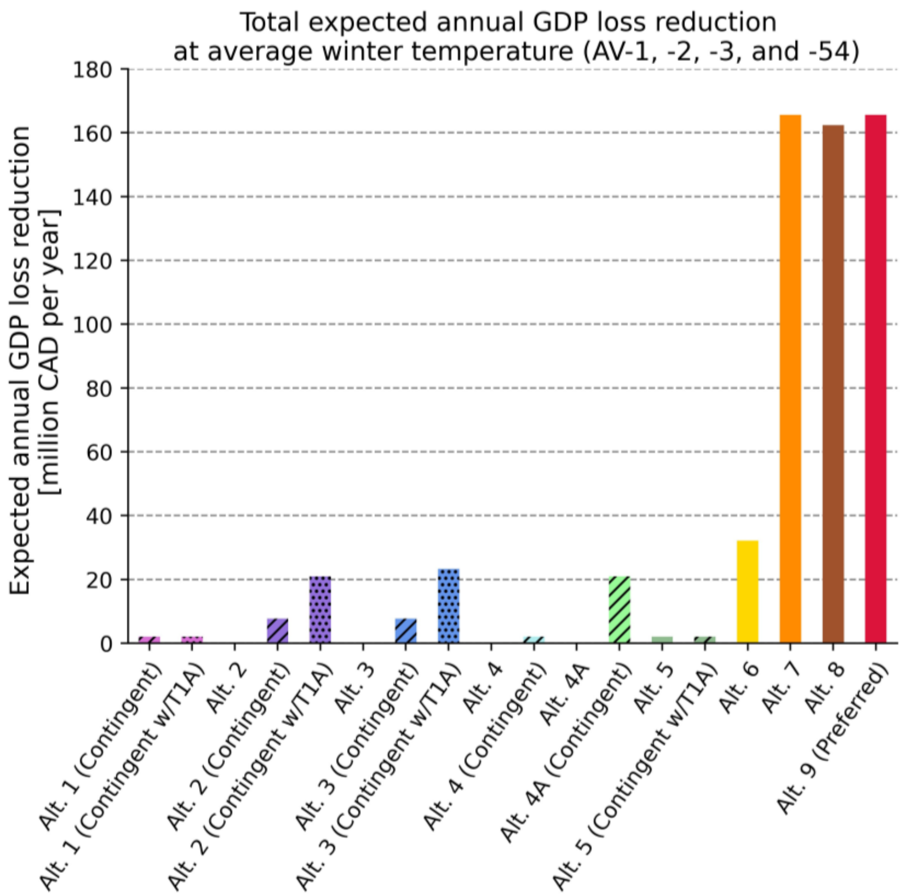


Figure 2: Total Expected Annual Winter-only GDP Loss Reduction, Considering AV-1, -2, -3, and -54, for Different Supplemental Alternatives Relative to Alternative 1 (Planning) (Reproduced from Figure 41 of Exponent's Report)



116.4.2 Please provide the failure rate (/km/year) associated with stress corrosion cracking following the implementation of integrity management mitigations (i.e. mitigated internal failure rate) assumed in JANA's 2021 Pipeline QRA for the relevant pipeline identified by Exponent as the most closely comparable to the noted AVs.

<u>Response:</u>

The relevant pipeline identified by Exponent as the most closely comparable to the noted AVs is not scheduled to be inspected with EMAT ILI until approximately 2026. As such, actual cracking (i.e., extent and severity) on this line is not known. Without this information, FEI is unable to estimate the potential reduction in failure rate that will be achieved by performing post-EMAT integrity digs and mitigating actual cracks.

116.5 Please explain why FEI did not refer to and/or include evidence from JANA's 2021 Pipeline QRA in its TLSE Project CPCN Application, or at any other point prior to adjournment of this proceeding.

Response:

Prior to the Adjournment Decision, the primary focus of the Application was Westcoast's T-South system and enhancing the resiliency of FEI's system in response to the 2018 T-South Incident. FEI had emphasized the catastrophic consequences of a winter T-South no-flow event, rather than the probability, given that a no-flow event had just recently occurred and FEI's experts were advising that the risk assessment should be focused on mitigating the potential for known catastrophic harm. Moreover, JANA's 2021 Pipeline QRA, which included a baseline system level safety QRA and estimated the contribution of cracking threats to overall frequency of failure and risk, did not relate to Westcoast's system and, therefore, was not within the scope of the analysis undertaken at the time to assess the TLSE Project need or alternatives.

In the Adjournment Decision, the BCUC emphasized the need for a holistic resiliency plan to "better understand the interaction of different projects that FEI may be contemplating in order to achieve greater resiliency", and indicated it wanted to see a probability-based risk analysis. It invited FEI to file such a plan in the TLSE proceeding. The 2024 Resiliency Plan assesses probability and consequences. It addresses vulnerabilities that are both on and off FEI's system, including those considered in JANA's 2021 Pipeline QRA. Therefore, to leverage the existing analysis completed for these assets, FEI provided JANA's 2021 Pipeline QRA to Exponent to support its analysis and, in particular, to use the existing internal failure rates calculated by JANA.

Table 3 from page 60 of Appendix RP 2 (the Exponent Report) is reproduced below:

Table 3. Winter-only annual rates of failure and cumulative probability of at least one failure in one, 23, and 67 years for the combination of AV-1, AV-2, AV-3, and AV-54.

Winter-only annual rate of failure							Cumulative probability of at least one failure					
Earthquake Hazards [/yr]		Non-Earthquake External Hazards [/yr]		Internal and 3rd Party Hazards [/yr]	Cumulative [/yr]		Annually [%]		In 23 years [%]		In 67 years [%]	
LB	UB	LB	UB	SV	LB	UB	LB	UB	LB	UB	LB	UB
9.20E-03	3.82E-02	5.32E-03	9.05E-02	3.06E-02	4.51E-02	1.59E-01	4%	15%	65%	97%	95%	100%

Page 66, in paragraph 157, of Appendix RP 2 (the Exponent Report) states:

> For each AV, Exponent calculated a lower bound ("LB") and an upper bound ("UB") on the annual winter only rate of failure. To determine the expected annual loss, Exponent used the annual winter-only rates of failure (probability) in conjunction with consequence data provided by FEI, or in the case of consequential economic (GDP) impacts, by PwC.

Page 67, in paragraph 160, of Appendix RP 2 (the Exponent Report) states:

> When an annual winter-only failure rate is multiplied by the consequences of said failure (in terms of GDP loss, customer outage-days, or customer outages), the result is the expected annual loss, which is a measure of the risk associated with an AV. The expected annual loss accounts for both the likelihood of a failure occurring as well as the magnitude of its consequences.

Page 76, in paragraph 176, of Appendix RP 2 (the Exponent Report) provides the expected winter-only loss associated with AV-1, AV-2, AV-3 and AV-54 as reproduced by the BCUC table below:

	Expected winter-only loss (in million CAD)		
	Over one year	Over 23 years	Over 67 years
AV-1	$175	$4,100	$12,000
AV-2	$22	$510	$1,500
AV-3	$33	$770	$2,200
AV-54	$44	$1,000	$2,900

116.6 Please reproduce Table 3 from the Exponent Report utilizing JANA's mitigated internal failure rate provided in IR 116.4.2 above.

Response:

The following response has been provided by Exponent:

Exponent does not have internal failure rate values that account for increased mitigation of stress corrosion cracking considering EMAT as JANA's study was produced prior to implementation of EMAT on FEI's system. The internal failure rate values used by Exponent already consider that the pipeline integrity is managed.

116.7 Please reproduce the information provided in paragraph 176 of the Exponent Report, specifically the expected winter-only loss associated with AV-1, AV-2, AV-3 and AV-54, based on a rate of failure calculated using JANA's mitigated internal failure rate provided in IR 116.4.2 above.

Response:

The following response has been provided by Exponent:

Please refer to Exponent's response to BCUC IR5 116.6. EMAT-mitigated internal failure rates from JANA are not available.

116.8 Please reproduce Table 8 on page 107 of the Exponent Report utilizing JANA's mitigated internal failure rate provided in IR 116.4.2 above.

Response:

The following response has been provided by Exponent:

Please refer to Exponent's response to BCUC IR 5 116.6. EMAT-mitigated internal failure rates from JANA are not available.

Attachment 1.5c to Exhibit B-15 provides JANA's white paper entitled "Assessment of Outage Probability." Page 2 of Attachment 1.5c states:

> The total length of the T-South system (L1 and L2 combined) is approximately 1834 km (= 2 × 917 km). The T-South system extends 917 km from Compressor Station 2 to the Huntingdon Meter Station in Huntingdon, BC. The NPS 36 L2 pipeline parallels the NPS 30 L1 pipeline in the same right-of-way throughout the T-South system… Construction of the NPS 36 L2 pipeline was completed in 1972. T-South system has been in service since 1957.

116.9 Please confirm that the probability of failure due to internal hazard of the L2 portion of the T-South system is lower than the probability of failure due to internal hazard of the L1 portion of the T-South system, due to different year and materials of construction.

116.9.1 If confirmed, please explain if and how FEI's assessment of the probability of failure of T-South due to internal hazard takes this into account.

Response:

For this response, FEI has redacted certain information for which FEI is requesting be filed on a confidential basis and be held confidential by the BCUC in perpetuity, pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-296-24. Consistent with Order G-19-25, the information is Restricted Confidential Information and FEI requests that the information only be accessible to the BCUC.

The following response has been provided by Exponent:

As indicated in Table R.1 of Exponent's report, the same internal failure rate is used for the L1 and L2 portions of the T South system. As explained in Appendix R, the choice of internal failure rate for AVs for which JANA did not perform detailed pipeline-specific analysis was based on JANA's internal failure rate for pipelines with the most similar year of construction and diameter. For both L1 and L2, the most similar pipeline was [redacted], which has a diameter of [redacted] and was constructed in [redacted].

Further, in Attachment 1.5c to Exhibit B-15, JANA estimates the annual rupture probability for the T-South pipeline and provides it in Figures 2 and 3.

116.10 Please compare the annual rupture probability for the T-South pipeline estimated by JANA in Attachment 1.5c to Exhibit B-15 to the internal rate of failure for AV-1, 2, 3 and 54 used by Exponent. If these values are different, please explain any variance between these estimates of T-South rupture probability and why the estimate used by Exponent continues to be appropriate.

Response:

The following response has been provided by Exponent:

Exponent used an internal failure rate of 6.51e-5 for the T South pipeline (per pipe). As discussed in the response to BCUC IR5 116.9, this was based on JANA's QRA of the most similar pipeline on FEI's system by age of construction and diameter.

JANA's estimate in Attachment 1.5c to BCUC IR1 1.5 (Exhibit B-15) considered historical pipeline rupture data from PHMSA and TSB data sets, representing roughly 476,366 km and 48,388 km of transmission pipelines, respectively. As described by JANA, "These numbers represent rupture probabilities for North American pipeline operators employing currently available integrity management practices and are considered to provide a reasonable basis for estimating future potential ruptures." JANA further stated, "There are potential factors that could, overtime [sic], cause these number to decrease (e.g., evolving integrity management practices, regulatory changes, etc.) or increase (e.g., increasing age of the pipelines, increasing frequency of extreme weather events, etc.) that were not considered in this analysis." It therefore appears that JANA did not consider age or any other factors such as pipeline diameter in their rates in Attachment 1.5c.

The below table compares JANA's estimates from Attachment 1.5c to BCUC IR1 1.5 to the values used by Exponent in their analysis.

	Ruptures (/km/yr)			Ignited Ruptures (/km/yr)		
Calculation	Mean	Lower Limit	Upper Limit	Mean	Lower Limit	Upper Limit
JANA – PHMSA	3.1e-5	2.7e-5	3.7e-5	1.1e-5	0.8e-5	1.4e-5
JANA – TSB	1.4e-5	0.6e-5	3.0e-5	0.6e-5	0.1e-5	1.8e-5
Exponent	6.51e-5	NA	NA	NA	NA	NA

On the basis that JANA's estimate in Attachment 1.5c appears to be based on general rupture rates without consideration of diameter and age, Exponent considered it to be more appropriate to use internal failure rates derived from JANA's more detailed analysis of pipes with similar age of construction and diameter on FEI's system.

116.10.1 Please clarify whether FEI continues to rely on the evidence provided by JANA in Attachment 1.5c to Exhibit B-15.

<u>Response:</u>

Yes. Although the 2024 Resiliency Plan relied on Exponent's analysis, FEI considers JANA's work in Attachment 1.5c to BCUC IR1 1.5 (Exhibit B-15) to be a useful data point in conjunction with Exponent's analysis.

On page 44 of Exhibit B-61, FEI states:

> Exponent conducted a desktop review of the pipeline routes, in relation to publicly-available information on various hazards identified by Exponent (e.g., earthquake surface wave, lateral spreading, settlement, and landslide, non-earthquake landslide, etc.). Exponent developed rates of failure for these hazards based on the methodologies developed as part of the Federal Emergency Management Agency's (FEMA) Hazus program and other technical literature.

Page 33, in paragraph 82, of Appendix RP 2 (the Exponent Report) states: "The 'natural' hazards considered for pipelines can be divided into those derived from earthquake or non-earthquake hazards."

On page 43 of FEI's Interior Transmission System (ITS) Transmission Integrity Management Capabilities (TIMC) CPCN Application, FEI stated the following with respect to the QRA completed by JANA related to FEI's transmission systems:

> At the system level, the QRA estimates that the CTS has the highest risk followed by the ITS and then the VITS. As detailed in FEI's CPCN Application for the CTS TIMC Project, the QRA identified that cracking was the top driver of risk for the CTS pipelines. With respect to the ITS, JANA's model estimates that cracking threats are the second highest threat for seven of the ITS pipelines identified as susceptible to cracking threats and third highest threat for the other two susceptible ITS pipelines. However, cracking threats are the top contributor to safety risk and rupture rate for segments of all nine ITS pipelines identified as susceptible to cracking threats…
>
> As indicated by the QRA, threats that were more highly ranked than cracking on the ITS pipelines include: (1) third-party damage; and (2) natural hazards. Third-party damage results from external interference such as third-party contact with the pipeline or vandalism. Natural hazards result from environmental factors such as landslides, floods or earthquakes and can expose and/or cause damage to the pipeline. FEI's IMP-P includes established activities, further discussed in Appendix E, to mitigate threats due to third-party damage and natural hazards, which are in accordance with standards and regulations or industry practice.

116.11 Please explain how JANA conducted its assessment of the probability of failure due to natural hazards for the QRA.

<u>Response:</u>

The following response has been provided by Exponent:

Exponent performed its own analysis of the probability of failure due to natural hazards. JANA's analysis therefore was not relevant to Exponent's assessment.

FEI also provides the following response:

FEI notes that, while JANA did consider natural hazards in its 2021 QRA, these failure probabilities were not used in the Supplemental Evidence or 2024 Resiliency Plan. For the 2024 Resiliency Plan, Exponent instead undertook its own QRA, addressing the following natural hazards:[6]

<u>Pipelines:</u>

- Earthquake-Induced Surface Wave;

[6] For pipelines, Exponent also undertook a preliminary analysis of the risk posed by wildfire, flooding and buoyancy, and lightning, but did not proceed further with the analysis. In the case of lightning and flooding and buoyancy, this was due to the relatively low probability. In the case of wildfire, this was due to the preliminary analysis suggesting wildfire was less of a threat than other external hazards considered.

- Earthquake-Induced Landslide;
- Earthquake-Induced Liquefaction;
- Non-Earthquake-Induced Landslide;
- Earthquake-Induced Bridge Shaking; and
- Earthquake-Induced Bridge Ground Movement.

<u>Compressor Stations, Control Stations, Valve Assemblies, and Gate Stations:</u>

- Earthquake-Induced Shaking;
- Earthquake-Induced Landslide;
- Earthquake-Induced Liquefaction;
- Non-Earthquake-Induced Landslide; and
- Flooding.

These natural hazards, in addition to internal failures and other failure mechanisms unrelated to natural hazards, form the basis for Exponent's risk analysis in the 2024 Resiliency Plan.

However, to be directly responsive to the question, JANA's 2021 QRA indicates that JANA used their proprietary J-TIMP™ Main Line Piping risk model to determine failure probabilities for natural hazards, describing failure probabilities due to natural hazards as follows:[7]

- **Lightning:** The frequency of failure due to lightning is based on an analysis of industry historical failure data including factors such as location and lightning strike density.
- **Heavy Rains or Floods:** The frequency of failure due to flooding is based on an analysis of industry historical failure data including factors such as location, flood potential, depth of cover, and stabilization (anchors, weights, etc.).
- **Earth Movement:** The frequency of failure due to earth movement is based on FEI's site-specific geotechnical and hydrotechnical assessments.

116.12 Please compare the rates of failure for natural hazards determined by JANA for CTS and ITS segment pipelines in proximity to the T-South pipeline to the rate of failure for natural hazards determined by Exponent for AV-1, AV-2, AV-3 and AV-54. Please explain any variance between the rates of failure determined by JANA and Exponent.

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7 FEI CTS TIMC Project CPCN Application, Exhibit B-1, Confidential Appendix B – JANA, Quantitative Safety Risk Assessment of FEI Mainline Transmission Pipelines, p. 11.

Response:

For this response, FEI has redacted certain information for which FEI is requesting be filed on a confidential basis and be held confidential by the BCUC in perpetuity, pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-296-24. Consistent with Order G-19-25, the information is Restricted Confidential Information and FEI requests that the information only be accessible to the BCUC.

The following response has been provided by Exponent:

The below table compares the natural hazards failure rate (ruptures/yr) computed by JANA for individual pipes to the winter-only natural hazards failure rate determined by Exponent (upper and lower bounds) for the AVs in proximity to the T-South pipeline. Exponent does not know the basis for JANA's calculations and cannot comment on the reasons for differences. Exponent's analysis considered location-specific natural hazard occurrence rates on a kilometer-by-kilometer basis. The threat posed by natural hazards can vary significantly geographically. For example, the non-earthquake-induced landslide failure rate can be very high where a pipeline traverses steep slopes, but it will be zero or close to zero in flatlands.

T-South Component	Exponent Natural Hazards Winter-Only Failure Rate (failures/yr)	CTS and ITS segment in proximity to T-South component	JANA Natural Hazards Failure Rate (ruptures/yr)
AV-1	Combined LB: 5.0e-3 Combined UB: 8.9e-2	[redacted]	
AV-2	Combined LB: 7.33e-4 Combined UB: 1.1e-2		
AV-3	Combined LB: 6.5e-4 Combined UB: 1.6e-2		
AV-54	Combined LB: 8.1e-3 Combined UB: 2.0e-2		

FEI also provides the following response:

FEI engaged Exponent to calculate the failure rates due to natural hazards, instead of relying on those produced by the JANA QRA, because many of the assets included in the 2024 Resiliency Plan were not included in JANA's analysis. Exponent was in a position to perform its own location-specific assessment of natural hazards across all AVs within the available time based on a consistent methodology. Further, Exponent's analysis in the 2024 Resiliency Plan had more granularity for natural hazard failure rates than the aggregated natural hazard failure rate that was reported in the JANA QRA. That is, Exponent's analysis calculated failure rates for each specific type of natural hazard (e.g., non-earthquake landslide, earthquake settlement, etc.), whereas the JANA QRA only reports the aggregated natural hazard failure rate for each pipeline. In Exponent's Monte Carlo analysis, the repair duration is determined based on the type of hazard that causes the failure. As a result, the failure rate associated with the specific type of natural hazard is required for the analysis. Accordingly, FEI cannot compare the rates of failure determined by JANA and Exponent.

116.13 Please explain how Exponent ranked the probability of natural hazards, third-party damage and internal failure for AV-1, AV-2, AV-3 and AV-54. Please discuss how Exponent's ranking of these hazards compared to JANA's ranking of these hazards for the ITS and CTS, and explain any variance.

Response:

For this response, FEI has redacted certain information for which FEI is requesting be filed on a confidential basis and be held confidential by the BCUC in perpetuity, pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-296-24. Consistent with Order G-19-25, the information is Restricted Confidential Information and FEI requests that the information only be accessible to the BCUC.

The following response has been provided by Exponent:

The below table shows the Exponent ranking of hazards for the T-South segments compared to the Interior Transmission System (ITS) and CTS rankings from JANA considering Supplemental Alternative 1 (baseline). Only the top five hazards are shown for brevity. There are several methodology differences to note:

- Exponent did not consider third-party damage as part of its evaluation of AV-1, AV-2, AV-3, and AV-54.
- Exponent ranked other hazards based on the expected annual GDP loss for each hazard. This methodology effectively considers that some hazards are more easily mitigated than other hazards, thus leading to lower losses for those hazards (e.g., because of shorter repair times, etc.). JANA's ranking is based on rupture rate (which doesn't consider the consequence of rupture due to different hazards).
- JANA's top hazard includes multiple hazard types which Exponent lumped together as part of internal hazards.
- Exponent's hazards include several types of natural hazards, which JANA lumped together.

As the location of the T-South pipeline is different than the ITS and CTS, the natural hazard rates are different. Based on the differences in methodology and location, it is not appropriate to draw conclusions from comparing Exponent's ranking to JANA's ranking.

T-South Component	Hazard Ranking by Exponent Expected Annual GDP Loss	CTS and ITS segment in proximity to T-South component	Hazard Ranking by JANA Annual Rupture Rate
AV-1	1. Non-EQ landslide 2. Internal 3. EQ lateral spreading 4. EQ landslide 5. EQ settlement	[redacted]	
AV-2	1. Non-EQ landslide 2. Internal 3. EQ lateral spreading 4. EQ landslide 5. EQ surface wave		
AV-3	1. Non-EQ landslide 2. Internal 3. EQ landslide 4. EQ settlement 5. EQ lateral spreading		
AV-54	1. EQ lateral spreading 2. EQ settlement 3. EQ surface wave 4. Internal 5. Non-EQ landslide		

116.14 Please clarify whether Exponent's assessment of the probability of failure due to natural hazards and third-party damage considered mitigations implemented by Enbridge to reduce the risk of these hazards.

Response:

The following response has been provided by Exponent:

Exponent's evaluation of probability of failure due to natural hazards did not consider specific mitigations implemented by Enbridge to reduce the risk of these hazards. However, as described below, the effect of mitigation more generally was indirectly accounted for through the industry data sets used and in factors applied for the analysis discussed below.

Exponent's evaluation of non-earthquake-induced landslides reduced the lower bound (and thus the average) to 10% of the baseline analysis probability of failure. A reduction in the landslide likelihood is expected in urban areas due to existing regulations for urban development. It is understood that some urban areas may have been developed before modern development regulations were created and enforced. However, it is assumed that some degree of stabilization is generally present in urban areas, and thus a reduction in the probability of a landslide is expected, all things being equal. For non-urban areas, a value of 0.1 was selected for these analyses. This value accounts for assumed studies that would be expected as part of the process of selecting of a gas transmission pipeline route; these studies are likely to result in the placement of a gas transmission pipeline in an area where the likelihood of a landslide is smaller than the average in the surrounding area. See Appendix H of Exponent's Report for further information.

For earthquake-induced landslides, surface-wave-induced rupture, and earthquake-induced liquefaction, damage functions from Hazus were used to determine probability of failure. Hazus damage functions are based on historical data from earthquakes. To the extent mitigations informed the historical data sets, general mitigations present in earthquake-prone areas are considered, but these are general and not specific to Enbridge's pipelines.

Following screening analysis, it was assumed that the probability of failure of Enbridge pipelines due to flooding and water hazards at crossings was zero, which underestimates the risk posed by T-South.

Third-party failures were not considered for T-South because of a lack of available data, which underestimates the risk posed by T-South (Exponent Report, p. 28, para. 64).

117.0 Reference: PROJECT NEED

Exhibit B-60 (Supplemental Evidence), pp. 60 – 67; Exhibit B-28, RCIA IR 31.2; FEI Reply Argument, p. 4, para. 9; Exhibit B-61 (2024 Resiliency Plan), Appendix RP 2 (Exponent Report), p. 21, para. 49,; p. 159, para. 242; Appendix U, p. U-81

Mitigations of Low Probability, High Consequence Events

On pages 66 to 67 of Exhibit B-60, FEI provides the following statement from Exponent:

> Scenario-based analysis considers the expected impacts of a failure, independent of the likelihood of the failure. PwC's [Pricewaterhouse Coopers] consequence analysis indicates that there are significant losses if certain AVs fail (the scenario), and Exponent's analysis indicates that this loss can be largely mitigated if it stems from certain hazards. <u>It is well established that scenario-based analysis is a valid approach for making mitigation decisions when the consequences of a loss are substantial, independent of the likelihood of the failure. Additionally, it is common and most productive to address the largest risk first and those with the highest benefit relative to mitigation cost first.</u>
>
> There is large uncertainty in predicting low-probability, high-consequence events because observations of such events are very sparse, and the observational time span is typically not long enough. <u>Therefore, the distributions fitted to the observed data tend to fit the central tendencies of the data, but may underestimate the rare tail events</u>, whereas distributions fitted to the extreme tail events must contend with a very small number of available observations. The large uncertainty in the occurrence of the tail events may lead to hazard and risk estimates that are highly sensitive to the distribution parameters and modeling assumptions [Emphasis included]

Further on page 67 of Exhibit B-60, FEI provides the following statement from JANA:

> When we land in Quadrant IV [limited knowledge, unpredictable timing and location of event, high consequences], what we must do is 1.) Accept that we cannot predict what will happen, or when; 2.) Reject all narratives and projections that try to tell us what will happen and when; and 3) Work towards mitigating the consequence of such an occurrence.

117.1 Please discuss FEI's efforts to consult broadly so as to address the uncertainty of predicting the probability and consequence of a no-flow event on the T-South pipeline. For example, please explain whether FEI consulted with the Canada Energy Regulator (CER), Westcoast/Enbridge, potentially impacted municipal governments, and/or the provincial government. Please summarize feedback received through these consultations, if any.

Response:

FEI prepared the 2024 Resiliency Plan based on its own system modelling, and the external expertise of PwC and Exponent. FEI is able to determine the direct consequences to its system from a T-South no-flow event (e.g., number of customers impacted, restoration timelines, existing resiliency capabilities that could mitigate the consequences, etc.). FEI retained PwC to quantify GDP impacts associated with the corresponding customer outage. PwC's modelling approach included inputs from interviews with representatives of various industry sectors (please refer to Appendix 1 to the PwC Report[8] and PwC's response to BCUC IR5 141.4) and accounts for uncertainty using high and low bands. PwC also provided information based on the impacts of other energy system outages (please refer to Appendix 4 of the PwC Report). Exponent's risk analysis recognized the uncertainty in probability, as noted below.

Please refer to the responses to BCUC IR5 116.1 and 116.3 regarding FEI's communication with Westcoast.

Please also refer to the response to BCUC IR5 120.1 which discusses how the CER's approach to regulatory shutdowns remains consistent with its process in place at the time of the 2018 T-South Incident.

In response to Residential Consumer Intervener Association (RCIA) IR 31.2, FEI provided this response from Guidehouse:

> In the case of supply disruption of the T-South Pipeline and its related consequence to FEI and FEI's customers, the focus on probability of occurrence is a distraction from the key question which is: "How can FEI best prepare to mitigate the consequence of a supply disruption during a period of heavy usage?"
>
> Decision makers often place too much emphasis on probability when addressing low probability but high consequence events. Low probability and high consequence events continue to be high risk events regardless of their probability. High risk must be mitigated in alignment with what a utility can tolerate.

On page 4, in paragraph 9, of its Reply Argument, FEI states:

> FEI submits that the BCUC should be no more willing to accept a 40+ percent cumulative probability of catastrophic harm than an 83.1 to 97.3 percent probability. Even if, hypothetically, the probability was 10 percent, that is still a material risk of catastrophic consequences… FEI's own assessment, based on

[8] Exhibit B-61, 2024 Resiliency Plan, Appendix RP 3.

risk management principles endorsed by experts in this proceeding, was that mitigating the risk is appropriate.

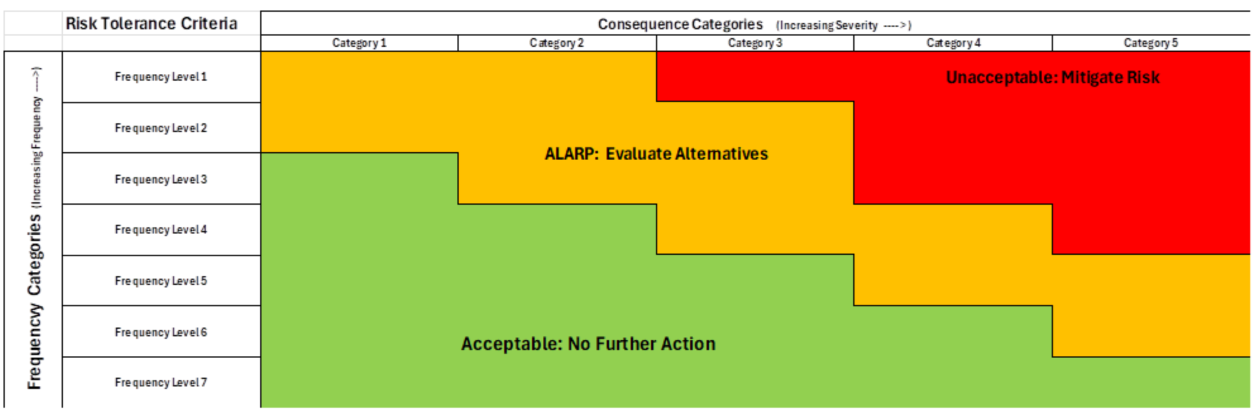
On page 21, in paragraph 49 of Appendix RP 2 (the Exponent Report) of Exhibit B-61, Exponent states:

> Per general good industry practices, subsequent to a proactive-risk assessment evaluation, the <u>high-risk scenarios should be reduced to acceptable levels</u>… subsequent to the more quantitative QRA studies, the likelihood for a specific hazard scenario(s) is usually mitigated <u>below a predetermined frequency and brought into an as-low-as-reasonably-practicable ("ALARP") zone</u>. [Emphasis added]

117.2 With respect to AVs 1, 2, 3 and 54, please explain to what extent the probability of an event (e.g. annual failure rate) would need to be reduced such that FEI considers the probability to be at an acceptable level or within the ALARP zone.

<u>Response:</u>

The following response has been provided by Exponent:



As depicted in the above figure, the ALARP zone is typically between "Unacceptable" and "Acceptable" levels of risk. It is generally understood that "Unacceptable" levels of risks need to be mitigated and "Acceptable" levels of risk do not need further mitigation. When Risk levels fall between these two "Unacceptable" and "Acceptable" levels of risk, then it is a "gray" zone. Often cost- benefit studies are required to justify additional risk mitigation efforts when the existing risks are already within this ALARP zone. If further cost- effective risk reduction measures can easily be implemented, then these should be implemented even when risk is within ALARP zone. It is only when such cost-effective risk reduction measures are taken that the risk can be characterized as having been reduced to "as low as reasonably practicable". On the other hand, if significant costs are required for further risk reduction to "Acceptable" levels and risk reduction for these mitigation measures is not commensurate with the invested cost expenditure, then such risk reduction measures are not considered pragmatic for ALARP risk levels.

Definitions of "Unacceptable" and "Acceptable" level of risk are based on "Risk Tolerance Criteria" which are project specific and often depend on Corporate, Governmental and Regulatory standards. Often while such definitions do exist for safety (fatality/injury) type risks for public/commercial projects, these are often not explicitly defined for Asset (Monetary/GDP) type losses. However, for such Asset (Monetary/GDP) loss-based risk assessments, the subsequent cost benefit analysis, i.e., to estimate the risk reduction for the additional invested risk mitigation effort costs, is a relatively straightforward exercise to perform without the need to explicitly define "Unacceptable" and "Acceptable" levels of risk.

The ALARP principle is not static and can change over time. For example, a future project with ancillary resiliency benefits may result in an opportunity to reduce the residual risk in a cost-effective manner. In such circumstances it may become appropriate to further reduce the underlying risk.

In the current situation, 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.

FEI also provides the following response:

For the purposes of this response, and others dealing with the distinction between "acceptable" / "unacceptable" risks and ALARP, FEI is grounding the discussion in Exponent's explanation above.

FEI regards the current risk posed by a winter T-South no-flow event to be unacceptable for reasons explained throughout the Supplemental Evidence. FEI does not believe that the probability of a T-South no-flow event could economically be reduced to the point where FEI's direct exposure to risk associated with a customer outage would fall within the ALARP zone as it relates to FEI.

While the overall risk calculated by Exponent is a function of both probability and consequences, the catastrophic losses that will flow from a winter no-flow event are a very significant contributor to the overall expected losses (i.e., Exponent's calculated risk). The direct consequences of the event (i.e., loss of service to hundreds of thousands of customers for many weeks) is a known consequence based on FEI's standard system modelling, and it is clear that an outage of this scale would have significant cascading GDP and other impacts. Even PwC's lower bound GDP loss estimate is very large, and PwC has noted that its analysis includes conservatism.

Given the severity of the consequences of a winter T-South no-flow event, even a very low probability of occurrence (which this is not) would represent a significant risk. The type of no-flow event envisioned has already materialized, demonstrating that this is more than just a hypothetical issue. Reducing the risk to levels that are no longer unacceptable (i.e., so that they fall within the ALARP zone, let alone being deemed acceptable) requires mitigating the potential consequences.

As noted in Section 3.2.5.2 of the Supplemental Evidence, Exponent stated the following with respect to mitigating the risk of T-South:[9]

> While there is uncertainty in the determination of failure probabilities, based on its analysis, Exponent does not consider the hazards and subsequent consequences that can impact FEI's system and the customers it serves to be "low probability" with respect to certain AVs (-1, -2, -3, -18, and -54). <u>There is significant benefit to mitigating the consequences of a failure – this would be true even if the hazards were considered to be low probability.</u> Scenario-based analysis considers the expected impacts of a failure, independent of the likelihood of the failure. PwC's consequence analysis indicates that there are significant losses if certain AVs fail (the scenario), and Exponent's analysis indicates that this loss can be largely mitigated if it stems from certain hazards. It is well established that scenario-based analysis is a valid approach for making mitigation decisions when the consequences of a loss are substantial, independent of the likelihood of the failure. Additionally, it is common and most productive to address the largest risk first and those with the highest benefit relative to mitigation cost first. Further discussion is provided in Section 10 of this report. [Emphasis added.]

117.3 With respect to AVs 1, 2, 3 and 54, please explain to what extent the consequence of an event (e.g. expected annual loss, $) would need to be reduced such that FEI considers the consequence to be at an acceptable level or within the ALARP zone.

117.3.1 Please explain whether Alternative 6 (1 BCF resiliency reserve) reduces the consequence of a no-flow event on the T-South to an acceptable level or within the ALARP zone. If not, please explain why not.

117.3.2 Please explain whether Alternative 8 (1.4 BCF resiliency reserve) reduces the consequence of a no-flow event on the T-South to an acceptable level or within the ALARP zone. If not, please explain why not.

<u>Response:</u>

The question appears to equate "expected annual loss" to a consequence metric. FEI clarifies that "expected annual loss" is the output of Exponent's risk calculation (i.e., probability x consequence), and not a consequence metric itself. The three consequence metrics used by Exponent were: (1) customer outages; (2) customer outage days; and (3) economic (GDP) losses as estimated by PwC. Exponent calculated "expected annual losses" for all three of the

[9] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, para. 22.

consequence metrics. Further, the ALARP principle speaks to risk, not consequence. As such, FEI has responded to this question in the context of risk rather than consequence.

Safety Risk Classification

FEI notes that while the concept of ALARP can be applied to other types of risk, it is typically applied to safety risk. For example, CSA Z662 Annex B quantifies risk thresholds for both safety risk and environmental risk, but not for economic risk. While there are clearly public safety issues associated with a widespread customer outage in colder temperatures, it would be very challenging to measure the risk using a mortality-based consequence metric. As such, FEI is unable to state absolutely whether the residual T-South risk (i.e., the T-South risk with the TLSE Project in place) is unacceptable, ALARP, or acceptable from the perspective of safety.

Non-Safety Risk Classification

In terms of the non-safety risk that was the focus of the 2024 Resiliency Plan risk assessment, FEI did not predetermine a bright line threshold to differentiate between risks that are unacceptable and those that fall within the ALARP zone. As Exponent notes in its response to BCUC IR5 117.2, whereas it may be possible to identify a brighter line when it comes to safety (fatality/injury), that is not typical for asset (monetary/GDP) type losses. Instead, 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.

FEI's and Exponent's analysis demonstrates that the current T-South risk is catastrophic. The consequences are very significant, regardless of how consequences are measured (i.e., in terms the number of customers affected, the customer outage days and the consequential GDP impacts). The probability of a no-flow event occurring is significant and a similar event has already occurred in 2018. It is by far FEI's greatest resiliency risk. FEI believes that, even without identifying a bright line threshold, it is clear that the risk is unacceptable at present.

As shown in Figure U.50[10] from the Exponent Report (reproduced below), there is significant disparity between: (a) the residual (non-safety) risk for Supplemental Alternatives 7 to 9; and (b) the status quo and all other Supplemental Alternatives. This significant disparity is evident regardless of the time horizon used. For alternatives that do not materially reduce the currently unacceptable risk, the risk remains unacceptable (i.e., not in the ALARP zone for non-safety risks).

[10] Appendix RP 2 to the 2024 Resiliency Plan (Exhibit B-61), Exponent Report, Report Appendix U, Section U.5.1.

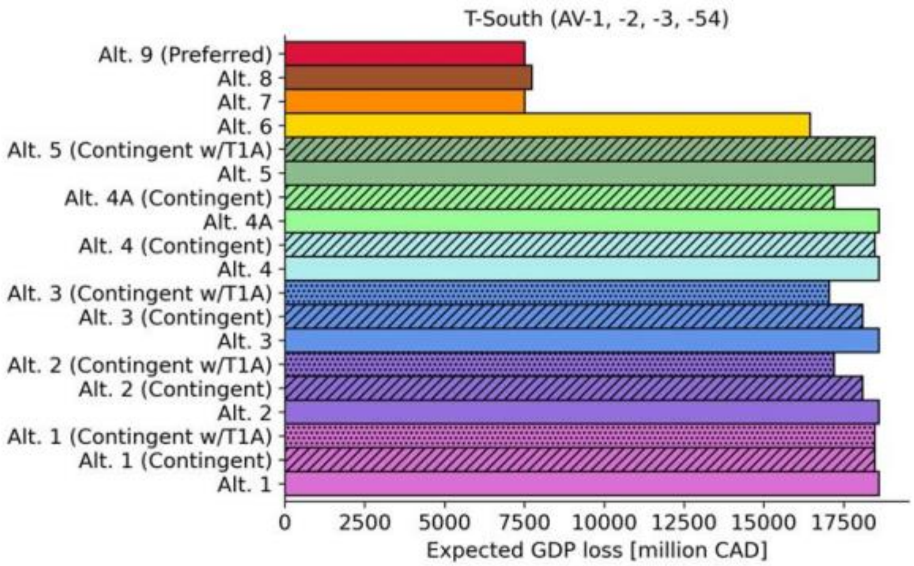


Figure U.50. Expected 67-year winter-only GDP loss in million CAD for T-South (AV-1, -2, -3, and -54) for the Tilbury Alternatives.

FEI considers that Supplemental Alternatives 7, 8 and 9 will all reduce the T-South winter no-flow sufficiently to move the monetary/GDP risk from “unacceptable” into the ALARP zone; however, those alternatives are not equal in terms of how much risk they reduce at lower temperatures, the unit cost of resiliency, or the present value (PV) of the cost of service. As Exponent notes above, all of these considerations come in to play when evaluating potential expenditures within the ALARP zone. FEI has concluded that a larger 3 Bcf tank, divided between a 2 Bcf resiliency reserve and 1 Bcf for gas supply (the Preferred Alternative), delivers significant additional value relative to Supplemental Alternatives 7 and 8. Notably:

- There are significant economies of scale with tank construction (please refer to Section 4.5.4.1.1 of the Supplemental Evidence);
- The additional allocation to the resiliency reserve relative to Supplemental Alternative 8 has a material risk reduction benefit at below average temperatures (please refer to Section 4.5.1.3 of the Supplemental Evidence); and
- The additional gas supply allocation will allow FEI to avoid significant gas supply costs by optimizing its gas portfolio (please refer to Sections 4.5.2 and 4.5.4.1.2 of the Supplemental Evidence).

As shown in Table 4-12 in Section 4.5.4.2 of the Supplemental Evidence (reproduced below), the Preferred Alternative has a positive risk reduction to dollar of rate impact ratio, meaning that the Project will mitigate more GDP risk than its cost of service. The ratio is higher than all of the other viable options, meaning that it is delivering the greatest risk reduction value for customers.

Table 4-12: Risk Reduction per Dollar of Rate Impact

Parameter	Supplemental Alternative 4	Supplemental Alternative 4A	Supplemental Alternative 8	Supplemental Alternative 9
(1) 67-Year Expected GDP Loss Reduction ($millions)	-	-	10,877	11,093
(2) Total PV of Cost of Service ($millions)	424	375	768	723
Ratio (1)/(2)	-	-	14.2	15.3

FEI provides a revised version of Table 4-12 below that includes Supplemental Alternatives 6 and 7.

Revised Table 4-12: Risk Reduction per Dollar of Rate Impact

Parameter	Supplemental Alternative 6	Supplemental Alternative 7
(1) 67-Year Expected GDP Loss Reduction ($millions)	2,153	11,093
(2) Total PV of Cost of Service ($millions)	943	1134
Ratio (1)/(2)	2.28	9.78

Based on the significant amount of risk that is mitigated, and on the positive risk reduction to dollar of rate impact ratio, FEI considers the TLSE Project to be a prudent risk mitigation investment.

FEI has summarized its conceptual classification of the T-South monetary/GDP risk in Table 1 below.

Table 1: Conceptual T-South Monetary/GDP Risk Classification

Scenario	Conceptual T-South Risk Classification	Rationale
Current Risk	Unacceptable (Not ALARP Zone)	The risk posed to FEI by a T-South failure is very significant. Investments in the Southern Crossing Pipeline in 2000 and Mt. Hayes LNG (CPCN issued in 2007), both of which were constructed for other purposes, had the effect of providing limited mitigation against a T-South no-flow event but the residual risk remains catastrophic and the potential consequences (customers lost, customer outage days and consequential GDP losses) have only increased since then. A T-South no-flow event occurred in 2018. As FEI has not made any significant investment targeted at reducing this risk, the risk has not been reduced to as low as reasonably practicable.
Supplemental Alternatives 2, 3, 4, 4A, and 5	Unacceptable (Not ALARP Zone)	These options do not materially reduce the current risk associated with a winter T-South no-flow event.

Scenario	Conceptual T-South Risk Classification	Rationale
Supplemental Alternative 6	Unacceptable (Not ALARP Zone)	Referring to Figure U.50[11] from the Exponent Report, Supplemental Alternative 6 does not provide material risk mitigation. The risk reduction to dollar of rate impact ratio for Supplemental Alternative 6 is 2.28 (relative to 15.3 for the Preferred Alternative). While the result is greater than 1, and thus more risk is being mitigated than the Supplemental Alternative's cost of service, the ratio is much lower than Supplemental Alternatives 8 and 9. This indicates that Supplemental Alternative 6 provides less resiliency value than Supplemental Alternative 8 and Supplemental Alternative 9 (the Preferred Alternative).
Supplemental Alternative 7	ALARP Zone, but more cost-effective mitigation is available with Preferred Alternative	Supplemental Alternative 7 (i.e., 2 Bcf tank exclusively dedicated as a resiliency reserve and 800 MMcf/d sendout) would be a prudent risk mitigation investment. This is because, as shown in Figure U.50 from the Exponent Report, Supplemental Alternative 7 provides material risk mitigation. It provides the equivalent resiliency to the Preferred Alternative, Supplemental Alternative 9. Additionally, Supplemental Alternative 7 has a risk reduction to dollar of rate impact ratio that is greater than 1. The risk reduction to dollar of rate impact ratio for Supplemental Alternative 7 is 9.78, as shown in the Revised Table 4-12 above. While both Supplemental Alternatives 7 and 9 provide the same risk mitigation (i.e., both contemplate a 2 Bcf resiliency reserve and 800 MMcf/d of sendout), Supplemental Alternative 9 has a higher ratio, indicating better resiliency value. This is because, due to the gas supply benefits that are absent from Supplemental Alternative 7, Supplemental Alternative 9 has a lower total PV of cost of service.
Supplemental Alternative 8	ALARP Zone, but better and more cost-effective mitigation available with Preferred Alternative	Supplemental Alternative 8 would be a prudent risk mitigation investment. This is because, as shown in Figure U.50 from the Exponent Report, Supplemental Alternative 8 provides material risk mitigation. Further, as shown in Table 4-12 of the Supplemental Evidence (and copied above), Supplemental Alternative 8 has a risk reduction to dollar of rate impact ratio that is greater than 1. While FEI considers Supplemental Alternative 8 to be a prudent risk mitigation investment, Supplemental Alternative 9 remains the Preferred Alternative for the reasons discussed in Section 4.5 of the Supplemental Evidence. Supplemental Alternative 8 significantly reduces the T-South risk and, as such, FEI considers it to be in the ALARP zone. However, as discussed below, Supplemental Alternative 9 is both more cost-effective and provides more risk mitigation than Supplemental Alternative 8 (particularly at temperatures below the average winter temperature).

[11] Appendix RP 2 to the 2024 Resiliency Plan (Exhibit B-61), Exponent Report, Report Appendix U, Section U.5.1.

Scenario	Conceptual T-South Risk Classification	Rationale
Supplemental Alternative 9 (Preferred Alternative)	ALARP Zone, risk reduced to "as low as reasonably practicable"	The Preferred Alternative significantly reduces the T-South risk, more than any other Supplemental Alternative save for Supplemental Alternative 7 (which allocates the entire 2 Bcf tank to a resiliency reserve, and thus provides the same risk mitigation as the Preferred Alternative). Supplemental Alternative 9 has the higher risk reduction to dollar of rate impact ratio, indicating that it has the best resiliency value among all Supplemental Alternatives. This is because, due to the gas supply benefits, Supplemental Alternative 9 has a lower total PV of cost of service than Supplemental Alternatives 7 and 8. It also provides more mitigation than Supplemental Alternative 8 (particularly at temperatures below the average winter temperature), and significantly more mitigation than any of Supplemental Alternatives 2-6. 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". As noted by Exponent above, FEI also notes that the ALARP principle is not static and can change over time. For example, a future project with ancillary resiliency benefits may result in an opportunity to reduce the residual risk in a cost-effective manner. In such circumstances it may become appropriate to further reduce the underlying risk.

117.4 Please discuss how FEI would determine that a certain risk mitigation is too costly to implement.

Response:

The concept of risk has differing meanings and criteria depending on the context. For example, as noted by Exponent in the response to BCUC IR5 117.2, the criteria applied in the context of public safety risk may differ from that of resiliency risk. Therefore, FEI has assumed that the reference to risk mitigation in the question refers to resiliency risk.

In the context of the 2024 Resiliency Plan, although FEI calculated metrics that incorporated a cost element (discussed below), FEI 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 AVs that:

- The T-South risk calculated by Exponent is very high, consistent with FEI's intuitive understanding and experience that its dependency on a single pipeline for most of its supply left customers very exposed to supply disruptions;
- There was a wide gulf between the risks associated with T-South AVs (AV-1, AV-2, AV-3 and AV-54) and all other AVs; and
- The risk associated with AVs other than T-South and AV-18, in addition to being much smaller, was also relatively comparable.

Moreover, based on FEI's experience with capital projects and understanding of its own system, FEI considers that: (a) eliminating single point of failure risks across 50+ AVs on its system is not economically practical; and (b) differentiating among those segments so as to justify resiliency specific investments (i.e., where resiliency is the primary project driver) for some and not others would be challenging. That is not to say risk mitigation on these segments would be imprudent, but it does speak to the value of considering such measures in the context of projects that have other non-resiliency drivers.

FEI included two quantitative metrics in the 2024 Resiliency Plan that assisted in reaching the above conclusion: (1) the levelized total rate impact; and (2) the risk reduction to dollar of rate impact ratio. The levelized total rate impact assisted in relative comparisons. The risk reduction to dollar of rate impact ratio provided a quantitative threshold of whether the risk mitigation provided was less than the project's cost of service (i.e., if the ratio was less than 1).

On page 159, in paragraph 242 of Appendix RP 2 (the Exponent Report) to Exhibit B-61, Exponent states:

> Because of the limitations associated with using traditional probabilistic risk assessment to analyze the impacts of low-probability high-consequence events, scenario risk analysis88 has emerged as a suitable method to study and identify the impacts of rare hazard events. Numerous studies advocate for the use of deterministic risk analysis using scenario-based methods in various contexts, 89 90 91 92 93 primarily based on the following arguments: a. Scenario risk analysis may reveal mechanisms or local effects that are not present or discernable in probabilistic analysis… b. Scenario risk analysis is deemed appropriate for cases where limited data is available, because their probabilistic analysis contains large uncertainties, and the estimated risks are often highly sensitive to changes in the underlying variables.

88 Scenario risk analysis involves developing loss or event scenarios and determining the consequence given that scenario occurs, without explicit consideration of the likelihood of the scenario.

89 National Research Council (2010). Review of the Department of Homeland Security's approach to risk analysis.

90 McGuire, R. K. (2001). Deterministic vs. probabilistic earthquake hazards and risks. Soil Dynamics and Earthquake Engineering, 21(5), 377-384.

91 Robinson, T. R., Rosser, N. J., Densmore, A. L., Oven, K. J., Shrestha, S. N., & Guragain, R. (2018). Use of scenario ensembles for deriving seismic risk. Proceedings of the National Academy of Sciences, 115(41), E9532-E9541.

92 Bommer, J. J. (2002). Deterministic vs. probabilistic seismic hazard assessment: an exaggerated and obstructive dichotomy. Journal of Earthquake Engineering, 6(spec01), 43-73.

93 Krinitzsky, E. L. (1995). Deterministic versus probabilistic seismic hazard analysis for critical structures. Engineering geology, 40(1-2), 1-7.

117.5 Please discuss how FEI determined that the scenario-based risk analysis is an appropriate risk analysis framework for natural gas system supply disruptions, given the numerous studies referred to in the preamble all relate to analysis of seismic risk.

<u>Response:</u>

The following response has been provided by Exponent:

Exponent used a quantitative/probabilistic analysis that considered the likelihood of different intensities of hazards, and the probability of failure of AVs at each possible intensity. A scenario-based analysis was not used. A description of the methods used by Exponent are in Sections 4 and 6 of Exponent's report, with additional information on specific methodologies contained in the Appendices referenced therein.

Section 10 of Exponent's report discusses how scenario-based analysis could be a valid approach for evaluating risk for low-frequency / high consequence events, however, a scenario-based analysis was not used. The quantitative/probabilistic approach indicated that a no-flow event on T-South is not a low-frequency event.

On page U-81 of Appendix U to the Exponent Report, Exponent provides Figure U.44 as reproduced below.

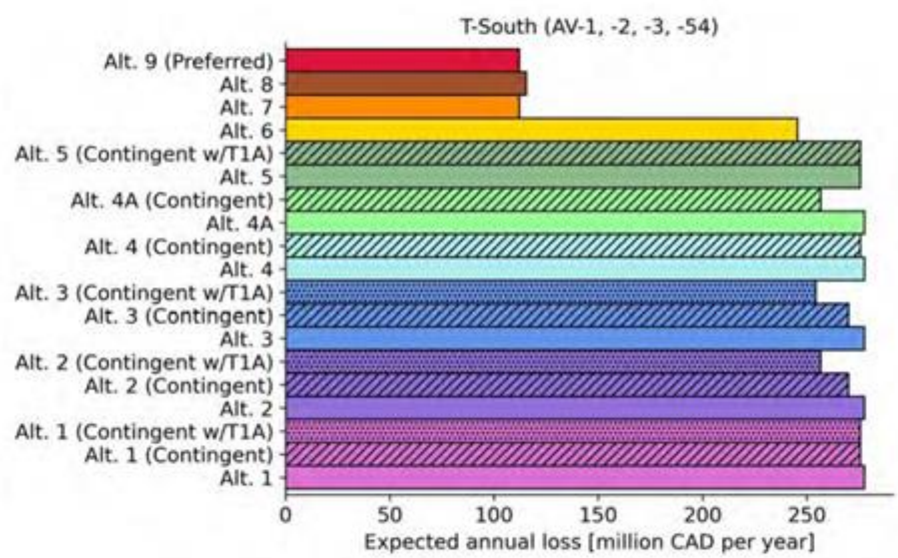


Figure U.44. Expected annual winter-only GDP loss in million CAD per year for T-South (AV-1, -2, -3, and -54) for the Tilbury Alternatives.

117.6 Please confirm, or explain otherwise, that Figure U.44. provides the residual risk of winter-only GDP loss following implementation of the various Tilbury Alternatives. For example, the residual risk of winter-only GDP loss following implementation of Alternative 8 is approximately $115 million.

117.6.1 If confirmed, does FEI consider the residual risk following implementation of Alternatives 7, 8, and 9 to be acceptable or within the ALARP zone.

Response:

The following response has been provided by Exponent:

Exponent confirms that the residual annual winter-only GDP loss with Alternative 8 is $115 million CAD. FEI is in the best position to discuss whether this is acceptable or within the ALARP zone.

FEI also provides the following response:

FEI confirms that Figure U.44 provides the residual risk of winter-only GDP loss following implementation of the various Supplemental Alternatives. FEI notes that Figure U.44 from the Exponent Report presents the risk on an annual basis. Figures U.47 and U.50 (reproduced below) present the risk based on the 23-year and 67-year time horizons, respectively.[12]

[12] Appendix RP 2 to the 2024 Resiliency Plan, Exponent Report, Appendix U, Section U.5.1.

Please refer to the responses to BCUC IR5 117.3 which discusses FEI's approach to risk tolerances and whether Supplemental Alternatives 7, 8 and 9 are considered to be acceptable or within the ALARP zone.

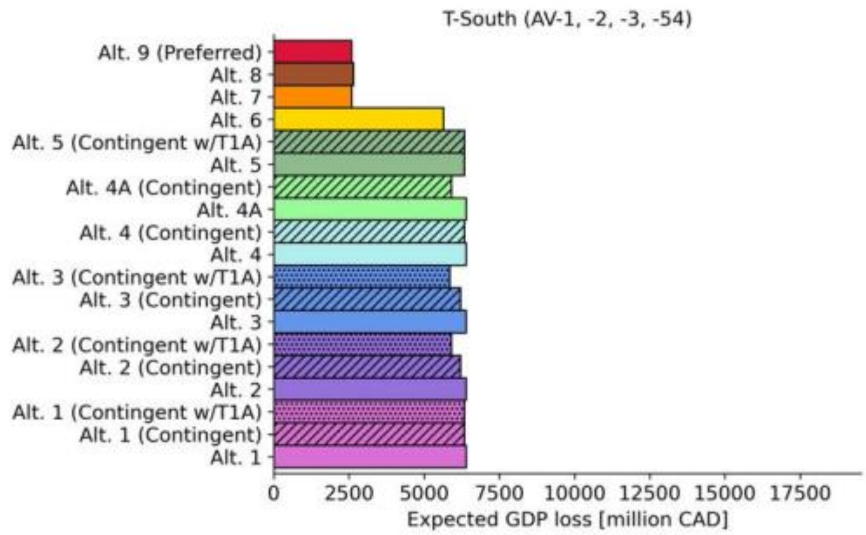


Figure U.47. Expected 23-year winter-only GDP loss in million CAD for T-South (AV-1, -2, -3, and -54) for the Tilbury Alternatives.

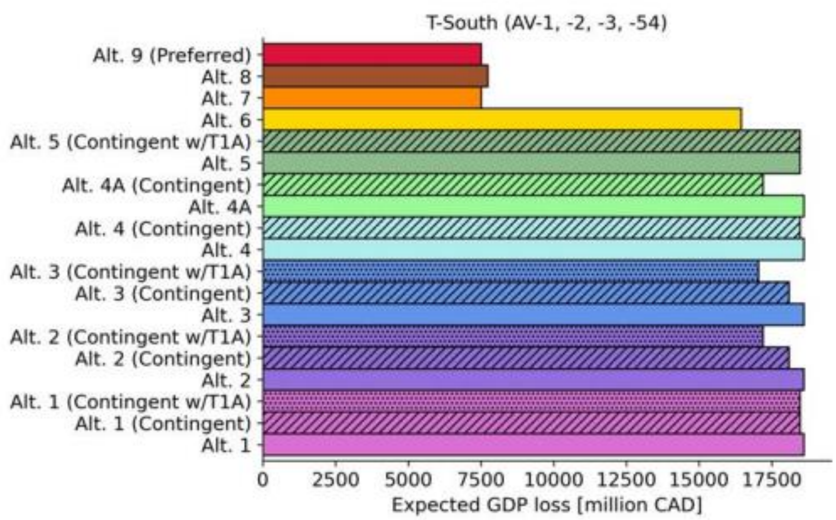


Figure U.50. Expected 67-year winter-only GDP loss in million CAD for T-South (AV-1, -2, -3, and -54) for the Tilbury Alternatives.

118.0 Reference: PROJECT NEED

Exhibit B-60 (Supplemental Evidence), pp. 85 – 87; FEI 2022 Long Term Gas Resource Plan proceeding, Exhibit B-1 (2022 LTGRP), Figure 4-9, p. 4-28

Peaking Supply Requirements

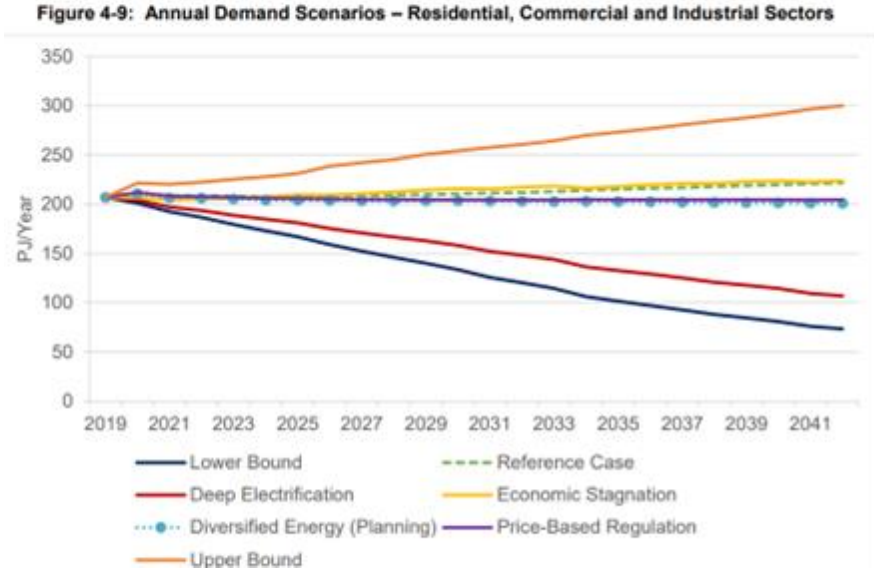
On pages 85 to 86 of Exhibit B-60, FEI states:

> The original design capacity of the Base Plant when it was constructed in 1971 was 150 MMcf/d of regasification and 0.6 Bcf, which means the Base Plant was designed to provide 150 MMcf/d (i.e., 0.15 Bcf/d) of daily deliverability for 4 days (150 MMcf/d x 4d = 0.6 Bcf). Over the past five decades, FEI's customer demand has increased significantly. The number of gas customers in the Lower Mainland has increased from approximately 200,000 in 1971 to 630,000 in 2023. Since 2016/2017 alone, FEI's peak day demand has increased by 125 MMcf/d, which is attributed to: (1) customer growth; and (2) Transportation Service customers (i.e., RS 23 and 25) returning to bundled service (i.e., RS 3 and 5). The demand growth has increased the need for gas supply resources within the portfolio. FEI's peaking capacity requirements now exceed 150 MMcf/d regasification capacity of the Base Plant, while the energy requirements now exceed 0.6 Bcf.

On page 87 of Exhibit B-60, FEI states: "As noted above, FEI requires 200 MMcf/d x 5 days (1.0 Bcf) of peaking supply and the majority of that is provided by Tilbury LNG [Liquefied Natural Gas]."

In the FEI 2022 Long Term Gas Resource Plan (LTGRP) proceeding, on page 4-28 of Exhibit B-1 (2022 LTGRP), FEI provided the following figure which illustrates forecasted customer demand under different scenarios:

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



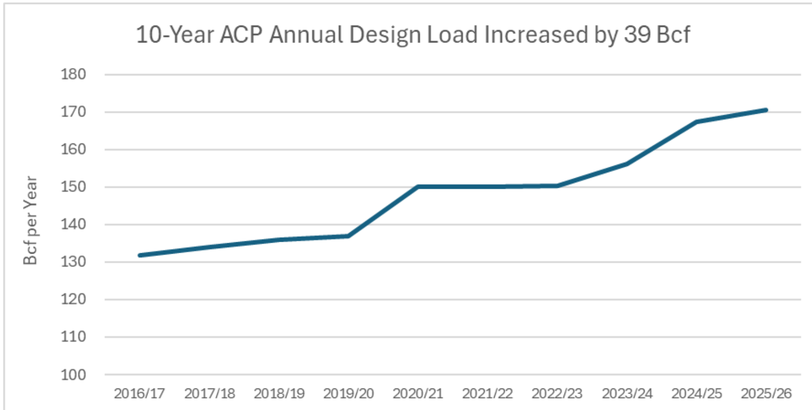
118.1 Please provide further supporting analysis to illustrate how demand growth has led to a requirement for 200 MMcf/d of regasification capacity and 1 Bcf of storage for peaking supply. For example, but not necessarily limited to: historical and forecasted demand trends and methodologies, explanation of how the load duration curve for the design year informs regasification and storage needs, and supporting commentary to explain key assumptions.

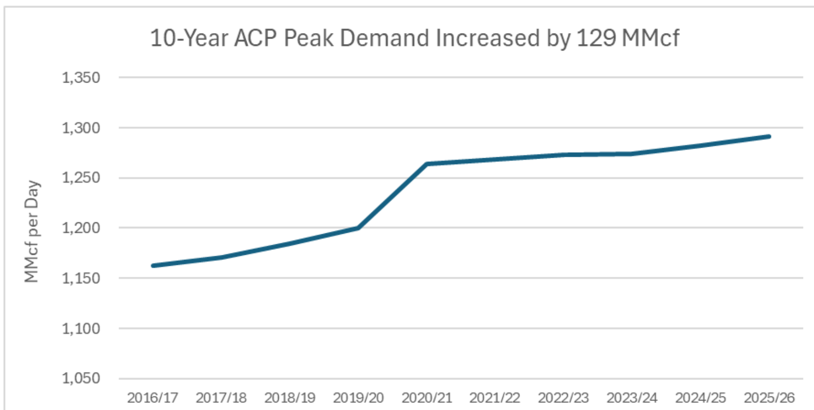
Response:

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.

Figure 1: ACP Annual Design Load and Peak Day Demand Increase





In the 2022/23 ACP, FEI provided an analysis to show the impact that the TLSE Project would have on the gas supply portfolio. The analysis shows if FEI had the option to increase Tilbury peak day supply from 0.6 to 1 Bcf, peak day sendout would increase from 150 to 190 MMcf/d for the gas year 2026/27. The details of the analysis are included in Appendix C of the 2022/23 ACP.

FEI files the ACP with the BCUC annually (May 1) based on a portfolio optimization model that assesses FEI's 5-year resource requirements. The purpose of the model is to determine the least-cost solution to meet customer demand at various locations across the entire year, using the following inputs: (1) demand; (2) supply; (3) transportation and storage capacity; and (4) the costs of securing gas supply resources from the market. Changes to these inputs impact the overall optimization results as the model rebalances the utilization of resources each year.

Further, each resource (or gas supply contract) has its own characteristics (duration and daily capacity) that are intended to match the load duration curve. For example:

- Pipeline capacity is contracted to provide base load supply all year round;
- Market area storage is contracted to provide incremental seasonal supply for about 10 to 60 days in a year; and
- LNG storage is used to provide peaking supply for up to 10 days each year when demand is above the contracted pipeline and storage deliverability.

While the optimal resource requirements are not static, and the required capacity for pipeline and storage will be different as the model captures changes in demand and supply inputs over time, the 39 Bcf annual demand increase supports the need for additional pipeline and storage capacity to meet ACP demand growth. Similarly, the 129 MMcf/d peak day increase supports the need for additional peaking resources.

Despite the reduced operating capacity of the Tilbury Base Plant, FEI has retained the same Tilbury LNG capacity (0.6 Bcf and 150 MMcf/d) in the ACP portfolio and, to date, has temporarily contracted pipeline and storage resources to meet the increasing ACP demand. Although it was initially intended that the excess pipeline capacity would be a contingency peaking resource, these resources have also been eroded in the past few years, particularly with Transportation customers returning to Core customers. FEI has had to contract for additional market resources such as call options at the risk of FEI customers potentially paying high commodity prices on cold days. As explained in Section 3.3.4.2 of the Supplemental Evidence, this approach is suboptimal. The TLSE Project will allow FEI to reduce some of the amount of supply provided through these short-term contracts. For these reasons, FEI determined using 200 MMcf/d with 1 Bcf Tilbury LNG for future ACP resource planning is appropriate and conservative to quantify the gas supply benefits of the TLSE Project.

Ultimately, FEI must re-balance its gas supply portfolio to maintain the effectiveness of asset utilization in response to the evolution of the load duration curve over time. The TLSE Project will provide new optionality to the ACP, with the availability of additional peaking supply.

118.2 Please confirm, or explain otherwise, that FEI did not outline a need for 200 MMcf/d of regasification capacity and 1 Bcf of storage for peaking supply as part of the original TLSE Application. If confirmed, please explain the key changes that have occurred since the date of the original Application that have prompted a need for increased peaking capacity and storage.

Response:

Not confirmed. FEI has known for many years that additional regasification from the Tilbury Base Plant would help optimize its gas supply portfolio of resources. While the Application was primarily focused on the need to enhance system resiliency to mitigate the risk of a winter T-South no-flow event, FEI also identified the importance of the ancillary benefits that will be provided by the TLSE Project as proposed. For example, in the Application, FEI identified that the TLSE Project "will improve FEI's physical security of peaking supply as FEI's customer demand grows"[13].

While, to date, FEI has met its peaking supply requirements with a combination of 150 MMcf/d and 0.6 Bcf from Tilbury (now comprised of 0.35 from the Base Plant and 0.25 Bcf from Tilbury

[13] Exhibit B-1-4, Section 4.4.1.5.2, p. 111.

1A, due to the Base Plant operating at reduced fill levels) and additional pipeline capacity on T-South, this approach is suboptimal and only a temporary measure. Through portfolio optimization modelling, FEI determined that 200 MMcf/d of regasification capacity and 1 Bcf of storage for peaking supply was appropriate.

Please also refer to the response to the BCUC IR5 118.1.

118.3 Please discuss whether FEI has historically experienced any situations where the 150 MMcf/day of regasification capacity and/or 0.6 Bcf of storage for peaking supply were insufficient for peak day and/or seasonal peaking requirements.

Response:

FEI has not experienced any actual supply shortage on peak day or the during winter season; however, the requirements for peaking supply have increased from a planning perspective beyond what the Tilbury Base Plant can provide. To meet increasing peaking demand requirements, FEI has contracted additional resources from the market (i.e., peaking call options and pipeline resources) in a less optimal way than if FEI had more peaking resources than the existing allocation from Tilbury (150 MMcf/d of regasification capacity and the 0.6 Bcf of LNG storage).

The proposed TLSE Project will allow FEI to optimize the portfolio by increasing the capacity from 150 to 200 MMcf/d, with the potential to use more than 200 MMcf/d in the future should the circumstances change. Please refer to the response to BCUC IR5 118.6 in this regard.

Please refer to the response to BCUC IR5 118.1 for further discussion regarding how FEI designs its supply portfolio to match the load duration curve.

118.4 Please explain whether in practice, FEI curtails all available interruptible load before utilizing peaking supply from the Tilbury Base Plant.

118.4.1 Please discuss whether FEI intends to use similar practices if the TLSE Project is constructed with increased regasification and storage for peaking purposes.

Response:

All available interruptible load may be, but is not necessarily, curtailed prior to utilizing peaking supply from the Tilbury Base Plant.

Decisions to curtail interruptible load are made by weighing available system supply and capacity against minimizing impacts to customers. The current practices for evaluating the need to curtail interruptible customers will continue if the TLSE Project is constructed, and the TLSE Project provides additional operational flexibility due to the additional regasification capacity and additional volume allocated for planning purposes to gas supply.

FEI notes that the above response only applies to the use of LNG supply allocated for *gas supply* purposes in relevant scenarios. For any scenario involving use of LNG for *resiliency* purposes (i.e., responding to a no-flow event), all interruptible load is assumed to be curtailed as soon as is practicable.

118.5 Please confirm, or explain otherwise, that the peak day is assumed to be the coldest day that is expected to occur once in 20 years.

118.5.1 Please discuss if and how FEI's assumptions for peak day, and other cold days which would require peaking supply from Tilbury, take into account potential warming trends resulting from climate change.

Response:

Confirmed. FEI designs the capacity of its system to meet peak demand in cold temperatures and not averages. FEI estimates peak day demand for each weather zone using the extreme value analysis (EVA) methodology. Detailed discussion about the EVA methodology can be found in the response to the BCUC IR1 55 series from the FEI 2022 LTGRP proceeding[14].

FEI does not explicitly project any bias related to future temperature and climate uncertainty in determining design temperature used to determine peak demand. FEI uses historical weather to statistically predict the likelihood of cold weather and periodically refreshes its calculations, bringing the most recent weather extremes into the 60-year data set used in determining the design temperatures.

While on average BC's climate is warming, more cold weather patterns are also occurring. Global climate change is expected to alter the intensity and frequency of cold weather events, but whether the cold occurrences will be colder or warmer than currently predicted is uncertain. If climate change ultimately results in colder temperature occurrences, those occurrences will be incorporated into FEI's extreme value analysis in the future and will result in colder design temperatures and higher estimates of peak demand. In contrast, if the data support warmer temperatures, the calculated design temperature in the future will warm, resulting in lower estimates of peak demand.

[14] Exhibit B-6, BCUC IR1 55 series: https://docs.bcuc.com/documents/proceedings/2022/doc_69352_b-6-fei-response-bcuc-ir1.pdf.

At this point in time, FEI's considers its determination of design temperatures used to forecast peak demand to be appropriate and not requiring adjustment to effectively deal with and account for climate change. In particular, the current process allows for observed changes in the occurrence of cold temperatures to be incorporated periodically. Nonetheless, FEI continues to monitor for changes to industry practice, standards, and regulations to determine if there is a need to adjust its peak demand forecasting methodology to account for climate change.

118.6 Please confirm, or explain otherwise, whether 200 MMcf/day is the maximum sendout which FEI would require on the peak day.

118.6.1 If confirmed, please explain why FEI requires storage equivalent to five peak days. As part of the response, please clarify whether FEI assumes for planning purposes that five peak days would occur in the same winter.

Response:

FEI confirms that its peaking capacity requirements are approximately 200 MMcf/d at present; however, 200 MMcf/d would not be the maximum regasification used for gas supply purposes if FEI had more regasification capacity available and at least 1.0 Bcf of storage (as it would with the Preferred Alternative).

Peaking requirements for Tilbury LNG can change each year depending on the load profile and other ACP resources available in the market. LNG is typically reserved as the last resource to provide up to 10 days of peaking supply each year. The short duration (i.e., up to 10 days) is due to the limited inventory the LNG facility can hold.

Access to more than 200 MMcf/d of regasification, combined with more storage, as part of the TLSE Project provides a valuable option for future gas supply portfolio planning to meet the changing load profile, and to provide flexibility in contracting market area resources. The flexibility of sending out more than 200 MMcf/d is only practical when a larger LNG reserve of at least 1.0 Bcf is available for gas supply. In particular, a 0.6 Bcf LNG reserve with 200 MMcf/d of regasification would use up Tilbury peaking supply in only 3 days.

FEI notes that its reference to five peak days was not intended to suggest that FEI is assuming five peak days occur in a single winter. Nor was it intended to suggest that FEI only needs LNG on five days in a winter. It is common in the industry to express the duration of peaking supply provided by an LNG facility based on the total volume available divided by the peaking supply requirements for planning purposes (i.e., 1 Bcf / 200 MMcf/d = 5 days). Despite this measurement convention, the actual daily sendout from storage will be different each day and different across each year depending on winter weather and the market conditions which might allow FEI to buy spot supply at reasonable prices and save LNG for the remaining winter.

118.7 Please clarify whether Figure 4-9 in the FEI 2022 LTGRP includes interruptible demand.

Response:

Confirmed. Figure 4-9 in the 2022 LTGRP displays the End Use Annual Method Demand Reference Case and alternate scenarios for the residential, commercial, and industrial demand categories. The figure includes RS 7, 22 and 27, which are considered interruptible.

For added clarity, FEI would not typically exclude interruptible rate schedules from annual demand projections as FEI is required to meet demand requirements of these customers except during short periods of curtailment that occur from time to time. However, FEI would typically exclude interruptible rate schedules from peak demand charts which aim to show the peak load for which FEI must secure supply resources to serve, including on-system storage.

FEI's analysis in the 2024 Resiliency Plan and Supplemental Evidence all assumes that interruptible customers have been curtailed already, such that only firm load is accounted for when measuring consequences and risk. This likely understates the impacts of a winter no-flow event on FEI's customers because interruptible customers, while able to accommodate short interruptions due to having a back-up capability, may not be able to operate that back-up capability for the entirety of a natural gas outage lasting many weeks.

118.7.1 Please confirm, or explain otherwise, that under FEI's Planning scenario in the 2022 LTGRP, firm customer demand from residential, commercial, and industrial customers is forecasted to decline over time.

Response:

Confirmed. 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. Please refer to the response to BCUC IR5 118.1 where 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.

Please note that Figure 4-9 includes interruptible Rate Schedules 7, 22 and 27, as stated in the response to BCUC IR5 118.7.

118.7.2 Please discuss how FEI takes into account its future demand forecasts in considering the required sizing of regasification and storage for peaking supply.

Response:

FEI used the design load forecast of gas year 2019/20 to determine required peaking supply. As discussed in the response of BCUC IR5 118.1, the demand for FEI's ACP customers has increased significantly since the Application was filed. This has increased the needs for all resource types, including peaking supply. FEI assesses the required peaking supply during the development of the ACP and has provided the results in Appendix C of the 2022/23 ACP.

FEI recognizes future demand forecasts could change, which will change the peaking supply requirements and other resource needs in the ACP over time. If future requirements for peaking supply decrease, FEI's gas supply portfolio has the flexibility to de-contract market area resources when the contracts expire. Similarly, if FEI's peaking requirements increase, the TLSE Project's ability to provide more than 200 MMcf/d would provide additional optionality for FEI in the future. Please refer to Section 4.5.5 of the Supplemental Evidence, which discusses how an on-system LNG facility is a unique asset when it comes to the flexibility afforded in response to changing load. Please also refer to the response to BCUC IR5 129.5.2.

119.0 Reference: PROJECT NEED

Exhibit B-60 (Supplemental Evidence), p. 86

RS 46 LNG Sales

On page 86 of Exhibit B-60, FEI states:

> Using Tilbury 1A tank volumes for peaking supply is only possible at present because LNG sales growth has been slower than anticipated to date; however, the recent provincial and federal approvals of the Tilbury Jetty are a significant development because delays in the jetty approval had represented a significant sales constraint. <u>FEI now expects RS 46 LNG sales to increase significantly and sell out Tilbury 1A as early as 2028</u>. [Emphasis added]

119.1 Please provide supporting evidence to the above underlined statement.

<u>Response:</u>

FEI's statement on page 86 of the Supplemental Evidence (referenced in the preamble) is supported by recent developments in the marine fueling market, including:

- In Q1 2024, FEI provided Seaspan Energy Limited (Seaspan) with a GGRR-enabled financial incentive intended to attract an LNG Bunker Vessel to establish LNG bunkering on the West Coast of North America in exchange for a commitment to take LNG from FEI;
- In Q2 2024, Tilbury Jetty Limited Partnership was granted provincial and federal environmental/impact assessment authorizations to construct a marine jetty at Tilbury Island, which is expected to enable access to the ship-to-ship marine fueling market for FEI;
- In Q4 2024, Seaspan conducted the first ship-to-ship transfer of LNG on the West Coast, in the Port of Long Beach; and
- In Q1 2025, the first ship-to-ship transfer of LNG occurred in the Port of Vancouver.

With the arrival of Seaspan's bunkering vessel in Q4 2024, FEI began providing LNG for marine fuel to the market. In the six months between October 2024 and March 2025, FEI provided approximately 775,000 GJ of LNG. Demand continues to grow with the availability of LNG fueling on the West Coast having now been demonstrated.

119.2 Please discuss FEI's ability to maintain the Tilbury 1A LNG tank at full storage capacity throughout the year in the event that the Tilbury Phase 2 Expansion Project proceeds, due to the increased liquefaction capacity included within that project.

Response:

Any increased liquefaction capacity built as part of the Tilbury Phase 2 LNG Expansion Project will be dedicated to the customer or market that the plant is built to support, and would not be available to support FEI's non-LNG customers on a planned basis as part of its ACP. Further, the Tilbury 1A liquefaction facility was constructed to support the transportation fueling market (including marine fueling) and has sufficient capacity to maintain the required LNG inventory in the Tilbury 1A tank to support expected RS 46 sales. Similar to the increased liquefaction from the Tilbury Phase 2 LNG Expansion Project, Tilbury 1A storage will not be available to support FEI's non-LNG customers on a planned basis as part of its ACP.

B. RESILIENCY PLAN

120.0 Reference: RESILIENCY PLAN

Exhibit B-26, BCUC IR 66.4, 68.8, 72.1; Exhibit B-61, Appendix RP 2 (Exponent Report), p. 29, para. 67; Appendix T, pp. T-2 – T-3, paras. 8-9; Appendix U, p. U-31, para. 53, Table U-8, p. U-32

Outage Duration Assumption

On pages T-2 to T-3, in paragraphs 8-9, of Appendix T to Appendix RP 2 (the Exponent Report), Exponent states:

> For AVs with parallel pipelines that fail due to mechanisms that are likely to impact only a single pipeline, it is the duration of the regulatory shutdown – rather than the repair time – that is key to determining the outage duration and, indeed, whether an outage occurs.
>
> The duration of the regulatory shutdown may vary. For example, following a failure on one of the parallel pipelines in AV-1, -2, -3, and -54 in 2018, the regulatory shutdown of the intact pipeline lasted two days. Based on discussion with FEI, <u>a regulatory shutdown duration of three days is assumed in Exponent’s risk analysis</u>. [Emphasis added]

In response to BCUC IR 66.4, FEI stated:

> FEI agrees that a precautionary shut-down of an adjacent pipeline does not necessarily mean a no-flow event lasting longer than two days; however, JANA has expressed the view, for the reasons set out in its response to BCUC IR2 68.8, that: “It is also considered likely, given the activities required to assess the integrity of the adjacent line, that the adjacent line would be out for a period of two days or longer.”

As provided in the response to MS2S IR1 4.i, the following factors (among others) that could impact the duration of a gas supply disruption include:

- The cause and nature of an outage situation;
- Any potential impacts on adjacent pipeline(s) from the outage situation, if applicable (e.g., concomitant damage);
- The potential for the originating site of the outage to be under law-enforcement jurisdiction for investigation purposes and to be inaccessible;
- The potential for regulatory directives to limit and/or restrict resumption of gas flow after an outage; and
- Uncertainty as to assessments and integrity verifications that may be deemed necessary by an operator following an outage situation.

In response to BCUC IR 68.8, FEI provided the following statement from JANA:

> It is also considered likely, given the activities required to assess the integrity of the adjacent line, that the adjacent line would be out for a period of two days or longer. For the 2018 T-South incident, based on the TSB "Pipeline Transportation Safety Investigation Report P18H0088", the NPS 36 L2 pipe ruptured. The coating was damaged on the adjacent Western NPS 12 pipeline (crude oil pipeline) and it was taken out of service. The NPS 30 L1 pipeline was not exposed during the occurrence. Even though the NPS 30 L1 pipeline was not exposed, it was still taken out of service. After a rupture of one pipeline in a shared ROW, a likely outcome is that the adjacent pipeline would be taken out of service, such as was done in the case of the T-South incident, until an investigation can be conducted to ensure a base level of integrity of the pipeline. This would be expected to occur for ruptures on pipelines the size of the two T-south pipelines whether the gas released from the rupture ignites or not and that is why the assessment considered a rupture as a "common mode" failure that would result in a loss of flow for both pipelines. It is also expected that the pipelines would be returned to service at reduced capacity (e.g. 80% of previous operating pressure) until further integrity verifications are completed (as was the case for both T-South pipelines).

120.1 Please clarify whether FEI has any further evidence to support its assumption that the duration of a regulatory shutdown of the intact T-South pipeline is 3 days following a rupture of the adjacent T-South pipeline, in addition to JANA's statement above. If so, please provide that further evidence.

<u>Response:</u>

For this response, FEI has redacted certain information for which FEI is requesting be filed on a confidential basis and be held confidential by the BCUC in perpetuity, pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-296-24. FEI requests this information be held confidential consistent with the confidentiality treatment approved by Order G-147-21.

The following response has been provided by FEI:

FEI's view that 3 days is a reasonable expectation for how long a regulatory shutdown will last was based on actual experience from the 2018 T-South Incident, and FEI believes that it remains a sound and meaningful data point, as previously affirmed by JANA.[15] Since filing the Application, FEI's view has been reinforced by: (1) the fact that the CER's process for responding in an emergency remains substantially the same since 2018; and (2) the opinion of Exponent that the expectation was reasonable. These points are discussed further below.

[15] Exhibit B-30, BCSEA IR2 13.4.

As discussed in Section 3.4.4.1 of the Application, the 2-day regulatory shutdown experienced in the 2018 T-South Incident was a function of the following very favourable conditions:[16]

[redacted]

As such, FEI assumed a 3-day regulatory shutdown in its analysis to account for the longer duration that could be expected if the rupture were to occur under less favourable conditions.

According to material from the CER's website,[17] the CER's current stated role in an emergency remains aligned with their response during the 2018 T-South Incident. This indicates that, all else being equal, the regulatory timelines for future emergency events will be similar to what occurred in 2018. FEI is not aware of any substantial changes to the CER's approach to emergency response that would, in and of itself, result in a material change in the regulatory shut-down duration.

For example, according to the TSB investigation report prepared following the 2018 T-South Incident, the CER (then the NEB) issued approvals for the restart of the pipeline. The TSB report states the following with respect to the action taken by the NEB:[18]

> On 10 October 2018, the NEB issued an inspection officer order[38] allowing Westcoast to return the NPS 30 L1 pipeline to service on 11 October 2018, but at a restricted operating pressure of 80% of its 60-day high pressure. On 23 October 2018, the NEB specified modified and additional measures, including the operation of the NPS 36 L2 (from Station 2 to Huntingdon Meter Station) with a restricted operating pressure of 80% of its 60-day high pressure. On 16 November 2018, NB-001-2018 (Amendment No. 2) was issued to allow Westcoast to increase NPS 36 L2's restricted operating pressure from 80% to 85% and modify its implementation of the overpressure protection system. The latest amendment to the inspection order was dated 24 December 2018. It restricted the operating pressure of NPS 36 L2 to 88% between Station 2 and Huntingdon Meter Station.

[16] Exhibit B-1-4, Section 3.4.4.1, p. 52.

[17] https://www.cer-rec.gc.ca/en/safety-environment/emergency-management/responding-emergencies/responding-emergencies.pdf.

[18] Pipeline transportation safety investigation report P18H0088, Section 4.1.3, para 1.

According to material from the CER's website, approving the restart of the pipelines remains part of the CER's role in an emergency.[19]

Additionally, in the 2018 T-South Incident, the CER inspected and examined the integrity of the pipeline to verify that repairs were completed appropriately. The TSB report states the following:[20]

> The NEB issued Notices to Resume Work or of Measures Satisfied after it was demonstrated that the relevant segments of the pipeline were fit for service to safely operate at their respective maximum operating pressures. In addition, field inspections[39] were performed to verify that regulatory requirements were being met. Technical meetings were held with Westcoast to evaluate crack detection tool reliability and run validation processes. Furthermore, Westcoast's integrity management practices were examined to verify that regulatory requirements were being met.

The task of verifying that repairs were completed remains the responsibility of the CER.

These tasks necessarily take time, which FEI believes would make it difficult in a significant event to materially shorten the regulatory shutdown period (i.e., no-flow event) from what took place in the 2018 T-South Incident. As noted in the Application, the verification process will take longer than in 2018 if it takes Enbridge longer due to, for example, weather and/or remoteness to reach the site, assess the issue and report information to the CER.

FEI has not received any feedback from the CER with respect to FEI's assumption of a 3-day regulatory shutdown, and published information from the CER does not specify a duration of a regulatory shutdown. However, FEI would not expect that the CER could provide a specific duration because it would depend on how fast they are able to obtain information and complete the work they need to perform. This would depend on the circumstances. As such, FEI has taken guidance from what occurred during the 2018 T-South Incident, and the surrounding circumstances that influenced response time.

Ultimately, as noted above, FEI continues to believe this is a meaningful data point, given that the CER's documented approach to emergencies remains consistent. Exponent's opinion, provided below, has reinforced that approach.

The following response has been provided by Exponent:

Exponent was instructed to consider that a regulatory shutdown period would last three days, which includes mobilization, planning, and conducting any evaluation required in advance of the resumption of service. Exponent considers this estimate to be reasonable, considering a previous outage on T-South in 2018 resulted in a two-day regulatory shutdown. In reality, the duration of a regulatory shutdown is out of FEI's and Enbridge's control.

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[19] Responding to Emergencies, p. 7.

[20] Pipeline transportation safety investigation report P18H0088, Section 4.1.3, para 2.

Exponent has conducted a sensitivity study on the expected annual GDP loss at average winter temperature on T-South varying the regulator shutdown period from 0.5 days to 6 days, in increments of 0.5 days. Results are presented in the figures below, for all Supplemental Alternatives and isolating Supplemental Alternatives 7, 8, and 9. The following observations are made:

- For a regulatory shutdown duration between 2.5 days and 3 days, the results are similar to what is presented in Exponent's report, i.e., there are significantly reduced losses with Supplemental Alternatives 7, 8, and 9 compared to other Supplemental Alternatives.
- For a regulatory shutdown duration between 3.5 and 4.5 days, the results are similar to the results for 2 to 3 days, except that the losses increase significantly for Supplemental Alternative 8 because the supply duration for this alternative is less than 3.5 days. Supplemental Alternatives 7 and 9 are the only two alternatives with substantial reduction in losses compared to the baseline scenarios.
- For a regulatory shutdown duration of 5 or more days, Supplemental Alternatives 7 and 9 see large increases in losses, because the supply durations for these alternatives are less than 5 days.
- For a regulatory shutdown duration of 2 days, the results are similar to what is presented in Exponent's report, except for with Supplemental Alternative 6, which now has a significant reduction in losses resulting in similar losses to those with Supplemental Alternatives 7, 8, and 9.
- For a regulatory shutdown duration of 1.5 days, the results are similar to what is presented in Exponent's report, except for Supplemental Alternatives 6, 2 (Contingent w/ T1A), 3 (Contingent w/T1A), and 4A (Contingent), which have a significant reduction in losses resulting in similar losses to those with Supplemental Alternatives 7, 8, and 9.
- For a regulatory shutdown duration between 0.5 and 1 day, the results are similar to what is presented in Exponent's report, except for Supplemental Alternatives 6, 2 (Contingent w/ T1A), 3 (Contingent w/T1A), 4A (Contingent), 2 (Contingent), and 3 (Contingent), which have a significant reduction in losses resulting in similar losses to those with Supplemental Alternatives 7, 8, and 9.

Figure 1: Expected Winter-only GDP Loss for Different Supplemental Alternatives for T-South (AV-1, -2, -3 and -54) at Varying Regulatory Shutdown Periods and at +4ºC

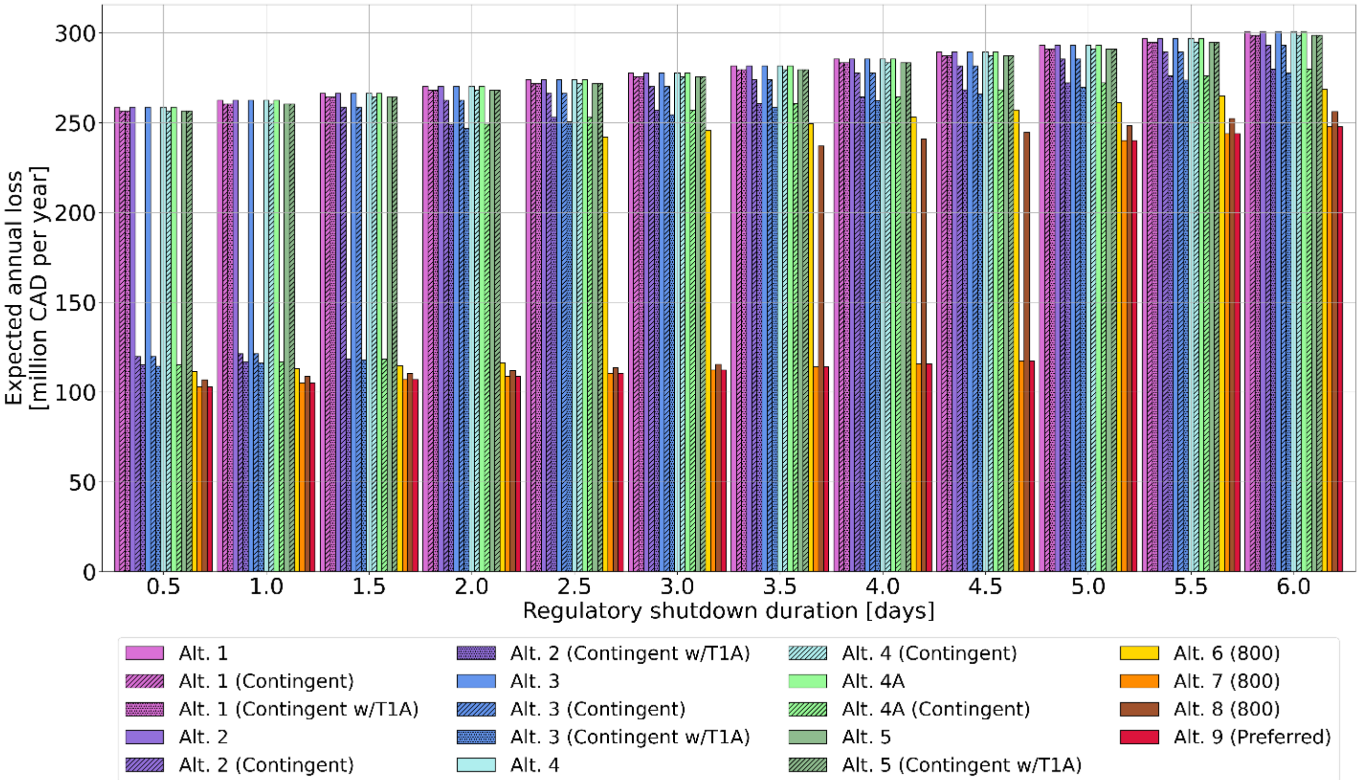
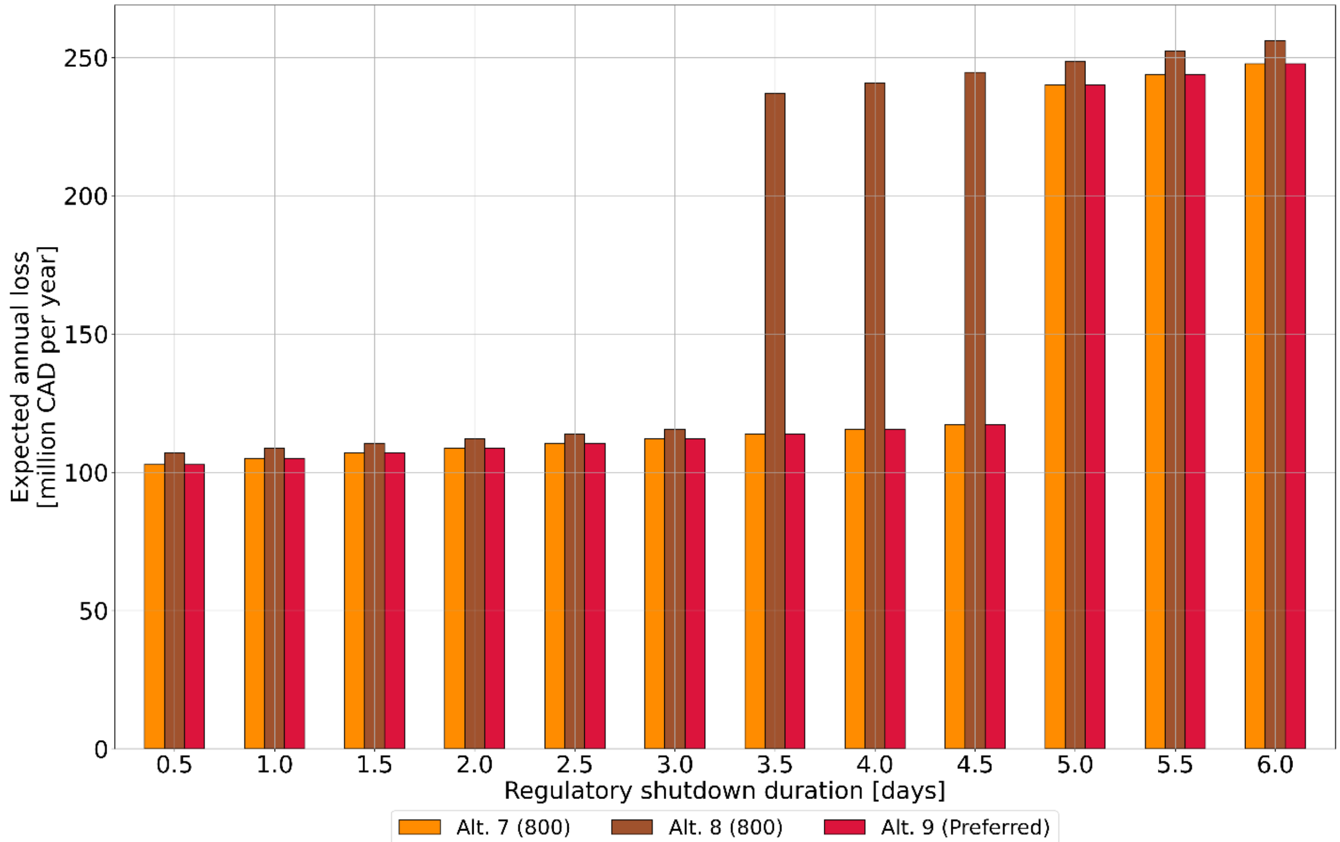


Figure 2: Expected Winter-only GDP Loss for Supplemental Alternatives 7, 8 and 9 for T-South (AV-1, -2, -3 and -54) at Varying Regulatory Shutdown Periods and at +4ºC



Based on the sensitivity analysis, there is a cliff-edge effect: if the regulatory shutdown duration exceeds the resiliency supply duration, the losses substantially increase compared to cases where the resiliency supply duration exceeds the regulatory shutdown duration.

Exponent has also analyzed the impact of alternative winter temperatures in tandem with varying regulatory shutdown durations (in 0.5ºC increments) on expected annual customer outage days (CODs) in the Lower Mainland for the T-South AVs. The below figures show the expected annual CODs for Alternatives 7, 8, and 9 for 4ºC, -1.4ºC and -10ºC.

- At 4ºC:
    - Supplemental Alternatives 7, 8 and 9 provide similar mitigation for regulator shutdown durations of 3 days or less and for 5 days and more.
    - Supplemental Alternatives 7 and 9 are significantly more effective than Supplemental Alternative 8 for regulator shutdown durations between 3.5 and 4.5 days.

- At -1.4ºC:
  - Supplemental Alternatives 7, 8 and 9 provide similar mitigation for regulator shutdown durations of 2.5 days or less and for 4 days and more.
  - Supplemental Alternatives 7 and 9 are significantly more effective than Supplemental Alternative 8 for regulator shutdown durations between 3 and 3.5 days.
- At -10ºC:
  - Supplemental Alternatives 7, 8 and 9 provide similar mitigation for regulator shutdown durations of 1.5 days or less and for 3 days and more.
  - Supplemental Alternatives 7 and 9 are significantly more effective than Supplemental Alternative 8 for regulator shutdown durations between 2 and 2.5 days.

The cliff-edge effect therefore appears at alternative winter temperatures as well, but it is shifted.

Figure 3: Expected Annual Winter-only Customer Outage-days for Supplemental Alternatives 7, 8 and 9 for T-South (AV-1, -2, -3 and -54) at Varying Regulatory Shutdown Periods and at +4ºC

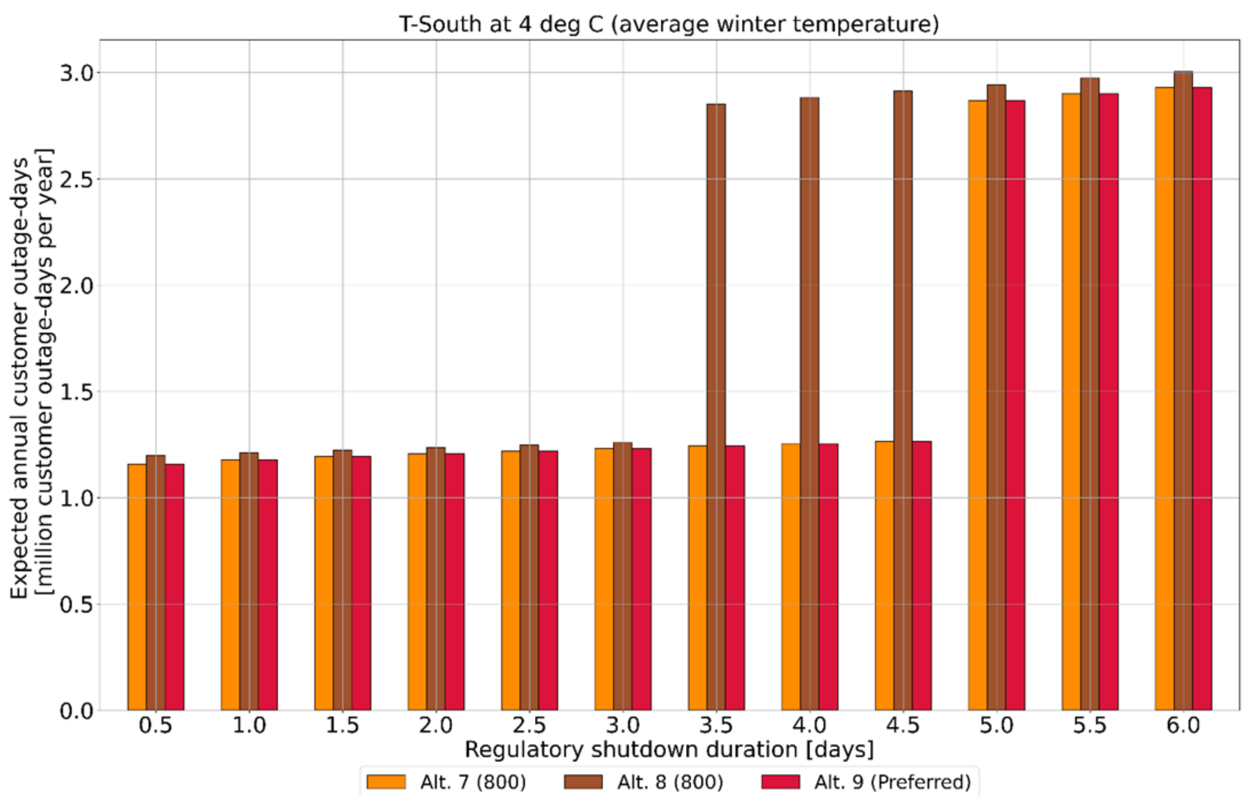


Figure 4: Expected Annual Winter-only Customer Outage-days for Supplemental Alternatives 7, 8 and 9 for T-South (AV-1, -2, -3 and -54) at Varying Regulatory Shutdown Periods and at -1.4ºC

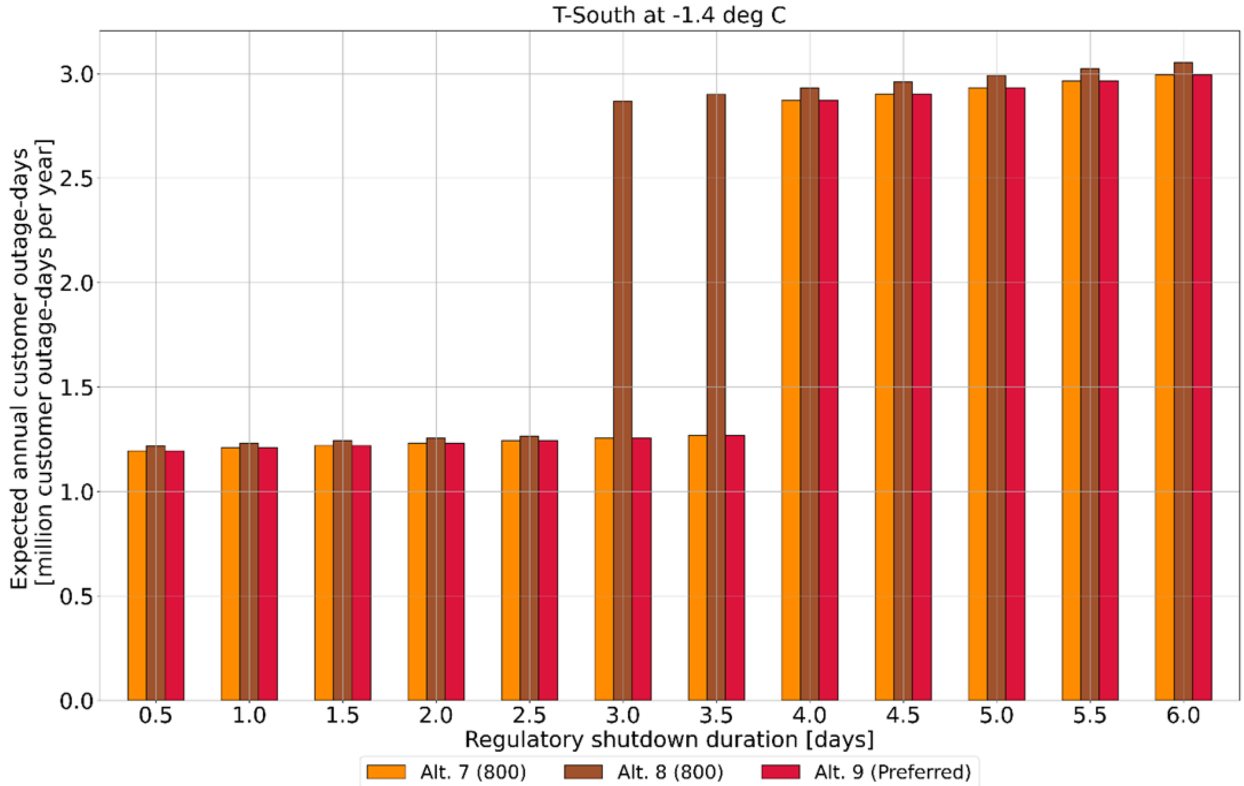
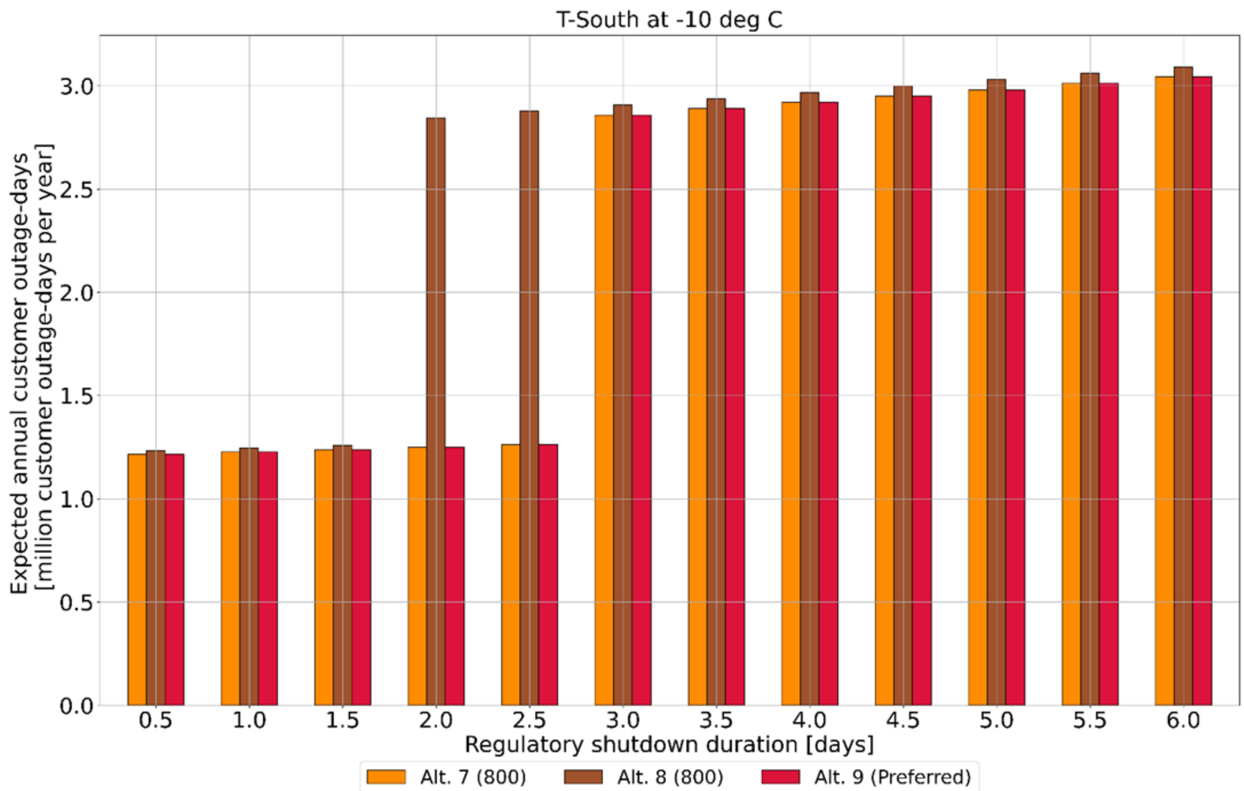


Figure 5: Expected Annual Winter-only Customer Outage-days for Supplemental Alternatives 7, 8 and 9 for T-South (AV-1, -2, -3 and -54) at Varying Regulatory Shutdown Periods and at -10ºC



In response to BCUC IR 72.1, FEI stated:

> In the case of more serious incidents, such as a pipeline failure, the CER will not allow the pipeline to return to service until it is satisfied that it is safe for operation. The CER can order operators to take actions that may extend the duration of a service disruption. As demonstrated by the CER's response to the Westcoast T-South rupture in 2018, the CER can impose a precautionary operating pressure restriction until such time that mitigating actions are completed and that it is satisfied that the pipeline can again be operated safely at its maximum operating pressure.

120.2 Please provide any feedback FEI has received from CER with respect to its assumption that the duration of a regulatory shutdown, as described in Appendix RP 2 of Exhibit B-61, is three days.

120.2.1 If FEI has not sought CER feedback with respect to its regulatory shutdown assumption, for internal and other types of failures, please explain why not.

Response:

Please refer to the response to BCUC IR5 120.1.

120.3 Please discuss whether FEI is aware of other natural gas utilities that plan on-system storage capacity based on a supply outage duration of three days.

Response:

The following response has been provided by FEI:

FEI is not aware of other natural gas utilities that plan on-system storage capacity based on a supply outage duration for 3 days. Each utility will have its own resiliency requirements, based on the accessibility and the size of the resource they require. This approach was endorsed in the independent expert report provided by Guidehouse as follows (see page 49 of Appendix A to the Application):

> There is no single industry standard approach to determine duration, i.e., the amount of natural gas required for a resiliency reserve. A standard calculation is challenged for several reasons, including:
>
> - Access to Existing Infrastructure: Gas supply redundancy varies across different natural gas utilities and is a function of access, both physical and contractual, to existing pipeline and underground storage infrastructure.
> - Demand Profile: Design day and peak load requirements are a function of a natural gas utility's customer count, profile and seasonality of demand.
>
> Implications of this include that if a utility has more diversity of supply (i.e., is less dependent on a single pipeline for the majority of its supply) its resiliency reserve will be less than a utility that is highly dependent on a single pipeline. This explains why no two natural gas utilities will have the same reserve resiliency requirements.

The following response has been provided by Exponent:

Exponent is not aware of specific supply durations planned by other natural gas utilities. We expect supply duration to be circumstance-specific.

Page U-31, in paragraph 53, of Appendix U to Appendix RP 2 (the Exponent Report) states:

> For AVs with parallel pipelines, each external hazard is assigned a probability of failing both pipelines simultaneously, p_simultaneous, based on the distance between the pipes and the type of hazard. Values of p_simultaneous used in this analysis are given in Table U.8…
>
> For internal hazards, the pipes are assumed never to fail simultaneously, i.e., p_simultaneous = 0.

Table U.8 on page U-32 of Appendix U to Appendix RP 2 (the Exponent Report) provides the probability of simultaneous failure for parallel pipeline segments in an AV by hazard. For Earthquake Landslide and Non-Earthquake Landslide, AV-1, AV-2, AV-3 and AV-54 have a probability of failure for parallel pipeline segments of 0.65.

120.4 Please explain the basis for the Earthquake Landslide and Non-Earthquake Landslide probability of simultaneous failure for parallel pipeline segments for AV-1, AV-2, AV-3 and AV-54 of 0.65.

Response:

The following response has been provided by Exponent:

Based on Attachment 1.5c to the response to BCUC IR1 1.5 (Exhibit B-15), prepared by JANA, as well as the 2018 incident TSB report,[21] the T-South pipeline consists of two parallel pipes for its entire length, often in the same right-of-way. Attachment 1.5c indicates each pipe is 917 km. The maximum probability of simultaneous failure is 1 and minimum probability of simultaneous failure is 0, which bounds the probability of simultaneous failure. Per FEI's internal standards, pipelines in the same right-of-way are typically spaced at least 4.5 m apart. It is unclear if Enbridge has similar standards, but we assume it does and that it is applicable to AV-1, AV-2, AV-3 and AV-54. At the location of the 2018 incident, the distance between the pipes was 9 m. Based on review of the CER Interactive Pipelines Map,[22] for at least 123 km, the AV-1, AV-2, AV-3 and AV-54 pipelines are separated by distances greater than 4.5 m, sometimes as much as a kilometer. Assuming these larger separations have zero probability of simultaneous failure due to landslides, the maximum probability of simultaneous failure for the referenced pipelines reduces to 0.87 (excluding 123 km out of 917 km). It is our view that both pipelines will not always fail in the same landslide, thus engineering judgement was used to reduce the probability of simultaneous failure from 0.87 to 0.65.

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[21] https://www.tsb.gc.ca/eng/rapports-reports/pipeline/2018/p18h0088/p18h0088.html.

[22] https://neb-gis.maps.arcgis.com/apps/webappviewer/index.html?id=2d11fd4e6a7a4f4ba7fe6bdf51ae52de.

120.5 Please explain the basis for the internal hazard probability of simultaneous failure for parallel pipeline segments for AV-1, AV-2, AV-3 and AV-54 of 0.

Response:

The following response has been provided by Exponent:

Internal hazards to pipelines include the following failure mechanisms: girth welds, human factors, stress corrosion and cracking ("SCC"), internal corrosion, external corrosion, pipe seam failures, and material defects and equipment failures. Ruptures due to these mechanisms are highly unlikely to occur at the same time at the same location as they are primarily the result of long-term mechanisms, not a discrete event that impacts both pipelines simultaneously (like an earthquake or a landslide). The probability of simultaneous failure due to internal failures is therefore zero.

A cascading failure, in which an ignited rupture of one pipe leads to the failure of the other pipe also has a low probability. The 2018 T-South pipe rupture incident caused a 13-meter-wide crater (approximately 6.5 meters on either side of the pipe and did not damage the other pipe. An oil pipeline between the two gas pipelines was damaged but did not rupture. Similarly, the crater created by the San Bruno pipeline (30-inch diameter) explosion was 8 meters wide (around 4 meters on each side of the pipe). Based on this past experience and the typical spacing between the pipes, we consider a cascading failure to be unlikely.

Human factors and equipment failures are not long-term mechanisms, but because the T-South pipeline segments are typically spaced apart, it is unlikely that the same human factor or equipment failure would impact both parallel segments simultaneously.

120.6 Please confirm, or explain otherwise, that the duration of a regulatory shutdown period following an internal pipeline failure is uncertain, and that there are circumstances where the regulatory shutdown period could conceivably be shorter or longer than 3 days.

Response:

The following response has been provided by Exponent:

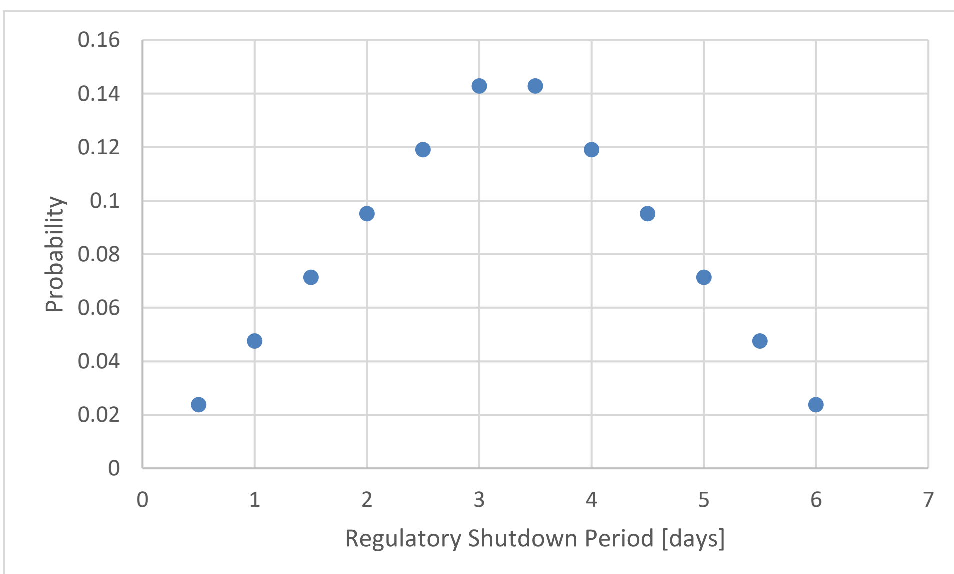
Exponent agrees that the regulatory shutdown duration could be shorter or longer than 3 days, and could be affected by, among other things:

- Distance from personnel to the failure location
- Weather conditions
- Available resiliency supply and associated public pressure

Based on experience from the 2018 no-flow event, which lasted 2 days, 3 days is a reasonable estimate for the regulatory shutdown period.

Exponent has conducted an analysis in which the regulatory shutdown period is a random variable, with probabilities indicated in the below table and figure:

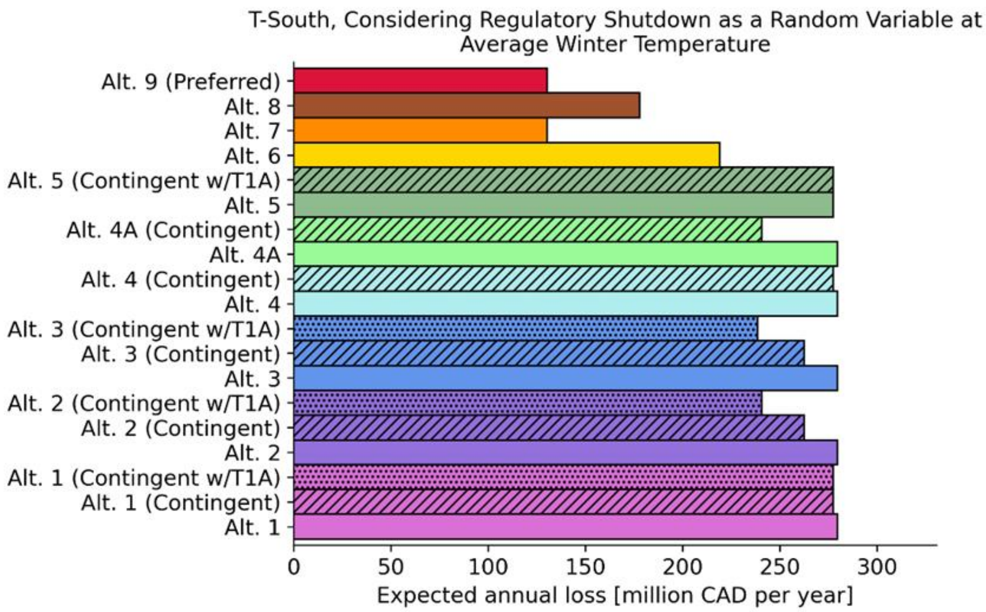
Regulatory Shutdown Period [days]	**Probability**
0.5	0.02381
1.0	0.047619
1.5	0.071429
2.0	0.095238
2.5	0.119048
3.0	0.142857
3.5	0.142857
4.0	0.119048
4.5	0.095238
5.0	0.071429
5.5	0.047619
6.0	0.02381



The results of this analysis at average winter temperatures (+4ºC) are presented in the below figure. Considering uncertainty in the regulatory shutdown period results in the following:

- Average Annual GDP Loss for Supplemental Alternatives 7 and 9 are similar to the results presented in Exponent's report, with an increase of 16%. The small increase is associated with the now finite probability of the regulatory shutdown period exceeding the 4.54-day supply duration.

- Average Annual GDP Loss for Supplemental Alternative 8 has increased by 54%. This increase is associated with the now 50% probability that the regulatory shutdown time will exceed the 3.33-day supply duration of Supplemental Alternative 8.
- Average Annual GDP Loss for Supplemental Alternative 6 has decreased by 11%. This decrease is associated with the now finite probability of the regulatory shutdown period being shorter than the 2.42-day supply duration.
- The Annual GDP loss for the remainder of the Supplemental Alternatives changed by less than 10%.



120.7 Please confirm, or explain otherwise, that the assumed regulatory shutdown period has a material impact on the results of the 2024 Resiliency Plan, for example the expected GDP loss and expected GDP loss reduction associated with different alternatives.

Response:

The following response has been provided by Exponent:

Exponent confirms that the assumed regulatory shutdown period has an impact on expected GDP loss and expected GDP loss reduction. See the response to BCUC IR5 120.1 showing sensitivity analysis results for T-South. See also the response to BCUC IR5 120.6 showing GDP losses when the regulatory shutdown period is considered to be a random variable, varying between 0.5 days and 6 days.

120.8 Please confirm, or explain otherwise, that Exponent's risk analysis methodology assumed a fixed regulatory shutdown duration of three days for all hazards and AVs.

120.8.1 Please discuss why the regulatory shutdown period is treated as a fixed assumption in the Exponent Report.

Response:

The following response has been provided by Exponent:

It is confirmed that Exponent's analysis considered a fixed regulatory shutdown period of 3 days. FEI provided the regulatory shutdown period based on the 2018 no-flow incident on T-South. See the response to BCUC IR5 120.6.

120.9 Please discuss the likelihood that the duration of a regulatory shutdown would vary based on the hazard.

120.9.1 Please discuss the likelihood that the duration of a regulatory shutdown following a non-earthquake landslide would be longer than following an internal failure.

Response:

The following response has been provided by Exponent:

The regulatory shutdown period may depend on the hazard, in particular if the hazard poses access difficulties or if the regulator is overwhelmed responding to multiple incidents in a broader region, which is more likely to occur during an earthquake than other hazard such as non-earthquake induced landslides.

The duration of a regulatory shut-down following a non-earthquake induced landslide could be longer or shorter than following an internal failure. A non-earthquake induced landslide that occurs close to a population center will likely be resolved more quickly than an internal failure that occurs further from a population center, and vice-versa. It is noted that for non-earthquake induced landslides, it is assumed that 65% of incidents involve failure of both pipes (in which case the regulatory shutdown period is irrelevant).

The hazard would only be directly relevant to the regulatory shutdown period if the hazard made it more difficult for the regulator to confirm the integrity of the pipeline segment to allow resumption of service. Exponent understands that this involves confirming if there are leaks or a high likelihood of incipient leaks. For non-earthquake induced landslides, if there is significant ground movement at the second segment, the segment would likely also have failed and is thus already accounted for. The hazard is therefore not relevant to the regulatory shutdown period in this context.

120.10 Please discuss how Exponent's risk analysis would be impacted if different regulatory shutdown durations were assigned to various hazards, based on the nature of the hazard.

<u>Response:</u>

The following response has been provided by Exponent:

As discussed in the response to BCUC IR5 120.9, Exponent does not expect that the regulatory shutdown period would vary by hazard, except if the regulator is delayed in evaluating the pipeline because they have other commitments during a widespread disaster, such as an earthquake.

Exponent has performed a sensitivity study where the regulatory shutdown period for earthquake-related hazard is changed to 5 days, at which point the supply provided by all Supplemental Alternatives does not bridge the regulatory shutdown period for the T-South AVs so results would be similar with longer regulator shutdown periods. The below figure compares the average annual GDP loss on T-South assuming the regulatory shutdown period is 3 days for all hazards to the case where the regulatory shutdown period is 5 days for the earthquake-induced hazards and 3 days for all other hazards.

Figure 1: Expected Annual Winter-only GDP Loss for T-South (AV-1, -2, -3, and -54) for the Supplemental Alternatives at +4ºC (3-Day Regulatory Shutdown for All Hazards)

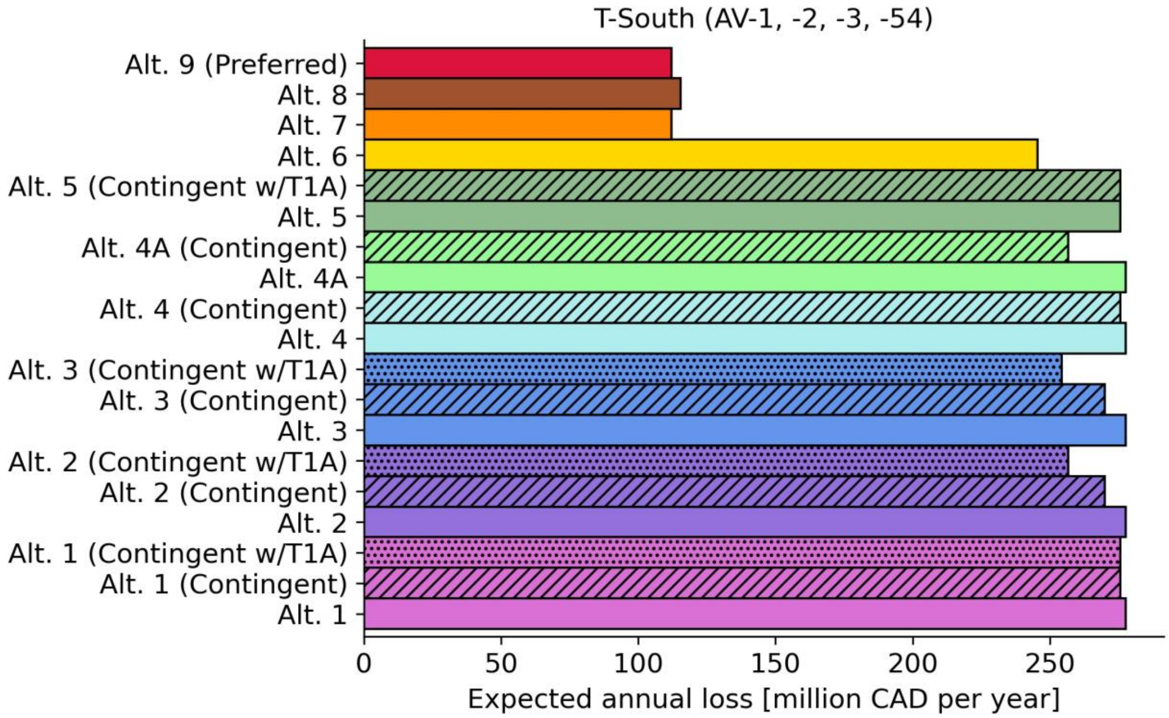
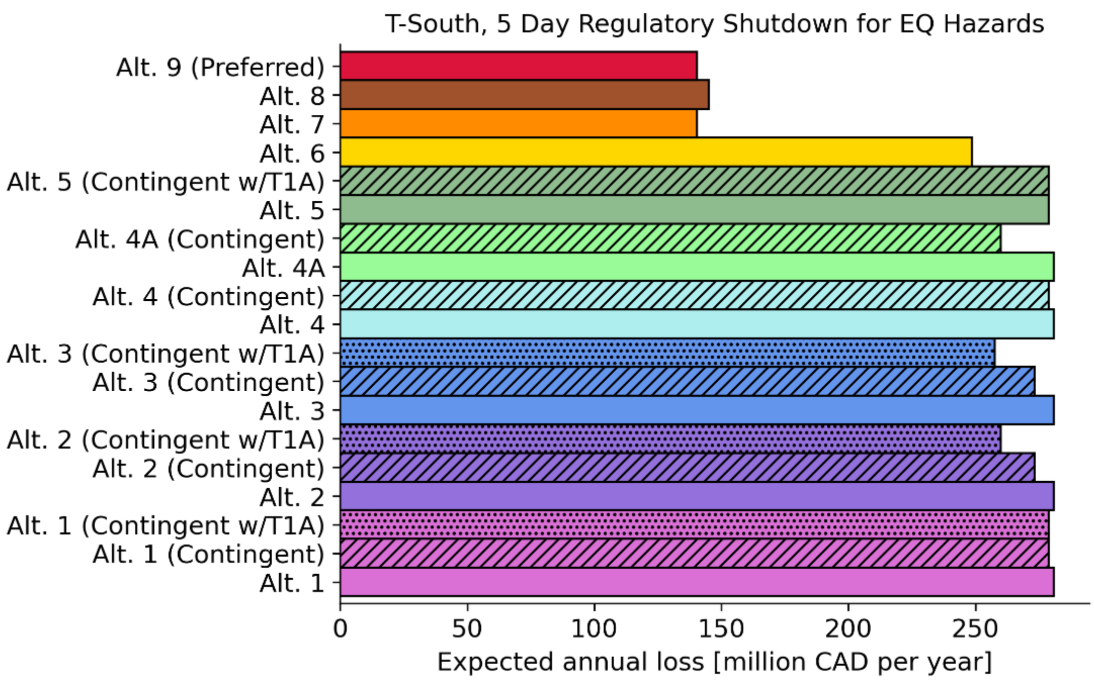


Figure 2: Expected Annual Winter-only GDP Loss for T-South (AV-1, -2, -3, and -54) for the Supplemental Alternatives at +4ºC (5-Day Regulatory Shutdown for Earthquake-Induced Hazards and 3-Day Regulatory Shutdown for All Other Hazards)



It can be seen that there is only a small increase (1% for the baseline Alternative 1 scenario) in the expected annual GDP loss on T-South for Supplemental Alternatives 1 through 6, which is expected because the supply duration for these alternatives can span neither a 3-day nor 5-day regulatory shutdown period, so the results are relatively unchanged. Furthermore, as indicated in Figures U.58, U.66, and U.74, the primary hazards impacting the T-South AVs -1, -2, and -3 are non-earthquake induced landslides and internal failures, which Exponent expects would not have a longer regulatory shutdown period because there would be no need for the regulator to respond to multiple incidents simultaneously, as would be the case with earthquakes.

There is a larger increase in expected annual GDP loss for Supplemental Alternatives 7 through 9 (approximately 25%). This increase is a result of the fact that the 5-day regulatory shutdown time for earthquake hazards is shorter than the backup supply duration for these alternatives (4.54 days). While, previously, if only one of the two pipes failed, there was no full shutdown (see paragraph 55, Section U.3.3), in this new sensitivity study there is now a full shutdown on the line (Figures U.10). AV-3 and AV-54 have significant risk contribution from earthquake hazards (Figures U.74 and U.82), which can no longer be mitigated by Supplemental Alternatives 7 through 9, resulting in greater expected annual GDP loss.

Page 29, in paragraph 67, of Appendix RP 2 (the Exponent Report) states:

> For certain geotechnical hazards, there is insufficient information available relating the occurrence of an anticipated hazard to engineering demand. For example, the amount of displacement expected from a rainfall-induced landslide cannot be known with sufficient certainty. For these hazards, the outcome of the assessment is the rate of hazard, rather than the rate of rupture. In this assessment, <u>Exponent conservatively assumed that those hazards always result in damage to the asset</u> (e.g., Exponent assumed that a rainfall-induced landslide affecting a pipeline will produce sufficient ground displacement to damage a brittle pipeline, and as such, the rate of landslide occurrence is equal to the rate of damage to a brittle pipeline). [Emphasis added]

120.11 Please confirm that, based on the information provided in Table U.8 of the Exponent Report, Exponent's analysis assumes that one of the parallel pipeline segments for AV-1, AV-2, AV-3 and AV-54 <u>does not fail</u> during 35 percent of the occurrences of an Earthquake Landslide and Non-Earthquake Landslide.

120.11.1 If confirmed, please reconcile Exponent's assumption that one of the parallel pipeline segments <u>does not fail</u> during 35 percent of the occurrences of an Earthquake Landslide and Non-Earthquake Landslide, with Exponent's assumption that certain geotechnical hazards damage the pipeline asset during every occurrence.

120.11.2 Please clarify whether FEI and/or Exponent considered assuming that certain geotechnical hazards do not damage pipeline assets during every occurrence. If not considered, why not? If considered, please explain how the results of Exponent's risk analysis are impacted.

Response:

The following response has been provided by Exponent:

Exponent confirms that it is assumed that 35% of the occurrences of landslides fail one pipe but not the other pipe on T-South.

Exponent considered that certain geotechnical hazards do not damage pipeline assets during every occurrence:

- For non-earthquake induced landslides, failure rates were decreased by 90% to account for human intervention during the design and operation of the pipelines that lowers the likelihood of damage.
- For earthquake induced landslides, the damage rates are based on Hazus, which considers historical data. The historical data explicitly would consider both pipelines that failed and didn't fail during a geotechnical hazard. Moreover, the methodology considers that 20% of incidents result in leaks, which are discounted from the analysis.
- For liquefaction, the Hazus methodology used herein considers historical data. The historical data explicitly would consider both pipelines that failed and didn't fail during a geotechnical hazard. Moreover, the methodology considers that 20% of incidents result in leaks, which are discounted from the analysis.

120.12 Please confirm, and provide a plain language explanation if confirmed, that the supply outage duration faced by FEI is either a) the regulatory shutdown if one of the parallel pipeline segments for AV-1, AV-2, AV-3 and AV-54 fails, or b) the repair duration if both parallel pipeline segments for AV-1, AV-2, AV-3 and AV-54 fail.

Response:

The following response has been provided by Exponent:

Confirmed: the supply outage duration is either:

1. The regulatory shutdown period (if one pipeline segment fails). When the regulatory shutdown periods ends, gas can resume flowing to the one pipeline segment that did not fail.
2. The repair durations, including mobilization and planning (if both pipeline segments fail). Gas cannot resume flowing until repairs are completed on at least one pipeline.

It is noted that customers will experience outages beyond the supply outage duration if resiliency supply is not available during the supply outage.

FEI also provides the following response:

Confirmed. With respect to failures on T-South, the duration of the supply outage (i.e., the duration of a no-flow event on T-South) is one of two parameters depending on the failure scenario:

1. For the failure scenario where only one of the two T-South pipelines fails and the other undamaged line is shut-in as a precaution (i.e., a regulatory shutdown), the duration of the supply outage is the duration of the regulatory shutdown.
2. For the failure scenario where both T-South pipelines fail, the duration of the supply outage is the repair duration.

In the 2018 T-South Incident, the governing parameter was 1 above. The no-flow event lasted 2 days as this was the duration until the CER allowed Westcoast to begin flowing gas in the unaffected line.

120.13 Please confirm, and provide a plain language explanation if confirmed, that in 35 percent of Earthquake Landslides and Non-Earthquake Landslides one of the parallel pipeline segments for AV-1, AV-2, AV-3 and AV-54 remains undamaged and therefore the outage duration is the regulatory shutdown.

Response:

The following response has been provided by Exponent:

In responding to this question, Exponent assumes that the language of the question is intended to be: Please confirm, and provide a plain language explanation if confirmed, that in 35 percent of Earthquake Landslides and Non-Earthquake Landslides one of the parallel pipeline segments for AV-1, AV-2, AV-3 and AV-54 remains undamaged and therefore the supply outage duration is the regulatory shutdown.

Exponent confirms that the supply outage duration is the regulatory shutdown period if one of the parallel pipe segments is undamaged. When the regulatory shutdown periods ends, gas can resume flowing to the one pipeline segment that did not fail.

121.0 Reference: RESILIENCY PLAN

Exhibit B-61 (2024 Resiliency Plan), pp. 33 – 41; Exhibit B-15, BCUC IR 4.2, 10.6, Attachment 4.2; Exhibit B-60 (Supplemental Evidence), pp. 106, 124

FEI's Existing Resiliency Capabilities

On pages 33 to 41 of Exhibit B-61, FEI describes its existing resiliency capabilities, and how they are accounted for in the plan. These include, amongst other things, mutual aid crews available for larger outages. On page 36 of Exhibit B-61, FEI describes this resiliency capability as follows:

> FEI has mutual aid agreements with other utilities under which FEI can request additional crews to assist with service restoration, recognizing that aid is voluntary and other utilities could require those crews in cases where emergency events affect multiple utilities.

In response to BCUC IR 4.2, FEI stated:

> The Northwest Mutual Assistance Agreement (NWMAA) member organizations met in 2019 to update the agreement, including revising the Executive Committee structure as well as Activation and De-activation protocols. The revised agreement was in place for the start of the November 2019 winter season.

Page 3 of the NWMAA (Attachment 4.2 of Exhibit B-15) states:

> In the event of a major natural gas regional emergency, it is expected that many or all of the Members could be directly involved in providing assistance. With the combined assistance of these Members, it is expected that the impact and duration of an emergency condition to affected regional markets could be minimized.

121.1 Please explain whether mutual aid assistance from the NWMAA was considered in the Resiliency Plan.

121.1.1 If no, please explain why not.

121.1.2 If yes, please explain whether the Resiliency Plan accounts for gas volumes to be provided by members of the NWMAA in the event of an emergency. If not, please explain why and clarify what level of support is assumed from the NWMAA.

Response:

FEI confirms that mutual aid from the NWMAA was considered in preparing the 2024 Resiliency Plan. In particular, the 2024 Resiliency Plan accounts for mutual aid via the number of technicians available to assist with the recovery effort. For example, in a T-South failure that results in customer outages, the 2024 Resiliency Plan assumes technicians will be made available to FEI from other mutual aid utilities to assist with relighting customers. Having these additional technicians shortens the total outage duration, thereby reducing the consequences of the event. In other words, if these technicians proved to be unavailable then (other things equal) the number of customer outage days and GDP losses would increase from what is shown in the 2024 Resiliency Plan.

The 2024 Resiliency Plan does not account for gas *volumes* to be provided to FEI from members of the NWMAA. This is the appropriate approach for the reasons below.

- First, in a winter T-South no-flow event, gas cannot physically flow northward from mutual aid partners to FEI's system. Due to this physical constraint, there are no gas volumes from NWMAA members that can be accounted for in the 2024 Resiliency Plan, which assesses the T-South risk under winter conditions. As explained in Section 4.3.4.3 of the Application, FEI would need to rely on displacement to make use of NWMAA members' capacity. However, as the displacement process is dependent on physical gas flow on T-South, FEI cannot rely on displacement to deliver NWMAA volumes during a winter T-South no-flow event.
- Second, even if the above constraint did not exist, during a winter T-South no-flow event, gas flow to NWMAA members in the I-5 corridor would also be impacted by the event. Therefore, there is no certainty on what volume FEI could receive given there is no obligation for the NWMAA to provide FEI any volume.

As such, from a resiliency planning perspective, FEI cannot rely on potentially available gas volumes from mutual aid partners.

Thus, these volumes were not accounted for in the 2024 Resiliency Plan.

121.2 Please explain how the inclusion of gas volumes provided in response to an emergency, as per the NWMAA, would impact the conclusions of the Resiliency Plan,

Response:

The assumption in the question would not be a reasonable basis on which to perform the risk calculations in the 2024 Resiliency Plan because FEI cannot plan on access to gas volumes from the NWMAA as they may not be available when needed. Please refer to the response to BCUC IR5 121.1 which explains that, under the parameters used for the 2024 Resiliency Plan (i.e., average winter conditions), FEI would be unable to rely on mutual aid gas volumes from the NWMAA during winter.

In response to BCUC IR 10.6, with regards to future resiliency investments, FEI stated:

> FEI is completing the initial scoping and planning for a Regional Gas Supply Diversity (RGSD) solution which would entail building a new pipeline route to the Lower Mainland connecting the Southern Crossing Pipeline in the BC Interior. The design of the RGSD project would be optimally sized to form a cost-effective resiliency solution in combination with FEI's other gas supply assets. The RGSD project would enhance gas supply resiliency by providing needed pipeline diversity in the region.

On page 106 of Exhibit B-60, FEI states: "FEI has recently determined not to pursue RGSD on its own, although FEI has not foreclosed participating with others in a similar pipeline project."

On page 124 of Exhibit B-60, FEI states:

> FEI's evaluation of potential alternative pipeline routes as part of its development work on the RGSD Project found that collaborating with other regional market participants on an integrated solution could be beneficial for the region and FEI's customers. This strategy would enhance the use of existing regional infrastructure, potentially lower costs, and balance risks for FEI and its customers. Therefore, FEI considers the current phase of the RGSD Project to have concluded and intends to explore <u>commercial discussions with other market participants to continue to advance an optimal integrated solution for the region</u>. [Emphasis added]

121.3 Please provide an update on any discussions FEI has had with other market participants regarding participation in a pipeline project similar to the RGSD Project.

<u>Response:</u>

For this response, FEI has redacted certain information for which FEI is requesting be filed on a confidential basis and be held confidential by the BCUC in perpetuity, pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-296-24. The information is commercially sensitive. FEI requests that the information only be accessible to the BCUC.

[redacted]

[redacted]

121.4 Please confirm, or explain otherwise, that an integrated solution in collaboration with other regional market participants was not considered as a resiliency capability in the Resiliency Plan.

121.4.1 If confirmed, please explain how the inclusion of such a project as an assumed resiliency asset would impact the conclusions of the Resiliency Plan.

Response:

Not confirmed. FEI's 2024 Resiliency Plan includes the diversification of pipeline supply as a potential long-term risk mitigation project that would complement increased on-system LNG storage and regasification. Incorporating an assumption that such a pipeline was already in place would not change the primary recommendation of the 2024 Resiliency Plan:[23]

> FEI has confirmed the need for resiliency-driven investment to mitigate FEI's greatest customer outage risk that is due to a winter T-South no-flow event (Assessed Vulnerabilities (AV) 1, 2, 3 and 54), as well as risk associated with AV 18. New and larger on-system LNG at Tilbury will mitigate both risks.

An integrated solution in collaboration with other regional market participants would not eliminate the risk of customer outages in the Lower Mainland from occurring as a result of a winter T-South no-flow event for two reasons:

- First, FEI would remain exposed to a single point of failure risk as there are no pipelines under consideration that would create a new connection to the Lower Mainland.
- Second, the gas supply contract framework is such that the earliest FEI could expect to contract or resource supply on a hypothetical future diversified pipeline would be on Day 3 of the event. This is because operational flows on pipelines have nominations (i.e., commercial commitments in place) which take time to adjust. As such, a diversified pipeline would not prevent a widespread outage on Days 1 and 2 of a winter T-South no-flow event even if the new pipeline path connected directly into the FEI system.

Ultimately, adding the assumption of a diversified pipeline as a resiliency asset without first expanding on-system LNG storage and regasification capacity would not address the risk of a Lower Mainland outage occurring as a result of a winter T-South no-flow event. However, once there is on-system LNG sufficient to bridge a no-flow event, a diversified pipeline serves to reduce residual risk.

On page 37 of Exhibit B-61, FEI states:

> Linepack is the volume of gas that is contained within the gas system. The amount of support that linepack can provide depends on the operating pressure, the length

[23] Exhibit B-61, p. 3.

and diameter of pipe holding the linepack, and the amount of load on the system. In the 2024 Resiliency Plan, linepack is accounted for in some AVs but not others.

121.5 Please explain whether any future pipeline expansions were considered in FEI's calculation of the level of support linepack is able to provide (for example, the T-South Sunrise Expansion).

121.5.1 If yes, please provide the names of the expansions as well as the length and diameter of pipe added.

121.5.2 If no, please explain why not.

Response:

FEI did not consider future pipeline expansions (e.g., the Sunrise Expansion of T-South) in the level of support that T-South linepack provides because, while pipeline expansions on the Westcoast system are expected, the potential change in available linepack will be unclear until entering service. Typically, expansions to transport more energy are built to serve additional customers and energy demand, which means that while there is more energy in the system (linepack), there is also correspondingly higher energy outflows to these new customers and demand points drawing down this linepack. Due to the uncertainty of this balance between additional available energy and additional demand, FEI considered that it was most appropriate to use the system as it is today when determining a reasonable assumption for the available T-South linepack.

122.0 Reference: RESILIENCY PLAN

Exhibit B-61 (2024 Resiliency Plan) , p. 21, Appendix RP 2 (Exponent Report), p. 2, Exhibit B-15, BCUC IR 10.2

FEI's Structured Process for Developing the 2024 Resiliency Plan

On page 21 of Exhibit B-61, FEI states that it retained independent experts Exponent to provide expert advice regarding "the overall design of the structured process for developing the 2024 Resiliency Plan."

On page 2 of Appendix RP 2 (the Exponent Report), Exponent states:

> FEI has undertaken a two-step consequence-based screening to identify vulnerabilities with the potential to result in significant customer outages that were then subject to further detailed quantification. Exponent considers that FEI's overall approach for its 2024 Resiliency Plan to identify and screen vulnerabilities (for subsequent detailed assessment and quantification) to be reasonable and along the lines of good industry risk assessment practices.

In response to BCUC IR 10.2, FEI stated:

> To FEI's knowledge, the North American natural gas industry does not have any industry-adopted reliability or resiliency standards, equivalent to the Mandatory Reliability Standards for electric utilities. However, the examination of gas system resiliency, specifically within the utilities that FEI has close contact with, is becoming increasingly relevant.

122.1 Please explain whether FEI is aware of any natural gas industry reliability or resiliency standards that have been developed or issued since FEI provided its response to BCUC IR 10.2.

122.1.1 If yes, please provide the name(s) of the relevant standard(s) and confirm, or explain otherwise, that that the Resiliency Plan aligns with these standards.

<u>Response:</u>

The following response has been provided by Exponent:

Exponent is not aware of any natural gas reliability or resiliency standards that have been developed since FEI issued its response to BCUC IR1 10.2. In fact, the Canadian Standards Association has recently solicited proposals for contractors to draft a report on the reliability and resilience in the natural gas chain, intended to gather information on use and standardization of these terms, which indicates the lack of maturity of this field.

FEI also provides the following response:

FEI is not aware of any natural gas industry reliability or resiliency standards that have been developed or issued since FEI provided its response to BCUC IR1 10.2.

FEI is aware that the Canadian Standards Association (CSA) Liquids and Gaseous Energy Systems Strategic Steering Committee (LGES SSC) has recently issued a public Request for Proposals (RFP) to conduct a "landscape analysis of reliability and resilience nomenclature, definitions, concepts and measurements (what is measured and the nomenclature used for measurement) across the natural gas value chain (upstream, midstream, downstream)." Please refer to Attachment 122.1 for a copy of the RFP.

As outlined in this RFP, the CSA is looking to identify and describe the existing reliability and resilience nomenclature, concepts and frameworks currently in use in the natural gas sector, and to explore the development of a consistent reliability and resilience nomenclature to provide the various natural gas sectors with a common understanding of the concepts of reliability and resilience. These concepts may be included in revisions to existing standards, or potentially lead to the development of new standards, as identified and affirmed by the LGES SSC.

123.0 Reference: RESILIENCY PLAN

Exhibit B-61 (2024 Resiliency Plan), p. 96

Lower Mainland

On page 96 of Exhibit B-61, FEI states that "the T-South no-flow event in winter is, by far, FEI's greatest customer outage risk" and that "the risk exposure facing the Lower Mainland, even after accounting for the pending implementation of AMI and future developments, is unacceptable and needs to be mitigated."

Further on page 96, FEI states that "new and larger on-system LNG at Tilbury is the only project that will materially mitigate the T-South risk."

123.1 Please confirm, or explain otherwise, that FEI defines "Lower Mainland" as including Metro Vancouver and the Fraser Valley.

123.1.1 If not confirmed, please explain whether FEI considers the risk exposure facing the Fraser Valley to be unacceptable and needs to be mitigated.

<u>Response:</u>

Not confirmed. For the purposes of the 2024 Resiliency Plan and Supplemental Evidence, FEI defines "Lower Mainland" as including all of Metro Vancouver and the parts of the Fraser Valley that are fed by FEI's Coastal Transmission System (i.e., downstream of FEI's Huntingdon Control Station in Abbotsford). The Fraser Valley population centres included within FEI's definition of "Lower Mainland" include Abbotsford and Mission.

The risk from a T-South no-flow event facing the parts of the Fraser Valley not included in FEI's definition of the "Lower Mainland" (e.g., Chilliwack and Hope) will not be mitigated by the TLSE Project. With the TLSE Project in place, the risk exposure facing these parts of the Fraser Valley is represented in Exponent's risk analysis as a subset of the residual T-South risk (i.e., the T-South risk with the TLSE Project in place).

As noted in the response to BCUC IR5 117.2, within the ALARP framework suggested in the information requests, FEI would characterize the residual risk of a T-South no-flow event after the Preferred Alternative is in place as being as low as reasonably practicable (ALARP) such that no additional resiliency-driven investments are necessary. Any future investments in resiliency would thus be predicated on some change (e.g., technology change or a project with a non-resiliency driver) that made it practicable to reduce the risk further.

123.2 Please confirm that a new and larger LNG facility at Tilbury will mitigate the risk exposure facing all areas of the Lower Mainland, including the Fraser Valley, to an acceptable level.

123.2.1 If not confirmed, please explain how FEI plans to mitigate customer outage risk to an acceptable level in all areas of the Lower Mainland, including the Fraser Valley.

Response:

Please refer to the response to BCUC IR5 117.3 for a discussion on how FEI classifies the residual T-South risk facing areas within FEI's definition of the "Lower Mainland" (as set out in the response to BCUC IR5 123.1) due to a winter T-South no-flow event.

The T-South risk facing FEI customers in the parts of the Fraser Valley that were excluded from FEI's definition of the "Lower Mainland" are part of that residual risk. Please refer to BCUC IR5 123.1 for a discussion regarding FEI's approach to this risk.

124.0 Reference: RESILIENCY PLAN

Exhibit B-61 (2024 Resiliency Plan), p. 16

Interdependencies between Natural Gas and Electric Systems

On page 16 of Exhibit B-61, FEI states:

> Technical discussions between FEI and British Columbia Hydro and Power Authority (BC Hydro) following the 2018 T-South Incident concluded that a widespread gas outage could require rotating electric feeder outages (i.e., brown outs). The resulting outages, whether planned or not, would pose a significant safety risk during cold weather conditions...

124.1 Please discuss whether FEI's resiliency planning explicitly considers the potential for a T-South no-flow event to trigger electric outages in the Lower Mainland.

124.1.1 If yes, please confirm whether FEI has identified any specific vulnerabilities in its gas distribution system, including the Tilbury LNG facility, to power outages.

Response:

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.

FEI has critical assets that rely on electrical power for operation. In the case of the Tilbury Base Plant, sendout would be possible during a BC Hydro power outage. More generally, where deemed necessary by FEI to support system reliability, certain assets in FEI's distribution system are equipped with backup power such as an Uninterruptible Power Supply (UPS) or an Auxiliary Power Unit (APU).

124.2 Please clarify whether FEI coordinated with BC Hydro to assess the potential for cascading failures between the gas and electric systems in the Lower Mainland since 2018.

124.2.1 If so, please provide details on the scope and outcome of these discussions.

124.3 Please describe the scenarios associated with a widespread gas outage that FEI and BC Hydro concluded could result in brown outs and please clarify <u>how</u> FEI and BC Hydro concluded that these scenarios could result in brown outs.

124.3.1 For scenarios associated with a widespread gas outage resulting in brown outs, please estimate the probability and duration of the brown outs. Please explain if and how the TLSE Project would mitigate the effects of such brown outs.

Response:

FEI and BC Hydro have not formally coordinated to assess the potential for cascading failures between the gas and electric systems in the Lower Mainland, and have not developed specific scenarios in which a gas outage could result in brown outs. FEI does not have the ability to perform that analysis unilaterally, given that it would need detailed technical information on the characteristics of BC Hydro's distribution system.

FEI has redacted the remainder of the response and is requesting it be filed on a confidential basis and be held confidential by the BCUC in perpetuity, pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-296-24. FEI requests that the information only be accessible to the BCUC, as the discussions referenced were the subject of a Non-Disclosure Agreement with BC Hydro. BC Hydro has reviewed this response and has indicated that it is in agreement with the content.

[redacted]

125.0 Reference: RESILIENCY PLAN

Exhibit B-61 (2024 Resiliency Plan), p. 82

Cyber Security

On page 82 of Exhibit B-61, FEI states:

> The [Government of Canada's Canadian Centre for Cyber Security] analysis, discussed in this section, suggests that there is now a material and increasing risk from cyber threat activity towards critical gas infrastructure from a variety of malicious actors… While FEI has a Corporate Security Risk Program to mitigate against successful cyber threats, FEI's assets are nonetheless exposed to this increasing risk.

125.1 Please explain how FEI can mitigate the resiliency risk posed by cyber attack on FEI or Westcoast.

Response:

Resiliency, as defined by Guidehouse and echoed by FEI, "is the ability to prevent, withstand and recover from system failures or unforeseen events such as damage and/or operational disruption that impact the operations of the system."[24] In the event there was a cyber attack resulting in a winter no-flow event affecting the Lower Mainland, only on-system LNG storage located in the Lower Mainland (such the TLSE Project) could materially mitigate the expected consequences to FEI's customers and the Lower Mainland generally.

In order to reduce the likelihood of cyber attacks occurring on FEI's infrastructure, FEI implements a combination of proactive and reactive strategies. FEI and FortisBC Inc. (FBC) (collectively, FortisBC) have agreements with several third parties, such as Electricity Information Sharing and Analysis Center (E-ISAC), Downstream Natural Gas Information Sharing and Analysis Center (DNG-ISAC), Gartner, PricewaterhouseCoopers (PwC), Dragos, and the SysAdmin, Audit, Network, and Security (SANS) Institute, to provide threat intelligence based on the regulated utility sector and the deregulated corporate sector. Further, FortisBC has a relationship with various organizations like the Canadian Gas Association, Electricity Canada, and the Canadian Centre for Cyber Security that helps actively monitor for suspicious activity and potential threats and contacts FortisBC with all cybersecurity concerns and alerts.

FortisBC also conducts regular security risk assessments that identify potential vulnerabilities and prioritizes them based on the level of risk to the asset. Assessments on the effectiveness of the FEI cybersecurity program by third-party experts are also performed annually to ensure the program is operating effectively. Mandatory annual training is provided to employees and contractors on cybersecurity practices needed to recognize potential threats and how to report them to the security team. There are also regular communications throughout the year, in-person and on FortisBC's intranet, regarding cybersecurity risks and good practices.

[24] Exhibit B-1-4, Appendix A, p. 6.

FEI does not have direct knowledge of Westcoast's approach to mitigating cyber security risk on its system.

126.0 Reference: RESILIENCY PLAN

Exhibit B-61 (2024 Resiliency Plan), p. 58, Exhibit B-15, BCUC IR 40.1, Exhibit B-60 (Supplemental Evidence), p. 129

Analysis period time horizon

On page 58 of Exhibit B-61, FEI states:

> FEI instructed Exponent to perform cumulative probability calculations for a winter-only disruption on all AVs based on two horizons:
>
> 1. The 67-year expected life of the TLSE Project, which FEI regards as the appropriate horizon; and
>
> 2. A 23-year sensitivity based on an assumed facility retirement in 2050, which FEI included to address the BCUC's commentary regarding the energy transition potentially shortening the useful life of a new LNG facility.

In response to BCUC IR 40.1, FEI stated:

> The estimated average service life of 60 years for the proposed 3 Bcf tank is recommended by Concentric based on the newer Mt. Hayes LNG storage tank, which entered service in 2011.

On page 129 of Exhibit B-60, FEI states:

> The levelized total rate impact criterion compares the incremental levelized total rate impact over a 67-year period between each supplemental alternative… The 67-year analysis period is used for the financial analysis to cover the expected useful life of the assets pertaining to all alternatives, which is 60 years for an LNG storage tank, plus seven prior years from 2024 to 2030 (assuming all alternatives are placed in-service by 2030).

126.1 Please explain why FEI instructed Exponent to perform cumulative probability calculations based on a 67-year time horizon if the TLSE Project only begins to offer resiliency benefits in 2030 and has an expected useful life of 60 years.

Response:

In responding to this question, it came to FEI's attention that it had inadvertently instructed Exponent to use different time horizons than the expected life (60 years) and a hypothetical early retirement in 2050 (20 years). The time horizons selected do not affect Exponent's underlying methodology for calculating the cumulative probabilities of failure used in FEI's 2024 Resiliency Plan, the relative risk posed by each AV, or the relative risk associated with each Supplemental Alternative.

The use of two different time horizons as an input to Exponent's cumulative probability calculations, in addition to annual values, was intended to provide multiple common bases for comparison across AVs and among alternatives. While the scenarios already provided continue to provide useful information in that regard, FEI recognizes the value of providing the results for 20 and 60 years. FEI has included below a revised Table 1-3 from the Supplemental Evidence, providing the results associated with 20- and 60-year time horizons. As shown in the table, Exponent's calculated winter only (90 days) probability remains high even over a 20-year horizon.

Revised Table 1-3: Exponent's Calculated Cumulative Probability Range of T-South No-Flow Event in Winter[25]

Calculation Horizon	Basis for Horizon	Exponent's Calculated Cumulative Winter Only (90 Days) Probability
67 years (original analysis)	Expected Life of TLSE Project	95% - 100%
60 years (revised analysis)		93% - 100%
23 years (original analysis)	Adverse sensitivity included in response to BCUC commentary assumes no further use of Tilbury facility for resiliency or gas supply after 2050	65% - 97%
20 years (revised analysis)		59% - 96%

For completeness, FEI also requested that Exponent reproduce, using the 20- and 60-year values, Tables 3 and 8 from the Exponent Report (as requested in BCUC IR5 126.3 and 126.4), as well as the following tables and figures from the Supplemental Evidence. Collectively, these tables and figures provide information on the winter-only risk for the 58 AVs, the relative expected losses and loss reduction for various Supplemental Alternatives, accounting for T-South only, and on a combined basis with other AVs.

Alternative Table 3 from Exponent Report:
Winter-only Annual Rates of Failure and Cumulative Probability of at Least One failure in One, 20, and 60 Years for the Combination of AV-1, AV-2, AV-3, and AV-54

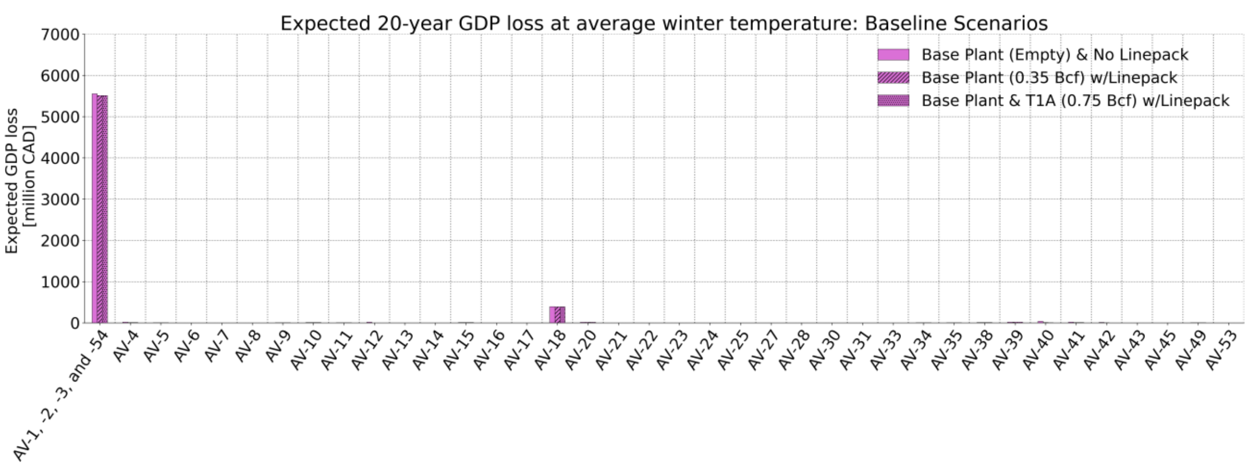
Winter-only annual rate of failure							Cumulative probability of at least one failure					
Earthquake Hazards [/yr]		Non-Earthquake External Hazards [/yr]		Internal and 3rd Party Hazards [/yr]	Cumulative [/yr]		Overall [% annually]		Overall [% in 20 years]		Overall [% in 60 years]	
LB	UB	LB	UB	SV	LB	UB	LB	UB	LB	UB	LB	UB
9.20E-03	3.82E-02	5.32E-03	9.05E-02	3.06E-02	4.51E-02	1.59E-01	4%	15%	59%	96%	93%	100%

[25] Reported as the lower bound and upper bound.

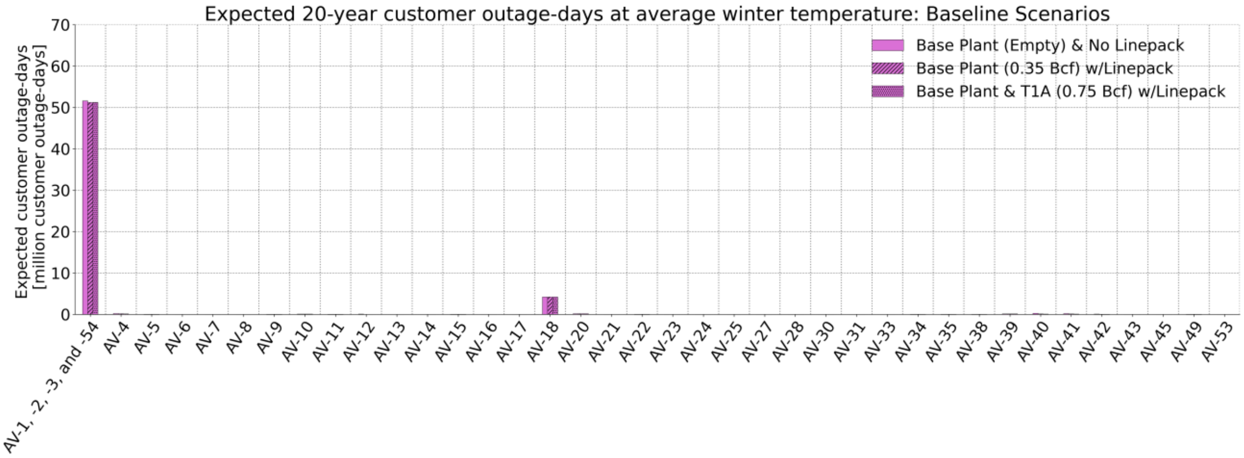
Alternative Table 8 from the Exponent Report:
Annual, 20-year, and 60-year Expected Winter-only GDP Loss Reductions in Million CAD for Alternatives 7, 8, and 9

	Alternatives 7 and 9			Alternative 8		
AV	Annual GDP Loss Reduction	20-Year GDP Loss Reduction	60-Year GDP Loss Reduction	Annual GDP Loss Reduction	20-Year GDP Loss Reduction	60-Year GDP Loss Reduction
AV-1	96.4	1928.8	5786.5	94.1	1882.5	5647.5
AV-2	12.2	243.5	730.5	11.9	237.4	712.3
AV-3	22.8	456.4	1369.3	22.5	450.3	1351.0
AV-4	0.7	13.9	41.8	0.6	12.5	37.4
AV-12	0.9	17.6	52.8	0.9	17.6	52.8
AV-13	0.0	0.0	0.0	0.0	0.0	0.0
AV-14	0.0	0.0	0.1	0.0	0.0	0.1
AV-16	0.0	0.0	0.1	0.0	0.0	0.1
AV-17	0.0	0.1	0.3	0.0	0.1	0.3
AV-18	14.6	291.9	875.8	14.4	287.5	862.5
AV-20	0.2	3.7	11.0	0.2	3.4	10.3
AV-23	0.0	0.0	0.1	0.0	0.0	0.1
AV-30	0.0	0.0	0.1	0.0	0.0	0.1
AV-40	1.8	36.9	110.7	1.7	35.0	105.0
AV-41	0.8	15.5	46.5	0.7	14.2	42.7
AV-42	0.6	11.7	35.1	0.6	11.1	33.4
AV-54	34.1	682.5	2047.5	33.8	676.6	2029.9
Combined	185.1	3702.8	11108.3	181.4	3628.5	10885.4

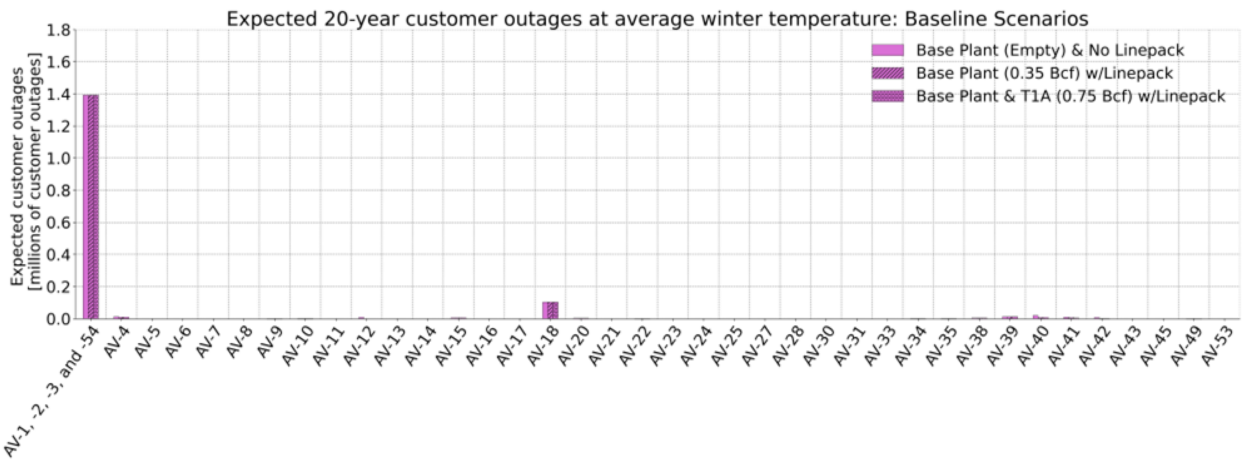
Alternative Figure 3-11: Expected 20-year Winter-only GDP Loss for the Combination of AV-1, -2, -3, and -54 and for Other AVs for the Tilbury Baseline Scenarios



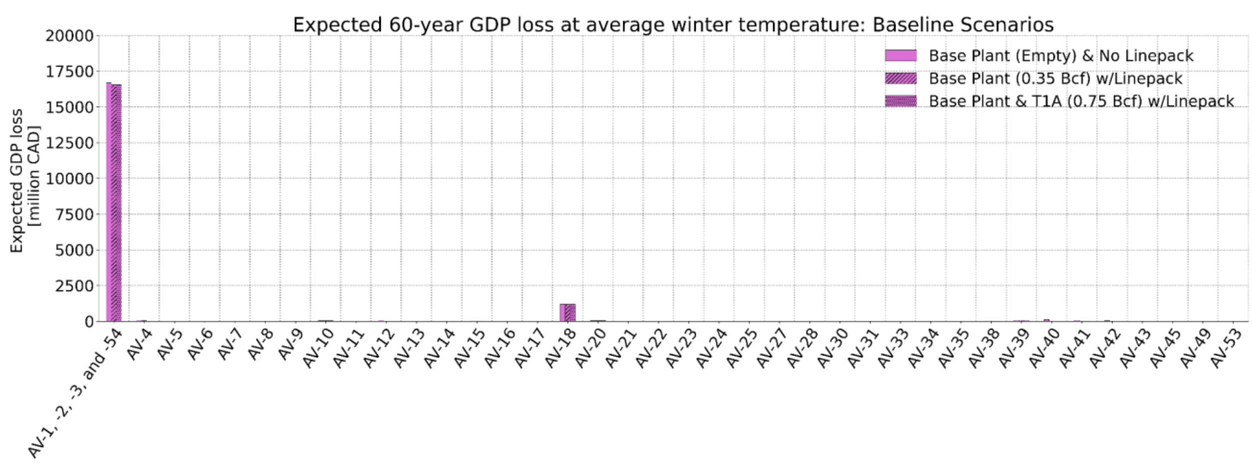
Alternative Figures 1-3 and 3-12: Expected 20-year Winter-only Customer Outage-days for the Combination of AV-1, -2, -3, and -54 and for Other AVs for the Tilbury Baseline Scenarios



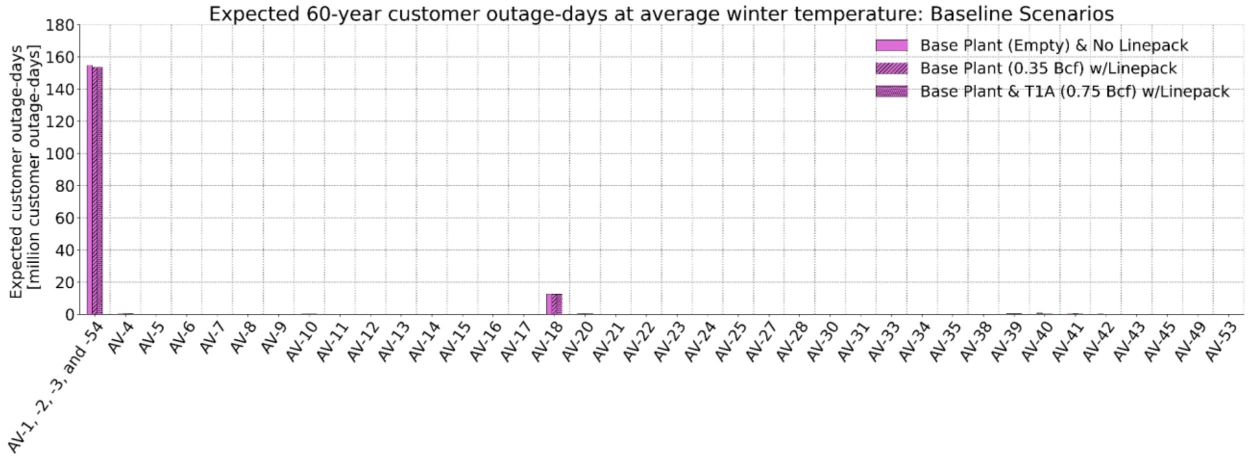
Alternative Figure 3-13: Expected 20-year Winter-only Customer Outages for the Combination of AV-1, -2, -3, and -54 and for Other AVs for the Tilbury Baseline Scenarios



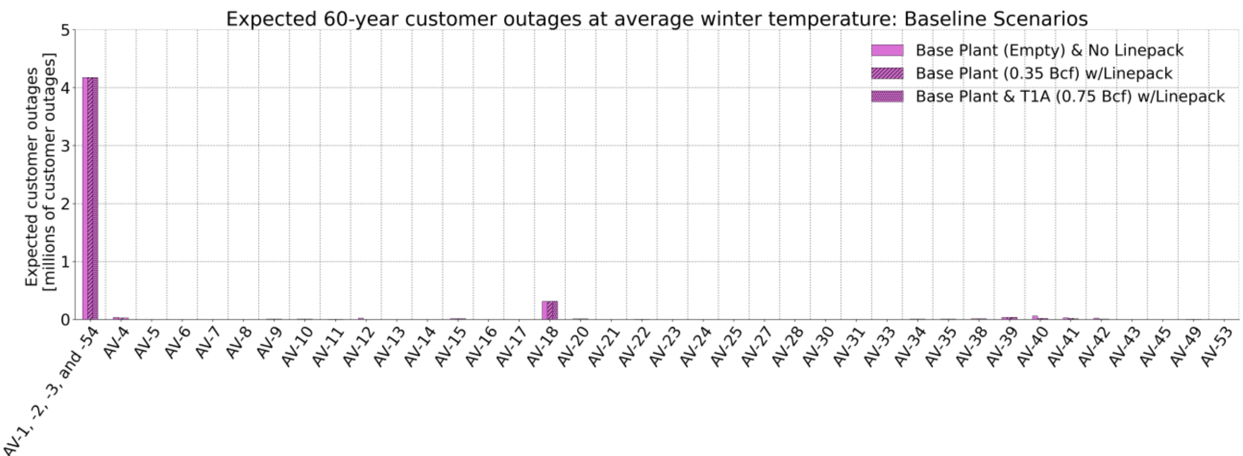
Alternative Figure 3-14: Expected 60-year Winter-only GDP Loss for the Combination of AV-1, -2, -3, and -54 and for Other AVs for the Tilbury Baseline Scenarios



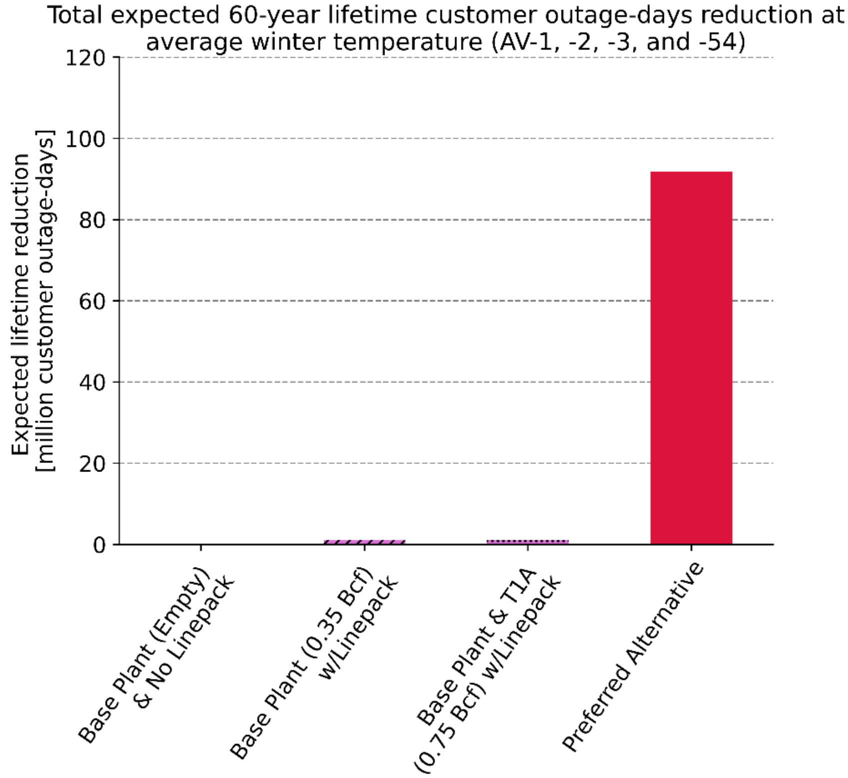
Alternative Figure 3-15: Expected 60-year Winter-only Customer Outage-days for the Combination of AV-1, -2, -3, and -54 and for Other AVs for the Tilbury Baseline Scenarios



Alternative Figure 3-16: Expected 60-year Winter-only Customer Outages for the Combination of AV-1, -2, -3, and -54 and for Other AVs for the Tilbury Baseline Scenarios

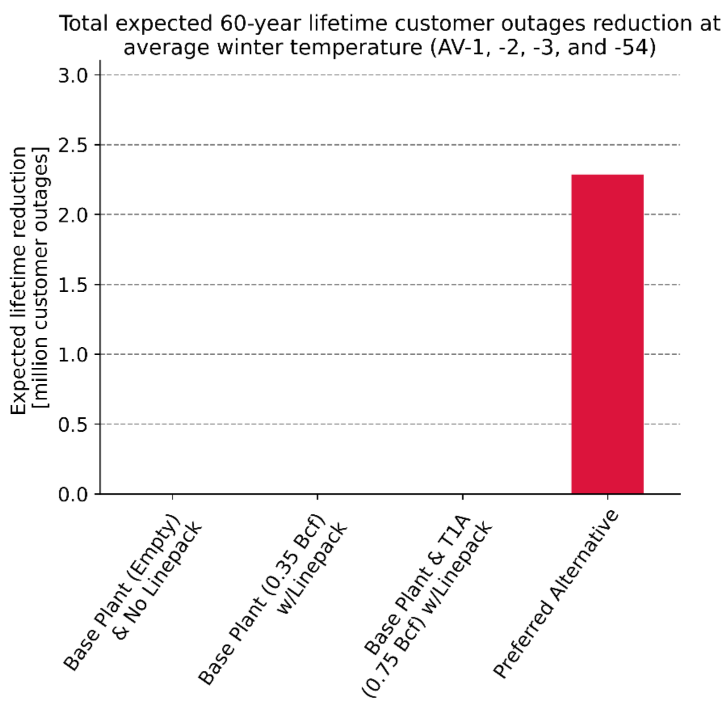


1 **Alternative Figure 4-24: Preferred Alternative 60-Year T-South-Only Expected Customer Outage**
2 **Days Reduction**



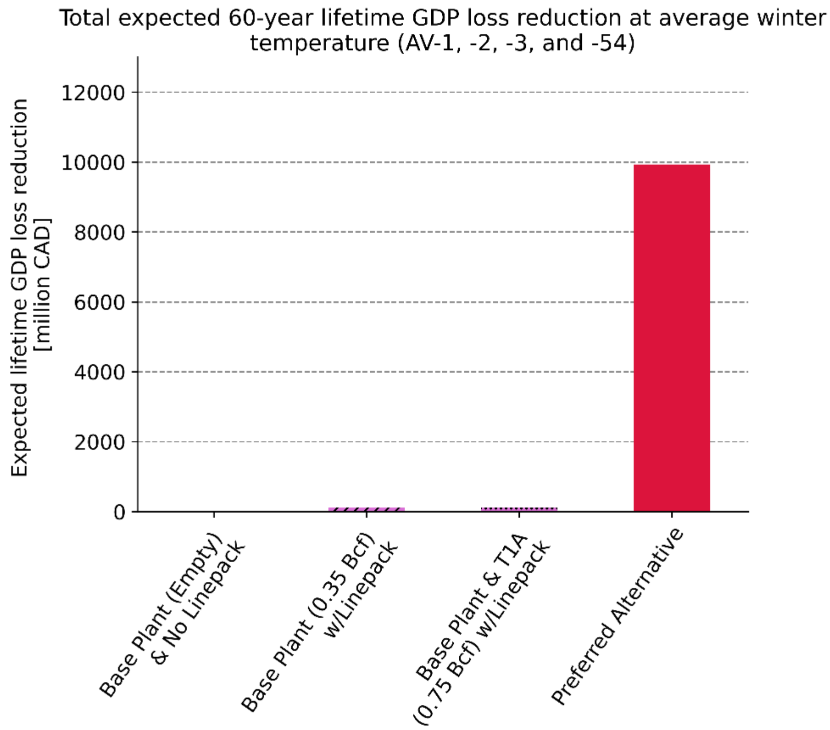
3

4 **Alternative Figure 4-25: Preferred Alternative 60-Year T-South-Only Expected Customer Outages**
5 **Reduction**

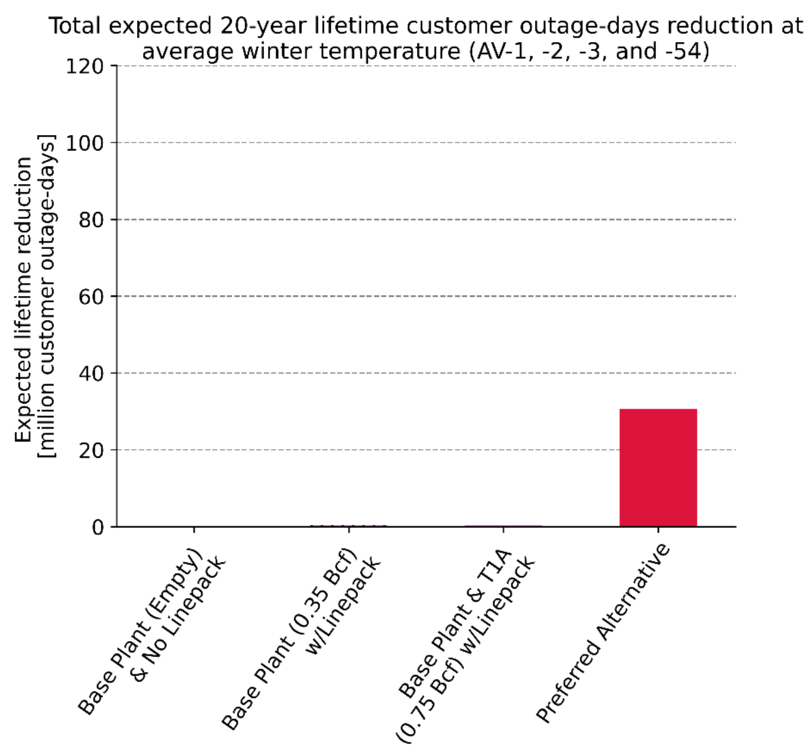


6

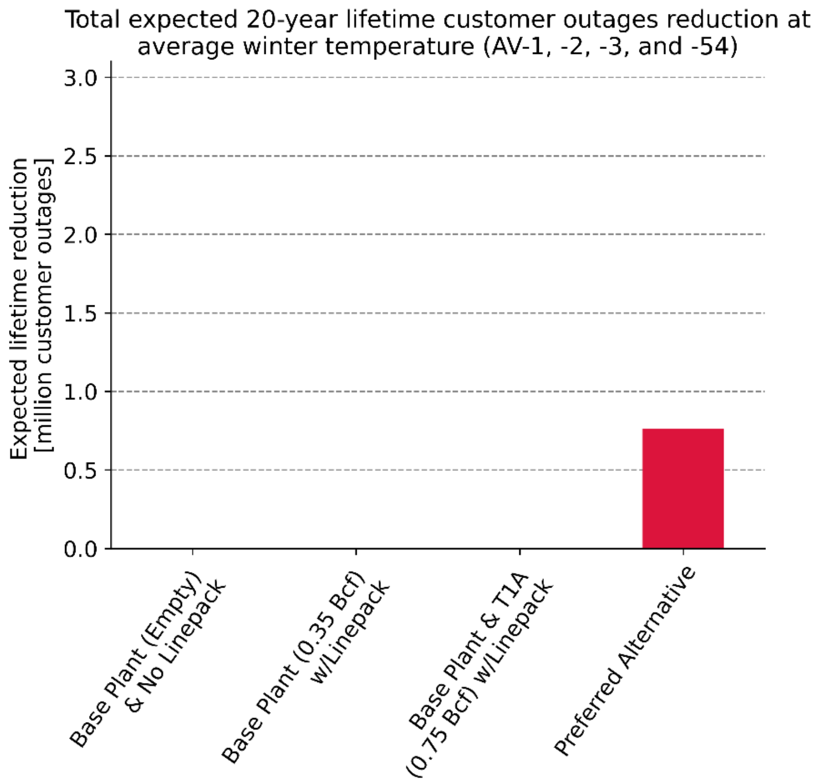
Alternative Figure 4-26: Preferred Alternative 60-Year T-South-Only Expected GDP Loss Reduction



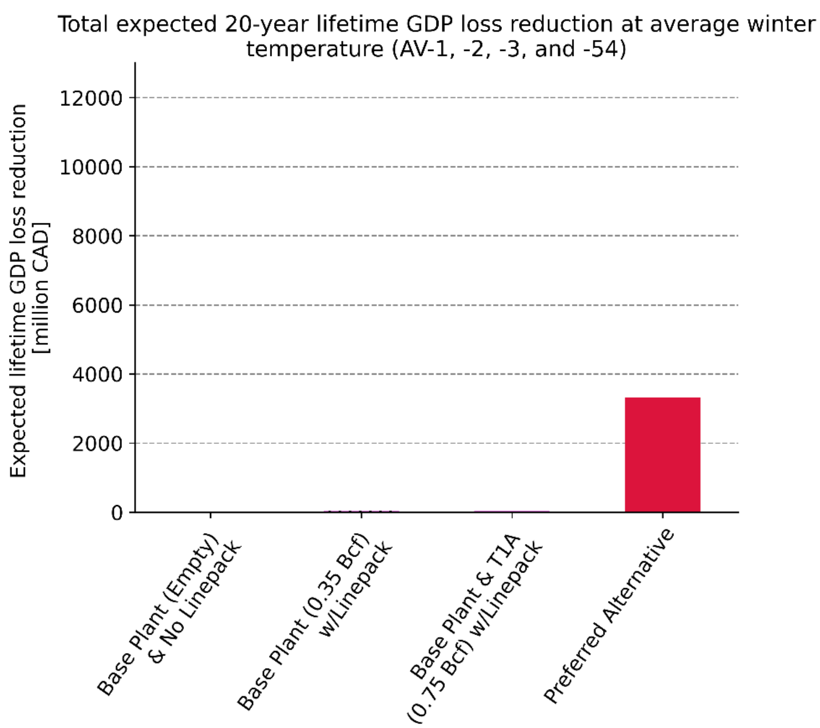
Alternative Figure 4-27: Preferred Alternative 20-Year T-South-Only Expected Customer Outage Days Reduction



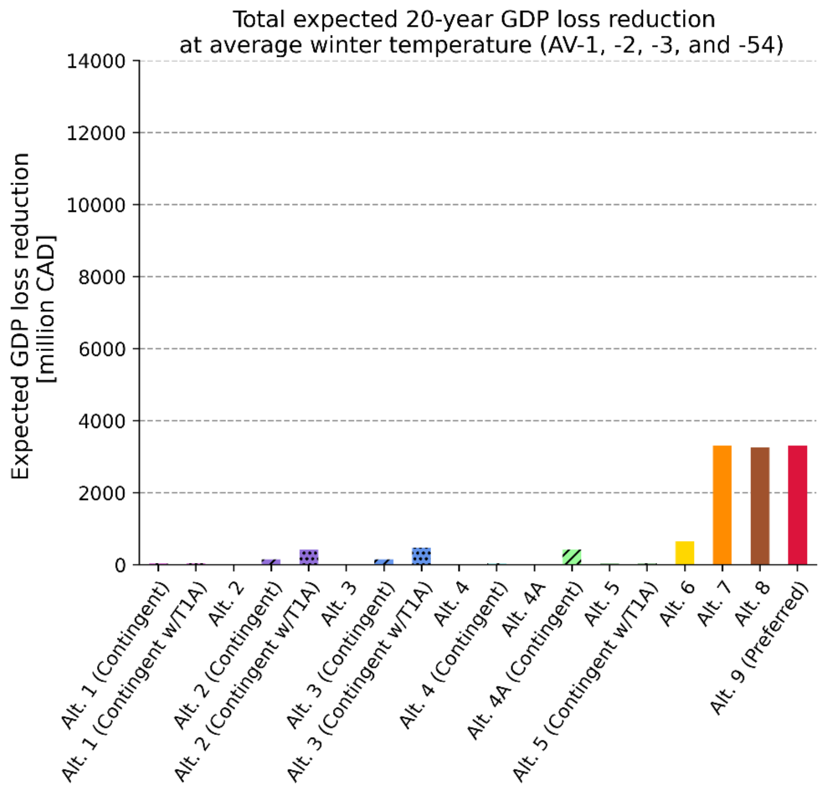
Alternative Figure 4-28: Preferred Alternative 20-Year T-South-Only Expected Customer Outages Reduction



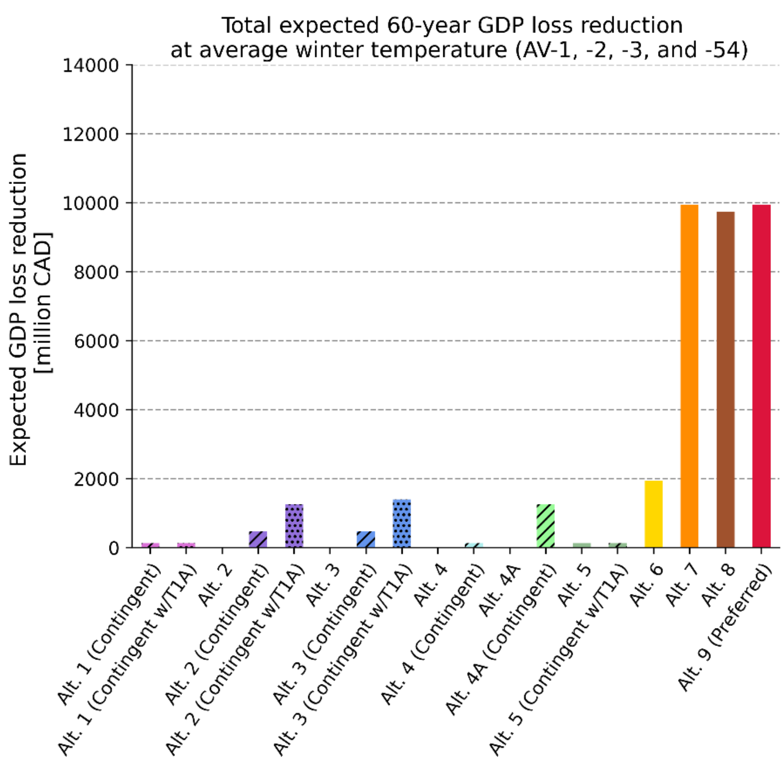
Alternative Figure 4-29: Preferred Alternative 20-Year T-South-Only Expected GDP Loss Reduction



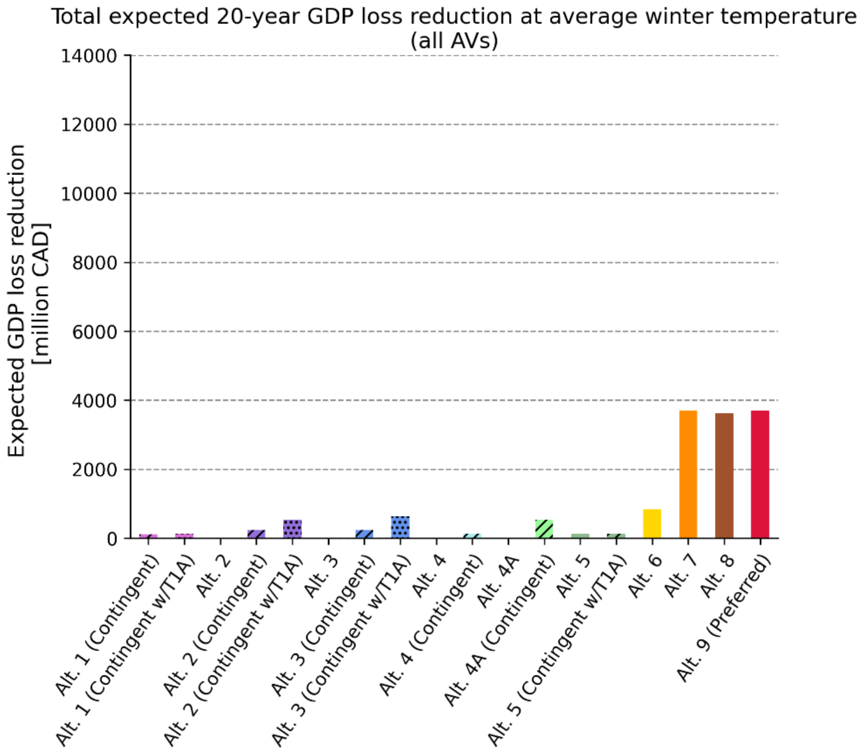
Alternative Figure C-4: T-South at Avg. Winter – Expected 20-Year Loss Reduction



Alternative Figure C-5: T-South at Avg. Winter – Expected 60-Year Loss Reduction



1 **Alternative Figure C-7: All AVs at Avg. Winter – Expected 20-Year Loss Reduction**



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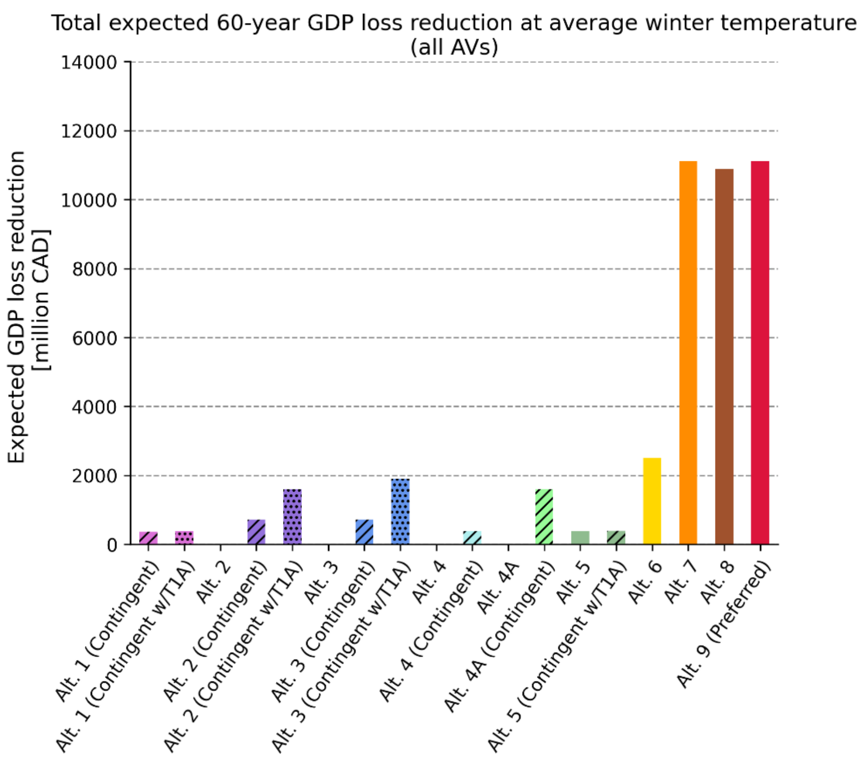
3 **Alternative Figure C-8: All AVs at Avg. Winter – Expected 67-Year Loss Reduction**



4

5

126.2 Please explain why FEI instructed Exponent to perform cumulative probability calculations based on a 23-year time horizon if the the TLSE Project only offers resiliency benefits for 20 years prior to an assumed facility retirement in 2050 (i.e. 2030 to 2050).

Response:

Please refer to the response to BCUC IR5 126.1.

126.3 Please reproduce Table 3 on page 60 of the Exponent Report based on the cumulative probability of at least one failure in 20 and 60 years for the combination of AV-1, AV-2, AV-3 and AV-54.

Response:

Please refer to the response to BCUC IR5 126.1.

126.4 Please reproduce Table 8 on page 107 of the Exponent Report based on 20-year and 60-year expected winter-only GDP loss reductions in million CAD for Alternatives 7, 8 and 9.

Response:

Please refer to the response to BCUC IR5 126.1.

C. EXPANDED ALTERNATIVES ANALYSIS

127.0 Reference: EXPANDED ALTERNATIVES ANALYSIS

Exhibit B-60 (Supplemental Evidence), p. 104, Table 4-6, p. 114, Table 4-8, p. 124

Contingent Scenarios

On page 104 of Exhibit B-60, FEI states:

> All of the Supplemental Alternatives listed in the table below reflect a **planning view** which means that they treat stored LNG as being available on a dependable basis for a single planned purpose, since it will not be dependable for any purpose if it is allocated to (or planned for) multiple purposes.
>
> […]
>
> FEI also investigated **"contingent" scenarios** for viable Supplemental Alternatives that would involve either only replacing the regasification equipment for a new facility with a tank less than 2 Bcf (i.e., Supplemental Alternatives 1, 2, 3, 4, 4A, and 5). In general, the contingent scenarios for a given alternative consider the case where some volume of LNG that is not set aside as a "resiliency reserve" is available on the day of a no-flow event. [Emphasis included]

On page 114 of Exhibit B-60, in Table 4-6, FEI identifies the nine "technically and commercially viable Supplemental Alternatives." The table has been partially reproduced by BCUC Staff below.

Supplemental Alternative #	Description
Alt 2	New Regasification Only - 400 MMcf/d (No Resiliency Reserve)
Alt 3	New Regasification Only - 600 MMcf/d (No Resiliency Reserve)
Alt 4	Like-for-Like (No Resiliency Reserve)
Alt 4A	New 1 Bcf Tank (No Resiliency Reserve) and 400 MMcf/d Regasification
Alt 5	Like-for-Like (Full Resiliency Reserve)
Alt 6	New 1 Bcf Tank (Full Resiliency Reserve) and 800 MMcf/d Regasification
Alt 7	New 2 Bcf Tank (Full Resiliency Reserve) and 800 MMcf/d Regasification
Alt 8	New 2 Bcf Tank (1.4 Bcf Resiliency Reserve) and 800 MMcf/d Regasification
Alt 9	New 3 Bcf Tank (2 Resiliency Reserve) and 800 MMcf/d Regasification

127.1 Please explain why contingent scenarios were not investigated for Supplemental Alternatives 6 to 9.

Response:

As explained in Section 4 of Appendix C to the Supplemental Evidence, FEI's expanded alternatives analysis included two types of contingent scenarios:

- **Contingent:** assuming gas volumes allocated for gas supply are available for resiliency on the day of a no-flow event; and
- **Contingent with Tilbury 1A:** optimistically assuming that, in addition to gas volumes allocated for gas supply, 0.4 Bcf is also available from the Tilbury 1A tank for resiliency.

FEI addresses the reason for not investigating each type of contingent scenario below. Please refer to the response to BCUC IR5 127.4 for the results of the expanded contingent scenarios considered for Supplemental Alternatives 6 to 9.

Contingent

FEI did not investigate "Contingent" scenarios for Supplemental Alternatives 6 to 9 for following reasons:

- In the case of Supplemental Alternatives 6 and 7, the full tank volume would already be allocated to resiliency, thus there are no contingent cases to consider.
- For Supplemental Alternative 8, the contingent scenario would result in a 2.0 Bcf tank volume assumed to be available for resiliency, which is the same as the Supplemental Alternative 7 and 9 planning scenarios. As such, while FEI did not explicitly consider a Supplemental Alternative 8 contingent scenario, the information was available.
- For Supplemental Alternative 9, FEI did not consider a contingent scenario (i.e., 3.0 Bcf assumed to be available for resiliency) because it remains of the view that resiliency planning should be based on dependable, not contingent, resources.

Contingent w/T1A

FEI only included "Contingent w/T1A" scenarios for Supplemental Alternatives that would rely on existing infrastructure (i.e., Supplemental Alternatives 1, 2, and 3). Although Supplemental Alternative 5 does not rely on existing infrastructure (Like-for-Like (Full Resiliency Reserve)), FEI included a Contingent w/T1A scenario because this scenario could be used as a proxy for the case where the Tilbury Base Plant is restored to its original design capacity of 0.6 Bcf, and 0.4 Bcf from Tilbury 1A is available. As Supplemental Alternatives 6 to 9 involved replacement of the existing Base Plant with new assets, FEI did not investigate "Contingent w/ T1A" scenarios.

FEI's logic was that Tilbury 1A was constructed pursuant to Direction No. 5 to the BCUC for the purpose of LNG sales, and FEI's use of the tank to support the Lower Mainland peaking load is only a temporary measure pending FEI's ability to address the deteriorating condition of the aging

Tilbury Base Plant. "Contingent w/T1A" scenarios are only available while LNG sales are ramping up. They are particularly uncertain now, given the recent proof of concept by Seaspan for West Coast bunkering (please refer to the response to BCUC IR5 119.1) and the favourable prospects for LNG sales from Tilbury 1A with the Tilbury Jetty receiving provincial and federal environmental assessment approval.

127.2 Please confirm, or explain otherwise, that in a scenario where Alternative 8 or 9 is constructed and a winter T-South no-flow event occurs, FEI would continue to supply customers with any remaining storage reserved for peaking supply after the resiliency reserve is depleted, prior to initiating a shutdown.

127.2.1 Please confirm, or explain otherwise, that in a scenario where an alternative with no resiliency reserve is constructed and a winter T-South no-flow event occurs, that FEI would continue to supply customers with any remaining storage reserved for peaking supply, prior to initiating a shutdown.

Response:

FEI's objective would be to minimize any harm to its customers. FEI will be exploring all potential ways to avoid or reduce the number of customer outages, and it is likely that using the remaining LNG reserved for gas supply purposes will be the least-harm approach in most instances. However, there will be certain circumstances where using the remaining LNG in the TLSE tank allocated to gas supply purposes may not be the best way to reduce harm to customers. For example:

- In a hypothetical scenario where FEI is informed that the T-South no-flow event will end within a timeframe that can be bridged by supplying some or all of FEI's customers with the storage reserved for gas supply, then FEI would use the gas supply reserve to prevent or reduce the geographic scope of the outage.
- In a hypothetical scenario where FEI has been told by Westcoast that the T-South no-flow event will persist beyond the support duration that the TLSE Project's resiliency reserve and gas supply volume can provide, then FEI may decide to implement a controlled shutdown leveraging only the resiliency reserve, rather than also using the volume reserved for gas supply. In this scenario, a customer outage will occur regardless of the available LNG volume in the TLSE tank; however, by preserving the gas supply volume, FEI and its customers may be in a better position once the no-flow event ends and FEI's customers are brought back online following a lengthy relight process. In particular, FEI maintaining access to a gas supply reserve during this period may be more beneficial for customers than deferring an inevitable outage as, like in 2018 and 2019 following the T-South Incident, gas markets may be constrained for a long period after the T-South no-flow event ends.

FEI will be in the position of having to make quick and difficult decisions based on the best information available at the time with the aim of minimizing the overall harm to FEI customers. This is one of the reasons why FEI believes it is appropriate for the BCUC to make its determination on the project alternatives by focusing on the planning allocations to resiliency reserve, rather than on the contingent assumption that LNG allocated to gas supply will also be present.

127.3 In a scenario where Alternative 8 or 9 is constructed, please discuss whether the full depletion of storage reserved for peaking supply would only be expected to occur following the end of the design year winter.

127.3.1 Please clarify whether FEI would maintain a 1.4 Bcf or 2 Bcf resiliency reserve for Alternatives 8 and 9 respectively in circumstances where storage reserved for peaking supply is fully depleted.

Response:

From the ACP planning perspective, the full depletion of gas supply storage would only occur following a design winter. FEI's ACP is developed on the basis that Tilbury LNG is available and consumed in a design year. The amount of LNG included in the portfolio optimization model has an impact on other ACP resources required.

In practice, actual usage of LNG could be different from the planned LNG usage for the following reasons:

- Actual winter weather differs from the design winter;
- Timing, duration and frequency of cold weather events;
- Availability of other ACP resources (i.e., inventory levels of market area storage); or
- Change of spot prices when a cold weather event occurs.

In a hypothetical scenario where the gas supply reserve has been fully depleted, FEI would seek to make up the supply shortfall through other resources (e.g., off-system storage, the Sumas market, etc.). If no other supply resources were available, making firm customer outages inevitable, FEI would access the resiliency reserve for its intended purpose; namely, to respond to a supply emergency that could harm its customers. The drawdown of the resiliency reserve in this hypothetical scenario would be small relative to the potential LNG volumes needed to respond to a winter T-South no-flow event.

127.4 Please provide an analysis of contingent scenarios for Supplemental Alternatives 6 to 9 and discuss how they compare to the other Supplemental Alternative's ability to withstand a winter T-South no-flow event.

127.4.1 Please discuss the likelihood that the contingent scenarios would be reflective of real-life conditions at the time of a no-flow event. In the response, please discuss the expected average volume of stored LNG for peaking supply and the likelihood that this volume will be fully depleted at the time of a T-South no-flow event.

Response:

FEI provides the following response:

Table 1 below summarizes the Supplemental Alternative 6 to 9 planning scenarios considered in the Supplemental Evidence, as well as the additional contingent scenarios requested in the question. As with the planning scenarios, FEI used its transient hydraulic modelling tool to determine the Lower Mainland Support duration for each of the contingent scenarios. FEI then provided the Load Support duration data for the new contingent scenarios to Exponent. Exponent used this data to calculate the risk mitigation provided by the new contingent scenarios. The results of this, represented by the total expected annual GDP loss reduction, can be seen in Exponent's figure below. A discussion on the risk mitigation provided by the new contingent scenarios is also provided by Exponent in this response.

Please refer to Section 4.1 of Appendix C to the Supplemental Evidence for further discussion on FEI's planning and contingent scenarios.

Table 1: Support Duration of Supplemental Alternatives 6 to 9 With Additional Contingent Scenarios

Supplemental Alternative	Scenario	Resiliency Modelling Parameters	Lower Mainland Support Duration (4°C)	Lower Mainland Support Duration (-1.4°C)	Lower Mainland Support Duration (-10°C)
6	Planning	1 Bcf at 800 MMcf/d	2 days and 10 hours	1 day and 21 hours	1 day and 9 hours
	Contingent w/ T1A	1.4 Bcf at 800 MMcf/d	3 days and 8 hours	2 days and 13 hours	1 day and 22 hours
7	Planning	2 Bcf at 800 MMcf/d	4 days and 13 hours	3 days and 12 hours	2 days and 17 hours
	Contingent w/ T1A	2.4 Bcf at 800 MMcf/d	5 days and 11 hours	4 days and 6 hours	3 days and 10 hours
8	Planning	1.4 Bcf at 800 MMcf/d	3 days and 8 hours	2 days and 13 hours	1 day and 22 hours
	Contingent	2 Bcf at 800 MMcf/d	4 days and 13 hours	3 days and 12 hours	2 days and 17 hours
	Contingent w/ T1A	2.4 Bcf at 800 MMcf/d	5 days and 11 hours	4 days and 6 hours	3 days and 10 hours
9	Planning	2 Bcf at 800 MMcf/d	4 days and 13 hours	3 days and 12 hours	2 days and 17 hours
	Contingent	3 Bcf at 800 MMcf/d	6 days and 17 hours	5 days and 5 hours	4 days and 7 hours
	Contingent w/ T1A	3.4 Bcf at 800 MMcf/d	7 days and 15 hours	5 days and 23 hours	4 days and 21 hours

Discussion of Contingent Scenarios

The "Contingent" scenarios assume that the full LNG volume intended for gas supply purposes happens to be available on the day of a winter T-South no-flow event and is instead used for resiliency.

The Contingent scenarios that reflect the full gas supply reserve in the new TLSE tank being available on the day of the winter T-South no-flow event (i.e., Supplemental Alternative 8 Contingent and Supplemental Alternative 9 Contingent) are not likely to represent real-life conditions. Exponent's analysis implicitly considered that the full gas supply reserve in the new TLSE tank is available for the entirety of the 90-day winter period. This overestimates the available LNG volumes that would be available on the day of a winter T-South no-flow event. FEI relies on the volume allocated to gas supply throughout the winter heating season to respond to peaking events. As a result, after the first use of the gas supply allocation, the available LNG on the day of a winter T-South no-flow event would be below the amounts assumed in the contingent modelling scenarios. As shown in the response to BCUC IR5 127.5, during the winter heating season, the LNG volume allocated to gas supply does not remain full as it is depleted throughout the winter heating season.

Discussion of Contingent w/T1A Scenarios for Supplemental Alternatives 6 and 7

For Supplemental Alternatives 6 and 7, the "Contingent w/ T1A" scenarios assume that 0.4 Bcf from Tilbury 1A is available. Since these Supplemental Alternatives do not have a gas supply reserve in the planning scenario (i.e., the full tank is dedicated to a resiliency reserve), there would be no gas supply reserve to use for resiliency.

For Supplemental Alternatives 6 and 7, the Contingent w/ T1A scenarios are not likely to represent real-life conditions. Similar to above, Exponent's analysis implicitly considered 0.4 Bcf from Tilbury 1A is available for the entirety of the 90-day winter period. However, as described in Section 4.2.2 of Appendix C to the Supplemental Evidence, and due to the nature of LNG sales patterns, while some volume of LNG in the Tilbury 1A tank may be available on a given day, there are likely to be times of unpredictable intervals when the tank is nearly depleted. FEI therefore does not consider the Contingent w/ T1A scenarios for Supplemental Alternatives 6 and 7 to likely represent real-life conditions.

Discussion of Contingent w/T1A Scenarios for Supplemental Alternatives 8 and 9

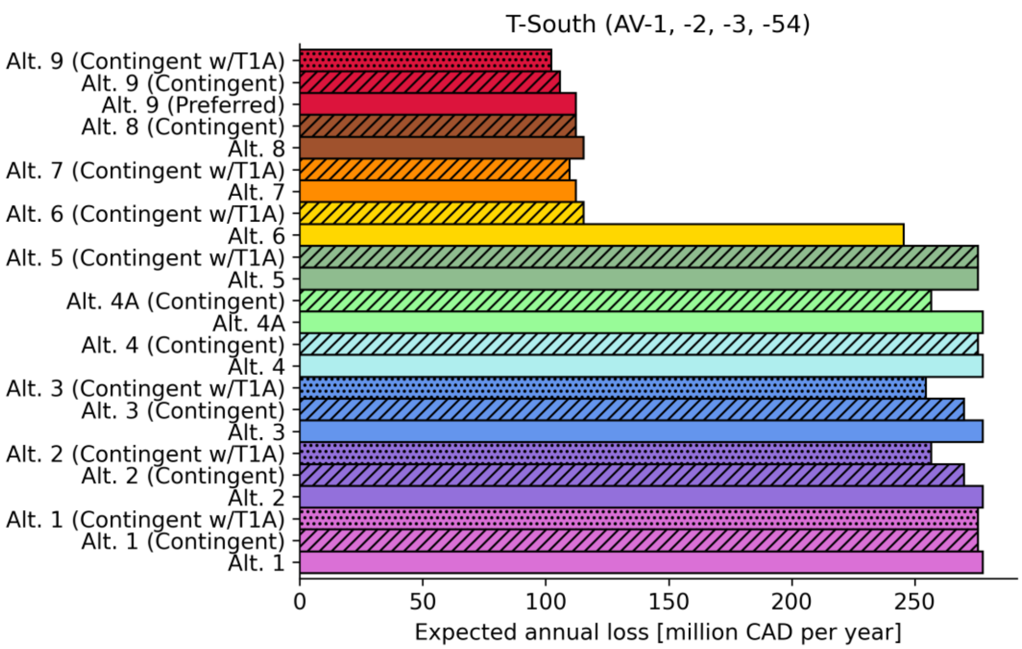
For Supplemental Alternatives 8 and 9, the "Contingent w/ T1A" scenarios assume that both of the following happen to be available on the day of a winter T-South no-flow event: (1) the full gas supply reserve; and (2) 0.4 Bcf from Tilbury 1A.

For Supplemental Alternatives 8 and 9, the Contingent w/ T1A scenarios are also not likely to represent real-life conditions. Not only do these scenarios require the gas supply reserve volume being available, which as described above is not likely to represent real-life conditions, but they also require 0.4 Bcf from Tilbury 1A to be available on the day of a winter T-South no-flow event. As these scenarios rely on two conditions occurring, they are the least likely to represent real-life conditions.

The following response has been provided by Exponent:

The below figures provide expected annual GDP loss for the combined T-South AVs considering the requested additional contingent scenarios for Supplemental Alternatives 6, 7, 8, and 9 at average winter temperatures (+4ºC). Unsurprisingly, for Supplemental Alternatives 7, 8, and 9, the contingent scenarios slightly reduce the expected annual loss because they provide additional load support duration to the Lower Mainland. There is not a large reduction because these scenarios already bridge the regulatory shutdown period without the contingents. Supplemental Alternative 6 contingent with T1A sees a large reduction in expected annual GDP loss compared to Supplemental Alternative 6 because its resilience supply duration is 3 days, 8 hours, exceeding the regulatory shutdown period of 3 days, while the resilience supply duration of Supplemental Alternative 6 was less than 3 days. The utility of Supplemental Alternative 6 is significantly reduced without the 0.4 Bcf provided by T1A.

Exponent understands that the likelihood of having contingent supply available during winter months is low.



127.5 Please provide the minimum, maximum and average Tilbury Base Plant LNG storage tank levels during the winter (Dec 1 – Feb 28) for the previous 4 years (2020-2021, 2021-2022, 2022-2023, 2023-2024). Please provide the minimum, maximum and average Tilbury Base Plant LNG storage tank levels during the requested time period as a percentage of design level. In providing its response, please clarify whether FEI has taken into consideration Tilbury Base Plant LNG storage tank's 16 metre fill limit.

Response:

Although the question references the Tilbury Base Plant only, FEI has not limited the response to the Base Plant alone because FEI's peaking capabilities are currently a function of the Base Plant and elements of the Tilbury 1A tank. The Tilbury Base Plant tank is operating at a reduced operating level of 0.35 Bcf due to seismic reasons, and FEI is relying on 0.25 Bcf of supply from the Tilbury 1A tank as a stop-gap measure (i.e., FEI is relying on LNG storage that is intended to serve RS 46 sales under Special Direction No. 5). Changing market conditions, along with the approval of the Tilbury Jetty and the anticipated delivery of an LNG marine bunker vessel to service the Port of Vancouver, have resulted in an expected increase in RS 46 sales. Therefore, FEI expects that the 0.25 Bcf of LNG from Tilbury 1A that FEI currently relies on for peaking supply will soon be unavailable.

The Tilbury Base Plant liquefaction is no longer functional. The Base Plant and Tilbury 1A tanks are interconnected, thus allowing Tilbury 1A liquefaction to fill the Base Plant tank at a rate of 5 MMcf/day to a 16.391 metre fill level. This interconnecting line also allows FEI to use LNG from either the Base Plant tank or the Tilbury 1A tank in the event that there is an equipment failure or issue with the Base Plant equipment. However, the Base Plant houses the only regasification equipment.

As such, FEI considers that actual gas sendout from the Base Plant and Tilbury 1A, as opposed to the Base Plant tank levels, most accurately represent FEI's reliance on the Tilbury facility for gas supply purposes. FEI has also provided an expanded sendout window (December 1 to April 15), as it is not uncommon for the Tilbury facility to send out in the months of March and April, while the weather is still cold. As shown in Table 1, had volume from the Tilbury 1A tank not been available due to LNG sales, the required sendout in 2022-2023 would have exceeded the available LNG storage in the Base Plant tank (0.464 Bcf sent out vs. 0.35 Bcf available in the Base Plant tank).

Table 1: Tilbury Gas Supply Sendout Volumes (December 1 – April 15)

Period Dec 1 – Apr 15, of years	Sendout Volume (Bcf)
2020 – 2021	0
2021 – 2022	0.218
2022 – 2023	0.464
2023 – 2024	0.174

Note: FEI has excluded volumes sent out for the purposes of testing and maintenance.

In order to be responsive, FEI also provides the table below which shows the minimum, maximum and average Tilbury Base Plant tank levels from December 1 to April 15 for the previous four years. As noted above, the Tilbury Base Plant tank is operating at a reduced operating level of 0.35 Bcf, which is below the tank's original design capacity. Therefore, FEI has assumed a maximum tank volume of 0.35 Bcf (maximum fill level of 16.391 metres). As noted above, these percentages do not accurately reflect FEI's reliance on the Base Plant for gas supply purposes.

Table 2: Tilbury Base Plant Levels for Previous 4 Years – 0.35 Bcf (December 1 – April 15)

	Dec 1 - April 15 (0.35 Bcf = 100%)			
	2020-2021	2021-2022	2022-2023	2023-2024
MIN	63%	48%	28%	43%
MAX	76%	91%	93%	94%
AVG	70%	76%	67%	82%

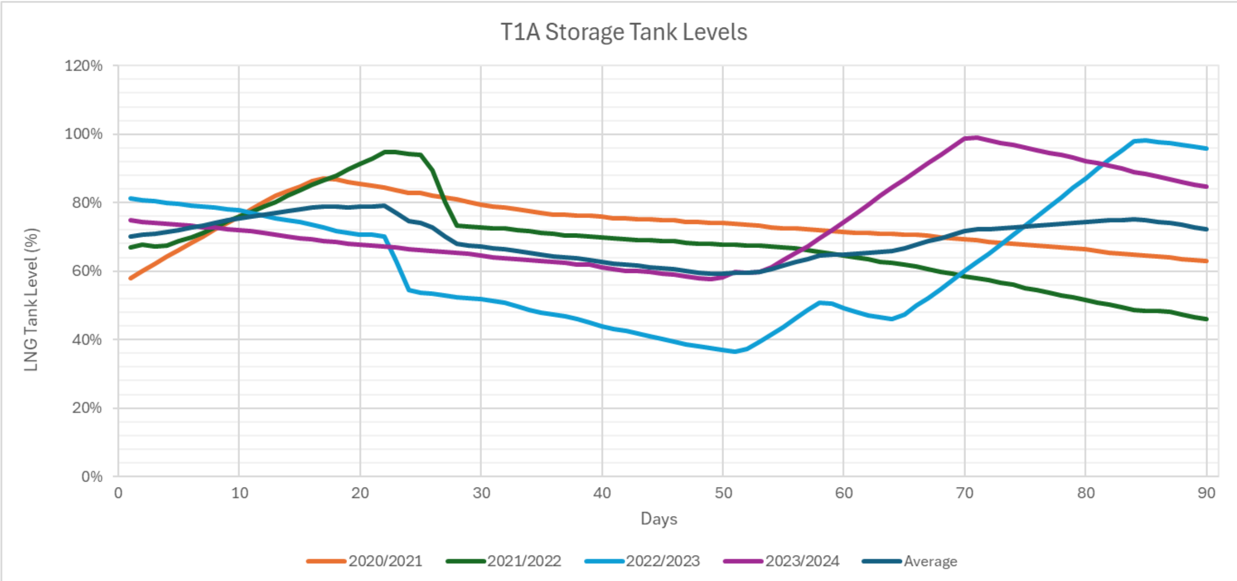
127.6 Please provide the minimum, maximum and average Tilbury T1A LNG storage tank levels during the winter (Dec 1 – Feb 28) for the previous 4 years (2020-2021, 2021-2022, 2022-2023, 2023-2024). Please provide the minimum, maximum and average Tilbury T1A LNG storage tank levels during this period as a percentage of design level.

Response:

Please refer to the following table for the requested minimum, maximum and average Tilbury 1A storage tank levels during the winter for the previous four years as a percentage of the design operating level. The design operating level for the Tilbury 1A tank is 30,214 mm.

	Dec 1 - Feb 28 (29) (100% = 1 Bcf)			
	2020-2021	2021-2022	2022-2023	2023-2024
MIN (mm)	56%	46%	36%	57%
MAX (mm)	87%	94%	98%	99%
AVG (mm)	73%	68%	62%	74%

The figure below shows the Tilbury T1A tank levels during winter (Dec 1 – Feb 28) for the last four years, based on the tank's design level.



On page 124 of Exhibit B-60, in Table 4-8, FEI provides the calculated load support duration in days provided by Supplemental Alternative 8 and 9 at different temperatures.

Temperature [degrees Celsius, °C]	Load support duration [days] Alternative 8	Alternative 9 (Preferred)
4	3.33	4.54
-1.4	2.54	3.5
-10	1.92	2.71

127.7 Please complete the following table.

	Load Support Duration [days]			
	Planning Scenario		Contingent Scenario	
Temperature [°C]	Alt 8	Alt 9	Alt 8	Alt 9
4	3.33	4.54		
-1.4	2.54	3.5		
-10	1.92	2.71		

<u>Response:</u>

Please see the table below. Please refer to the response to BCUC IR5 127.4 for a description of the Supplemental Alternative 8 and 9 contingent scenarios and why contingent scenarios are not likely to represent real-life conditions.

	Load Support Duration [days]					
	Planning Scenario		Contingent Scenario		Contingent w/ T1A Scenario	
Temperature [°C]	Alt 8	Alt 9	Alt 8	Alt 9	Alt 8	Alt 9
+4	3.33	4.54	4.54	6.70	5.46	7.63
-1.4	2.54	3.5	3.5	5.20	4.25	5.96
-10	1.92	2.71	2.71	4.30	3.42	4.88
Resiliency Modelling Parameters	1.4 Bcf at 800 MMcf/d	2.0 Bcf at 800 MMcf/d	2.0 Bcf at 800 MMcf/d	3.0 Bcf at 800 MMcf/d	2.4 Bcf at 800 MMcf/d	3.4 Bcf at 800 MMcf/d

127.8 Please identify at which temperature Supplemental Alternative 8 is unable to provide three days of load support under a contingent scenario.

Response:

Please refer to Table 1 below. FEI has not provided a value for the Supplemental Alternative 8 Contingent w/ T1A scenario since at temperatures colder than -10°C, the regasification capacity becomes a constraint. However, FEI notes that at -10°C, Supplemental Alternative 8 Contingent w/ T1A provides approximately 3.4 days of support.

Table 1: 3-day Load Support Duration Temperature Cutoff

Scenario	Resiliency Modelling Parameters	Temperature at Which Scenario Cannot Provide 3-days of Load Support (°C)
Supplemental Alternative 8 Contingent	2 Bcf at 800 MMcf/d	-7°C
Supplemental Alternative 8 Contingent w/ T1A	2.4 Bcf at 800 MMcf/d	NA

128.0 Reference: EXPANDED ALTERNATIVES ANALYSIS

Exhibit B-60 (Supplemental Evidence), pp. 123 – 124, Table 4-8, p. 171

Resiliency Modeling Parameters

On page 171 of Exhibit B-60, in Table 4-18 and footnotes 213 to 215, FEI describes the temperature conditions at which it used its transient modelling to determine load support duration in the event of a loss of supply from T-South. The following table created by BCUC staff outlines this information.

Temperature Condition (°C)	Description from footnotes
-10.0 (very cold winter day)	Due to the low probability of having multiple -10°C days in a row in the Lower Mainland, the -10°C temperature condition analysis assumes the following: the first day is -10°C, the second and third days are -7°C, the fourth day is -3°C, and all subsequent days are +4°C
-1.4 (warmest winter in last 10 years)	The warmest winter in the last 10 years was found by determining the minimum daily average temperature for each year over a 10-year period from 2013-2022, then selecting the highest value. The analysis was based on data from YVR.
+4.0 (average Lower Mainland winter)	Defined as the average of the daily average temperatures for December, January, and February over a 10-year period from 2013-2022. The average winter day is based on data from YVR.

128.1 Please discuss the rationale for each temperature condition under which FEI compared the load support duration for feasible alternatives.

Response:

In the normal course, FEI designs the system based on the design degree day (DDD) temperature, which is the coldest day that is statistically likely to occur only once in any given 20-year period (the DDD is -12.2°C in the Lower Mainland). This is considered good utility practice because utilities need to be able to serve firm load reliably in temperature conditions that can reasonably be expected to occur in a given region. FEI deliberately selected three warmer (i.e., lower demand) temperature conditions when preparing the 2024 Resiliency Plan to represent more likely T-South winter no-flow risk events. Although it is plausible for the design degree day temperature (-12.2°C) to occur at the same time as a T-South no-flow event, the probability is low (i.e., the failure event would have to occur concurrently with a 1 in 20-year cold weather event).

FEI notes the following regarding the temperature conditions used for Exponent's risk analysis:

1. All risk calculations completed by Exponent to support the 2024 Resiliency Plan were conducted at average winter temperatures, based on the location of the given AV.

2. The risk mitigation results used to compare the Supplemental Alternatives that passed the Step 2 screen were based on the average winter temperature (refer to Section 4.5.1.2 of the Supplemental Evidence).
3. The risk analysis used to further investigate the mitigation capabilities of Supplemental Alternatives 8 and 9 (i.e., the Supplemental Alternatives that had demonstrated a material risk reduction at average winter temperatures) were conducted at the -1.4°C temperature condition.

As described in footnote 215 of the Supplemental Evidence (page 171), FEI selected +4.0°C when assessing T-South risk as it is the average Lower Mainland temperature during the winter (December, January and February).

FEI selected the -10.0°C temperature condition to represent the range of winter temperature conditions that can occur in the Lower Mainland.

Finally, FEI selected the -1.4°C temperature condition (i.e., the warmest winter in the last 10-years) as a sensitivity to demonstrate the results in years where the Lower Mainland experiences a mild winter. The -1.4°C temperature condition was also used in Section 3.5.4.1.5 of the Application to demonstrate that the Base Plant's regasification capacity is insufficient to support the Lower Mainland load on most days of the year.

128.1.1 Please explain whether FEI is aware of any other natural gas utilities taking a similar approach to temperature conditions for resiliency planning.

<u>Response:</u>

The following response has been provided by Exponent:

Exponent is not aware of whether other utilities use a similar approach for resiliency planning, but considers FEI's approach to the 2024 Resiliency Plan, including the temperature conditions assumed, to be reasonable.

FEI also provides the following response:

FEI is not aware of any other natural gas utilities taking a similar approach to temperature conditions for resiliency planning. However, when FEI engaged other utilities regarding their resiliency goals and objectives, one utility indicated that they strive to have more than one source of supply to a community where possible, and that each source on its own should be able to meet the community's load down to a temperature of -20°C. The utility noted that they consider this to be a best practice as opposed to a mandatory requirement, and that typically some level of cost benefit analysis is completed to justify the additional costs to achieve the goal. The utility did not provide the basis for selecting a temperature of -20°C, but FEI notes that this utility operates in a much colder climate than FEI.

For clarity, the temperature conditions used in the 2024 Resiliency Plan and Supplemental Evidence are not those used in the design and sizing of FEI's assets. They are the temperature conditions under which the risk from each AV was calculated, as well as the conditions under which the risk mitigation provided by the Supplemental Alternatives was calculated.

128.2 Please explain whether the -1.4°C temperature condition assumes consecutive days of -1.4°C and if so, how many consecutive days.

Response:

Confirmed. The -1.4°C temperature condition assumes consecutive days of -1.4°C until the tank volume is depleted. Similarly, the +4.0°C temperature condition assumes consecutive days of +4.0°C until the tank volume is depleted.

On page 124 of Exhibit B-60, FEI states:

> The key finding from this analysis was that Supplemental Alternative 9 is superior to Supplemental Alternative 8 throughout a temperature range of approximately -6.8°C to +1.7°C. Above 1.7°C, Supplemental Alternatives 8 and 9 both provide at least a 3-day support duration. This translates to similar amounts of risk mitigation because they can both bridge a regulatory shutdown of an undamaged T-South pipe for up to 3 days. However, between -6.8°C and +1.7°C, only Supplemental Alternative 9 will provide 3 days of load support.

128.3 Please explain why a load support duration of 3 days at a temperature at or above 1.7°C is not considered to be adequate for the purposes of the Project.

128.3.1 Please discuss the likelihood that the Lower Mainland experiences temperatures below 1.7°C for three consecutive days.

128.3.2 Please discuss the likelihood that a T-South no-flow event will occur when the Lower Mainland is experiencing temperatures below 1.7°C for three consecutive days.

Response:

The following response has been provided by Exponent:

Upon review of winter temperature data in the Lower Mainland over a ten-year period, it is found that 22% of days fall below +1.7ºC (see Exponent report, Figure 74, p. 152). Supplemental Alternative 8 provides resilience capacity for 3 days at +1.7ºC, bridging the 3-day regulatory shutdown period. However, at temperatures below +1.7ºC, Supplemental Alternative 8 provides less than 3 days of resilience capacity and thus no longer bridges the regulatory shutdown period. Exponent's report showed that the expected annual customer outage days on T-South are markedly larger when the Tilbury resilience supply is less than 3 days (Exponent Report, Figure U.102, p. U-132, reproduced below for convenience). In fact, there are more than double the expected annual customer outage days with Supplemental Alternative 8 than with Supplemental Alternatives 7 or 9 (Preferred).

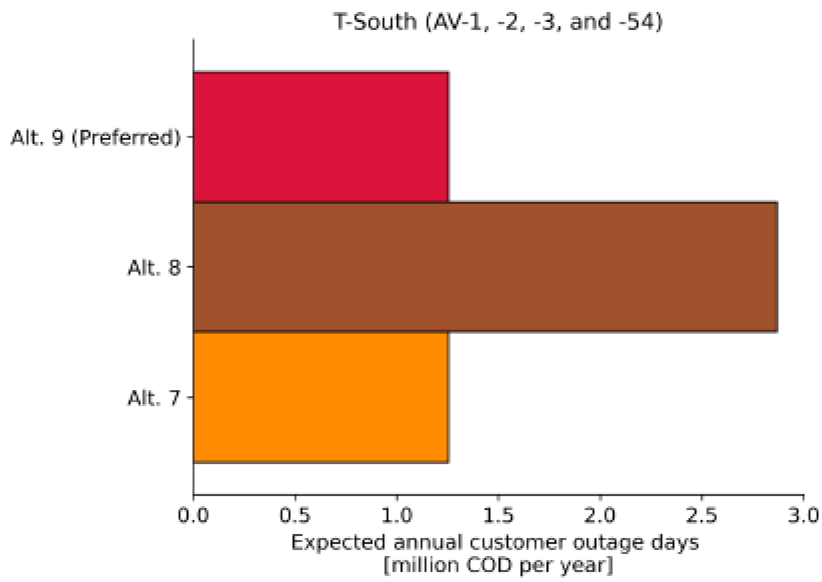


Figure U.102. Expected annual winter-only customer outage-days loss for different Tilbury Alternatives for T-South (AV-1, -2, -3, and -54) at -1.4 °C.

Supplemental Alternative 9 provides at least 3 days of resilience supply for temperatures as low as -6.8ºC, as discussed in Exponent's Report (Section 9). 21% of all winter days are between -6.8ºC and +1.7ºC, and only 1% of days are below -6.8ºC.

Review of historical temperature data indicates that there are around 3 occurrences per year of at least 3 consecutive days of +1.7ºC or below.

It is also noted that if the regulatory shutdown period is longer than 3 days in warmer weather, the resilience supply will also last longer and reduce the likelihood of an outage requiring relighting customers.

129.0 Reference: EXPANDED ALTERNATIVES ANALYSIS

Exhibit B-60 (Supplemental Evidence), pp. 143 – 144, 156

Underutilized Asset Risk

On page 144 of Exhibit B-60, FEI states:

> Starting with the DEP Scenario, which includes FEI's core customers in Rate Schedules (RS) 1 to 5 and 7 in the Lower Mainland, FEI adjusted the customer count for these hypothetical adverse sensitivities as follows:
>
> - […]
> - FEI assumed that new residential and commercial customers would continue to connect to FEI's gas distribution system until the year 2030. After 2030, commencing in 2031, FEI assumed it would stop adding new customers and residential and commercial customers would begin to decrease by either 2 percent or 5 percent per year. The 2 percent decline assumption (mDEP 2%) is a modification from the DEP Scenario, but is in line with the estimated demolition rate provided in FEI's 2022 LTGRP. FEI considers the 5 percent assumption (mDEP 5%) to be an extreme hypothetical sensitivity.
> - FEI did not adjust the number of industrial customers, which account for approximately 0.1 percent of FEI's customers and approximately 30 percent of FEI's load.

129.1 Please provide rationale for the selection of 2 percent and 5 percent declines per year for the hypothetical adverse sensitivities and discuss the likelihood of occurrence for each.

129.1.1 Please explain the relevance of the demolition rate provided in FEI's 2022 LTGRP for the hypothetical adverse sensitivities modeling.

Response:

FEI selected a 2 percent annual load decline assumption (mDEP 2%) that aligns with the annual demolition rates assumption from FEI's 2022 LTGRP for the following reasons:

- First, FEI expects the BC Energy Step Code to reach its maximum efficiency requirements by 2032, which FEI assumed will result in new customer connections foregoing adding gas fired space or water heating appliances because these appliances would only be used a few days per year. Any new residential or commercial load would therefore be negligible.
- Second, like the BC Energy Step Code, the Zero Carbon Step Code is a plan to improve new buildings over time, with the objective to reach zero emissions performance from all new buildings by 2030. It complements the BC Energy Step Code's emphasis on efficiency by focusing on emission reduction. FEI expects the Zero Carbon Step Code to reach its maximum level by 2030. At that time, a newly constructed home will be limited to a certain greenhouse gas intensity (GHGi) per unit of space. This limited GHGi effectively negates

the ability for a homeowner to use conventional gas for space and water heating. Further, there is currently no pathway for RNG within the Zero Carbon Step Code so customers are unable to use RNG to comply with the code.

With the above conditions in place in 2030, and beyond, if an existing customer were to demolish and rebuild their premises, they would be constrained by the above two building and energy codes. It was therefore reasonable for FEI to assume that these customers would not (or could not) connect to FEI's natural gas distribution system, thus resulting in both peak and annual load loss.

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.

The hypothetical mDEP scenarios were designed to provide a hypothetical adverse view of customer and load loss between 2030 and 2050 (i.e., no new customer connections after 2030), with the starting point of 2 percent load decline grounded in the assumptions of FEI's most recent LTGRP. While FEI cannot quantify the likelihood of these scenarios occurring as modelled, FEI notes the following considerations which are not reflected in its modelling. In particular, some jurisdictions outside of British Columbia are slowing their decarbonization strategy by eliminating natural gas bans as a means to preserve energy affordability (mitigating rate increases). While BC has not changed its policies in this way, affordability is a greater topic of conversation and could influence how quickly BC adopts GHG reduction strategies.

129.2 Please provide rationale for not adjusting the number of industrial customers for the hypothetical adverse sensitivities modelling and discuss the likelihood that this will be reflective of reality.

129.2.1 Please explain whether FEI considered changing energy usage patterns of industrial customers in its hypothetical adverse sensitivities modelling and provide rationale for the approach. If not considered, please explain why not.

Response:

While FEI recognizes the potential for industrial load to change, the policy direction and methods for decarbonization are not as clear with industrials as compared to buildings. Additionally, while individual industrial customers may decarbonize, provincial economic growth could cause net overall increases in energy (natural gas) use. FEI expects that its industrial load will continue to be influenced by many factors, including customer behavior, economic activity, DSM, government policies, and new technology, among other things; therefore, FEI continues to consider its assumptions to be appropriate.

On pages 143 and 144 of Exhibit B-60, FEI states:

> FEI considered two illustrative “book-end” approaches to reallocating the TLSE Project’s capabilities in the face of hypothetical declining load – resiliency maximization and resiliency retention. […]
>
> - For the **resiliency maximizing strategy**, FEI determined the load support duration under average winter conditions using the 2050 Year mDEP (2% and 5%) load scenario and maintaining the current resiliency and gas supply allocations defined for each alternative; and
> - For the **resiliency retention strategy**, FEI determined the resiliency reserve volume required such that, using the 2050 Year mDEP (2% and 5%) load scenario, the alternative would provide the same support duration as under current year load. As this would result in a lower resiliency reserve volume, and thus a larger gas supply reserve volume, this approach assessed if a Supplemental Alternative would be underutilized for gas supply. [Emphasis included]

129.3 Please explain how, and at what frequency, FEI intends to review and revise the resiliency reserve and gas supply allocations under changing load conditions over the lifespan of the Project.

<u>Response:</u>

FEI intends to consider the TLSE Project’s resiliency reserve and gas supply allocations as part of preparing its ACP filings for acceptance by the BCUC pursuant to section 14 of the BCUC Rules for Natural Gas Energy Supply Contracts.

FEI does not anticipate proposing regular adjustments to the allocation. The allocations would generally be considered in response to material changes in circumstances, including changing load conditions over the lifespan of the TLSE Project. For example, under a hypothetical scenario where FEI’s load has reduced dramatically, a smaller resiliency reserve may adequately mitigate the risk posed by a winter T-South no-flow event and FEI would then consider reallocating some of the resiliency reserve to gas supply. FEI’s assessment would be driven by what is in the best interest of FEI’s customers.

129.4 For each viable alternative, please discuss FEI's ability to reallocate storage volume for the resiliency reserve and gas supply over the lifespan of the TLSE Project.

129.4.1 Please explain whether FEI plans to seek BCUC approval for any future reallocation of storage volumes.

Response:

FEI considers Supplemental Alternatives 4, 4A, 8, and 9 to be the only viable Supplemental Alternatives (i.e., the Supplemental Alternatives that remain after Step 1 and Step 2 of the expanded alternatives analysis).

Conceptually, FEI's ability to reallocate storage volume between a resiliency reserve and gas supply is determined by two constraints: (1) the reallocation must not result in the operation that the volume was reallocated from no longer being able to perform its required function (e.g., gas supply volume should not be reallocated to a resiliency reserve if it will result in a shortfall in FEI's ACP); and (2) whether the facility specifications can utilize the reallocated volume for the desired purpose (e.g., if volume is to be reallocated from gas supply to resiliency, the facility must have an adequate sendout capacity to make use of the increased resiliency reserve). Given these two constraints, a larger facility would increase the ability to reallocate volume between the resiliency reserve and gas supply.

FEI discusses each of the four viable Supplemental Alternatives in detail below.

Supplemental Alternative 4:

Supplemental Alternative 4, which consists of a new 0.6 Bcf tank fully allocated to gas supply and 150 MMcf/d of regasification, has very little (if any) ability to reallocate from the gas supply portion of the tank to a resiliency reserve. Under current load conditions, doing so would result in FEI not being able to meet its gas supply needs in the ACP and therefore violate constraint (1) above. Even under the mDEP (2% and 5%) hypothetical adverse load loss sensitivities, FEI's peaking supply requirements exceed what Supplemental Alternative 4 can provide. Thus, under the mDEP (2% and 5%) hypothetical adverse load loss sensitivities, it would only be in some future year that a component of the gas supply volume would become eligible for reallocation to a resiliency reserve.

The facility's sendout capacity of 150 MMcf/d is also insufficient for resiliency purposes. Even under the most pessimistic future load sensitivity considered by FEI in the Supplemental Evidence (mDEP (5%)), in 2050 the Lower Mainland load at +4°C is estimated to be approximately 321 MMcf/d, which is more than double the Supplemental Alternative 4 sendout capacity of 150 MMcf/d. As a result, what little volume could potentially be reallocated in a future year from gas supply to a resiliency reserve would not provide material risk mitigation. This would contravene constraint (2) above.

Supplemental Alternative 4A:

Supplemental Alternative 4A, which consists of a new 1.0 Bcf tank fully allocated to gas supply and 400 MMcf/d of regasification, has a very limited ability to reallocate from gas supply to a resiliency reserve. Under current load conditions, instead of avoiding the need to continue augmenting the peaking supply with regional market resources (which, as explained in Section 3.3.4.2 of the Supplemental Evidence, is a temporary and suboptimal measure), FEI could instead reallocate a portion of the gas supply volume to a resiliency reserve. In this scenario, FEI would have to contract additional peaking supply from the spot market such as Sumas or Kingsgate and risk paying high commodity prices on cold winter days. In this scenario, it would be possible for FEI to contract an additional 50 MMcf/d of market area resources to meet its gas supply requirements (albeit in a less optimal way and with potentially higher costs); therefore, constraint (1) above is not contravened.

However, as the facility only has 400 MMcf/d of sendout capacity, which as discussed in Section 5.2.2.2 of Appendix C to the Supplemental Evidence is insufficient for the current system demand, this reallocation would violate constraint (2) above. FEI considers Supplemental Alternative 4A to have limited ability for reallocation (instead of no ability). This is because under the extreme hypothetical mDEP (5%) load sensitivity, the load would eventually decline to the point that the 400 MMcf/d sendout capacity would be sufficient for the load (e.g., the 2050 +4°C load of 321 MMcf/d).

Supplemental Alternative 8:

Supplemental Alternative 8, which consists of a new 2.0 Bcf tank and 800 MMcf/d of regasification (1.4 Bcf resiliency reserve and 0.6 Bcf for gas supply), has the ability to reallocate the storage volume between the resiliency reserve and gas supply, but only in the future under the hypothetical adverse load loss mDEP sensitivities.

Under the current load, Supplemental Alternative 8 cannot reallocate volume from gas supply to the resiliency reserve or vice versa. First, as with Supplemental Alternative 4, reallocating volume from gas supply to the resiliency reserve would result in FEI being unable to meet its gas supply needs. Second, Supplemental Alternative 8 cannot reallocate volume from the resiliency reserve to gas supply as this would result in insufficient risk mitigation. For example, if 0.4 Bcf were reallocated from the resiliency reserve to gas supply, then the resiliency modelling parameters for Supplemental Alternative 8 would become 1.0 Bcf and 800 MMcf/d (i.e., the same as Supplemental Alternative 6). As discussed in Section 2.5.1 of Appendix C to the Supplemental Evidence, the risk mitigation provided by a 1.0 Bcf and 800 MMcf/d facility (i.e., Supplemental Alternative 6) is not material. For these two reasons, constraint (1) above would be contravened, therefore precluding relocation of any volume for Supplemental Alternative 8.

Under the future hypothetical adverse load loss sensitivities, Supplemental Alternative 8 would be able to reallocate resiliency reserve volumes to gas supply. This is because, due to the hypothetical reduction in load, FEI could maintain the same level of risk mitigation with a smaller resiliency reserve, and thus reallocate the difference in volume to gas supply. Please refer to Section 4.5.5.4 of the Supplemental Evidence for further discussion.

Supplemental Alternative 9:

Supplemental Alternative 9, which consists of a new 3.0 Bcf tank and 800 MMcf/d of regasification (2.0 Bcf resiliency reserve and 1.0 Bcf for gas supply), has the greatest ability to reallocate the storage volume between the resiliency reserve and gas supply. In the current year, similar to Supplemental Alternative 4A, FEI could continue to rely on market area resources and thus reallocate 0.4 Bcf from gas supply to resiliency without contravening constraint (1) above; however, this would be suboptimal from a gas supply portfolio perspective. Additionally, under current load conditions, FEI could reallocate 0.6 Bcf of resiliency reserve to gas supply (resulting in a resiliency reserve of 1.4 Bcf) and still maintain material risk reduction for a T-South no-flow event that occurs under average winter conditions. However, the risk mitigation capabilities under colder temperatures would be negatively impacted, and having 1.0 Bcf allocated to gas supply is already sufficient to optimize the gas supply portfolio. The flexibility described in the future under the adverse load sensitivities for Supplemental Alternative 8 also applies to Supplemental Alternative 9.

Please refer to the response to BCUC IR5 129.3 for a discussion of how FEI proposes to review and seek acceptance from the BCUC for the resiliency reserve and gas supply allocations.

On page 156 of Exhibit B-60, FEI states:

> Mr. Mason's opinion is that LNG storage in the Lower Mainland will continue to have financial value regardless of how FEI's own customer demand evolves:
>
> > Assuming that the TLSE Project is constructed, and FEI were to have space capacity that is not required to meet customer demand or resiliency, FEI would be able to generate excess revenues to offset the cost of service of the facility by selling its excess supply into the market. Based on my assessment of the available supply and demand in the Huntingdon/Sumas natural gas market, and assuming current market conditions persist, I expect the daily market can reasonable absorb 300-400 MMcf/d of natural gas across multiple days (e.g., 10 days) during winter without influencing daily prices in a manner that could limit monetization values.

129.5 Please discuss the current market conditions mentioned in the preamble and discuss the likelihood that they persist over the lifespan of the Project.

Response:

The following response has been provided by Ray Mason:

The reference to current market conditions in the preamble was referring to the Huntington/Sumas market being constrained. This market dynamic is likely to continue in the Pacific Northwest for the foreseeable future because of the need for more electricity, in particular due to: (1) increasing development and resulting variability of renewables; (2) constraints in hydro-electric resource capacity; and (3) increased calls for power from consumers including, in particular requests from industrial customers (which I address in my report and below). As such, the electric system will require the versatility of gas-fired resources for the foreseeable future; namely, their ability to operate as an on-demand back-stop resource. These market dynamics will require immediate supply responses, like those provided by an LNG peaking resources such as the TLSE Project.

Assuming that the TLSE Project is constructed, and FEI were to have spare capacity that is not required to meet customer demand or resiliency, FEI would be able to generate revenues to offset the cost of service of the facility by selling its excess supply into the market. This assessment remains consistent to the market conditions discussed in my report at pages 38-45, and 51. These market conditions are also further supported by recent announcements/statements made by energy market participants in the Pacific Northwest, which I discuss below.

For ease of reference, I have organized this discussion in alignment with the primary areas of focus in the above noted pages of my report.

1. Impact of Seasonal Weather on Demand

On pages 38-41 of my report, I discuss the coexistence of the electric and natural gas infrastructure and the interconnectivity of regions who are managing the evolution of demand. In particular, the coincidental peak demand from electric and natural gas systems in the Pacific Northwest, and the current deliverability constraints due to the lack of dependable supply resources, is forcing the industry to build infrastructure. This is further supported by the following recent announcements/statements made by industry players after finalizing my report:

1. BC Hydro 2024 Call for Power[26] indicating a lack of supply resources in the region.
2. FortisBC Inc.'s Requests for Expressions of Interest ("RFEOI") for new power, in late 2024,[27] indicating a lack of supply resources in the region.
3. Western Electricity Coordinating Council stating in their 2024 Western Assessment of Resource Adequacy Report[28] that variability will continue to increase, exacerbating the risk of having inadequate dispatchable energy.

[26] https://www.bchydro.com/2024CallforPower.

[27] https://www.fortisbc.com/about-us/projects-planning/energy-projects/current-electricity-projects/request-for-expressions-of-interest-for-new-power.

[28] https://feature.wecc.org/wara/.

4. Northwest Power and Conservation Council, August 2024 Report[29] stating significant increases in variable electricity resources, changes in hydroelectric operating constraints, and other added complexities, the region can no longer assume that it has sufficient capacity to meet all demand.
5. Northwest Gas Association, 2024 Pacific Northwest Natural Gas Market Outlook[30] stated the average utilization of the region's interstate pipeline system exceeded 95 percent over the last five years, making storage a critical regional asset.

Gas-fired generation is currently the most economic resource to manage demand growth, while providing the "on demand" backstop for renewable resources. This is supported by the ongoing and growing gas-fired generated electricity accessed by utilities in the Pacific Northwest. Therefore, gas-fired generation will remain a necessary resource providing on-demand backup to renewable variability. Similarly, the TLSE Project, with its on-demand asset characteristics, would remain a valuable economic tool in the Pacific Northwest for managing planned and unplanned outages, and meeting the coincidental peak-day demand generated by electrical and natural gas delivery systems.

2. Social & Economic Pressure to Reduce GHG Emissions

On pages 41-43 of my report, I reviewed the social and economic pressure to reduce GHG emissions, population growth, and the advancement of new technologies. These market dynamics generate a fundamental challenge for the energy industry in the Pacific Northwest.

In particular, as consumers and governments become more aware of the costs associated with energy infrastructure expansion, they will become more engaged in the debate of balancing affordability with environmental stewardship (i.e., GHG reductions). This balancing is made more difficult by shifting, or fundamentally differing, policy priorities across the region. For example, jurisdictions without natural gas generation that extend electricity transmission lines for import/export will increasingly be drawing on more carbon intensive generation sources, while simultaneously claiming zero emission generation. The incremental costs associated with such transmission expansions, may become more undesirable from an affordability perspective, where it is more economical to instead rely on such generation in the jurisdiction itself.

Population growth is a leading driver of the incremental demand for housing, and the economic health of a region. British Columbia, Oregon, and Washington continue to witness significant growth in population and economic prosperity which translates to energy demand for natural gas and electricity. Both existing and new inventory of residential and commercial buildings, with continued Demand Side Management initiatives, will still require energy systems to manage peak-day seasonal conditions. The irregularity in weather and supply resources will require on-demand assets, that can be dispatched quickly, which I expect will continue to be needed over the lifespan of the TLSE Project.

[29] https://www.nwcouncil.org/fs/18853/2024-4.pdf.
[30] https://www.nwga.org/post/nwga-releases-2024-pacific-northwest-natural-gas-market-outlook.

Finally, the new technologies discussed in my report (i.e., Cap & Trade Activities, Carbon Capture Utilization and Storage, and Low Carbon Fuels) remain viable options in the future. However, the rate at which energy demand is increasing, presents a challenge given the time it takes to advance new technologies. In particular, scaling up alternative fuels to a meaningful level is subject to a number of uncertainties that, in turn, make it difficult to forecast how much these resources will contribute to the market's future resource mix. This is creating uncertainty and variability in the Pacific Northwest. For example, economic volatility and changes in government, as has occurred in the United States and Canada, can lead to dramatic shifts in environment and energy policy. This includes announcements from: (1) The United States Environmental Protection Agency regarding deregulation;[31] and (2) Canada's Federal Government's (and British Columbia) commitment to discontinue the consumer carbon pricing policy. Furthermore, the extent of cap and trade activities and carbon market pricing developments, remains uncertain as industry struggles to maintain energy affordability while meeting, in some case, aggressive emissions reduction targets.

Regardless of the pressures discussed above, in my opinion the reliability of natural gas-fired generation as a baseload or peaking resource will remain a vital tool in a portfolio of resources for the foreseeable future.

3. Large Industrial

On page 45 of my report, I explain that large industrial demand is growing the Pacific Northwest. The pressures associated with such demand have intensified due to increased competition to secure specific projects within certain jurisdictions. These projects, which include data centers, manufacturing facilities, and cryptocurrency mining operations, can be economically beneficial (and are therefore desirable) but have large load requirements. These operations can be constructed quickly, assuming energy supply is available to meet a variety of demands these projects can have (i.e., firm baseload and large ramping capability). To be successful in securing these large industrial projects, industry and government must develop additional capacity into a system that is there to support all consumer demands, especially during peak-day seasonal demand driven by weather. For example, in early 2025, the Governor of Washington States signed an Executive Order directing the Washington State Department of Revenue to establish and lead a data center workgroup to ensure Washington remains a leader in technology and sustainability while balancing industry growth, tax revenue needs, energy constraints and sustainability.[32] Therefore, I expect the use of gas-fired generation, servicing these new industrial loads, will persist throughout the region given its versatility in the face of the variety of demands noted above.

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31 https://www.epa.gov/newsreleases/epa-launches-biggest-deregulatory-action-us-history.

32 https://governor.wa.gov/news/2025/governor-bob-ferguson-signs-executive-order-establishing-data-center-workgroup.

129.5.1 Please discuss any factors, and their likelihood of occurrence, (i.e., new regional capacity, electrification, etc.) that could cause market conditions to be less favourable to selling excess supply over the lifespan of the Project.

Response:

The following response has been provided by Ray Mason:

The factors that could, all else being equal, cause conditions to be less favorable from a pricing perspective to selling excess supply over the lifespan of the Project would be the development of incremental assets that are interconnected to the Pacific Northwest region. For example, the expansion of pipelines and/or southern off-system storage developments could affect market dynamics such that market conditions become less favourable. Conversely, the development and high utilization of incremental gas-fired generation and industrial expansion could affect market dynamics such that market conditions become more favorable. The size of the development (whether capacity of demand) will impact the level and duration of any market pricing influence, directly impacting monetization values over the lifespan of the TLSE Project.

Ultimately, while these developments could create uncertainty in the monetization values generated by selling excess supply over the lifespan of the TLSE Project, for the reasons identified in my response to BCUC IR5 129.5 above, I expect the usefulness and versatility of the asset to persist for the foreseeable future.

129.5.2 Should market conditions be less favourable to selling excess supply, please discuss the risk that the preferred alternative would be considered to be underutilized.

129.5.3 Should market conditions be less favourable to selling excess supply, please explain how FEI would intend to utilize excess stored LNG volumes and discuss the expected value of the stored LNG volumes.

Response:

Due to the unique versatility of on-system storage, there is negligible risk that the Preferred Alternative would be underutilized if market conditions were less favourable to selling excess supply. As discussed in Section 4.5.5.4.1 of the Application, FEI would use on-system LNG as a substitute for other supply resources when optimizing its resource portfolio, thus maximizing the continued utilization of the TLSE Project and leveraging the versality of its on-system storage assets for the benefit of FEI’s customers.

In particular, if market conditions were less favourable such that selling excess supply was no longer beneficial to FEI’s customers, FEI would adjust its ACP portfolio to increase its reliance on Tilbury peaking supply while de-contracting other gas supply resources as contracts expire. This would include utilizing LNG volumes reserved for resiliency, should FEI's resiliency requirements change over the lifetime of the TLSE Project. FEI adjusts its ACP annually, which allows it to adjust or shed resources that are no longer needed due to changes in demand or load duration curves. For example, because FEI optimizes the utilization of ACP resources for all gas customers in the Lower Mainland, Interior and Vancouver Island regions, having extra peaking supply available in the Lower Mainland could potentially displace a portion of market area supply contracted for the Interior on cold winter days. In essence, the only way that this asset would be stranded is if there is both: (a) less than 3 Bcf of demand on FEI's entire system; and (b) no market to sell in to. This is extremely unlikely to occur over the life of the TLSE Project.

130.0 Reference: EXPANDED ALTERNATIVES ANALYSIS

Exhibit B-60 (Supplemental Evidence), p. 175

Resiliency when No-Flow Event is Too Long to Bridge

On page 175 of Exhibit B-60, FEI states:

> In a worst-case scenario where a T-South no-flow event is longer than the Preferred Alternative's load support duration, the Preferred Alternative will still: (1) avoid the uncontrolled depressurization and the attendant safety risks expected today; and (2) provide valuable time for customers, governments and social / health services to prepare.

130.1 Please provide the length of time FEI would need to rely on supply from the resiliency reserve at Tilbury to avoid uncontrolled depressurization in the event of a T-South no-flow event. Please provide the volume of LNG required to avoid uncontrolled depressurization in these circumstances and list all assumptions.

<u>Response:</u>

As discussed in Section 3.4.1.2.2 of the 2024 Resiliency Plan, FEI made the following assumptions with respect to the required support duration to implement a controlled shutdown:

a. 72 hours is enough time to implement a controlled shutdown. Therefore, if the Tilbury facility provides at least 72 hours of support, then the AV switches from an uncontrolled shutdown to a controlled shutdown.

b. Between 24 hours and less than 72 hours there is uncertainty as to whether implementing a controlled shutdown is possible. Therefore, if the Tilbury facility provides more than 24 hours but less than 72 hours of support, then the AV is analysed under both cases.

c. Having less than 24 hours is not enough time to implement a controlled shutdown. Therefore, if the Tilbury facility provides less than 24 hours of support, then the AV remains an uncontrolled shutdown.

In summary, the assumption states that the exact time required by FEI to execute a controlled shutdown in the Lower Mainland is unknown but falls between 1 and 3 days, with longer support durations resulting in a higher likelihood that the controlled shutdown will be successful. The uncertainty in the duration to complete a controlled shutdown is due in part to the fact that the timing of FEI's decision to *initiate* the shutdown will depend on the quality of the information FEI has about the no-flow event cause and expected duration. FEI needs good information to ensure it is not unnecessarily initiating a shutdown.

The table below presents the LNG volume required at +4°C, -1.4°C, and -10.0°C to provide a 1-day and 3-day support duration, and thus provide the possibility of achieving a controlled shutdown.

Table 1: LNG Volume Requirements at Modelled Temperature Conditions[33]

Lower Mainland Support Duration	LNG Volume Required at -10.0°C (Bcf)	LNG Volume Required at -1.4°C (Bcf)	LNG Volume Required at +4°C (Bcf)
1 day	0.78	0.49	0.34
3 days	2.14	1.68	1.27

The LNG volumes presented in the table are based on the "Support Duration vs Tanks Size" graph which itself consists of data points obtained through FEI's transient modelling tool. As the Support Duration versus Tank Size relationship is linear, FEI considers that the extrapolated/interpolated scenarios accurately reflect the LNG volume requirements.

130.2 Please provide a comparative analysis of each viable alternative's ability, in the event of a T-South no-flow event, to: (i) avoid uncontrolled depressurization and attendant safety risks; (ii) provide time for customers, governments and social / health services to prepare; and (iii) provide any other resiliency benefits.

Response:

FEI considers Supplemental Alternatives 4, 4A, 8, and 9 to be the viable Supplemental Alternatives (i.e., the Supplemental Alternatives that remain after Step 1 and Step 2 of the expanded alternatives analysis). FEI discusses each of the four viable Supplemental Alternatives in detail below.

Supplemental Alternative 4:

1. **Avoid uncontrolled depressurization and attendant safety risks:** Supplemental Alternative 4 would not have the ability to avoid an uncontrolled depressurization and attendant safety risks. Even if assuming the full gas supply volume were available to be used for resiliency (i.e., 0.6 Bcf and 150 MMcf/d), at +4.0°C the Lower Mainland support duration is only 7 hours, which is less than FEI's assumed minimum time required to potentially execute a controlled shutdown (1 day). Please refer to Section 3.4.1.2.2 of the 2024 Resiliency Plan and the response to BCUC IR5 130.1 for more detail regarding FEI's assumptions regarding controlled and uncontrolled shutdowns.
2. **Provide time for customers, governments and social / health services to prepare:** As discussed above, Supplemental Alternative 4 (Contingent) would only provide a 7-hour support duration under average winter conditions. This would not be enough time for customers, governments and social / health services to prepare for the impending outage.

[33] All scenarios assume 800 MMcf/d of regassification is available, meaning that it is not a constraint on the duration in these scenarios.

With no resiliency reserve, Supplemental Alternative 4 (Planning) would provide no time for these groups to prepare.

3. **Provide any other resiliency benefits:** From a planning perspective, Supplemental Alternative 4 would not be able to provide other resiliency benefits (i.e., provide mitigation to other, non-T-South AVs) because Supplemental Alternative 4 has no resiliency reserve. Under average winter conditions, Supplemental Alternative 4 (Contingent) would be able to provide 3 days of load support or greater to 11 of the non-T-South AVs.

Supplemental Alternative 4A:

1. **Avoid uncontrolled depressurization and attendant safety risks:** From a planning perspective, Supplemental Alternative 4A would not have the ability to avoid an uncontrolled depressurization and attendant safety risks. This is because Supplemental Alternative 4A does not have a resiliency reserve. Assuming the full gas supply volume was available to be used for resiliency (i.e., 1.0 Bcf and 400 MMcf/d), at +4.0°C the Lower Mainland support duration is 1 day and 19 hours, which is within the range where there is uncertainty as to whether implementing a controlled shutdown is possible (i.e., between 1 and 3 days). Therefore, Supplemental Alternative 4A (Contingent) may or may not be able to prevent an uncontrolled depressurization. At -1.4°C and -10°C, the support duration provided by Supplemental Alternative 4A (Contingent) would be too short to prevent an uncontrolled depressurization.

2. **Provide time for customers, governments and social / health services to prepare:** As discussed above, Supplemental Alternative 4A (Contingent) would provide a 1 day and 19-hour support duration under average winter conditions. This would likely be enough time for customers, governments and social / health services to begin preparing for the impending outage, but would likely not be enough time to fully execute all preparations. With no resiliency reserve, Supplemental Alternative 4A (Planning) would provide no time for these groups to prepare.

3. **Provide any other resiliency benefits:** From a planning perspective, Supplemental Alternative 4A would have no ability to provide other resiliency benefits (i.e., provide mitigation to other, non-T-South AVs). This is because Supplemental Alternative 4A has no resiliency reserve. Under average winter conditions, Supplemental Alternative 4A (Contingent) would be able to provide 3 days of load support or greater to 11 of the non-T-South AVs.

Supplemental Alternative 8:

1. **Avoid uncontrolled depressurization and attendant safety risks:** Under average winter conditions (+4.0°C), Supplemental Alternative 8 would provide a Lower Mainland support duration of 3 days and 8 hours, which is enough time to execute a controlled shutdown. The support duration at the -1.4°C and -10°C temperature conditions, 2 days and 13 hours and 1 day and 22 hours, respectively, are within the range where there is uncertainty as to whether a controlled shutdown would be possible; therefore, the shutdown may be controlled or uncontrolled.

2. **Provide time for customers, governments and social / health services to prepare:** The support duration provided by Supplemental Alternative 8 at +4.0°C (3 days and 8 hours) would likely provide sufficient time to execute most of the preparations described in Section 4.7.3.2 of the Supplemental Evidence (e.g., setting up warming shelters). At the shorter support durations provided under the colder temperature conditions of -1.4°C and -10°C, the preparation activities may not be fully executed prior to the outage.

3. **Provide any other resiliency benefits:** Under average winter conditions, Supplemental Alternative 8 would be able to provide 3 days of load support or greater to 13 of the non-T-South AVs.

Supplemental Alternative 9:

1. **Avoid uncontrolled depressurization and attendant safety risks:** Supplemental Alternative 9 will avoid an uncontrolled depressurization and attendant safety risks under most temperature conditions. For example, at -10°C, Supplemental Alternative 9 will provide a support duration of 2 days and 17 hours, which is within the range where there is uncertainty regarding whether a controlled shutdown is possible. However, given that the support duration is almost 3 days (the required time to have certainty that a controlled shutdown can be executed), it is more likely that the shutdown would be controlled than uncontrolled. At the +4.0°C and -1.4°C temperature conditions, Supplemental Alternative 9 will avoid an uncontrolled depressurization and attendant safety risks.

2. **Provide time for customers, governments and social / health services to prepare:** The support duration provided by Supplemental Alternative 9 at +4.0°C (4 days and 13 hours) will likely be sufficient time to execute most of the preparations described in Section 4.7.3.2 of the Supplemental Evidence (e.g., setting up warming shelters). At the shorter support durations provided under the colder temperature conditions of -10°C, the preparation activities may not be fully executed prior to the outage. However, since Supplemental Alternative 9 provides longer support duration than Supplemental Alternative 8, it has a greater ability to provide time to prepare.

3. **Provide any other resiliency benefits:** Under average winter conditions, Supplemental Alternative 9 would be able to provide 3 days of load support or greater to 13 of the non-T-South AVs. Please refer to Section 4.7 of the Supplemental Evidence for a detailed discussion of the resiliency benefits of Supplemental Alternative 9.

130.3 For each viable alternative, please discuss the expected frequency of T-South no-flow events over the expected lifespan of the Project that would not be bridged by the stored LNG volume.

Response:

The following response has been provided by Exponent:

Exponent understands the viable alternatives to include Supplemental Alternatives 4, 4A, 8, and 9. The average number of winter no-flow events on T-South over 20-, 23-, 60- and 67-year horizons is calculated and reported in the table below. These are calculated using the average of the upper bound and lower bound failure rates for T-South.

Mitigation Alternative	Residual Winter No-Flow Events in 23 years	Residual Winter No-Flow Events in 20 years	Residual Winter No-Flow Events in 67 Years	Residual Winter No-Flow Events in 60 years
Alternative 4 (Planning)	2.3	2.0	6.8	6.1
Alternative 4 (Contingent)	2.3	2.0	6.8	6.1
Alternative 4A (Planning)	2.3	2.0	6.8	6.1
Alternative 4A (Contingent)	2.2	1.9	6.3	5.7
Alternative 8	1.0	0.8	2.8	2.5
Alternative 9 (Preferred)	0.9	0.8	2.8	2.5

For Supplemental Alternatives 7, 8, and 9, there is a residual risk of approximately 40% of the unmitigated risk. While this represents a still-significant risk, 60% of the risk has been mitigated, which is substantial and consistent with, for example, the widespread implementation of covered conductors to reduce wildfire risk in Southern California.

131.0 Reference: EXPANDED ALTERNATIVES ANALYSIS

Exhibit B-60 (Supplemental Evidence), pp. 130, 132 – 135, Table 4-11, p. 139, p. 203

Avoided Gas Cost

On page 133 of Exhibit B-60, FEI states:

> Currently, the only planned regional infrastructure upgrade that FEI is aware of is the T-South Sunrise Expansion which will only offset the capacity of Woodfibre LNG and does not provide any added capacity to the region. FEI is also not aware of any other potential for regional market area storage upgrades, other than the North Mist Expansion Project which is anticipated to complete in 2029. Any subsequent expansion at Mist, if possible, would take multiple years to develop post 2029. Therefore, FEI considers 2035 is a reasonable assumption for regional infrastructure upgrades.

On page 135 of Exhibit B-60, FEI states:

> for the purposes of the financial analysis, FEI would begin to incur higher tolls in 2035 (whether it is from new regional storage or pipeline expansion) under the baseline scenario (i.e., Supplemental Alternative 1) as well as any other Supplemental Alternatives (i.e., 2, 3, 5, 6, and 7) that do not have on-system LNG storage for peaking gas supply. In contrast, for those Supplemental Alternatives that have on-system LNG storage either fully or partially allocated for gas supply (i.e., 4, 4A, 8, and 9), the higher tolls in 2035 would effectively be gas supply costs savings or avoided costs reflected in the calculation of the levelized total rate impact and to the benefit of FEI's customers.

131.1 Please discuss the expected additional capacity provided by the North Mist Expansion Project that is anticipated to be complete in 2029 and explain how this will impact FEI.

Response:

The North Mist Expansion Project cannot replace the TLSE Project and *vice versa* for the reasons below.

First, the need and characteristics of FEI's off-system/market area storage assets, such as the North Mist Expansion Project, are different than the TLSE Project which is an on-system storage resource. As discussed in the Application, FEI's efficient supply portfolio requires three distinct assets that each serve a different purpose:[34]

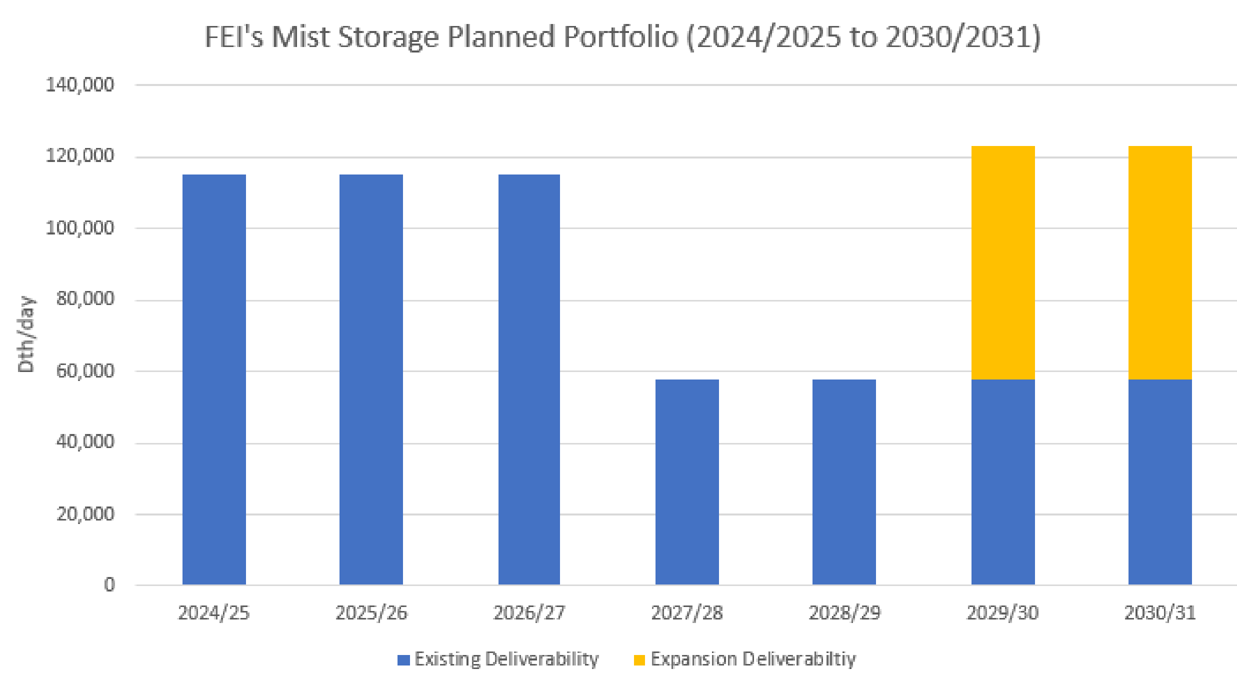
- Pipeline capacity to address base load i.e., consistent demand throughout the year;

[34] Exhibit B-1-4, Application, Section 1.2.2.1.2 (p. 8).

- Off-system underground [market area] storage, which includes Mist, to provide short to medium duration seasonal supply; and
- On-system LNG storage resources for short duration supply to cover events such as winter peak demand, which occurs for short periods driven by weather conditions.

The deliverability provided by an on-system LNG storage resource (i.e., 150-200 MMcf/d) is very valuable because the resource does not have to comply with the commercial arrangements as it relates to the nominations/scheduling windows of off-system resources. This is very important as the weather forecasts change and impact demands across the system.

Second, as illustrated in the figure below, based on the expected NW Natural recalls and the estimated in-service date of the expansion (Winter 2029/2030), the new deliverability from the North Mist Expansion Project will only replace existing deliverability that FEI will lose beginning in 2027/2028. Until the replacement Mist deliverability is in place, FEI will be short market area storage for 2 years (2027/2028 and 2028/2029) and will be exposed to short-term supply arrangements tied to the Sumas price (the only viable alternative to the lost deliverability). FEI has agreed to contract 50 percent of the expected total 4.3 Bcf and 130,000 Dekatherms per day (Dth/day) of capacity and deliverability from the North Mist Expansion Project.[35] The drivers of this decision included the scope of the North Mist Expansion Project and NW Natural's evolving Mist recall schedules.[36] The 50 percent share is consistent with FEI's strategies in the LTGRP and the ACP in terms of contracting for enough capacity to maintain FEI's existing amount of storage deliverability and capacity from Mist.

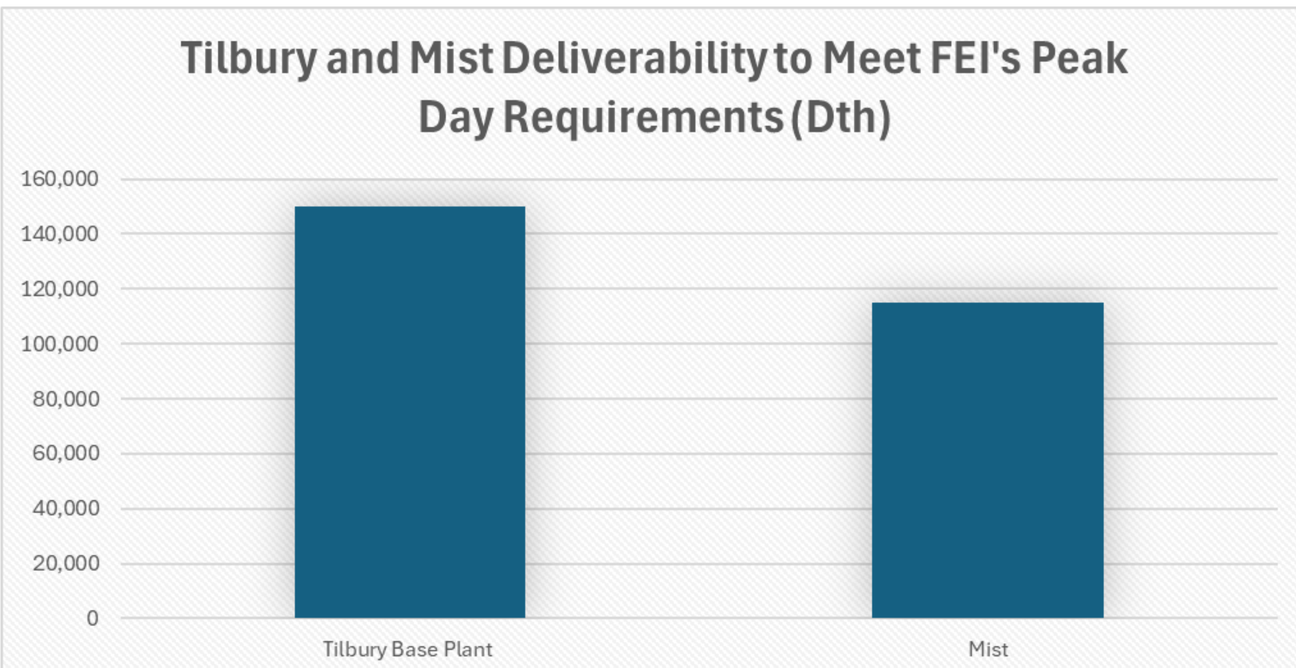


[35] 1,000 Dekatherm = 1 MMcf.

[36] Exhibit B-60, Supplemental Evidence, pp. 91-92: "FEI's Existing Regional Supply Assets are Exposed to Non-Renewal Risk."

The loss of FEI's existing market area storage at Mist is significant given the constrained infrastructure in the region and the price volatility at the Sumas/Huntingdon market. Taking no action to mitigate the loss of the Mist storage capacity would pose significant price and security of supply risk for customers. These risks also apply if the expansion is not completed to the anticipated capacity or timing laid out above. FEI assessed the alternatives to the North Mist Expansion Project, including the TLSE Project which would only be able to mitigate a very small portion of the recallable supply and only at the expense of compromising FEI's ability to respond to short-term supply disruptions. For example, FEI would require the entire storage (i.e., 3 Bcf leaving no resiliency reserve) to compensate for the Mist recall. Further, even if FEI could obtain the 3 Bcf of storage, the TLSE Project does not have enough liquefaction capability, nor is it normal operation for FEI's on-system LNG facilities to handle high volumes of supply for daily load balancing requirements that are better suited for market area storage.

Third, although the North Mist Expansion Project would provide enough storage capacity, it would not be enough deliverability to make up for what the Tilbury Base Plant provides to meet FEI's peak day requirements. The below graph illustrates the deliverability required from the Tilbury Base Plant and from FEI's Mist storage assets to meet FEI's Core Customer Peak Day load requirements.



For example, as explained above, the 65,000 Dth of deliverability that FEI will receive from the North Mist Expansion Project only replaces the loss of FEI's existing Mist deliverability requirements due to the recalls. If FEI chose to contract 100 percent of the North Mist Expansion Project to replace the Tilbury Base Plant or the TLSE Project, FEI would still be short 80,000 Dth/day or 130,000 Dth/day, respectively.[37] Any further expansion to the Mist storage facilities

[37] It is also important to note that the North Mist Expansion Project was fully subscribed after FEI's decision to contract for 50 percent of the project.

would come at a higher cost than the existing project because there is not enough transmission capacity to move the gas out of the Mist storage facilities, therefore requiring major upgrades on NW Natural's utility system and/or Northwest Pipeline.

Finally, even if FEI could hypothetically replace the Tilbury Base Plant or the need for the TLSE Project with additional Mist or other market area storage capacity and deliverability, it would go against the objectives of FEI's ACP in terms of security and diversity of supply. FEI's on-system supply which is reserved for extreme events (weather or emergency disruptions) is already extremely low and would drop further.

131.1.1 Should the North Mist Expansion Project not be completed to the anticipated capacity or timing, please discuss any potential impacts to FEI and the selection of the preferred alternative for the Project.

Response:

From a resiliency perspective, Mist cannot provide any mitigation against a winter T-South no-flow event. This is because in winter it is not possible to reverse the gas flow on NWP to move gas northbound, which would be required for gas from Mist to support the Lower Mainland during a T-South no-flow event. Therefore, any changes in the North Mist Expansion Project will not impact the Preferred Alternative from a resiliency point of view.

From a gas supply perspective, although the TLSE Project could help if the expected amount of deliverability and capacity is slightly lower than the North Mist Expansion Project, it could not replace the expected amount of recalled Mist capacity. Please refer to the response to BCUC IR5 131.1 for further discussion.

131.2 Please explain why FEI considers 2035 to be a reasonable assumption for regional infrastructure upgrades.

131.2.1 Please discuss any potential impacts to FEI and the selection of the preferred alternative for the Project should regional infrastructure upgrades occur: (i) earlier; and (ii) later than 2035. Please also discuss the potential impacts if no further regional infrastructure upgrades occur.

131.2.2 Please explain why FEI considers it is reasonable for the financial analysis to be based upon higher tolls associated with hypothetical post-2035 upgrades to regional infrastructure.

<u>Response:</u>

Existing regional infrastructure is fully contracted with only the following regional upgrades planned in the near-term (i.e., 5 years): (1) the Enbridge T-South Sunrise Expansion expected to be in-service in 2028; and (2) the North Mist Storage Expansion Project expected to complete in 2029.

As explained in Section 3.3.4.3.1 of the Supplemental Evidence, Enbridge's Sunrise Expansion will only provide enough additional capacity to offset the needs of Woodfibre LNG. Similarly, the North Mist Storage Expansion will restore the capacity that will be recalled by Northwest Natural from the existing Mist storage facility for their own use and cannot replace the TLSE Project, as discussed in the response BCUC IR5 131.1.

Given the ongoing increased reliance on natural gas-fired power generation in western North America to offset the loss of supply from retirements of coal-fired generation (as discussed on pages 88 to 89 of the Supplemental Evidence), FEI expects regional infrastructure to remain constrained. This is likely to necessitate regional infrastructure upgrades which will, in turn, result in higher pipeline tolls. As such, it is reasonable, and also realistic for the purposes of the financial analysis, to assume there will be further regional infrastructure upgrades and higher tolls resulting from those upgrades. In particular, as noted in Section 3.3.4.4 of the Supplemental Evidence, FEI's customers could face curtailments if the hypothetical future regional infrastructure upgrades do not occur and the Tilbury peaking supply from the Base Plant is not replaced with the TLSE Project to provide the full requirement of 1.0 Bcf and 200 MMcf/d.

As explained in Section 4.5.4.1.2 of the Supplemental Evidence, the reason FEI picked 2035 for the purpose of the financial analysis is because FEI believes this is the earliest time that a regional infrastructure upgrade (whether it is a regional storage or pipeline expansion) can realistically occur. Given the Enbridge Sunrise Expansion and the North Mist Storage Expansion are expected to be completed in 2028 and 2029, respectively, it would be unrealistic to assume another regional infrastructure could be developed and put in service within one or two years of these two projects. Further, in FEI's experience, it can take up to 10 years to plan and construct a new regional pipeline expansion in BC (e.g., Enbridge held an open season in 2022 for the T-South Sunrise Expansion, and FEI presumes that planning commenced prior to the 2022 Open Season). As such, using a 10-year timeframe that encompasses the planning through to the project's in-service date for any potential regional infrastructure upgrades, FEI considers 2035 is a reasonable assumption for the next regional pipeline or storage expansion to be in-service.

Importantly, FEI's selection of the Preferred Alternative for the TLSE Project would not change if the next regional infrastructure upgrade occurred <u>earlier</u> than 2035. In this case, the higher tolls due to the regional infrastructure upgrades would begin earlier than 2035, which would increase the PV of avoided gas supply costs for Supplemental Alternative 9 over Supplemental Alternative 8 (as shown in Table 4-9 of the Supplemental Evidence), and would result in a further reduction to the overall PV of Cost of Service over the 67-year analysis period for Supplemental Alternative 9 compared to Supplemental Alternative 8. FEI also notes that, all else equal, if there are no regional infrastructure upgrades until year 2048, then the PV of Cost of Service over the 67-year analysis period for Supplemental Alternatives 8 and 9 would equal each other. However, as discussed above, it would be unrealistic to assume there would be zero regional infrastructure upgrades for more than 20 years given the current constraints on the regional infrastructure (i.e., 23 years from 2025 to 2048).

On page 132 of Exhibit B-60, FEI states:

> Since FEI requires 200 MMcf/d and 1.0 Bcf of peaking gas supply, the existing Tilbury Base Plant is already undersized. To make up this level of peaking gas supply, the current ACP [Annual Contracting Plan] includes 150 MMcf/d and 0.6 Bcf of LNG from Tilbury, plus 50 MMcf/d of year-round pipeline capacity on T-South, which FEI then must try to resell (mitigate) during most of the year. FEI estimates the annual costs it incurs at present for holding the 50 MMcf/d of pipeline capacity on T-South year-round are approximately $7 million, net of mitigation of the unused capacity.

131.3 Please explain how FEI estimates approximately $7 million for the current annual costs of holding 50 MMcf/d of pipeline capacity on T-South, net of mitigation. Please discuss all assumptions and any historical data that has informed this estimate.

<u>Response:</u>

While responding to this information request, FEI noticed there was a rounding error in the calculation for the annual costs of holding approximately 50 MMcf/d of pipeline capacity on T-South year-round. The annual cost should be approximately $18 million instead of $17 million, and the post-mitigation costs should be approximately $7.9 million instead of $7 million. FEI also clarifies that the annual gas supply cost of $18 million was calculated using 52,000 GJ/d, which is equivalent to approximately 46 MMcf/d. For simplicity in the Supplemental Evidence, FEI rounded this number to 50 MMcf/d. Please refer to Table 1 below which provides the calculation as well as assumptions for the estimated annual gas supply cost of $18 million and post-mitigation costs of $7.9 million.

Further, FEI calculated the annual cost ($18 million) of contracting 52,000 GJ/d of pipeline capacity based on Enbridge's T-South toll estimate after the Sunrise Expansion project is completed in 2028. In addition, FEI estimated $10 million in mitigation revenue based on the historic T-South values. Therefore, $7.9 million is the T-South costs net of potential winter mitigation, which FEI considers is a conservative estimate for the gas supply benefits the TLSE Project could provide.

Table 1: Calculation of Annual Cost for Holding Approximately 50 MMcf/d of Pipeline Capacity on T-South

Line	T-South Toll and Mitigation Revenue	Assumptions	Unit	Reference
1	T-South Toll Post-Sunrise Expansion	0.95	$/GJ	Westcoast application to the CER for Sunrise Expansion (See Note 1)
2	Winter Mitigation Revenue	(1.62)	$/GJ	T-South values based on settled market prices between Jan 2016 and March 2023
3	Daily Deliverability	52,000	GJ/d	Equivalient to 46 MMcf/day; Rounded to 50 MMcf/day for ease of discussion (See Note 2)
4	Days for Contracting T-South Firm Sevice	365	days	
5	Days of Winter Mitigation	120	days	
6	Annual Cost	18.0	Mil $/Year	Line 1 X Line 3 X Line 4 / 100,000
7	Winter Mitigation Revenue	(10.1)	Mil $/Year	Line 2 X Line 3 X Line 5 / 100,000
8	**Net Annual Cost**	**7.9**	Mil $/Year	Line 6 + Line 7

Notes to Table:

- *Estimated based on Enbridge's T-South Sunrise Expansion, expected to complete in 2028. Please refer to the response to BCUC IR5 131.4.*
- *Based on FEI's 2024/25 ACP for T-South holdings, FEI determined an incremental 52,000 GJ/d of peaking supply is needed to meet the ACP load growth. Please also refer to the response to BCUC IR5 118.1 for further discussion regarding excess pipeline capacity. FEI notes that the incremental peaking supply requirements are not constant. Gas supply assesses the requirements for all types of assets based on demand and supply inputs updated on an annual basis.*

This small rounding error also resulted in a minor change to the financial analysis in terms of the PV of the Cost of Service and the levelized total rate impact over the 67-year analysis period. This change had no impact on the scoring between the Supplemental Alternatives. Please refer to a revised version of Table 4-9 from the Supplemental Evidence below which provides the revised financial analysis between Supplemental Alternatives 4, 4A, 8, and 9. Supplemental Alternative 9 continues to have a lower levelized total rate impact than Supplemental Alternative 8 while also being able to optimize the risk against a winter T-South no-flow event when compared to Supplemental Alternatives 4 and 4A.

Revised Table 4-9: Revised Financial Analysis for Feasible Supplemental Alternatives 4, 4A, 8 and 9 (in the same format as Table 4-9 of the Supplemental Evidence)

	Alt 4 - 0.6 BCF 150 MMcf/d (No resl)	Alt 4A - 1 BCF 400 MMcf/d (No resl)	Alt 8 - 2 BCF 800 MMcf/d (1.4 BCF resl)	Alt 9 - 3 BCF 800 MMcf/d (2 BCF resl)
Total Capital Costs during Construction, As-Spent $ ($000s)	826,921	893,199	1,030,286	1,140,962
PV of Cost of Service, excl. Gas Supply Costs/Savings ($000s) over 67 years	790,047	892,594	1,133,984	1,240,803
PV of Gas Supply Cost/Savings ($000s) over 67 years	(366,362)	(519,585)	(366,362)	(519,585)
Total PV of Cost of Service over 67 years ($000s)	**423,685**	**373,009**	**767,622**	**721,218**
Levelized Total Rate Impact (Incl. Cost of Gas) 67 years (%)	1.44%	1.26%	2.60%	2.44%
Levelized Total Rate Impact (Incl. Cost of Gas) 67 years ($/GJ)	0.134	0.118	0.242	0.228

On page 134 of Exhibit B-60, FEI states:

> Since the currently planned T-South Sunrise Expansion is expected to result in tolls of $0.95/GJ, which is a significant increase (46 percent) over current embedded tolls on T-South, FEI assumes it would incur those $0.95/GJ tolls to continue to hold 50 MMcf/d of pipeline capacity that it currently uses to supplement Tilbury LNG in the ACP. Paying the higher toll on 50 MMcf/d represents approximately $17 million per year of annual peaking supply costs, before mitigation. Assuming FEI's current ability to mitigate that pipeline capacity, the post mitigation cost remains at approximately $7 million.

131.4 Please explain why FEI expects tolls of $0.95/GJ from the currently planned T-South Sunrise Expansion, including any quotes, market research, and other assumptions to support this estimate.

Response:

The $0.95/GJ is the estimated T-South toll according to Westcoast's filing with the CER for the Sunrise Expansion.[38] The table reproduced from page 228 of that filing illustrates the toll impact of the Sunrise Expansion project.

Table 12-2 presents the illustrative unit toll impact for this same five-year forecast period based on the annual cost-of-service changes described above. As shown, the change in the unit toll is projected to be 36.1 cents per Mcf for the first year, with the change being 37.4 cents per Mcf on average during the five-year forecast period.

Table 12-2: T-South Illustrative Toll Impact, CS-2 to Huntingdon (¢/Mcf)

	2029	2030	2031	2032	2033
Illustrative Toll Impact CS-2 to Huntingdon	36.1	38.0	36.8	37.8	38.4

The $0.95/GJ is calculated by adding the minimum rate impact of the Sunrise Expansion to the 2025 Interim toll for the Huntingdon delivery area. The calculation is shown in Table 1 below:

Table 1: Calculation of the $0.95/GJ Used as Estimation of T-South Toll

Line	Particular	Unit	Toll	Reference
1	Westcoast Energy Inc (WEI) 2025 Interim Toll	$/Mcf	$0.721	WEI 2025 interim toll (5-year TDR) for the firm transportation services at Huntingdon delivery area
2	Minimum Rate Impact of Sunrise Expansion	$/Mcf	$0.361	Minimum toll amount found by WEI in their toll impact analysis
3	***Expected T-South Sunrise Expansion Toll***	***$/Mcf***	***$1.082***	***Line 1 + Line 2***
4	***Expected T-South Sunrise Expansion Toll***	***$/GJ***	***$0.955***	***Line 3 * Conversion Rate from per Mcf to per GJ (1 Mcf = 1.133 GJ)***

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[38] Section 12.3: Estimated Cost of Service and Toll Impact, Pp. 12-1 to 12-2. C29824-2_Sunrise_Expansion_Program_-_Application_Pursuant_to_Section_183_of_the_Canadian_Energy_Regulator_Act_-_A8Y4R3.pdf (cer-rec.gc.ca),

FEI considers $0.95/GJ to be a conservative estimate because it is based on the lowest toll impact in the first five years. Inflation between now and 2028 could potentially further increase the base toll.

131.4.1 Please provide the toll price at which the NPV of Supplemental Alternatives 9 and 8 would be the same, and discuss the likelihood of this toll price materializing.

Response:

FEI has assumed that the reference to NPV in the question refers to the Total PV of Cost of Service, including Gas Supply Costs (or Savings), as presented in Table 4-9 of the Supplemental Evidence.

There is no realistic T-South toll price (instead of $0.95 per GJ) before 2035 for holding approximately 50 MMcf/d of pipeline capacity that could make the total PV of cost of service of Supplemental Alternative 8 equal to Supplemental Alternative 9. Mathematically, even in a hypothetical scenario where the T-South toll (post-Sunrise Expansion) became zero (i.e., $0.00 per GJ, meaning that Enbridge would be giving the capacity to FEI for free), FEI would still have to, at the same time, be able to increase the winter mitigation to $2.00 per GJ from the current estimate of $1.62 per GJ in order to have the same PV of total cost of service for both alternatives. As such, there is no realistic scenario that would achieve the result contemplated in this question.

Please also refer to the response to BCUC IR5 132.2.1 for further discussion on the circumstances, including annual gas costs for 2035 and onwards, which would result in the PV of total cost of service over the 67-year analysis period between Supplemental Alternatives 8 and 9 being equal.

131.5 Please discuss FEI’s historic ability to resell unused pipeline capacity.

Response:

FEI has the Gas Supply Mitigation Incentive Program (GSMIP) in place, which aligns the interests of customers and shareholders as a method for FEI to capture market opportunities on unutilized assets (commodity, storage and pipeline/transportation) provided for in the ACP. FEI optimizes contracted ACP assets on a daily and seasonal basis in order to meet firm core load for customers in Rate Schedules 1 to 7 and 46. In particular, FEI enters into commercial transactions with counterparties and market participants to extract value out of the unutilized assets, capturing these mitigation activities in the GSMIP and recovering costs in the Midstream Cost Reconciliation

Account (MCRA). FEI submits two GSMIP reports for each gas year to the BCUC, the Winter Report by May 31 and the Year End Report by December 31. The current GSMIP is set to expire on October 31, 2025 and FEI will undertake a renewal application to extend the program for a three-year period from November 1, 2025 to October 31, 2028.

As shown in the table below, for the gas years from 2016-17 to 2022-23, FEI generated a total of approximately $358 million in T-South mitigation activities under the GSMIP. Over the same period, during the winter months (November to March), FEI generated a total of approximately $113 million in T-South mitigation activities under the GSMIP.

Gas Year	T-South Mitigation ($CAD)	Winter Months	T-South Mitigation ($CAD)
2015-16	$ 30,732,681.00	Nov15-Mar16	$ 763,971.00
2016-17	$ 43,420,066.00	Nov 16-Mar17	$ 1,725,347.00
2017-18	$ 34,883,558.00	Nov17-Mar18	$ 6,838,036.00
2018-19	$ 29,649,245.00	Nov18-Mar19	$ 696,590.00
2019-20	$ 8,030,861.00	Nov19-Mar20	$ 6,096,276.00
2020-21	$ 24,590,624.00	Nov20-Mar21	$ 2,449,607.00
2021-22	$ 68,835,065.00	Nov21-Mar22	$ 1,545,422.00
2022-23	$ 117,628,189.00	Nov22-Mar23	$ 93,082,715.00
Total	$ 357,770,289.00		$ 113,197,964.00

The T-South mitigation recoveries demonstrate that the current gas infrastructure has a high utilization rate year-round. This suggests there is demand for new infrastructure in the region under existing conditions.

131.6 Please discuss FEI's expected future ability to resell unused pipeline capacity, should it be necessary to do so, for the time periods of: (i) Present to 2030, (ii) 2030 to 2035; and (iii) 2035 onwards.

131.6.1 For each time period, please discuss any potential factors that may improve or limit FEI's future ability to resell unused pipeline capacity.

Response:

FEI considers it reasonable to assume, for the purposes of determining avoided gas supply costs in the financial analysis, that FEI would be able to generate some mitigation revenue in non-peak periods from holding pipeline capacity. For the reasons noted below, FEI considers that it would be possible to generate some mitigation revenues throughout the three periods identified in the question. The assumption that FEI would be able to generate mitigation revenue has the effect of reducing the assumed benefits (avoided costs) from the Preferred Alternative.

The response to BCUC IR5 131.5 demonstrates FEI's historical success in reselling unused pipeline capacity, subject to pricing volatility between years.

FEI's ability to resell unused pipeline capacity in the future, at a high level, largely depends on the supply/demand dynamics in the market when the capacity is being sold. Examples of factors that could impact supply in the future include, but are not limited to, how well-developed or constrained the regional market infrastructure is, including production, processing, storage and transmission facilities. In particular, how much gas can physically flow into the NWP system due to existing constraints at various locations (i.e., Chehalis is constrained at 0.8 Bcf) is a key driver of how much T-South capacity can be mitigated into the market especially in summer or shoulder periods (i.e., November or March).

Examples of factors that could impact demand in the future include, but are not limited to, the extent to which residential, commercial and industrial customers change their natural gas consumption in response to climate change and other drivers. This could result in increased natural gas demand (e.g., if longer and colder spans of cold weather in the winter were to occur) or decreased demand in response to decarbonization policies. Please refer to the response to BCUC IR5 131.2 where FEI discusses the increased usage of natural gas for electricity generation.

While FEI cannot predict with certainty its ability to resell unused pipeline capacity in the future, the market dynamics that are described in Section 4.5.5 of the Supplemental Evidence, the independent expert report of Ray Mason, and the responses to BCUC IR5 129.5 and 129.5.1, suggest a reasonable likelihood that there will be an ongoing demand for pipeline capacity in the Pacific Northwest.

On page 139 of Exhibit B-60, in Table 4-11, FEI presents the avoided annual gas supply costs for supplemental alternatives, a portion of which has been reproduced below by BCUC staff.

		Annual Gas Supply Costs ($ millions)			Incremental to Baseline / (Avoided Costs) ($ millions)		
Supplemental Alternatives	**Description**	**Present to 2030**	**2030 to 2035**	**2035 onwards**	**Present to 2030**	**2030 to 2035**	**2035 onwards**
1	No Capital Upgrades (Continue to rely on existing Base Plant until it fails. No on-system peaking gas supply thereafter and no resiliency reserve)	7.0	7.0	63.0			
8	New 2 Bcf Tank and 800 MMcf/d Regasification (1.4 Bcf resiliency reserve and 0.6 Bcf for peaking gas supply)	7.0	7.0	17.0	-	-	(46.0)
9	New 3 Bcf Tank and 800 MMcf/d Regasification (2 Bcf resiliency reserve and 1 Bcf for peaking gas supply)	7.0	-	-	-	(7.0)	(63.0)

131.7 Please explain whether the annual gas supply costs analysis assumes that FEI's peak demand remains constant for the expected lifetime of the TLSE Project.

Response:

FEI is not assuming its overall peak demand will remain constant for the expected life of the TLSE Project. The financial analysis completed as part of the Supplemental Evidence assumes the optimal peak supply requirements from Tilbury will remain at approximately 200 MMcf/d (peak day sendout) and 1 Bcf (annual LNG supply) over the expected life of the TLSE Project (i.e., 67-year analysis period). This is consistent with the unique flexibility associated with on-system LNG.

As discussed in Section 4.5.5 of the Supplemental Evidence, even under the most extreme adverse hypothetical load loss scenarios, FEI would still be serving hundreds of thousands of customers in the Lower Mainland in 2050, with approximately 60 PJ (equivalent to approximately 53 Bcf) of Lower Mainland load per year and peak day demand of approximately 460 MMcf/d (Figure 4-12 and Figure 4-14, respectively). This is well-above the storage and regasification capacity that the TLSE Project can provide. As further discussed in Section 4.5.5.4 of the Supplemental Evidence, even in the event of extreme load declines, the TLSE Project will continue to provide value to FEI's customers. FEI could elect to allocate more of the tank to the gas supply portfolio (i.e., as much as 2.42 Bcf of the 3.0 Bcf storage tank under the Preferred Alternative) which would create opportunities to optimize FEI's gas supply portfolio for the benefit of its customers such as using the additional peak demand supply from Tilbury to substitute other more expensive supply resources or generate more mitigation revenue as demonstrated in Figure 4-18 of the Supplemental Evidence, both of which will reduce FEI's gas supply costs for the benefit of its customers.

As such, FEI considers it reasonable to assume that, at minimum, the optimal peak supply requirement from Tilbury would remain at approximately 200 MMcf/d and 1 Bcf for the purpose of the financial analysis for the TLSE Project. Tilbury will continue to provide significant value through avoided gas supply costs over the life of the TLSE Project (Preferred Alternative) even if FEI were to experience the most extreme adverse load loss scenarios.

131.8 Please confirm, or explain otherwise, that FEI assumes it will be unable to sell unused pipeline capacity from 2035 onwards under Supplemental Alternative 8.

131.8.1 If confirmed, please provide the rationale for this assumption.

Response:

Not confirmed. FEI clarifies the $17 million of annual gas supply costs under Supplemental Alternative 8 in Table 4-11 is not the same as the $17 million of annual peaking supply costs (i.e., $7 million post-mitigation) for holding approximately 50 MMcf/d of pipeline capacity prior to 2035 discussed on page 134 of the Supplemental Evidence. It was a coincidence that the two numbers are both equal to $17 million. Therefore, FEI's ability to sell unused pipeline capacity is not related to the difference between the $7 million for years prior to 2035 and the $17 million for 2035 onwards as shown in Table 4-11. Additionally, as noted in the response to BCUC IR5 131.3, FEI discovered a small rounding error in the calculation; as a result, the annual peaking supply costs for holding approximately 50 MMcf/d of pipeline capacity prior to 2035 should have been $18 million and the resulting annual costs net of mitigation should have been $7.9 million.

The $17 million shown in Table 4-11 under Supplemental Alternative 8 for 2035 onwards is related to the estimated incremental cost for FEI to hold 50 MMcf/d and 0.4 Bcf of peaking supply from the regional market. As explained in the Supplemental Evidence, the optimal peaking supply requirement from Tilbury is 200 MMcf/d regasification and 1 Bcf of storage. Since Supplemental Alternative 8 will retain 150 MMcf/d and 0.6 Bcf of storage for on-system gas supply, FEI would have to incur additional gas supply costs from the regional market to make up the remaining 50 MMcf/d and 0.4 Bcf.

FEI assumed the incremental cost to make up the remaining 50 MMcf/d and 0.4 Bcf under Supplemental Alternative 8 would be $17 million, i.e., $63 million less $46 million. This assumption was based on the following from the Supplemental Evidence:

- The lower range estimate of the annual cost (post-mitigation) for holding 1 Bcf and 200 MMcf/d from the regional market (with future infrastructure expansion) is $63 million (as shown in Figure 4-7 of the Supplemental Evidence); and
- The lower range estimate of annual cost (post-mitigation) for holding 0.6 Bcf and 150 MMcf/d from the regional market (with future infrastructure expansion) is $46 million (as shown in Figure 4-8 of the Supplemental Evidence).

Please also refer to the response to BCUC IR5 131.9 for the detailed calculation of the $63 million and $46 million.

131.9 Please explain how FEI estimates $17.0 million in Annual Gas Supply Costs for Supplemental Alternative 8 from 2035 onwards. Please provide a breakdown and discuss any assumptions and analysis that have informed each component of this estimate. If available, please provide the current volume and unit cost, assumed future escalated unit cost (in dollars per unit and percentage change from current price), and future volume (per unit and percentage change) for each cost component.

Response:

As explained in the response to BCUC IR5 131.8, the $17 million in Annual Gas Supply Costs for Supplemental Alternative 8 from 2035 onwards as shown in Table 4-11 is the difference between the lower end estimates of $63 million (post-mitigation) for holding 1 Bcf and 200 MMcf/d from the regional market with future infrastructure expansion and $46 million (post-mitigation) for holding 0.6 Bcf and 150 MMcf/d from the regional market with future infrastructure expansion.

Since Supplemental Alternative 9 (Preferred Alternative) will provide the full peaking supply requirement of 200 MMcf/d and 1 Bcf from Tilbury, FEI will not be incurring annual gas supply costs for holding the same 200 MMcf/d and 1 Bcf from the regional infrastructure (with future expansion), thus fully avoiding the estimated $63 million of annual gas supply costs for 2035 onwards as shown in Table 4-11 of the Supplemental Evidence.

Please refer to Tables 1 and 2 below for the detailed calculations of the $63 million and $46 million, respectively, of annual gas supply costs for 2035 onwards. For the detailed calculations and assumptions for the annual gas supply costs, including mitigation prior to 2035, please refer to the response to BCUC IR5 131.3.

Table 1: Annual Cost to Access 1.0 Bcf Capacity and 200 MMcf/d Deliverability on Expanded Regional Infrastructure from 2035 Onwards

Line	Particular		Assumptions	2035 onwards	Reference
1	**RATE CHARGES**				
2		Sumas Summer Price ($US/MMBtu)		$ 4.19	
3		Market Area Storage Storage charge ($US/MMBtu)		$ 7.25	
4		Market Area Storage Injection/Withdrawal Fuel Rate (%)		0.49%	
5		NWP TF-1 Transport Demand Charge ($US/MMBtu)		$ 0.37	
6		NWP Transport Fuel Rate (%)		1.06%	
7		Storage Deliverability Required Mcf/d		200,000	
8		Days of Storage		10	
9					
10	**STORAGE CHARGE ($US 000)**				
11	Demand:	Market Area Storage Storage Charge 150MMcf/d * 8 days	10	$ 14,500	Line 3 X Line 7 X Line 8 / 1,000
12	Fuel:	Storage Fuel		$ 41	Line 2 X Line 4 X Line 7 X Line 8 / 1,000
13					
14	**TRANSPORT CHARGE ($US 000)**				
15	Demand:	Estimated NWP Expansion costs	100%	$ 27,193	Line 5 X Line 7 X 365 X 100% / 1,000
16	Fuel	NWP Transport Fuel		$ 89	Line 2 X Line 6 X Line 7 X Line 8 / 1,000
17		Local Pipeline Expansion		$ 5,133	
18					
19	**TOTAL STORAGE & TRANSPORT**				
20		($US 000)		$ 46,956	Line 11 + Line 12 + Line 15 + Line 16 + Line 17
21		($Cdn 000) applying Fx = 0.74 $US/$CAD	0.74	$ 63,454	Line 20 X Fx Rate

Table 2: Annual Cost to Access 0.6 Bcf Capacity and 150 MMcf/d Deliverability on Expanded Regional Infrastructure from 2035 Onwards

Line	Particular	Assumptions	2035 onwards	Reference
1	**RATE CHARGES**			
2	Sumas Summer Price ($US/MMBtu)		$ 4.19	
3	Market Area Storage Storage charge ($US/MMBtu)		$ 7.25	
4	Market Area Storage Injection/Withdrawal Fuel Rate (%)		0.49%	
5	NWP TF-1 Transport Demand Charge ($US/MMBtu)		$ 0.37	
6	NWP Transport Fuel Rate (%)		1.06%	
7	Storage Deliverability Required Mcf/d		150,000	
8	Days of Storage		8	
9				
10	**STORAGE CHARGE ($US 000)**			
11	Demand: Market Area Storage Storage Charge 150MMcf/d * 8 days	8	$ 8,700	Line 3 X Line 7 X Line 8 / 1,000
12	Fuel: Storage Fuel		$ 25	Line 2 X Line 4 X Line 7 X Line 8 / 1,000
13				
14	**TRANSPORT CHARGE ($US 000)**			
15	Demand: Estimated NWP Expansion costs	100%	$ 20,394	Line 5 X Line 7 X 365 X 100% / 1,000
16	Fuel NWP Transport Fuel		$ 53	Line 2 X Line 6 X Line 7 X Line 8 / 1,000
17	Local Pipeline Expansion		$ 5,133	
18				
19	**TOTAL STORAGE & TRANSPORT**			
20	($US 000)		$ 34,306	Line 11 + Line 12 + Line 15 + Line 16 + Line 17
21	($Cdn 000) applying Fx = 0.74 $US/$CAD	0.74	$ 46,359	Line 20 X Fx Rate

For the purposes of the financial analysis, FEI conservatively used the lower end estimate of off-system storage costs of $63 million for holding 1 Bcf and 200 MMcf/d and $46 million for holding 0.6 Bcf and 150 MMcf/d, instead of the higher end pipeline cost of $79.0 million and $59 million (net of mitigation) shown in Figure 4-7 and Figure 4-8, respectively. Using the higher end pipeline cost would have the effect of improving the levelized total rate impact of Supplemental Alternative 9 relative to Supplemental Alternative 8.

The assumptions for off-system storage are noted in Section 4.5.4.1.2 of the Supplemental Evidence, which involve: (1) a storage demand charge; and (2) the associated transportation charge, as summarized below:

1. The assumed storage demand charge (Line 3 of Tables 1 and 2 above) is based on a Mist storage expansion project which FEI is currently involved with. FEI's current ACP portfolio includes approximately 115 MMcf/d of Mist storage, out of which up to 50 percent capacity will be recalled by the storage owner NW Natural. FEI is currently participating in an expansion project in order to maintain the same level of Mist capacity in future ACP portfolios. This expansion project does not have additional capacity to replace the required Tilbury send out. FEI is uncertain if another expansion would be feasible at the current Mist facility. Recent study of this incremental project at Mist indicates the transportation charge for moving the Mist supply will be significantly higher. FEI has used existing tolls for the transportation charges in these avoided cost calculations. In addition, FEI has used the storage demand charge from the Mist storage expansion project.
2. The associated transportation charge (Line 5 of Tables 1 and 2 above) is the cost of obtaining pipeline capacity on NWP to deliver gas (by displacement) to FEI's service territory. The expected regional storage cost increase includes a transportation charge based on current NWP tolls. However, the regional storage facilities (JPS and Mist) are in

the US, and future expansion of either storage facility will also require an expansion on the NWP system because existing transportation capacity required to access these locations is fully contracted and utilized during the winter period. Therefore, if an expansion was required, the costs to upgrade the NWP system would have to be paid by the expansion shippers (i.e., FEI) to NWP. As such, the expansion costs to FEI would be even higher than the current NWP tolls used in FEI's calculation.

FEI notes that the volumes and unit costs shown in Tables 1 and 2 above remain constant for each year from 2035 onwards over the life of the TLSE Project. For the volume, please refer to the response to BCUC IR5 131.7 for a discussion of why FEI considers it appropriate to assume an optimal peak supply requirement of 200 MMcf/d and 1 Bcf from Tilbury over the life of the TLSE Project. For the unit costs (i.e., storage demand charge and transportation charge), FEI conservatively did not forecast any future escalation from 2035 onwards. Any additional escalation on the storage demand charge and transportation charges for years beyond 2035 would have the effect of further improving the levelized total rate impact for Supplemental Alternative 9 relative to Supplemental Alternative 8.

Please refer to Attachment 131.9 for the excel calculations shown in Tables 1 and 2 above as well as the volume and unit costs used for the periods prior to 2035 and for 2035 onwards.

On page 135 of Exhibit B-60, FEI states "[a]s the cost of holding capacity on regional infrastructure is a function of the expected tolls and charges, the costs will be higher than they are today by virtue of the capital costs of upgrades being reflected in the tolls and charges."

131.10 In a table format and in excel, please provide a well-annotated breakdown of the avoided cost of gas for the preferred alternative, including the current volume and unit cost, assumed future escalated unit cost (in dollars per unit and percentage change from current price), and future volume (per unit and percentage change from current volume as applicable) for each cost and mitigation line item for the following time periods: present to 2030, 2030 to 2035, and 2035 onwards.

<u>Response:</u>

Please refer to the response to BCUC IR5 131.9.

132.0 Reference: EXPANDED ALTERNATIVE ANALYSIS

Exhibity B-60 (Supplemental Evidence), Table 4-9; Section 6.1.2, Table 6-1, p. 195; Section 6.2.1, Table 6-4, p. 199; Section 6.3, Table 6-5, p. 203

Project Cost Estimate and Rate Impact

On page 130 of Exhibit B-60, in Table 4-9, FEI provides a summary of capital costs, cost of service, gas supply costs/savings, and levelized total rate impacts for feasible supplemental alternatives. Table 4-9 shows the levelized total rate impact for Alternative 8 is 2.60%.

FEI presents Table 6-1, Table 6-4, and Table 6-5 to show a Breakdown of the TLSE Project Cost Estimate, Financial Analysis of the Project over a 67-year Analysis Period, and Summary of Delivery Rate Impact for the TLSE Project, respectively.

132.1 Please provide the following for Alternative 8:

132.1.1 A financial schedule in excel to support the levelized total rate impact calculation of 2.60 percent.

132.1.2 Replicate Table 6-1: Breakdown of the TLSE Project Cost Estimate; Table 6-4: Financial Analysis of the Project – 67-year Analysis Period; and Table 6-5: Summary of Delivery Rate Impact for the TLSE Project with information for Alternative 8.

Response:

Please refer to Confidential Attachment 132.1 for the corresponding financial schedules in excel for Supplemental Alternative 8. The calculation for the levelized total rate impact of 2.60 percent can be found on Schedule 10, Line 39 (i.e., “Levelized Rate Calculation” tab).

FEI is requesting that Attachment 132.1 be filed on a confidential basis and be held confidential by the BCUC in perpetuity, pursuant to Section 18 of the BCUC’s Rules of Practice and Procedure regarding confidential documents as set out in order G-296-24. The financial schedules contained in Attachment 132.1 include cost estimates, containing capital cost estimates for the TLSE Project. This information is commercially sensitive and should be kept confidential on the basis that FEI may be going to the market to seek competitive bids for the material and construction work for the Project. If the estimated costs for the material and construction work are disclosed, FEI reasonably expects that its negotiating position may be prejudiced. For instance, the bidding parties with knowledge about the estimated costs may use the estimate costs as a reference for their bidding.

In preparing this response, FEI noted there was a minor rounding error in the total capital costs of Supplemental Alternative 8 used in the calculation of the PV of Cost of Service as presented in Table 4-9 of the Supplemental Evidence. Please refer to Table 1 below for the updated summary of the financial analysis for Supplemental Alternative 8 in the same format as provided in Table 4-9 of the Supplemental Evidence. This minor error only changed the total PV of Cost of Service for Supplemental Alternative 8 by approximately $1 thousand and there is no change to the levelized total rate impact of 2.60 percent when rounded to two decimal places.

Table 1: Revised Financial Summary of Capital Costs, Cost of Service, Gas Supply Costs/Savings, and Levelized Total Rate Impact for Supplemental Alternative 8

	Original Alt 8 - 2 BCF 800 MMcf/d (1.4 BCF resl)	Revised Alt 8 - 2 BCF 800 MMcf/d (1.4 BCF resl)	Difference
Total Capital Costs during Construction, As-Spent $ ($000s)	1,030,287	1,030,286	(1)
PV of Cost of Service, excl. Gas Supply Costs/Savings ($000s) over 67 years	1,133,983	1,133,984	1
PV of Gas Supply Cost/Savings ($000s) over 67 years	(366,362)	(366,362)	-
Total PV of Cost of Service over 67 years ($000s)	**767,621**	**767,622**	**1**
Levelized Total Rate Impact (Incl. Cost of Gas) 67 years (%)	2.60%	2.60%	-
Levelized Total Rate Impact (Incl. Cost of Gas) 67 years ($/GJ)	0.242	0.242	-

Please refer to Table 2 below for the breakdown of the cost estimate for Supplemental Alternative 8 in the same format as Table 6-1 of the Supplemental Evidence.

Table 2: Breakdown of Supplemental Alternative 8 Cost Estimate ($ millions)

	2023 $	As-Spent $
LNG Tank (2 BCF)	296.203	348.753
Regasification Equipment	142.089	167.298
Ground Improvement	46.843	55.153
Auxiliary System	154.472	181.877
Base Plant Demolition	14.876	17.515
Subtotal Capital Cost	654.482	770.596
Contingency	126.200	149.602
Subtotal Project Capital Costs w/ Contingency	780.682	920.197
CPCN Application	4.945	4.945
CPCN Preliminary Stage Development	1.546	1.546
Subtotal w/ Deferral Costs	787.173	926.688
AFUDC	-	110.549
Tax Offset	-	(4.025)
TOTAL Project Cost	***787.173***	***1,033.213***

<u>*Note to Table:*</u>

The difference between the $1,030.286 million shown in Table 1 above and the total estimated As-spent Project Cost of $1,033.213 million shown in Table 2 is the CPCN Application and CPCN Preliminary Stage Development costs. The CPCN Application cost is $4.945 million (equal to $4.165 million net of tax and AFUDC) and the CPCN Preliminary Stage Development cost is $1.546 million (equal to a credit of $1.238 million net of tax and AFUDC) as shown in Table 6-3 of the Supplemental Evidence.[39]

[39] $1,033.213 million - $4.165 million + ($1.238 million) = $1,030.286 million.

Please refer to Table 3 below for the summary of the financial analysis completed for Supplemental Alternative 8 in the same format as Table 6-4 of the Supplemental Evidence.

Table 3: Financial Analysis of Supplemental Alternative 8 over a 67-year Analysis Period

Line	Particular	TOTAL	Reference (BCUC IR5 132.1.1 , Confidential Attachment 132.1)
1	Total Charged to Gas Plant in Service ($ millions)	1,007.518	Schedule 6; Line 65
2	Base Plant Demolition Costs ($ millions)	22.767	Schedule 6; Sum of Line 62 (2026 to 2029)
3	Total Project Deferral Cost, Net of Tax ($ millions)	2.927	Schedule 9; Line 6 + Line 15
4	***Total Project Cost ($ millions)***	**1,033.213**	**Sum of Line 1 to Line 3**
5			
6	Incremental Delivery Margin in 2035 ($ millions)	107.467	Schedule 1; Line 12 (2035)
7	Incremental Cost of Gas Benefits in 2035 ($ millions)	(46.000)	Schedule 1; Line 2 (2035)
8	***Net Incremental Revenue Requirement in 2035 ($ millions)***	**61.467**	**Line 6 + Line 7**
9			
10	PV of Incremental Delivery Margin 67 years ($ million)	1,133.984	Schedule 10; Line 22
11	PV of Incremental Cost of Gas Benefits 67 years ($ million)	(366.362)	Schedule 10; Line 32 - Line 22
12	***Net PV of Incremental Revenue Requirement 67 years ($ million)***	**767.622**	**Line 10 + Line 11**
13			
14	Delivery Rate Impact in 2035 (%)	9.42%	Schedule 10; Line 25 (2035)
15	Total Rate Impact (incl. Cost of Gas) in 2035 (%)	3.28%	Schedule 10; Line 35 (2035)
16			
17	***Levelized Total Rate Impact (Incl. Cost of Gas) 67 years (%)***	**2.60%**	**Schedule 10; Line 39**
18	***Levelized Total Rate Impact (Incl. Cost of Gas) 67 years ($/GJ)***	**0.242**	**Schedule 10; Line 46**

Please refer to Table 4 below for the Summary of Delivery Rate Impact pertaining to Supplemental Alternative 8 in the same format as Table 6-5 of the Supplemental Evidence.

Table 4: Summary of Delivery Rate Impact for Supplemental Alternative 8

	2026	2027	2028	2029	2030	2031
Annual Delivery Margin, Incremental to 2025 Approved, Non-Bypass ($ millions)	1.355	1.405	10.935	30.738	52.243	113.416
% Increase to 2025 Approved Delivery Margin, Non-bypass	***0.12%***	***0.12%***	***0.96%***	***2.69%***	***4.58%***	***9.94%***
Incremental % Delivery Rate Impact (Year-over-Year)	***0.12%***	***0.00%***	***0.83%***	***1.72%***	***1.83%***	***5.13%***

132.2 Please identify all cost items identified in Table 6-1 that are different between Supplemental Alternative 8 and Supplemental Alternative 9 in table format and in excel.

Response:

Please refer to Table 1 below which shows the difference in cost items between Supplemental Alternatives 8 and 9. Please also refer to Attachment 132.2 for the Excel version of Table 1. FEI notes that the capital cost estimates for both Supplemental Alternatives 8 and 9 were developed to an AACE Class 3 level. The key differences in the capital cost estimate between the two alternatives are presented in the Notes to the Table below.

Table 1: Difference in Capital Cost Estimate between Supplemental Alternatives 8 and 9 ($ millions)

As-Spent ($ millions)	Alt 9	Alt 8	Difference	
LNG Tank	423.480	348.753	74.727	*See Note 1*
Regasification Equipment	166.547	167.298	(0.750)	*See Note 3*
Ground Improvement	71.740	55.153	16.587	*See Note 2*
Auxiliary System	181.239	181.877	(0.637)	*See Note 3*
Base Plant Demolition	17.571	17.515	0.056	*See Note 3*
Subtotal Capital Cost	860.578	770.596	89.982	
Contingency	160.749	149.602	11.148	*See Note 4*
Subtotal Project Capital Costs w/ Contingency	1,021.327	920.197	101.130	
CPCN Application	4.945	4.945	-	
CPCN Preliminary Stage Development	1.546	1.546	-	
Subtotal w/ Deferral Costs	1,027.818	926.688	101.130	
AFUDC	120.096	110.549	9.547	*See Note 5*
Tax Offset	(4.025)	(4.025)	-	
TOTAL Project Cost ($ millions)	***1,143.889***	***1,033.213***	***110.677***	

Notes to the Table:

1. *Supplemental Alternative 9 includes a 3.0 Bcf storage tank whereas Supplemental Alternative 8 includes a 2.0 Bcf storage tank. The larger tank size resulted in higher material and construction. It can be seen from Table 1 above that majority of the difference in the total capital cost between the two supplemental alternatives is related to the size of the tank.*

2. *Due to the larger tank size for Supplemental Alternative 9, the Ground Improvement cost, which includes the storage tank foundation costs, is higher than Supplemental Alternative 8.*

3. *The design and equipment for the regasification, auxiliary system, and base plant demolition is the same between Supplemental Alternatives 8 and 9. The reason for the small difference in costs for these three cost items is due to the allocation of the pre-construction development costs, which as discussed on page 195 of the Supplemental Evidence, include actual pre-construction development costs of $28.347 million from 2020 to 2023 and a forecast of $14.399 million from 2024 to 2025. The pre-construction development costs are the same between Supplemental Alternatives 8 and 9, which are allocated based on the capital cost of each asset. Since the percentage breakdown of the assets is different between Supplemental Alternatives 8 and 9, the allocation of the same pre-construction development costs between each asset would be slightly different between the two alternatives.*

4. *A P50 contingency is applied to both Supplemental Alternatives 8 and 9. FEI re-engaged Validation Estimating to update the quantitative analysis for both Supplemental Alternatives used to determine the appropriate level of contingency, which was presented in Confidential Appendix I of the Supplemental Evidence. In general, the higher base cost estimate for Supplemental Alternative 9 resulted in a higher overall contingency than Supplemental Alternative 8.*

5. *The same AFUDC rate is applied to Supplemental Alternatives 8 and 9, and the construction schedules between the two alternatives are similar. The reason Supplemental Alternative 9 has a higher financial cost in AFUDC is due to the higher base capital cost estimate.*

132.2.1 Please discuss under what circumstances would the PV of Alternative 8 over a 67-year Analysis Period equal the PV of Alternative 9 over the same analysis period.

Response:

Financially speaking, there are scenarios in which the PV of the total cost of service of Supplemental Alternative 8 could equal the PV of Supplemental Alternative 9 over the same 67-year analysis period:

1. The capital cost of Supplemental Alternative 8 decreases while the capital cost of Supplemental Alternative 9 remains the same (or conversely that the capital cost of Supplemental Alternative 9 increases while the capital cost of Supplement Alternative 8 remains the same); or
2. The annual regional gas supply costs decrease, which in turn will decrease the amount of annual avoided gas supply costs provided by Supplemental Alternative 9 over Supplemental Alternative 8.

However, as FEI explains below, the likelihood of these circumstances occurring is very low. It is highly unlikely that customers would be financially better off on an NPV basis (67-year analysis period) with Supplemental Alternative 8, relative to Supplemental Alternative 9.

1. Capital Cost Scenario:

All else equal, if the base cost estimate of Supplemental Alternative 8 is approximately 5.36 percent lower while the base cost estimate of Supplemental Alternative 9 remains the same (or conversely if the base cost estimate of Supplemental Alternative 9 is approximately 4.86 percent higher while the base cost estimate of Supplemental Alternative 8 remains the same), then the total PV of cost of service for the two Supplemental Alternatives over the 67-year analysis period will be equal[40].

However, the likelihood of the above situations occurring is very low. First, the base cost estimates for both Supplemental Alternatives are at an AACE Class 3 level of accuracy. Second, any risks that might materialize during construction and therefore lead to an increase or decrease in capital costs would likely impact both Supplemental Alternatives in a similar way, because the design and scope of both alternatives are very similar, with essentially the only difference being the tank size. As noted in the Risk Analysis and Contingency Estimate for the 2 and 3 Bcf Tank Options by Validation Estimating (Confidential Appendix I of the Supplemental Evidence), all risk ratings are the same for the 2 and 3 Bcf options with the exception of the minor difference in the rating for the percentage of major equipment and fixed (non-equipment) costs.[41]

---

[40] All PVs of cost of service discussed in this response include the correction of small rounding error in the calculation for the annual gas costs up to 2035 discussed in the response to BCUC IR5 131.3.

[41] The difference in the risk ratings between 2 and 3 Bcf for major equipment and fixed (non-equipment) costs is due to the percentage of major equipment costs and fixed (non-equipment) costs over the total capital costs (i.e., for the same equipment, the percentage of the cost over the total capital cost of a 2 and 3 Bcf option would be different).

Therefore, if there is any circumstance during construction that could cause the capital costs of one Supplemental Alternative to increase, the same event would likely occur with the other Supplemental Alternative. For example, events such as global or regional inflationary increases, foreign exchange rate increases, regional or provincial labour shortages, or discoveries on site that cause delays in construction would be applicable to both Supplemental Alternatives 8 and 9, thus the capital costs of both alternatives would increase or decrease commensurately. As such, the likelihood that the PV of total cost of service of the two Supplemental Alternatives could be equal due to changes in the capital cost is small.

2. Annual Gas Supply Costs Scenario:

For the annual gas supply costs scenario, FEI separates the discussion into two periods (i.e., the years prior to 2035 and the years from 2035 and onwards):

- For the years prior to 2035, please refer to the response to BCUC IR5 131.4.1 which explains that there is no realistic T-South toll price for holding approximately 50 MMcf/d of pipeline capacity at which the PV of total cost of service over the 67-year analysis period of Supplemental Alternatives 8 and 9 would equal.
- For the years of 2035 and onwards, the PV of total cost of service of Supplemental Alternatives 8 and 9 over the 67-year analysis period depend on the cost of holding 1 Bcf and 200 MMcf/d from the regional market with a future market infrastructure expansion. As explained in the response to BCUC IR5 131.9, the financial analysis of both alternatives used the lower end estimates of $63 million (post-mitigation) for holding 1 Bcf and 200 MMcf/d from the regional market starting in 2035. If this cost is reduced to approximately $42 million (which is a reduction of approximately 33.3 percent), then the PV of total cost of service over the 67-year analysis period between Supplemental Alternatives 8 and 9 would be equal. However, given the $63 million used for the financial analysis is already at the lower end of the estimated costs (and FEI also conservatively did not forecast any future escalation of the annual gas costs beyond 2035, as discussed in the response to BCUC IR5 131.9), FEI has no evidence to support an assumption that the future annual gas supply costs could be 33.3 percent lower than the estimate used in the Supplemental Evidence. FEI expects the future annual gas supply costs for holding 1 Bcf and 200 MMcf/d would be higher than the $63 million used in the financial analysis (i.e., as shown in Figure 4-7 of the Supplemental Evidence, FEI estimated the upper end costs would be $79 million, post-mitigation).

Based on the discussion above, FEI considers it to be highly unlikely that the PV of the total cost of service of Supplemental Alternative 8 could equal the PV of the total cost of service of Supplemental Alternative 9. As stated above, it is highly unlikely that customers would be financially better off on an NPV basis (67-year analysis period) with Supplemental Alternative 8, relative to Supplemental Alternative 9.

As such, the difference in the risk rating for major equipment and non-equipment costs is not due to any construction difference between the 2 and 3 Bcf options.

132.3 For Alternative 8 and 9, respectively, please replicate Table 4-9, Table 6-4 and Table 6-5, under each of the following scenarios:

(i) Total Capital Costs during Construction are 50 percent higher than expected; and

(ii) Total Capital Costs during Construction are 100 percent higher than expected.

Response:

There is no evidence to support that the actual Project cost would be 50 percent or 100 percent higher than the forecast provided in Table 4-9 of the Supplemental Evidence. As explained in Section 6.1 of the Supplemental Evidence, FEI, in conjunction with Linde, HCBI, WSP, and SMCI, developed the Project base cost estimate using AACE International Recommended Practices 18R-97 and 97R-18. Further, Validation Estimating completed a quantitative analysis to evaluate the impact of Project-specific risks and systemic risks. FEI considers the P10 and P90 cost distributions developed based on the systemic and Project specific risks pertaining to the TLSE Project represent a more probable and reasonable range of Project costs that should be used to evaluate the range of delivery rate impacts, rather than on a hypothetical range of costs.

Using the P10 and P90 confidence of cost distribution and escalation risk of the Project developed by Validation Estimating (as provided in Confidential Appendices I and J of the Supplemental Evidence), the Project cost estimate under Supplemental Alternative 8 ranges from $675.193 million to $1,310.478 million and for Supplemental Alternative 9, $741.890 million to $1,464.268 million.

For the P10 and P90 confidence of cost estimate for both Supplemental Alternatives 8 and 9, please refer to:

- Tables 1 and 2 below for the summary of capital costs, cost of service, gas supply costs/savings, and levelized total rate impact of Supplemental Alternatives 8 and 9, respectively, replicating Table 4-9 of the Supplemental Evidence;
- Tables 3 and 4 below for the financial analysis of Supplemental Alternatives 8 and 9, respectively, replicating Table 6-4 of the Supplemental Evidence; and
- Tables 5 and 6 below for the summary of delivery rate impact from 2026 to 2031 for Supplemental Alternatives 8 and 9, respectively, replicating Table 6-5 of the Supplemental Evidence.

FEI notes that as discussed in the response to BCUC IR5 131.3, a small rounding error was discovered in the calculation of the annual costs of holding approximately 50 MMcf/d of pipeline capacity on T-South year-round. All numbers shown in the tables below for Supplemental Alternative 9 reflect the correct annual gas supply costs.

Table 1: Supplemental Alternative 8 – Summary of P10 to P90 Capital Costs, Cost of Service, Gas Supply Costs/Savings, and Levelized Total Rate Impacts

	Confidence Level		
	P10	As-Filed	P90
Total Capital Costs during Construction, As-Spent $ ($000s)	675,193	1,030,286	1,310,478
PV of Cost of Service, excl. Gas Supply Costs/Savings ($000s) over 67 years	818,559	1,133,984	1,383,519
PV of Gas Supply Cost/Savings ($000s) over 67 years	(366,362)	(366,362)	(366,362)
Total PV of Cost of Service over 67 years ($000s)	**452,197**	**767,622**	**1,017,156**
Levelized Total Rate Impact (Incl. Cost of Gas) 67 years (%)	1.53%	2.60%	3.45%
Levelized Total Rate Impact (Incl. Cost of Gas) 67 years ($/GJ)	0.143	0.242	0.321

Table 2: Supplemental Alternative 9 – Summary of P10 to P90 Capital Costs, Cost of Service, Gas Supply Costs/Savings, and Levelized Total Rate Impacts

	Confidence Level		
	P10	As-Filed	P90
Total Capital Costs during Construction, As-Spent $ ($000s)	741,890	1,140,962	1,464,268
PV of Cost of Service, excl. Gas Supply Costs/Savings ($000s) over 67 years	889,422	1,240,803	1,526,272
PV of Gas Supply Cost/Savings ($000s) over 67 years	(519,585)	(519,585)	(519,585)
Total PV of Cost of Service over 67 years ($000s)	**369,837**	**721,218**	**1,006,687**
Levelized Total Rate Impact (Incl. Cost of Gas) 67 years (%)	1.25%	2.44%	3.41%
Levelized Total Rate Impact (Incl. Cost of Gas) 67 years ($/GJ)	0.117	0.228	0.318

Table 3: Supplemental Alternative 8 – P10 to P90 Financial Analysis Over 67-year Analysis Period

		Confidence Level		
Line	Particular	P10	As-Filed	P90
1	Total Charged to Gas Plant in Service ($ millions)	660.941	1,007.518	1,281.258
2	Base Plant Demolition Costs ($ millions)	14.252	22.767	29.220
3	Total Project Deferral Cost, Net of Tax ($ millions)	2.927	2.927	2.927
4	***Total Project Cost ($ millions)***	**678.120**	**1,033.213**	**1,313.405**
5				
6	Incremental Delivery Margin in 2035 ($ millions)	75.050	107.467	133.070
7	Incremental Cost of Gas Benefits in 2035 ($ millions)	(46.000)	(46.000)	(46.000)
8	***Net Incremental Revenue Requirement in 2035 ($ millions)***	**29.050**	**61.467**	**87.070**
9				
10	PV of Incremental Delivery Margin 67 years ($ million)	818.559	1,133.984	1,383.519
11	PV of Incremental Cost of Gas Benefits 67 years ($ million)	(366.362)	(366.362)	(366.362)
12	***Net PV of Incremental Revenue Requirement 67 years ($ million)***	**452.197**	**767.622**	**1,017.156**
13				
14	Delivery Rate Impact in 2035 (%)	6.58%	9.42%	11.66%
15	Total Rate Impact (incl. Cost of Gas) in 2035 (%)	1.55%	3.28%	4.65%
16				
17	***Levelized Total Rate Impact (Incl. Cost of Gas) 67 years (%)***	**1.53%**	**2.60%**	**3.45%**
18	***Levelized Total Rate Impact (Incl. Cost of Gas) 67 years ($/GJ)***	**0.143**	**0.242**	**0.321**

Table 4: Supplemental Alternative 9 – P10 to P90 Financial Analysis Over 67-year Analysis Period

Line	Particular	Confidence Level P10	As-Filed	P90
1	Total Charged to Gas Plant in Service ($ millions)	727.784	1,118.238	1,434.799
2	Base Plant Demolition Costs ($ millions)	14.106	22.724	29.468
3	Total Project Deferral Cost, Net of Tax ($ millions)	2.927	2.927	2.927
4	***Total Project Cost ($ millions)***	**744.817**	**1,143.889**	**1,467.195**
5				
6	Incremental Delivery Margin in 2035 ($ millions)	82.285	118.662	148.162
7	Incremental Cost of Gas Benefits in 2035 ($ millions)	(63.000)	(63.000)	(63.000)
8	***Net Incremental Revenue Requirement in 2035 ($ millions)***	**19.285**	**55.662**	**85.162**
9				
10	PV of Incremental Delivery Margin 67 years ($ million)	889.422	1,240.803	1,526.272
11	PV of Incremental Cost of Gas Benefits 67 years ($ million)	(519.585)	(519.585)	(519.585)
12	***Net PV of Incremental Revenue Requirement 67 years ($ million)***	**369.837**	**721.218**	**1,006.687**
13				
14	Delivery Rate Impact in 2035 (%)	7.21%	10.40%	12.98%
15	Total Rate Impact (incl. Cost of Gas) in 2035 (%)	1.03%	2.97%	4.55%
16				
17	***Levelized Total Rate Impact (Incl. Cost of Gas) 67 years (%)***	**1.25%**	**2.44%**	**3.41%**
18	***Levelized Total Rate Impact (Incl. Cost of Gas) 67 years ($/GJ)***	**0.117**	**0.228**	**0.318**

Table 5: Supplemental Alternative 8 – P10 to P90 Delivery Rate Impact from 2026 to 2031

		2026	2027	2028	2029	2030	2031
P10	Annual Delivery Margin, Incremental to 2025 Approved, Non-Bypass ($ millions)	1.413	1.738	8.118	21.548	35.193	78.128
	% Increase to 2025 Approved Delivery Margin, Non-bypass	***0.12%***	***0.15%***	***0.71%***	***1.89%***	***3.08%***	***6.85%***
	Incremental % Delivery Rate Impact (Year-over-Year)	***0.12%***	***0.03%***	***0.56%***	***1.17%***	***1.17%***	***3.65%***
As-Filed	Annual Delivery Margin, Incremental to 2025 Approved, Non-Bypass ($ millions)	1.355	1.405	10.935	30.738	52.243	113.416
	% Increase to 2025 Approved Delivery Margin, Non-bypass	***0.12%***	***0.12%***	***0.96%***	***2.69%***	***4.58%***	***9.94%***
	Incremental % Delivery Rate Impact (Year-over-Year)	***0.12%***	***0.00%***	***0.83%***	***1.72%***	***1.83%***	***5.13%***
P90	Annual Delivery Margin, Incremental to 2025 Approved, Non-Bypass ($ millions)	1.310	1.125	13.327	38.312	65.943	141.259
	% Increase to 2025 Approved Delivery Margin, Non-bypass	***0.11%***	***0.10%***	***1.17%***	***3.36%***	***5.78%***	***12.38%***
	Incremental % Delivery Rate Impact (Year-over-Year)	***0.11%***	***(0.02%)***	***1.07%***	***2.16%***	***2.34%***	***6.24%***

Table 6: Supplemental Alternative 9 – P10 to P90 Delivery Rate Impact from 2026 to 2031

		2026	2027	2028	2029	2030	2031
P10	Annual Delivery Margin, Incremental to 2025 Approved, Non-Bypass ($ millions)	1.414	1.797	9.877	23.159	36.852	86.164
	% Increase to 2025 Approved Delivery Margin, Non-bypass	***0.12%***	***0.16%***	***0.87%***	***2.03%***	***3.23%***	***7.55%***
	Incremental % Delivery Rate Impact (Year-over-Year)	***0.12%***	***0.03%***	***0.71%***	***1.15%***	***1.18%***	***4.19%***
As-Filed	Annual Delivery Margin, Incremental to 2025 Approved, Non-Bypass ($ millions)	1.328	1.456	13.834	33.280	54.792	125.920
	% Increase to 2025 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%***
P90	Annual Delivery Margin, Incremental to 2025 Approved, Non-Bypass ($ millions)	1.248	1.163	17.280	41.874	69.652	158.122
	% Increase to 2025 Approved Delivery Margin, Non-bypass	***0.11%***	***0.10%***	***1.51%***	***3.67%***	***6.10%***	***13.85%***
	Incremental % Delivery Rate Impact (Year-over-Year)	***0.11%***	***(0.01%)***	***1.41%***	***2.12%***	***2.35%***	***7.31%***

D. PROJECT DESCRIPTION

133.0 Reference: PROJECT NEED

Exhibit B-60 (Supplemental Evidence), p. 79

Boil-off Gas

On page 79 of Exhibit B-60, FEI states:

> The Base Plant tank was constructed with one boil off gas compressor to manage pressure build up within the tank (boil off gases). In addition, the tank was designed to operate under a very narrow pressure range. Under normal operations, this compressor manages the pressure in the tank within the design ranges and captures the boil off gases and sends them back to the pipeline. However, even under minor upset conditions or during periods of maintenance for the compressor, the pressure can build up in the tank beyond the design range and is released to atmosphere through a vent at the top of the tank. This design configuration was common practice for tanks built in the 1970s; however, current day standards require multiple boil off gas compressors (to provide redundancy), and include a wider range of design pressures to <u>avoid venting boil off gases to atmosphere</u>. [Emphasis added]

133.1 Please explain how boil off gases from the TLSE Project LNG tank are handled during normal operation. Please include discussion of the proposed boil-off gas (BOG) compressor(s) redundancy and proposed utilization of compressed BOG within the Tilbury site.

<u>Response:</u>

The normal boil-off gas from the TLSE Project's LNG tank will be re-directed into FEI's transmission system (through send out gas pipelines) via a boil-off gas compressor.

The boil-off gas management system will incorporate redundancy, through multiple boil-off gas compressors, ensuring that boil-off gas can be directed to the transmission system across the entire operational spectrum of the TLSE Project.

133.2 Please explain how boil off gases from the TLSE Project LNG tank are handled during upset conditions or periods of maintenance.

<u>Response:</u>

During upset conditions or planned maintenance, the TLSE Project will rely on redundant boil-off gas compressors to manage the boil-off gas. These backup compressors will be activated to maintain continuous operation. If the entire boil-off gas management system becomes unavailable despite the redundancy, alternative operating solutions will be employed. These include increasing the tank's operating pressure within its design range to suppress boil-off gas generation or decreasing the pressure before planned maintenance to allow for a gradual rise.

If all these backups are exhausted, FEI would use the discretionary vent on the tank to release the boil-off gas into the atmosphere, as necessary, to stabilize the TLSE tank's operating pressure.

133.3 In the event that the BOG compressor(s) is/are not available, please explain whether FEI proposes to vent BOG to atmosphere or to a flare system.

Response:

Please refer to the response to BCUC IR5 133.2.

133.4 Please confirm, or explain otherwise, that a flare system is not within the scope of FEI's proposed TLSE Project.

Response:

Confirmed. A dedicated flare system is not within the proposed TLSE Project scope.

133.5 Please confirm, or explain otherwise, that a flare system is included within the scope of the Tilbury Phase 2 Expansion Project.

133.5.1 If confirmed, please clarify whether FEI proposes to utilize the Tilbury Phase 2 Expansion Project flare system in the event that the TLSE Project BOG compressor(s) are not available.

Response:

Confirmed. The design for the liquefaction facility that forms part of the scope of the Tilbury Phase 2 LNG Expansion project includes a flare system, as well as its own boil-off gas management system. A flare system will only be necessary if the Phase 2 liquefaction facility enters operation.

In the event that the TLSE boil-off gas compressors are unavailable, FEI will determine whether to vent the boil-off gas or direct it to the Phase 2 liquefaction facility's flare system (if constructed) based on operational requirements, safety considerations, and emission regulations once both projects are fully operational.

133.6 Please confirm, or explain otherwise, that the scope of the Tilbury Phase 2 Expansion Project includes BOG compressors for use during delivery of LNG to the Tilbury Marine Jetty (i.e. LNG delivered to marine transportation fuel customers).

Response:

Confirmed. The design of the liquefaction facility within the scope of the Tilbury Phase 2 LNG Expansion project includes dedicated boil-off gas compressors to facilitate delivery of LNG to the Tilbury Marine Jetty. This facility does not form part of the TLSE Project scope.

134.0 Reference: PROJECT DESCRIPTION

Exhibit B-60 (Supplemental Evidence), 195, Exhibit B-1, p. 135

LNG Tank Costs

On page 195 of Exhibit B-60, FEI states that cost of the proposed 3 BCF LNG tank is $359.749 million in 2023 dollars.

134.1 Please confirm the final cost to construct and commission FEI's LNG tank at Mt. Hayes (in 2023 dollars).

Response:

The Mt. Hayes LNG tank (1.5 Bcf) was completed in 2011 and the final cost was approximately $63.096 million (tank only). After applying inflationary increases[42] and accounting for differences in the exchange rate between US Dollars and Canadian Dollars from 2011 to 2023[43], a similar Mt. Hayes LNG tank with 1.5 Bcf storage capacity built in 2023 would be approximately $105.656 million[44]. This is equivalent to approximately $70.437 million per Bcf, compared to approximately $119.916 million per Bcf for the proposed 3 Bcf TLSE tank.

FEI notes that it would not be appropriate to directly compare the cost (or the unit cost) of the 1.5 Bcf Mt. Hayes LNG storage tank to the proposed 3 Bcf TLSE LNG storage tank, even after accounting for inflationary increases and changes in the exchange rate. The design and safety requirements of the two tanks are different. The Mt. Hayes LNG tank was designed to be a single containment tank with spill impoundment dikes and an earthen berm for spill containment, while the proposed TLSE 3 Bcf tank is designed to be a full containment tank, with the outer tank designed to contain the LNG in case of an inner tank failure (thus providing a higher level of safety for spill containment).

In the Supplemental Evidence, FEI included a cost estimate for a 1 Bcf tank (i.e., Alternatives 4A and 6) and a cost estimate for a 2 Bcf tank (i.e., Alternatives 7 and 8, also see BCUC IR5 132.1). Based on the cost estimates of these two tank sizes, FEI expects the cost to build a 1.5 Bcf LNG storage tank based on the design and safety requirements for Tilbury would range from $235 million to $296 million. Using the mid-point of this range (i.e., $265.5 million), this is equivalent to a unit cost of approximately $177 million per Bcf, which is higher than the proposed 3 Bcf tank (i.e., $119.916 million per Bcf). This observation aligns with the discussion in Section 4.5.4.1.1 of the Supplemental Evidence, which showed that there are significant economies of scale (i.e., the capital cost per unit of storage decreases as the size of the LNG storage increases).

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[42] Average indices of BC CPI for 2011 and 2023 were 116.5 and 151.2, respectively, i.e., an increase of 28.8 percent: https://catalogue.data.gov.bc.ca/dataset/2c75c627-3eb6-41ee-bb54-7b089eade484/resource/93e4367b-56af-4e1c-aea7-48fb48f0727c/download/cpi_annual_averages.pdf.

[43] Average USD to CAD in 2011 was 0.9891 and average USD to CAD in 2023 was 1.3497, i.e., an increase of 36.5 percent. Bank of Canada Historical noon and closing rates: https://www.bankofcanada.ca/rates/exchange/legacy-noon-and-closing-rates/.

[44] $60.096 million x (1 + 0.288) x (1 + 0.365) = $105.656 million.

134.2 Please confirm the final cost to construct and commission FEI's LNG T1A tank at Tilbury (in 2023 dollars).

Response:

The Tilbury 1A LNG tank (1 Bcf) was completed in 2018 and the final cost was approximately $167.178 million (tank only). After applying inflationary increases[45] and accounting for differences in the exchange rate between US Dollars and Canadian Dollars from 2018 to 2023[46], a similar Tilbury 1A LNG tank with 1 Bcf storage capacity built in 2023 would be approximately $205.207 million.[47] FEI notes that this is in the same range of cost for the 1 Bcf LNG tank estimated for Supplemental Alternatives 4A and 6 of the TLSE Project, which is approximately $235 million.

On page 135 of Exhibit B-1, FEI states:

> HCBI [Horton CB&I] specializes in providing bulk gas and liquid storage solutions, including low-temperature and cryogenic storage tanks and systems. HCBI's services have been retained for the engineering of the 3 Bcf LNG storage tank. The HCBI estimate includes the complete design, supply, fabrication, construction, inspection, testing, drying and purging of a full containment concrete LNG tank.

134.3 Please provide a list of the final costs to construct and commission the LNG tanks that HCBI has been involved in designing and constructing over the last 10 years (in 2023 dollars). Please provide the volume (m3) of each tank.

Response:

The following response was provided by HCBI:

HCBI has developed the estimates for LNG Tanks provided to FEI based on information such as estimated quantities, estimated/actual costs from past projects it has executed, current market cost data and other relevant information to develop Class III Estimates. HCBI cannot provide confidential information such as costs for other LNG Tanks that HCBI has designed and built as

45 Average indices of BC CPI for 2018 and 2023 were 128.4 and 151.2, respectively, i.e., an increase of 17.8 percent: https://catalogue.data.gov.bc.ca/dataset/2c75c627-3eb6-41ee-bb54-7b089eade484/resource/93e4367b-56af-4e1c-aea7-48fb48f0727c/download/cpi_annual_averages.pdf.

46 Average USD to CAD in 2018 was 1.2957 and average USD to CAD in 2023 was 1.3497, i.e., an increase of 4.2 percent. Bank of Canada Historical noon and closing rates: https://www.bankofcanada.ca/rates/exchange/legacy-noon-and-closing-rates/.

47 $167.178 million x (1 + 0.178) x (1 + 0.042) = $205.207 million.

such information is commercially sensitive to both HCBI and its customers and cannot be provided to FEI or others.

134.3.1 Please discuss how FEI's $359.749 million estimate for the 3 BCF tank compares to the actual costs reported by HCBI in the preceding IR.

Response:

The following response was provided by HCBI:

The estimate provided by HCBI for the 3 BCF LNG Tank is in line with HCBI's global estimating guidelines and takes into account HCBI's previous actual experience in building LNG tanks all over the world. This includes projects with similar weather characteristics such as South Hook (Wales), Isle of Grain (England), Sakhalin Island (Russia), and Puget Sound Energy (Washington State), as well as many others elsewhere around the world. As noted previously, HCBI cannot provide confidential information such as costs for other LNG Tanks that HCBI has designed and built as such information is commercially sensitive to both HCBI and its customers is commercially sensitive and cannot be provided to FEI or others.

134.4 Please list common causes of LNG tank construction cost overruns, based on the LNG industry experience of FEI and its consultants.

134.4.1 Please discuss how these causes of cost overruns do or do not apply to the TLSE Project, and how FEI has addressed those that do.

Response:

FEI, in consultation with its external experts, identified the following common causes of LNG tank construction cost overruns, all of which may apply to the TLSE Project. FEI also describes how it plans to address these common causes of overruns.

- **Increased Labour Costs:** The labour market fluctuates with demand and has historically had an effect on pricing. FEI is working with contractors to ensure labour charges are in line with the current market and will utilize comprehensive contract strategies to secure competitive pricing.
- **Increased Equipment and Bulk Material Costs:** The cost of equipment and bulk materials, such as steel, used in LNG tanks tend to increase over time and may lead to cost overruns. The potential for such increases is accounted for in FEI's escalation

calculations. FEI continues to monitor markets, and, where possible, orders long lead and bulk materials early to mitigate the potential impact of cost overruns of this kind. Obtaining regulatory approval for a Project earlier in the Project development increases certainty and enables earlier procurement, and can result in cost savings.

- **Vendor Execution Issues:** A vendor's failure to meet expectations or complete specific work can lead to cost overruns. Before establishing these key supplier relationships, FEI verifies each vendor's background during the prequalification selection.
- **Brownfield Construction:** Brownfield construction on sites containing operating facilities creates work constraints and challenges. The TLSE Project team is coordinating with the Tilbury Operations team to pre-plan work activities at the Tilbury site, and will continue to do so though Project development.
- **Timing Permit and Regulatory Approvals:** The uncertainty of timing and obtaining permits and other regulatory approvals can create delays in a project's schedule and lead to increased costs. FEI is building flexibility in the TLSE Project schedule to account for uncertainties in permitting timelines.

135.0 Reference: PROJECT DESCRIPTION

Exhibit B-60 (Supplemental Evidence), p. 189

Geotechnical Requirements

On page 189 of Exhibit B-60, FEI states:

> The geotechnical requirements for the Preferred Alternative have changed due to changes in the seismic design standards since the Application was filed.
>
> The 2020 geotechnical costs, linked to design based on an earlier version of the CSA Z276 code, are no longer valid due to significant changes in seismic hazard and design criteria according to the latest code CSA Z276: 2022 (April 2023 version). The geotechnical costs from 2020 have been re-evaluated using new construction rates from 2023. To improve the accuracy of the cost estimate, WSP reviewed the design assumptions and consulted with a specialty ground improvement contractor to ensure the design requirements could be met.
>
> Detailed geotechnical work will be carried out prior to commencing detailed design to ensure the proposed ground improvements will meet the limits of the ground settlement specified by the tank vendor.

135.1 Please explain how the ground improvement scope of work as currently proposed has changed in comparison to the scope of work proposed in 2020.

Response:

Compared to the scope of work in 2020, the revised scope of work related to ground improvements includes the following changes:

- Changes to the center-to-center spacings of the stone columns beneath the TLSE tank to meet the latest seismic hazard and design criteria requirements;
- The installation of cutter soil mix panels installed to 12 metre depth; and
- The installation of wick drains to improve drainage within the upper 12 metre depth below the tank foundations.

The revised scope of work is subject to further detailed engineering analysis to be conducted in subsequent phases of Project development.

135.1.1 Please provide a copy of any reports prepared by WSP with respect to the design assumptions and ground improvement work related to the Preferred Alternative (3 BCF tank).

Response:

FEI provides a copy of the WSP report with respect to the design assumptions and ground improvement work, dated October 17, 2023, in Confidential Attachment 135.1.1.

FEI is requesting that Attachment 135.1.1 be filed on a confidential basis and be held confidential by the BCUC in perpetuity, pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-296-24. The document includes capital cost estimates for the TLSE Project and should be kept confidential on the basis that FEI may be going to the market to seek competitive bids for the materials and construction work for the Project. If the estimated costs for the material and construction work are disclosed, FEI reasonably expects that its negotiating position may be prejudiced. For instance, the bidding parties with knowledge about the estimated costs may use the estimate costs as a reference for their bidding.

135.2 Please explain what mitigations FEI can take prior to commencing detailed design to ensure that there is no requirement to escalate the proposed ground improvement scope and costs to meet the limits of the ground settlement specified by the tank vendor.

Response:

Prior to commencing detailed design engineering, there are several investigative tools that can act as mitigation measures that FEI can explore. These investigative tools include:

- Cone penetration tests (CPTs) to determine the geotechnical engineering properties of the soil;
- Boreholes to collect data that would be analyzed for determination of the properties of the subsurface; and
- Shear wave velocity survey to measure the mechanical properties of the soil.

The data gathered from this investigation will serve as inputs for the geotechnical analysis.

In parallel, FEI intends to carry out a Probabilistic Seismic Hazard Analysis (PSHA), followed by detailed calculations on ground response analysis with the new hazard parameters to estimate the ground settlement. Once FEI has engaged a tank vendor, there would be further iterative discussions on mitigative measures and costs.

135.3 Please confirm, or explain otherwise, that FEI has consulted with the tank vendor with respect to the latest ground improvement information available to FEI. Such as, for example, providing the tank vendor with the work completed by WSP.

Response:

FEI intends to consult with the tank vendor once further investigative work is completed (e.g., further field investigation, studies) related to the geotechnical analysis. This information will be provided to the tank vendor prior to initiating detailed design of the tank.

135.4 Please discuss lessons learned by FEI during the construction of the T1A LNG tank at Tilbury, with respect to site specific geotechnical requirements. How has FEI implemented these lessons learned into the design of the TLSE Project?

Response:

As noted in the preamble, seismic design standards have changed since Tilbury 1A was constructed. The Tilbury 1A tank was designed with the expertise of the geotechnical engineer of record and tank vendor to meet code requirements at the time. These requirements enabled differing grounds improvements of -30 metres under the tank and -16 metres in other non-tank areas.

Information gained from the experience of constructing Tilbury 1A has informed the design of the TLSE tank; however, codes and geotechnical requirements are periodically updated and are generally becoming more stringent. As a result, FEI has incorporated current seismic design standards along with information gained from Tilbury 1A (primarily how the existing ground improvements have performed) into its approach to developing the TLSE Project and is also planning to conduct more comprehensive geotechnical studies during detailed design for the larger TLSE tank.

136.0 Reference: PROJECT DESCRIPTION

Exhibit B-60 (Supplemental Evidence), pp. 68, 201

O&M savings due to the demolition of Tilbury Base Plant

On page 201 of Exhibit B-60, FEI states:

> Incremental O&M: An estimate of incremental O&M costs resulting from the TLSE Project of approximately $5.729 million in 2023 dollars ($6.953 million in 2031 dollars). These costs are comprised of:
>
> - approximately $8.818 million in 2023 dollars ($10.585 million in 2031 dollars) of new O&M costs, including electricity costs, associated with the new 3 Bcf LNG 11 tank, the new 800 MMcf/d regasification equipment, and auxiliary systems;
> - offset by O&M savings, including electricity costs, of approximately $3.089 million in 2023 dollars ($3.631 million in 2031 dollars) due to the demolition of the Tilbury Base Plant.

On page 68 of Exhibit B-60, FEI states:

> Additional engineering analysis on the Base Plant, and its recent deteriorating performance despite further investment, indicate that the Base Plant has reached end-of-life.

136.1 Please confirm, or explain otherwise, that FEI has offset O&M costs resulting from the TLSE Project by O&M savings due to the demolition of the Tilbury Base Plant for each year of the 67-year analysis period.

136.1.1 If confirmed, please clarify why FEI has accounted for 67 years of O&M savings from the demolition of the Tilbury Base Plant if the Tilbury Base Plant has at present reached end-of-life.

<u>Response:</u>

Confirmed. However, FEI clarifies that the term “savings” was intended to convey the amount that FEI subtracted from the total O&M of the proposed TLSE Project in the financial model over the analysis period in order to determine the incremental O&M impact to FEI’s customers resulting from the TLSE Project. FEI further explains below.

Although Section 3 of the Supplemental Evidence discussed that the Tilbury Base Plant has at present reached its end-of-life, FEI has been continuing to operate it at a derated capacity with an annual O&M cost, including electricity, of approximately $3.089 million (in 2023 dollars). For the financial analysis, FEI assumed it would continue to operate the Tilbury Base Plant until 2030, at which point it would undergo demolition and the new TLSE facility would be in-service. As such, FEI has included an incremental O&M cost of $5.729 million (in 2023 dollars) to the revenue requirement due to the proposed TLSE Project (as stated on page 201 of the Supplemental Evidence) which is the difference between the current Tilbury Base Plant O&M cost of $3.089

million (in 2023 dollars) and the estimated O&M cost of $8.818 million (in 2023 dollars) for the new TLSE facility. The $3.089 million (in 2023 dollars) related to the Tilbury Base Plant O&M is already included as part of FEI's current revenue requirement and rates.

As such, the $3.089 million (in 2023 dollars) is not a "savings" to O&M; rather, it was subtracted from the total O&M of the proposed TLSE Project in the financial model over the entire analysis period in order to provide only the incremental O&M impact to FEI's customer due to the TLSE Project. If the $3.089 million was not subtracted from the estimated O&M of the proposed TLSE facility, then the current O&M cost of $3.089 million, which is already included in FEI's rates, would be double counted in the financial analysis for the proposed TLSE Project.

E. CONSULTATION AND ENGAGEMENT

137.0 Reference: CONSULTATION AND ENGAGEMENT

Exhibit B-60 (Supplemental Evidence), pp. 209 – 214; Exhibit B-15, BCUC IR 58; BC Environmental Assessment Office(EAO), Schedule B - Assessment Plan for the Tilbury Phase 2 LNG Expansion Project, June 13, 2022[48]; BC EAO, December 2, 2024 Letter from EAO to FortisBC regarding Tilbury Phase 2 EAC Application[49]

Indigenous Consultation

On pages 209 to 210 of Exhibit B-60, FEI states that its engagement with Indigenous groups with respect to the TLSE Project is taking place through this CPCN Application and the Environmental Assessment (EA) process for the FortisBC Tilbury Phase 2 Expansion Project, which includes components of the TLSE Project. FEI applies comments received from Indigenous groups through this synchronized process to all applicable aspects of the developments at Tilbury, including the TLSE Project, to ensure they are appropriately captured and addressed.

FEI's states its engagement through the EA process has been consistent with the BC Environmental Assessment Office's (BC EAO) framework for consensus-seeking with Indigenous groups, as outlined in the June 13, 2022 Assessment Plan (Assessment Plan) for the Tilbury Phase 2 Expansion Project, and provided a link to the Assessment Plan.[50]

On pages 210 to 211, in Table 8-1 and Table 8-2 of Exhibit B-60, FEI identifies Indigenous Groups potentially affected by the TLSE Project.

137.1 Please clarify if the most recent list of Indigenous Groups participating in the Tilbury Phase 2 EA, and their level of participation, is the same as that found in Sections 2.1 to 2.3 of the Assessment Plan or explain otherwise, providing any necessary updates.

Response:

FEI confirms that the lists of Indigenous groups identified in Tables 8-1 and 8-2 of the Application currently remain consistent with those identified in Sections 2.1 to 2.3 of the Assessment Plan in the Tilbury Phase 2 LNG Expansion Project Environmental Assessment. There have been no amendments to the Assessment Plan since it was finalized in 2022. However, FEI anticipates amendments related to Sections 2.1 to 2.3 of the Assessment Plan will come into effect once the

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48 https://projects.eao.gov.bc.ca/api/public/document/62c75af8e04a3a00225b7d84/download/Tilbury%20LNG%20Phase%202%20-%20Assessment%20Plan%20-%20Rev1%20-%20June%2013%202022%20%28EPIC%20Posting%29.pdf.

49 https://projects.eao.gov.bc.ca/p/5df7f1bfb7434b002164961c/project-details.

50 Exhibit B-60, p. 210, footnote 260.

BC EAO issues a revised Process Order in the near future. The BC EAO is currently consulting with Indigenous Nations on the proposed revised Process Order.

In response to BCUC IR 58, FEI provided an update to the Indigenous Engagement Log, including activities up to July 5, 2021.

Section 3.1 of the Schedule B-Assessment Plan refers to certain deliverables which FortisBC must develop as part of the Application Information Requirement for the EAO.

137.2 Please provide an updated Indigenous Engagement log, which includes a chronology of meetings, other communications and actions covering the consultation activities relevant to the TLSE project from July 2021 to the present. Noting the twinned process, this may include materials already provided to the BC EAO.

Response:

The environmental assessment process for the Tilbury Phase 2 LNG Expansion Project, which involves components of the TLSE Project, is underway in parallel to this proceeding. Where possible, FEI has synchronized engagement activities between these regulatory processes. This approach provides potentially affected Indigenous groups a significant and meaningful opportunity to engage in a process of dialogue and consensus-seeking over the course of project development. Because FEI applies comments received from Indigenous groups through this synchronized process to all applicable aspects of the developments at Tilbury, including the TLSE Project, consultation activities that are specific to the TLSE Project alone are often intermingled with other aspects of the Tilbury Phase 2 Expansion Project and developments at Tilbury generally. In preparing the updated Indigenous Engagement log, included as Attachment 137.2, FEI has narrowed the consultation activities to those relevant to the TLSE Project to the extent practicable.

137.3 Please provide copies of any relevant, non-confidential written documentation regarding consultation, such as notes or minutes of meetings or phone calls, or letters received from or sent to Indigenous Groups.

Response:

The updated Engagement log provided in the response to BCUC IR5 137.2 includes summaries of meetings, phone calls, emails and other correspondence with Indigenous groups from July 2021 to February 2025.

FEI and potentially affected Indigenous groups have also attended Technical Advisory Committee (TAC) meetings held by the BC EAO as part the ongoing environmental assessment of the Tilbury Phase 2 LNG Expansion Project. These meetings have spanned the Process Planning (2022), Application Development (2024) and ongoing Application Review (2025) phases of the assessment. The table below provides links to the TAC meeting minutes.

Table 1: Technical Advisory Committee Meeting Notes

Date	Meeting Notes / Minutes
January 26, 2022	Tilbury Phase 2 LNG Expansion Project Process Planning Technical Advisors Meeting #1 Summary Meeting Notes
February 23, 2022	Tilbury Phase 2 LNG Expansion Project Process Planning Technical Advisors Meeting #2 Meeting Notes
March 8, 2022	Tilbury Phase 2 LNG Expansion Project Process Planning Technical Advisors Meeting #3 - Air Quality & Human Health Risk Assessment Meeting Notes
April 5, 2022	Tilbury Phase 2 LNG Expansion Project Process Planning Technical Advisors Meeting #4 Greenhouse Gas Emissions Meeting Notes
April 26, 2022	Tilbury Phase 2 LNG Expansion Project Process Planning Technical Advisors Meeting #5 Accidents and Malfunction/Public Safety Meeting Notes
December 10, 2024	Tilbury Phase 2 LNG Expansion TAC Summary Meeting Notes
December 13, 2024	Tilbury Phase 2 LNG Expansion TAC Summary Meeting Notes
January 7, 2025	Tilbury Phase 2 LNG Expansion TAC Summary Meeting Notes
January 8, 2025	Tilbury Phase 2 LNG Expansion TAC Summary Meeting Notes
January 9, 2025	Tilbury Phase 2 LNG Expansion TAC Summary Meeting Notes
January 13, 2025	Tilbury Phase 2 LNG Expansion TAC Summary Meeting Notes

As part of preparing the environmental assessment application for the Tilbury Phase 2 LNG Expansion Project, potentially affected Indigenous groups developed, or co-developed with FEI, comprehensive summaries of engagement with Indigenous groups. These summaries, which address the period of July 2021 to November 2024, are provided in Section 11 of the environmental assessment application, with a chapter for each potentially affected Indigenous group. A summary of engagement, including issues raised can be found in subsection 3 of each chapter. For example, the engagement summary for Musqueam Indian Band can be found in *Tilbury Phase 2 LNG Expansion – Application – 11.07 Musqueam – Subsection 11.7.3 – Summary of Engagement*. The table below provides links to each chapter of Section 11 of the environmental assessment application.

Table 2: Indigenous Engagement Summaries in Section 11 of EA Application

Indigenous Group	Section 11 Chapter
Cowichan Tribes Halalt First Nation Stz'uminus First Nation Penelakut Tribe Lyackson First Nation	11.4 Quw'utsun Nation

Indigenous Group	Section 11 Chapter
Katzie First Nation	11.5 Katzie First Nation
Kwantlen First Nation	11.6 Kwantlen First Nation
Musqueam Indian Band	11.7 Musqueam Indian Band
Seabird Island Band Shxw'ōwhámél First Nation Skawahlook (Sq'ewá:lxw) First Nation Soowahlie First Nation	11.8 S'ólh Téméxw Stewardship Alliance
Tsawwassen First Nation	11.9 Tsawwassen First Nation
Tsleil-Waututh Nation	11.10 Tsleil-Waututh Nation
Ts'uubaa-asatx Nation	11.11 Ts'uubaa-asatx
Metis Nation British Columbia	11.12 Métis Nation British Columbia
Semiahmoo First Nation	11.13 Semiahmoo First Nation
Snuneymuxw First Nation	11.14 Snuneymuxw First Nation
Squamish Nation	11.15 Sḵwx̱wú7mesh Úxwumixw
Stó:lō Nations	11.17 Stó:lō Nations

On Dec 2, 2024, the BC EAO notified FEI that review of the Draft Phase 2 Application had begun.[51] The public comment period runs from Jan 14 to March 3, 2025. Once the application is accepted, the BC EAO will begin its assessment of the potential positive and negative impacts of the project, including whether any adverse impacts can be appropriately mitigated.

137.4 Please provide an update on the specific issues or concerns raised by any First Nations during the EA comment period which are relevant to the TLSE Project, and describe how the specific issues or concerns raised by the First Nation were avoided, mitigated or otherwise accommodated, or explain why no further action is required to address an issue or concern.

Response:

As explained in the response to BCUC IR5 137.2, FEI has synchronized engagement activities for the TLSE Project with those of the environmental assessment process for the Tilbury Phase 2 LNG Expansion Project. As such, consultation activities that are specific to the TLSE Project alone are often intermingled with other aspects of the Tilbury Phase 2 Expansion Project and developments at Tilbury generally.

As described in Section 8.2.4 of the Supplementary Evidence and the updated Engagement log provided in the response to BCUC IR5 137.2, FEI has engaged extensively with Indigenous groups. In particular, since July 2021, FEI has undertaken over 700 individual engagements with

51 https://projects.eao.gov.bc.ca/p/5df7f1bfb7434b002164961c/project-details.

Indigenous groups related to the TLSE Project through email, phone calls, meetings and site tours. Several comment processes are also ongoing simultaneously as part of the environmental assessment process for the Tilbury Phase 2 LNG Expansion Project, including opportunities for Indigenous groups to provide comments and ask questions. The comment process for Indigenous groups is ongoing; however, at the time of filing this response, FEI had received and responded to one round of comments from the following Indigenous groups:

- Musqueam Indian Band;
- Quw'utsun Nation (Cowichan Tribes, Halalt First Nation, Lyackson First Nation, Stz'uminus First Nation, Penelakut Tribe);
- Tsawwassen First Nation;
- Tsleil-Waututh Nation;
- Snuneymuxw First Nation; and
- Ts'uubaa-asatx.

Together, these groups have submitted more than 855 unique comments and/or information requests to FEI to date. Given the volume and technical nature of many of these comments and information requests, FEI has summarized themes of the issues relevant to the TLSE Project in the table below. A complete record of each comments and/or information request received by Indigenous groups to date, as well as FEI's responses will be posted on the BC EAO's EPIC website once the comment period for Indigenous groups is complete.

1 **Table 1: Summary of the Issues/Concerns of Indigenous Groups**

Issue	Description of Issue	FEI's Response
Potential Environmental Impacts	**Cumulative Effects:** Cumulative effects of increased development on and near Tilbury Island, as well as increased shipping on the Fraser River are a key area of concern for Indigenous groups. Concerns regarding the methodology for assessing the potential cumulative effects of the Tilbury Phase 2 LNG Expansion Project and the adjacent Tilbury Marine Jetty Project. Concerns regarding the utilization of a material offloading facility (MOF) for the Tilbury Phase 2 LNG Expansion Project to deliver Project materials to site during construction.	FEI reiterated to Indigenous groups that the effects assessment was conducted in accordance with the methodology described in the Application Information Requirements (AIR) (June 2022) and BC EAOs Effects Assessment Policy (BC EAO 2022). FEI acknowledged that there are existing cumulative effects on the Fraser River. With the implementation of proposed mitigation measures, FEI does not anticipate any residual effects on the Fraser River and therefore, that the Tilbury Phase 2 LNG Expansion Project will contribute no incremental effects to existing or future conditions or cumulative effects on the Fraser River. FEI responded to multiple questions regarding the adjacent Tilbury Marine Jetty Project and re-directed Indigenous groups to the separate environmental assessment process for that project. FEI worked with Indigenous groups to incorporate their perspectives on cumulative effects into their respective Section 11 Indigenous Interests chapters of the environmental assessment application, when and as requested. FEI committed to the removal of water-borne deliveries of construction materials and committed to no longer utilizing a MOF for the Tilbury Phase 2 LNG Expansion Project. As a result of this mitigation, marine impacts are no longer in scope of the TLSE Project.
	Greenhouse (GHG) Emissions: FEI heard concerns and interest from some Indigenous groups regarding GHG emissions including those: • associated with construction and operation of the Tilbury Phase 2 Expansion Project and • beyond the scope of the environmental assessment. Some Indigenous groups also asked questions about the environmental benefits associated with LNG as a fuel.	FEI provided further information regarding how air quality and emissions were assessed in the environmental assessment application. The scope of FEI's emissions assessment was aligned with the Strategic Assessment of Climate Change (SACC) framework. FEI reiterated its commitment that the Tilbury Phase 2 LNG Expansion Project be a net-zero operating facility once operational. FEI shared information about the appropriate regulator or regulatory proceeding to address questions relating to upstream and downstream emissions in relation to the TLSE Project components, as these matter are beyond the scope of the environmental assessment. FEI outlined that the primary purpose of the TLSE Project is to support resiliency of FEI's gas system. FEI committed to implement known effective emission reduction technologies during operation to support net-zero operations requirements, including the electrification of refrigeration and compression systems and the use of renewable natural gas.

Issue	Description of Issue	FEI's Response
Safety	**LNG Safety and Emergency Planning** Multiple information requests regarding LNG safety and emergency planning: • LNG's safety characteristics as a fuel; • FEI's assessment of potential accidents and malfunctions for the Tilbury Phase 2 LNG Expansion Project; and • The proposed emergency response and planning measures for the Tilbury Phase 2 LNG Expansion Project.	FEI provided further information regarding how severe accidents, such as LNG containment loss or hazardous material spills, were assessed in the accidents and malfunctions value component. FEI re-iterated that the likelihood of any unplanned or accidental release of LNG is extremely remote. Such releases, both at the existing facility and the Tilbury Phase 2 LNG Expansion Project, would be quantified and reported to the regulator as required. FEI outlined how operational experience, existing corporate emergency response planning, and industry best practices were integrated into assessing risks of accidents and malfunctions for the Tilbury Phase 2 LNG Expansion Project. FEI committed to engaging with Indigenous groups regarding emergency communication protocols in post-Environmental Assessment Certificate (EAC) permitting.
Economic Opportunities	**Workforce Development:** Inquiries regarding workforce and training opportunities at Tilbury, as well as clarification regarding how Indigenous groups would be engaged regarding workforce opportunities.	FEI outlined its commitment to working with Indigenous Peoples on securing opportunities for procurement, training and employment, if the TLSE Project is approved. FEI continues to work in collaboration with local Indigenous communities, community career and training centers, post-secondary institutions, and contractors to promote and support hiring a local workforce for the TLSE Project. Where applicable, FEI outlined its commitment to implement commitments of socio-economic agreements for the Tilbury Phase 2 LNG Expansion Project, regarding business and employment opportunities.
	Economic Opportunities: Requests for equitable access to business opportunities, particularly for Indigenous groups that are not in immediate proximity to the Tilbury site. Inquiries into how FEI would evaluate and monitor business opportunities throughout the development of the Tilbury Phase 2 LNG Expansion Project.	FEI responded by committing to work closely with Indigenous groups and Indigenous suppliers in regional proximity to the Tilbury site to raise awareness of potential business and contracting opportunities, which may include business-to-business networking sessions. FEI reiterated the commitment to keep Indigenous groups informed of potential business opportunities as they come available, through future Project engagement. FEI responded to inquiries on evaluation and measurement of economic opportunities by confirming the Tilbury Phase 2 LNG Expansion Project will evaluate progress of socio-economic commitments, such as Indigenous employment, Indigenous contracting and local participation, through regular reporting during design-execution phase of Project development.

Issue	Description of Issue	FEI's Response
Engagement	**Incorporation of Feedback in the Environmental Assessment Application:** Comments, inquiries and concerns related to incorporation of input and characterization of Indigenous knowledge in the environmental assessment application for the Tilbury Phase 2 LNG Expansion Project. Clarifications and requests to edit Indigenous interest chapters during the Application Review period.	Where appropriate, FEI requested clarifications and edits to Indigenous interests' chapters where Indigenous groups suggested such changes through information requests. FEI outlined its comprehensive process for identifying, characterizing and incorporating Indigenous knowledge into the environmental assessment, including the following best practices: • Verification of secondary source lists; • Hosting Indigenous Knowledge workshops with Indigenous Nations (two to date and also presenting the information separately to those participating Indigenous nations who requested their own session; • Gathering feedback on the incorporation of Indigenous Knowledge into the Indigenous interest assessments as part of the environmental assessment Application; • Incorporating nation-specific Indigenous Knowledge • Equal consideration of Indigenous Knowledge and western science; • Ensuring consistency with information sharing commitments for each Indigenous group as identified within capacity funding agreements; and • Regular discussion regarding the characterization of Indigenous knowledge at project engagement meetings with Indigenous groups.
	Engagement in the Future: Inquiries regarding FEI's plans for future engagement regarding areas of interest (e.g., potential environmental impacts, safety, business opportunities, post-EAC project permitting, etc.).	FEI reiterated that it remains committed to engaging Indigenous groups on post-EAC activities, such as condition management planning. As outlined in the environmental assessment application for the Tilbury Phase 2 LNG Expansion Project, FEI will engage Indigenous groups may on the following activities during the Post-EAC phase, including: • The development of management plans; • Engagement during future permitting; • Construction, contracting and procurement; • Environmental monitoring and reporting; and • Other compliance and enforcement activities.

Issue	Description of Issue	FEI's Response
Technical Comments Regarding the Environmental Assessment	**General Comments:** FEI received various comments, clarifications and inquiries regarding the value component chapters and technical appendices of the environmental assessment application, including the following topics: • Wildlife • Fish and fish habitat • Surface water • Ground water • Acoustics • Air quality • Vegetation • Land and resource use • Archaeology and heritage resources • Culture • Human health • Infrastructure and services • Greenhouse gas emissions • Accidents and malfunctions • Employment and economy	FEI responded to information requests with information on the process FEI took for developing the environmental assessment application, which is consistent with the Application Information Requirements (AIR) (June 2022) and BC EAOs Effects Assessment Policy (BC EAO 2022). FEI has also responded to each individual information request and, where appropriate, revised the environmental assessment application.

Please also refer to the response to BCUC IR5 137.3 for links to the summaries of engagement with Indigenous groups prepared as part of the environmental assessment application for the Tilbury Phase 2 LNG Expansion Project.

138.0 Reference: CONSULTATION AND ENGAGEMENT

Exhibit B-60 (Supplemental Evidence), pp. 214 – 216; Exhibit B-26, BCUC IR 104.1; BC EAO, December 2, 2024 Letter from EAO to FortisBC regarding Tilbury Phase 2 Application[52]

Public Consultation

On page 214 of Exhibit B-60, FEI states that since its last evidentiary update, FEI has continued to engage with the public, governments and other stakeholders regarding the TLSE Project using a variety of engagement methods and, in particular, through the ongoing EA process.

On December 2, 2024, the BC EAO notified FEI that review of the Draft Phase 2 Application had begun.[53] The public comment period runs from January 14 to March 3, 2025.

On page 216 of Exhibit B-60, FEI states it has engaged with nearby local, provincial, and federal government agencies to share updates and seek feedback regarding the TLSE Project.

FEI stated in response to BCUC 104.1 that FEI and FortisBC Holdings Inc. had not received any formal notification of official opposition from municipalities or other government agencies with respect to the Tilbury Phase 2 LNG Expansion Project, but were aware that the cities of Richmond, Port Moody, Vancouver and New Westminster had passed motions to oppose the Project. In addition, the City of Burnaby passed a motion to support Richmond's resolution opposing the TLSE Project.

138.1 Please discuss if FEI is aware of any new municipal motions either supporting or opposing the project.

<u>Response:</u>

FEI is only aware of a municipal motion supporting the TLSE Project.

On February 3, 2025, the City of Delta unanimously passed a Motion titled "Immediate Actions to Put Canada First and Support Canadian Businesses."[54] The Motion directs the staff to write to Premier Eby to "Urge the expedited approval of Fortis BC's Tilbury Phase 2 LNG expansion project in Delta, which is anticipated to generate $1.7 billion in GDP growth and create hundreds of long-term local jobs".

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52 https://projects.eao.gov.bc.ca/p/5df7f1bfb7434b002164961c/project-details.

53 https://projects.eao.gov.bc.ca/p/5df7f1bfb7434b002164961c/project-details.

54 Delta – Document Center (civicweb.net).

138.2 Please provide an update on:

- the specific issues or concerns raised by the public, government or other stakeholders to date, including the EA comment period, which are relevant to the TLSE Project, and
- describe the measures planned to address issues or concerns, or an explanation of why no further action is required to address an issue or concern.

Response:

The environmental assessment process for the Tilbury Phase 2 LNG Expansion Project, which involves components of the TLSE Project, is underway in parallel to this proceeding. Where possible, FEI has synchronized engagement activities between these regulatory processes to provide stakeholder groups meaningful opportunities to engage in a process of dialogue over the course of Project development.

Comments received from government, government agencies and the public through this synchronized process apply to all aspects of the developments at Tilbury, including the TLSE Project. Therefore, issues raised that are specific to the TLSE Project alone are often intermingled with other aspects of the Tilbury Phase 2 Expansion Project and developments at Tilbury generally. In preparing the updated summary of the specific issues or concerns raised by the public, government or other stakeholders to date, including the environmental assessment public comment period, which are relevant to the TLSE Project, FEI has narrowed the issues to those relevant to the TLSE Project to the extent practicable.

As described in the response to BCUC IR5 137.4, several BC EAO comment processes are occurring simultaneously, and government, through the Technical Advisory Committee (TAC), provides comments and feedback in a separate process from the public that submits comments during the public comment period noted in the question. For this response, issues and concerns raised by government have been summarized separately from issues and concerns raised by the public. At the time of responding to this question, the public comment period has closed; however, the comment process for the TAC is ongoing.

Technical Advisory Group (TAC)

FEI has received initial sets of comments from TAC members. This response describes the specific issues or concerns raised by the TAC to date. The issues, concerns and opportunities raised by the TAC remain current and consistent with those previously summarized in Section 8.3.4 of the Supplemental Evidence. Since submitting the Supplemental Evidence, FEI filed the Draft Application for the Tilbury Phase 2 LNG Expansion Project on November 29, 2024, and has received more than 660 unique information requests from the TAC. Given the volume and technical nature of many of the comments provided, many of which are specifically related to the Draft Application itself, FEI has summarized the main themes of the issues raised that are relevant to the TLSE Project in the table below to the extent practicable. While the comment process is ongoing, FEI does not anticipate any new issues or concerns will be raised beyond the themes already detailed in this response.

Issue Theme	Description of Issue	FEI's Response
Environmental Impacts	Greenhouse gas (GHG) concerns, including: • associated with construction and operation of the Tilbury Phase 2 Expansion Project; and • beyond the scope of the environmental assessment.	FEI provided further information on how air quality and emissions were assessed in the environmental assessment application. The scope of FEI's emissions assessment was aligned with the Strategic Assessment of Climate Change (SACC) framework. FEI reiterated its commitment for the Tilbury Phase 2 Expansion Project to be a net-zero operating facility upon operations. FEI re-directed questions relating to upstream and downstream emissions to the appropriate regulator or regulatory proceeding, as these are out of scope of the Tilbury Phase 2 Expansion Project. FEI outlined the primary purpose of the TLSE Project is to support resilience of FEI's gas system. FEI committed to implement advanced and known effective emission reduction technologies during operation to support net-zero operations, including the use of renewable natural gas.
	Effects to fish and fish habitat and southern resident killer whales	As a result of the feedback FEI received from some Indigenous groups during engagement, FEI has mitigated this impact by removing the Material Offloading Facility (MOF) from the scope of the Tilbury Phase 2 Expansion Project(including the TLSE Project components). Because the TLSE Project will no longer involve the construction or use of a MOF for waterborne deliveries or any in-river works or activities, no fish habitat will be adversely affected by the TLSE Project.
	Upstream production of fossil fuels to supply the Tilbury Phase 2 Expansion Project	FEI responded that this is out of scope of the environmental assessment for the Tilbury Phase 2 Expansion Project.
	Concerns about the need for the TLSE Project, with the Province trying to phase out fossil fuels	As a provider of critical energy services, serving almost 1.3 million homes and businesses in British Columbia, FEI has an important role in meeting the province's energy needs while supporting overall emissions reductions for a lower-carbon energy future. • Tilbury LNG's lifecycle GHG emissions used to fill the TLSE tank are about 30 percent lower than other LNG facilities on because the Tilbury facility is powered by BC's renewable hydroelectric grid. • The TLSE Project is committed to be net-zero by operation which will meet the provincial emission reduction requirements.
	Soil removal during construction	FEI follows Contaminated Sites Regulation (CSR), regulated by the BC *Environmental Management Act* (EMA), and provides responsible parties with guidance and protocols for contaminated sites, including soil quality standards (BC CSR Schedule 3.1) and soil relocation (Protocol 19).

Issue Theme	Description of Issue	FEI's Response
	Environmental monitoring	Details of the environmental monitoring that will be done during construction and operations will be developed during the permitting phase of the TLSE Project and described in the construction environmental management plan and the operation environmental management system.
	Water quality	The Tilbury Phase 2 Expansion Project site's contribution of stormwater volume discharged to the Tilbury Slough is expected to remain unchanged. With the engineering controls for site runoff, and testing of water prior to discharge from containment areas, the quality of stormwater from the site is expected to be similar quality than the current site runoff. As a result, the site runoff is not expected to influence water quality in the slough. FEI does not discharge to the Fraser River and only surface water runoff discharges to Tilbury Slough via the City of Delta stormwater drainage system. FEI is not able to comment on the process used by the City of Delta to manage the water levels of the Tilbury Slough; however, excess flows from the Project Site to the City of Delta stormwater drainage system are not anticipated because much of the project site will be covered by permeable surfaces (that is, gravel), limiting surface water runoff as much as feasible. Hydrostatic test water will likely be sourced from the municipal water system (confirmation of this will occur during detailed design). For clarity, the current facility does not require a water license and if a *Water Sustainability Act* permit were required for the Project, FEI would submit the application to the BCER, not the BC Ministry of Fisheries and Aquaculture.
	Flaring	While the TLSE Project scope does not include a flare, flares are a common feature of LNG facilities and act as safety devices designed to safely relieve pressure and prevent the uncontrolled release of flammable gases during unplanned operational disruptions. The liquefaction component of the Tilbury Phase 2 Expansion Project has selected to proceed with a totally-enclosed ground flare (TEGF) through the detailed engineering phase of the project. A TEGF has the advantage of being totally enclosed, reducing potential visual and skyglow impacts and reducing potential interactions with wildlife (specifically bird species flying over the project location).
Traffic Impacts	Traffic and parking for workers	Mitigation measures will be developed as part of the Construction Environmental Management Plan (CEMP). Stakeholders will be engaged during development of the CEMP and have an opportunity to review proposed mitigation measures.

Issue Theme	Description of Issue	FEI's Response
Safety	Malfunctions and emergency response	FEI evaluated all types of accidents and malfunctions scenarios. A summary of this chapter can be found on the BC EAO's EPIC website.[55] FEI outlined how operational experience, existing corporate emergency response planning, and industry best practices were integrated into assessing risks of accidents and malfunctions for the Tilbury Phase 2 Expansion Project.
	Safety training	FEI prioritizes safety and provides regular employee safety training. An emergency response plan will be developed for the Tilbury Phase 2 Expansion Project outlining emergency response protocol.
	Earthquake, tsunami, and seismic mitigation	The TLSE Project design considers potential extreme weather events (such as flooding, tsunamis, extreme heat and extreme cold) and mitigates these potential effects when combined with FEI's current procedures. Flooding from the Fraser River or a tsunami is unlikely to cause an adverse effect on the Project infrastructure based on the design, maintenance, and futureproofing of the dike infrastructure under the management of Delta and the Project design for drainage infrastructure. Seismic events are considered to have a low probability of occurrence, with low to medium potential effects to the Project based on the adoption of stringent industry standards as stipulated by Liquefied Natural Gas Facility Regulation under the *Energy Resources Activities Act* (previously the *Oil and Gas Activities Act* (OGAA)) and design requirements for LNG facilities (CSA Z276) account for seismic hazards.
Project Construction and LNG Facility Operation	Noise impacts	The environmental assessment application includes a Noise and Vibration Technical Data Report which provides a prediction of potential noise levels from the Tilbury Phase 2 Expansion Project at receptors based on Health Canada and the BC Energy Regulator guidelines. Proposed mitigation measures during construction and operation to reduce potential effects are described in the Report. As noise levels in the area are already relatively high as an industrial zoned area, potential increases in noise are not expected to result in adverse effects compared to existing conditions.
	Use of RNG and renewables	FEI's net-zero plan relies on the use of RNG and drop in fuels, as they develop, to meet the 2030 targets.
Socio-Economic	Gender Based Assessment (GBA+) considerations	FEI conducted an assessment of potential disproportionate effects on distinct human populations who may be more vulnerable to potential project effects. Where information was available, subgroups were identified as part of a "GBA+" approach based on their potential to experience disproportionate effects from the Tilbury Phase 2 Expansion Project. When available, information has been disaggregated for each Indigenous nation's contextual information, and existing conditions to

55 https://www.projects.eao.gov.bc.ca/api/public/document/674ab42018e13c0022214d74/download/TIL2_Volume1_Section09_Malfunctions_Accidents_20241129.pdf.

Issue Theme	Description of Issue	FEI's Response
		reflect a GBA+ approach. Because these assessments rely heavily on secondary sources, disaggregated data and information are very limited.
	Social and economic factors	FEI monitors the implementation of hiring practices through regular reporting intervals with contractors. FEI works with contractors on major projects to gather socio-economic reporting for projects at the design-execution phase of development. The TLSE Project will continue to evaluate progress of socio-economic commitments, such as Indigenous employment rates, through reporting during the design-execution phase of development, similar to other FEI-led projects, if the TLSE Project is approved. FEI's Socio-economic Impact Program contains specific objectives to connect Indigenous, local, and underrepresented group businesses with contract opportunities across major projects and, in partnership with communities, invest in initiatives that contribute to social goals. FEI also seeks to leverage project activities for broader positive outcomes by connecting individuals and businesses with other FEI contracting opportunities outside of the TLSE Project. Additionally, FEI requires suppliers and contractors on major projects to submit project-specific Indigenous participation plans during the bid process.
	Skilled labor and trades training initiatives	FEI has an existing relationship with Skilled TradesBC and will work collaboratively with them to identify education and training opportunities on the TLSE Project. Skilled TradesBC has programing specifically for Indigenous Peoples in trades and Equity in the Trades. FEI responded to inquiries on evaluation and measurement of economic opportunities by confirming the TLSE Project will evaluate progress of socio-economic commitments, such as Indigenous employment, Indigenous contracting and local participation, through regular reporting during design-execution phase of Project development.

EA Public Comment Period

FEI received comments from 272 members of the public and 12 letters from organizations during the EA Public Comment Period that ran from January 14 to March 3, 2025. The comments received are consistent with the issues or concerns summarized in Section 8.3.4 of the Supplemental Evidence, and Section 8.3.8 of the Application. FEI has provided a table below that organizes these issues and concerns into themes that have been raised during the public comment period. At the time of preparing this response, responses to the public comments had not yet been sent by FEI to the BCEAO; however, FEI has provided the planned responses in the table below. FEI will submit a public engagement report to the BC EAO by April 2, and all final responses will be publicly available once the BCEAO posts the report to their EPIC website.

Issue Theme	Description of Issue	FEI's Planned Response
Safety: Malfunctions and Accidents	LNG spill impacts	The Tilbury LNG facility has been safely operating since 1971. The safety of our employees, the public, and the environment remain top priority. In the event of a spill or leak, LNG would warm, turn back into its gaseous state, rise and dissipate without leaving any residue on land or in water. The risks to human health and Indigenous interests from a fire, explosion and release of LNG are assessed in Section 9 of the environmental assessment application.[56]
	LNG explosion impacts	The Tilbury LNG facility has been safely operating since 1971. The safety of our employees, the public, and the environment remain top priority. When stored as a liquid, LNG is not flammable or explosive because there is no oxygen to create a mixture that could ignite. When natural gas mixes with air, it becomes too diluted to burn. If the volume of natural gas in the air is below about 5 percent or above about 15 percent, it will not burn. This is a very narrow range of flammability compared to other petroleum-based fuels. The risks to human health and indigenous interests from a fire, explosion and release of LNG are assessed in Section 9 of the environmental assessment application.[57]
	Earthquakes	The Tilbury LNG facility has been in operation since 1971 and has continued to operate safely through several seismic events. The TLSE Project will be designed and constructed to meet seismic design standards for earthquake and flood safety, undergoing regular safety and seismic inspections. Additional information regarding the potential for infrastructure damage and failure during a seismic event is addressed in the mitigation and design considerations for the TLSE Project.
Effects on the Environment	Fracking	Natural gas processing is regulated by the BC Energy Regulator (BCER), which has the authority to determine if natural gas processing is done in an environmentally safe manner and ensure all requirements are met. As a regulated utility, FEI's role is to buy and deliver natural gas at the lowest reasonable cost to almost 1.3 million homes and businesses across BC. More information in this regard is available on the BC Energy Regulator's website: https://www.bcogc.ca/node/11416/download
	Methane impacts worse than CO2	As a provider of critical energy services, serving almost 1.3 million homes and businesses in British Columbia, FortisBC has an important role in

56 https://projects.eao.gov.bc.ca/api/public/document/674ab42018e13c0022214d74/download/TIL2_Volume1_Section09_Malfunctions_Accidents_20241129.pdf.

57 https://projects.eao.gov.bc.ca/api/public/document/674ab42018e13c0022214d74/download/TIL2_Volume1_Section09_Malfunctions_Accidents_20241129.pdf.

Issue Theme	Description of Issue	FEI's Planned Response
		meeting the province's energy needs while supporting overall emissions reductions for a lower-carbon energy future. Our renewable hydroelectricity-powered facilities and net-zero project requirements combined with upstream methane regulations make the LNG among the lowest-carbon intensity LNG in the world on a lifecycle basis.[58] FEI is focused on reducing all greenhouse gas emissions in the form of carbon dioxide equivalent (CO2e), including both methane and CO2, to effectively mitigate climate change.
	Climate change/Global warming	The primary purpose of the TLSE Project is to strengthen FEI's Lower Mainland gas system by increasing LNG storage capacity ensuring a reliable supply of energy to our current and future customers. While GHG emissions from the Tilbury Phase 2 LNG Expansion are relatively low due to the nature of the facility (i.e. energy storage with a portion set aside as a resiliency reserve pending a supply emergency), FEI's renewable hydroelectricity-powered facilities and net-zero project requirements combined with upstream methane regulations make the LNG among the lowest-carbon intensity in the world on a lifecycle basis.[59] FortisBC has also committed to implementing advanced air emission reduction technologies during operation (see Appendix P of the Application, Tilbury Phase 2 LNG Expansion (BAT Study))[60] and to produce net-zero greenhouse gas (GHG) emissions by the start of operations. As technology advances with low, no or negative carbon footprint fuel, our approach is to adopt these fuel alternatives to help reduce carbon emissions associated with the existing gas infrastructure and support emissions targets.
	Air pollution concerns leading to human health concerns	The TLSE Project is an opportunity to continue providing reliable, economical, and safe energy to BC's growing population. LNG produced at Tilbury is already among the lowest carbon intensity in the world and, in accordance with Provincial regulations, the TLSE Project will be net-zero once in operation.
	Flaring	The scope of the TLSE Project does not include flares. However, flares are a common feature of many LNG facilities and act as safety devices designed to safely relieve pressure and prevent the uncontrolled release of flammable gases during unplanned operational disruptions. The scope of the liquefaction component of the Tilbury Phase 2 Expansion Project includes a Totally Enclosed Ground Flare (TEGF) as the preferred flare alternative. Compared to other alternatives (i.e. multipoint ground flare or elevated flare), a TEGF limits the opportunity for wildlife interactions with

58 https://sphera.com/resources/report/life-cycle-ghg-emission-study-on-the-use-of-lng-as-marine-fuel/.

59 https://sphera.com/resources/report/life-cycle-ghg-emission-study-on-the-use-of-lng-as-marine-fuel/.

60 https://projects.eao.gov.bc.ca/api/public/document/674abcacd6087e00228ede48/download/TIL2_Volume2_AppendixP_BAT_Study_20241129.pdf

Issue Theme	Description of Issue	FEI's Planned Response
		flames (due to being enclosed) and has the lowest noise and flame-related visual effects.
Effects on Customer Energy Rates	Project cost	The TLSE Project replaces critical gas supply functions, including enabling the purchase and storage of gas to optimize gas supply portfolio costs, while also adding resiliency to the gas system to mitigate against significant economic risks posed by upstream gas supply disruptions.
Effects on Wildlife	Marine life concerns due to increased traffic, pollution, underwater noise	To be responsive to concerns around potential TLSE Project impacts to the Fraser river, FortisBC decided not to use waterborne deliveries of construction materials or utilize a Material Offloading Facility (MOF) for the Tilbury Phase 2 Expansion Project. This means that the project does not impact the Fraser River, fish, fish habitat, water mammals or their habitat.
Indigenous Engagement	Concerns that the Indigenous groups do not have input	As part of the BC EAO process, FortisBC is and has been engaging with Indigenous groups, local, provincial, and federal government agencies, the public and stakeholders since 2019. FortisBC has engaged in collaborative dialogue with Indigenous groups focused on continual learning through knowledge and information sharing, to help develop the Tilbury Phase 2 LNG Expansion Project.
Economy	Concerns that this Tilbury Phase 2 Expansion Project will not contribute to the economy compared to larger LNG projects	The Tilbury Phase 2 LNG Expansion Project is an opportunity to continue reliable energy service to our customers while providing economic growth and benefits to local communities and Indigenous partners. The project has many benefits associated with it which can help strengthen the local economy: • The Tilbury Phase 2 LNG Expansion Project will provide around 1,000 full time employment, training and contracting opportunities during the 6-year construction period; • Construction could generate approximately $300 million in tax revenue for the provincial government and $130 million annually for the federal and provincial governments during operation; and • Approximately $1.7 billion could be added to BC's GDP during construction, and an estimated $700 million could be added annually during operation contributing to infrastructure needs such as hospitals and schools.

138.3 Please describe what future public consultation is contemplated by FEI subsequent to the EA public comment period that concludes in March 2025.

Response:

Following the public comment period, FEI will continue public consultation through various activities, ensuring that stakeholders remain informed and have opportunities to provide input into the Project. Future engagement will include:

- **Public Comment Opportunities:** Additional environmental assessment public comment periods will be held during the Application Review and Effects Assessment & Recommendation phases, complemented by in-person and virtual open houses.
- **Stakeholder Meetings, Presentations & Notifications:** Ongoing meetings with identified stakeholders to provide updates and address any emerging questions or concerns. In addition, stakeholders will be notified by email about project milestones.
- **Site Tours:** Offering tours for interested parties to enhance their understanding of the Project.
- **Community Events:** Participation in local events to share information and connect with the public.
- **Website Communication:** The Talking Energy website will serve as a central hub for project updates, engagement opportunities, and access to official regulatory documents.
- **Educational Materials:** Informational content such as videos, blogs, and social media updates will be shared to enhance public understanding of LNG and the proposed project.

FEI remains committed to ongoing public consultation, and adapting engagement efforts as needed to ensure that public questions and input are addressed. Feedback received will inform future outreach activities, helping to maintain open and transparent communication with interested parties. If the Tilbury Phase 2 LNG Expansion Project and the TLSE Project are approved, FEI will develop all necessary public consultation plans to support future permitting requirements and construction, similar to what FEI has done to support other major projects. This could include plans such as a public impact mitigation plan and a traffic management plan, and the plans will be designed to meet municipal, provincial, and federal requirements.

For reference, FEI's future public consultation plans following the environmental assessment public comment period are also outlined in Section 3.2 of the Public Engagement Plan, which was filed as a required deliverable with the BC EAO on June 7, 2024.[61]

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61 https://projects.eao.gov.bc.ca/api/public/document/66df79498b061b0022749279/download/TP2_Public%20Engagement%20Plan_June2024.pdf.

F. RAYMOND MASON REPORT (EXHIBIT B-60 APPENDIX F)

139.0 Reference: Raymond Mason Report

Exhibit B-60 (Supplemental Evidence), pp. 83, 94, Appendix F (Ramond Mason Report), pp. 4, 7, 8, 19, 26 – 29, Exhibit B-1, p. 59

Spot Market Gas, Interruptible Load, Hypothetical Financial Value

On page 4 of Appendix F (the Ramond Mason Report) to Exhibit B-60, Raymod Mason states that:

> …based on the results of my market research evaluating third-party arrangements, the costs for peaking resources are extremely expensive, do not support a consistent long term supply resource, and would require a portfolio of participants to be able to meet FEI winter demand. To put this in perspective, FEI would be competing/accessing the Huntingdon/Sumas gas supply market, on the coldest days of the winter, for significant volumes historically destined to the PNW (rapidly escalating pricing throughout daily trading hours).

On page 19 of Appendix F (the Ramond Mason Report) to Exhibit B-60, Raymond Mason states: “Based on information provided by FEI, its Lower Mainland region has seen a 10% decline in the number of interruptible customers between 2018 and 2023. As such, there is less of this contractual peaking resource available to FEI.”

On pages 26 to 29 of Appendix F (the Ramond Mason Report) to Exhibit B-60, Raymond Mason provides an overview of third-party peaking gas supply contracts. On page 26, Raymond Mason states:

> These commercial arrangements typically maintain 24-hour notice periods prior to the deployment of the resource. A third-party offering this service will want to recover the underlying costs of maintaining their asset portfolio while earning a fair return for its use during the period it is contracted.

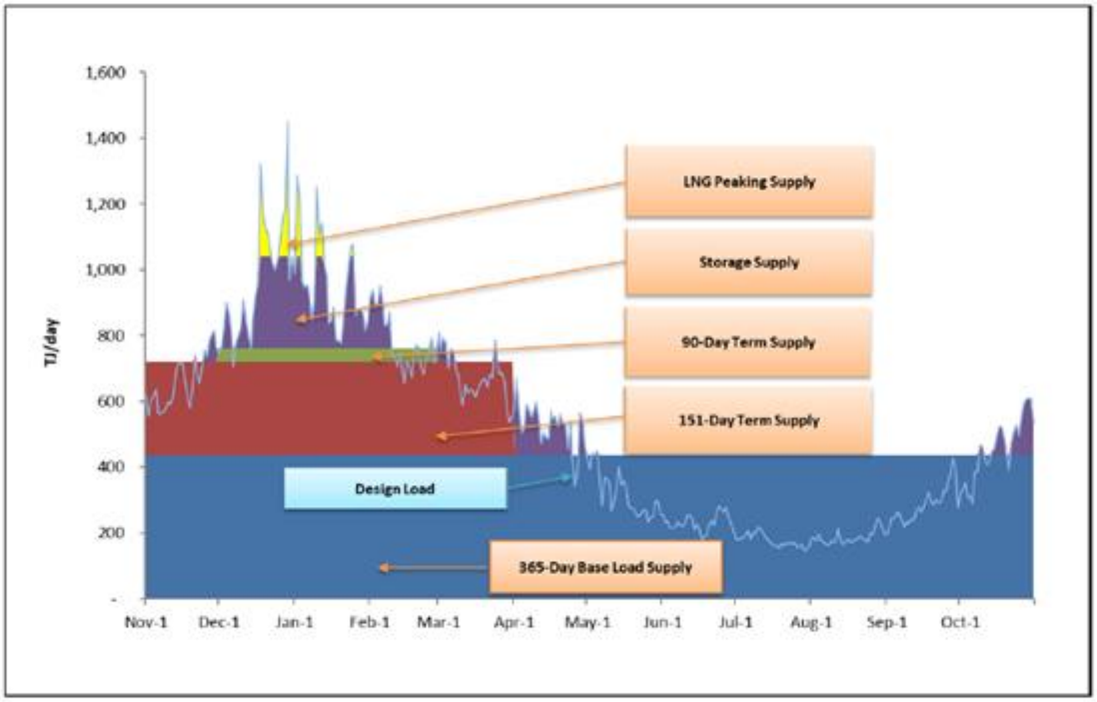
Page 27 of Appendix F (the Ramond Mason Report) to Exhibit B-60 states:

> A third-party gas supply peaking arrangement also includes a commodity charge portion, which I discuss in further detail below. Since these agreements are required for daily deployment, their underling commodity charge(s) are based on daily spot pricing. Daily spot prices trade in a range throughout a trading day, and in some instances, can trade at a significantly wide range

On page 94 of Exhibit B-60, FEI states:

> *Any Gas Successfully Procured on the Spot Market Will Be Very Costly*
>
> To the extent that FEI was successful in partially replacing the lost on-system peaking gas supply from Tilbury with ad hoc contractual arrangements on the day, FEI customers would be very exposed to price risk.

On page 83 of the Exhibit B-60, FEI presents a graph showing its 2024/2025 Design and Peak Day Load vs Recommended Supply Portfolio, as reproduced below.



139.1 Please explain how often FEI utilizes its on-system LNG peaking supply to meet demand on the coldest days in practice, as opposed to the approximately 10 days of supply reserved each year for planning purposes.

Response:

The actual usage of on-system LNG peaking supply depends on the extent of winter weather experienced across the FEI system each year, as well as unplanned operational disruptions which occur during cold weather events and lead to unplanned outages of other planned resources. For gas supply planning, FEI generally reserves on-system LNG for sendout when other supply resources (e.g., market area storage) are fully utilized.

The table below shows the number of days FEI used LNG supply from Tilbury and Mt. Hayes facilities to meet gas demand from 2020 to 2024.

Table 1: Deployment of On-System LNG Peaking Supply (2019-2024)

	Number of Days	
Year	**Tilbury (Base Plant & T1A)**	**Mt Hayes**
2019	**0**	**21**
2020	**0**	**3**
2021	**11**	**22**
2022	**10**	**7**
2023	**6**	**4**
2024	**5**	**7**

The following table shows when Tilbury and Mt. Hayes have been required to send out between 2019 and 2024 inclusive. The table identifies which tank's LNG was used, and the overall volume of gas supplied to the gas pipeline.

Table 2: History of Sendout from Tilbury Base Plant, Tilbury 1A and Mt. Hayes (2019-2024)

Date Start	Date Stop	T1A	Tilbury Base Plant	Mt. Hayes	Total MSCF Sent Out	Reason for Sendout
4-Feb-19	13-Feb-19			X	360,420	Demand - Cold weather
27-Feb-19	2-Mar-19			X	83,610	Demand - Cold weather
5-Mar-19	5-Mar-19			X	25,150	Demand - Cold weather
7-Mar-19	7-Mar-19			X	26,540	Demand - Cold weather
10-Apr-19	11-Apr-19			X	55,820	Demand - Cold weather
16-Apr-19	18-Apr-19			X	67,780	Demand - Cold weather
13-Jan-20	15-Jan-20			X	130,360	Demand - Cold weather
8-Feb-21	14-Feb-21			X	305,270	Demand - Cold weather
12-Jul-21	14-Jul-21	X			23,700	Demand - Maintenance on transmission system
24-Sep-21	26-Sep-21		X		146,354	Demand - Maintenance on transmission system
26-Dec-21	28-Dec-21	X			137,700	Demand - Cold weather
30-Dec-21	31-Dec-21		X		47,600	Demand - Cold weather
6-Jan-22	7-Jan-22		X		32,600	Demand - Cold weather
16-Nov-21	19-Nov-21			X	140,070	Demand - Cold weather
19-Dec-21	22-Dec-21			X	95,420	Demand - Cold weather
26-Dec-21	1-Jan-22			X	344,730	Demand - Cold weather
5-Jan-22	7-Jan-22			X	12,410	Demand - Cold weather
2-Dec-22	5-Dec-22			X	125,780	Demand - Cold weather
8-Dec-22	9-Dec-22		X		71,900	Demand - Maintenance on transmission system
19-Dec-22	24-Dec-22	X	X		294.800	Demand - Unplanned compressor outage and cold weather

Date Start	Date Stop	T1A	Tilbury Base Plant	Mt. Hayes	Total MSCF Sent Out	Reason for Sendout
31-Jan-23	1-Feb-23			X	90,440	Demand - Maintenance on transmission system
31-Jan-23	31-Jan-23		X		23,932	Demand - Maintenance on transmission system
24-Feb-23	25-Feb-23		X		31,000	Demand - Cold weather
1-Mar-23	2-Mar-23		X		42,994	Demand - Unplanned compressor outage
20-Apr-23	20-Apr-23		X		10,845	Demand - Cold weather
24-Oct-23	25-Oct-23			X	39,840	Demand - Maintenance on transmission system
10-Jan-24	16-Jan-24			X	335,270	Demand - Cold weather
11-Jan-24	14-Jan-24		X		174,400	Demand - Cold weather

FEI describes the reasons for sending out LNG between 2019 and 2024 below.

- On October 9, 2018, Westcoast's T-South pipeline experienced a serious rupture which caused disruptions throughout the region (the T-South Incident). Westcoast was not able to operate at the full operating pressure while they did repairs on the pipe and therefore Firm shippers were authorized to transport less than 100 percent of their firm capacity during the Winter of 2018/2019, Summer 2019 and the beginning of Winter 2019. On-system storage was used to manage the impacts of this event.
- Post Rupture in November 2021, segments of the Westcoast system were again impacted by an extreme weather event caused by heavy rain causing flooding in Southern BC. Westcoast capacity was reduced to 75 percent as isolation was required on the pipe. As a result, Tilbury halted liquefaction that was occurring at the time, and FEI drew upon on-system LNG to address the shortfall. In December 2021, cooler temperatures and higher loads continued, with Westcoast's capacity restriction still in place, resulting in FEI needing to use on-system LNG for supply.
- In early December 2022, FEI relied on on-system LNG to meet load due to operational issues on the Westcoast system. The month of December began with Westcoast in low line pack conditions and temperatures in the Lower Mainland with lows of -2°C. There was a scheduled tool run required by Westcoast on the T-South system, which reduced capacity down to 78 percent which, in turn, reduced the firm resource which FEI relies on. By mid-December, the Lower Mainland reached a low of -8°C. On December 19, cold weather caused an unplanned outage on the Westcoast system, in conjunction with another on T-South. On-system LNG sendout was required until December 24. During this period, the Mt. Hayes facility set a new record for the highest send-out in a winter season (November to March) and the Tilbury facility had its second highest sendout in a season.
- In late January 2023, FEI relied on on-system LNG in response to an unplanned outage on T-South caused by a suspected leak. Please refer to Section 3.2.3.2.1 of the Supplemental Evidence for additional information. Enbridge resumed full service of the Westcoast T-South system, restoring full capacity and supply to FEI's CTS approximately 24 hours after the initial shut in. During this outage, firm capacity was reduced by

approximately 64 percent. Both the Mt. Hayes and Tilbury facilities were used to make up the lost supply.

- In March 2023, Westcoast experienced compressor issues and electrical issues leading to reduced capacity and low line pack levels on the pipe. The Tilbury facility was used for sendout to maintain pressure on FEI's system.
- In April 2023, FEI relied on sendout from the Tilbury facility due to higher-than-expected overnight loads. In the summer months (April to October), firm resources are less available than during the winter period, and it can be particularly challenging to serve the variability from typical load patters during the shoulder months of April and October. During this overnight period, off-system storage from Mist was unavailable. While JPS was used to cover the forecast shortfall, higher than expected loads in the late hours of the day necessitated sendout from Tilbury.
- In January 2024, LNG sendout from the Mt. Hayes and Tilbury facilities was required to meet load requirements in response to extreme cold weather that impacted BC, Alberta and the Pacific Northwest. The region experienced a multi-day cold weather event that resulted in high levels of natural gas demand (including gas demand for electricity). Market prices were elevated throughout this period and multiple regional pipelines experienced reliability challenges leading to a number of operational issues on multiple days during this period. LNG sendout was crucial as some locations in the region saw record low temperatures and there were numerous operational issues on regional pipes as a result of the cold weather. For example, Westcoast experienced a compressor issue, TC Energy experienced multiple compressor issues, GTN issued a force majeure event (not a direct impact to FEI, but impacting the region as a whole) and Mutual Aid was also activated by NWP due to an unplanned JPS outage.

FEI relies on on-system LNG to meet peaking supply requirements, and to avoid supply shortages due to unexpected operational outages. As evident from the above, LNG supply from the Tilbury and Mt. Hayes facilities is critical for FEI's ability to manage through events without having to curtail services to firm customers.

139.2 Please explain which option is typically more cost-effective for meeting peak demand: curtailing interruptible load or purchasing equivalent volumes on the spot market. Additionally, please describe FEI's usual practice in this regard.

<u>Response:</u>

The following response has been provided by Ray Mason:

While I cannot specifically comment on FEI's usual practices, it is imperative that gas operators ensure sufficient capacity is available to meet firm consumer demands throughout the distribution system. Depending on where and when the occurrence of peak demand occurs, if capacity is required, and the interruption of load provides the necessary supply while off-system purchases from the spot market would not, the gas operator will generally curtail interruptible load. If sufficient capacity is available, and there is a requirement for incremental gas supply to meet demand, customer would not be curtailed.

FEI also provides the following response:

FEI plans to serve firm sales customers with reliable and cost-effective supply resources. FEI's strategy for contacting gas supply resources has been to rely on physical assets to meet the majority of the supply requirements. While the spot market is an option, and FEI includes a limited amount of spot supply in the current gas supply portfolio, the spot peaking supply at the Sumas market hub is inherently at risk from commodity price increases and/or delivery risk under certain weather conditions. Buying gas from the spot market at the Sumas market hub is not a recommended strategy given the market characteristics at the Sumas trading hub and given the volume of gas FEI needs on a peak day (i.e., up to 200 MMcf/d).[62]

Forecast ACP demand underlying the demand curve provided in the Supplemental Evidence excludes interruptible load on cold winter days and the design peak day; therefore, the ACP resources FEI secured are sufficient to meet firm demand, but additional resources would be required to serve interruptible load. Although FEI is not obligated to serve interruptible customers when supply is constrained, FEI makes a curtailment decision based on the market conditions.

Ultimately, neither spot market gas supply, nor curtailments of interruptible customers, are considered a reliable source for peaking supply. In particular, it is difficult to predict future spot market prices (especially when peaking supply is needed). FEI does not consider it to be prudent to rely on market gas or curtailments of interruptible customers to provide peaking supply to FEI's Core customers.

139.2.1 If FEI's usual practice is to purchase gas on the spot market, please specify the typical volumes purchased, the conditions under which these purchases occur, and the markets from which the gas is sourced. Additionally, if historical data is available for the past three years, please provide it.

Response:

The definition of "spot market" can have different meanings depending on the context. Most commonly, the "spot market" refers to when parties enter into a transaction that is daily priced gas (i.e., fixed price or daily index) and the term of the transaction is for 1-3 days. However, the "spot

[62] 200 MMcf/d is approximately 10 percent of the firm volume available on the Westcoast system. Westcoast firm service from Station 2 to Huntingdon/Sumas on T-South is 1,800 MMcf/d.

market" can also mean gas that is priced off a daily index but the underlying commitment to each party can span 30 days,151 days, or 365 days.

FEI applies "spot market' transactions under these two definitions in a variety of ways. For example:

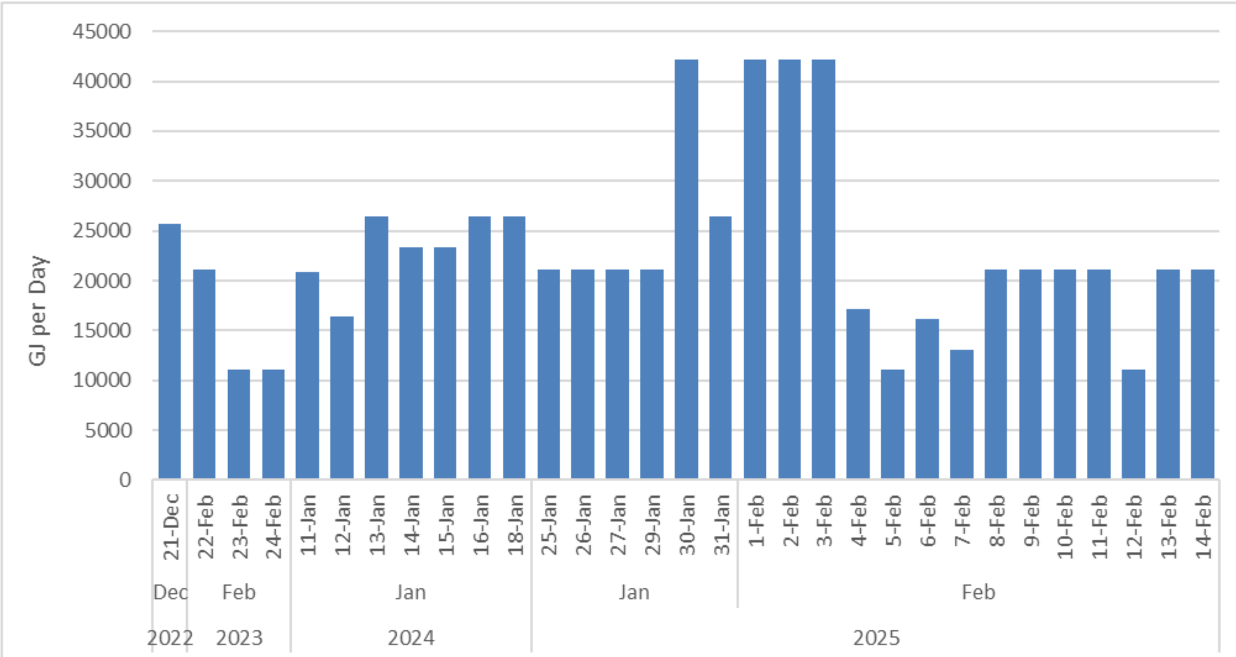
- Meeting supply requirements by buying at certain market hubs (i.e., Station 2 or Kingsgate);
- Providing flexibility for daily operations; and
- Mitigating unutilized ACP resources based on short-term forecasts and market conditions.

FEI plans gas supply resources to meet the 365-day design load forecast. However, actual demand, driven by winter weather, often deviates from the ACP load forecast, creating the need for daily balancing between demand and the supply resources planned through the ACP. Market area storage and spot purchases are both used by FEI to balance daily demand and supply.

For example, the current ACP portfolio includes approximately 1.7 PJ (1.5 Bcf) of daily priced supply received at Kingsvale/East Kootenay, with a daily volume up to 100 TJ (88 MMcf) transacted through peaking call options. This amount of supply is needed in a design year. The physical supply is sourced from Alberta and the amount that is flowing by this point (i.e., Kingsgate) on TC Foothills is approximately 2.6 Bcf/day. This is 0.8 Bcf/day more than what physically flows at Huntington/Sumas. FEI would not implement this buying strategy at Huntington/Sumas, as the market characteristics are different. For example, if FEI did not have Tilbury currently in the supply stack of the ACP portfolio, FEI would be left with trying to secure 150 MMcf/d of peaking supply under "spot market transactions". This approach is very risky from a reliability and pricing perspective.

As the figure below shows, the actual supply received by FEI in the past three years was between approximately 11,000 to 42,000 GJ/day (10 to 37 MMcf/day). FEI has made these purchasing decisions based on the Kingsgate market characteristics at that supply point and also in consideration of other options within the ACP portfolio to manage this price risk.

Figure 1: Actual East Kootenay Peaking Supply



The lower-than-planned supply was a result of warmer winter weather in general (over the full 151-day period of each year), and the interruptible transport services offered by TC Energy's system. The interruptible transportation services offered by TC Energy allowed FEI to procure cheaper supply from the AECO spot market, instead of exercising East Kootenay call options which were transacted based on Maline prices. For clarity, FEI does not plan the ACP portfolio based on uncertain interruptible services that pipeline operators might offer in the future or in the day.

FEI's 5-year ACP Outlook indicates a 1.7 PJ (1.5 Bcf) peaking supply requirement for 2025, and the volume increases to 2.6 PJ (2.3 Bcf) in the next five years when a significant amount of Mist storage is recalled. The additional LNG from the TLSE Project for gas supply will allow FEI to reduce this spot supply and provide optionality in future ACP portfolios.

139.3 In a circumstance where FEI did not have on-system LNG storage, please provide an analysis of the expected additional number of days per year and potential costs associated with purchasing gas supply on the spot market. Please assume that FEI curtails all available interruptible load prior to purchasing on the spot market. Please include estimates for an average winter and the design winter.

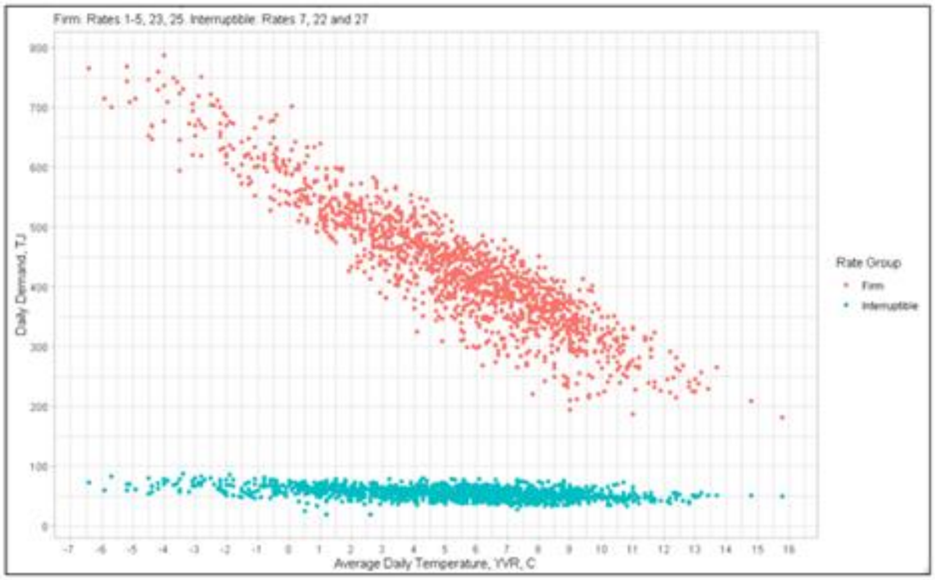
Response:

As discussed in Section 3.3.4 of the Supplemental Evidence, there is no back-up option for dependable peaking supply if the 150 MMcf/d and 0.6 Bcf provided by Tilbury is no longer available. Losing access to some or all the peaking capacity and energy currently provided by Tilbury would impair FEI's ability to provide uninterrupted service to customers in winter. With today's highly constrained regional pipeline and storage infrastructure, even inferior fallback options for market-dependent peaking supply no longer exist. FEI could not replace 150 MMcf/d and 0.6 Bcf of peaking supply in the market. Relying on the spot market for all of FEI's peaking supply would be a significant deviation from FEI's longstanding practice of relying on on-system resources and would put its firm customers at a significant risk of losing service.

The quote in the preamble from page 94 of the Supplemental Evidence should be understood as a hypothetical, taken in light of the comments above. That is, it is the unavailability of the supply, not the price, that is the primary concern in the scenario posed. In the response to BCUC IR5 131.1, FEI provides information about the number of days per year that it has relied on LNG sendout from Tilbury in recent years, which provides some indication.

It is difficult to predict with any confidence what the market price would be for any supply in the hypothetical situation contemplated in the question given the constrained market conditions, and FEI has never attempted to buy this much supply (i.e., up to 150-200 MMcf/day on cold days at Sumas). Given the risk as to whether FEI could actually secure the supply, it is FEI's strong belief that a strategy of relying on buying spot gas on a peak day for the volume of supply that FEI gets from Tilbury (i.e., 150-200 MMcf/day) would be contrary to the best interest of customers. In any event, FEI expects that the market could command a significant premium from FEI for any hypothetical volumes given that the alternative in this hypothetical scenario would be shutting off service to a significant number of firm demand customers.

On page 59 of Exhibit B-1, FEI provides a graph showing weather sensitivity of firm and interruptible Lower Mainland loads, as reproduced below.



On page 19 of Appendix F (the Ramond Mason Report) to Exhibit B-60, Raymond Mason states:

> Access to "on-system" natural gas supplies, through the displacement of one customer (i.e., interruptible) for the benefit of others (i.e., core customers), is a method of managing capacity which <u>should be maximized wherever possible</u>. [Emphasis added]

139.4 Please explain the frequency and circumstances under which FEI curtails its interruptible load. As part of your response, please clarify whether FEI prioritizes curtailment of interruptible loads before use of on-system LNG storage.

<u>Response:</u>

FEI relies on on-system LNG resources, such as the Tilbury and Mt. Hayes facilities, to meet peak day requirements (among other functions). These resources form part of FEI's supply stack within the ACP.

In accordance with Section 4.2 of RS 7, RS 27 and RS 22, FEI may curtail interruptible load for any length of time, as deemed necessary:

> If at any time FortisBC Energy, acting reasonably, determines that it does not have capacity on the FortisBC Energy System to accommodate the Shipper's request for interruptible transportation FortisBC Energy may, for any length of time, interrupt or curtail transportation Service under this Rate Schedule.

Over the past 3 winters, FEI has curtailed interruptible customers for a total of 9 days, with curtailments each winter for 3 consecutive days. The number of curtailments is approximately 1 day per year on average based on historical information dating back to 1994.

To free up capacity on the system for the peak demand heating requirements of firm customers, FEI typically curtails interruptible load when temperatures reach planning criteria for the fifth coldest day. For example, in the Lower Mainland, interruptible customers are curtailed at approximately 25HDD (i.e., -7˚C average temperature for the day).

Interruptible customers can either:

1. receive gas supply from FEI as a sales customer under RS 7; or
2. receive their commodity from a gas marketer as a transportation service customer under RS 22 or 27.

If FEI curtails interruptible customers, there is no guarantee that FEI will have access to the natural gas supplies for those interruptible customers served by a gas marketer under RS 22 and 27. Gas marketers have no obligation to deliver supply to FEI for their customers that have been curtailed, meaning FEI cannot rely on those volumes as a source of supply.

With respect to the maximum duration that curtailment of interruptible load can be sustained, FEI's interruptible customers usually have limited on-site storage for their backup fuel which may require refilling during curtailment. As backup fuels are generally significantly more expensive to operate than primary gas systems, customers may elect to shutdown their businesses depending on the associated costs. While the efficacy with which customers' facilities can operate on a backup fuel varies by customer, generally speaking, FEI understands from interruptible customers that backup systems can be harder and more labour intensive to operate, while also being less reliable.

Given the frequency and length of curtailments in the past 3 years, some interruptible customers are choosing to return to firm service. For example, as described in the expert report of Ray Mason (Appendix F, page 19 of the Supplemental Evidence), FEI has seen a 10 percent decline in the number of interruptible customers between 2018 and 2023 in the Lower Mainland.

Please also refer to the responses to BCUC IR5 118.4 and 139.1 regarding the use of LNG and curtailment of interruptible load.

139.5 Please provide the total load for Lower Mainland interruptible rate schedule customers (in TJ/day) that FEI can curtail.

139.5.1 Please compare with the actual interruptible load reported in FEI's Annual Contracting Plan and discuss any differences.

Response:

During the winter months of 2024 (Jan, Feb, Mar, Nov, Dec), the total load for Lower Mainland interruptible rate schedule customers in TJ/day was approximately as high as 80 TJ/day (71 MMcf/d) and on average around 45 TJ/day (40 MMcf/d). Approximately 50 percent of those values are Sales (RS 7) customers and the other 50 percent are Transportation Service (RS 27 or 22) customers.

The amount of interruptible Lower Mainland load that FEI can curtail, and what is reported in FEI's ACP, are consistent because within the ACP, FEI would supply the bundled RS 7 customer load throughout the year, while assuming this interruptible load would be curtailed under peak winter conditions as part of the ACP planning process.

Within past ACPs, FEI has stated that it does not consider the peaking requirements for RS 7 interruptible service customers in forecasting the peak day demand for the Lower Mainland service area.[63] This is because FEI has the right to curtail these customers for various reasons, but particularly during cold weather events, typically when temperatures drop below -7°C.

For clarity, within the ACP, Industrial curtailment is only related to RS 22A customers and is separate from curtailment of RS 7 customers. Within the RS 22A tariff, FEI can curtail customers and also use their gas on five days during each contract year. This potential source of supply is therefore included in FEI's peak day portfolio.

Since customers choose their rate class, this analysis could change from year-to-year depending on the rate schedule that customers elect to be served under. As such, FEI may see some change between Sales and Transportation Service, as well as changes in the number of firm and interruptible customers per year.

139.6 Please describe the frequency and maximum duration that curtailment of the interruptible load can be sustained during winter months, and the reason for any limitations.

Response:

Please refer to the response to BCUC IR5 139.4.

63 The adjustment does not impact FEI's other service areas because the majority of the RS 7 customers are in the Lower Mainland.

On pages 7-8 of Appendix F (the Ramond Mason Report) to Exhibit B-60, Raymond Mason provided a summary of financial analysis for hypothetical value of monetizing surplus from the TLSE Project in the market.

139.7 Please further explain how the hypothetical financial value would be recovered for FEI customers and reflected in rates.

Response:

The potential options for treating the surplus (excess resiliency) from the TLSE Project could include:

- Capturing the financial value of the surplus (excess resiliency) in a deferral account and flowing this value to FEI's customers through amortization of the deferral account; or
- Reallocating the resiliency storage to gas supply storage with an associated adjustment to FEI's ACP, resulting in de-contracting of other midstream resources.

In the event this circumstance were to arise in the future, FEI would make an assessment at the time as to what would be most beneficial for customers and would seek approval from the BCUC under the applicable section(s) of the *Utilities Commission Act* (UCA) (e.g., FEI would seek deferral account treatment pursuant to sections 59 to 61 of the UCA).

On page 34 of Appendix F (the Ramond Mason Report), Raymond Mason states:

> First, as with the option of committing to more long-term mainline transportation, the intended use of the southern resource alternatives may shift as FEI's resource stack evolves over time. Even so, these resources will generally maintain underlying commercial deployment value over their useful life. For example, annual demand shifts do not represent a one for one change to peak demand. <u>Annual demand could decline while peak demand escalates</u>, requiring a different stack of resources to manage a shift in consumer demand. [Emphasis added]

139.8 Please explain the circumstances which would result in annual demand declining while peak demand escalates.

Response:

The following response has been provided by Ray Mason:

For clarity, my reference to "peak demand escalates" was intended to suggest that the demand curve will become peakier, with a more pronounced winter peak. I was not intending to suggest that peak day demand would increase in absolute terms relative to today's peak day demand.

The context of the comments provided in my report, as it relates to annual demand declining while peak demand remains high, is referencing a hypothetical example where FEI's resource stack has evolved such that annual mainline capacity could be turned back due to underutilization and/or insufficient mitigation values are made available to cover its costs, and FEI continues to utilize peaking resources to sufficiently supply its customers. This scenario would likely require less average winter resources (i.e., 151-365 days), but still require peak-day resources (i.e., 5-10 days).

A change in consumption technologies such as increased energy efficiency and newer housing/commercial inventory could reduce average demand, but would also lead to greater sensitivity to weather, lifting peak demand levels in the winter relative to average levels for the year. For example, applying this principle to future installations of higher efficiency heating appliances such as dual fuel heat pumps (i.e., electricity with natural gas back-up), to older housing/commercial inventory where the building envelope is not as efficient, and to new inventory of housing/commercial with greater energy efficient envelopes, average consumption will decline, but when colder temperatures prevail, peak-demand will persist. The ratio of average demand to peak demand will go up, resulting in a steeper load duration curve.

For further information please refer to pages 16-19 of my report.

140.0 Reference: Raymond Mason Report

Exhibit B-60 (Supplemental Evidence), Appendix F (Ramond Mason Report), pp. 42 – 43, Exhibit B-15, BCUC IR 21.2, Exhibit B-26, BCUC IR 83.5; FEI 2022 Long Term Gas Resource Plan proceeding, Exhibit B-1, p. 7-40

Low Carbon Fuels

On page 42 of Appendix F (the Ramond Mason Report) to Exhibit B-60, Raymond Mason states:

> The blending of low carbon fuels, such as Renewable Natural Gas ("RNG") and hydrogen into the existing natural gas system continues to be an effective and efficient means of mitigating GHG emissions by increasing the amount of low carbon energies in the market… Further, the 2019 British Columbia Hydrogen Study demonstrated that concentrations of hydrogen between 5 and 15 percent by volume, blended into the existing natural gas system, could be a viable opportunity of delivering renewable energy to markets without significantly increasing risks/cost to the energy value chain (i.e., production, midstream, transportation, distribution, and consumption). Aligning a peak shaving (on-system) resource, with the potential of increased renewable benefits, will continue to bring social and commercial market value.

In response to BCUC IR 21.1, FEI stated:

> FEI does not anticipate impacts on the TLSE Project, nor on its liquefaction process, as a result of increasing hydrogen content in the gas stream as hydrogen can be separated if introduced upstream of the Tilbury facility.

In response to BCUC IR 83.5, FEI stated:

> FEI will likely require natural gas-hydrogen separation at existing LNG storage facilities if hydrogen is present in the feedstock gas supply to the LNG facility. However, 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.

On page 7-40 of FEI's 2022 Long Term Gas Resource Plan, FEI stated:

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

As it is still early in the development of the production and delivery of hydrogen along with other renewable gases in the CTS, FEI does not yet have sufficient definition to provide projections on their specific impact to the capacity of the system. The hydrogen "backbone" described earlier is a likely and flexible way that the system can be expanded later in the forecast period considering the number of factors, yet be fully determined, that may need to be defined and managed.

140.1 Please provide an update with respect to FEI's plans to blend hydrogen into the CTS upstream of the Tilbury facility and FEI's subsequent plans to install hydrogen separation facilities at LNG facilities connected to the CTS and VITS.

Response:

FEI is currently undertaking the British Columbia Gas System Hydrogen Blending Study and Technical Assessment project to better understand how hydrogen integration will affect FEI's legacy system and how it can accommodate hydrogen blending. FEI currently expects to complete this technical feasibility work in 2027. This, in turn, will inform any potential plans to blend hydrogen into the CTS upstream of the Tilbury facility and any subsequent plans to install hydrogen separation facilities at LNG facilities connected to the CTS and VITS.

140.2 Please explain how, if at all, the currently proposed TLSE Project scope accounts for the delivery of a blend of hydrogen and natural gas to the Tilbury facility.

140.2.1 If the currently proposed TLSE Project scope does not account for the delivery of a blend of hydrogen and natural gas to the Tilbury facility, please explain all additions or alterations to the TLSE Project scope that may be required should FEI decide to blend hydrogen into the CTS upstream of the Tilbury facility in the future.

Response:

The following response has been provided by Ray Mason:

The question appears to be assuming that I am suggesting the TLSE Project could use hydrogen directly as an alternate fuel; however, this was not my intent. The section of my report, pages 43-45, referenced a 2019 British Columbia Hydrogen Study[64] that suggested low levels of hydrogen (i.e., 5 to 15 percent by volume) <u>could be included in existing natural gas streams</u>, but does not suggest it be used as a complete replacement for natural gas.

[64] BC Hydrogen Study, https://www2.gov.bc.ca/assets/gov/government/ministries-organizations/zen-bcbn- hydrogen-study-final-v6.pdf.

FEI also provides the following response:

The scope of the TLSE Project does not account for the delivery of a blend of hydrogen and natural gas to the Tilbury facility. As described in the response to BCUC IR5 140.1, FEI is still studying the potential for hydrogen blending and no projects are imminent. However, 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.

G. PRICEWATERHOUSE COOPERS (PWC) REPORT (EXHIBIT B-61 APPENDIX RP 3)

141.0 Reference: PWC REPORT

Exhibit B-61 (2024 Resiliency Plan), Appendix RP 3 (PWC Report), pp. 3, 4, 6, 8, 10

Economic Impact Estimates

On page 3 of Appendix RP 3 (the PWC Report) of Exhibit B-61, PWC lists the Assessed Vulnerabilities ("Reviewed Scenarios") for which FEI requested an estimate of the economic impact. This includes the economic effects of a widespread gas customer outage affecting AV-3, AV-49, AV-33, AV-30, AV-4 (Columbia), AV-45, and AV-4 (Salmon Arm).

On page 4 of Appendix RP 3 (the PWC Report) to Exhibit B-61, PWC states that it conducted a sub-regional analysis to assess the impact of smaller outages within sub-regions related to the Reviewed Scenarios.

141.1 Please confirm, or explain otherwise, whether FEI selected only seven Reviewed Scenarios as the focus because they were identified as the most significant vulnerabilities in FEI's 2024 Resiliency Plan.

<u>Response:</u>

FEI provides the following response:

Not confirmed. Selecting the seven Reviewed Scenarios for different geographic regions of FEI's service territory ensured that PwC's analysis captured the different economic makeup of different areas of the province. In particular, FEI's basis for selecting the seven Reviewed Scenarios was to select AVs whose combined outage impact area (i.e., the geographic area in which customers would lose service) covered as much of FEI's service territory as practical. FEI's approach was to have a Reviewed Scenario for each region in FEI's service territory considered in the 2024 Resiliency Plan. Within each region, FEI then selected AVs with an outage impact area that covered the largest geographic area within that region. AVs with smaller impact areas that fell within the impact area of a given Reviewed Scenario were then assessed as part of PwC's sub-regional analysis.

The following response has also been provided by PwC:

Another consideration was the availability of data and the economic geography of B.C. in terms of the boundaries of Census Areas and Census Metropolitan Areas. These boundaries were considered when determining the geographies of the Reviewed Scenarios to enable economic analysis to be undertaken. The combination of the Reviewed Scenarios also represent approximately the area that is covered by FEI's supply.

141.2 Please elaborate on the differences between the Reviewed Scenarios and the sub-regional scenarios.

Response:

The following response has been provided by PwC:

To expand on the description in section 2.5 of the PwC report, the key difference between the economic analysis approach for the Reviewed Scenarios and the sub-regional scenarios is the way in which the base-case economic output of the affected region was estimated (where base-case is defined as the estimated GDP in the absence of a gas supply disruption).

The approach for each Reviewed Scenario entailed estimating granular GDP figures at the NAICS 3-digit level for each Census Area (CA) and Census Metropolitan Area (CMA) in BC. This was done using Statistics Canada data on province-wide average levels of GDP per worker in each industry (as such data is not available at the sub-regional level), combined with granular data on employment within each CA and CMA.

This base case estimate of GDP for each CA and CMA was then combined with estimates of the reduction in output arising from gas outages to develop the impact estimates in the PwC report.

At the sub-regional scenario level, the data required to build up granular base-case estimates of GDP for smaller geographies is more limited and more uncertain. Amongst other factors it is affected by lower sample sizes used in the collection of this and data privacy considerations over what data is published.

As a consequence, the base case level of GDP in the subregional scenarios was derived from the estimates developed for the corresponding Reviewed Scenario in which they are geographically located, by scaling the results for the different number of gas customers affected.

Aside from the computation of the base case GDP, in all other respects the approach used for the Reviewed Scenarios and the sub-regional scenarios was unchanged.

141.3 Please explain how the economic impact estimates in the report were used in the TLSE project alternatives analysis.

Response:

The following response has been provided by Exponent:

Exponent used the GDP loss estimates to calculate the daily losses if there is a no-flow event on each AV. Exponent then simulated no-flow events, including the regulatory shutdown period, whether shutdowns were controlled or uncontrolled, and the repair time, and estimated the duration that the supply was disrupted, and the system purge and relight duration. Based on the duration of different stages of outages, Exponent calculated the GDP losses for each simulation. Simulations were aggregated to determine the statistics of GDP losses. The methodology is presented in Appendix U of Exponent's report.

On page 6 of Appendix RP 3 (the PWC Report) to Exhibit B-61, PWC states that its primary research involves interviews with gas users from sectors contributing around 58 percent of the provincial GDP.

On page 8 of Appendix RP 3 (the PWC Report) to Exhibit B-61, PWC explains that it developed direct customer shocks by using interview data and applying "professional judgment to convert those into a range of percentage reductions to direct economic activity (i.e., GDP) in the subject sector."

141.4 Please explain the specific methodology used to translate qualitative input from interview data into quantitative estimates of percentage reductions in direct economic activity.

Response:

The following response has been provided by PwC:

The interviews conducted provided a range of quantitative and directional inputs for the analysis. In terms of the translation of primary interview-based input into quantitative estimates of reductions in economic activity, the approach varied depending on the feedback received. These approaches can be categorized broadly into four categories:

1. **Cases where stakeholders provided specific quantitative inputs on activity reduction:** In these cases, the translation of interview feedback to reduction in economic activity was straightforward. For example, in some sectors feedback indicated with a high level of confidence that activity across the whole industry would immediately cease in the absence of natural gas supply and would not restart until supply was restored. Where this was the case, a 60%-80% economic reduction was applied during the outage period. The maximum reduction in activity was set at 80% rather than 100% to build conservatism into the approach and to reflect that there could be specific businesses insulated from the outage that interviewees were not aware of.
2. **Cases where stakeholders provided predominantly directional inputs on activity reduction:** Where stakeholders had high certainty of a negative impact on activity but were uncertain on the quantum of impact, additional research was performed to support the assumption used. This research varied from sector-to-sector as described in Appendix 1 of the PwC report. For example, in the retail sector, the historic performance of the retail sector in B.C. during Covid crisis was reviewed, where many physical stores were closed.

Interview feedback indicated that gas supply outages would lead to similar closure of physical stores so the observed historic data was used as a benchmark for the level of activity reduction assumed.

3. **Cases where stakeholders indicated they expected there to be little or no impact on economic activity:** In these cases, it was assumed there would be no reduction in economic activity.

4. **Sectors where no interviews were held:** It was assumed there would be no impact on any of the economic sectors where no interview was held. As these sectors represent almost 40% of the province's economic output, it is likely that such impacts could add materially to the economic impact on the province, even if these sectors experience only mild levels of disruption. This approach was designed to add conservatism to the estimates.

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.

141.5 Please clarify whether PWC used any benchmarks to confirm the robustness of these estimates.

<u>Response:</u>

The following response has been provided by PwC:

A literature review of economic impacts of major disaster related utility outages is included in Appendix 4 of the PwC report. While no two events are precisely alike, and can be considered true benchmarks, a number of these studies estimate economic impacts that are of similar magnitude, or in many cases, higher than those in the PwC report.

The literature review also highlighted several other potential impact areas that were not included in the scope of the PwC analysis which could significantly add to the consequence of a major gas outage event.

- The inter-related nature of gas and electricity infrastructure can mean that the outage of one system can lead to cascading failures in the other. This linkage can be direct, for example where a lack of gas leads to a shutdown of gas-powered electricity stations, or indirect, for example, if many businesses and residents attempt to switch to electrical heating from gas heating during the outage overload the grid. These potential effects are not measured in the PwC analysis.

- An outage could lead to substantial personal hardship on residents due to colder temperatures, increased illness, mortality rates and disruption to everyday life. These "economic welfare" effects are not measured in the PwC analysis but evidence from other utility outages suggests they can be substantial. For example, evidence from electrical outages in the United States put these welfare costs at around US$1,750 per household for a one-month outage.[65]

141.6 Please describe the specific findings in the updated economic impact estimates that directly highlight the necessity of the TLSE Project compared to the previous PWC report filed as part of the Application.

Response:

The following response has been provided by PwC:

The scope of the updated PwC report differs from that in the previous PwC report:

- Firstly, the previous PwC report developed high level scenarios based upon entire sub-regions of B.C. losing access to natural gas which were not tied to specific system vulnerabilities. The updated PwC report uses specific scenarios for outages provided by FEI based on an engineering analysis of known system vulnerabilities and an assessment of the time required to repair infrastructure damage and relight customers. As a result, the updated PwC report assesses fundamentally different outage scenarios in terms of geography and duration that are specifically tied to real-world vulnerabilities.
- Secondly, the updated PwC report broadened the analysis by including primary research in additional sectors of the economy, not assessed in the previous PwC report.

In addition, assumptions from the previous PwC report were also re-examined through primary and secondary research and tested to consider if any developments in the five-year period between the two reports needed to be reflected. For example, the research considered if the Covid crisis may have impacted the ability of companies to operate in the event of the closure of workplaces.

The updated PwC report estimated the potential for significant impacts on the B.C. economy from supply outage events. For example, the AV-3 scenario was estimated to have an impact of between $2.1bn – $3.8bn on B.C. GDP.

[65] S. Baik, A. L. Davis, J. W. Park, S. Sirinterlikci, and M. G. Morgan, "Estimating what US residential customers are willing to pay for resilience to large electricity outages of long duration," Nat. Energy, vol. 5, no. 3, Art. no. 3, Mar. 2020, doi: 10.1038/s41560-020-0581- 1.

FEI also provides the following response:

The 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. As discussed in Section 3.2.2.1.2 of the Supplemental Evidence, 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. The Project need also includes replacing the Tilbury Base Plant which has reached end of life.

On page 10 of Appendix RP3 (the PWC Report) to Exhibit B-61, Figure 5, PWC provides the summary of scenarios with highest estimated economic impact.

141.7 Please explain how the economic loss for each of the seven Reviewed Scenarios differs before and after implementing Alternative 8 and Alternative 9, assuming worst-case conditions.

Response:

The following response is provided by FEI:

As described in the response to BCUC IR5 141.1, 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. Exponent conducted that analysis, using PwC's results as one of its three consequence metrics (GDP, customer outage days and customer outages).

The following response has also been provided by Exponent:

Exponent understands that PWC did not consider the mitigation Alternatives in preparing their analysis. Exponent's analysis calculates the daily losses associated with an outage on each AV, based on PWC's analysis. Exponent then calculates the total outage duration, including the customer relight period when daily losses descend, to determine the losses associated with a particular Alternative. Appendix U of Exponent's report details how losses are calculated.

Attachment 122.1

January 30, 2025

Canadian Standards Association,
operating as CSA Group ("**CSA Group**")
178 Rexdale Blvd.
Toronto, ON M9W 1R3

Subject: **Request for Proposal for <u>Reliability and resilience in the natural gas value chain</u> ("RFP")**

This document represents an invitation to proponents to submit proposals to the CSA Group for a standards research report that identifies and describes the existing reliability and resilience nomenclature, concepts and frameworks in the natural gas value chain.

Notice of Intent to Submit a Proposal (the "**NOI**") must be received by CSA Group no later than [12:00 hours (noon) EST on February 14, 2025] and must be submitted in writing to pablo.fernandezmarchi@csagroup.org. The NOI must contain the following information:

- The name of your company
- Name of the proposal contact
- The name of the RFP you're responding to
- A clear statement of your intention to submit a proposal.

Proposals must be received by CSA Group no later than **12:00 hours (noon) EST on March 3, 2025.** It is the proponent's responsibility to deliver their proposal prior to the **time/date of bid closing**. <u>Proposals received after 12:00 hours will not be accepted.</u>

Proponents must submit an electronic copy of their proposal to **pablo.fernandezmarchi@csagroup.org** by the time/date of bid closing noted above. It is Proponent's responsibility to follow up by phone on the proposal submission within a week past the time/date of bid closing, if no confirmation of proposal is received via email. The follow up must be performed via phone at 416-747-2314.

Questions with respect to the meaning or intent of this Request for Proposal (RFP), or requests for correction to any apparent ambiguity, inconsistency or error in the RFP, must be submitted in writing to Pablo Fernandez (pablo.fernandezmarchi@csagroup.org) and must be received before **12:00 hours (noon) EST on February 17, 2025**. Answers will be posted on CSA Communities where the RFP resides or emailed to all prospective proponents.

CSA Group is not obliged to accept the lowest bid or any proposal.

RELIABILITY AND RESILIENCE IN THE NATURAL GAS VALUE CHAIN

SECTION ONE

1.1 ***Background and Introduction***

Established in 1919, CSA Group is an independent, not-for-profit member-based association dedicated to advancing safety, sustainability and social good. CSA Group is an internationally-accredited standards development and testing and certification organization, and also provides consumer product evaluation and education and training services. CSA Group conducts and funds research to strengthen the development of standards and to determine where society would benefit from standardization.

Reliability (the capacity of a system to deliver the product when it is needed) and resilience (the capacity of a system to withstand and recover from adverse events) are necessary during production, transmission, and distribution of natural gas to maintain supply level requirements, to prevent unscheduled maintenance and repair work, as well as to avoid costly accidents and to prevent environmental damage.

Reliability and resilience in the production (extraction, processing) and transmission (high volume/pressure transportation and storage) context is different than in the natural gas distribution system context (utilities delivering gas to end use customers). Defining and understanding the nomenclature and concepts is important as it strongly influences the way both reliability/resilience and risks are assessed, managed, communicated and benchmarked. Therefore, differences in how reliability and resilience are understood, combined with the complex nature of the natural gas value chain, can lead to fundamental misalignment in how these important concepts are implemented, coordinated, communicated and compared across the natural gas value chain. Ultimately, a reliable and resilient system is intended to help to ensure that customers have access to natural gas when they need it.

Note: *The term "natural gas" used in this document may include emerging and low-carbon fuels such as hydrogen blends and biomethane.*

1.2 **Purpose of the Request for Proposal**

The purpose of this research project is to identify and describe the existing reliability and resilience nomenclature, concepts and frameworks currently in use in the natural gas sector, and to explore the development of a consistent reliability and resilience nomenclature to provide the upstream, midstream, and downstream natural gas sectors with a common understanding of the concepts of reliability and resilience, how they differ across the value chain, and the unique concerns and considerations across the value chain. It will also include recommendations for potential standard-based opportunities related to natural gas reliability and resilience to enable better alignment across the value chain in Canada.

1.3 **Location of Work**

Not applicable.

1.4 **Project Scope and Deliverables**

The research will include a landscape analysis of reliability and resilience nomenclature, definitions, concepts and measurements (what is measured and the nomenclature used for measurement) across the natural gas value chain (upstream, midstream, downstream). The research will also identify Canadian regulatory, standards-based requirements, and best practices relevant to natural gas reliability and resilience and how these apply in the industry. Findings in the literature and the impact of potential changes need to be validated and assessed through interviews of relevant stakeholders (i.e. regulators, operators and SMEs). Additionally, a comparison and analysis of natural gas reliability and resilience nomenclature, and concepts across the oil and gas value chain, including assessment of challenges and opportunities to increase standardization across the natural gas value chain will be covered. Finally, recommendations for potential standardization to address identified challenges and opportunities related to reliability and resilience in the natural gas value chain must be included.

The project deliverables will include:
1) A research report (drafts/final) to be prepared using the CSA Group Research Report Template.
2) A research report presentation to be prepared using the CSA Group Presentation Template for use by CSA Group staff and to be delivered by the proponent at a meeting of relevant CSA committee(s).

CSA Group will establish a Research Advisory Panel for this project, composed of CSA Group staff and external subject matter experts. CSA Group will organize regular touch base meetings and meetings with the Research Advisory Panel to ensure feedback and recommendations are communicated to the selected proponent. As applicable, the proposal should account for expected costs for accessing relevant codes, standards, and literature. Published CSA standards can be made available through view access to the selected Proponent. The research findings will be published in the form of a review and evaluative report on the CSA Group Standards Research website.

1.5 Delivery Schedule and Milestones

The following delivery schedule is recommended for the listed deliverables:

Deliverable	Due Date	Comments
Project work plan/ report outline		
Draft report 1		CSA to provide comments within two weeks (subject to change)
Draft report 2		CSA to provide comments within two weeks (subject to change)
Final draft		CSA to provide comments within two weeks (subject to change)
Final research report and presentation		Allow a few revisions as required during the finalization process

1.6 Pricing and Payment Schedule

The prices and/or rates quoted as part of the proponent's proposal must not include any provision for taxes. CSA Group reserves the right to negotiate an acceptable payment schedule prior to the awarding of a contract.

The total value of the fixed fee contract awarded to the winning proponent shall not exceed $70,000 excluding all applicable taxes (Goods and Services Tax or Harmonized Sales Tax, as appropriate). The Contractor will be solely responsible for any/all expenses.

SECTION TWO

2.1 Proposal Format

Proposals must be submitted in Adobe form (.pdf). Proposals must be submitted in the English language and include all of the required content set out in Section Three. The entire proposal, *excluding* the proposal cover sheet, resumes, budget form, budget narrative, schedule, and references, should not exceed 10 pages in length.

2.2 Submission Criteria

Click or tap here to enter text.

Proposals must be submitted by electronic mail to [**pablo.fernandezmarchi@csagroup.org**]. It is the proponent's responsibility to deliver their proposal on or before the Submission Deadline set out in Section 2.3.

Please contact CSA Group at the email provided above, if you do not receive an email confirmation from CSA Group within twenty-four (24) hours following the submission of your Proposal or Submission Deadline.

2.3 Submission Deadline

Proposals must be received by CSA Group no later than **12:00 hours (noon) EST on March 3, 2025**.

2.4 Late Proposals

Any proposal received after the Submission Deadline will not be considered unless it is the only proposal received, or it offers significant cost or technical advantages to CSA Group, and it is received before a retainer has been negotiated with another proponent.

2.5 Questions

Questions with respect to the meaning or intent of this Request for Proposal (RFP), or requests for correction to any apparent ambiguity, inconsistency or error in the RFP, must be submitted by electronic mail to [enter email address] and must be received no later than **12:00 hours (noon) EST** on **February 17, 2025**. Answers will be posted on CSA Communities where the RFP resides or emailed to all prospective proponents.

2.6 Final Selection

CSA Group anticipates that the proposal selection process will be completed by March 10, 2025.

SECTION THREE

3.1 Required Proposal Content

Proposals must include the following components:

3.1.1 Overview of organization

3.1.2 Background and Objectives

3.1.3 Research Approach – Describe how the proposed research will be conducted and the tasks necessary to accomplish the objectives.

3.1.4 Research Team and Participants – Identify the key members of the research team and provide brief statements of their qualifications to conduct the proposed research. Identify any other organizations that have committed to collaborate on the proposed research. Resumes for research team members are required, please see 3.1.10 below.

3.1.5 Relevant Experience and Expertise – Include summaries of similar work previously completed.

3.1.6 Budget – A detailed budget narrative and itemized budget form using the following format:

Task / Deliverable / Milestone	**Professional Fees**	**Travel**	**Other Fees (please specify)**	**<u>Total</u>**

Total				

3.1.7 Schedule of Work – A detailed timeline of milestone completion and communication plan with CSA Group.

3.1.8 Agreement with the terms of the RFP – Indicate your agreement with the terms of the RFP, including the copyright assignment and moral rights waiver requirements.

3.1.9 Credentials / references regarding experience on equivalent projects.

3.1.10 Resumes for each research team member – limit the documents for each member to two pages of information relevant to the individual's role on this project and work that is of similar nature to this role.

SECTION FOUR

4.1 Selection Process

Evaluation of the proposals will be based on the demonstrated experience and competence, including the background and objectives, research approach, research team and participants, relevant experience, and budget, as well as the schedule of work and presentation, in accordance with the rating scale set out in Appendix A.

CSA Group reserves the right to reject any or all proposals. The right is reserved to award the work in whole or in part to other than the lowest cost proposal and the right to not award the work. CSA Group may award the work based on initial proposals received, without discussion of such proposals.

4.2 Liability

CSA Group does not assume any responsibility or liability for costs incurred by a proponent in replying to this RFP or prior to signing of a contract. This is not a tender. CSA Group reserves the right to contact, negotiate with, or interview one or more proponents but shall not be obligated in any manner to any proponent until a written formal contract has been duly executed for the selected proposal.

4.3 Privacy and Confidentiality

Proponents may specify that certain portions or all of a proposal is to be treated as confidential. CSA Group agrees not to copy or distribute contents of a proposal other than as necessary for the evaluation purposes.

The information contained in this document is proprietary to CSA Group and is provided to your organization for the express intent of replying to this RFP. CSA Group grants you permission to share it only among the employees within your organization working on the proposal in response to this RFP. This document is not to be otherwise reproduced or distributed, unless Proponent has requested and received permission in writing from CSA Group to share with additional individual(s) or organization(s), and those individual(s)/organization(s) contact information would need to be provided to CSA Group and these individual(s)/organization(s) would need to agree to comply with privacy and confidentiality requirements set out in this RFP.

4.4 Publication Rights

CSA Group will own the intellectual property rights, including full copyright, in all works created or arising from the services and/or as a result of the project.

The selected proponent(s) must therefore assign and transfer to CSA Group the entire right, title and interest for Canada and all other countries in and to the copyright for such work(s). The selected proponent(s) must do all things and execute without further consideration, such assurances, confirmatory assignments, applications and other instruments as may reasonably be required to obtain copyright registrations for such work(s) and to vest the copyright registrations in CSA Group, its successors and assigns.

The selected proponent(s) must also waive, as against CSA Group, its successors and assigns and licensees, all moral rights which the proponent may have or will acquire in respect of the copyright in the work(s). The selected proponent(s) must have each of its employees or third party sub-contractors who create copyrighted work for delivery to CSA Group, provide to CSA Group a written waiver which waives, as against CSA Group, its successors and assigns and licensees, all moral rights which such employee or third party contractor may have or will acquire in respect of the work(s).

4.5 Constraints

If, for whatever reason, the proponent is unable to use the services of any or all individuals who meet the qualifications specified in its proposal, it must provide a replacement with similar qualifications and experience. The replacement must meet the same criteria that were originally proposed and be acceptable to CSA Group, at its sole discretion. The proponent must, as soon as possible, give notice to CSA Group of the reason for the replacement by providing the name, qualifications and experience of the proposed replacement. The proponent must not, in any event, allow performance of the work by unauthorized replacement persons.

4.6 Proposal Validity

The proponent warrants and agrees that their proposal will remain firm and valid for a period of 90 calendar days from the Submission Deadline.

APPENDIX A

EVALUATION CRITERIA

Requirement	Score
Background and Objectives	/5
Research Approach	/30
Research Team and Participants	/20
Relevant Experience and Expertise	/15
Presentation	/5
Schedule of Work	/5
Budget	/20
TOTAL	/100

Attachment 131.9

REFER TO LIVE SPREADSHEET MODELS

Provided in electronic format only

(accessible by opening the Attachments Tab in Adobe)

Attachment 132.1

REFER TO LIVE SPREADSHEET MODELS

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FILED CONFIDENTIALLY

(accessible by opening the Attachments Tab in Adobe)

Attachment 132.2

REFER TO LIVE SPREADSHEET MODELS

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(accessible by opening the Attachments Tab in Adobe)

Attachment 135.1.1

FILED CONFIDENTIALLY

Attachment 137.2

REFER TO LIVE SPREADSHEET

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