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British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: Commission Secretary

Dear Sirs/Mesdames:

Re: FortisBC Energy Inc.
Application for a Certificate of Public Convenience and Necessity for the Tilbury Liquefied Natural Gas Storage Expansion Project

We enclose for filing in the above proceeding the Post-Adjournment Final Submissions of FortisBC Energy Inc., dated June 19, 2025.

Yours truly,

FASKEN MARTINEAU DuMOULIN LLP

Matthew Ghikas
Personal Law Corporation

Enclosures

BRITISH COLUMBIA UTILITIES COMMISSION

AND

FORTISBC ENERGY INC.

APPLICATION FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE TILBURY LIQUEFIED NATURAL GAS STORAGE EXPANSION PROJECT

POST-ADJOURNMENT FINAL SUBMISSIONS OF FORTISBC ENERGY INC.

JUNE 19, 2025

Fasken Martineau DuMoulin LLP
Matthew Ghikas and Niall Rand

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PART ONE: INTRODUCTION

1. The extensive body of evidence filed prior to the British Columbia Utilities Commission (**BCUC**)'s March 23, 2023, adjournment decision (**Adjournment Decision**[1]) described, among other things, the importance of a resilient system and the widespread and lengthy outage that will occur following a winter T-South supply disruption (**no-flow event**). FEI detailed how the 2018 pipeline rupture on Enbridge's T-South system (**2018 T-South Incident**) unfolded, highlighting how fortunate customers and British Columbians were that the incident occurred in the shoulder season and in a location that was quickly accessible to repair crews. FEI also demonstrated the importance of on-system supply in buying time to respond to a winter T-South no-flow event and avoiding an uncontrolled system depressurization. The BCUC's Adjournment Decision, while identifying areas where additional information was required, acknowledged: the need for resilient utility infrastructure;[2] FEI's vulnerability to a supply interruption to the Lower Mainland (a no-flow event);[3] and that the Tilbury Liquified Natural Gas Storage Expansion (**TLSE**) Project will mitigate that risk.[4]

2. FEI's Supplemental Evidence,[5] the 2024 Gas System Resiliency Plan (2024 Resiliency Plan),[6] and responses provided by FEI and independent experts to rounds five and six information requests (**IRs**), have comprehensively addressed the information gaps identified in the Adjournment Decision. The BCUC now has, among other things, the requested[7] holistic

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1 Decision and Order G-62-23, dated March 23, 2023.

2 Adjournment Decision, p. 12: "The Panel accepts the need for resilient utility infrastructure and the importance of resiliency in the provision of safe and reliable service."

3 Adjournment Decision, p. 16: "The existing system currently has limited ability to mitigate a three day no-flow event. While it may be able to do so in July, it would be very challenged to do so in cooler months and not at all likely to be able to do so in a typical December or January."

4 Adjournment Decision, p. 16: "The Panel is satisfied with the evidence provided by FEI on the limitations of the system's ability to mitigate a 3 day no-flow event and finds that the TLSE Project will mitigate a 3-day no-flow event, provided the no-flow event does not occur simultaneously with the design peak day. In that latter circumstance, there would be insufficient regasification capacity. However, we accept FEI's assertion that even in this circumstance, the TLSE Project would provide FEI more time to conduct a more orderly shutdown than it otherwise would be able to conduct within the limits of the existing infrastructure."

5 Exhibit B-60.

6 Exhibit B-61.

7 Adjournment Decision, pp. 14, 25-33, 39-40 and 51.

assessment of system vulnerabilities, additional information on the remaining life of the Tilbury LNG Facility Base Plant (**Base Plant**), an evaluation of additional Tilbury and non-Tilbury alternatives, and evidence on how potential future developments might impact the alternatives assessment. The post-Adjournment Decision evidence shows the situation facing customers today to be even worse than FEI had previously described.

3. The 2024 Resiliency Plan confirms, through the quantitative (consequence x probability) risk analysis of the independent expert Exponent, that a winter T-South no-flow event poses an unacceptably severe risk, much larger than any other customer outage risk. This unacceptable risk needs to be mitigated. In addition, the new information on the condition of the Base Plant demonstrates that the facility is end-of-life. Reliability is deteriorating, equipment is obsolete, there are inherent problems in the 55-year-old design, and engineering consultants have recommended against refurbishing the tank. A market analysis confirms that, upon the failure of the Base Plant, FEI will be unable to replace the peaking gas supply in the market. The Base Plant has provided excellent value to customers for 55 years, and a replacement facility is needed to ensure that firm customers will continue to receive uninterrupted service in normal operations.

4. The supplemental alternatives analysis confirms that FEI customers will obtain the greatest value from a new facility with 800 MMcf/d of regasification and a 3 Bcf tank that is allocated between a 2 Bcf "resiliency reserve" and a third Bcf for gas supply (Supplemental Alternative 9, the **Preferred Alternative**). This is due to a combination of considerations, including: (1) providing the most customer outage risk mitigation in respect of a winter T-South no-flow event and other known vulnerabilities; (2) meeting FEI's full peaking supply requirements, which exceed the current Tilbury capabilities, in an optimal manner within FEI's overall gas supply portfolio; and (3) its ability to deliver these benefits more cost-effectively than other alternatives. FEI has used hypothetical adverse load loss sensitivities to demonstrate that all of the Supplemental Alternatives can be expected to remain highly useful and fully utilized in the future, reflecting on-system Liquefied natural gas (**LNG**)'s unique versatility.[8]

[8] Exhibit B-69, BCUC IR6 151.1.

5. FEI continues to rely on its Pre-Adjournment Final Submissions and Reply Submissions, as they address a substantial body of evidence that remains relevant. The additional evidence, discussed in these Post-Adjournment Final Submissions, reinforces that the Preferred Alternative is in the public interest. FEI respectfully submits that the BCUC should approve the TLSE Project as proposed, along with the proposed deferral accounts and depreciation rates set out in Section 6 of the Application.[9] FEI also submits that the BCUC is in a position to accept the 2024 Resiliency Plan pursuant to section 44.1 of the *Utilities Commission Act* (**UCA**) at this time, rather than await the next Long-Term Gas Resource Plan (**LTGRP**) proceeding.

6. These Final Submissions are organized as follows:

- **Part 2: General Comments on Themes** – Provides general comments on themes arising from IRs on the Supplemental Evidence and 2024 Resiliency Plan.
- **Part 3: Project Need – Mitigating Unacceptable Customer Outage Risk** – The risk posed by a winter T-South no-flow event is unacceptably severe and should be mitigated to as-low-as-reasonably-practicable.
- **Part 4: Project Need – Base Plant Is End-of-Life and Must Be Replaced** – The Base Plant has reached end-of-life after 55 years of operation. It needs to be replaced now to ensure that FEI can continue to provide dependable firm service in normal operations.
- **Part 5: Supplemental Alternatives Analysis** – The comprehensive supplemental alternatives analysis demonstrates that the public interest is best served by constructing the TLSE Project with 800 MMcf/d of regasification capacity and a 3 Bcf tank that is allocated between a 2 Bcf “resiliency reserve” and 1 Bcf for gas supply (Supplemental Alternative 9).
- **Part 6: Project Description** – The TLSE Project remains largely unchanged since the Application was filed, and all four major Project components are still required to meet the Project objectives.
- **Part 7**: **Financial Analysis** – FEI’s updated Project cost estimate and levelized rate impact analysis are sound bases for the BCUC to assess the TLSE Project.
- **Part 8**: **Environmental and Archaeological Impacts** – Based on the additional assessment work performed since the Application, FEI has downgraded the TLSE Project’s level of environmental and archaeological risk. The potential impacts can

9 Exhibit B-1-4.

be mitigated through additional assessments, permitting, and standard protection and mitigation measures.

- **Part 9: Consultation and Engagement** – FEI's consultation and engagement with the potentially affected Indigenous groups, the public, government and other stakeholders has been meaningful, timely and sufficient, having regard to the approvals sought and current stage of Project development. It remains consistent with the BCUC's CPCN Guidelines.[10]

- **Part 10: BC Energy Objectives and Long-Term Gas Resource Plan** – The TLSE Project is consistent with "the applicable of British Columbia's energy objectives", including being a direct driver of economic growth and job creation, while also being consistent with the goal of reducing greenhouse (GHG) emissions. This Application considers and is aligned with the outcome of the 2022 LTGRP proceeding.

- **Part 11: Additional Orders and Terms** – The two proposed deferral accounts are just and reasonable, and the BCUC will have appropriate oversight during the development and construction phases. The BCUC also has jurisdiction to include terms in its CPCN addressing the planning allocation of the TLSE Project tank. Any such term must preserve FEI's ability to respond effectively in real time to adverse operating conditions.

- **Part 12: Conclusion and Order Sought**.

- **Appendix A: Modelling Parameters that Tend to Understate Current Risk and the Preferred Alternative's Financial Benefits** – There are a number of modelling parameters/inputs that tend to understate: (1) the current customer outage risk; and (2) the financial benefits (avoided gas supply costs) associated with LNG allocated to gas supply, thus potentially understating the benefits of the Preferred Alternative relative to most other alternatives. This table includes notable examples.

- **Appendix B: Figure 4-20 – Step 3 Scoring Results** – A larger version of the summary of the scoring results for all four viable Supplemental Alternatives including the key choices and trade-offs.

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[10] Appendix A to Order G-20-15, dated February 20, 2015, p. 9.

PART TWO: GENERAL COMMENTS ON THEMES ARISING

7. This Part comments on themes in round five and six IRs, relating to the two Project drivers and the supplemental alternatives analysis. FEI's detailed submissions on these matters follow in Parts Three to Five, respectively.

A. THE CUSTOMER OUTAGE RISK IS REAL AND VERY SIGNIFICANT FOR CUSTOMERS AND THE PROVINCE GENERALLY

8. While it has been over six years since the 2018 T-South Incident, the underlying concern raised by the BCUC in its wake remains equally relevant today. Extreme and unforeseeable events can still, as the BCUC noted in its February 5, 2019 letter to FEI, "damage critical infrastructure and significantly restrict utilities' ability to provide safe and reliable energy services to customers".[11] We have collectively witnessed instances of high-impact events in recent years – the failure of the Texas electric grid during record low temperatures, the shut-down of the Colonial oil pipeline serving the Eastern seaboard due to a ransomware cyberattack, a Colorado outage caused by vandalism, the destruction of Fort McMurray due to wildfires, and flooding of the Sumas Prairie following record flows in adjacent rivers, to name a few. This Application presents an opportunity to proactively mitigate a known, unacceptably severe risk.

9. FEI's 2020 Application identified the scope and likely duration of a customer outage, while treating as self-evident the potential for a winter T-South no-flow event given the recent occurrence of the same type of disruption. The BCUC required more information to determine this Application,[12] including a consequence x probability risk assessment. FEI has provided the requested risk analysis, which was undertaken by independent experts. The analysis confirmed and quantified the severe consequences and found a relatively high probability of occurrence over any reasonable time horizon.

10. The IRs have tested the experts' assessments of consequences and probability and asked them to adjust various assumptions – always in ways that would tend to produce lower calculated

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[11] BCUC Letter L-1-19, dated February 5, 2019: Exhibit B-15, BCUC IR1 8.2.

[12] Exhibit B-60, Supplemental Evidence, p. 1.

risk results. FEI's experts have provided compelling answers explaining the reasonableness of their own inputs, and why the modified assumptions presented in IRs are invalid or less realistic. They have nevertheless run those modified scenarios wherever feasible. In each case, the resulting expected losses (risks) are still unacceptably severe.

11. The reality is that there is a high degree of confidence around the severity of the direct customer service impacts. Moreover, PricewaterhouseCoopers (**PwC**)'s calculated economic (GDP) losses, and the cumulative probabilities determined by Exponent, are both so high that no plausible combination of adjustments to customer outage duration (available personnel, relight productivity rates, etc.), economic loss assumptions (business closures, etc.), probability inputs (failure rates, natural event frequency, etc.), or the expected life assumption (e.g., the suggested 20-year sensitivity), change the overall conclusion that the risk facing FEI customers at present is unacceptably severe and should be mitigated.

12. It also bears noting that, while the IRs focused on alternative inputs that would reduce the calculated risk, the risk could also be higher. The already-severe risk reflects numerous factors that tend to understate risk results, as catalogued in the attached **Appendix A – Modelling Parameters that Tend to Understate Current Risk and the Preferred Alternative's Financial Benefits**. To name just two examples: In order to simplify modelling, PwC assumed that entire sectors of the economy experienced no losses whatsoever. The scope of the T-South probability assessment did not include the potential for deliberate action (cyberattack, terrorism, vandalism) to cause a no-flow event, but government studies (and the successful Colonial Pipeline attack) indicate that important pipelines are prime targets.

13. FEI respectfully submits that, while the consequence x probability risk analysis is important, we cannot not lose sight of the big picture:

- FEI's unique location in the region, and the limited capabilities of its infrastructure, make FEI far more exposed than other North American utilities to a supply disruption. Intuitively, there can be little doubt that an outage of this scale and duration in the most populous and urbanized part of British Columbia will have severe service and consequential economic consequences.

- Pipeline integrity programs (e.g., Electro Magnetic Acoustic Transducer in-line inspection (**EMAT ILI**)) and operator due diligence can never reduce the probability of a winter no-flow event on T-South to zero, and the 2018 T-South Incident occurred despite Enbridge's EMAT ILI. Natural hazards will continue to exist along the approximately 952 km long T-South corridor. Malicious actors pose a widely recognized threat to energy infrastructure. Even if the probability were much lower than Exponent calculates, this event of severe consequence could happen as early as this winter, in back-to-back years, or numerous times over a 20- or 60-year period. FEI has already had two further near-miss events since the 2018 T-South Incident.

14. Every relevant expert in this proceeding – Guidehouse, PwC, JANA Corporation (**JANA**) and Exponent – have emphasized that the appropriate risk management approach for addressing plausible severe consequence events with uncertain frequency and timing is to mitigate the potential consequences.

15. Ultimately, FEI's ability to avoid or reduce the known catastrophic harm depends on the regasification and storage capabilities of the Tilbury LNG facility. FEI's analysis shows that adding more on-system regasification <u>and</u> storage is the only practical and effective way to bridge a winter T-South no-flow event. FEI's existing Tilbury Base Plant is the right type of infrastructure, but it has reached end-of-life and is undersized in terms of both regasification capacity and tank volume. Allocating a portion of the new, larger tank to a "resiliency reserve" (LNG set aside for resiliency purposes) ensures that the necessary supply is available when an emergency occurs. The TLSE Project, as proposed, mitigates currently unacceptable customer outage risk to as-low-as-reasonably-practicable.

B. <u>THE BASE PLANT HAS REACHED END-OF-LIFE AND PEAKING SUPPLY FROM TILBURY IS MORE IMPORTANT THAN EVER</u>

16. The second Project driver, discussed in Part Four below, is the pressing need to replace the critical gas supply functions that Tilbury LNG provides in normal operations.

17. The BCUC, in its Adjournment Decision, expressed a desire for additional evidence on the condition of the Tilbury Base Plant.[13] The evidence that the Base Plant has reached end-of-life is

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13 Adjournment Decision, pp. 14, 51.

now overwhelming. Despite further investment, the Base Plant's performance continues to deteriorate. Key components of the regasification equipment – the only regasification equipment at Tilbury – are now experiencing failure rates at least six times greater than industry norms.[14] There is every reason to expect worsening performance, as the 55-year-old facility is well-past its expected service life and has many deteriorating and obsolete components. The new independent engineering studies detail the poor condition of the Base Plant tank and fundamental issues with the foundations; the experts advise against refurbishment.[15] Investments intended to address the many issues with the Base Plant equipment or tank would still leave unaddressed the seismic, flood exposure and environmental issues inherent in a 55-year-old facility design. In aggregate, these problems demonstrate that the Base Plant facility is end-of-life. Simply put, FEI's customers have benefited from the Base Plant for 55 years, and we have now reached the point where replacement provides better value than making investments in the Base Plant that have uncertain prospects of extending its life and leave unaddressed the underlying design problems.

18. While FEI received relatively few IRs on the condition of the Base Plant, FEI did respond to a number of IRs that appeared to be directed at assessing whether FEI could "make-do" without replacing the Base Plant. The evidence discussed in Part Four shows this is not reasonable. On-system LNG storage is used throughout western North America because it has a number of unique attributes, including a very short response time and deliverability that does not depend on third-party infrastructure or counterparties. These characteristics make on-system LNG ideal for short-duration supply in peak periods, managing unforeseen load variances on short notice, and responding to short-duration supply constraints due to off-system equipment failures or planned maintenance. In the case of FEI, these are all circumstances where the alternative to using Tilbury LNG may well be curtailment of firm load.[16]

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[14] Exhibit B-60, Supplemental Evidence, pp. 69-70; Exhibit B-69, BCUC IR6 157.1.

[15] Exhibit B-60-1, Confidential Supplemental Evidence, Confidential Appendices D and E.

[16] See Part Four, Section C below.

19. Load has increased since the Base Plant was constructed in 1971 and FEI already must augment its peaking supply with year-round pipeline capacity and peaking call options, neither of which shares the valuable LNG attributes described above. There is no more surplus capacity on regional infrastructure that could provide a replacement for Base Plant supply. Nor could FEI conceivably secure enough peaking call options, and they would not be a dependable source of supply in any event. The infrastructure constraints are likely to continue or worsen, given the push for new gas-fired generation in the US Pacific Northwest. Simply put, when the Base Plant is no longer available, FEI's firm customers will face service disruptions in normal operations unless and until another (currently hypothetical) major pipeline and/or regional gas storage expansion occurs. Being reliant on a potential future regional infrastructure expansion for peaking supply would subject firm customers to significant risk of curtailments for an indeterminate period. When the hypothetical expansion materializes, customers face the certainty of paying much higher tolls. FEI estimates those costs to be at least $46 million annually.[17]

20. The fact that FEI has typically used Tilbury LNG relatively infrequently (raised in several IRs) speaks to the function of on-system LNG within the gas supply portfolio, rather than being an indicator that Tilbury LNG is superfluous. Tilbury LNG is, in effect, last resort peaking supply and a back up to other off-system resources in the portfolio. It is used infrequently because FEI conserves it, recognizing that using the LNG means exposing firm customers to considerable risk of losing service if, for example, a cold snap occurs, changes in weather drive load variances on short notice, or if there is an unplanned outage somewhere on FEI's system. FEI's Annual Contracting Plan (**ACP**) has long been predicated on FEI being able to serve firm customers in a 1-in-20-year cold weather event, and that has always been accepted by the BCUC. FEI almost reached this design peak temperature in 2021, and it is impossible to predict when this will next occur.[18]

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[17] See Part Four, Section E below.

[18] Exhibit B-69, BCUC IR6 145.6.

21. FEI respectfully submits that the additional evidence discussed in Part Five demonstrates, overwhelmingly, that the Tilbury Base Plant needs to be replaced. Irrespective of resiliency considerations, the increasing importance of on-system LNG for providing firm customers with dependable gas supply in normal operations means that this is not a decision that can reasonably be deferred.

C. THE PREFERRED ALTERNATIVE PROVIDES THE GREATEST CUSTOMER VALUE

22. Over the course of this proceeding, FEI has evaluated over 30 potential alternatives including pipelines, regional storage, different sites for on-system LNG, and different sizes and configurations of LNG facilities at Tilbury. The alternatives considered include every one of the alternatives identified by the BCUC in the Adjournment Decision. The evidence discussed in Part Five below makes a compelling case for the proposed TLSE Project size and configuration (Supplemental Alternative 9).

23. The Supplemental Alternatives involving something other than constructing replacement LNG facilities at Tilbury are not technically or commercially feasible, and FEI received no IRs on them. Otherwise, the key differences among the technically and commercially feasible Supplemental Alternatives relate to: (1) the amount of regasification capacity; (2) the tank size; and (3) the allocation of the tank for planning purposes between the gas supply portfolio and a "resiliency reserve" (i.e., supply that remains unused until it is necessary to avoid loss of firm load).

24. As discussed in Part Five, FEI has undertaken a detailed supplemental alternatives evaluation, measuring the performance of the viable options against five specific evaluation criteria that tie back to the two purposes of the Project (resiliency and peaking gas supply), address relative cost-effectiveness and consider the BCUC's concern about future usefulness. Supplemental Alternative 9 is the clearly superior option in that analysis. With reference to those five evaluation criteria, Supplemental Alternative 9 scores highest because:

- It provides the greatest reduction in customer outage risk among the viable alternatives;

- It provides peaking supply capabilities that maintain FEI's Tilbury peaking supply, while giving FEI the flexibility to avoid annual gas supply costs by displacing other resources in its gas supply portfolio;

- Like the other viable alternatives, it addresses the age-related challenges associated with the existing Base Plant;

- Compares favourably to smaller replacement facilities in terms of levelized total rate impact due to significant economies of scale and greater annual gas supply benefits (avoided costs); and

- Like the other viable alternatives, it is likely to continue generating value for customers throughout its expected service life.

25. There is considerable evidence on the record, including a significant amount of independent expert analysis, to support FEI's scoring.

26. Intuitively, the relative scoring results make sense. The scores reflect that all four viable Supplemental Alternatives address reliability issues with the Base Plant (as they are replacement facilities) and have similar prospects of being used well into the future. The key choices that will drive different value for customers are:

1. Whether or not the facility is sized to reduce the customer outage risk posed by a winter T-South no-flow event to as-low-as-reasonably-practicable at average winter temperatures or colder; and

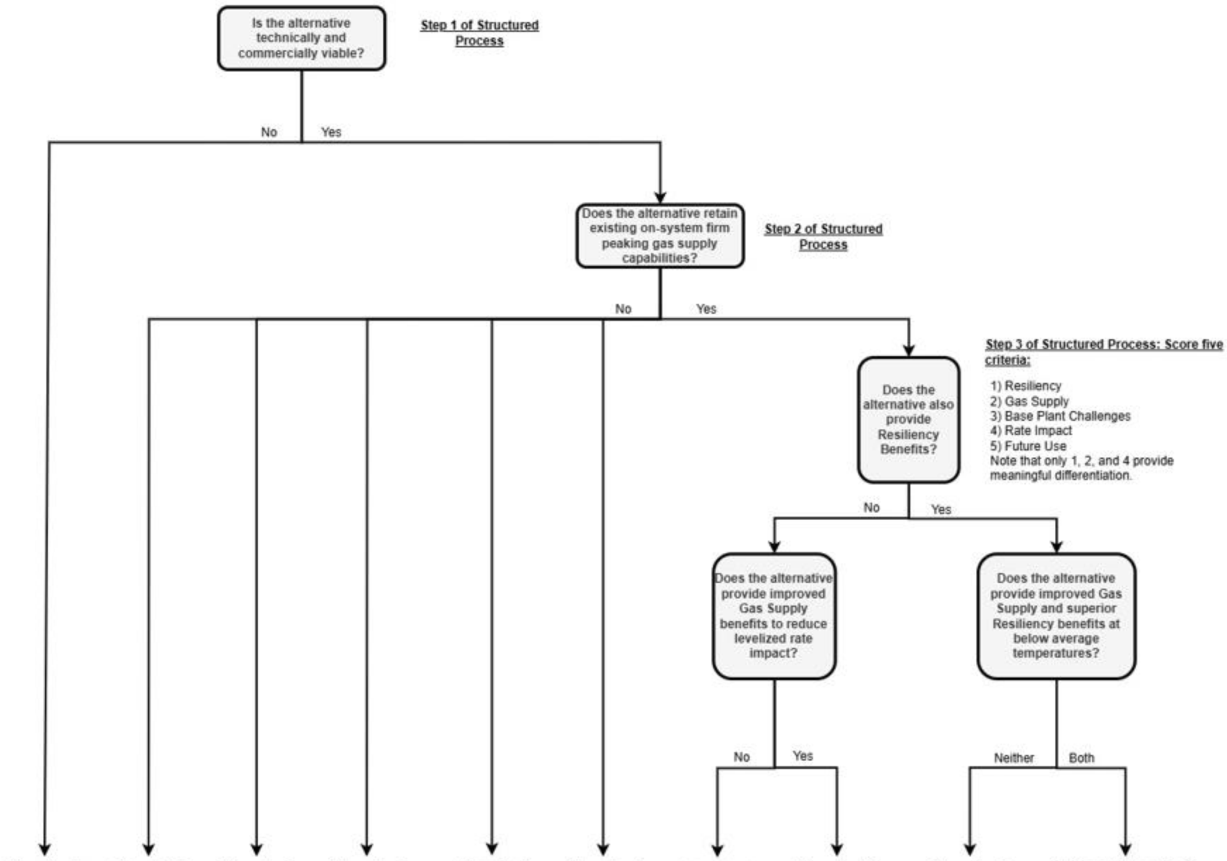
2. Whether the facility only maintains Tilbury's undersized gas supply capabilities (150 MMcf/d and 0.6 Bcf), or whether those capabilities are increased to meet FEI's full peaking supply requirements (200 MMcf/d and 1.0 Bcf) in a more optimal way than is done today[19].

27. These choices, and the trade-offs inherent in them, are summarized in the figure below.[20] A larger version of the figure is provided in **Appendix B**.

[19] As described in Part Four, Section D, FEI must currently augment the 150 MMcf/d and 0.6 Bcf from Tilbury with 50 MMcf/d of year-round pipeline capacity and non-dependable peaking call options to achieve its required peaking gas supply.

[20] This figure was originally presented in FEI's Supplemental Evidence, p. 161; however, this version has been updated to reflect a 60-year evaluation period (the original 67 years was in error), and a 20-year hypothetical adverse sensitivity. The updated information was taken from Exhibit B-63, BCUC IR5 126.1.

Figure 4-20: Step 3 Scoring Results



	Alternative 1	Alternative 2	Alternative 3	Alternative 5	Alternative 6	Alternative 7	Alternative 4	Alternative 4A	Alternative 8	Preferred (Alternative 9)
Viability:	Not Viable	Not Viable	Not Viable	Not Viable	Not Viable	Not Viable	Viable	Viable	Viable	Viable
Levelized Total Rate Impact (%):	1.8%	3.3%	3.4%	4.4%	4.9%	5.6%	3.2%	3.0%	4.4%	4.2%
Levelized Total Rate Impact - Incremental to Alt 1 (%):	NA	1.57%	1.66%	2.68%	3.2%	3.84%	1.44%	1.27%	2.60%	2.45%
20-Year Expected GDP Loss Reduction ($millions):	0	0	0	41.6	642.7	3,311.2	0	0	3,246.8	3,311.2
60-Year Expected GDP Loss Reduction ($millions):	0	0	0	124.9	1,928.0	9,933.8	0	0	9,740.6	9,933.8
Expected Annual COD - Cold Weather (-1.4C):	NA	NA	NA	NA	NA	1,250,000	NA	NA	2,900,000	1,250,000
Scoring Results	NA	0.1	0.1	0.4	0.0	1.5	1.4	1.8	1.9	2.9

28. Looking at the results holistically, the superior customer value associated with the Preferred Alternative (Supplemental Alternative 9) comes from its ability to:

- Provide the greatest risk mitigation among the viable alternatives; and

- Meet FEI's entire peaking supply requirements (200 MMcf/d and 1.0 Bcf), which allows FEI to avoid other gas supply portfolio costs over the useful life of the TLSE Project.

29. The economies of scale in LNG tank construction are such that the capital cost of the smallest viable option represents approximately 73 percent of the capital cost of the largest facility – and it would not provide any material protection against a winter T-South no-flow event or FEI's full peaking gas requirements. A larger facility with a "resiliency reserve" is required to provide material customer outage risk protection. A facility that also meets FEI's full peaking supply requirements will avoid more than enough annual pipeline or regional storage tolls to offset the additional capital cost of a 3 Bcf tank versus a 2 Bcf tank in a 67-year levelized rate impact calculation.

30. The IRs primarily focused on testing a limited number of Exponent's customer outage risk modelling inputs and inputs in the levelized rate impact analysis. In each instance, Exponent and FEI provided cogent reasons for why the selected inputs were reasonable. Notably, Exponent and FEI also performed sensitivity analyses demonstrating that Supplemental Alternative 9 remains the Preferred Alternative with the varied input assumptions. A very unlikely confluence of events would be necessary for customers to be financially better off on an NPV basis with a 2 Bcf tank (Supplemental Alternative 8). Part Five, Section F provides additional explanation in this regard.

31. FEI submits that there is a strong case that customers will receive the best value from FEI's investment in the Preferred Alternative.

PART THREE: PROJECT NEED – MITIGATING UNACCEPTABLE CUSTOMER OUTAGE RISK

A. INTRODUCTION

32. In this Part, FEI addresses the first Project driver: FEI's exposure to a widespread customer outage following a winter no-flow event on the T-South system.

33. The post-Adjournment Decision evidence confirms that the customer outage risk, measured by Exponent as consequence x probability, is severe. The direct customer service impacts of a winter T-South no-flow event are well understood – at least 600,000 customers will lose service for many weeks. PwC estimates billions of dollars of consequential economic losses in the province from a single event, noting that vulnerable populations will also be at risk of physical harm. The probability of a winter T-South no-flow event is high over any reasonable time horizon, and the two further near-misses since the 2018 T-South Incident underscore the potential for a no-flow event to occur at any time or multiple times. FEI submits that the BCUC should find risk of this magnitude to be unacceptable, and that it is in the public interest to mitigate it.

34. The subsections in this Part make the following supporting points:

- First, the 2024 Resiliency Plan provides a sound basis for the BCUC to find that, in prioritizing the TLSE Project, FEI is appropriately targeting its highest customer outage risk.
- Second, the loss of T-South supply lasting only a matter of hours, even under average winter conditions, will have catastrophic consequences in the form of a widespread and prolonged outage, consequential economic impacts and adverse health and mortality impacts.
- Third, the cumulative probability of a winter no-flow event on the T-South system is very high over the expected service life of the TLSE Project, and is still high over a shorter hypothetical 20-year horizon to 2050.
- Fourth, Exponent's analysis supporting the 2024 Resiliency Plan confirms that a winter T-South no-flow event presents severe customer outage risk, far more than any other customer outage risk. This is true regardless of the consequence metric, and regardless of whether a 60-year or 20-year horizon is used.

- Fifth, prioritizing mitigation of the risk posed by a winter T-South no-flow event reflects sound risk management principles.

B. FEI'S 2024 RESILIENCY PLAN PROVIDES THE NECESSARY ADDITIONAL INFORMATION TO CONCLUDE THERE IS A NEED FOR RESILIENCY INVESTMENT AT TILBURY

35. While the BCUC accepted the need for resilient utility infrastructure and the importance of resiliency in the provision of safe and reliable service in the Adjournment Decision,[21] it identified areas where additional analysis was required.[22] In particular, the Panel emphasized that, in its view, resiliency objectives are best assessed on a holistic level by comparing various resiliency options and prioritizing and planning against various outage scenarios, and then developing a comprehensive resiliency plan.[23] The 2024 Resiliency Plan, which FEI prepared over approximately 19 months following the Adjournment Decision, is a holistic and comprehensive plan. The primary recommendation of the Plan is:[24]

> 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 the risk associated with AV 18. New and larger on-system LNG at Tilbury will mitigate both risks.
>
> Four other AVs have been identified as warranting further investigation, but FEI is not recommending at this time any additional investment where the primary driver is resiliency.
>
> Based on FEI's current analysis, the AVs other than those noted above are already managed in a reasonable manner accounting for the magnitude of the risk of customer outages and the cost of mitigation, recognizing it is not feasible to fully mitigate every outage risk on a natural gas system.
>
> For all Assessed Vulnerabilities, FEI will consider further risk mitigation in sustainment capital planning, as assets come due for replacement, and in the context of potential projects that also have other non-resiliency drivers.

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21 Exhibit B-60, Supplemental Evidence, p. 31.

22 In Decision and Order G-78-24 (dated March 20, 2024), accepting FEI's 2022 LTGRP, the BCUC rejected the initial version of the Resiliency Plan and noted FEI's commitment to file a more comprehensive and robust resiliency analysis as being reasonable and appropriate: Exhibit B-61, 2024 Resiliency Plan, p. 2.

23 Adjournment Decision, p. 12.

24 Exhibit B-61, 2024 Resiliency Plan, pp. 3-4.

36. For the reasons discussed below, the 2024 Resiliency Plan provides a sound basis for the BCUC to find that, in prioritizing the TLSE Project, FEI is appropriately targeting a severe customer outage risk that dwarfs all other customer outage risks.

(a) The 2024 Resiliency Plan Is a Holistic Plan that Addresses the BCUC's Commentary

37. The 2024 Resiliency Plan is holistic and comprehensive in that it involved a holistic scan of on-system and off-system supply-related customer outage risks, and a detailed assessment of 58 "**Assessed Vulnerabilities**" or "**AVs**". The Plan consists of a lengthy public document that, among other things, describes the analytical process and anonymized risk results. It appends reports from Exponent and PwC. It also includes 58 AV-specific appendices that provide, for example, location information, the number of customers and load served by the AV, the existing resiliency capabilities applicable to the AV, and the AV-specific results from the risk assessment.

38. FEI provided a concordance in Appendix B to the Supplemental Evidence showing specifically how the 2024 Resiliency Plan addresses the BCUC's comments.

(b) Independent Experts Played a Significant Role in the 2024 Resiliency Plan

39. Independent experts added considerable rigour to the 2024 Resiliency Plan.

40. Exponent played a significant role in various aspects of creating the Resiliency Plan, its inputs and results. Exponent's team had substantial cross-disciplinary expertise,[25] enabling it to, for example: (1) assess the reasonableness of FEI's identification and screening of system vulnerabilities for assessment in the 2024 Resiliency Plan; (2) perform a quantitative risk assessment, including the estimation of probabilities and calculation of the expected losses (i.e., risk) posed by vulnerabilities; and (3) confirm that FEI's approach to resiliency planning aligns with good industry risk assessment practices.[26] The Exponent report is very detailed, and devotes considerable attention to describing its methodology and inputs.

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[25] See Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, paras. 25-36 and Appendix A.

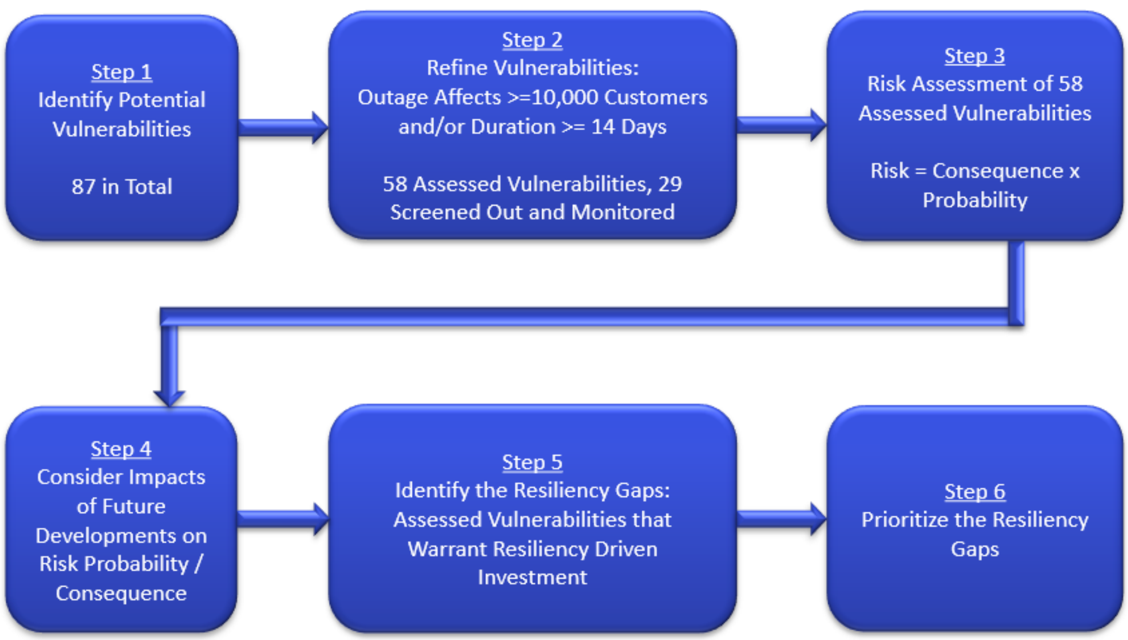
[26] Exhibit B-61, 2024 Resiliency Plan, pp. 21-22.

41. PwC, which previously provided expert evidence in this proceeding prior to the Adjournment Decision,[27] was involved in one aspect of the risk calculations. It estimated the consequential economic (GDP) impacts of the specific customer outages (as determined by FEI system modelling) associated with the 58 AVs. PwC's economic consequence results were used in Exponent's quantitative risk assessment to calculate the results for one of three consequence measures (i.e., GDP loss).[28] In addition to its quantitative GDP loss calculations, PwC provided a qualitative discussion of social, environmental and other consequences associated with a widespread loss of gas supply during winter.[29]

(c) FEI Developed the Step-By-Step Assessment Process With Expert Guidance

42. The 2024 Resiliency Plan was the product of the structured process detailed in Section 3 of the 2024 Resiliency Plan and summarized below. Exponent provided input on, and endorsed, the process.

Figure 3-1: Approach to the 2024 Resiliency Plan



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27 Exhibit B-1-4, Application, Appendix B.

28 Exhibit B-61, 2024 Resiliency Plan, p. 22. PwC's calculations did not factor into risk calculations using the "customer outage" and "customer-outage-days" measures, which measured direct customer service impacts.

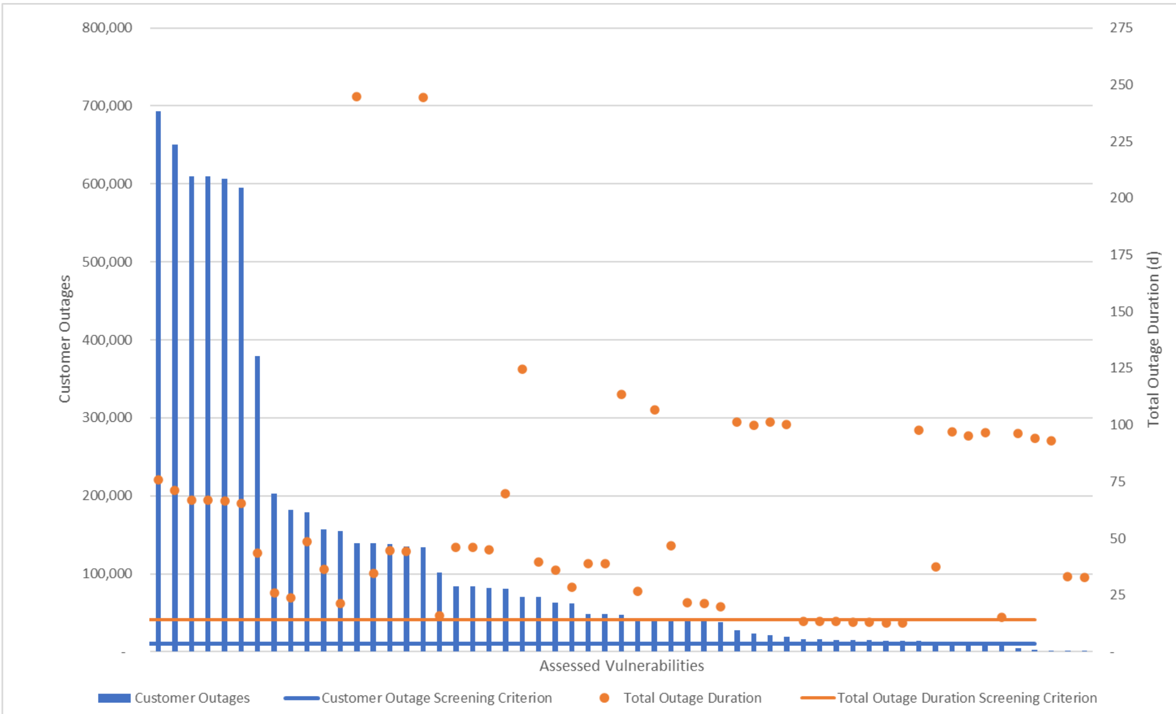
29 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 3, PwC Report.

Step 1: Identification of Potential Vulnerabilities
FEI undertook a comprehensive review of potential vulnerabilities associated with infrastructure upstream of FEI's own system, as well as those associated with FEI's transmission system, transmission pressure laterals and intermediate pressure (**IP**) portions of FEI's distribution system. The 87 potential vulnerabilities identified could result in a material customer outage through a single failure or event based on: (1) the approximate number of firm customer outages at design degree day conditions; (2) a high-level estimate of the expected duration of the no-flow event; and (3) the expected total duration of the outage.[30]
Step 2: Screening of Vulnerabilities
FEI then applied the following initial screen to identify a sub-set of 58 vulnerabilities that gave rise to the most severe outcomes (i.e., large number of customer outages or prolonged outage duration):[31] Include only those vulnerabilities where an outage occurring on the design degree day would affect 10,000 or more customers AND/OR would be expected to take FEI two or more weeks to fully restore service to affected customers. The figure below, reproduced from the 2024 Resiliency Plan, shows the 58 vulnerabilities that successfully passed the screening criteria, and how they compare to the screening criteria.

[30] Exhibit B-61, 2024 Resiliency Plan, p. 23.

[31] Exhibit B-61, 2024 Resiliency Plan, p. 24.

Figure 4-3: 58 Assessed Vulnerabilities Pass the Screens



Using a consequence-based screen, while ultimately judgment-based, was endorsed by Exponent as "reasonable and along the lines of good industry risk assessment practices". The detailed rationale for the metrics used are set out in Section 3.3.1 of the 2024 Resiliency Plan.[32]

Vulnerabilities that met this initial screen proceeded through a more detailed risk (consequence x probability) analysis as "Assessed Vulnerabilities" or "AVs" but would not necessarily warrant resiliency-driven investments.[33]

Step 3: Risk Assessment

As described in detail in Section 3.4 of the 2024 Resiliency Plan, in order to assess the current overall risk of each of the 58 AVs, FEI determined the number of customer outages and the peak hour flow at risk, as well as the estimated customer outage period (Total Outage Duration[34]) accounting for FEI's existing resiliency capabilities. PwC estimated the AV-specific consequential economic harm to society. Exponent calculated the AV-specific annual failure rates and cumulative probabilities of a winter failure.

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32 Exhibit B-61, 2024 Resiliency Plan, pp. 25-26.

33 Exhibit B-61, 2024 Resiliency Plan, p. 24.

34 This period is defined as the estimated period in days starting on Day 1 of the customer outage to the day when service is finally restored to the last customer: Exhibit B-61, 2024 Resiliency Plan, p. 27.

Exponent's quantitative risk analysis involved multiplying the individual consequences (based on three different metrics[35]) by their respective cumulative probabilities of occurrence over prescribed time horizons.[36] The objective of the risk analysis was to identify where significant investments to mitigate the risk are potentially required. Exponent's analysis confirmed that "the expected annual winter-only loss on the combined AV-1, -2, -3, and -54 is more than eight times the combined expected annual winter-only loss of all other AVs…".[37] The consequence and probability inputs, as well as the results of this analysis are described in further detail in Part Three, Sections C and D below.
Step 4: Consideration of Impacts of Future Developments
FEI qualitatively considered whether future events or developments (including those identified in the Adjournment Decision) may impact the current overall risk assessment for the AVs. FEI identified that considerations like climate change, asset health, new technology, changes in codes/standards, cyberattack and different gas compositions could impact the probability of a no-flow event occurring, while current considerations like winter load/customer numbers and the loss of contracted capacity on regional infrastructure could impact the associated consequence. Projects that have been approved, including those related to integrity, sustainment, upgrade, or replacement could impact both the probability and consequence of a no-flow event occurring.[38]
Step 5: Identification of Resiliency Gaps
FEI conducted a holistic review of the risk analysis results to determine which AVs ought to be considered resiliency gaps. FEI considered the inputs and risk results for each AV, the impact of FEI's existing resiliency capabilities on the results (e.g., mutual aid), and Exponent's recommendations regarding which AVs warranted mitigation.[39] A T-South no-flow event (AV-1, 2, 3, and 54) and AV-18 were the only AVs that currently warrant resiliency driven investment.

[35] These consequence metrics were: (1) customer outage days; (2) customer outages; and (3) economic harm to society/GDP impact, which incorporates the work done by PwC: Exhibit B-61, 2024 Resiliency Plan, p. 27.

[36] Exhibit B-61, 2024 Resiliency Plan, pp. 27-46.

[37] Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, para. 245.

[38] Exhibit B-61, 2024 Resiliency Plan, pp. 47-48.

[39] Exhibit B-61, 2024 Resiliency Plan, pp. 49-50.

Step 6: Prioritization of Resiliency Gaps
FEI then determined the priority of the resiliency gaps. FEI's approach, which is consistent with the advice of Exponent, is to prioritize the largest resiliency risk first, which is the risk associated with a T-South no-flow event.[40]

43. Exponent concluded that the overall approach FEI used to identify, assess and quantify system risks was "reasonable and along the lines of good industry risk assessment practices."[41] In reaching this conclusion, Exponent endorsed addressing system-level risk in a "top down" manner by prioritizing the screening of high-interest vulnerabilities, thus enabling the identification of areas where detailed risk assessment efforts should be focused.[42]

44. In particular, Exponent supported the Step 2 screening of the original list of vulnerabilities, which yielded the 58 AVs. Exponent agreed that 29 of the vulnerabilities with low severity outcomes fall into a low risk/negligible risk category and did not justify further investigation. As Exponent explained:[43]

> These low severity scenarios are usually identified as "operational upset" scenarios that are considered probable but are associated with "low" to "acceptable" levels of risks. Further detailed quantification of such scenarios is not particularly beneficial as the risk levels are already "low to acceptable".

45. Moreover, with respect to those AVs assessed as having a high risk as part of its quantitative risk assessment, including the risk of a winter T-South no-flow event (AV-1, 2, 3, and 54), Exponent endorsed reducing these risks so that they are no longer unacceptable. Specifically, it cited "general good industry practices" that usually mitigate a high risk scenario to the "as-low-as-reasonably-practicable ("ALARP") zone, such that it is no longer unacceptable.[44] FEI has proposed to achieve that outcome with the TLSE Project.

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[40] Exhibit B-61, 2024 Resiliency Plan, p. 50.

[41] Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, para. 50.

[42] Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, para. 42.

[43] Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, para. 43.

[44] Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, para. 49.

(d) Modelling Inputs Are Well-Supported and May Tend to Understate Risk of a Winter T-South No-Flow Event

46. As shown in **Appendix A: Modelling Parameters that Tend to Understate Current Risk and the Preferred Alternative's Financial Benefits** (attached), both Exponent and PwC incorporated a number of modelling parameters in their analyses that tend to understate the current calculated risk associated with the AVs. FEI has addressed later in this Part the specific modelling issues raised in IRs.

C. <u>CATASTROPHIC CONSEQUENCES WILL RESULT FROM A WINTER T-SOUTH NO-FLOW EVENT LASTING ONLY A MATTER OF HOURS</u>

47. The evidence discussed below demonstrates that the consequences of a winter T-South no-flow event, regardless of the consequence metric used, will be catastrophic. FEI's Lower Mainland gas system will, without question, fail on Day 1 even at average winter temperatures (+4ºC). Hundreds of thousands of customers will be without gas service for many weeks. The customer outage will cause billions of dollars of consequential economic harm, and can be expected to result in adverse health impacts and deaths in vulnerable populations.

(a) Lower Mainland Relies on T-South Being Functional to Obtain Adequate Supply in Winter

48. The severity of the consequences discussed in this Section are attributable to FEI being uniquely, and unavoidably, dependent on T-South for the majority of its gas supply. For example, approximately 85 percent of the gas entering FEI's system during 2018 was shipped on the T-South system.[45]

49. FEI addressed this point extensively in Part Three, Section B of the Pre-Adjournment Final Submissions. In essence, FEI's dependence on T-South is a function of the limited infrastructure in British Columbia and the US Pacific Northwest, the limited interconnectedness of that infrastructure, and the location of FEI's service territory in relation to it.[46] There are physical limitations on the extent to which FEI can rely on supply from the Southern Crossing Pipeline

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[45] Exhibit B-1-4, Application, p. 37.

[46] Exhibit B-1-4, Application, p. 37; Tr. 1, p. 147, ll. 5-17 (Chernikhowsky).

(SCP) and the Williams Northwest pipeline in the US Pacific Northwest during a T-South no-flow event. SCP is small relative to Lower Mainland winter firm load. System hydraulics preclude physical flows northwards across the Canada-US border in winter.[47] The interruption of physical gas flows on the T-South system prevents contractual access to gas from the US.[48]

50. Utilities in the US Pacific Northwest are far less exposed to a disruption on the T-South system because they have pipeline diversity and much more on-system storage. An east-to-west interconnecting pipeline in the Columbia River Gorge corridor provides 534 MMcf/d of daily deliverability for the utilities in the US Pacific Northwest, five times more than SCP can provide for the Lower Mainland.[49] The underground gas storage facilities at Mist and JPS are located in the heart of the service territories of major gas utilities in the US Pacific Northwest. They provide approximately 44 Bcf of on-system storage and up to 1,798 MMcf/d of daily sendout – approximately 73 times more energy and 11 times more capacity than the Tilbury Base Plant.[50]

51. The TLSE Project is intended to replicate, on a smaller scale, the same type of risk mitigation against a winter T-South no-flow event that utilities in the US Pacific Northwest receive from having underground storage located in their service territories. Even with the TLSE Project, FEI will remain more exposed to a winter T-South no-flow event than the US Pacific Northwest utilities, but the risk will be significantly mitigated.

(b) Direct Impacts on Customers: Hundreds of Thousands of Customers Lose Service for Many Weeks

52. Table 3-1 from the Supplemental Evidence, reproduced below, summarizes the direct customer service impacts associated with a winter T-South no-flow event at average winter temperature (+4°C in the Lower Mainland). The direct customer service impacts were measured

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47 Exhibit B-1-4, Application, p. 71. Tr. 1, p. 52, ll. 2-20 (Hill).

48 Exhibit B-1-4, Application, p. 70; Tr. 1, p. 61, l. 23 to p. 62, l. 13 (Slater); Tr. 1, p. 121, l. 12 to p. 123, l. 9 (Moran).

49 Exhibit B-1-4, Application, pp. 38-39. Ontario has even more proximate storage than the US Pacific Northwest (248 Bcf) storage, and greater pipeline diversity: Exhibit B-1-4, Application, Appendix A, p. 36.

50 Exhibit B-1-4, Application, p. 38; Tr. 1, p. 141, l. 21 to p. 142, l. 1 (Moran).

using both “customer outages”[51] and “customer-outage days”.[52] The consequences vary depending on the location of the disruption on T-South (the analysis segmented T-South into AV-1, AV-2, AV-3 and AV-54); however, in all cases, the consequences will be catastrophic.[53]

Table 3-1: Quantitative Metrics Related to Severity of a T-South No-Flow Event at Average Winter Temperatures by Incident Location[54]

Type of Impact	Quantitative Metric	AV-1 Value	AV-2 Value	AV-3 Value	AV-54 Value
Direct customer service impact	Number of firm customers losing service on Day 1	640,100	600,400	640,400	600,400
Direct customer service impact	Total Outage Duration[70]	63.3 days	60.2 days	71.9 days	66.3 days
Direct customer service impact	Total firm customer-outage-days	24 million	21 million	32 million	28 million

53. The consequences in this case are similar to those considered in the FEI Huntington Station Bypass CPCN Application. In its decision, the BCUC characterized a loss of service to the Lower Mainland as a “severe” consequence and approved a risk mitigation investment:[55]

> The Commission Panel finds that, given the risks and potential severe consequences of large-scale service disruption to 600,000 customers and economic loss resulting from failure of Huntingdon Station, a risk mitigation project is in the public interest.

High Degree of Certainty as to the Number of Customers Losing Service on Day 1

54. FEI was able to use its standard hydraulic modelling to determine the “Number of firm customers losing service on Day 1” metric. The hydraulic modelling allows FEI to calculate the extent and timing of a customer outage under specified supply demand conditions.[56] Transient hydraulic modelling shows the time-dependent changes in system pressure due to fluctuations in gas supply and demand due to a supply outage. FEI consistently assumed in the modelling that existing resiliency capabilities (e.g., curtailment of interruptible load, on-system LNG) are

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51 A measure of the number of customers impacted: Exhibit B-61, 2024 Resiliency Plan, p. 27.

52 A measure of the number of customers affected multiplied by the estimated number of days that the customers are without service: Exhibit B-61, 2024 Resiliency Plan, p. 27.

53 Exhibit B-60, Supplemental Evidence, pp. 41-42. See also, pp. 52-53.

54 See Exhibit B-60, Supplemental Evidence, p. 42 which summarizes how these values were calculated.

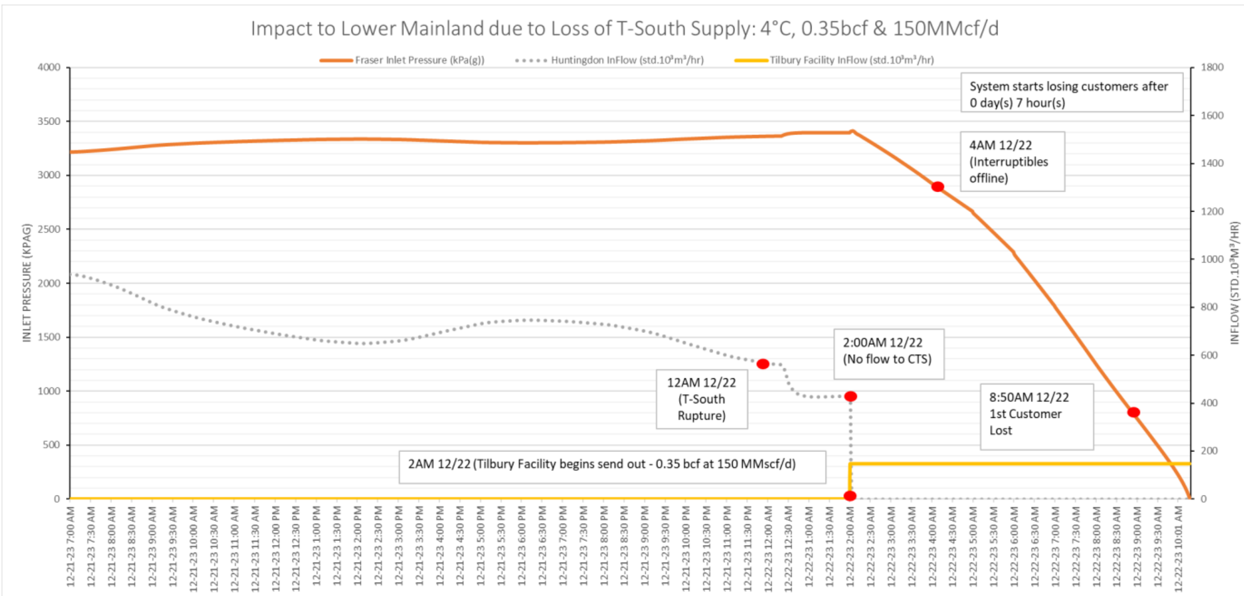
55 Decision and Order C-6-14, dated April 4, 2024, p. 2.

56 See Exhibit B-60, Supplemental Evidence, Section 3.2.2.1.2.

available plus gas Advanced Metering Infrastructure (AMI); tthe consequences could be higher if any of the existing supply capabilities were unavailable on the day of the no-flow event.[57]

55. As shown in the figure below, customers in the Lower Mainland would begin losing service within only 7 hours of gas supply to FEI's system ceasing at average winter temperatures.[58]

Figure 3-4: Impact to Lower Mainland at +4°C due to Loss of T-South Supply, with Mitigation from Existing Tilbury Facilities (150 MMcf/d Regas and at Least 0.35 Bcf LNG)



56. The Tilbury facility send-out is insufficient to prevent the rapid depressurization of the Lower Mainland system on Day 1 at average winter temperatures (+4°C) because the current Tilbury regasification capacity of 150 MMcf/d is only a fraction of the daily Lower Mainland load during winter. Put simply, regardless of how much LNG is stored at Tilbury at the time of a winter no-flow event, FEI would be unable to regasify it fast enough to support the Lower Mainland system load and maintain system pressure.[59] FEI detailed the governing regasification constraint in Part Three, Section D(h) of FEI's Pre-Adjournment Final Submissions.

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[57] Exhibit B-61, 2024 Resiliency Plan, p. 27. Other resiliency capabilities, such as linepack and conservation messaging, are not expected to materially reduce the risk of a given AV: Exhibit B-61, 2024 Resiliency Plan, pp. 33-41.

[58] Exhibit B-60, Supplemental Evidence, Figure 3-4 (p. 47).

[59] Exhibit B-60, Supplemental Evidence, pp. 47-49.

57. The number of affected customers across FEI's system will increase markedly at below average winter temperatures.[60] One other factor that can increase the number of affected customers following a winter T-South no-flow event is changing the assumed location of a failure within a single AV segment on T-South; FEI modelled AVs assuming that a pipeline failure occurs at the far downstream end of the pipeline segment, which produces the lowest number of affected customers because it does not capture any customers served by that pipeline segment itself.[61] For example, under design day conditions, a prolonged failure in one T-South AV (and at a different failure location than assumed in the 2024 Resiliency Plan) would result in approximately 955,000 customer outages.

58. FEI submits that the modelling provides a consistent and reasonable basis for assessing customer outages.

Restoring Service After T-South Gas Flows Resume Will Take Weeks

59. The estimated time to fully restore service to the Lower Mainland following a T-South no-flow event is now well-trodden ground in this proceeding. The evidence demonstrates that it will take <u>8 to 10 weeks</u> (57 to 70 days) to restore service to all affected customers following the resumption of flows on T-South,[62] assuming circumstances that are very favourable to restoration work and FEI's AMI is in place. The calculation of customer-outage-days in the above table is based on linear progress towards full restoration.

60. As outlined in Part Three, Section F of FEI's Pre-Adjournment Final Submissions, an estimated restoration timeframe averaging 9 weeks is well-supported, objectively reasonable, and corroborated by the experience of other utilities. In particular, FEI's Rebuttal Evidence to RCIA, which was prepared by five internal experts with a combined 150 years of relevant

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60 Exhibit B-60, Supplemental Evidence, Table 3-2 (p. 44). More information regarding the temperature assumptions used in the analysis can be found in the following IRs: CEC IR5 141.1, 141.2, 141.4 and 141.5 (Exhibit B-66).

61 Exhibit B-60, Supplemental Evidence, p. 41.

62 Exhibit B-60, Supplemental Evidence, p. 49.

experience in gas system operations and tested through IRs, relies on realistic inputs and provides explanations of the key inputs and a working spreadsheet.[63] As FEI explained:[64]

> FEI recognizes that an actual event would vary somewhat from the assumptions used; however, the potential for time variances is asymmetrical. That is, although unforeseen events (e.g., identification of major leaks, bad weather, competing demands limiting mutual aid assistance) could cause significant delays in the restoration work, it is much less likely that opportunities for time savings would meaningfully shorten the time required. FEI has performed its own sensitivity testing of the working model (refer to the response to Q36) to test the assumptions and does not foresee any realistic scenario where there could be time savings of the magnitude hypothesized by REL.

61. FEI has also responded to interveners on this point in Part Two, Section B(b) of its Pre-Adjournment Reply Submissions. FEI submits that, prior to the Adjournment Decision, neither RCIA nor CEC put forward a realistic alternative approach that would materially shorten the outage duration, such that catastrophic harm would be avoided. Indeed, as RCIA recognized, "the response to a T-South outage is complicated".[65] While FEI will take the steps that it can reasonably and safely take to accelerate restoration, given the magnitude of the consequences in question, approaches based on optimistic assumptions or with a high tolerance for significant safety risks, must be rejected.

62. Ultimately, FEI submits that the restoration timelines FEI has relied on for the purposes of this proceeding are unlikely to be materially shorter and could be materially longer than 8 to 10 weeks.

(c) Severe Economic Harm Will Result from Winter T-South No-Flow Event

63. The third consequence metric used in the 2024 Resiliency Plan was economic (GDP) losses, which Exponent described as a commonly used measure in the utilities industry that considers the welfare of the general public and aligns with the mandate of utilities in benefiting

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[63] See Exhibit B-46-1, Rebuttal Evidence to RCIA Evidence.

[64] Exhibit B-46-1, Rebuttal Evidence to RCIA Evidence, p. 19.

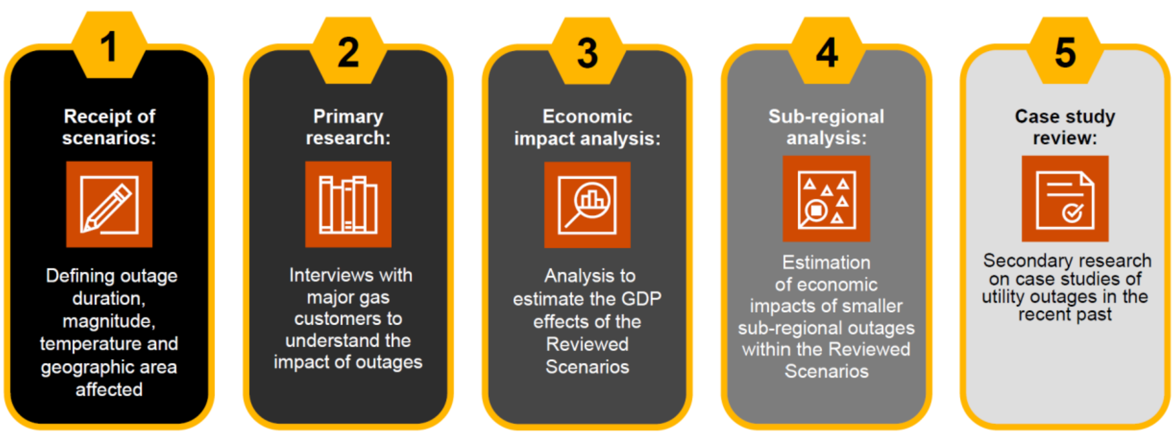
[65] RCIA Pre-Adjournment Final Argument, p. 24.

the general public.[66] PwC calculated that the economic impacts of a single incident on any segment of T-South (AV-1, AV-2, AV-3 and AV-54), during an average winter, ranges from between $1.7 billion and $3.8 billion – which is well in excess of the cost of the Preferred Alternative.[67] FEI submits, for the reasons set out below, that the BCUC should accept PwC's quantification of GDP losses as a reasonable estimate for the purposes of assessing the TLSE Project. The economic consequences will, quite clearly, be catastrophic.

PwC Employed a Widely-Used Methodology and Vulnerability-Specific Inputs

64. First, PwC employed a rigorous methodology (depicted in Figure 2 from the PwC Report shown below[68]) that is widely used by economists to measure the economic impacts of different scenarios.[69]

Figure 2: Overview of approach



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66 Exhibit B-66, CEC IR5 136.1.

67 Exhibit B-60, Supplemental Evidence, Figure 3-9 (p. 54); Exhibit B-70, BCOAPO IR6 1.1 and 1.2. Figure 6 from the PwC Report provides a sectoral breakdown of the impacts in the Lower Mainland, demonstrating the breadth of sectoral economic impacts.

68 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 3, PwC Report, p. 4.

69 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 3, PwC Report, pp. 4-9 and 23. For example, the federal government lists input-output analysis as a tool to perform economic impact assessments in its documentation of the *Impact Assessment Act*.

65. PwC's methodology involved quantifying the economic harm based on the specific circumstances of every AV.[70, 71] In particular, PwC used specific outage scenarios based on engineering analysis of known system vulnerabilities provided by FEI.[72, 73] Each scenario defined: (1) a specific disruption duration; (2) temperature conditions; (3) a geographic area impacted by the disruption; and (4) the magnitude of the disruption (i.e., whether a partial or no-flow event).[74] These scenarios captured the different economic makeup of different areas associated with each AV using Statistics Canada data at the provincial and sub-provincial levels.[75]

66. As part of its primary research, PwC undertook a total of 42 interviews with FEI customers or organizations that had direct knowledge of the impact on FEI's customers. The interviewees represented the industrial, commercial, government and institutional sectors.[76] The interviews expanded upon the primary research that supported the Original PwC Report, assessing sectors of the economy that were not assessed in the Original PwC Report, and ultimately provided a range of quantitative and directional inputs that PwC translated into estimated reductions in economic activity as part of the economic impact analysis.[77]

67. PwC explained that the results of these interviews confirm that FEI's customers would experience a range of direct effects and other effects if a prolonged winter outage (2-4 weeks) were to occur (e.g., reduced output due to loss of natural gas for production and space and/or

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70 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 3, PwC Report.

71 Exhibit B-1-4, Application, Appendix B; see also Exhibit B-23-2, RCIA Confidential IR1 27.1. PwC's initial report filed with the Application (Original PwC Report) had modelled three hypothetical outage scenarios. It had nevertheless provided a clear directional indication that the consequences of a widespread and prolonged winter outage will be severe, resulting in societal disruption and harm on an unprecedented scale in British Columbia.

72 See Exhibit B-63, BCUC IR5 141.2 which describes the differences between the Reviewed Scenarios and the sub-regional scenarios.

73 In contrast, the Original PwC Report used high level scenarios based upon entire sub-regions of BC losing access to natural gas which were not tied to specific system vulnerabilities: Exhibit B-63, BCUC IR5 141.6.

74 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 3, PwC Report, p. 4.

75 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 3, PwC Report, p. 8; Exhibit B-63, BCUC IR5 141.2.

76 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 3, PwC Report, Table 2 (pp. 6-7); Exhibit B-70, BCOAPO IR6 2.4.

77 Exhibit B-63, BCUC IR5 141.4 and 141.6.

water heating).[78] British Columbians generally (including those who are not gas customers) would also experience knock-on effects (indirect and induced effects) as a result of an outage, resulting in significant economic disruption. For example, if an industrial customer were to experience reduced economic output due to a natural gas supply disruption, it will likely reduce its supply chain expenditure on inputs (indirect effects) and potentially lay-off workers (leading to induced impacts through lower labour income).[79] PwC factored in back-up energy sources when they were identified through interviews, thus reducing the economic impact for certain sectors.[80]

68. PwC confirmed that the economic impacts broadly aligned with the literature review of economic impacts of major disaster-related utility outages provided as Appendix 4 to the PwC report.[81]

PwC's Economic Harm Estimates Are Potentially Significantly Understated

69. Second, PwC's calculation of the economic impact of a winter T-South no-flow event is potentially <u>understated</u> for a number of reasons. For example:

- PwC assumed there would be no impacts from economic sectors where it did not interview any organization in the sector.[82] These sectors represent approximately 40 percent of BC's economy. In practice these sectors would likely also experience some level of economic disruption from a natural gas outage.[83]

- PwC did not quantify the impacts of an outage on the residential sector. While the associated impacts would likely primarily include impacts on health, education (through school closures) and welfare effects resulting from inconvenience and disruption to everyday life, some of these impacts would have a negative economic impact.[84]

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78 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 3, PwC Report, p. 7 and Appendix 1; Exhibit B-70, BCOAPO IR6 2.2.

79 Exhibit B-72, CEC IR6 160.4.

80 Exhibit B-66, CEC IR5 143.11; Exhibit B-70, BCOAPO IR6 2.3; Exhibit B-72, CEC IR6 167.2 and 167.3.

81 Exhibit B-63, BCUC IR5 141.5; Exhibit B-61, 2024 Resiliency Plan, Appendix RP 3, PwC Report, Appendix 4.

82 Exhibit B-60, Supplemental Evidence, p. 54; Exhibit B-61, 2024 Resiliency Plan, Appendix RP 3, PwC Report, p. 8.

83 Exhibit B-70, BCOAPO IR6 2.3.

84 Exhibit B-72, CEC IR6 160.4.

- PwC did not take into account longer-term economic implications beyond the outage period, such as permanent business closures that would result in reduced GDP output.[85]

- PwC did not take into account the impact of property damage (e.g., frozen pipes or equipment) and how this could impact an organization's ability to generate economic output.[86]

- No sectors were assumed to be fully shutdown during an outage.[87]

- There may also be economic impacts beyond British Columbia because of an outage (e.g., supply chain disruptions across Canada). These potential impacts were not quantified in PwC's analysis.[88]

- PwC excluded the impact of consequential outages on the Lower Mainland electric system, but concluded that "[n]atural gas supply outages in B.C. may also place a strain on the electrical grid as many households and businesses may seek to substitute the energy provided by gas to that from electricity."[89] Please refer to Part Three, Section C(c) below for further discussion regarding PwC's qualitative evaluation of how the loss of electric service would affect the GDP impact results.

70. Please also see the attached **Appendix A: Modelling Parameters that Tend to Understate Current Risk and the Preferred Alternative's Financial Benefits.**

71. Intuitively, there can be little doubt that an outage of this scale and duration in the most populous and urbanized part of British Columbia will have severe economic consequences. FEI submits that PwC's estimated impacts – both the low- or high-end of the range – are so large that no reasonable combination of adjustments to the modelling assumptions could reduce the associated economic impacts to the point where they are anything other than catastrophic.

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85 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 3, PwC Report, p. 9.

86 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 3, PwC Report, p. 9.

87 Exhibit B-72, CEC IR6 160.2.

88 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 3, PwC Report, p. 9.

89 Exhibit B-60, Supplemental Evidence, pp. 54-55; Exhibit B-61, 2024 Resiliency Plan, Appendix RP 3, PwC Report, Appendix 4; Exhibit B-63, BCUC IR5 141.5.

(d) A Prolonged Winter Outage in the Lower Mainland Will Have Serious Public Health, Mortality and Safety Implications

72. The evidence, discussed below, indicates that a winter T-South no-flow event can reasonably be expected to have a negative impact on the health and safety of British Columbians. The inherent difficulty in quantifying these impacts makes them no less real or important. FEI submits that public health and safety is a key public interest consideration, and the BCUC should take them into account.

Safety Concerns With the Expected Uncontrolled Depressurization of the Lower Mainland System

73. The uncontrolled depressurization of the Lower Mainland gas system following a winter T-South no-flow event would be hazardous to the public and poses a significant safety risk due to the potential for a fire or explosion to occur.[90] FEI's system modelling demonstrates that an uncontrolled outage is likely to occur in most temperature conditions.[91]

The Link Between Cold Residences / Workplaces and Poor Health and Mortality

74. The expert evidence in this proceeding addressed a known link between cold residences and workplaces and incidences of poor health and mortality. PwC stated that excess winter deaths are a well-documented phenomenon generally within Canada and many other countries.[92] PwC elaborated:[93]

> **Health and safety** may also be impacted, as cold residences and workplaces would likely lead to an increase in the incidence of poor health such as respiratory illnesses. There is extensive evidence of the link between temperature and poor health. For example, mortality rates in Canada are 11% higher in winter than in summer on a like-for-like basis, with death rates amongst the elderly rising by 1-2% for every 1°C drop in external temperature. This statistic does not incorporate any loss of heating capacity; thus, it is reasonable to assume that with loss of some heating capacity excess deaths would be higher than a typical winter.

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90 Exhibit B-60, Supplemental Evidence, p. 55.

91 Exhibit B-60, Supplemental Evidence, Table 3-2 (p. 44).

92 Exhibit B-66, CEC IR5 144.7.

93 Appendix RP 3 to the 2024 Resiliency Plan, PwC Report, p. 14.

> Linked to the above point, whilst main hospitals are required to have at least three days of backup heating on-site (often in the form of fuel oil), this is often not the case at smaller medical facilities such as **family doctors' offices**, which may close in the event of a natural gas outage.
>
> [Emphasis in original and references omitted]

75. NERC, FERC and other regional reliability entities identified loss of heat as a factor when 210 people died in the February 2021 Texas electricity outage:[94]

> …most of the deaths connected to the power outages, of causes including hypothermia, carbon monoxide poisoning, and medical conditions exacerbated by freezing conditions. Among the deaths were a mother and her seven-year-old daughter, and an 11- year-old boy who died in his bed, who all died of carbon monoxide poisoning, and a 60-year-old disabled man who died of hypothermia. A grandmother and three children trying to keep warm using a wood-burning fireplace died in a house fire.

The number of customers who lost power in Texas was greater than the number of customers that will lose service following a winter T-South no-flow event (4.5 million vs. 600,000 customers), although the four-day Texas outage was far shorter than the anticipated 8-10 week outage following a T-South no-flow event.

76. To be clear, FEI is not asking the BCUC to find that the same number of deaths would necessarily occur following a winter T-South no-flow event. But the NERC reporting on the Texas event, combined with the increased mortality rates cited by PwC above, highlight that vulnerable populations will be at risk. Exponent observed that, even if one assumes that measures intended to protect vulnerable populations will be implemented, a "certain degree of planning prior to the disruption of gas" is necessary to actually protect individuals, communicate critical information to the public and sustain medical services.[95] Delaying the loss of heat (i.e., delaying the customer

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[94] Exhibit B-60, Supplemental Evidence, p. 56. See FERC, NERC and Regional Entity Staff Report, "The February 2021 Cold Weather Outages in Texas and the South Central United States" (November 2021): https://www.nerc.com/pa/rrm/ea/Documents/February_2021_Cold_Weather_Report.pdf.

[95] Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, paras. 248-250.

outage itself), which the TLSE Project will accomplish, would enable emergency preparedness strategies to be implemented, thus potentially saving lives.[96]

77. PwC also noted that adverse health impacts could increase significantly in the event of consequential outages on the electric system.[97] The evidence suggests that the potential exists for electric system outages to follow a Lower Mainland-wide customer outage, as discussed in the next section.

78. PwC was not tasked with quantifying non-GDP impacts; however, PwC expressed the opinion that, had it performed such modelling, the non-GDP impacts of a large natural gas outage will be material:[98]

> The literature also measures "consumer surplus" effects on residential customers associated with electrical outages, which can be defined as effects on consumer wellbeing that are not measured by GDP such as inconvenience, health impacts, leisure and other factors. At a high level, studies have placed this cost at around US$1,750 per household for a one-month blackout. This cost would equate to US$3.5 billion if applied to the 2 million households in B.C. <u>While our study has not measured consumer surplus effects of a natural gas outage, we would also expect these to be material given the impacts on health, education, reduced ability to heat homes and other disruptions that residents would likely experience</u>.
>
> [Emphasis added]

79. FEI submits that there is ample evidentiary basis for the BCUC to find that a widespread and lengthy customer outage in winter will have adverse health implications for some people, or even contribute to deaths among vulnerable populations. Avoiding this outcome is a critical public interest consideration supporting the TLSE Project.

(e) Calculated Consequences Do Not Include Potential Cascading Electric System Outages

80. FEI consequence metrics, including PwC's GDP loss calculations, excluded the impact of any electric system outages that could occur during a prolonged gas system outage following a

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[96] e.g., relocating vulnerable populations, setting up warming centres, supplying essential facilities, etc.: Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, paras. 248-250.

[97] Exhibit B-60, Supplemental Evidence, pp. 56-57.

[98] Exhibit B-60, Supplemental Evidence, p. 57.

winter T-South no-flow event.[99] FEI does not have the ability to unilaterally assess the potential for cascading failures between the gas and electric systems in the Lower Mainland[100]; however, 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.[101]

81. The potential for a consequential outage on the electric system is related to gas customers trying, in large numbers, to replace gas heat with electric devices such as portable space heaters, electric hot water tanks, and electric hot plates. FEI's gas system currently delivers approximately double the energy capacity of BC Hydro's system on a cold winter day. This large energy differential is compounded by the electric system's relative lack of ramping capability compared to the gas system and a lack of sufficient transmission and distribution infrastructure to take on the winter peak heating load that is currently served by the gas system.[102] Little could be done to control people's use of alternative electric devices to prevent use from exceeding the available capacity of portions of the BC Hydro system.[103]

82. PwC's qualitative evaluation of how the loss of electric service would affect the GDP impact results is instructive and aligns with FEI's evidence:[104]

> Natural gas supply outages in B.C. may also place **a strain on the electrical grid** as many households and businesses may seek to substitute the energy provided by gas to that from electricity. At peak hourly demand, B.C. consumes 65 TJ of natural gas, compared to only 37 TJ of electricity, so the ability of the electrical grid to make up for the loss of natural gas is likely to be limited, and attempts to do so may lead to infrastructure damage or the need for mitigation actions such as managed power brownouts to protect the grid. In Appendix 4 we have reviewed literature on other utility outage events with a focus on electrical outages to give insights into the possible consequences of any knock-1 on effects on the grid. In summary our literature review suggest that:

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99 Exhibit B-60, Supplemental Evidence, p. 54.

100 Exhibit B-63, BCUC IR5 124.2. The redacted portion of the response describes FEI's discussions with BC Hydro.

101 Exhibit B-63, BCUC IR5 124.1.

102 Exhibit B-66, CEC IR5 133.1.

103 Exhibit B-72, CEC IR6 155.2.

104 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 3, PwC Report, p. 14.

- Economic impacts estimated from full power blackouts tend to be more acute than those estimated in this report for a natural gas outage. The natural gas outage scenarios in this report estimate an impact in the region of 5% to 20% of GDP for the duration of the outage; in the case of a complete loss of electricity, the literature provides examples where economic losses can be in the 25% to 50% range, or higher in some cases.

[Emphasis in original and references omitted]

83. The GDP losses calculated by PwC are already catastrophic before accounting for any cascading failures between the gas and electric systems. However, the potential for those cascading failures to occur only strengthens the need for the TLSE Project.

(f) The Relight Plan in the P&R Plan Minimizes Overall Harm to Society

84. In round six IRs, CEC proposed trying to mitigate the expected GDP losses by prioritizing relighting business and industrial customers.[105] FEI submits that this approach of shifting the burden of the customer outage to other customers would prolong the overall outage and likely increase the overall harm to customers and society.

85. FEI's System Preservation and Restoration Plan (**P&R Plan**), which sets out a detailed service restoration plan, is based on extensive analysis and consideration of industry practices. Its objective is to reduce the overall harm to customers and society. It is consistent with FEI's approved GT&Cs and tariff and the BCUC has found it to be in the public interest and not unduly discriminatory.[106]

86. The P&R Plan achieves its objective of reducing overall harm by adopting the most efficient approach to service restoration that delivers the shortest overall customer outage period. The most efficient approach is restoration of service by area, rather than prioritizing particular customer classes over others. The P&R Plan allocates crews efficiently to reduce standby time and unnecessary travel.[107] Prioritizing the restoration of any subgroup of customers (e.g., industrial and commercial customers) would prolong the overall outage because it is

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[105] See e.g., Exhibit B-72, CEC IR6 162.1 and 162.2.

[106] Exhibit B-66, CEC IR5 138.2; Exhibit B-72, CEC IR6 162.1; Order L-32-18, dated December 7, 2018.

[107] Exhibit B-66, CEC IR5 138.2; Exhibit B-67, MS2S IR5 2.3.

inefficient. The rate at which FEI's crews can relight customers would decrease markedly because crews would need to revisit areas at least twice.[108]

87. PwC stated, and it stands to reason, that the suggested approach of leaving people's homes cold for longer so as to relight industrial and commercial customers can put people at greater risk of physical harm:[109]

> First, prioritizing relighting industrial and commercial customers may exacerbate the health, social and welfare impacts and disruption to residents caused by an outage (assuming residential relights would be de-prioritized under such a scenario and so residents face longer outages).

88. PwC also questioned the premise underlying the intervener suggestion that prioritizing industrial and commercial customer relights reduces economic losses:[110]

> Second, there may be attendant economic effects of prioritizing relighting industrial and commercial customers. For example, many residents may not be able to work at a normal level or attend their workplace due to the need to care for children (due to school closures) and elderly and vulnerable adults (who may have no access to heating).
>
> Third, extending the outage duration for residential customers would act as an offset for the potential mitigations to GDP loss that prioritization of industrial and commercial users may offer. This is because deprioritizing residential customers would increase the duration of social disruptions (e.g., school closures, need to care for elderly relatives), thus negatively impacting people's ability to work and/or their productivity, even if their workplace had access to natural gas. Based on PwC's experience, it anticipated significant negative GDP impacts even if industrial and customer customers were prioritized.

89. FEI submits that the existing relight approach in the P&R Plan remains appropriate. In any event, no amount of modification to the relight plan can make the overall harm from a winter T-South no-flow event anything less than catastrophic.

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108 Exhibit B-72, CEC IR6 162.1.

109 Exhibit B-72, CEC IR6 162.3.

110 Exhibit B-72, CEC IR6 162.3.

D. THERE IS A HIGH CUMULATIVE PROBABILITY OF A WINTER T-SOUTH NO-FLOW EVENT OCCURRING DURING THE EXPECTED LIFE OF THE PROJECT

90. Exponent's expert opinion, as summarized in the table below, is that there is a very high cumulative probability of a winter T-South no-flow event occurring during the 60-year expected life of the TLSE Project.[111] The probability remains high even based on a 20-year hypothetical adverse sensitivity, which is unreasonably short. The BCUC should find, for the reasons outlined below, that Exponent's 60-year probability results provide a reliable basis for the assessment of risk in this Application. Exponent stated: "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)." [112]

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%

91. The BCUC should find, for the reasons outlined below, that Exponent's 60-year probability results provide a reliable basis for the assessment of risk in this Application.

(a) Exponent Performed a Quantitative Risk Assessment Based on Site-Specific Hazards

92. The first reason to accept Exponent's probability calculations is that Exponent's analysis (through a quantitative risk assessment) was thorough and methodologically sound, and accounted for site-specific hazards.

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111 Exhibit B-63, BCUC IR5 126.1.

112 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, para. 22. For further discussion, see Section 10 of the Exponent Report.

Exponent Identified and Assessed Actual Site Specific Hazards for Each AV

93. As part of developing the 2024 Resiliency Plan, FEI instructed Exponent to calculate the cumulative probabilities of failure over the 90-day winter period (December to February) for each of the 58 Assessed Vulnerabilities.[113] Exponent's calculations included both a 60-year time horizon (the expected life of the TLSE facilities) and a hypothetical 20-year service life of the TLSE Project (i.e., retirement in 2050).[114]

94. At a high level, Exponent's first step involved identifying the applicable site-specific hazards (modes of failure) for each AV and assessing probabilities of failure for each hazard.[115] Exponent accounted for specific types of system components (pipelines, compressor stations, control stations, valve assemblies, and bridges carrying pipelines),[116] as well as different pipeline configurations (e.g., parallel pipelines in the same right-of-way).[117]

95. For example, Exponent used the following inputs for the T-South pipeline (comprised of segments AV-1, AV-2, AV-3 and AV-54):[118]

- **Internal Hazards:** Since neither FEI nor Exponent are privy to detailed internal hazard rates of failure rate (ruptures per kilometer per year) for T-South, Exponent assigned internal hazard rates of failure from the most closely comparable FEI pipeline evaluated in JANA's 2021 Qualitative Safety Risk Assessment Report (**2021 JANA QRA**). The 2021 JANA QRA had been filed in support of FEI's BCUC-approved CTS and ITS TIMC Projects.[119]

- **Natural Hazards:** Exponent used a methodology called Performance-Based Engineering (**PBE**) to evaluate the risks associated with the T-South pipeline due

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113 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, Appendix B.

114 Exponent was initially inadvertently instructed to use 67-year and 23-year horizons. Exponent performed the 60- and 20-year calculations in the response to BCUC IR5 126.1 (Exhibit B-63).

115 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, Sections 4.4.9-4.4.16; Exhibit B-63, BCUC IR5 116.11.

116 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, paras. 8, 68 and 80.

117 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, paras. 73-78.

118 Exponent did not consider third-party damage as part of its evaluation of AV-1, AV-2, AV-3, and AV-54 because T-South was included within the scope of the 2021 JANA QRA: Exhibit B-63, BCUC IR5 116.13.

119 The basis of comparison between Assessed Vulnerabilities was: (1) pipeline diameter; and (2) year of construction, both of which are correlated with the rate of internal failures: Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, Appendix R.

to different natural hazards.[120] This methodology is sophisticated, well-recognized and has been applied for decades. It involved using "hazard curves" and "fragility curves" to quantify the relationship between the hazard intensity and the vulnerability of the T-South pipeline to these hazards, combining the hazard and fragility functions to calculate the annual rate (λ) at which each unwanted outcome (i.e., failure) is expected to occur.[121] This involved, in particular:

- Obtaining natural hazard-specific data from a number of governmental and other sources (e.g., British Columbia Soil Information Finder Tool (BC SIFT)).[122]

- Drawing extensively from the methodologies developed as part of the US Federal Emergency Management Agency's (**FEMA**) Hazus program, which is a foundational resource in the field of risk analysis and management for estimating potential losses from natural hazards for large areas (e.g., earthquakes and floods). Hazus includes fragility curves that are asset-specific, including gas pipelines, and incorporates various datasets, including building inventories, geographic information systems (**GIS**) data and hazard-specific information, to generate risk and probability assessments.[123] Exponent also indirectly accounted for the effect of mitigations implemented to reduce the probability of failure due to natural hazards.[124]

- Considering location-specific natural hazard occurrence rates on a kilometer-by-kilometer basis, reflecting that 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.[125] The natural hazard failure rates reported in the 2021 JANA QRA were not used in Exponent's analysis because Exponent required the failure rate associated with each specific type of natural hazard, rather than an aggregated natural hazard failure rate.[126]

- Accounting for pipeline-specific characteristics, including pipe diameter, specified minimum yield stress (**SMYS**), wall thickness and year of construction, while modifying repair rate curves for ground movement-related failures using a Bayesian updating procedure and historical repair data (European Gas Pipeline Incident Data Group (**EGIG**), US Department of

[120] Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, paras. 53-55.

[121] Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, paras. 55-56.

[122] Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, para. 60.

[123] Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, para. 58.

[124] Exhibit B-63, BCUC IR5 116.14.

[125] Exhibit B-63, BCUC IR5 116.12.

[126] Exhibit B-63, BCUC IR5 116.12.

Transportation Pipeline and Hazardous Material Safety Administration (**PHMSA**)). This approach is consistent with other pipeline risk assessments.[127]

96. The table below summarizes the numerous hazards accounted for in Exponent's calculation of the cumulative probabilities of failure for T-South, and where additional information regarding the analysis of each can be found on the record:[128]

Hazard / Mode of Failure	Input Source and Discussion
Internal Hazards *Girth Welds* *Human Factors* *Stress Corrosion and Cracking* *Internal Corrosion* *External Corrosion* *Pipe Seam Failures* *Material Defects and Equipment Failure*	2021 JANA QRA (see Exponent Report, Appendix S)
Natural Hazards	
Earthquake-Induced Surface Wave Rupture	Exponent Report, para. 88 and Appendix D
Earthquake-Induced Landslides	Exponent Report, paras. 89-90 and Appendix E
Earthquake-Induced Liquefaction	Exponent Report, paras. 91-92 and Appendix F
Non-Earthquake-Induced Landslides	Exponent Report, paras. 96-97 and Appendix H
Earthquake-Induced Bridge Shaking	Exponent Report, paras. 93-95 and Appendix G
Earthquake-Induced Bridge Ground Movement	Exponent Report, paras. 93-95 and Appendix G

97. Exponent then calculated the overall cumulative probabilities for each Assessed Vulnerability by:[129]

- Combining the annual failure rate associated with all of the applicable hazards capable of being assigned a failure rate. Exponent conservatively assumed integrity related rupture risk was consistent across the year.[130]

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127 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, paras. 120-125 and Appendix C.

128 Exponent also undertook a preliminary analysis of wildfire, flooding/buoyancy and lightning hazards for pipelines. These hazards were off-ramped and no site-specific analysis was undertaken due to a combination of factors, including low anticipated vulnerability and high uncertainty surrounding the hazard or insufficient availability of reliable data: Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, para. 62.

129 Exhibit B-60, Supplemental Evidence, pp. 58-59.

130 As raised by the BCUC in the Adjournment Decision, Exponent confirmed that the rate of occurrence for most hazards is not seasonal (and therefore would not change in winter); however, some are influenced by seasonal rainfall patterns and could vary seasonally in practice: Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, paras. 126-127.

- Translating the annual failure rate into a winter-only rate by pro-rating to 90 days. The winter months are when FEI is most exposed to severe consequences, given the prevalence of heating load. The time period aligns to FEI's system modelling for the Assessed Vulnerabilities and PwC's economic consequences analysis.[131]

- Translating the winter-only annual failure rate into a cumulative probability over a defined period, in this case 60 and 20 years.

98. Table 2 and Appendix S to the Exponent Report provide the complete winter-only failure rates (with upper and lower bounds, as applicable[132]) and cumulative probabilities for each AV.[133]

(b) The High Cumulative Probability Stands to Reason Given the Specific Characteristics of T-South

99. The second reason to accept Exponent's probability calculations for a winter T-South no-flow event is that the results are intuitive. A high cumulative probability stands to reason given that T-South is so long.

100. One of the key takeaways from Exponent's analysis is that the length of a pipeline is a significant determinant of the cumulative probability of a no-flow event. Exponent explained "the correlation of longer lengths with higher rates of failure is clear" because the longer a pipeline is, the greater the exposure length for both internal and external hazards.[134] The T-South pipeline is approximately 952 km long (and is comprised of two pipelines, effectively creating 1,904 km of exposure). It is, by far, the longest pipeline considered in Exponent's analysis and is exposed to the most hazards.

(c) Exponent's Calculated Probabilities Are Consistent With Industry Rupture Rates

101. Pipeline industry rupture rates and ignited rupture rates (i.e., internal failures) offer a reasonableness check on Exponent's calculations of the T-South internal failure rate, while

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131 Exhibit B-61, 2024 Resiliency Plan, p. 45.

132 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, p. 132.

133 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2.

134 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, para. 144.

recognizing that these statistics do not reflect other potential causes of failure considered by Exponent. They align.[135]

(d) Exponent's Calculated Probabilities Are Understated Due to Additional Potential for Cyberattacks and Other Malicious Actions

102. Exponent's probability calculations for a winter T-South no-flow event also provide a reasonable basis for assessment because, if anything, they are understated due to the exclusion of cyberattacks and other malicious acts from the scope of Exponent's work. The evidence demonstrates that the number, scope or sophistication of cyberattacks on energy infrastructure have increased. Simply put, important energy infrastructure like T-South is a prime target for malicious actors.

103. The BCUC has, for some time, recognized cybersecurity attacks as a risk facing British Columbia's energy providers, as well as the increasing volume and sophistication of such threats.[136]

104. The June 2023 report from the Government of Canada's Canadian Centre for Cyber Security, which is an authoritative body on this topic, similarly concluded the risk facing energy infrastructure is increasing:[137]

> It is difficult to overstate the importance of the oil and gas sector to national security because much of our critical infrastructure depends on oil and gas products to operate. At the same time, critical infrastructure, and especially the energy sector, is increasingly at risk from cyber threat activity. In the United States, for example, Colonial Pipeline garnered international attention in May 2021 when it was forced to shut down the operation of one of the largest gasoline, diesel, and jet fuel pipelines in the US, due to a ransomware incident. Although the pipeline was restarted a few days later, the disruption in the fuel supply resulted in shortages that caused the re-routing of flights, panic buying, and short-term price spikes. It was estimated that, at the time that the pipeline was restarted, the Eastern US was only a few days away from experiencing food and

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[135] Exhibit B-75, BCUC Confidential IR3 23.1; see also FEI Pre-Adjournment Final Submissions, Part Three, Section C(b).

[136] Decision and Order G-187-21, dated June 17, 2021 (BC Hydro F2022 Revenue Requirement), p. 32; Decision and Order G-69-25, dated March 18, 2025 (FortisBC 2025 to 2027 Rate Setting Framework), p. 55.

[137] Exhibit B-61, 2024 Resiliency Plan, p. 82 (Canadian Centre for Cyber Security, The cyber threat to Canada's oil and gas sector (June 2023)); see also Exhibit B-18, BCSEA IR1 6.1. Exhibit B-33, CEC IR2 100.1.

> other shortages from the disruption of fuel to other sectors such as truck transportation.

105. The Canadian Centre for Cyber Security further concluded that malicious actors will "almost certainly continue to target high-value organizations in the oil and gas sector in Canada and globally".[138] In particular, expanding attack surfaces for bad actors, more readily available cyber tools, and the attractiveness of the oil and gas sector to financially-motivated bad actors (including state-aligned actors)[139] have increased the risks of cyberattacks on oil and gas assets.[140]

106. Cyberattacks can be motivated by several factors. The Canadian Centre for Cyber Security identified the highest potential of cyberattack on energy infrastructure to be from financially motivated actors, which leaves a deep pool of potential malicious actors:[141]

> The oil and gas sector, like other parts of the energy sector, reportedly attracts more than its share of attention from financially-motivated cyber threat actors due to the high value of the industry's assets and the degree of customer dependence on the industry's products. Other assets of value in the oil and gas sector targeted by cybercriminals include intellectual property and business plans, and stores of client information.
>
> Since oil and gas organizations are part of Canadian critical infrastructure (CI), they are attractive targets for extortion because of the importance of these products and services to Canadians. Cybercriminal activity has the potential to disrupt operations and critical delivery of products by limiting a company's access to essential business data in the IT network, or by preventing safe control of industrial processes in the OT network. The disruption or sabotage of OT systems in Canadian CI poses a costly threat to owner-operators of large OT assets and could conceivably jeopardize national security, public and environmental safety, and the economy.

107. Cybercriminals are ultimately opportunistic and will not hesitate to exacerbate a crisis for profit, as evidenced by disruptions to delivery of oil products in parts of continental Europe in

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[138] Exhibit B-61, 2024 Resiliency Plan, p. 83.

[139] The Canadian Centre for Cyber Security considered there to be "an even chance of a disruptive incident in the oil and gas sector in Canada caused by Russia-aligned actors, due to their higher tolerance for risk, the increase in their numbers and activity, as well as the number of vulnerable targets in the sector overall": Exhibit B-61, 2024 Resiliency Plan, p. 84.

[140] Exhibit B-61, 2024 Resiliency Plan, p. 82.

[141] Exhibit B-61, 2024 Resiliency Plan, p. 83.

early 2022 which may have worsened the energy crisis caused by Russia's imminent invasion of Ukraine.[142]

108. The potential also exists for physical sabotage. For example, vandalism at three Black Hills Energy facilities in Aspen, Colorado in 2020 resulted in a gas outage impacting 3,500 customers and required manual shutdown of the system to prevent a total system collapse.[143]

109. It is reasonable to expect that, among energy infrastructure that could potentially be targeted, T-South ranks relatively high. It is among the most significant gas pipelines in western North America.[144] It is, in this respect, analogous to the Colonial Pipeline in eastern North America that has already been successfully targeted and disrupted.[145] It is public knowledge that western North America is most reliant on T-South in winter.

110. While the risk of a successful attack on T-South is difficult to quantify and the timing is impossible to predict, it is not unreasonable to conclude that a winter no-flow event could be caused by deliberate action. FEI has no detailed information about the state of Enbridge's cybersecurity or physical protection for T-South, as such information is highly sensitive.[146] However, continued investment in cyber and physical security cannot reduce the risk to zero. Cybersecurity is a moving target, and it is not possible to provide constant on-site protection to a long and often remote pipeline like T-South. FEI's resiliency planning is properly focused on withstanding supply disruptions if and when they occur, as the consequences will be catastrophic.

[142] Exhibit B-61, 2024 Resiliency Plan, p. 83.

[143] Exhibit B-15, BCUC IR1 5.2.1; Exhibit B-33, CEC IR2 100.1.

[144] Exhibit B-61, 2024 Resiliency Plan, p. 47; Exhibit B-63, BCUC IR5 125.1.

[145] Exhibit B-61, 2024 Resiliency Plan, p. 82.

[146] Exhibit B-63, BCUC IR5 116.1.

(e) Questions Regarding Exponent's Analysis Were Narrowly Focused on the Assumed Rate of Internal Failure for T-South

111. IRs regarding Exponent's cumulative probability analysis focused on the internal failure rate.[147] The IRs asked whether the internal failure rate used by Exponent was overstated because, it was suggested, the failure rates did not account for EMAT ILI. FEI submits that the internal failures rates used are reasonable for the reasons stated below. In any event, internal failures were only one of a number of modes of failure reflected in the T-South overall probability of failure rate. The current risk is still large even when assuming a reduced internal failure rate for internal failures, and the TLSE Project will still provide a large expected loss (risk) reduction.[148]

Exponent Needed a Proxy Internal Failure Rate in the Absence of T-South Specific Data

112. There is no means for FEI and its experts to directly ascertain the internal rate of failure for T-South. FEI, as a shipper on T-South, engages regularly with Enbridge on a range of matters, and Enbridge provided FEI with an update on improvements to Enbridge's asset and integrity management systems in 2021. However, Enbridge does not provide its shippers with the type of information necessary to quantify probability of failure on T-South. This type of information is highly sensitive, similar to FEI's own system information in the 2024 Resiliency Plan.[149] As such, whereas Exponent was able to perform its own analysis on natural hazards to T-South, it needed a proxy for T-South internal failure rates.

Exponent Used a Reasonable Proxy Value for Internal Failures on T-South

113. Exponent recommended assigning an internal failure rate of 6.51e-5/km/year to T-South, using the most closely comparable pipeline from the 2021 JANA QRA of FEI's own system.[150] This made sense for two reasons:

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[147] 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.

[148] Exhibit B-63, BCUC IR5 116.4.

[149] Exhibit B-63, BCUC IR5 116.1 and 116.3.

[150] See Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, Appendix R; Exhibit B-63, BCUC IR5 116.9.

- FEI had previously filed the 2021 JANA QRA in support of FEI's CTS TIMC and ITS TIMC CPCN applications.[151] JANA's calculations were also reviewed and tested by interveners and the BCUC's independent consultant;[152] and

- JANA had assessed FEI pipelines of similar size and vintage to T-South.

114. The questions posed to FEI and Exponent on this topic narrowed to whether Exponent should have used the values from JANA's "Mitigated Cracking Threats" scenario rather than the "Baseline" scenario value. FEI submits that Exponent's use of the "Baseline" scenario value was reasonable for several reasons.

115. First, despite JANA's shorthand description of the "Baseline" scenario as being "with no additional risk mitigation", the "Baseline" value did not exclude any and all mitigation. JANA had derived it considering FEI's pre-existing integrity management program in conjunction with historical industry failure rates that include pipelines with a range of hazard management (mitigation) practices, including EMAT ILI.[153]

116. Second, Exponent confirmed that the rate it used is similar to the mean rupture rate of the relevant PHMSA datasets. These datasets include a large sample of transmission pipelines with various hazard management (mitigation) practices, including EMAT ILI.[154] JANA, in its evidence filed prior to the Adjournment Decision, had also used PHMSA data to estimate the cumulative probability of integrity-related rupture events on T-South.[155]

117. Third, JANA's "Mitigated Cracking Threats" scenario, which was an estimate of a reduced post-EMAT ILI rupture rate for stress corrosion cracking assuming FEI's implementation of EMAT ILI (1.3 E-06/km/year), was idealized insofar as it assumes that EMAT ILI is not only in place *but*

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151 Exhibit B-61, 2024 Resiliency Plan, p. 44.

152 Exhibit B-61, 2024 Resiliency Plan, p. 44.

153 Exhibit B-63, BCUC IR5 116.4; Exhibit B-75, BCUC Confidential IR3 23.1.

154 Exhibit B-63, BCUC IR5 116.4 and 116.10.

155 According to JANA, the forecast cumulative probability of a rupture event is between 83.1% to 97.9% and the forecast cumulative probability of an ignited rupture is between 53.4% and 73.9%: Exhibit B-15, BCUC IR1 1.5, Attachment 1.5C (Assessment of Outage Probability – JANA Project 2347 White Paper).

also that all other actions necessary to maximize the effectiveness of EMAT ILI are in place. The extent of any reduction would ultimately depend on the following occurring:[156]

1. The EMAT tool must be run at an adequate inspection frequency through the length of the pipeline;

2. The raw EMAT tool signal interpretation and tool vendor reporting must identify and size (e.g., depth and length) cracks with sufficient accuracy and completeness such that all cracks that could cause pipeline failure are adequately identified and characterized;

3. The vendor-reported cracking must be analyzed by the operator to identify the actions, including their associated timing, to assess and respond to cracking (e.g., tool validation and other integrity digs); and

4. Cracks requiring repair must be repaired in a timely manner before failure occurs.

118. Exponent pointed out that JANA's "Mitigated Cracking Threats" value is near zero. JANA was clear in its pre-adjournment probability evidence that it is not possible to reduce residual risk, including internal failure rates, to zero.[157] Similarly, Exponent indicated that it would be "optimistic, and not technically rigorous, to assume internal pipeline failure rate risk is near zero after mitigation of cracking threats":[158]

> While the specific wording in JANA's report might be interpreted on its face in the way implied by the question, we question that interpretation because it would imply that the risk is reduced to near zero simply by introducing EMAT. This is unrealistic, based on our knowledge of EMAT, and the fact that the industry data being used in the unmitigated calculations already included pipelines with EMAT. It is optimistic to assume that the "Mitigated Cracking Threats" rate reduces the risk to near zero (1.3 E -06 ruptures per kilometer per year).
>
> […]
>
> EMAT's [sic – JANA's] internal pipeline failure "Mitigated Threat Rate" is part of the risk calculation to show improvement, but it is not an absolute guarantee. Changing operating conditions, third-party damage, or unexpected material behavior can still cause internal pipeline failures despite mitigations. Long-term

[156] Exhibit B-75, BCUC Confidential IR3 23.3 and 23.4.

[157] Exhibit B-63, BCUC IR5 116.4; Exhibit B-75, BCUC Confidential IR3 23.4.

[158] Exhibit B-75, BCUC Confidential IR3 23.4.

> degradation mechanisms might continue or re-activate if conditions allow. It would be optimistic, and not technically rigorous, to assume internal pipeline failure rate risk is near zero after mitigation of cracking threats. Instead, best practice is to treat mitigation as risk reduction, accompanied by ongoing monitoring, inspection, and reassessment cycles to manage the residual and evolving risks.
>
> [Emphasis added]

119. The 2018 T-South Incident is a demonstration of this point as Enbridge already had EMAT ILI in place.[159]

TLSE Project Still Provides Significant Expected Loss Reduction When Substituting Improved Internal Failure Rates

120. In response to the IRs discussed above, Exponent conducted two sensitivities that reduced (i.e., improved) the "Baseline" scenario internal failure rate by 20 percent and 49 percent, respectively. The latter sensitivity reflects the mid-point between the "Baseline" and "Mitigated Cracking Threats" scenarios. As explained below, Exponent gave a compelling reason to reject these sensitivities in favour of the "Baseline". In any event, the expected GDP losses remain well in excess of the TLSE Project cost, and the Preferred Alternative materially reduces the recalculated risk.[160]

121. Exponent observed that each of these sensitivities assume, in effect, that Enbridge's integrity program is, respectively, 20 percent and 49 percent better than the industry standard. As discussed above, the rate that Exponent used is similar to the mean rupture rate of the relevant PHMSA datasets, and JANA had also used the PHMSA value as a proxy for the T-South rupture and ignited rupture rates. Exponent characterized the assumption that T-South is 20 or 49 percent superior to industry as optimistic:[161]

> The JANA internal pipeline failure rates are based on composite pipeline industry experience that already accounts for industry standard pigging operations, inline inspections and implementation of appropriate mitigation measures like the EMAT proposed mitigation measures. A 20% reduction of JANA's internal pipeline

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159 Exhibit B-63, BCUC IR5 116.4.

160 Exhibit B-63, BCUC IR5 116.4; Exhibit B-75, BCUC Confidential IR3 23.4.

161 Exhibit B-75, BCUC Confidential IR3 23.4.

failure rate implicitly assumes that the EMAT proposed/implementation measures are much better than the pipeline industry standard ILI tools and associated risk mitigation measures. A 49% (midpoint) reduction of JANA's internal pipeline failure rate based on EMAT proposed/implementation measures is likely to be optimistic and thus not conservative.

[Emphasis added]

122. FEI submits that there is no evidentiary basis to conclude that Enbridge's mitigation practices are so markedly superior to the industry practices as to justify FEI basing its resiliency planning on these sensitivities. To the contrary, a 2024 paper presented by Enbridge and an ILI service provider highlighted the challenges of actually implementing crack mitigation in a manner that is both effective and efficient.[162]

123. In any event, the sensitivities do not change the key take-away from the risk analysis, which is that FEI's customers are exposed to unacceptably severe risk. Under the 20 percent scenario, the annual loss reduction provided by the TLSE Project decreases by 9 percent (from $166 million to $151 million). Under the 49 percent scenario, the annual loss reduction provided by the TLSE Project decreases by 21 percent (from $166 million to $131.1 million). The following tables show Exponent's original results and the two sensitivities for 60-year and 20-year time horizons. The "Alt. 1" column reflects the "No Capital Upgrades" option (i.e., *status quo*), while "Alt. 9" is the Preferred Alternative. The expected loss reduction is lower than the assumed reduction in the internal failure rate because the majority of GDP losses stem from other failures.[163]

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[162] Exhibit B-63, BCUC IR5 116.1.

[163] Exhibit B-63, BCUC IR5 116.4.

60-year Expected Annual GDP Loss on T-South - Sensitivities (Improved Internal Failure Rates)

Analysis	Alt. 1 GDP Loss [million CAD]	Alt. 9 Loss [million CAD]	Loss Reduction with Alt. 9 (risk mitigated by TLSE, Alt. 1 Loss - Alt. 9 Loss) [million CAD]
Original report	16664.5	6730.7	9933.8
20% reduction on internal failure rate	15822.2	6726.1	9096.1
Midpoint analysis	14586.9	6719.3	7867.6

20-year Expected Annual GDP Loss on T-South - Sensitivities (Improved Internal Failure Rates)

Analysis	Alt. 1 GDP Loss [million CAD]	Alt. 9 Loss [million CAD]	Loss Reduction with Alt. 9 (risk mitigated by TLSE, Alt. 1 Loss - Alt. 9 Loss) [million CAD]
Original report	5554.8	2243.6	3311.3
20% reduction on internal failure rate	5274.1	2242.0	3032.0
Midpoint analysis	4862.3	2239.8	2622.5

124. In considering the reasonableness of using Exponent's T-South risk calculation as a basis for assessing the TLSE Project need, FEI submits that it is important to view the probability calculations holistically. That is, even if the BCUC concludes that another internal failure rate input would have been preferable, it should recognize that there are a number of other modelling parameters that lead to Exponent's probability calculations being understated. Notable examples are included in **Appendix A: Modelling Parameters that Tend to Understate Current Risk and the Preferred Alternative's Financial Benefits.**

(f) Three "Near-Misses" Since 2018 Highlight the Potential for Disruption to Occur

125. There have been three "near misses" since 2018 which further highlight FEI's exposure to a winter T-South no-flow event.

126. First, the 2018 T-South Incident, described in detail in the Application[164] resulted in a no-flow event that FEI could not have withstood had it occurred during the winter instead of in October.[165]

127. Second, in November 2021, a flooding river left a portion of the T-South pipeline submerged, resulting in restricted T-South flows (FEI lost 175 TJ of supply destined for the Lower Mainland). As shown in the photograph below, the pipeline was clearly at risk.[166] FEI was able to rely on market area storage to supplement on-system LNG in that case, but could only do so because gas continued to flow on T-South. FEI can only access market area storage in the US via displacement (contractual arrangements) and the physical gas underlying those arrangements actually comes from T-South. Physical gas will not flow northwards in the winter.[167]

Figure 3-10: T-South Pipe Partially Submerged in Coquihalla River

164 Exhibit B-1-3, Revised Confidential Application, pp. 39-49 set out a detailed timeline of the T-South Incident, provided context and discussed the significance.

165 Exhibit B-60, Supplemental Evidence, p. 59.

166 Exhibit B-60, Supplemental Evidence, pp. 60-61.

167 See FEI’s Pre-Adjournment Final Submissions, para. 24; see also Exhibit B-63, BCUC IR5 121.1.

128. Third, on January 31, 2023, Enbridge identified a potential leak on T-South and, as a result, proactively shut down the NPS 36 pipeline (it was not a CER-initiated regulatory shutdown). It took 24 hours to investigate the matter, demonstrating that the time to investigate an incident can easily exceed Tilbury's current load support duration. This was a false alarm, but the consequences of a false alarm can still be significant if FEI is forced to initiate a controlled shut-down before the truth is known so as to avoid the potential for a much more severe uncontrolled depressurization. Having enough on-system LNG on hand to support the Lower Mainland load while FEI assesses a situation like this will avoid the potential for false alarms to trigger an unnecessary system shut-down.[168]

129. There have been other supply disruptions on T-South due to a number of factors, including production problems for upstream operators, operational upsets experienced by the pipeline itself, operating difficulties on downstream interconnecting pipelines, and because commercial arrangements have failed.[169]

E. A WINTER T-SOUTH NO-FLOW EVENT PRESENTS UNACCEPTABLY SEVERE RISK, FAR MORE THAN ANY OTHER VULNERABILITY

130. As part of its 2024 Resiliency Plan analysis, Exponent used the consequence and probability inputs for each of the 58 AVs to calculate expected losses (i.e., risk) for the three consequence metrics (customer outages, customer outage days and GDP losses). As discussed below, Exponent's expected loss calculations confirm that, regardless of the consequence metric or time horizon: (1) there is unacceptably severe risk associated with a winter T-South no-flow event (combined AVs 1, 2, 3 and 54); and (2) the T-South risk is, by far, FEI's single largest resiliency risk.[170]

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[168] Exhibit B-60, Supplemental Evidence, pp. 59-60.

[169] Exhibit B-15, BCUC IR1 3.1 includes a list of the incidents dating back to 2000.

[170] Exhibit B-61, 2024 Resiliency Plan, p. 78.

(a) Exponent's Methodology Allowed for Direct Risk Comparisons and Accounted for Uncertainty

131. Exponent's methodology allowed for direct comparisons among all Assessed Vulnerabilities and accounted for uncertainty.

132. The Exponent Report details each step of the risk assessment, the underlying calculations and the results for all of the AVs.[171] At its most basic, Exponent multiplied the annual winter-only failure rate by the consequences of the associated failure for all three loss measures (customer outages, customer outage days and GDP loss). The resulting expected annual loss for each measure represents the winter-only risk associated with a given vulnerability assuming average winter temperatures.[172] The higher (lower) the expected loss, the higher (lower) the risk.

133. Exponent accounted for uncertainties in both the probabilities of failure and consequences of failure using Monte Carlo analysis, which is a commonly used tool for quantifying likelihoods or risks in complex conditions.[173] The Monte Carlo analysis enables the estimation of conditional[174] losses considering variability in repair times when a failure occurs and the resulting consequences, including variation in repair times for pipeline failures caused by different hazards (e.g., the time to repair a rupture caused by a landslide is likely greater than the time to repair a rupture caused by internal corrosion). As Exponent explained:[175]

> Exponent developed functions to estimate hazard- and asset-specific conditional GDP loss, conditional CODs, and conditional customer outages given a failure based on total outage duration, daily GDP loss, and the number of customers served by the AV. First, Exponent estimated probability distributions for repair time (used to calculate total outage duration) and daily GDP loss based on the economic analysis prepared by PwC, customer outage information provided by FEI, and engineering judgement. […] Next, large numbers of random samples were generated from these distributions. For each pair of repair time and daily loss samples, the resulting conditional GDP loss, conditional CODs, and conditional

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171 See Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, Sections 6 and 7 and Appendices U, V, W.

172 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, para. 160; Exhibit B-66, CEC IR5 138.1.

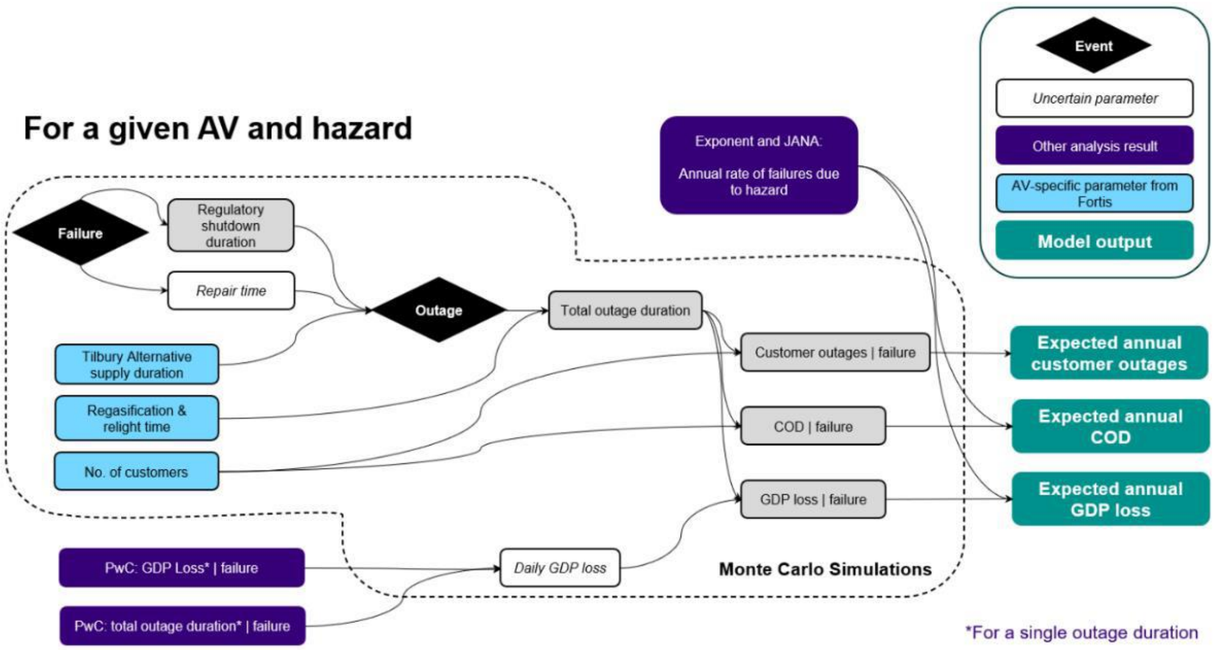
173 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, Appendix U, para. 9.

174 The word "conditional" refers to the loss being contingent on a failure occurring.

175 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, para. 163; see also Appendix U for further discussion regarding the Monte Carlo analysis.

customer outages were calculated. The resulting samples of each type of conditional loss characterize the probability distribution for that type of conditional loss.

134. The figure below from the Exponent Report shows the analysis undertaken for each AV and hazard type, including the extent of Monte Carlo simulations.[176]



135. The BCUC should find that Exponent's methodology was a sound basis for calculating the winter-only risk posed by a no-flow event on T-South and all other AVs.

(b) Risk Posed by T-South Is More than Eight Times Higher than All Other AVs Combined

136. The results of Exponent's risk calculations are clear: a winter T-South no-flow event presents unacceptably severe risk that is far greater than any other resiliency risk.

137. The table below shows Exponent's expected losses (i.e., risk) associated with a T-South no-flow event occurring during winter months. It presents the results for each of the three quantitative consequence metrics on an annual basis, as well as over 20-year and 60-year time

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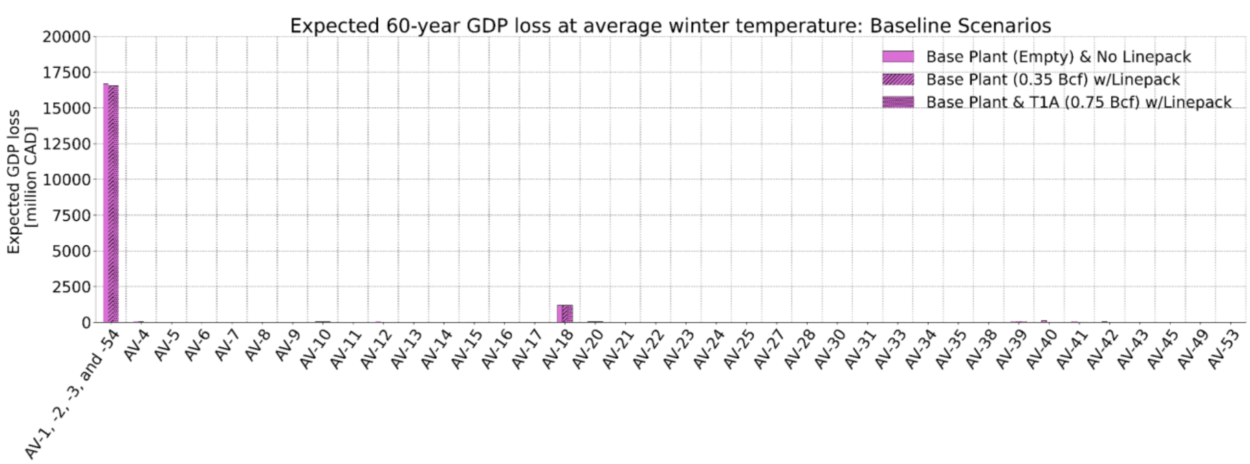
[176] Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, Figure 10 (p. 72).

horizons.[177] FEI submits that the magnitude of the expected losses warrants FEI's characterization of the risk as unacceptable.

Winter-only T-South Expected losses (Risk) - Three Metrics Over Various Time Horizons

Time Horizon (Winter-Only)	Economic (GDP) Loss	Customer Outage Days	Customer Outages
1-Year	$278 million	2.6 million	69,600
20-Year	$5.6 billion	51.6 million	1.4 million
60-Year	$16.7 billion	154.7 million	4.2 million

138. In order to facilitate comparisons among AVs, Exponent provided graphics depicting the winter-only risk results for every AV, for various time horizons (1 year, 20 years and 60 years) and for all three consequence metrics. All of the figures show results in three scenarios where FEI has, or does not have, access to other supply resources (including a very optimistic scenario where the Base Plant is full, there is significant linepack and FEI uses 40 percent of the Tilbury 1A facility (**Tilbury 1A**)). For example, the figure below provides the estimated GDP losses for T-South and every other AV over the 60-year service life of the TLSE Project.[178] The relative risk is similar regardless of the consequence metric (customer outages, customer-outage-days or GDP losses) or time horizon considered (1 year, 20-years or 60-years).[179]



177 The values for 20 years and 60 years are approximate based on graphics provided by Exponent in the response to BCUC IR5 126.1 (Exhibit B-63), as the specific values were not included on the evidentiary record.

178 Exhibit B-63, BCUC IR5 126.1.

179 See BCUC IR5 126.1 (Exhibit B-63) for figures of the GDP loss, customer outage and customer outage-day results over 20-year and 60-year time horizons.

139. It is easy to see from these graphics that the risk posed by a winter T-South no-flow event is far greater than the risk for any other AV. The winter-only loss is more than eight times the expected annual winter-only loss of all other AVs combined.[180] It is particularly striking that, given the large units Exponent had to use on the y-axis to capture the very significant T-South expected losses (risk), the expected losses for almost all of the other AVs evaluated in the 2024 Resiliency Plan are sufficiently small so as to appear in the graphic to have no associated losses.[181]

F. PRIORITIZING MITIGATION OF T-SOUTH RISK REFLECTS SOUND RISK MANAGEMENT PRACTICES

140. The primary recommendation of the 2024 Resiliency Plan is that investment is appropriate to mitigate the unacceptably severe risk associated with a winter T-South no-flow event. As discussed below, standard risk management practices support this recommendation.

(a) Exponent Recommends Targeting Resiliency Investment at the Largest Risks

141. Exponent's expert opinion is that it is reasonable to prioritize mitigating the risk posed by a winter T-South no-flow event, given that the expected losses are very high in both absolute terms and relative to any other AV.[182] Exponent explained that it is good industry practice to target resiliency investments at the highest-risk vulnerabilities:[183]

> It is a good industry practice for a Resiliency Risk Assessment Plan to address the System Level Risks in a Top Down manner. In order to conserve and prioritize allocation of risk assessment effort resources to the most critical areas, a good risk assessment often begins with a prioritized screening of high-interest vulnerabilities. Such an effort to identify high-interest vulnerabilities and performance of a prioritized screening allows the identification of areas where subsequent and detailed risk assessment efforts should be focused.
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> […]
>
> In general, mitigating assets in descending order of risk – that is, mitigating the highest-risk assets first – is considered an effective approach to reducing risk.

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180 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, para. 245.

181 See BCUC IR5 126.1 (Exhibit B-63) for figures of the GDP loss, customer outage and customer outage-day results over 20-year and 60-year time horizons.

182 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, para. 245.

183 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, para. 42.

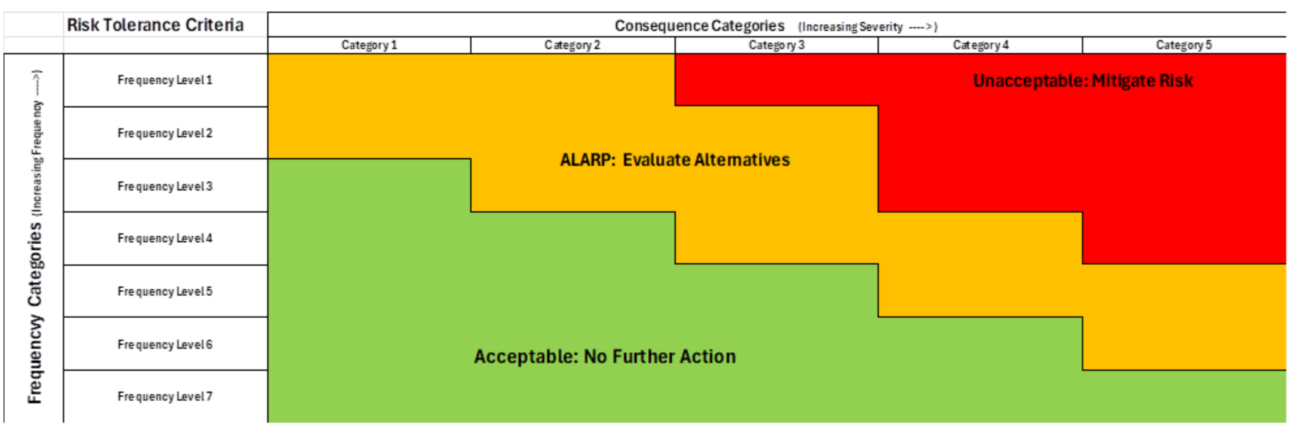
> Given the probability of failure in combination with the consequences associated with AV-1, -2, -3, and -54, Exponent would expect the risk on these AVs to be prioritized for mitigation.[184]
>
> [Emphasis added]

142. FEI submits that Exponent's expert advice in this regard supports the TLSE Project, which mitigates FEI's single largest customer outage risk as well as other risks.[185]

(b) Under the ALARP Analytical Approach the T-South Risk is "Unacceptable", Not "As-Low-As-Reasonably-Practicable"

143. Exponent has also provided expert evidence regarding the "As-Low-as Reasonably-Practicable" (**ALARP**) risk management approach and its application in this context. FEI submits that the ALARP analytical approach provides additional support for mitigating the severe risk posed by a winter T-South no-flow event.

144. The ALARP analytical approach is depicted in the following figure prepared by Exponent. The "ALARP" zone typically lies between "Unacceptable" and "Acceptable" levels of risk.[186]



145. Exponent explained that it is generally understood that "Unacceptable" levels of risks need to be mitigated, and "Acceptable" levels of risk do not need further mitigation, with a "gray" ALARP zone falling between these levels. "High-risk scenarios", being unacceptable, should be

184 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, para. 246.

185 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, para. 244.

186 Exhibit B-63, BCUC IR5 117.2.

mitigated.[187] Explicitly defined boundary lines are neither necessary nor possible in the context of economic (GDP) type losses:[188]

> 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.
>
> [Emphasis added]

146. Exponent observed that "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."[189] The evidence discussed in Parts Three and Five of these submissions supports that characterization.

147. As discussed in Part Five below, FEI has considered numerous alternatives to mitigate the currently unacceptable risk. On-system LNG is the only viable way to mitigate the risk effectively. The Preferred Alternative provides the greatest risk mitigation among all of the alternatives, and does so more cost-effectively. It is delivering the greatest risk reduction value for customers.[190]

(c) All Experts Warn Against Allowing Uncertainty in Probability and Timing to Overshadow Catastrophic Consequences

148. Exponent's risk analysis indicates that a winter T-South no-flow event is a high-probability-high-consequence risk when considered over any reasonable time period.[191] Regardless, risk management principles cited by all four of the relevant experts in this proceeding

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[187] Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, para. 244.

[188] Exhibit B-63, BCUC IR5 117.2.

[189] Exhibit B-63, BCUC IR5 117.2.

[190] See also BCUC IR5 117.2 (Exhibit B-63) which provides the conceptual risk classification of the current T-South risk, as well as under the various alternatives considered in the Supplemental Evidence.

[191] Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, para. 22. For further discussion, see Section 10 of the Exponent Report.

(Exponent, PwC, Guidehouse and JANA) would also support a resiliency investment at much lower calculated probabilities. They are unanimous that, where consequences from a plausible event are known to be unacceptably severe, the appropriate response is to mitigate the consequences to levels that that can be tolerated.

Exponent on Risk Management for Plausible Events With Severe Consequences

149. Exponent's expert opinion, which rests on sound empirical and academic footing, is that standard probabilistic risk assessment may underestimate the impacts of rare events:[192]

> 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. Therefore, the distributions fitted to the observed data tend to fit the central tendencies of the data, but may underestimate the rare tail events, 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.
>
> […]
>
> Standard probabilistic risk assessment may underestimate the impacts of rare events because of the difficulty to estimate their probabilities and quantify their impacts, and the sensitivity of the risk to the variables of the hazard and modeling decisions. In addition, some studies suggest that risk analysis based on fat-tailed power laws may still underestimate rare risk events. Specifically, the presence of outliers (defined as extreme events which may be significantly larger than the predictions of power-law distributions) has been documented. Those are events that are sometimes referred to as Black Swans or Dragon Kings, and have been identified in nuclear accident datasets, and the magnitude-frequency distribution of earthquakes in localized regions in southern California.
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> [Emphasis added and references omitted]

150. Exponent recommended addressing uncertainty in the determination of probability by complementing conventional probabilistic risk assessment with "scenario-based" analysis:[193]

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[192] Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, paras. 235 and 240.

[193] Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, para. 22. For further discussion, see Section 10 of the Exponent Report, p. 233.

> 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). 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. 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.
>
> [Emphasis added]

151. Exponent's expert opinion is that, in making resiliency investment decisions, it is sufficient "that it is foreseeable that a failure could occur, and the consequences of a failure are substantial", including when the rate of failure (probability) is low.[194] The 2018 T-South Incident, in and of itself, demonstrates that a winter T-South no-flow event is foreseeable. The subsequent incident where T-South was submerged was another "near miss". The "swamp gas" incident shows how even a false alarm could prompt a pre-emptive shutdown. (See Part Three, Section D(f) above). The calculated probabilities suggest a no-flow event is likely, not just foreseeable, over time horizons as short as 20 years.

JANA on Risk Management for Plausible Events With Severe Consequences

152. JANA's Pre-Adjournment Decision paper *Managing Low Probability – High Consequence Pipeline Risk* reached the same conclusion as Exponent, with reference to the four-quadrant risk management approach posited by Professor Nassim Taleb (the academic who popularized the term "black swan"). JANA explained Taleb's approach to mitigating low-probability high-consequence pipeline risk as follows:[195]

> When we land in [Taleb's] Quadrant IV [limited knowledge, unpredictable timing and location of event, high consequences], what we must do is 1.) Accept that we

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194 Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, para. 231.

195 Exhibit B-32, BCOAPO IR2 2.3.

> 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.
>
> The fourth quadrant, then, as defined by Taleb, is about the areas in our domain (in our case, pipelines) where our knowledge is limited AND that limitation has the capability to result in an event of high consequence. Also, while we may know the probability of an event occurring, due to the complexity of the system, we will not be able to predict it in terms of where and when. This need not imply that we need to be a victim of the situation. We can take action to change our risk position.
>
> [Emphasis added]

153. The point is, in essence, we can not predict when or how many times a winter T-South no-flow event will occur, but we know it could happen next winter and it could happen multiple times and that the consequences are unacceptable. An investment that prevents the unacceptable consequence, like the TLSE Project, is an appropriate response.

PwC on Risk Management for Plausible Events With Severe Consequences

154. PwC expressed a similar view, distinguishing a high-consequence-low probability resiliency investment decision from a typical risk management decision. In essence, when consequences are less severe such that one can live with them, one can afford to undertake probability-adjusted spending. In a circumstance where one cannot accept the outcome, the outcome should be mitigated until it is tolerable. PwC stated:[196]

> Natural gas disruption represents "black swan" events that are of an unforeseen, binary nature that either happen or they don't. For this reason a probabilistic or risk adjusted approach is not applicable and system resiliency investment decisions should be considered on the basis of total potential impact that may occur in the event of disruption.

Guidehouse on Risk Management for Plausible Events With Severe Consequences

155. Guidehouse concurred, referencing the work of Zuppinger and the Project Management Institute:[197]

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[196] Exhibit B-15, BCUC IR1 3.4.

[197] Exhibit B-28, RCIA IR2 31.2; Exhibit B-28, RCIA IR2 34.3. See also Assessing Risk is it a Black Swan, 2012. https://www.pmi.org/learning/library/assessing-risk-black-swan-fukushima-6084.

> Black swan events, although improbable, are not impossible and if the consequence is too severe to be tolerated, the risk must be managed effectively so that they do not take us by surprise. Probability is important, but can be misleading in risk assessment by creating biases that convince of the unlikeliness without understanding the real severity of the risk in question.

156. Guidehouse drew an analogy between resiliency investments and insurance, where the probability of an event occurring "can cloud" decision making: "We do not purchase insurance based on a probability adjusted basis. We purchase insurance based on whether or not we can tolerate the consequences of the event."[198] That is, people purchase earthquake insurance or fire insurance annually because they cannot afford to lose and rebuild their house, not because there is a high probability of an earthquake or fire occurring within the next year.

BCUC Applies this Approach in the Context of Dam Safety Investments

157. As further discussed in Part Three, Section G(b) of FEI's Pre-Adjournment Final Submissions, the BCUC has applied the risk management approach outlined by the four experts in the context of dam safety. The BCUC has approved significant capital investments in dams to mitigate the risk of low-probability-high consequence events.

G. SUMMARY AND REQUESTED FINDING ON RESILIENCY PROJECT DRIVER

158. FEI submits that the BCUC should find that a winter T-South no-flow event poses an unacceptably severe risk, such that it is in the public interest to mitigate it.

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[198] Exhibit B-28, RCIA IR2 31.2; Exhibit B-18, BCSEA IR1 2.1; Exhibit B-15, BCUC IR1 10.8.

PART FOUR: PROJECT NEED – THE TILBURY BASE PLANT HAS REACHED END-OF-LIFE AND MUST BE REPLACED

A. INTRODUCTION

159. This Part addresses the second Project driver: the pressing need to replace the Tilbury Base Plant (both regasification and storage) to ensure that FEI can continue to provide dependable firm service in normal operations. The post-Adjournment Decision evidence, discussed below, shows this concern to be worse than previously described.

160. Despite further investment, the Base Plant's performance continues to deteriorate. Key components of the regasification equipment – the only regasification equipment at Tilbury – are now experiencing failure rates at least six times greater than industry norms.[199] There is every reason to expect worsening performance, as the 55-year-old facility is well-past its expected service life and has many deteriorating and obsolete components. The new independent engineering studies detail the poor condition of the Base Plant tank and fundamental issues with the foundations; the experts advise against refurbishment.[200] Investments intended to address the many issues with the Base Plant equipment or tank would still leave unaddressed the seismic, flood exposure and environmental issues inherent in a 55-year-old facility design. In aggregate, these problems demonstrate that the Base Plant facility is end-of-life. Simply put, FEI's customers have benefited from the Base Plant for 55 years, and we have now reached the point where replacement provides better value than making investments in the Base Plant that have uncertain prospects of extending its life and leave unaddressed the underlying design problems.

161. Moreover, continuing to operate the Base Plant as its reliability deteriorates would mean exposing FEI's firm customers to progressively greater risk of losing service in normal operations. The evidence discussed below demonstrates the specific and critical role that LNG plays in FEI's gas supply portfolio. A short response time and lack of reliance on third-party infrastructure allows FEI to depend on this resource to provide peaking supply when market resources are

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199 Exhibit B-60, Supplemental Evidence, pp. 69-70; Exhibit B-69, BCUC IR6 157.1.

200 Exhibit B-60-1, Confidential Supplemental Evidence, Confidential Appendices D and E.

severely constrained or unavailable, to respond to unanticipated supply and demand fluctuations in real time, and to maintain service during equipment failures and routine system maintenance outages related to other resources (i.e., off-system pipeline and storage). The Base Plant is already undersized based on FEI's load by a considerable margin; FEI has been relying on its contingency pipeline resources to reach the necessary 200 MMcf/d and 1.0 Bcf of peaking supply, which is sub-optimal in several respects. The 150 MMcf/d and 0.6 Bcf of Tilbury LNG, and the attributes of those resources, are irreplaceable in the highly constrained regional market and those market constraints are only getting worse.

162. In short, the BCUC should find that continuing to rely on a deteriorating critical supply portfolio asset longer than absolutely necessary (i.e., the time it takes to construct a replacement facility) will jeopardize reliable service for FEI's firm customers.

163. The subsections in this Part make the following supporting points:

- First, the totality of the issues with the Base Plant regasification equipment, foundations, tank and inherent design demonstrate that the facility has reached end-of-life.
- Second, on-system LNG at Tilbury is a critical part of FEI's portfolio due to the unique attributes of on-system LNG and the amount of peaking supply Tilbury provides.
- Third, FEI's peaking supply needs from a planning perspective have exceeded the capabilities of its on-system LNG facilities for several years, and the resources that FEI is relying on to make up the shortfall lack the valuable attributes of LNG and add portfolio risk.
- Fourth, losing the Tilbury Base Plant would jeopardize FEI's ability to meet peak loads in normal operations due to the lack of peaking supply alternatives in the market.
- Fifth, Tilbury 1A cannot fill the role currently provided by the Base Plant.
- Sixth, an investment decision to replace the Tilbury Base Plant is needed now given the lead time to implement a replacement solution.

B. THE BASE PLANT IS END-OF-LIFE

164. The evidence, discussed below, is that there are numerous age-related issues with the Base Plant regasification equipment that are already significantly compromising reliability despite ongoing investment. The regasification equipment is obsolete and difficult and costly to maintain or repair.[201] There are also unresolvable problems associated with the 55-year old design. Considered in totality, the conclusion is inescapable that the facility has reached end-of-life and requires replacement.

(a) Deteriorating Condition of Base Plant Regasification Equipment Has Compromised Existing Peaking Gas Supply and Resiliency

165. The Base Plant houses the only regasification equipment at Tilbury and it is now 55 years old.[202] The major components of the regasification equipment[203] that are compromising reliability include the send-out pumps and vaporizers.

Critical Send-Out Pumps Are Now Failing at a Rate at Least Six-Times Higher than Industry Norms

166. Functioning send-out pumps are essential to access any gas supply from Tilbury.[204] In essence, send-out pumps (along with their associated motors) pull LNG from the Base Plant tank, and push it into the vaporizers, where it is gasified and pushed into the distribution gas pipeline.[205] The Base Plant send-out pumps are no longer reliable and cannot be feasibly replaced, meaning the peaking supply that FEI needs to serve firm peak loads (i.e., 1-10 days of demand) is no longer reliable. As a result, FEI's firm service is no longer reliable in the coldest periods of winter.

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201 Exhibit B-60, Supplemental Evidence, pp. 68 and 70-73.

202 Exhibit B-60, Supplemental Evidence, p. 68.

203 Exhibit B-60, Supplemental Evidence, p. 69.

204 The Base Plant is designed with four send-out pumps; however, currently only the "A", "B" and "C" pumps can run in parallel. The "D" pump does not have the same performance curve, and therefore it does not function as a spare for the other three pumps.

205 Exhibit B-60, Supplemental Evidence, p. 69.

167. Over the past three years, the Base Plant's three functioning send-out pumps have experienced a failure rate at least six times greater than the standard industry-accepted failure frequency.[206] The recent failures have had multiple causes, including seizing, vibrations, arcing, seal failure and sustained oil leaks, among others.[207]

168. These failures have had real implications. There have been multiple instances where send-out was delayed by up to 12 hours when called upon.[208] While FEI has been able to readjust in these instances, delays of this kind can have potentially significant implications for FEI's customers. As discussed later in Part Four, Section C, LNG is an important resource because it is capable of quickly responding to unforeseen fluctuations in supply or demand with as little as 2 hours notice[209] when market resources are severely constrained. Other supply resources in FEI's ACP do not share these attributes and, in any event, have typically already been called upon by the time LNG send-out is needed.[210]

169. The decreasing reliability and availability of the send-out pumps is not something that can be addressed merely by increasing testing and preventative maintenance. FEI explained that, despite undertaking testing ahead of and during send-out season to detect hidden failures, failures may remain hidden until send-out is necessary. Further, even if a pump failure is discovered, the system cannot be taken down for repair until the send-out season (i.e., winter heating period) is over; isolating any pump for repair requires taking down the entire send-out system for 1-2 weeks.[211] FEI is effectively left hoping the Base Plant pumps will operate when called upon for immediate send-out, which is an untenable position when FEI's ability to meet firm demand depends on it.

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[206] Exhibit B-69, BCUC IR6 157.1.

[207] e.g., Exhibit B-60, Supplemental Evidence, pp. 69-70.

[208] Exhibit C-68, RCIA IR5 63.1; Exhibit B-69, BCUC IR6 157.1.

[209] Exhibit B-1-4, Application, p. 129 and Exhibit B-15 BCUC IR1 34.1; see also Exhibit B-60, Supplemental Evidence, p. 68 and Appendix F, Raymond Mason Report, p. 23.

[210] Exhibit B-68, RCIA IR5 63.1; Exhibit B-69, BCUC IR6 157.1.

[211] Exhibit B-69, BCUC IR6 157.1.

170. Significant work would be necessary to increase the reliability and availability of the Base Plant send-out pumps and it may not be feasible, let alone practical. In addition to replacing the send-out pumps, FEI would need to install isolation valves and piping. The work would necessitate de-inventorying and thermal cycling of the tank to allow demolition of the existing piping, pumps and shelter. Cycling an LNG tank of this age may not be possible. Even if it is possible, there are a number of factors that could cause significant cost escalation. Having the send-out system offline during all or part of a winter season puts at risk FEI's ability to serve firm customers during peak periods. This work would also leave unresolved the problems with other regasification equipment components, discussed below.[212]

Vapourizers Are Corroded and Increasingly Unreliable

171. FEI's ability to regasify LNG from Tilbury also depends on functioning vapourizers. The Base Plant has four 50 MMcf/d vapourizers (only three of which can operate at any given time). Like the send-out pumps, the vapourizers are unreliable and their reliability will continue to decline. FEI's ability to provide reliable firm service in normal operations will continue to decline along with them.

172. Like the send-out pumps, the vapourizers are well-beyond their design life.[213] Despite cycling through the vapourizers and trying to address the potential causes of unreliability during planned maintenance, it has become common to take multiple attempts to start the vapourizers when send-out is required. These failed attempts have caused delays in sending-out gas by up to 4 to 8 hours.[214] That is a significant, and highly problematic, delay given on-system LNG's role in FEI's gas supply portfolio as a rapidly deployable resource during peak periods, unforeseen fluctuations in supply / demand, and unplanned equipment outages. In a circumstance where LNG is the last resort source of supply, such delays could be expected to manifest in curtailments of firm load.

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[212] Exhibit B-66, CEC IR5 147.2 and 147.3.

[213] Exhibit B-60, Supplemental Evidence, pp. 70-71.

[214] Exhibit B-60, Supplemental Evidence, p. 70.

173. Corrosion, in particular, is a significant and worsening issue. FEI explained that corrosion is affecting many aspects of the vapourizers, providing photographs (two of which are reproduced below). For example, the walls of all four vapourizers are bowed out of shape due to thermal cycling and three vapourizers have had significant coating failures.[215]

Figure 3-17: Severe Corrosion in Vaporizer Stack A

[215] Exhibit B-60, Supplemental Evidence, pp. 70-73.

Figure 3-20: Discoloration and Bowing of the Bath Walls

174. It is inevitable that reliability of the Base Plant vapourizers will further decrease over time as the cumulative corrosion increases and distortion of the vaporizer walls continues.[216] The existing vapourizers, unlike modern vapourizers, are also prone to decreased combustion efficiency.[217]

Insufficient Isolation Valves Impede Emergency Repairs and Maintenance

175. The over 55-year-old design of the Tilbury Base Plant impedes emergency repairs and maintenance, which compounds the risk of service interruption from declining regasification equipment reliability.

176. For example, the Base Plant's limited number of isolation valves results in FEI having to warm-up large sections of piping and equipment (e.g., pumps, motors, and valves that interconnect the tanks with the regasification equipment) to isolate safely. This process, plus the

[216] Exhibit B-60, Supplemental Evidence, p. 71.

[217] Exhibit B-60, Supplemental Evidence, p. 71.

subsequent re-cooling, adds 6-10 days to the total repair duration.[218] Moreover, the lack of isolation valves complicates the removal and recertification of the 44 pressure safety valves in the Base Plant, which must occur once every 30 months per CSA Z276.[219] While FEI has evaluated the potential to install additional isolation valves to reduce the down time required for maintenance activities on the regasification system, there is insufficient room to do so. Even if additional valves could be installed, the associated work would require a lengthy outage.[220]

(b) The 1960's Tank Design Creates Risks and Limits its Use

177. While the immediate reliability issues arise from the regasification equipment, the Base Plant tank has unresolvable issues stemming from the lower engineering and safety standards that were in place in 1969 when facility construction began. As discussed below, the Base Plant tank: (1) is being operated well-below its design capabilities for seismic reasons; (2) does not meet current emissions design expectations; and (3) is susceptible to flooding. Replacing the Base Plant in its entirety is the only way to address these issues.

Base Plant Tank is Operating Well-Below Its Design Capacity for Seismic Reasons

178. More stringent design requirements have been put in place since 1969 that reflect improved understanding of seismic risk. FEI now operates the Base Plant tank at 58 percent capacity, or 0.35 Bcf, after recent seismic assessments by CB&I (an industry expert in the design and construction of tanks). CB&I concluded in its 2020 study that filling the tank to its design level of 0.6 Bcf:[221]

- would impose unacceptable levels of stress on the inner tank in a seismic event;
- would not comply with current day seismic requirements; and
- may result in the tank's ring wall foundation unloading.

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218 Exhibit B-60, Supplemental Evidence, p. 74.

219 Exhibit B-60, Supplemental Evidence, p. 74.

220 Exhibit B-60, Supplemental Evidence, p. 74.

221 Exhibit B-60-1, Confidential Supplemental Evidence, Appendix D.

179. CB&I then performed a second study in 2023 which raised the possibility that the operating level may need to be further reduced. CB&I indicated that, even when filled to 0.35 Bcf, unloading of the ring wall foundation may still occur.[222] FEI continues to evaluate the tank to determine if further reduction in the fill level will be necessary in light of the tank condition or future changes to seismic codes.[223]

180. The existing 0.35 Bcf falls well-short of meeting FEI's peaking supply and operational requirements. As described in Part Four, Section D below, FEI requires 200 MMcf/d and 1.0 Bcf of dependable peaking supply. Even before the tank capacity was reduced to 0.35 Bcf, FEI had already been relying on 50 MMcf/d of year-round pipeline capacity to make up its peaking supply shortfall, which is inefficient. Now, with the reduction of the Base Plant tank to 0.35 Bcf, FEI is also having to rely on 0.25 Bcf from Tilbury 1A, but this is a stop-gap measure (see Part Four, Section F below). Cobbling together critical peaking supply in this manner is suboptimal from a portfolio design perspective for the reasons explained in Part Four, Section E below.

Design of Base Plant Tank Entails Higher Environmental Risk

181. The Base Plant tank does not meet current design expectations as it relates to emissions. The tank was designed to operate under a very narrow pressure range, and pressure build-up within the tank (i.e., boil-off gases) is only managed with a single boil-off compressor.[224] Current standards require multiple boil-off gas (**BOG**) compressors, which provide redundancy and a wider range of design pressures to avoid venting boil-off gases to the atmosphere. Moreover, the Base Plant tank only has open-air secondary containment, meaning that if a leak were to occur the LNG would vent to atmosphere as it changes from a liquid to a gas. Tanks are now designed with full secondary containment to prevent methane venting to atmosphere in the event of a breach.[225]

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[222] Exhibit B-60, Supplemental Evidence, pp. 76-77.

[223] Exhibit B-60, Supplemental Evidence, p. 79.

[224] Exhibit B-60, Supplemental Evidence, p. 79.

[225] Exhibit B-60, Supplemental Evidence, pp. 79-80.

Base Plant Is Susceptible to Flooding

182. The Base Plant was constructed at an elevation that makes it susceptible to flooding. Flood modelling indicates that there is a very high risk of a flood causing significant damage to the Base Plant control room and other process buildings. The flooding of this equipment would likely interrupt FEI's ability to rely on the Base Plant for months, leaving it with no ability to send out gas. FEI explained that it would be impractical, in terms of construction risk, complexity and cost, to address the flood risk without replacing the Base Plant.[226]

Tank and Geotechnical Experts Advise Against Trying to Refurbish the Base Plant Tank

183. FEI retained two independent engineering firms (CB&I and WSP) to assess the feasibility of refurbishing the Base Plant tank to: (1) return it to its original design capacity of 0.6 Bcf; and (2) meet recent minimum seismic requirements. These engineering assessments, which were appended to the Supplemental Evidence,[227] demonstrate that refurbishing the tank is not feasible:

- CB&I recommended against attempting to remediate the deficiencies in the tank itself, as it would be "fraught with significant risk". In this regard, CB&I cited: the numerous elements of the tank that would not comply with current design and construction standards, deficiencies in the anchor straps holding the inner tank, the compressive strength of the outer tank concrete wall, and the outer tank anchor strap attachments.[228]

- Even if the all the tank repairs identified by CB&I could be completed, WSP concluded that it would not be cost-effective or feasible to replace the foundation to avoid the tank failing due to earthquake-caused differential settlement.[229]

C. <u>ON-SYSTEM LNG AT TILBURY IS A CRITICAL PART OF FEI'S GAS SUPPLY PORTFOLIO</u>

184. Tilbury LNG serves a specific and critical role in FEI's gas supply portfolio that reflects the unique attributes of on-system LNG.[230]

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226 Exhibit B-60, Supplemental Evidence, p. 80.

227 Exhibit B-60-1, Confidential Supplemental Evidence, Confidential Appendices D and E.

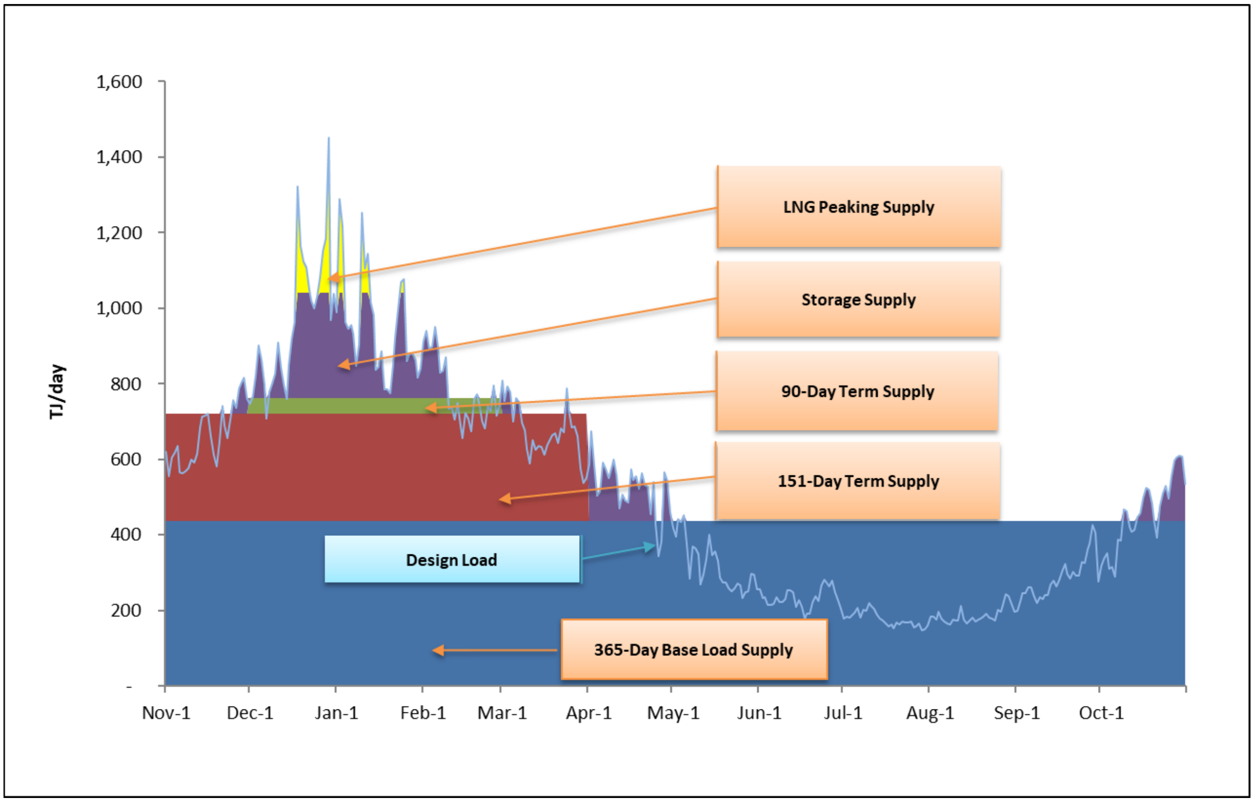
228 Exhibit B-60, Supplemental Evidence, pp. 77-78; Exhibit B-60-1, Confidential Supplemental Evidence, Confidential Appendix D.

229 Exhibit B-60, Supplemental Evidence, p. 79.

230 Exhibit B-60, Supplemental Evidence, pp. 81-85.

185. Each year, FEI files its ACP for BCUC acceptance. FEI's ACP has always included a mix of supply resources to meet forecast firm demand for Rate Schedules 1 to 7 in a design year (1 in 20-year temperature), including pipeline, market area storage and on-system LNG storage.[231] Figure 3-21 from the Supplemental Evidence, reproduced below, shows the mix of resources that FEI uses to meet forecast demand.[232]

Figure 3-21: 2024/25 Design and Peak Day 1 Load vs. Recommended Supply Portfolio



186. FEI's LNG supply is typically reserved for peak days (i.e., 1-10 days of demand) unless it is required on short notice to address unexpected supply or demand fluctuations. This is by design. Each resource in the ACP has different supply durations (energy), daily deliverability (capacity) and other attributes.[233] The attributes of on-system LNG include:

- **Avoids Holding Year-Round Pipeline Capacity:** While LNG represents a very small amount of *energy* (stored LNG, measured in Bcf or TJ) relative to other resources

[231] Exhibit B-60, Supplemental Evidence, pp. 81-82; Exhibit B-69, BCUC IR6 143.1.

[232] Exhibit B-60, Supplemental Evidence, p. 83.

[233] Exhibit B-60, Supplemental Evidence, pp. 81-82.

in FEI's gas supply portfolio, it provides significant *capacity* (determined by regasification output, measured in MMcf/d or TJ/d) and enough energy to last several days.[234] It avoids the need for FEI to hold upstream pipeline capacity and/or off-system storage that is only required during a few days each year. This, in turn, avoids annual tolls and the risk associated with trying to mitigate those fixed annual costs by selling underutilized capacity during the remainder of the year.[235] As discussed later, due to lack of availability in the market, FEI could not add incremental pipeline or regional storage resources to its portfolio in any event.

- **Immediate Response Time:** On-system LNG storage allows FEI to access energy on short notice, thus enabling an immediate response (i.e., maximum deliverability in real time) to hourly changes in weather, which can change rapidly, and urgent operational needs.[236] Balancing the system in this way ensures system pressure, and therefore reliability, is maintained. This contrasts with upstream pipeline and storage supply, which both require scheduling well in advance.[237] Mr. Raymond Mason, an expert in regional gas supply markets, observed that on-system LNG facilities "…typically provide reliable supply in areas where pipeline/distribution capacity limitations and/or weather conditions tend to cause supply and demand discrepancies."[238]

- **Maintaining Control Over Supply:** On-system LNG storage avoids the need to rely on counterparties and third-party assets for delivery during cold weather when marketplace conditions are the most costly and risky (e.g., difficult to secure or guarantee delivery).[239]

- **Backstopping Other Supply Resources:** On-system LNG provides supply and operational flexibility, enabling FEI to meet its load requirements when other supply resources become unavailable due to planned maintenance or unplanned outages. It is not uncommon for multiple operational issues to occur in the region during cold weather events. During a cold snap in January 2024, mutual aid across the Pacific Northwest was activated after operational issues occurred on TransCanada's Foothills system and at JPS. In that case, Tilbury and Mt. Hayes LNG send-out helped to maintain the pressure on T-South.[240]

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234 Exhibit B-60, Supplemental Evidence, p. 82

235 FEI's gas supply portfolio is already subject to considerable cost mitigation risk given the load profile of the customer base. For example, RS 1 has an approximately 30 percent load factor, meaning the profile is very "peaky": Exhibit B-60, Supplemental Evidence, p. 83.

236 Exhibit B-1-4, Application, p. 129 and Exhibit B-15 BCUC IR1 34.1.

237 Exhibit B-60, Supplemental Evidence, p. 83; Exhibit B-69, BCUC IR6 151.1.

238 Exhibit B-60, Supplemental Evidence, Appendix F, Raymond Mason Report, pp. 19-20.

239 Exhibit B-60, Supplemental Evidence, pp. 83-84.

240 Exhibit B-60, Supplemental Evidence, p. 84.

187. The unique attributes of on-system LNG storage make it a common resource for utilities in the Pacific Northwest region that share FEI's load profile (a pronounced winter peak).[241]

D. FEI'S NEED FOR PEAKING SUPPLY EXCEEDS FEI'S ON-SYSTEM LNG CAPABILITIES

188. As discussed below, FEI's peaking supply needs from a planning perspective have exceeded the capabilities of its on-system LNG facilities for several years, such that FEI has relied on sub-optimal and finite market resources to supplement it. FEI's standard portfolio modelling used for ACPs demonstrates that a larger Tilbury LNG facility with at least 200 MMcf/d of regasification capacity and 1.0 Bcf of LNG for gas supply portfolio purposes is necessary to optimize the portfolio from a cost and risk perspective.[242]

189. The inadequacy of the Tilbury LNG peaking supply is attributable to customer growth since the facility was constructed – there were approximately 200,000 customers in 1971 and there are more than 600,000 today.[243] Over the last 10 years alone, ACP peak day demand (a more relevant measure than annual demand in the context of a peaking resource like LNG[244]) has increased by 129 MMcf/d – a very significant increase given that Tilbury can only provide 150 MMcf/d of peaking supply. This increase is attributable to customer growth and Transportation Service customers (i.e., RS 23 and 25) returning to bundled service:[245]

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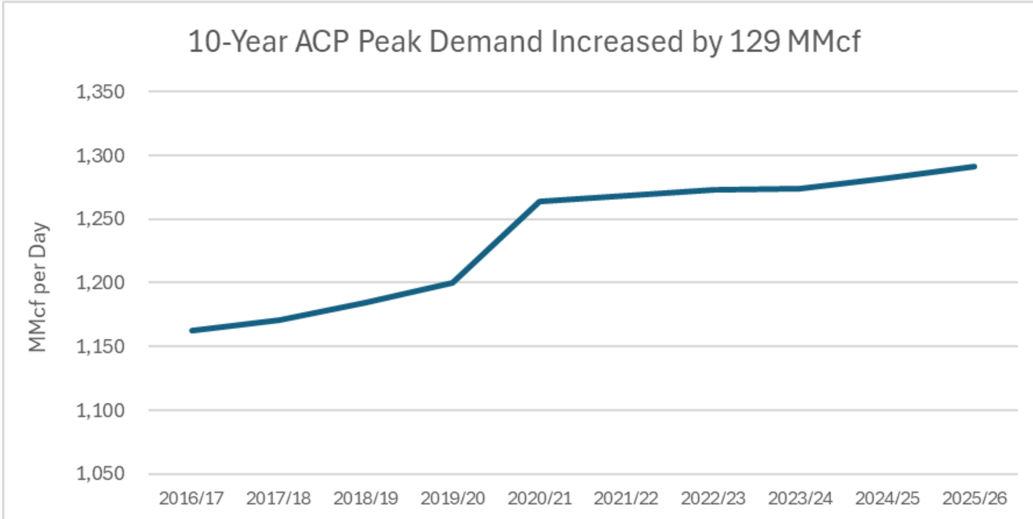
[241] See Exhibit B-60, Supplemental Evidence, Figure 3-22 (p. 85) and Appendix F, Raymond Mason Report, p. 20.

[242] FEI designs the capacity of its system to meet peak demand in cold temperatures, and not averages, by estimating peak day demand for each weather zone using the extreme value analysis (**EVA**) methodology: Exhibit B-63, BCUC IR5 118.5; Exhibit B-60, Supplemental Evidence, p. 85.

[243] Exhibit B-60, Supplemental Evidence, p. 85.

[244] See Exhibit B-63, BCUC IR5 118.7.1.

[245] Exhibit B-63, BCUC IR5 118.1.



190. Meeting the growing peaking supply requirements in recent years has required FEI, in its ACPs, to supplement its existing Tilbury peaking supply with: (1) additional T-South pipeline capacity that had originally been intended to be used only as a contingency resource; and (2) peaking call options (e.g., from the East Kootenay interconnect (**EKE**)).[246] While these resources have thus far proved workable, they are not by any means a like-for-like substitution for on-system LNG. As noted above, on-system LNG has unique characteristics including being available on very short notice and non-reliance on third-party infrastructure or counterparties. Peaking call options typically require 24-hours advance notice, and FEI similarly needs to make advance decisions about whether to try selling its pipeline capacity to mitigate fixed tolls or keep it.[247] Moreover, the peaking call options (as described in Part Four, Section E(b) immediately below) are not dependable and come with significant price exposure. All of these factors underlie FEI's characterization of the current gas supply portfolio as sub-optimal.

191. The existing inadequacy of the Tilbury LNG facility from a peaking supply perspective is set to get worse in the short-term. The most recent peak day forecast used in the 2025/26 ACP indicates that peak day demand will increase by 8 MMcf/d each year in the next five years (2025-2030). The methodology used for this forecast has provided accurate projections compared to

[246] Exhibit B-69, BCUC IR6 143.3; see also Exhibit B-69, BCUC IR6 143.1 and 143.2.

[247] Exhibit B-60, Supplemental Evidence, Appendix F, Raymond Mason Report, p. 26.

actuals,[248] and this will mean relying even more heavily on peaking call options, given the unavailability of any pipeline or off-system storage resources (see Part Four, Section E(b) immediately below).

192. The design weather conditions that underpin the ACP modelling and portfolio are demonstrably sound. Several recent winter events have approached the design weather conditions used in the model.[249]

193. As discussed below, due to current regional market conditions, FEI will be very challenged to meet its peak demand even with a fully functioning Tilbury Base Plant. If FEI were to lose access to Tilbury LNG, FEI would be unable to replace that peaking supply in the market.

E. FEI COULD NOT REPLACE TILBURY'S 150 MMCF/D CAPACITY AND 0.6 BCF ENERGY IN THE MARKET

194. At some point, the Base Plant regasification equipment will fail permanently – the only question is when. When it happens, FEI will be left with a 150 MMcf/d and 0.6 Bcf gap in its peaking gas supply, which represents most of FEI's current peaking requirements and supply (200 MMcf/d and 1.0 Bcf). The evidence, discussed below, demonstrates that:

- Due to regional infrastructure constraints, FEI could not replace the dependable peaking gas supply provided by the Tilbury facility in the market;
- Unless and until a hypothetical regional pipeline or storage expansion occurs at some unknown time in the future, the likely outcome of losing access to Tilbury's 150 MMcf/d capacity and 0.6 Bcf of energy will be curtailment of firm customers in normal operations; and
- A hypothetical future pipeline or storage expansion would be accompanied by tens of millions of dollars in additional annual tolls that would be passed on to customers.

195. FEI submits that this outcome is unacceptable and contradicts the gas supply planning approach that has long underpinned FEI's BCUC-accepted ACPs.

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248 Exhibit B-69, BCUC IR6 144.1. See also BCUC IR6 144.2, 144.3, 144.4 and 144.5 for more information regarding FEI's peak demand forecast.

249 Exhibit B-69, BCUC IR5 139.1; BCUC IR6 145.2, 145.3, 145.4, 145.5 and 145.6.

(a) Existing Regional Infrastructure Is, and Will Remain, Fully Contracted

196. There are two issues that would preclude replacing lost Tilbury LNG supply with other dependable (albeit less well-suited) supply resources: (1) pipelines are fully contracted; and (2) regional storage facilities are fully contracted.

197. FEI can only access peaking supply from market hubs (Station 2, AECO/NIT, and East Kootenay and the NGTL expansion) or regional storage facilities (Aitken Creek, JPS and Mist) if transmission capacity is also available to deliver the resources to FEI's system.[250] There is no more pipeline capacity available. Throughput on the T-South system has already surpassed rated pipeline capacity during winter.[251] Further, FEI cannot simply send more East Kootenay supply to the Lower Mainland and Interior because the SCP is already fully utilized on the peak day.[252] FEI's contracted supplies from the East Kootenay and AECO already fill the current SCP capacity.[253]

198. The major off-system storage facilities are also fully contracted, as is the pipeline capacity required to access any additional storage capacity.[254] The independent gas expert Mr. Mason explains:[255]

> Due to the nature of the regional demands, third-party off-system storage and companies offering peaking gas supply arrangements, are constrained by the ability to transport the underlying supply of natural gas as well as the potential for unplanned outages.
>
> […]
>
> While, increasing existing upstream (i.e., Aitken Creek) and/or downstream (i.e., Mist and JPS) off-system storage is theoretically an alternative capacity resource, in practice, these facilities are currently fully contracted and will require expansions to meet any incremental capacity requests from FEI. In addition, increases to off-system storage resources will remain contingent on the deliverability of interconnected mainline pipeline networks (i.e., which are already facing capacity constraints).

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250 Exhibit B-69, BCUC IR6 145.12.

251 Exhibit B-60, Supplemental Evidence, Appendix F, Raymond Mason Report, p. 25 and Figure 5.

252 Exhibit B-69, BCUC IR6 143.4.

253 Exhibit B-69, BCUC IR6 145.11.

254 Exhibit B-60, Supplemental Evidence, p. 87.

255 Exhibit B-60, Supplemental Evidence, Appendix F, Raymond Mason Report, pp. 4, 22 and 24.

199. The regional demand causing the constraints on regional infrastructure shows no sign of subsiding, given that a key driver of the demand is natural gas-fired power generation in both the I-5 Corridor and the broader Western energy markets. These natural gas-fired power plants are increasingly needed to meet the Pacific Northwest region's electricity demand, as intermittent (non-firm) renewable resources replace legacy firm resources and large industrial loads continue to develop in the region.[256] Demand from these gas-fired generators in the last several years averaged 220 MMcf/d higher than the 5-year average between 2016 and 2020. These plants have begun to operate at or near maximum capacity on a daily basis throughout the entire winter period, straining both baseload and storage resources.[257] NERC[258] and WECC[259], two organizations dedicated to ensuring the interconnected electric grid remains reliable, have both identified the need for more capacity and energy in western North America.

200. The two announced expansions to regional infrastructure, which are not yet under construction, do not add the incremental resources that would be necessary to replace the loss of the Base Plant:

- **Enbridge T-South Sunrise Expansion Only Replaces Capacity Lost to Woodfibre LNG:** When the Woodfibre LNG facility enters service, the facility will require approximately 15 percent of the total existing T-South capacity. Woodfibre LNG already holds that capacity, but has been reselling it into the market. Enbridge's T-South Sunrise Expansion Project (up to 300 MMcf/d) will not add capacity beyond what will be lost to the Woodfibre LNG facility.[260]

- **Mist Expansion Project Only Replaces Recalled Capacity:** FEI has recently contracted 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. However, this new deliverability will only replace existing deliverability

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256 Exhibit B-60, Supplemental Evidence, p. 88 and Appendix F, Raymond Mason Report, pp. 36-43.

257 Exhibit B-60, Supplemental Evidence, p. 89 and Figure 3-24.

258 Exhibit B-60, Supplemental Evidence, p. 89. North American Electric Reliability Corporation (NERC) has concluded that Western North America is currently at an elevated risk of having insufficient capacity available and energy from resources during extreme and prolonged weather events.

259 Exhibit B-60, Supplemental Evidence, pp. 89-90. The Western Electricity Coordinating Council (WECC) has similarly concluded that Western North America was not prepared to meet the rapidly increasing demand in the region over the next 10 years.

260 Exhibit B-60, Supplemental Evidence, p. 90.

that FEI will lose beginning in 2027/2028. It could not replace the peaking supply that the Tilbury Base Plant provides.[261]

201. There are no other announced infrastructure projects that would add new capacity and alleviate the regional constraints that preclude replacing Tilbury LNG.

(b) Short-Term Commercial Agreements Could Not Make Up for the Loss of Tilbury Supply

202. Without Tilbury LNG, and with no dependable pipeline or regional storage to replace the peaking supply, FEI would be left reliant on *ad hoc* short-term contractual arrangements (peaking call options).[262] This would be untenable for three reasons.

203. First, it is not realistic to expect that FEI could replace the existing 150 MMcf/d, which is equivalent to 8 percent of the current firm T-South capacity, by cobbling together peaking call options *ad hoc*.[263] Simply put, many FEI firm customers would face losing service in cold periods.

204. Second, even if one were to assume hypothetically that some *ad hoc* resources would be available, peaking call options are not dependable sources of "last resort" peaking supply:

- These commercial arrangements typically maintain 24-hour notice periods prior to the deployment of the resource.[264] As noted above, part of the value of having LNG in a portfolio is attributable to being available on very short notice; and
- Peaking call options still require that the counterparty has rights to pipeline capacity. FEI explained that, at the best of times, such commercial peaking deals are volatile in terms of physical delivery on peak day as the counterparty may or may not hold physical capacity on regional infrastructure and, as a result, may fail to provide the gas when called upon.[265] As noted above, T-South is already at its

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[261] Exhibit B-60, Supplemental Evidence, pp. 91-92; Exhibit B-63, BCUC IR5 131.1 and 131.9.

[262] Call options allow FEI to request deliveries of the contracted quantity from counterparties on any day during the Delivery Period (i.e., December to February). The contract specifies the number of days (e.g., 15 days) that FEI can exercise the option during the Delivery Period. FEI pays a premium (demand charge) to the counterparty to receive the additional supply and, if FEI executes the call option, a commodity price under the contract at a price that is tied to the daily index at the market hub where FEI receives the supply: Exhibit B-69, BCUC IR6 145.8.

[263] Exhibit B-60, Supplemental Evidence, p. 92.

[264] Exhibit B-60, Supplemental Evidence, Appendix F, Raymond Mason Report, p. 26.

[265] The current resource constraints in the region limit FEI's ability to mitigate this non-performance risk by contracting for the underlying firm service with the pipeline and/or storage resource: Exhibit B-60, Supplemental Evidence, p. 94.

> maximum capacity, and FEI holds more than one-third of that capacity. It is unlikely other parties would have capacity to spare during cold winter periods when peaking gas supply is needed, given that demand in the I-5 corridor is similarly winter peaking.[266] If these peaking call options are FEI's last resort, a counterparty default translates into loss of service for firm customers.

205. Third, peaking call options, to the extent they were even available, would also come at a very significant cost for customers. FEI explained that the lack of existing regional infrastructure already results in extreme price volatility and price spikes during peak demand. FEI's customers would be more exposed to price risk if FEI was faced with also trying to replace lost on-system peaking gas supply from Tilbury with *ad hoc* contractual arrangements. To illustrate the magnitude of potential costs customers could face, FEI prepared a hypothetical illustrative calculation assuming that supply was available in the market and that it was necessary for FEI to procure its peaking supply from the Sumas market during the 2022/23 winter. The costs associated with acquiring 150 MMcf/d for only 4 days (0.6 Bcf) would have been between $8.1 million and $40.5 million that winter. This calculation does not account for the upward price impacts that could be expected from FEI trying to buy such large volumes in an already tight market.[267] These figures are for a single winter, but FEI would be faced with doing this every year until pipeline capacity became available.

206. Mr. Mason summarized the risks of relying on *ad hoc* arrangements as follows:[268]

> …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). These factors, when taken together, are not conducive to contract for dependable peaking supply resources.

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[266] Exhibit B-60, Supplemental Evidence, p. 93.

[267] Exhibit B-60, Supplemental Evidence, pp. 95-96, Table 3-4.

[268] Exhibit B-60, Supplemental Evidence, Appendix F, Raymond Mason Report, p. 4.

207. Put simply, relying on peaking call options as a replacement for Tilbury LNG would expose customers to service disruptions and very high gas supply costs.[269]

(c) Counting on a Hypothetical Future Regional Infrastructure Expansion to Replace Tilbury LNG Supply Would Be Risky and Costly for Customers

208. It would take another significant regional infrastructure expansion beyond those already announced (i.e., beyond the Enbridge T-South Sunrise Expansion and the Mist Expansion projects) to make up for the loss of Tilbury LNG supply. And again, those types of resources do not share the attributes that make LNG ideal for "last resort" peaking gas supply. FEI respectfully submits that hoping a regional infrastructure expansion occurs before FEI loses access to Tilbury LNG peaking supply would not be an appropriate gas supply planning strategy.

209. First, ACPs are based on an expectation of serving firm demand in design conditions, and have relied on dependable resources to meet firm demand.[270] It would be reasonable to expect a significant period of unknown duration between the permanent failure of the Tilbury Base Plant and the construction of a new (hypothetical, yet to be announced) pipeline expansion . During period, FEI would have a very significant deficit of dependable peaking supply.[271] FEI does not have control over the timing or size of any future unannounced upgrades.

210. Second, there is a very significant annual cost associated with obtaining FEI's required 200 MMcf/d and 1.0 Bcf of peaking supply from a significantly expanded regional pipeline or storage facility. The owners of that infrastructure would incur significant capital costs which, in turn, would be passed along to shippers like FEI in tolls. Those tolls flow through to FEI customers through cost of gas. In the case of pipeline expansions, rolled-in tolling design means FEI would pay higher tolls than today for all of its capacity (i.e., existing holdings plus new incremental holdings). That means that all of FEI's existing capacity holdings on the regional infrastructure would also become more expensive for customers. A further expansion to the US-based storage facilities will also come at a higher cost because (a) storage tolls will similarly increase; and (b)

[269] Exhibit B-60, Supplemental Evidence, p. 94.

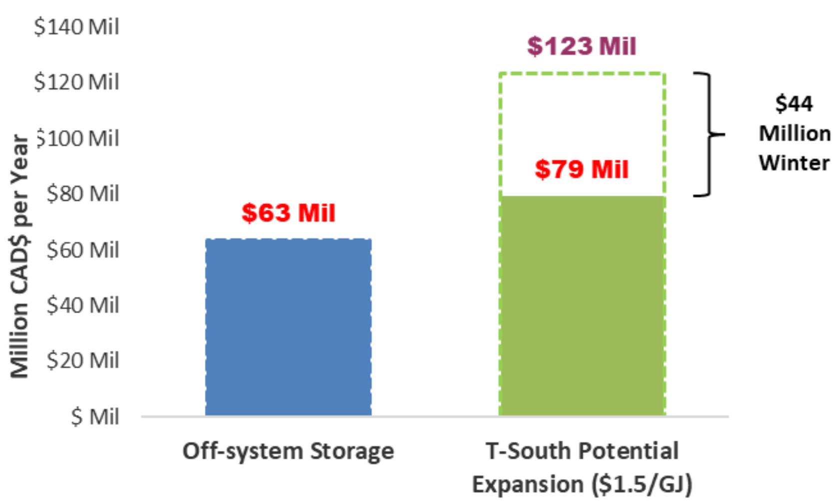
[270] Exhibit B-60, Supplemental Evidence, p. 96.

[271] Exhibit B-60, Supplemental Evidence, p. 96.

there is not enough transmission capacity to move the gas out of the Mist storage facilities, necessitating major pipeline upgrades that will increase pipeline tolls.[272]

211. FEI has estimated the annual post-mitigation cost to hold 200 MMcf/d of peaking capacity (i.e., FEI's existing 50 MMcf/d of pipeline capacity plus 150 MMcf/d to replace Tilbury LNG) on an expanded regional storage facility or pipeline to be $63 million to $79 million per year, respectively. This calculation makes the favourable assumption that FEI is entirely successful in reselling underutilized capacity in the non-peak times, and these figures would be higher to the extent FEI is unsuccessful. The results are summarized in the following figure:[273]

Figure 4-7: Annual Cost (Post Mitigation) of Using Expanded Regional Infrastructure to Supply Equivalent of 1 Bcf, 200 MMcf/d



212. Applying the same methodology and favourable mitigation assumption, the annual post-mitigation cost just to acquire the 150 MMcf/d of replacement capacity from an expanded regional storage facility or pipeline is $46 million to $59 million per year, respectively. The results are summarized in the following figure:[274]

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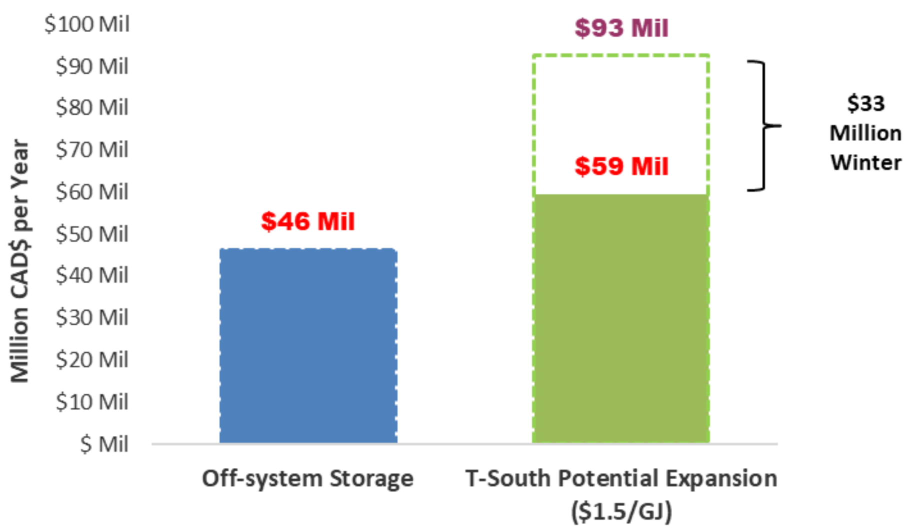
[272] Exhibit B-60, Supplemental Evidence, pp. 91-92; Exhibit B-63, BCUC IR5 131.1 and 131.9.

[273] Exhibit B-60, Supplemental Evidence, Figure 4-7 (p. 136).

[274] Exhibit B-60, Supplemental Evidence, Figure 4-8 (p. 138).

Figure 4-8: Annual Cost (Post Mitigation) of Using Expanded Regional Infrastructure to Supply Equivalent of 0.6 Bcf, 150 MMcf/d



213. FEI detailed its calculation methodology and inputs in the Supplemental Evidence.[275] At a high level, because the cost of holding capacity on regional infrastructure is driven by the expected tolls and charges, the costs will be higher than they are today by virtue of the capital costs of upgrade projects. This is notable and likely understates the post-mitigation costs because FEI only used information from "currently proposed pipeline and storage expansions to derive the cost estimates for peaking resources on expanded regional pipeline or storage infrastructure".[276] FEI submits that the calculations are well-founded based on the available information about pipeline and storage expansion capital costs and the existing tolling methodologies. The methodology used by FEI for the purposes of these calculations is similar to the one used in a confidential section 71 application recently accepted by the BCUC.[277]

214. FEI's levelized rate impact analysis that informed the selection of the Preferred Alternative (see Part Five, Section F(d) below) accounts for these toll costs by treating them as avoided costs for the Supplemental Alternatives that provide gas supply. That is, the alternatives

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[275] Exhibit B-60, Supplemental Evidence, pp. 134-138.

[276] Exhibit B-60, Supplemental Evidence, p. 135.

[277] Order G-241-24, dated September 10, 2024; Exhibit B-60, Supplemental Evidence, p. 135.

analysis properly recognizes that failing to replace the Base Plant, or sizing it so as to provide less than the required 200 MMcf/d and 1.0 Bcf of gas supply, has a significant annual gas supply cost for customers. The Supplemental Alternatives that provide 200 MMcf/d and 1.0 Bcf (i.e., FEI's full peaking supply requirement) avoid more annual gas supply costs than options that only provide 150 MMcf/d and 0.6 Bcf (i.e., only maintain the current LNG supply and leave FEI continuing to rely on its existing 50 MMcf/d of peaking supply pipeline capacity). The avoided gas supply costs associated with the incremental 50 MMcf/d and 0.4 Bcf, combined with the significant economies of scale in tank construction, means that the largest facility (the Preferred Alternative) actually has a lower levelized cost of service than some smaller facilities. It is notable that this outcome occurred despite FEI basing its levelized rate impact analysis on the lower storage costs in the figures above; using the higher pipeline costs in the figures above would improve the relative financial performance of the Preferred Alternative.

(d) Any Loss of Other Supply Resources Would Increase the Likelihood of Curtailing Firm Customers

215. All of the above analysis, which is already demonstrating a substantial risk to customers, assumes that FEI does not lose any other resources that FEI relies upon during the winter. The risk of customers being curtailed during peak demand periods would increase to the extent that FEI is unable to renew dependable market resources that it currently relies upon in the ACP to provide supply in the winter. Pipeline capacity originally intended to serve as a contingency is being used for peaking supply already.

216. For example, FEI currently holds approximately 3 Bcf of storage and approximately 110 MMcf/d of deliverability from the Mist facility, 50 percent of which could be recalled by winter 2027/28. The announced expansion of the Mist facility is expected to restore this capacity by 2029/30; however, FEI continues to be exposed to non-renewal rights on some of its other existing regional supply resources.[278] As discussed above, utilities in the Pacific Northwest who own the storage facilities have their own challenges with increasing peak load.

[278] Exhibit B-60, Supplemental Evidence, pp. 91-92.

217. FEI submits that, in this context, it is even more important to ensure that FEI has sufficient LNG to meet its actual peaking supply requirements (200 MMcf/d and 1.0 Bcf).

F. TILBURY 1A IS NOT A SOLUTION TO THE LOSS OF THE BASE PLANT

218. FEI fielded IRs about whether Tilbury 1A, a relatively new 1.0 Bcf tank with liquefaction capability, can fulfil the role currently provided by the Base Plant. It cannot, for the two reasons discussed below.

(a) The Base Plant Houses the Only Regasification Equipment at Tilbury

219. First, the Tilbury facility cannot serve any gas supply function, or any resiliency or operational support function, without regasification capacity. Regardless of how much LNG is stored at Tilbury (whether from the Base Plant or Tilbury 1A tank) these LNG volumes can only be used if they are re-gasified. The Base Plant houses the only regasification equipment at the Tilbury facility. As explained in Part Four, Section B(a), the key components of the Base Plant's regasification system are unreliable, obsolete and are difficult to maintain or repair. Once the Base Plant's regasification system is no longer in service, FEI will have no access to gas supply from Tilbury until new regasification capacity is constructed.

(b) Accessing Tilbury 1A Storage is a Temporary "Stop-Gap" Measure that Will Soon be Unavailable

220. The Supplemental Alternatives assessed by FEI included options to add new regasification capacity only, but these options were properly rejected for not being feasible (see Part Five, Section E). In any event, even if these options were feasible, adding new regasification capacity alone would not transform Tilbury 1A into a replacement source of dependable peaking gas supply. A new tank is also required.

221. Tilbury 1A was built pursuant to Direction No. 5 to the BCUC on the basis that it is to be used for serving natural gas to the transportation sector to reduce GHG emissions by using

cleaner fuels (i.e., Rate Schedule 46 LNG sales).[279] It is inconsistent with the intent of Direction No. 5 to compromise the provision of LNG service so as to provide a gas supply function.

222. The need to operate the Base Plant tank at 0.35 Bcf for seismic reasons has forced FEI to rely on 0.25 Bcf of supply from Tilbury 1A as a "stop gap" measure. The evidence demonstrates that FEI's ability to continue this practice is time-limited. FEI explained that using LNG volumes from Tilbury 1A for peaking supply has only been possible because LNG sales growth has been slower than anticipated to date due to the COVID-19 pandemic and delays in approvals for the Tilbury Marine Jetty project.[280] It is not currently interfering with LNG sales. However, FEI's updated assessment of LNG fuelling demand indicates that Rate Schedule 46 LNG sales will increase significantly and sell out Tilbury 1A as early as 2028.[281]

223. While early forecasts for LNG sales failed to materialize, the market has evolved significantly since then. There have been tangible and material developments in the marine fueling market that support FEI's updated expectations for LNG sales demand:[282]

- In Q1 2024, FEI provided Seaspan Energy Limited (Seaspan) with a *Greenhouse Gas Reduction (Clean Energy) Regulation*[283] (**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 the Tilbury Marine Jetty project, 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.

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[279] Exhibit B-60, Supplemental Evidence, p. 86.

[280] Exhibit B-60, Supplemental Evidence, p. 86 and Appendix C, p. 39.

[281] Exhibit B-60, Supplemental Evidence, pp. 86 and 115.

[282] Exhibit B-63, BCUC IR5 119.1.

[283] B.C. Reg. 102/2012.

224. The shift from sales of LNG loaded onto ISO containers towards being loaded onto ships for transport will significantly shift sales volumes. For comparison, one ISO container is 40 m^3 (1,412ft^3) while an LNG bunker vessel (fuelling ship) can range from 3,000-18,000 m^3 (105,944 – 635,664 ft^3). These larger volumes will result in a quicker drawdown of LNG volumes in Tilbury 1A.[284] The trend of increased demand has already begun. Between October 2024 (when FEI began providing LNG for marine fuel to the market) and March 2025, FEI has already provided approximately 775,000 GJ of LNG. These developments demonstrate that, as availability of LNG fueling increases, so too does demand.[285]

225. While some of the LNG in the Tilbury 1A tank could be present on a given day, the amount and timing will be unpredictable. This uncertainty is incompatible with the role that on-system LNG has always played in FEI's ACP. As described in Part Four, Section C above, LNG is used in circumstances where other resources may be unavailable, too slow or fully engaged already.

G. CONCLUSION: THE DECISION TO REPLACE THE BASE PLANT MUST BE MADE NOW

226. FEI submits that it has provided compelling evidence about the deteriorating condition of the Base Plant and its importance within FEI's gas supply portfolio. The Base Plant has reached end-of-life and needs to be replaced to ensure FEI can continue to serve firm customers reliably in normal operations. FEI already needs more peaking supply than the Base Plant can provide, and the supply resources FEI has used to fill the shortfall do not possess LNG's desirable attributes. The BCUC should find that delaying the Base Plant's replacement would pose an unacceptable reliability risk for customers that would be inconsistent with well-established ACP principles, and result in higher annual gas supply costs.

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[284] Exhibit B-60, Supplemental Evidence, Appendix C, p. 39.

[285] Exhibit B-63, BCUC IR5 119.1.

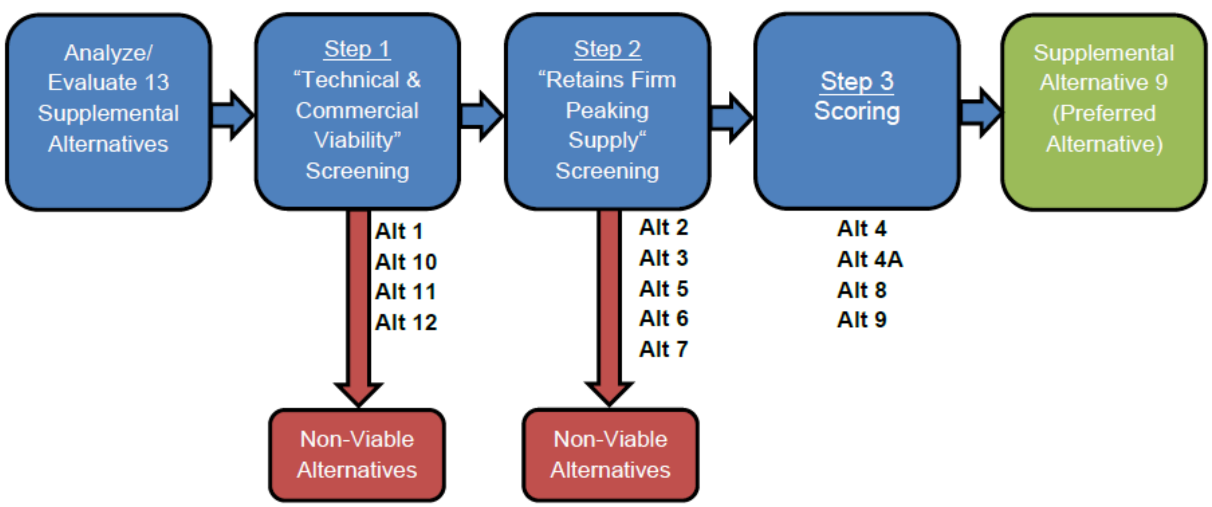
PART FIVE: SUPPLEMENTAL ALTERNATIVES ANALYSIS

A. INTRODUCTION

227. This Part explains FEI's selection of Supplemental Alternative 9 as the Preferred Alternative. Supplemental Alternative 9 involves replacing the end-of-life Base Plant with a new Tilbury facility with 800 MMcf/d of regasification capacity and a 3 Bcf tank that is allocated for planning purposes between a 2 Bcf "resiliency reserve" and 1 Bcf for gas supply.

228. The combination of the original alternatives analysis in the Application and the post-Adjournment Decision analysis has been very comprehensive. A key takeaway from the original analysis, which remains true, is that additional on-system LNG sited in the Lower Mainland is the only feasible means of mitigating the risk exposure to a winter T-South no-flow event. In response to the BCUC's commentary in the Adjournment Decision, FEI analyzed 13 "Supplemental Alternatives" using the three-step analytical framework depicted in Figure 4-19 below. These Supplemental Alternatives included all of the suggested options in the Adjournment Decision, as well as other sizes and configurations of a new LNG facility at Tilbury.

Figure 4-19: Results from Structured Process to Identify the Preferred Alternative



229. The four Supplemental Alternatives evaluated and scored at Step 3 are those that are both technically and commercially feasible, and at a minimum preserve FEI's existing peaking supply so as to avoid likely disruptions of firm service in normal operations. They differ from each

other in one or more of the following ways: (1) the amount of regasification capacity; (2) the tank size; and (3) the allocation, for planning purposes, of the tank between gas supply (i.e., performing the same role as the Base Plant has since 1971) and a “resiliency reserve” (supply that remains unused until firm customers are faced with losing service).

230. FEI submits, and the BCUC should find, that the overall alternatives analysis provides a sound basis for identifying the Preferred Alternative. Supplemental Alternative 9 will provide FEI’s customers with the greatest value among the viable alternatives and is in the public interest. In particular it:

- Provides the greatest reduction in customer outage risk among the viable alternatives;
- Provides peaking supply capabilities that maintain FEI’s Tilbury peaking supply, while giving FEI the flexibility to avoid annual gas supply costs by displacing other resources in its gas supply portfolio;
- Addresses the age-related challenges associated with the existing Base Plant;
- Compares favourably to smaller replacement facilities in terms of levelized total rate impact due to significant economies of scale and greater annual gas supply benefits (avoided costs); and
- Is likely to continue generating value for customers throughout its expected service life.

231. The subsections in this Part make the following supporting points:

- First, FEI’s pre-Adjournment Decision alternatives analysis demonstrated, among other things, that on-system LNG sited at Tilbury is the only way to mitigate the consequences of a winter T-South no-flow event.
- Second, FEI’s supplemental alternatives analysis was responsive to the Adjournment Decision, applied appropriate screens, and applied reasonable evaluation criteria and weightings to the viable options.
- Third, only the Supplemental Alternatives providing both new regasification and storage at Tilbury were technically and commercially feasible.
- Fourth, options that would leave FEI without its required peaking supply were unacceptable as they would likely result in curtailments in normal operations.

- Fifth, among the four remaining Supplemental Alternatives scored at Step 3, Supplemental Alternative 9 delivers on the Project objectives in a way that provides superior customer value.

B. FEI'S PRE-ADJOURNMENT ALTERNATIVES ANALYSIS IDENTIFIED ON-SYSTEM LNG AS THE ONLY FEASIBLE APPROACH TO MITIGATING CUSTOMER OUTAGE RISK

232. Parts Four and Five of FEI's Pre-Adjournment Final Submissions addressed FEI's original alternatives analysis in detail. Notably, FEI's pre-adjournment analysis demonstrated the following points, which remain relevant:

- A widespread and lengthy customer outage would currently be unavoidable following a T-South winter no-flow event;
- FEI requires more on-system LNG in the Lower Mainland to be able to withstand a winter T-South no-flow event. The customer outage could not be avoided or lessened by additional load management approaches (AMI was already reflected in the analysis), off-system storage, or any of the four different regional pipeline solutions including an SCP expansion; and
- Tilbury was the only feasible site for new on-system LNG.

233. FEI also assessed different tank sizing and regasification capacities at Tilbury that could support Lower Mainland load for at least three days during the winter, given (among other considerations) the duration of the 2018 T-South Incident and industry statistics on pipeline outage durations. FEI identified a replacement facility with 800 MMcf/d of regasification and a 3 Bcf tank as achieving that objective in the most cost-effective manner.[286] While the pre-adjournment sizing analysis remains valid, it has largely been replaced by the more expansive and detailed analysis in the Supplemental Evidence.

C. SUPPLEMENTAL ALTERNATIVES ANALYSIS WAS COMPREHENSIVE, RESPONSIVE AND REASONABLE

234. Section 4 and Appendix C of the Supplemental Evidence provides FEI's supplemental alternatives analysis methodology and results. The BCUC should find, for the reasons described below, that FEI's supplemental alternatives analysis was comprehensive, responsive to the

[286] See Exhibit B-1-4, Application, Section 4.

Adjournment Decision, applied appropriate screens, and used reasonable evaluation criteria and weightings on the viable options.

(a) Notable Features of the Supplemental Alternatives Analysis

235. The following five features of the supplemental alternatives analysis highlight the rigour applied.

FEI Addressed the BCUC's Commentary

236. First, FEI designed the supplemental alternatives analysis to address the BCUC's commentary in the Adjournment Decision, including the recommendations to:

- Evaluate additional non-Tilbury options;
- Evaluate the Supplemental Alternatives against broader criteria of costs and benefits (i.e., considering alternatives that provide varying degrees of resiliency);[287]
- Consider that, despite LNG being allocated for planning purposes to gas supply and LNG for transportation, it may nonetheless be available on the day of a winter no-flow event;[288] and
- Consider how potential future developments, such as changes in load, might impact the overall analysis.[289]

237. FEI's Supplemental Evidence included a concordance that identified how and where FEI addressed the BCUC's commentary.[290]

FEI Examined Many Options to Provide Capacity and Energy

238. Second, FEI cast a wide net when identifying potential options to evaluate. The 13 Supplemental Alternatives included: (1) the non-Tilbury options identified by the BCUC in the Adjournment Decision; (2) options that involved grafting new regasification equipment onto the

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[287] Adjournment Decision, p. 25.

[288] In the response to the BCUC IR5 27 series (Exhibit B-63), FEI explained why it did not undertake additional contingent analyses for Supplemental Alternatives 6-9, but provided these additional analyses.

[289] Adjournment Decision, pp. 39-40.

[290] Exhibit B-60, Supplemental Evidence, Appendix B.

existing Tilbury tank facilities; and (3) replacement facilities with various regasification capacities, tank sizes and tank allocations between gas supply and a "resiliency reserve". FEI also provided further explanation of why an SCP expansion is not technically capable of performing the resiliency role met by on-system LNG. The Supplemental Alternatives, and the evidence on SCP, are summarized in Part Five, Section C(b) immediately below.

239. The various regasification capabilities, tank sizes and tank allocations among Supplemental Alternatives determine the amount of **capacity** and **energy** available. Capacity and energy are different attributes, and both are critical in the context of resiliency and gas supply. In this context:

- **Capacity** refers to the physical ability to deliver enough supply to meet FEI's daily Lower Mainland load (measured in MMcf/d). The capacity provided by an LNG storage facility refers to the capability of regasification equipment to convert stored LNG back into gas for use by customers.[291] Any capacity shortfall will manifest in FEI being unable to serve a corresponding portion of its customer load in normal operations or on Day 1 of a no-flow event; and

- **Energy** refers to having sufficient supply (measured in Bcf) to continue meeting daily load each day during a cold weather event in normal operations or during a supply disruption.[292] The energy provided by an LNG storage facility is a function of the volume of the storage tank. FEI needs enough peaking supply to last through a period of very cold weather (based on the temperature parameters defined in the ACP), otherwise firm customers will lose service. Following a no-flow event on T-South, any energy shortfall will similarly result in FEI running out of alternate supply to serve customers before service on T-South is restored.

240. The existing <u>capacity</u> limitation at Tilbury will dictate the outcome following a winter T-South no-flow event. That is, although the current storage volume (i.e., tank size) at Tilbury is also insufficient, the primary limiting factor currently is the regasification rate. Regardless of how much LNG is stored at Tilbury, FEI could not re-gasify it fast enough to maintain operating pressure in FEI's Coastal Transmission System in months with higher gas demand (including the entirety of the winter).[293] The storage tank size only comes into play if the regasification

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[291] Exhibit B-1-4, Application, p. 94.

[292] Exhibit B-1-4, Application, p. 94.

[293] Exhibit B-26, BCUC IR2 76.1 and 78.1.

constraint is remedied. But then the tank becomes a limiting factor; the faster rate of regasification would quickly empty the existing Base Plant tank. The capacity and energy constraints at the existing Tilbury facilities become particularly critical in winter because other alternative sources of capacity and energy are physically unavailable.

241. FEI's ACP is in place and reviewed by the BCUC annually to ensure that FEI's gas supply portfolio is adequate to maintain firm service in normal operating conditions. That means ensuring FEI has sufficient **capacity** to serve peak demand at a given point in time and has access to sufficient **energy** to serve demand consistently over a period of time. As described in Part Four, Section C above, on-system LNG is, first and foremost, a capacity resource. It provides a significant amount of capacity in peak periods, backed by sufficient stored energy to last several days. As such, the Supplemental Alternatives that provide more regasification than the Base Plant (i.e., more than 150 MMcf/d) have significant value in FEI's portfolio by displacing other costly capacity.

242. As discussed in Part Five, Section F below, the alternatives that provide the greatest benefits for customers include both increased capacity (regasification capacity) and energy (LNG storage).

FEI Performed a Full Evaluation of All 13 Supplemental Alternatives

243. Third, although FEI screened out some Supplemental Alternatives due to their technical and/or commercial infeasibility (Supplemental Alternatives 1, 10, 11 and 12) or because they would likely result in firm load curtailments in normal operations (Supplemental Alternatives 2, 3, 5, 6 and 7), FEI still performed a full Step 3 assessment for completeness. Section 4 of the Supplemental Evidence focuses on the four options that passed both screens (Supplemental Alternatives 4, 4A, 8 and 9), while the detailed analysis for all 13 Supplemental Alternatives is in the 120-page Appendix C.[294]

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[294] Exhibit B-60, Supplemental Evidence, Appendix C.

Independent Experts Played a Prominent Role in the Analysis

244. Fourth, the Step 3 scoring analysis for the Supplemental Alternatives reflected input from independent experts. Exponent calculated the risk mitigation provided by each option. FEI involved experts when updating the capital cost estimates for options.[295] An independent expert also validated FEI's determination that floating LNG is not feasible.[296] The scoring regarding long-term stranding risk was informed, in part, by the opinion of Mr. Mason, an expert in the regional gas market.[297]

FEI Evaluated "Planning" (Dependable) and "Contingent" (Non-Dependable) Scenarios

245. Fifth, the assessment of customer outage risk reduction accounted for both "planning" and "contingent" scenarios, given the BCUC's commentary about LNG potentially being present on the day of a no-flow event even if it is intended to be used for other purposes.

246. The **"planning"** view treats stored LNG as being available on a dependable basis, which requires that it be allocated to a single planned purpose (e.g., only resiliency, gas supply or LNG for transportation). The "planning" approach is generally accepted practice for gas supply, reflected in FEI's ACPs that contemplates securing dependable gas supply to meet load specified temperature conditions.[298] It recognizes that it is not possible to depend on supply (in this case, LNG) being present for any purpose if it is allocated or planned for multiple purposes. In the alternatives analysis, a "resiliency reserve" represents LNG dedicated to resiliency so that it is dependable, while the gas supply allocation in the tank is dependable peaking supply accounted for in FEI's ACP.

247. The **"contingent"** scenarios assume that LNG at Tilbury allocated for planning purposes to gas supply and Rate Schedule 46 LNG sales (as applicable) is nonetheless present on the day of a winter no-flow event. As discussed in Part Five, Section F below, FEI does not endorse using this approach for planning purposes because FEI cannot rely on these LNG volumes being

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[295] Exhibit B-60, Supplemental Evidence, p. 106.

[296] Exhibit B-60, Supplemental Evidence, Appendix C-1.

[297] See Part Five, Section F(e) below.

[298] Exhibit B-60, Supplemental Evidence, p. 16, Appendix C, p. 37 and Appendix F, Raymond Mason Report, p. 22.

available when they are needed. In any event, none of the contingent scenarios change the Preferred Alternative.

(b) Description of the 13 Supplemental Alternatives

248. The 13 Supplemental Alternatives fall into one of the following five categories, depending on the alternative's characteristics:[299]

- **Alternatives Reliant on Existing Facilities:** These alternatives include prolonged reliance on the Base Plant tank with no dependable resiliency reserve, declining reliability, and a high likelihood of relying on the market for some replacement gas supply.
- **New Facility with Gas Supply But No Resiliency Reserve:** These alternatives do not include a dependable resiliency reserve but provide different amounts of peaking gas supply and improved reliability.
- **New Facility with Resiliency Reserve But No Gas Supply:** These alternatives provide improved reliability, allocate the entire tank to a resiliency reserve and rely on the market to replace Tilbury's gas supply functions.
- **New Facility with Both Resiliency Reserve and Replacement of Gas Supply:** These alternatives provide improved reliability and include a tank allocation divided, for planning purposes, between a resiliency reserve and gas supply.
- **Non-Tilbury Alternatives:** These alternatives were identified by the BCUC in the Adjournment Decision that contemplate investments apart from Tilbury.

249. The table below provides summary descriptions of each of the 13 Supplemental Alternatives. More detailed descriptions, including the modelling parameters for the planning and contingent scenarios, are included in Appendix C to the Supplemental Evidence.

[299] Exhibit B-60, Supplemental Evidence, pp. 105-106.

Supp Alt #	Name	Description
		Alternatives Reliant on Existing Facilities
Alt 1	No Capital Upgrades with Optimized Liquefaction (No Resiliency Reserve)	Run the Base Plant until it is no longer usable with no resiliency reserve. Supplemental Alternative 1, which is essentially the ***status quo*/do nothing option**, represents the **baseline** against which other alternatives are assessed in Step 3. The risk associated with this option is the existing risk calculated by Exponent. There are no capital costs included in the financial analysis for this option. There are, however, significant annual gas supply costs associated with replacing the Tilbury peaking supply in the market (after a period between the Base Plant failing and a future hypothetical regional infrastructure expansion, during which firm customer curtailments are likely instead). The ability of other alternatives to avoid some or all of those annual gas supply costs is reflected in the financial analysis for those other alternatives as a financial benefit.[300]
Alt 2	New Regasification Only – 400 MMcf/d (No Resiliency Reserve)	Replace the Base Plant regasification with 400 MMcf/d of new capacity, but continue to rely on a non-refurbished Base Plant tank until it is no longer usable. There is no resiliency reserve.
Alt 3	New Regasification Only – 600 MMcf/d (No Resiliency Reserve)	Replace Base Plant regasification with 600 MMcf/d of new capacity but continue to rely on a non-refurbished Base Plant tank until it is no longer usable. There is no resiliency reserve.
		New Facility with Gas Supply But No Resiliency Reserve
Alt 4	Like-for-Like (No Resiliency Reserve)	Replace the Base Plant like-for-like to restore the 1971 design capacity (150 MMcf/d regasification and 0.6 Bcf tank) and continue using Tilbury as a supply peaking resource, without a resiliency reserve.
Alt 4A	New 1 Bcf Tank (No Resiliency Reserve) and 400 MMcf/d Regasification	Replace the Base Plant with the smallest new facility capable of providing FEI's optimum peaking gas supply, including a 1 Bcf tank and 200 MMcf/d regasification (with an additional 200 MMcf/d for redundancy). Continue using it as a supply peaking resource, without a resiliency reserve.
		New Facility with Resiliency Reserve But No Gas Supply
Alt 5	Like-for-Like (Full Resiliency Reserve)	Replace the Base Plant like-for-like to restore the 1971 design capacity (150 MMcf/d regasification and 0.6 Bcf tank) and allocate the entire tank as a resiliency reserve.
Alt 6	New 1 Bcf Tank (Full Resiliency Reserve) and 800 MMcf/d Regasification	Replace the Base Plant with a 1 Bcf tank and 800 MMcf/d regasification. Allocate the entire tank as a resiliency reserve.

[300] See Part Five, Section F(d) below.

Supp Alt #	Name	Description
Alt 7	New 2 Bcf Tank (Full Resiliency Reserve) and 800 MMcf/d Regasification	Replace the Base Plant with a 2 Bcf tank and 800 MMcf/d regasification. Allocate the entire tank as a resiliency reserve.
New Facility with Both Resiliency Reserve and Replacement of Gas Supply		
Alt 8	New 2 Bcf Tank (1.4 Bcf Resiliency Reserve) and 800 MMcf/d Regasification	Construct the smallest facility that allows FEI to both avoid curtailments of firm peak load in normal operations and provide some resiliency reserve. This includes replacing the Base Plant with a 2 Bcf tank and 800 MMcf/d regasification, of which 1.4 Bcf is allocated as a resiliency reserve, and 0.6 Bcf is allocated to replace the existing gas supply functions at Tilbury.
Alt 9	New 3 Bcf Tank (2 Bcf Resiliency Reserve) and 800 MMcf/d Regasification	Construct a facility that both significantly mitigates FEI's largest customer outage risks and meets FEI's required peaking gas supply in an optimal manner (since it no longer requires relying on year-round pipeline capacity to provide short-term peaking supply). Replace the Base Plant with a 3 Bcf tank and 800 MMcf/d regasification and allocate 2 Bcf as a resiliency reserve, and 1 Bcf to gas supply.
Non-Tilbury Alternatives		
Alt 10	Alt 1 plus VITS Reverse Flow	FEI would retain the existing Tilbury facilities with no capital upgrades (i.e., Supplemental Alternative 1). FEI would also construct the necessary facilities to allow significant reverse flows on the Vancouver Island Transmission System (VITS) at all times during the year, such that the combined daily delivery is at least 550 MMcf/d.
Alt 11	LNG from Woodfibre LNG	Use the existing Tilbury facilities with no capital upgrades (i.e., Supplemental Alternative 1). FEI would also contract with Woodfibre LNG for a long-term firm supply of LNG.
Alt 12	Floating LNG	Purchase a vessel to provide floating LNG storage. Acquire a water lot that would allow for permanent mooring. Add more regasification capacity, either as an integrated component of the LNG storage vessel or on the adjacent shoreline. Construct onshore facilities, including a jetty and interconnecting pipe.

Additional Evidence on Why a New Pipeline Project Cannot Prevent a Customer Outage

250. In the Adjournment Decision,[301] the BCUC indicated that it was unable to make any findings regarding the ability of FEI's Regional Gas Supply Diversity (RGSD) Project to address the resiliency need. As explained in Section 5.6.3 of Appendix C to the Supplemental Evidence, FEI has ceased development of the RGSD Project, but has not foreclosed participating with others in

[301] Adjournment Decision, p. 25.

a similar pipeline project.[302] As such, FEI's Supplemental Evidence included more explanation about why any SCP expansion would be incapable of preventing the Lower Mainland system from depressurizing on the first day of a winter T-South no-flow event.

251. In short, it would take too long for FEI to get sufficient gas from the SCP to restore pressure in FEI's Lower Mainland system. It would take approximately two days for FEI to be able to deliver supply through an SCP extension to the Lower Mainland because pipeline supply is scheduled the day before current day delivery, and the evidence shows that the Lower Mainland system will depressurize well before the supply arrives.[303] By contrast, FEI is able to deploy on-system LNG on very short notice.[304] An SCP expansion could provide additional resiliency against a winter T-South no-flow event only if sufficient on-system LNG is first constructed at Tilbury to maintain pressure until FEI could access more pipeline supply from SCP.[305]

252. From a gas portfolio standpoint, an SCP extension could provide year-round energy that would be a like-for-like substitute for FEI's existing long-duration pipeline capacity on T-South. Pipeline capacity is sub-optimal as a source of peaking supply. As described in Part Four, Section C of these submissions, pipeline capacity does not share the attributes that make LNG ideally suited for peaking supply, notably the ability to respond on very short notice (two hours[306] vs. two days). Moreover, paying for year-round pipeline capacity for peak load that only materializes a few days a year is inefficient and best avoided.[307]

253. In FEI's submission, the BCUC should find that, were an SCP expansion to take place in the future, it would not meet the Project need. It would be complementary to, but not a substitute for, the TLSE Project.

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302 Exhibit B-60, Supplemental Evidence, p. 124.

303 Exhibit B-60, Supplemental Evidence, Appendix C, p. 123.

304 Exhibit B-60, Supplemental Evidence, Appendix C, p. 123.

305 Exhibit B-60, Supplemental Evidence, Appendix C, p. 123.

306 Exhibit B-1-4, Application, p. 129 and Exhibit B-15 BCUC IR1 34.1; see also Exhibit B-60, Supplemental Evidence, p. 68 and Appendix F, Raymond Mason Report, p. 23.

307 Exhibit B-60, Supplemental Evidence, Appendix C, p. 124.

(c) The Three-Step Alternatives Analysis Framework Was Reasonable

254. As shown in Figure 4-19 in the introduction to this Part, FEI's structured three-step process involved evaluating all 13 Supplemental Alternatives, and then: (1) determining which alternatives were technically and commercially viable; (2) determining whether the alternative at least retained FEI's current ability to serve firm customers in normal operations;[308] and (3) scoring the alternatives that met those screens against the set of five weighted criteria used to determine the preferred alternative.[309] FEI summarizes the methodology behind each step below, and explains why the evaluation criteria at each step are appropriate.

Step 1: FEI Eliminated Technically and Commercially Non-Viable Alternatives

255. After evaluating all 13 Supplemental Alternatives, FEI screened out non-viable Supplemental Alternatives by considering the balance of technical and commercial challenges associated with each alternative and then considered the associated viability holistically.[310] The technical and commercial viability of the Supplemental Alternatives is a necessary threshold consideration, as it would not be in the interest of customers if FEI were to propose projects it could not develop. Screening for feasibility is explicitly referenced in the BCUC's CPCN Guidelines.[311]

Step 2: FEI Eliminated Alternatives That Do Not Retain FEI's Existing Firm Peaking Gas Supply

256. At Step 2, FEI screened out Supplemental Alternatives that would not retain FEI's existing firm peaking gas supply capabilities. Specifically, FEI limited the screening to the following parameters: (1) the Supplemental Alternative removes FEI's existing on-system peaking resource without replacement; or (2) the Supplemental Alternative relies on a resource that is expected to be unavailable in the future due to market conditions (e.g., no capacity available on pipelines

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308 Exhibit B-60, Supplemental Evidence, pp. 106-107.

309 As noted above, for completeness and to be full responsive to the Adjournment Decision, FEI also completed detailed analysis and scoring for the Supplemental Alternatives that would retain its existing on-system firm peaking gas supply capabilities: see Exhibit B-60, Supplemental Evidence, Appendix C.

310 Exhibit B-60, Supplemental Evidence, p. 107.

311 BCUC CPCN Guidelines, Section 2(i).

or regional storage) or aging FEI infrastructure.[312] In both cases, firm customers would likely experience curtailments in normal operations.

257. FEI submits that this screen was appropriate, given the evidence described in Part Four above. Specifically, given the winter-peaking load profile, FEI needs peaking supply to ensure that firm customers receive reliable service. FEI will not be able to rely on the Base Plant for peaking supply much longer given its end-of-life condition and there are currently no available substitutes in the market to replace the associated capacity and energy.[313] Simply put, FEI's firm customers would likely face service disruptions in normal operations during the coldest times of the year without a new facility that: (i) has at least 150 MMcf/d of regasification capacity and 0.6 Bcf of energy at Tilbury (supplementing FEI's existing 50 MMcf/d of pipeline peaking supply); and (ii) makes that amount of capacity and energy available for the provision of dependable peaking gas supply in the ACP.[314] FEI submits that it is unacceptable to expose firm customers – who have long been able to count on service in cold periods – to the risk of curtailment in normal operations.

Step 3: FEI Scored the Four Viable Alternatives Relative to the Base Plant (No Capital Upgrades)

258. Step 3 involved scoring the Supplemental Alternatives that passed the Step 1 and 2 screens to select a preferred alternative. FEI submits that the evaluation criteria, and the weighting assigned to each criterion, provide a transparent and appropriate basis for identifying the preferred alternative.

259. In essence, FEI scored the viable Supplemental Alternatives against five evaluation criteria. FEI selected these criteria to reflect, in particular, the objectives driving the Project need discussed in Parts Three and Four above, the total anticipated rate impacts, and potential for the energy transition to affect the appropriate sizing of the TLSE Project (as raised by the BCUC in the

[312] Exhibit B-60, Supplemental Evidence, p. 108.

[313] Exhibit B-60, Supplemental Evidence, p. 108.

[314] Exhibit B-60, Supplemental Evidence, pp. 107-108.

Adjournment Decision).[315, 316] Each criterion had a well-defined evaluation metric to facilitate comparison. FEI assessed the impact the Supplemental Alternatives would have on each evaluation criteria, assigning an impact score (e.g., medium positive impact) and corresponding un-weighted numerical score (e.g., +3) relative to Supplemental Alternative 1 (i.e., continuing to operate the end-of-life Tilbury Base Plant).[317] FEI multiplied these un-weighted numerical scores by the percentage weighting assigned to each criterion.[318] The weighting assigned to each criterion reflected its relative importance based on a qualitative review undertaken by FEI's Subject Matter Leads. The Supplemental Alternative with the highest total weighted numerical score was the preferred alternative.

260. The table below[319] summarizes each criterion, the evaluation metric and the weighting applied to each criterion:

Evaluation Criterion	Evaluation Metric[320]	Weighting[321]
Resiliency Benefit (Resiliency)	This criterion evaluated the Supplemental Alternative's ability to mitigate the risk associated with a winter T-South no-flow event. The evaluation was based on the quantitative risk assessment performed by Exponent that considered various winter temperature conditions and the results of FEI's system modelling.[322]	30%
Availability of Dependable Gas Supply During Peak Demand (Gas Supply)	This criterion qualitatively evaluated the Supplemental Alternative's impact on the availability of dependable gas supply during peak demand conditions.[323]	20%

315 Adjournment Decision, pp. 22 and 52.

316 Due to the broad similarities in the viable alternatives (i.e., all involve on 1 -system LNG at Tilbury), FEI excluded some criteria that FEI typically considers, such as constructability, from this evaluation. Environmental considerations are reflected in the "Base Plant Challenges" criterion: Exhibit B-60, Supplemental Evidence, p. 110.

317 See Table 4-2 of the Supplemental Evidence which shows the scoring system used to score the viable Supplemental Alternatives (Exhibit B-60).

318 Exhibit B-60, Supplemental Evidence, pp. 109 and 112.

319 FEI prepared this table for its Post-Adjournment Final Submissions by compiling information from various evidence, as footnoted.

320 The Supplemental Alternatives were compared relative to retaining the existing Base Plant in its current state with no capital upgrades (Supplemental Alternative 1).

321 Exhibit B-60, Supplemental Evidence, pp. 111-112.

322 Exhibit B-60, Supplemental Evidence, pp. 109-110 and 117.

323 Exhibit B-60, Supplemental Evidence, pp. 109-110.

Evaluation Criterion	Evaluation Metric[320]	Weighting[321]
Resolves Age Related Base Plant Challenges (Base Plant Challenges)	This criterion qualitatively evaluated the Supplemental Alternative's impact on the age-related Base Plant challenges that are preventing it from reliably performing its critical gas supply function, as discussed in Part Four above.[324]	20%
Levelized Total Rate Impact (Rate Impact)	This criterion evaluated the levelized total rate impact of the Supplemental Alternative over a 67-year analysis period, including: [325] • The impact to FEI's delivery rates due to the associated capital and operating costs; and • The impact to FEI's cost of gas rates (which include both commodity and midstream costs) due to the associated incremental gas supply costs/benefits to FEI's customers. The 67-year analysis period is used for the financial analysis to cover the 60-year expected useful life of the assets pertaining to all alternatives, plus seven prior years from 2024 to a 2030 in-service date.[326]	20%
Useful Under the Modified Diversified Energy (Planning) Scenario (mDEP 2% and 5%) Between the In-Service Date and 2050 (Future Use)	This criterion qualitatively evaluated if the Supplemental Alternative will be useful for FEI's own resiliency and gas supply portfolio (the latter use being either to serve load or generate mitigation revenue), and its potential to be underutilized based on two hypothetical adverse future load sensitivities. This criterion is responsive to the BCUC's commentary in the Adjournment Decision around future stranding risk.[327] The adverse sensitivities, "mDEP 2% and 5%", use FEI's 2022 LTGRP Diversified Energy (Planning) Scenario (DEP Scenario) as a base case, with modifications to assume higher rates of customer and load loss (2% and 5% annually) between the in-service date and 2050.[328] See Part Five, Section F(e) below for why these represent very adverse scenarios.	10%

[324] Exhibit B-60, Supplemental Evidence, pp. 109-110 and 129.

[325] Exhibit B-60, Supplemental Evidence, pp. 109-111 and 129.

[326] Exhibit B-60, Supplemental Evidence, p. 199.

[327] Adjournment Decision, pp. 22 and 52.

[328] Exhibit B-60, Supplemental Evidence, pp. 109, 111 and 142.

Relative Weight of Evaluation Criteria is Reasonable

261. The IRs on the design of Step 3 focused on the selected weightings assigned to each criterion, rather than the criteria themselves. FEI submits the selected weightings are reasonable for the reasons below.

262. FEI weighted the "Resiliency Benefit" as the highest individual criterion (30 percent).[329] The higher weighting is appropriate because of the severity of the risk posed by a winter T-South no-flow event, as discussed in Part Three above. The direct consequences on customer service are very large, and the GDP losses could far exceed the cost and rate impact associated with the TLSE Project.[330] The cumulative probabilities suggest that we can expect at least one winter T-South no-flow event over the 60-year expected life of the TLSE Project. FEI submits that the current risk is unacceptable, such that a "Resiliency Benefit" should be a priority.

263. FEI's decision to weight "Gas Supply" and "Rate Impact" criteria at 20 percent each makes sense:

- In the context of having the weightings of five criteria add up to 100 percent, allocating 40 percent to these two factors signifies that they are important.
- The "Gas Supply" criterion should be weighted lower than the "Resiliency Benefit" criterion because the Step 2 screening already ensured that only those alternatives that could at least maintain FEI's existing peaking gas supply capabilities were scored in Step 3.[331] The scoring under this criterion is thus more concerned with whether the option is providing the required amount of peaking supply in an optimal manner from a portfolio design standpoint, having regard to price and risk. In particular, it compares the cost of holding more on-system LNG for required gas supply against the cost of obtaining that required peaking supply from significantly expanded pipeline or regional storage at higher tolls.
- There is no viable alternative that is cost-free for customers. FEI needs peaking supply, the Base Plant won't be able to provide it for much longer, and relying on existing and new capacity on expanded regional infrastructure for peaking supply would be very costly. Reducing the unacceptable customer outage risk will also have a cost associated with it. As such, since weightings must total 100 percent,

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329 Exhibit B-64, BCOAPO IR5 2.1, 2.2, 2.3 and 2.4.

330 See Exhibit B-60, Supplemental Evidence, Table 4-12 (p. 142).

331 Exhibit B-64, BCOAPO IR5 2.1.

elevating the weighting of the "Rate Impact" criterion at the expense of the "Resiliency Benefit" and "Gas Supply" criteria, would unduly minimize the importance of its ability to deliver on the primary drivers for the Project.[332]

- The capital cost of the viable alternatives reflects significant economies of scale, such that the cost of the smallest viable facility represents approximately 73 percent of the capital cost of the largest facility. Moreover, larger facilities are not necessarily more costly for customers over time if they provide gas supply benefits. In that context, adjusting the weightings to place even more weight on the "Rate Impact" criterion can produce inappropriate results. For example, as shown in the response to BCOAPO IR5 2.4, modifying the weightings so as to place little weight on resiliency and a high weight on the rate impact results in higher ratings for the Supplemental Alternatives with zero resiliency benefit, but with costs that are nearly as high as the Supplemental Alternatives with resiliency benefits.[333]

264. FEI assigned the "Future Use" criterion a lower weighting (10 percent) given the inherent uncertainty in forecasting future potential load loss scenarios.[334] A higher weighting would have resulted in placing more weight on something that has less certainty (i.e., FEI's future load), and less weight on two things that are certain (i.e., the significant risk facing FEI today due to a winter T-South no-flow event and the Base Plant's end-of-life as a peaking supply resource).[335]

265. Ultimately, FEI demonstrated in response to IRs that, even when the weighting of the five evaluation criteria is modified, the scoring of the Preferred Alternative remains the same or similar relative to other alternatives – further substantiating its selection.[336]

D. RESULTS OF STEP 1: SUPPLEMENTAL ALTERNATIVES 1, 10, 11 AND 12 ARE NOT TECHNICALLY OR COMMERCIALLY VIABLE

266. FEI investigated each of the following alternatives specifically identified by the BCUC in the Adjournment Decision and determined that each was technically or commercially non-viable.[337] FEI provided significant information regarding the evaluation of each of these

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[332] Exhibit B-64, BCOAPO IR5 2.2 and 2.3.

[333] Exhibit B-64, BCOAPO IR5 2.4.

[334] Exhibit B-64, BCOAPO IR5 2.2.

[335] Exhibit B-64, BCOAPO IR5 2.3.

[336] Exhibit B-64, BCOAPO IR5 2.3 and 2.4.

[337] Exhibit B-60, Supplemental Evidence, p. 113.

alternatives in Appendix C to the Supplemental Evidence,[338] and did not receive any information requests. FEI submits that its determination to screen out these alternatives at Step 1 was clearly reasonable and appropriate.

Supp Alt #	Name	Summary of Why Non-Viable
Alt 1	No Capital Upgrades with Optimized Liquefaction (No Resiliency Reserve)	As described in Section 5.1.1 of Appendix C to the Supplemental Evidence, Supplemental Alternative 1 assumed that FEI is able to continue relying on the existing Tilbury Base Plant tank and regasification. It also assumed that the existing Tilbury 1A liquefaction is able to replenish consumed LNG faster, so as to increase the potential for LNG to be present on the day of a no-flow event (i.e., 0.35 Bcf in the Base Plant tank and 0.4 Bcf in Tilbury 1A despite RS 46 LNG sales).[339] Continuing to rely on the Base Plant without capital upgrades is not technically viable. As discussed in Part Four above, the Tilbury Base Plant has reached its end-of-life and can no longer reliably perform its intended function.[340]
Alt 10	Alt 1 plus VITS Reverse Flow	As described in Section 5.5.1 of Appendix C to the Supplemental Evidence, Supplemental Alternative 10 would involve constructing the necessary facilities to allow FEI to reverse the flow on the VITS in winter to flow sufficient gas towards the Lower Mainland to provide a material resiliency improvement. Currently, gas can only flow westward on the VITS (i.e., from Coquitlam to Vancouver Island) during the winter.[341] This alternative is not viable for the following reasons.[342] • First, even with significant upgrades, the amount of reverse flow that is possible through the VITS is limited due to a hydraulic constraint in the Coquitlam Watershed. This constraint would be insurmountable in a reasonable amount of time due to the associated environmental and permitting challenges. • Second, this alternative would also be significantly more costly compared to Tilbury-based alternatives, as it would involve looping significant portions of FEI's VITS and completing multiple compressor station upgrades.

338 Exhibit B-60.

339 As part its analysis of this alternative, FEI determined that increased use of liquefaction would not change the consequence associated with a winter T-South no-flow event: Exhibit B-60, Supplemental Evidence, Appendix C, p. 47.

340 Exhibit B-60, Supplemental Evidence, p. 113 and Appendix C, pp. 45-52.

341 Exhibit B-60, Supplemental Evidence, Appendix C, p. 112.

342 Exhibit B-60, Supplemental Evidence, p. 113 and Appendix C, pp. 112-115.

Supp Alt #	Name	Summary of Why Non-Viable
Alt 11	LNG from Woodfibre LNG	As described in Section 5.5.2 of Appendix C to the Supplemental Evidence, Supplemental Alternative 11 would involve FEI entering into a contract with Woodfibre LNG for a long-term firm supply of LNG.[343] This alternative is not viable for the following reasons.[344] • First, the vast majority of the available Woodfibre LNG capacity is already contracted and any additional LNG storage is being inventoried to ensure customer vessels are filled on time. As such, FEI does not believe that there is any commercial arrangement that FEI could make with Woodfibre LNG that would not be extremely disadvantageous to FEI's customers given the significant uncertainty Woodfibre would be required to bear. • Second, even assuming FEI were able to contract for LNG supply from Woodfibre LNG, FEI would then need significant new infrastructure to make use of the LNG (i.e., building a custom vessel to transport to Tilbury or constricting regasification at Woodfibre) – neither of which is viable.
Alt 12	Floating LNG	As described in Section 5.5.3 of Appendix C to the Supplemental Evidence, Supplemental Alternative 12 would use floating LNG storage as an alternative to the TLSE Project.[345] This alternative is not viable for the following reasons. • First, FEI determined that the requirements to undertake this alternative would be so complex that it would likely be infeasible and, even if it were feasible, FEI's independent consultant concluded that it would nonetheless be very costly (without providing commensurately greater resiliency benefits). • Second, there are no appropriate sites to accommodate floating LNG storage due to issues with technical feasibility, and difficulty and uncertainty of additional regulatory approvals, including a potential environmental assessment.[346]

343 Exhibit B-60, Supplemental Evidence, Appendix C, p. 116.

344 Exhibit B-60, Supplemental Evidence, Appendix C, pp. 116-119.

345 Exhibit B-60, Supplemental Evidence, Appendix C, p. 120.

346 Exhibit B-60, Supplemental Evidence, Appendix C, pp. 119-122 and Appendix C-1.

E. RESULTS OF STEP 2: SUPPLEMENTAL ALTERNATIVES 2, 3, 5, 6 AND 7 WOULD LIKELY RESULT IN FIRM CUSTOMER CURTAILMENTS IN NORMAL OPERATIONS

267. As described in Part Five, Section C(c) above, Step 2 involved screening out Supplemental Alternatives that would not, at a minimum, retain FEI's existing firm peaking gas supply capabilities. Among the technically and commercially viable alternatives, Supplemental Alternatives 2, 3, 5, 6 and 7 would result in FEI losing existing firm gas supply capabilities, thus creating a high risk of material firm load curtailments in normal operations during peak winter periods.[347] FEI describes below why these alternatives would result in FEI losing existing firm gas supply capabilities.

(a) Adding Regasification Capacity Alone Does Not Address the Loss in Dependable Gas Supply

268. Supplemental Alternatives 2 and 3 fail to maintain FEI's peaking supply because they only add new regasification facilities (400 or 600 MMcf/d, respectively). Regardless of the amount of new regasification capacity these alternatives would provide, FEI's continued reliance on the Tilbury Base Plant tank would leave FEI with less than 0.6 Bcf of dependable peaking gas supply:[348]

- First, FEI can only maintain its current peaking supply capabilities if the Base Plant remains in operation at its current capacity, which is in doubt. As explained in Part Four above, FEI already operates the Base Plant tank well-below its design capabilities for seismic reasons inherent to its design. Experts have advised against tank retrofits to restore it to 0.6 Bcf and have raised the possibility that the operating levels will need to be further reduced.
- Second, FEI's ability to rely on 0.25 Bcf of LNG from Tilbury 1A storage as a stop-gap measure is time limited. There is objective evidence to support RS 46 sales significantly increasing such that Tilbury 1A will be sold out for its intended purpose by 2028 (see Part Four, Section F above).

269. FEI would not have a back-up option to obtain dependable peaking supply in the regional market, for the reasons described in Part Four, Section E above.

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[347] Exhibit B-60, Supplemental Evidence, Table 4-6 (p. 114).

[348] Exhibit B-60, Supplemental Evidence, pp. 86, 115 and Appendix C, p. 63; Exhibit B-63, BCUC IR5 119.1.

(b) Alternatives with 100 Percent Resiliency Reserve Fail to Retain Gas Supply

270. Although Supplemental Alternatives 5, 6, and 7 all involve replacing the existing Tilbury Base Plant with a new storage tank and regasification, they did not pass the Step 2 screen because of the way the tank is allocated for planning purposes. In both cases, the entirely of the tank is set aside as a resiliency reserve, leaving no LNG available for gas supply in normal operations. While these alternatives would potentially reduce the risk exposure to a T-South winter no-flow event and would address reliability considerations and age-related issues with the Base Plant, they would also leave FEI entirely reliant on the market for its peaking gas supply. As discussed in Part Four, Section E above, there is no longer capacity available on regional infrastructure, meaning that FEI would be unable to provide dependable firm service in peak winter periods.[349]

F. RESULTS OF STEP 3: SUPPLEMENTAL ALTERNATIVE 9 WILL PROVIDE SUPERIOR OVERALL CUSTOMER VALUE

271. The results of the Step 3 analysis demonstrate that Supplemental Alternative 9 will provide superior overall customer value and is the Preferred Alternative, having regard to the five evaluation criteria. As shown in the table below, Supplemental Alternative 9 scored the highest.[350]

[349] Exhibit B-60, Supplemental Evidence, p. 116.

[350] Exhibit B-60, Supplemental Evidence, Table 4-16, p. 160. See also Appendix C, Figure C-2 for the scoring of all technically and commercially viable alternatives.

Table 4-16: Step 3 Scoring Results

Evaluation Criterion	Criterion Weightin	Alternative 4	Alternative 4A	Alternative 8	Alternative 9
Resiliency Benefit	30%	No Impact	No Impact	Medium Positive Impact	High Positive Impact
Availability of Dependable Gas Supply During Peak Demand	20%	Medium Positive Impact	High Positive Impact	Medium Positive Impact	High Positive Impact
Resolves Age Related Base Plant Challenges	20%	High Positive Impact	High Positive Impact	High Positive Impact	High Positive Impact
Levelized Total Rate Impact	20%	Low Negative Impact	Low Negative Impact	Medium Negative Impact	Medium Negative Impact
Useful Under the Modified Diversified Energy (Planning) Scenario (mDEP) Between the In-Service Date and 2050	10%	No Impact	No Impact	No Impact	No Impact
	Total Weighted Score:	1.4	1.8	1.9	2.9
					Preferred

272. There is considerable evidence on the record, including a significant amount of detailed analysis from independent experts, to support FEI's scoring. FEI addresses each evaluation criterion in the subsections below, focusing on specific issues raised in IRs.

273. As noted in Part Two, Section C above, the scoring results reflect that all four viable Supplemental Alternatives address reliability issues with the Base Plant (as they are replacement facilities) and have similar prospects of being used well into the future. The key differences among them are the results for the other three criteria, which are driven by two factors:

1. Whether or not the facility is sized to reduce the customer outage risk posed by a winter T-South no-flow event to as-low-as-reasonably-practicable at average winter temperatures or colder; and

2. Whether the facility only maintains Tilbury's undersized gas supply capabilities (150 MMcf/d and 0.6 Bcf), or whether those capabilities are increased to meet FEI's full peaking supply requirements (200 MMcf/d and 1.0 Bcf) in a more optimal way than is done today.[351]

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[351] As described in Part Four, Section D, FEI must currently augment the 150 MMcf/d and 0.6 Bcf from Tilbury with 50 MMcf/d of year-round pipeline capacity and non-dependable peaking call options to achieve its required peaking gas supply.

274. As will be seen from the discussion of each criterion below, Supplemental Alternative 9 delivers the most value because: (1) customers will benefit from the maximum customer outage risk reduction practicable; and (2) the facility will meet FEI's full peaking supply requirements with LNG instead of a sub-optimal mix of resources with less-responsiveness, higher costs and less dependability.

(a) Criterion #1: Preferred Alternative Provides Superior Winter T-South No-Flow Event Risk Mitigation

275. As demonstrated in Part Three above, the risk of a winter T-South no-flow event is sufficiently high to warrant being considered unacceptable and requiring mitigation. The question then for the BCUC is how much risk is tolerable, as each of these four Supplemental Alternatives provides varying degrees of risk reduction. As discussed below, FEI's assessment of the relative resiliency benefits is based on multiple quantitative risk analyses performed by Exponent using varying parameters. Supplemental Alternative 9 provides significant risk mitigation, superior to the other three Step 3 alternatives. It was the only alternative to merit a "High Positive Impact" for the "Resiliency Benefit" criterion.

276. The IRs regarding the Resiliency Benefit criterion focused on a few discrete areas, which are addressed in turn below.

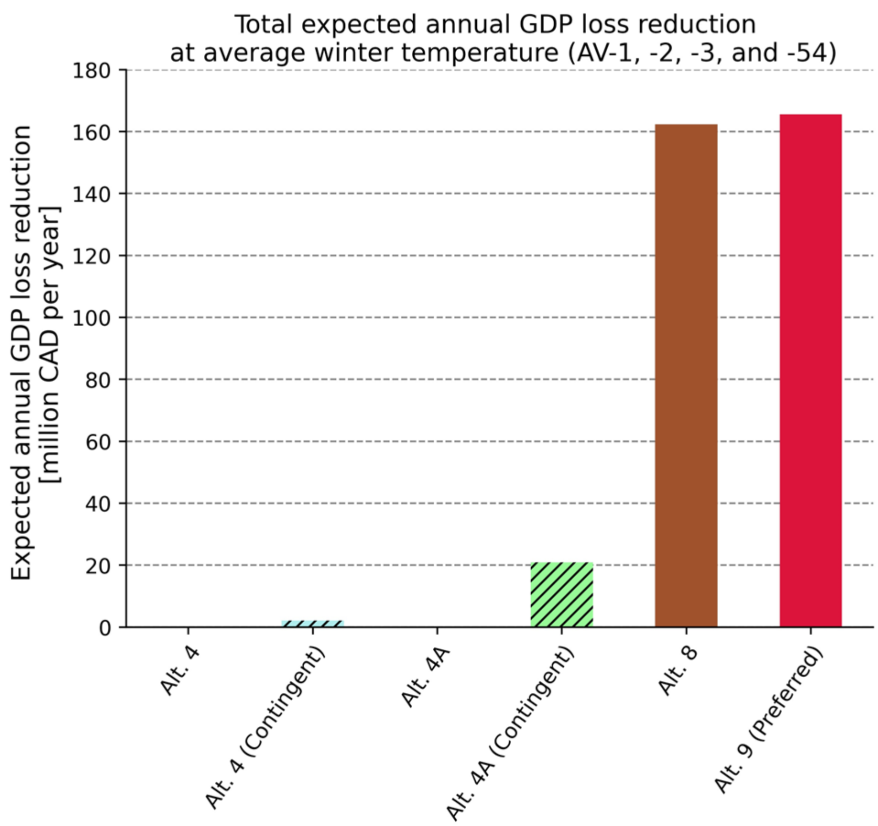
Only Supplemental Alternatives 8 and 9 Are Large Enough to Provide Significant Risk Mitigation at Average Winter Temperature

277. Exponent conducted expected loss analyses at different temperatures, since demand increases with colder temperatures and (other things being equal) shortens the load support duration. Exponent's first analysis was at average winter temperature in the Lower Mainland (+4°C), and only Supplemental Alternatives 8 and 9 provide significant risk mitigation at this temperature.

278. The figure below shows the annual expected GDP loss reduction associated with Supplemental Alternatives 4, 4A, 8 and 9 relative to Supplemental Alternative 1 (a planning

scenario that involves no capital upgrades), at average winter temperature (+4°C).[352] Supplemental Alternatives 4 and 4A, the two alternatives that are intended primarily to provide gas supply, barely move the needle on risk and, as such, the residual risk exposure remains unacceptable. Supplemental Alternatives 8 and 9, which are intended to address both Project needs (gas supply and resiliency), provide material risk mitigation at +4°C.

Figure 4-2: T-South at Average Winter – Expected Annual Loss Reduction



Supplemental Alternative 9 Distinguishes Itself at Below Average Temperatures

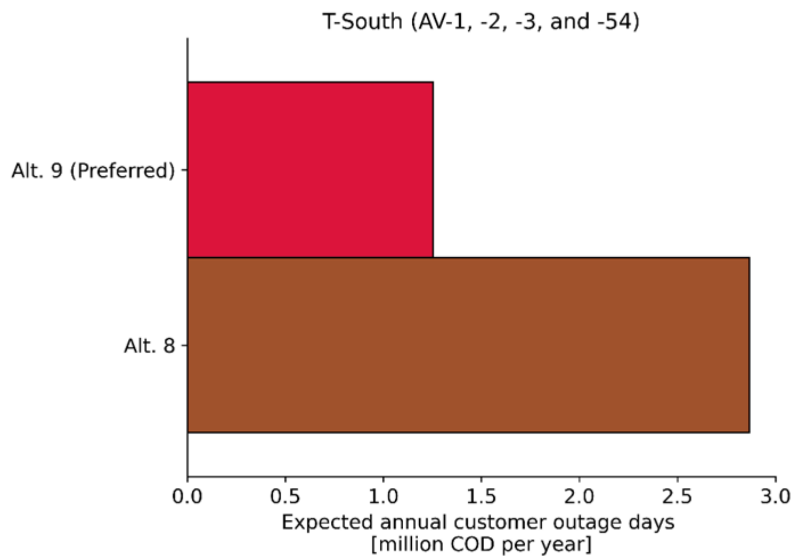
279. Supplemental Alternatives 8 and 9 provide different risk mitigation at below average winter temperatures – which historically have occurred for a quarter of the winter period. Supplemental Alternative 9 provides materially greater risk mitigation.[353] This is evident in the

352 Exhibit B-60, Supplemental Evidence, p. 119.

353 For the purposes of the cold weather analyses, FEI simplified the assumptions to focus only on the Lower Mainland; Exhibit B-60, Supplemental Evidence, p. 121.

figure below produced by Exponent, which shows the expected annual risk calculations in terms of customer-outage-days assuming a temperature condition of -1.4°C.[354]

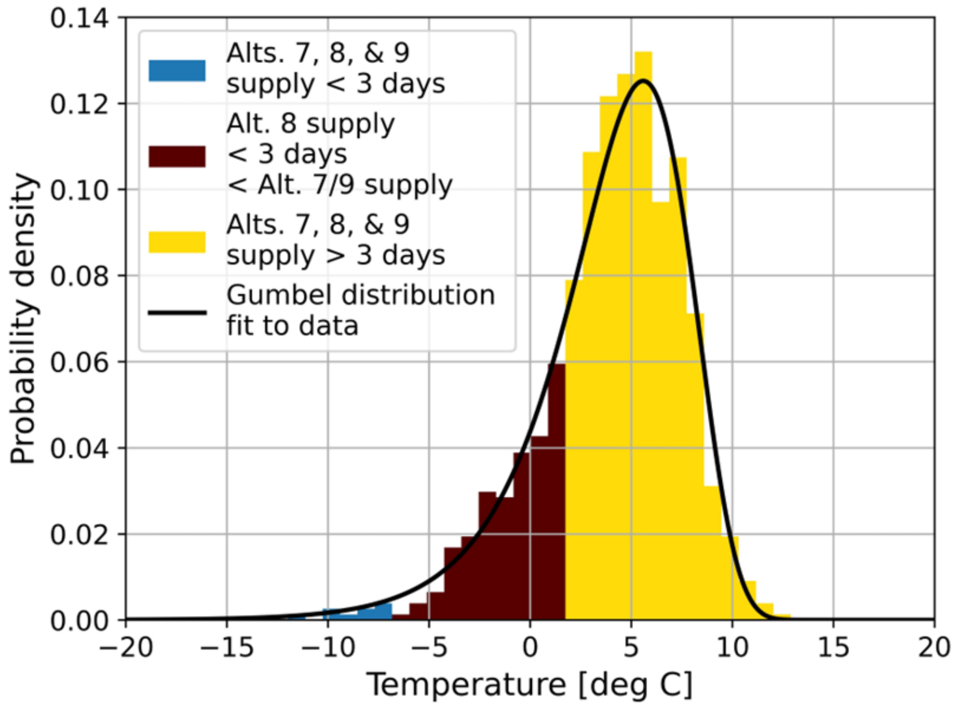
Figure 4-3: Expected Annual Winter-only Customer Outage Days Loss for Different Supplemental Alternatives for T-South (AV-1, -2, -3, and -54) at -1.4°C



280. In addition to the fixed (-1.4°C) colder temperature analysis above, Exponent also considered the load support duration of Supplemental Alternatives 8 and 9 as a function of temperature based on historical daily average temperature data. The results of this variable temperature analysis again demonstrate that Supplemental Alternative 9 provides superior risk mitigation in colder weather temperatures. As shown in the burgundy portion of the figure produced by Exponent below, the load support duration provided by Supplemental Alternative 9 exceeds three days between -6.8°C and +1.7°C, whereas Supplemental Alternative 8 does not. Nearly a quarter of winter days fall in the range in which Alternatives 7 and 9 (Preferred) can bridge a 3-day no-flow period but Alternative 8 cannot.

[354] Exhibit B-60, Supplemental Evidence, Figure 4-3 (p. 121).

Figure 4-5: Distribution of Average Daily Winter (December through February) Temperature in the Lower Mainland (Vancouver Airport) between January 2013 and December 2022



Factors Driving Supplemental Alternative 9's Superior Resiliency Benefit

281. Several factors drive the superior resiliency benefits provided by Supplemental Alternative 9 relative to the other three options:

- **Addresses Regasification Constraint:** The 800 MMcf/d of regasification provided by Supplemental Alternative 9 addresses the existing governing regasification constraint at Tilbury. Part Three, Section C above explains why the existing amount of regasification capacity (150 MMcf/d) is insufficient; a Day 1 widespread customer outage will occur even at average winter temperatures because, at average winter temperatures, the system demand greatly exceeds 150 MMcf/d. The regasification capacity provided by Supplemental Alternative 9 is sufficient to support the Lower Mainland daily load in all but the coldest of conditions. Smaller amounts of regasification, such as those associated with Supplemental Alternatives 4 and 4A remain undersized for the Lower Mainland winter load.[355]

- **Provides Additional LNG Volume Dedicated to Resiliency:** In addition to increased regasification, Supplemental Alternative 9 also sets aside 2 Bcf of LNG storage within the 3 Bcf tank as a resiliency reserve. A resiliency reserve ensures that LNG

[355] Exhibit B-60, Supplemental Evidence, p. 125 and Appendix C, p. 29.

is available when needed, rather than hoping that LNG assigned to gas supply happens to be present on the day of a no-flow event. The other three alternatives evaluated at Step 3 either provide no resiliency reserve, or a much smaller one. Exponent confirmed that relatively few hazards are mitigated with 1 Bcf or less of LNG, even at average winter temperatures (+4°C), resulting in no improvement in resiliency for Supplemental Alternatives 4 and 4A relative to the *status quo*. Supplemental Alternative 9's additional 0.4 Bcf of resiliency reserve relative to Supplemental Alternative 8 makes a material difference at below average Lower Mainland winter temperatures. Ultimately, the longer Tilbury can serve winter load, the greater the potential to bridge a no-flow event and avoid depressurization and customer outages.[356]

- **Support Duration Bridges a 3-Day Regulatory Shutdown Period:** Supplemental Alternative 9 will bridge a 3-day regulatory shutdown period at average winter temperatures (+4°C) and colder (+1.7°C to -6.8°C), while other alternatives will not. The ability to outlast a regulator-directed shutdown is important in the risk analysis because many of the hazards identified by Exponent have a low probability of causing a simultaneous failure on <u>both</u> T-South pipelines (which run in parallel). Instead, a likely outcome of a T-South failure is that only a single line is physically damaged and the adjacent undamaged line is temporarily shut-in as a precaution by the regulator (i.e., a regulatory shutdown).[357] As explained by Exponent, being able to bridge this shutdown period is a key driver in the associated risk mitigation provided by Supplemental Alternative 9:[358]

> Larger on-system LNG volumes (such as 2 Bcf) provide enough backup supply to bridge the three-day regulatory shutdown period on AVs-1, 2, 3, 54 [T-South], and 18, which are AVs with parallel pipeline segments. Bridging the regulatory shutdown period significantly reduces losses on these AVs, except for cases in which the two parallel pipeline segments fail simultaneously.

  As discussed below, Exponent's initial analysis (reflected in the Supplemental Evidence) assumed a 3-day regulatory shutdown, but also included modelling for different and variable durations. Changing the assumed duration does not change the overall assessment of the relative scoring of the viable Supplemental Alternatives under the Resiliency Benefit criterion.

- **Provides Time to Execute a Controlled Shutdown:** Even if the duration of a no-flow event were to exceed the support duration provided by the LNG storage, Supplemental Alternative 9 will afford FEI adequate response time in most

[356] Exhibit B-60, Supplemental Evidence, p. 126 and Appendix C, pp. 29-30; Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, para. 192.

[357] Exhibit B-60, Supplemental Evidence, pp. 126-127.

[358] Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2, Exponent Report, para. 192.

> temperature conditions to enable a controlled shutdown of the Lower Mainland system. This means avoiding an uncontrolled depressurization and the associated safety risks, while also allowing customers, governments and social/health services time to prepare if temperatures are around winter averages. A controlled shutdown will also reduce the number of customer outage days and therefore the associated GDP losses. Other alternatives would not provide this ability in below average temperatures, which represents a significant portion of the winter.[359]

Temperature Assumptions Reflect Common Conditions in Lower Mainland

282. FEI submits that the three temperature conditions selected for FEI's 2024 Resiliency Plan and the Supplemental Evidence (+4°C, -1.4°C and -10.0°C) are representative of Lower Mainland historical temperatures and using them avoids overstating losses.

283. The primary temperature assumption of +4°C represents average winter temperatures (December, January, and February) over a 10-year period from 2013-2022, while the other two temperature assumptions were selected for the following reasons:[360]

- FEI selected the -1.4°C temperature condition (i.e., the warmest winter in the last 10-14 years) as a sensitivity to demonstrate the results in years where the Lower Mainland experiences a mild winter.

- FEI selected the -10.0°C temperature condition to represent the range of winter temperature conditions that can occur in the Lower Mainland. In particular, 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 until the tank is depleted. This temperature mirrored an event that occurred in December 2022.[361]

284. FEI designs its system in the normal course based on a colder design degree day (DDD) temperature (i.e., the coldest day that is statistically likely to occur only once in any given 20-year period, -12.2°C in the Lower Mainland). FEI determined that using warmer temperatures was appropriate for the 2024 Resiliency Plan and the assessment of the relative Resiliency Benefit of various alternatives because DDD temperatures were unlikely to occur at the same time as a T-South no-flow event. The three selected temperature conditions are representative of the conditions T-South winter no-flow risk events are more likely to occur under based on actual

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[359] Exhibit B-60, Supplemental Evidence, p. 127; Exhibit B-63, BCUC IR5 130.1. and 130.2.

[360] Exhibit B-63, BCUC IR5 128.1; see also Exhibit B-60, Supplemental Evidence, p. 171, fn. 213-215.

[361] Exhibit B-66, CEC IR5 141.4.

historical temperature data from the Lower Mainland. The conditions have also been endorsed by Exponent as reasonable[362] and FEI is not aware of any mandatory temperature requirements for resiliency planning.[363]

Assumption of 3-Day Regulatory Shutdown Period is Reasonable, But the Relative Assessment Doesn't Change if a Different Assumption is Used

285. Exponent determined that a likely outcome of a T-South failure is that only one of the two pipelines is physically damaged, and the adjacent undamaged line is shut-in as a precaution by the regulator. This is referred to as the "regulatory shutdown period", and in such cases it is the duration of the regulatory shutdown period that determines the duration of the no-flow event. Exponent needed to include an assumption in its risk modelling about the duration of a regulatory shutdown period. As described below, the evidence supports the 3-day assumption used in the Exponent Report. In any event, the relative ranking of the four Supplemental Alternatives under the Resiliency Benefit criterion remains the same under different duration assumptions.

286. At the outset, it is worth noting that the way in which Exponent used the 3-day assumption in its Report is fundamentally different from how FEI had used the 3-day assumption originally in the Application. In the Application, FEI had treated its ability to withstand a 3-day no-flow event as a specific minimum resiliency planning objective (i.e., being able to withstand and recover from a 3-day no-flow event on the T-South system) that defined Project need. In the Adjournment Decision, the BCUC had concluded that FEI had not established the objective as a "reasonable criterion" upon which to assess the Project need.[364] By contrast, in the supplemental alternatives analysis the need is driven by a risk assessment that is unaffected by the duration of the regulatory shut down (i.e., we know the system will depressurize before it even becomes an issue). The duration of the regulatory shutdown period now only relates to one factor in the alternatives analysis, and it is only one input among many in Exponent's calculation of relative

362 Exhibit B-63, BCUC IR5 128.1.1.

363 This is 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: Exhibit B-63, BCUC IR5 128.1.

364 Adjournment Decision, p. 50.

risk mitigation. FEI submits this is entirely appropriate, and consistent with the Adjournment Decision.

287. While, in practice, the regulatory shutdown period may be longer or shorter than the assumed 3-days, the evidence demonstrates the reasonableness of using that risk modelling input:

- First, the role of the Canadian Energy Regulator (**CER**) in approving the restart of the pipelines following an emergency event like the 2018 T-South Incident has not changed. Therefore, all else equal, the regulatory timelines for future emergency events will be similar to what occurred in 2018.[365]

- Second, FEI's actual experience from the 2018 T-South Incident supports the assumption. The 2018 T-South Incident resulted in a 2-day regulatory shutdown under very favourable conditions, including the absence of snow (because it occurred in October), the location, and the accessibility by road.[366] The CER's verification process will take longer than in 2018 if it takes Enbridge longer to assess the issue and report information to the CER, due to the event location (remoteness), weather, or if the hazard makes it more difficult for the regulator to confirm the integrity of the pipeline segment.[367] Exponent confirms that the regulatory shutdown period would be affected by such factors.[368] A 3-day regulatory shutdown thus accounts for a T-South no-flow event occurring under less favourable winter conditions.[369]

- Third, both relevant independent experts in this proceeding, JANA[370] and Exponent,[371] consider it reasonable to expect an outage duration of 3 days.[372]

288. Regardless, Exponent has conducted various other analyses reflecting different assumed regulatory shutdown periods. Even if a shorter or longer regulatory shutdown assumption is

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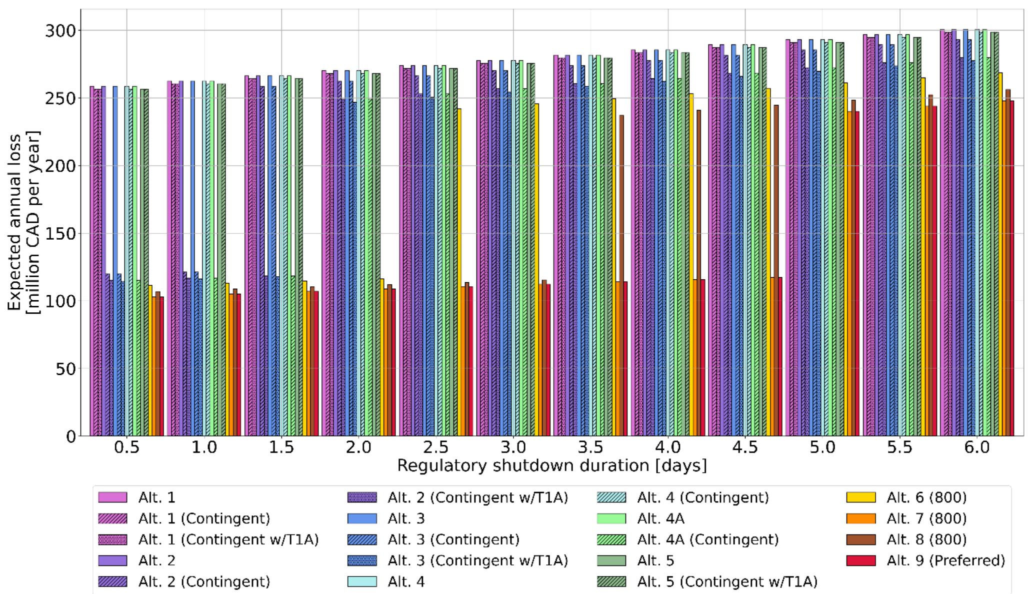
365 Exhibit B-63, BCUC IR5 120.1.
366 Exhibit B-1-3, Revised Confidential Application, p. 52.
367 Exhibit B-63, BCUC IR5 120.1 and 120.9.
368 Exhibit B-63, BCUC IR5 120.6.
369 Exhibit B-63, BCUC IR5 120.1.
370 Exhibit B-30, BCSEA IR2 13.4.
371 Exhibit B-63, BCUC IR5 120.1.
372 Exhibit B-63, BCUC IR5 120.1 and 120.3.

used, Supplemental Alternative 9 significantly reduces the risk associated with a winter T-South no-flow event and does to a greater extent than other alternatives:[373]

- **Sensitivity Analysis with Variable Durations at Average Winter Temperature:** As illustrated in the figure below, Exponent's sensitivity analysis at average winter temperature confirms that Supplemental Alternative 9 continues to significantly reduce economic (GDP) losses if the regulatory shutdown period is between 0.5 and 4.5 days. Losses increase if the regulatory shutdown duration increases to 5 or more days, as its supply duration (i.e., how long it can support firm load in the Lower Mainland) is less than 5 days. Loss reductions for the other smaller alternatives only improve with short regulatory shutdowns that are likely unrealistic for significant incidents on T-South for the reasons described above.[374]



- **Sensitivity Analysis with Variable Durations at Colder Temperatures:** Exponent also analyzed the impact of alternative winter temperatures in tandem with varying regulatory shutdown durations. The results confirm that, whether at +4°C, -1.4°C or -10°C, Supplemental Alternative 9 is consistently more effective than Supplemental Alternative 8. For example, while Supplemental Alternatives 8 and 9 provide similar mitigation at -1.4°C for 2.5 days or less and for 4 days and more, Supplemental Alternative 9 is significantly more effective during between 3 and 3.5.[375]

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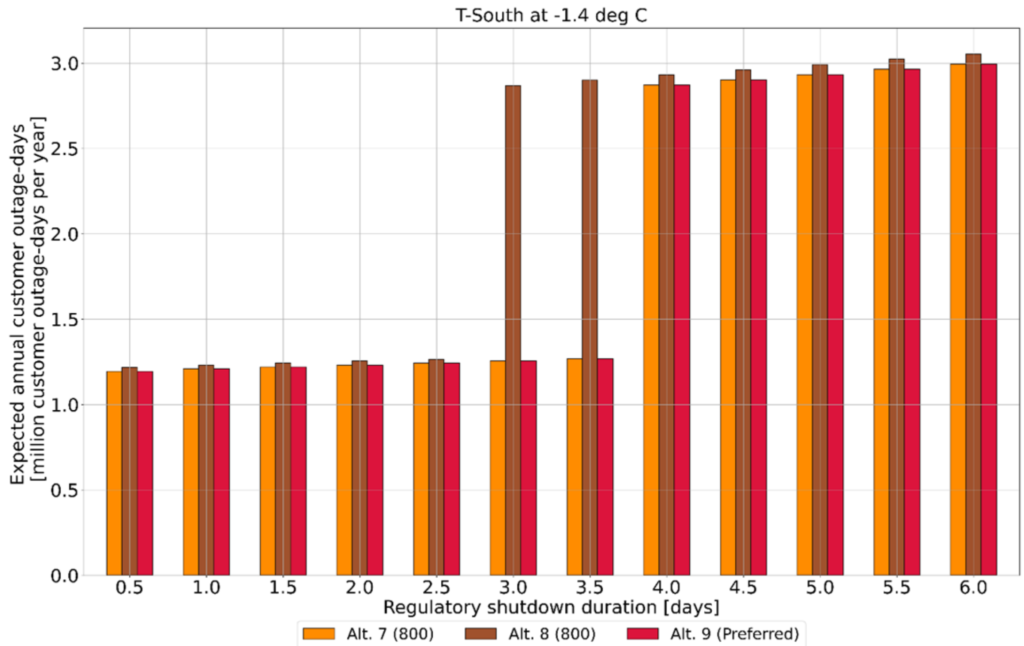
[373] In the response to BCUC IR5 120.10 (Exhibit B-63), Exponent also provided a sensitivity analysis assuming a longer 5-day regulatory shutdown period for earthquake-induced hazards and a 3-day period for all other hazards. However, Exponent does not expect that the regulatory shutdown period would vary by hazard, except to the extent it delays a regulator evaluating the pipeline.

[374] Exhibit B-63, BCUC IR5 120.1.

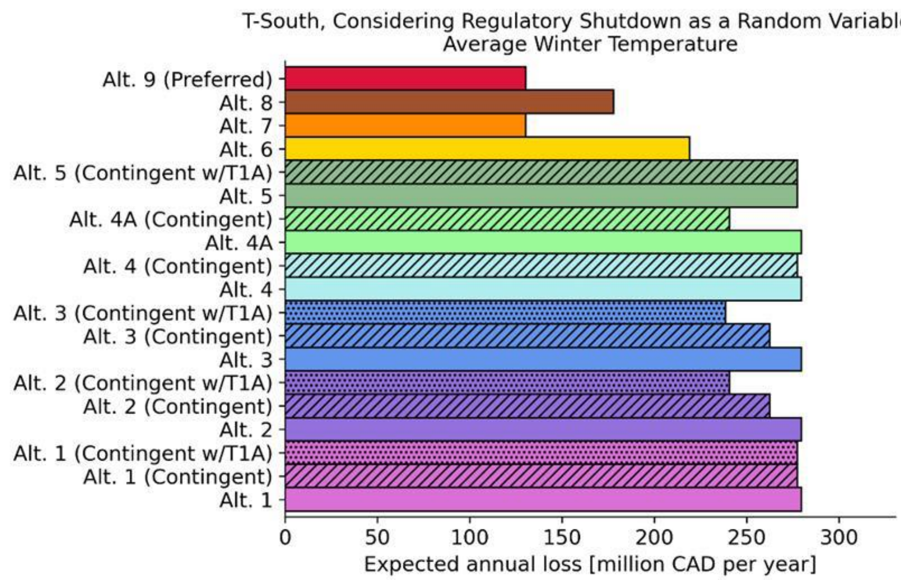
[375] Exhibit B-63, BCUC IR5 120.1.



- **Random Variable Analysis at Average Winter Temperatures:** Exponent also conducted an economic (GDP) loss analysis assuming the regulatory shutdown period is a random variable between 0.5 and 6 days (each with an associated probability of occurrence). The figure below shows the expected annual losses for each Supplemental Alternative.[376] Whereas the expected losses for Supplemental Alternative 9 remain similar to the results assuming a 3-day regulatory shutdown, the losses associated with Supplemental Alternative 8 increase by more than 50 percent due to the increased likelihood of the regulatory shutdown period exceeding the supply duration. This analysis demonstrates that considering uncertainty in the regulatory shutdown period does not have a significant impact on the losses if the mean regulatory shutdown period is similar to the assumed 3-day regulatory shutdown period.[377]

376 Exhibit B-63, BCUC IR5 120.6.

377 Exhibit B-69, BCUC IR6 149.1.



Assessing Resiliency Benefit Based on "Resiliency Reserve" Volumes Is Appropriate and Non-Dependable "Contingent" Volumes Do Not Change Overall Picture Anyway

289. As discussed in Part Five, Section C(a) above, FEI performed its supplemental alternatives analysis accounting for "planning", "contingent" and "contingent w/T1A" scenarios.[378] IRs explored the reasonableness of using a planning view,[379] questioned why certain contingent scenarios were not investigated,[380] and requested that FEI analyze additional contingent scenarios.[381] FEI submits that there is a sound rationale, articulated below, for focusing on the "planning volume" (i.e., resiliency reserve) when assessing the resiliency benefit provided by each viable alternative. The selected contingent scenarios meet the BCUC's desire to consider the potential for other non-reserved LNG to be present on the day of a no-flow event, and do not fundamentally alter the Resiliency Benefit criterion assessment in any event.

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378 The "**planning**" scenarios assume stored LNG is available on a dependable basis for a single planned purpose.

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 with T1A**" scenarios are more optimistic, and assume that an additional 0.4 Bcf from Tilbury 1A is also present and available for resiliency.

379 Exhibit B-63, BCUC IR5 127.2 and 127.3.

380 Exhibit B-63, BCUC IR5 127.1 and 127.4.

381 Exhibit B-69, BCUC IR6 155.1.

290. Using the "resiliency reserve" volume in assessing relative risk mitigation is valid for two reasons:

- First, as explained in the Supplemental Evidence, relying on contingent volumes, as opposed to a dedicated resiliency reserve, is a strategy that is, by definition, risky because it *assumes* rather than *guarantees* LNG volumes will be present when called upon. The evidence is clear that such an assumption is ill-founded and that FEI cannot rely on contingent volumes. FEI's peaking gas requirements already exceed its existing Tilbury capabilities and, as discussed in Part Four, Section F above, FEI's reliance on LNG volumes from Tilbury 1A is time limited as RS 46 sales are expected to increase rapidly and significantly.[382] Moreover, sizing infrastructure assuming LNG volumes that may or may not be available when needed is contrary to typical utility planning principles premised on sizing infrastructure to be able to meet firm customer requirements consistently.[383]

- Second, while FEI's objective will always be to minimize any harm to its customers caused by a winter T-South no-flow event, it may not always be the case that using available LNG reserved for gas supply (if any) will be consistent with this approach. For example, in some cases, preserving gas supply volumes, will leave customers in a better position once the no-flow event ends and customers are brought back online.[384] This possibility supports focusing on the planning allocations to a resiliency reserve, rather than assuming that contingent LNG allocated to gas supply will also be present and will, with certainty, be reallocated to resiliency such that a new LNG tank can be undersized.

291. The figure below from Exponent confirms that the risk mitigation provided by the four Step 3 alternatives does not materially improve at average winter temperature (+4°C), even in the extreme optimistic contingent scenarios (i.e., "Contingent w/T1A") that assumes the entire TLSE Tank is full plus there is 0.4 Bcf from Tilbury 1A present.[385] This contingent scenario requires that 0.4 Bcf from Tilbury 1A would be available for the entirety of the 90-day winter period, which does not represent real-life conditions. Unlike the Base Plant tank, which is used as a gas supply portfolio resource of last resort, LNG levels in the Tilbury 1A tank are a function of both overall

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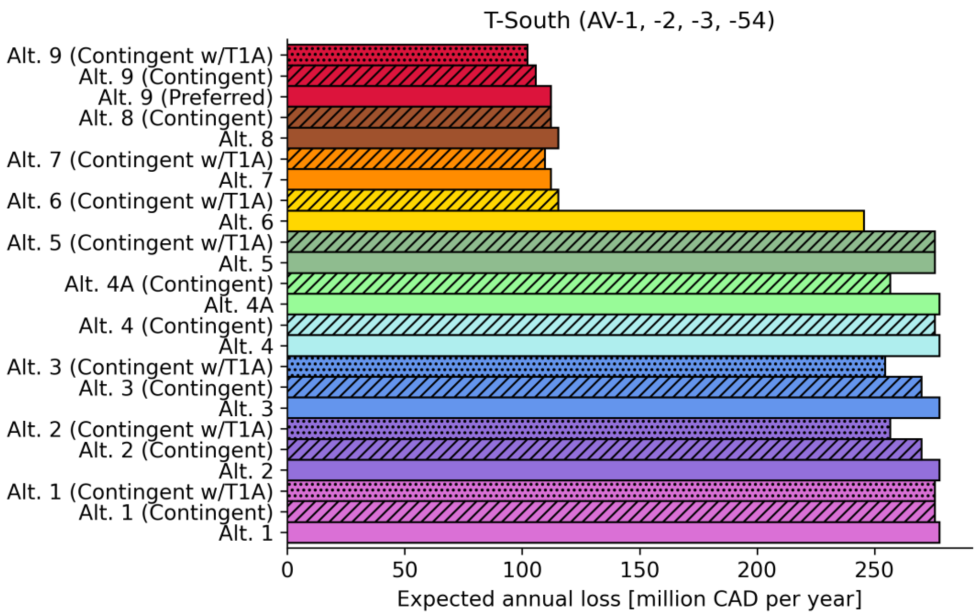
382 Exhibit B-60, Supplemental Evidence, Appendix C, pp. 38-42.

383 Exhibit B-60, Supplemental Evidence, Appendix C, p. 37.

384 Exhibit B-63, BCUC IR5 127.2.

385 Exhibit B-63, BCUC IR5 127.4. The only alternative that improves is Supplemental Alternative 6 (Contingent w/T1A), which was ruled out because it would leave FEI reliant on non-existent market resources for all of its peaking gas supply.

RS 46 demand and the patterns of sales over the course of a year.[386] In practice, while some volumes of LNG will potentially be present on a given day, there will likely be unpredictable intervals where the tank is significantly depleted.



292. FEI was asked to consider another contingent scenario where, in addition to the resiliency reserve, half of the gas supply allocation is available (i.e., a midpoint). Exponent's results, designated "Contingent – Midpoint", confirmed that adopting a mid-point availability contingent scenario would not change the Preferred Alternative. Supplemental Alternative 8 (Contingent – Midpoint) would provide more risk mitigation at colder temperatures than Supplemental Alternative 8; nevertheless, Supplemental Alternative 9 still provides superior risk mitigation because it will bridge the regulatory shutdown over a higher percentage of winter days.[387] It should also be noted that any improved resiliency associated with the contingent portion of the LNG in this scenario comes with significant uncertainty attached, since a significantly depleted gas supply reserve is a distinct possibility.[388]

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386 Exhibit B-60, Supplemental Evidence, Appendix C, p. 39; Exhibit B-69, BCUC IR6 155.1.

387 Exhibit B-69, BCUC IR6 155.1.

388 Exhibit B-69, BCUC IR6 155.1.

Supplemental Alternative 9 is a Prudent Risk Mitigation Investment and Reduces Risk to As-Low-as-Reasonably-Practicable

293. As discussed in Part Three, Section F(b) above, the existing risk posed by a winter T-South no-flow event is, in the context of the ALARP framework, "unacceptable" and not within the ALARP zone. While it is fair to say that Supplemental Alternatives 8 and 9 would result in the risk no longer being "unacceptable" and represent prudent risk mitigation investments, they are not equal in terms of where they fall within the ALARP zone. As discussed below, the additional value provided by Supplemental Alternative 9 is a proper consideration when evaluating two potential expenditures that both fall within the ALARP zone.[389]

294. First, Supplemental Alternative 9 reduces the risk posed by a winter T-South no-flow event more than any other alternative considered in Step 3 of the alternatives analysis. In particular, as discussed above, Supplemental Alternative 9 outperforms Supplemental Alternative 8 at colder than average temperatures due to the additional LNG volumes allocated to its larger 2 Bcf resiliency reserve, which enables a longer load support duration. While residual risk remains with Supplemental Alternative 9 in service, to further reduce the risk by a substantial amount would have a significant cost, which FEI determined would not be practicable at this time.[390] Therefore, Supplemental Alternative 9 reduces the T-South risk to "as-low-as-reasonably-practicable".[391]

295. Second, Supplemental Alternative 9 is more cost-effective than Supplemental Alternative 8 due to the combination of significant tank construction economies of scale and greater gas supply benefits (avoided costs).

- The economies of scale result in a positive risk reduction to dollar of rate impact ratio that is higher than all of the other viable alternatives. This means Supplemental Alternative 9 will mitigate more GDP risk than its cost of service, and deliver the greatest risk reduction value for customers.[392] In particular,

389 Exhibit B-63, BCUC IR5 117.3.

390 The ALARP principle is not static and can change over time. As such, a future project with ancillary resiliency benefits may result in an opportunity to reduce the residual risk in a cost-effective manner: Exhibit B-63, BCUC IR5 117.3.

391 Exhibit B-63, BCUC IR5 117.3.

392 Exhibit B-63, BCUC IR5 117.3.

Supplemental Alternative 9 has a risk reduction to dollar of rate impact ratio of 15.3, as compared to the next closest duration of 14.2 for Supplemental Alternative 8.[393]

- As discussed in Part Five, Section F(d) below, Supplemental Alternative 9's additional gas supply allocation of 1 Bcf will allow FEI to avoid significant gas supply costs by optimizing its gas portfolio. Supplemental Alternative 8 would only maintain FEI's existing Tilbury gas supply capabilities.

296. Together, these considerations support Supplemental Alternative 9 being the Preferred Alternative.

(b) Criterion #2: FEI Needs 1 Bcf of Dependable Peaking Supply and Meeting the Need with LNG is Optimal

297. There is no means of replacing the peaking gas supply provided by Tilbury LNG in the market, making the choice when it comes to gas supply straightforward: (1) size the facility to maintain FEI's existing sub-optimal Tilbury gas supply capabilities (Supplemental Alternatives 4 and 8); or (2) increase those capabilities so as to provide FEI's required peaking supply in a less-risky and more cost-effective way (Supplemental Alternatives 4A and 9). As described below, Supplemental Alternatives 9's ability to deliver the latter warranted the "High Positive Impact" rating on the "Availability of Dependable Gas Supply During Peak Demand" criterion.

298. In preparing each ACP, FEI undertakes portfolio optimization modelling to re-balance its gas supply portfolio and maintain the effectiveness of asset utilization in response to the evolution of its load duration curve over time. FEI uses a consistent modelling approach from year to year.[394] Mr. Mason, an independent expert, explained that there are a number of benefits to FEI optimizing its gas supply portfolio:[395]

> In particular, a natural gas portfolio that has been optimized by the utility will respond to shifts in supply and demand to maintain security of supply, while balancing the economic benefits to customers. The elements of an optimal resource portfolio for FEI are therefore multi-faceted, leveraging transportation,

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393 Exhibit B-60, Supplemental Evidence, Table 4-12.

394 Exhibit B-69, BCUC IR6 143.4; Exhibit B-63, BCUC IR5 118.1.

395 Exhibit B-60, Supplemental Evidence, Appendix F, Raymond Mason Report, p. 3.

storage, peak shaving facilities, and third-party arrangements to meet the demands of its customers throughout the year.

299. As discussed in Part Four, Section D, FEI's peaking supply needs now exceed the capabilities of its on-system LNG facilities, such that FEI has relied on sub-optimal and finite market resources to supplement it. FEI's portfolio optimization analysis shows that being able to access the 1 Bcf of LNG storage and 200 MMcf/d of regasification capacity provided by Supplemental Alternatives 4A and 9 will allow FEI to reallocate resources to reduce portfolio risk and annual gas supply costs.[396]

- **Annual Cost Savings:** As discussed further in Part Five, Section F(d) below, FEI estimates significant annual gas cost savings (avoided costs) from having both an additional 50 MMcf/d of send-out and an additional 0.4 Bcf of LNG storage in its ACP. The savings result from FEI being able to replace the 50 MMcf/d of year-round T-South capacity currently being held solely to meet peak demand.[397] The cost savings would increase significantly if additional regional infrastructure upgrades proceed in the future to address the constrained Pacific Northwest market.

- **Gas Portfolio Risk-Reduction**: The additional storage and regasification capacity provided by Tilbury will reduce the amount of short-team peaking supply (e.g., peaking call options at EKE) needed on the peak day.[398] Peaking call options not deployable on the same day (require 24-hours notice), are not dependable sources of supply and, at the best of times, are volatile in terms of physical delivery on peak day (see Part Four, Section E(b) above).

300. Supplemental Alternative 9, unlike Supplemental Alternative 4A, provides access to more than 200 MMcf/d of regasification capacity. Although the additional regasification above 200 MMcf/d is installed for resiliency purposes, it does have value from a gas supply perspective when combined with an additional 0.4 Bcf of storage. It will provide a valuable option for future gas supply portfolio planning to meet the changing load profile, as well as flexibility in contracting market area resources.[399]

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396 Exhibit B-63, BCUC IR5 118.1 and 118.2.

397 Exhibit B-69, BCUC IR6 143.4.

398 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: Exhibit B-63, BCUC IR5 139.2.1.

399 Exhibit B-63, BCUC IR5 118.6.

301. In summary, the optimization of FEI's gas supply portfolio enabled by Supplemental Alternative 9 will offer incremental benefits beyond those offered by Supplemental Alternative 8 in terms of cost savings, risk reduction and flexibility now and in the future.

(c) Criterion #3: All of the Step 3 Alternatives "Resolve the Age-Related Base Plant Challenges"

302. All four of the Step 3 alternatives, including Supplemental Alternative 9, have a "High Positive Impact" on the "Resolves Age-Related Base Plant Challenges" criterion. The installation of a new tank and regasification equipment built to modern standards entirely addresses the end-of-life and inherent design issues identified in Part Four above.[400]

(d) Criterion #4: Economies of Scale and Gas Supply Benefits Reduce "Levelized Total Rate Impact" for Supplemental Alternative 9

303. FEI characterized Supplemental Alternatives 8 and 9 as both having a "Medium Negative Impact" characterization, but Supplemental Alternative 9's levelized total rate impacts are actually lower, and customers are getting significantly more value for their investment.

304. FEI 's characterization of Supplemental Alternatives 8 and 9 as having a "Medium Negative Impact" was appropriate in the context of the other impact characterizations used in Step 3. It is important to recognize in considering this criterion that rate impacts are unavoidable. The only alternative to constructing a new facility – planning for curtailments of firm load in normal operations during cold winter periods – is untenable. Resiliency will also decline, rather than improve, if FEI can no longer send out from Tilbury.[401] In practice, the levelized total rate impact associated with a like-for-like replacement of the Base Plant (Supplemental Alternative 4) is the minimum. FEI characterized the total levelized rate impact associated with a like-for-like replacement as "Low Negative Impact". At the other end of the impact spectrum were screened-out alternatives (e.g., Supplemental Alternatives 6 and 7) that had a higher levelized rate impact and were assessed as having a "High Negative Impact".

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[400] Exhibit B-60, Supplemental Evidence, p. 129.

[401] e.g., During the 2023 "Swamp Gas" Incident on T-South, FEI relied on the Tilbury facility to provide system resiliency and make up for the supply shortfall: see Exhibit B-60, Supplemental Evidence, p. 59.

305. Although Supplemental Alternatives 8 and 9 share the same "Medium Negative Impact" characterization, they are by no means equal. Supplemental Alternative 9 has a lower levelized total rate impact than Supplemental Alternative 8, despite being a larger facility that provides superior resiliency and more gas supply. The table below provides the financial results for Supplemental Alternatives 8 and 9 based on the capital and operating cost estimates, as well as the estimate of gas supply costs/savings over the 67-year[402] analysis period. Note that the table reflects updated information provided through the IR process.

Updated Summary of Capital Costs, Cost of Service, Gas Supply Costs/Savings, and Levelized Total Rate Impacts for Supplemental Alternatives 8 and 9

	Alt 8 - 2 BCF 800 MMcf/d (1.4 BCF resl)[403]	Alt 9 - 3 BCF 800 MMcf/d (2 BCF resl)[404]
Total Capital Costs during Construction, As-Spent $ ($000s)	1,030,286	1,140,962
PV of Cost of Service, excl. Gas Supply Costs/Savings ($000s) over 67 years	1,133,984	1,240,803
PV of Gas Supply Cost/Savings ($000s) over 67 years	(366,362)	(519,585)
Total PV of Cost of Service over 67 years ($000s)	**767,622**	**721,218**
Levelized Total Rate Impact (Incl. Cost of Gas) 67 years (%)	2.60%	2.44%
Levelized Total Rate Impact (Incl. Cost of Gas) 67 years ($/GJ)	0.242	0.228

306. As discussed below, the lower levelized total rate impact of Supplemental Alternative 9 over the 67-year analysis period is significantly influenced by: (1) economies of scale in tank construction; and (2) additional gas supply benefits, which are addressed in turn below.

Supplemental Alternative 9 Benefits from Significant Economies of Scale

307. Supplemental Alternative 9 benefits from significant economies of scale in tank construction. Figure 4-6 below illustrates the strength of the economies of scale with reference to the four Step 3 alternatives and the updated cost estimates provided in the Supplemental Evidence.[405] The capital cost per unit of storage declines materially as the tank size increases, with Supplemental Alternative 9 having by far the lowest unit cost.

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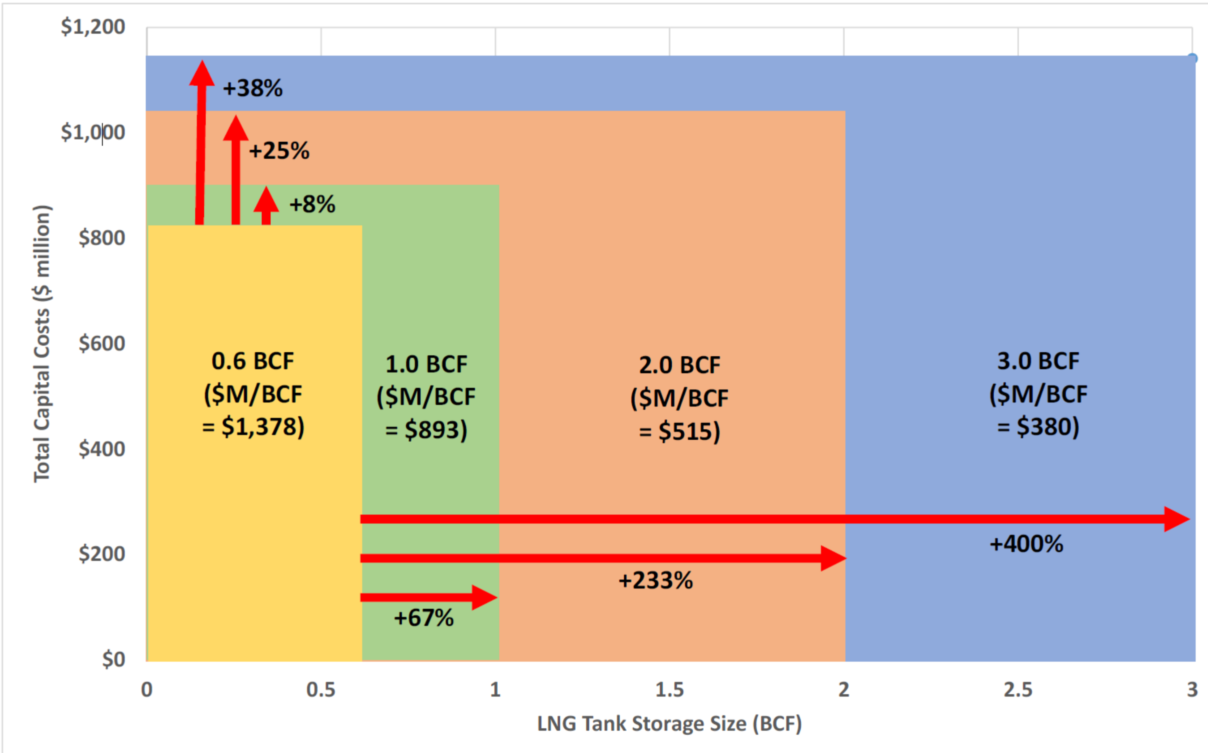
402 A 67-year analysis period is appropriate for the financial analysis because it encompasses the 7-year construction period plus the expected life of the assets of 60 years: see Part Seven, Section C.

403 Exhibit B-63, BCUC IR5 131.3.

404 Exhibit B-63, BCUC IR5 131.3.

405 Exhibit B-60, Supplemental Evidence, p. 131; see also Exhibit B-1-4, Application, p. 107.

Figure 4-6: Graphical Illustration of Economies of Scale by Tank Capacity (from 0.6 Bcf to 3.0 Bcf)



308. As shown above, Supplemental Alternative 9 provides 50 percent more storage than Supplemental Alternative 8 for an additional capital cost of only 11 percent (approximately $111 million). Further, the unit cost for Supplemental Alternative 9 with a 3 Bcf tank is approximately $135 million less per Bcf than the unit cost of Supplemental Alternative 8 with a 2 Bcf tank. Based on this measure, customers are receiving the greatest value from Supplemental Alternative 9.[406]

Supplemental Alternative 9 Provides Significant Gas Supply Benefits

309. Supplemental Alternative 9 also provides significant gas supply benefits that, over time, more than offset the additional capital cost of adding a "third Bcf" to the tank (as shown in the table above).[407]

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[406] Exhibit B-60, Supplemental Evidence, pp. 132-133.

[407] See the table titled "Updated Summary of Capital Costs, Cost of Service, Gas Supply Costs/Savings, and Levelized Total Rate Impacts for Supplemental Alternatives 8 and 9".

310. FEI has been very transparent about its calculation inputs, and has provided cogent explanations for its decisions. FEI varied its assumptions for various time periods within the 67-year analysis period to reflect changes in the regional market and how the alternatives considered changed FEI's gas supply portfolio:

- **Present to 2030:** FEI assumed that Tilbury will continue to deliver 0.6 Bcf and 150 MMcf/d of peaking gas supply to 2030. To meet FEI's gas supply requirements of 1 Bcf and 200 MMcf/d, FEI currently holds an additional 50 MMcf/d of year-round pipeline capacity, which costs approximately $7.9 million per year, net of mitigation.[408] As FEI will continue to hold this capacity until at least 2030 regardless of the alternative, no associated avoided cost was recorded for any Supplemental Alternative.[409]

- **2030 to 2035:** FEI assumed the end date for the existing Base Plant is 2030. This is a reasonable assumption for the analysis because, as discussed in Part Four above, the Base Plant has reached end-of-life and FEI's ability to rely on Tilbury 1A volumes as a dependable source of peaking supply is time limited. Absent the completion of a (currently hypothetical) regional infrastructure upgrade that is sufficiently large to replace the lost peaking supply from Tilbury: (a) FEI cannot replace the lost 0.6 Bcf and 150 MMCf/d of peaking gas supply in the market, and FEI will effectively save gas costs during this period because it will be curtailing firm customers instead of serving them; and (b) FEI will need to continue holding its 50 MMcf/d of year-round pipeline capacity (at a cost of approximately $7.9 million per year, net of mitigation) that it currently relies on to supplement its peaking supply, unless the alternative provides 1 Bcf and 200 MMcf/d. FEI would need to incur this $7.9 million annual cost with Supplemental Alternative 8, but Supplemental Alternative 9 will avoid that annual cost.[410]

- **2035 and Beyond:** FEI assumed that the period when FEI needs to curtail firm customers in peak periods would end in 2035 with the construction of a regional infrastructure expansion that could meet FEI's full peaking gas supply requirements of 1 Bcf and 200 MMcf/d (currently comprised of Tilbury plus 50 MMcf/d of pipeline capacity). Unless on-system LNG storage with a gas supply allocation is built by this time, FEI would begin to incur higher tolls on expanded regional infrastructure for 200 MMcf/d and 1.0 Bcf of peaking supply. FEI used the

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408 As explained in the responses to BCUC IR5 131.5 and 131.6 (Exhibit B-63), current gas infrastructure has a high utilization rate year-round enabling approximately $358 million in T-South mitigation activities under the GSMIP from 2016-17 to 2022-23. While FEI cannot predict with certainty its ability to resell unused pipeline capacity in the future, FEI submits there is a reasonable likelihood that there will be an ongoing demand for pipeline capacity in the Pacific Northwest.

409 Exhibit B-60, Supplemental Evidence, pp. 132-133; Exhibit B-63, BCUC IR5 131.3.

410 Exhibit B-60, Supplemental Evidence, pp. 133-134.

lower bound figure for the cheapest potential market resource (market storage) for its avoided cost calculations, being: $63 million for 1 Bcf and 200 MMcf/d (net of mitigation) and $46 million for 0.6 Bcf and 150 MMcf/d (net of mitigation).[411]

311. The table below shows the relative expected peaking gas supply costs in each of the periods described above, as well as the incremental avoided gas supply costs for Supplemental Alternatives 8 and 9.

Updated Avoided Annual Gas Supply Costs for Supplemental Alternatives 8 and 9 ($ millions)[412]

		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)	7.9	7.9	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)	7.9	7.9	17.0[413]	-	-	(46.0)
9	New 3 Bcf Tank and 800 MMcf/d Regasification (2 Bcf resiliency reserve and 1 Bcf for peaking gas supply)	7.9	-	-	-	(7.9)	(63.0)

312. As shown above, Supplemental Alternative 9 avoids all annual peaking gas supply costs once in service (i.e., from 2030 onward). In particular, Supplemental Alternative 9 provides significant gas supply benefits by: (1) providing flexibility to shed existing resources in the ACP ($7.9 million per year); and (2) avoiding annual gas supply costs of at least $63 million per year from the expanded regional infrastructure for 1 Bcf and 200 MMcf/d.[414] Supplemental Alternative 8, in contrast, only partially avoids these costs because FEI must continue to acquire 0.4 Bcf and 50 MMcf/d of peaking resources from the market from 2030 onward.[415]

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411 Exhibit B-60, Supplemental Evidence, pp. 134-138; Exhibit B-63, BCUC IR5 131.9.

412 This table revised the values in Table 4-11 from the Supplemental Evidence (Exhibit B-60) based on the information provided in the response to BCUC IR5 131.3 (Exhibit B-63), and removes Supplemental Alternatives 4 and 4A.

413 See BCUC IR5 131.8 (Exhibit B-63) which clarifies that this value represents the incremental cost to make up the remaining 0.4 Bcf and 50 MMcf/d (i.e., $63 million less $46 million).

414 Exhibit B-60, Supplemental Evidence, p. 139; Exhibit B-63.

415 Exhibit B-60, Supplemental Evidence, pp. 139-140; Exhibit B-63, BCUC IR5 131.8 and 131.9.

313. Section 4.5.4.1.2 of the Supplemental Evidence provides a detailed breakdown of the expected gas supply costs which inform the avoided cost calculations.[416] FEI submits that the BCUC can have considerable confidence that its avoided cost calculations are a reasonable basis for comparing alternatives:

- First, the annual gas supply costs used until 2035 are FEI's actual costs for its existing 50 MMcf/d of pipeline capacity used for peaking supply;
- Second, for the period post-2035, FEI used the lower bound figure for the cheapest potential market resource (market storage) for all of its avoided cost calculations (i.e., the much higher estimated future pipeline costs play no role in the levelized rate impact calculations).[417] The tolls used post-2035 for market storage reflect the tolls that FEI will pay under arrangements that the BCUC has already reviewed in a confidential section 71 filing.[418] This value likely understates post-2035 storage tolls because:
    - FEI did not forecast any escalation on the storage demand charge and transportation charges; and
    - Tolls would reasonably be expected to increase with the next expansion.[419]

Highly Unlikely Customers Will be Financially Better Off with Supplemental Alternative 8

314. FEI responded to IRs aimed at determining what would have to occur for Supplemental Alternative 9 to no longer have a lower levelized rate impact than Supplemental Alternative 8. FEI's responses demonstrated that a very unlikely confluence of events would be necessary for customers to be financially better off on an NPV basis with Supplemental Alternative 8.

315. First, the capital cost variances that would be required are unrealistic. There is a very little likelihood of the capital cost of Supplemental Alternative 8 decreasing by approximately 5.36 percent or more over the 67-year analysis period, while the capital cost of Supplemental Alternative 9 remains the same. It is similarly unlikely that the capital cost of Supplemental Alternative 9 will increase by approximately 4.86 percent or more over the same period while

416 Exhibit B-60, Supplemental Evidence, pp. 132-138.

417 Exhibit B-60, Supplemental Evidence, pp. 134-138; Exhibit B-63, BCUC IR5 131.9.

418 Order G-241-24, dated September 10, 2024.

419 Exhibit B-63, BCUC IR5 131.9.

the capital cost of Supplement Alternative 8 remains the same. The base cost estimates are at an AACE Class 3 level of accuracy and, in any event, any cost increases that might materialize during construction would likely impact both Supplemental Alternatives in a similar way. The only material difference between these alternatives is the tank size (i.e., all risk ratings are the same), which means that both alternatives would be affected in a similar way by 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.[420]

316. Second, there is a very low likelihood that annual regional gas supply costs will decrease over the 67-year analysis period such that Supplemental Alternative 8 has a lower levelized rate impact than Supplemental Alternative 9.

- For the period prior to 2035, there is no realistic T-South toll price for continuing to hold approximately 50 MMcf/d of pipeline capacity at which the total cost of service for Supplemental Alternative 8 would be lower than Supplemental Alternative 9 over the 67-year analysis period.[421] Indeed, the toll for T-South capacity would need to be reduced to zero for the alternatives to be equal financially.[422]

- For the years after 2035, annual gas supply costs would need to decrease by at least 33 percent from those assumed in the Supplemental Evidence.[423] As explained above, FEI's calculations use the tolls for expansion capacity, which the BCUC has reviewed. FEI has not included any escalation or any allowance for toll increases that would flow from the next expansion.

317. Third, it is reasonable to assume that FEI can continue to generate gas supply benefits from the full 1 Bcf and 200 MMcf/d over the 67-year analysis period. Tilbury will continue to provide significant financial value through avoided gas supply costs over the life of the TLSE Project even if FEI were to experience the most extreme adverse load loss scenarios.[424]

- As discussed further in Part Five, Section F(e) below, FEI would still be serving hundreds of thousands of customers in the Lower Mainland in 2050 with

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420 Exhibit B-63, BCUC IR5 132.2.1.

421 Exhibit B-63, BCUC IR5 132.2.1.

422 Exhibit B-63, BCUC IR5 131.4.1.

423 Exhibit B-63, BCUC IR5 132.2.1.

424 Exhibit B-63, BCUC IR5 131.7.

approximately 60 PJ (equivalent to approximately 53 Bcf) of Lower Mainland load per year and peak day demand of approximately 460 MMcf/d. This is well-above the storage and regasification capacity that Supplemental Alternative 9 (the Preferred Alternative) can provide.[425]

- Second, Supplemental Alternative 9 provides FEI with flexibility to allocate more of the tank to the gas supply portfolio in the event of extreme load declines. Re-allocating the tank in this way would create opportunities to optimize FEI's gas supply portfolio for the benefit of its customers, such as using the additional peaking supply from Tilbury to replace more expensive supply resources or generate more mitigation revenue.[426]

318. Fourth, while FEI considers the assumptions in the financial evaluation underpinning the Supplemental Evidence to be reasonable and supported by evidence, even when unrealistic assumptions are applied (e.g., delaying a regional infrastructure expansion to 2050 despite an already constrained regional market, shortening the expected service life or both), Supplemental Alternative 9 often remains financially superior or similar to Supplemental Alternative 8.[427] The matrix below shows that even based on the most extreme assumptions (i.e., the "least charitable" assumptions for Supplemental Alternative 9) the total cost of service of Supplemental Alternatives 8 and 9 still diverge by only approximately $55 million.[428]

[425] Exhibit B-63, BCUC IR5 131.7.

[426] Exhibit B-63, BCUC IR5 131.7.

[427] See Exhibit B-63, BCUC IR5 131.2 which discussed why it would be unrealistic to assume there would be zero regional infrastructure upgrades for more than 20 years.

[428] Exhibit B-69, BCUC IR6 156.1.

Table 2: Difference in the Total PV of Cost of Service Between Supplemental Alternatives 8 and 9 Over Various Combinations of Analysis Periods and Years of Regional Infrastructure Upgrade ($000s)

Analysis Period (Years)	Regional Infrastructure Upgrade in Place -> 2035	2040	2045	2048	2050
27	9,997	29,750	44,348	51,207	55,118
29	583	20,336	34,934	41,793	45,721
32	(8,411)	11,343	25,941	32,800	36,728
37	(19,956)	(202)	14,396	21,255	25,183
42	(28,277)	(8,523)	6,074	12,934	16,862
47	(34,279)	(14,526)	72	6,931	10,860
52	(38,607)	(18,853)	(4,255)	2,604	6,532
57	(41,722)	(21,968)	(7,370)	(511)	3,417
62	(43,958)	(24,205)	(9,607)	(2,747)	1,181
67	(46,404)	(26,650)	(12,052)	(5,193)	(1,265)

319. FEI expects the financial difference between Supplemental Alternatives 8 and 9 is highly likely to be in the lower-left quadrant of the matrix as: (1) the risk that the TLSE Project will cease to be used and useful after 20 years is very remote; and (2) the constraints on regional infrastructure and the growth in regional demand strongly suggest that upgrades could not wait until 2040 or 2050.[429]

320. Simply put, by selecting Supplemental Alternative 8 the BCUC would be sacrificing the superior resiliency and optimal gas supply provided by Supplemental Alternative 9 for a small chance of obtaining a cumulative cost savings of $55 million over 67 years. FEI submits that would be a poor trade-off for customers. It is far more likely that customers would be worse off with Supplemental Alternative 8 on a levelized rate impact basis. Moreover, Exponent's probability analysis shows that a no-flow event should be expected at least once during the expected life of the TLSE Project.

[429] Exhibit B-69, BCUC IR6 156.1.

321. In summary, in addition to providing superior resiliency and optimal gas supply, Supplemental Alternative 9 has a lower cost and provides greater risk reduction per dollar spent than Supplemental Alternative 8.[430]

(e) Criterion #5: TLSE Project Will Remain Used and Useful

322. The "Future Use" criterion is not determinative of the choice of the preferred alternative because all of the Step 3 alternatives received the same assessment of "No Impact" on "Future Use". The evidence supports FEI's assessment. As discussed below, by virtue of the inherent flexibility of on-system LNG, all four of these alternatives will remain useful for resiliency and gas supply even hypothetically assuming extreme customer losses in the Lower Mainland by 2050.[431]

The Two Hypothetical Adverse mDEP Scenarios Are a Reasonable Basis to Assess "Future Use"

323. FEI assessed "Future Use" against two hypothetical adverse sensitivities that are based on the 2022 LTGRP DEP Scenario. While FEI continues to support the DEP Scenario in the LTGRP, using extreme hypothetical adverse sensitivities in this alternatives analysis acknowledges the uncertainties inherent to forecasting future load. FEI submits that the approach provides a reasonable basis for determining the Application.

324. The two hypothetical adverse "modified DEP" (**mDEP**) sensitivities simulate significant hypothetical core customer losses in the Lower Mainland between 2030 and 2050:[432]

- **mDEP 2%:** assuming a 2 percent per year decline in core customers, which aligns with the annual demolition rates assumption from FEI's 2022 LTGRP; and
- **mDEP 5%:** assuming a 5 percent per year decline in core customers, which models the potential impact of an extreme hypothetical accelerated load decline scenario where the annual expected demolition rate more than doubles.

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430 Exhibit B-60, Supplemental Evidence, Table 4-12 (p. 142).

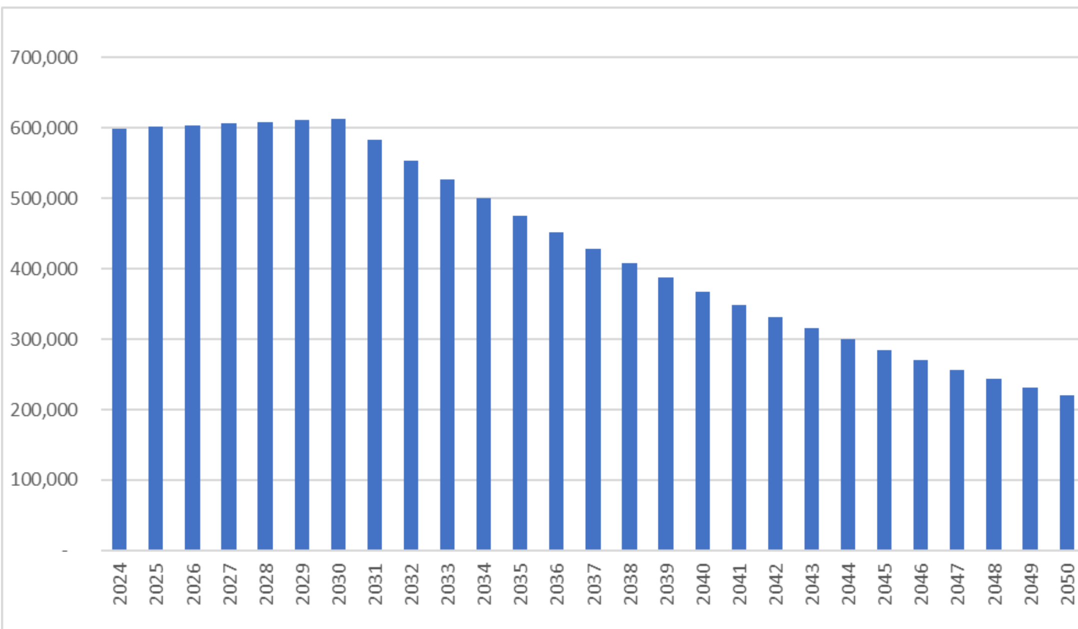
431 Exhibit B-60, Supplemental Evidence, pp. 142-143.

432 Exhibit B-60, Supplemental Evidence, Section 4.5.5.2; Exhibit B-63, BCUC IR5 129.1. In both scenarios, FEI did not adjust the number of industrial customers for the reasons set out in BCUC IR5 129.2 (Exhibit B-63).

325. These sensitivities estimate the number of customers, annual and peak load that will remain on FEI's system between 2030 and 2050, assuming no new customer connections after 2030.

326. As shown in the figures below, there are significant annual customer losses assumed in the mDEP 2% and mDEP 5% sensitivities, which would reduce annual load in the Lower Mainland and decrease peak day demand. However, even under the extreme hypothetical sensitivity (mDEP 5%), FEI would still be serving hundreds of thousands of customers in the Lower Mainland in 2050.[433]

Figure 4-10: Lower Mainland 2050 Customers at 5 Percent Customer Decrease Per Year (mDEP 5% Adverse Sensitivity)



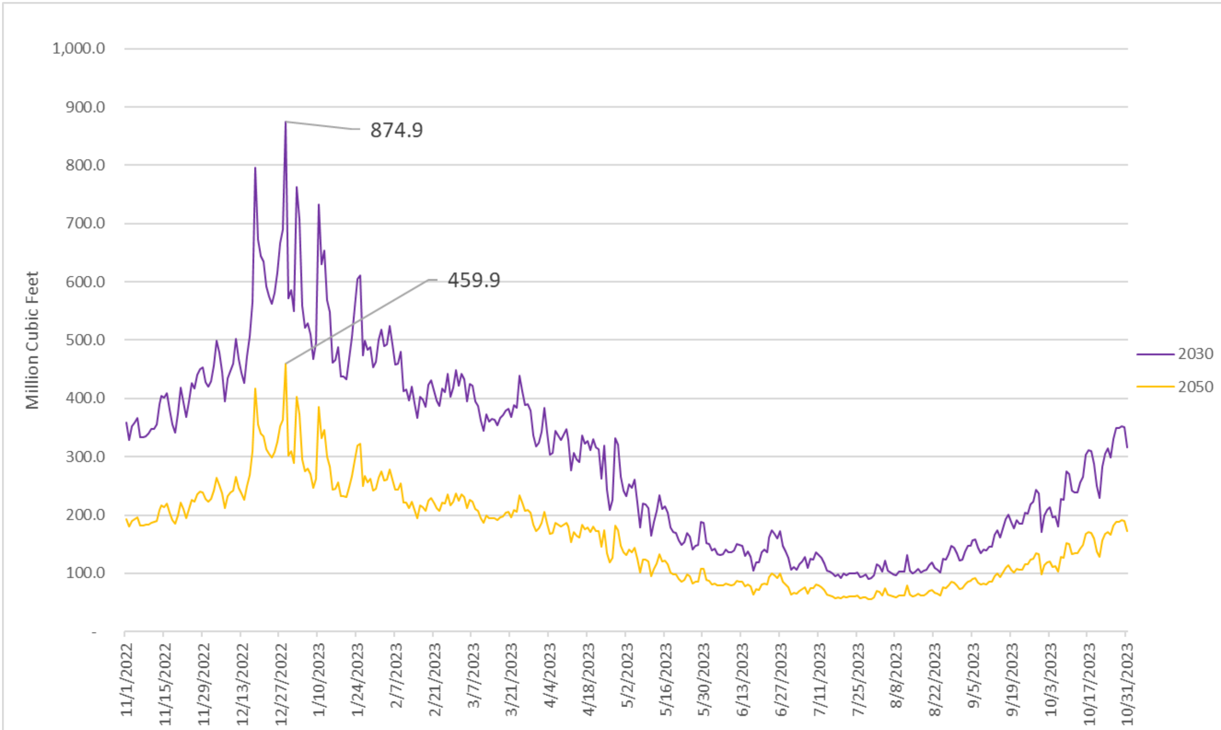
327. FEI's annual load in the Lower Mainland would still be substantial at approximately 80 PJ under the mDEP 2% sensitivity and approximately 60 PJ (or approximately half of the 2024 levels) under the mDEP 5% sensitivity.[434] Further, as the figure below shows, peak day demand remains significant despite a decline.[435]

[433] Exhibit B-60, Supplemental Evidence, Figure 4-10 (p. 146).

[434] Exhibit B-60, Supplemental Evidence, Figures 4-10 and 4-11 (pp. 146-147).

[435] Exhibit B-60, Supplemental Evidence, p. 149.

Figure 4-14: Load Duration Curve 2030 & 2050 Showing Peak Day Demand Assuming 5% Per Year Customer Decrease (mDEP 5% Adverse Sensitivity)



FEI provides a detailed breakdown of the assumptions underlying the mDEP scenarios in Section 4.5.5.2 of the Supplemental Evidence.

328. In other words, absent the TLSE Project, the 220,000-410,000 customers left in the Lower Mainland by 2050 (depending on the hypothetical sensitivity) would still be exposed to a significant customer outage with the associated social, human health and economic consequences following a winter T-South no-flow event.[436] In the intervening years between when the TLSE Project is constructed and 2050, it would provide resiliency support for hundreds of thousands of customers in the Lower Mainland. FEI's customers would still need to be served on cold winter days, and the TLSE Project is the best asset to do that due to the attributes of on-system LNG described in Part Four, Section C above.

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436 Exhibit B-60, Supplemental Evidence, pp. 142-143.

On-System LNG Offers Unique Flexibility in Response to Changing Load

329. Applying these hypothetical load loss sensitivities in the context of the alternatives analysis illustrates how the TLSE Project is a unique and valuable type of asset when it comes to the flexibility afforded in response to changing load. This flexibility, regardless of how load ultimately changes over the expected service life, is maximized by the 3 Bcf of storage and 800 MMcf/d of regasification capacity provided by Supplemental Alternative 9.

330. The TLSE Project's inherent flexibility is demonstrated by FEI's examples of two potential approaches to allocating the TLSE tank in 2050, assuming load were to decline to the extent posited by the mDEP 2% and mDEP 5% hypothetical adverse sensitivities. These approaches represent the "bookends" of a spectrum of potential choices that could be used in the future in response to declining load:

> **"Bookend" Approach #1:** Maximizing resiliency in 2050 by maintaining the same resiliency reserve to achieve progressively more customer outage risk reduction; or
>
> **"Bookend" Approach #2:** Retaining the initial level of resiliency upon commissioning by progressively reallocating some of the resiliency reserve to gas supply.

FEI discusses each approach below. FEI has addressed the BCUC's oversight of any such changes in tank allocation in Part Eleven below.

<u>"Bookend" Approach #1: Maximizing Resiliency in 2050 Would Continue to Provide Significant Risk Mitigation</u>

331. If load on FEI's system declines in the future, maintaining the same 2 Bcf resiliency reserve would progressively improve the outage risk reduction provided by Supplemental Alternative 9 until at least 2050. FEI's transient modelling confirms that, all else equal, the facility would be able to support less load for a longer period at average winter temperatures following a winter T-South no-flow event.[437] The table below shows the 2050 load support duration under both the mDEP 2% and mDEP 5% sensitivities for Supplemental Alternatives 8 and 9.

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[437] Exhibit B-60, Supplemental Evidence, Figures 4-15 and 4-16 (p. 151).

Table 4-13: Resiliency Reserve Support Under Two Hypothetical Customer Loss Sensitivities

Parameter	2050 mDEP (2%)	2050 mDEP (5%)
Lower Mainland Customers	409,831	220,395
Annual Throughput (TJ)	78,847	62,380
Lower Mainland Load +4°C (MMcf/d)	406	321
Supplemental Alternative 8 Lower Mainland Support Duration +4°C	7 days and 19 hours	9 days and 20 hours
Supplemental Alternative 9 Lower Mainland Support Duration +4°C	10 days and 20 hours	13 days and 14 hours

Based on current load, the 2 Bcf of LNG provided by Supplemental Alternative 9 will be able to maintain service for all firm Lower Mainland customers for approximately 4.5 days at average winter temperatures.[438] If peak load were to decline by 5 percent per year, the same 2 Bcf reserve would last approximately 13.5 days by 2050.[439]

332. There is ample evidence demonstrating that, were this extreme hypothetical adverse scenario to materialize, this additional load support duration would provide value. Exponent's risk assessment shows that there are modes of failure that could result in a no-flow event longer than 4.5 days – some of which could increase in likelihood in the future due to climate change (e.g., flooding).[440] Exponent calculated that the risk mitigation provided by Supplemental Alternative 9 remains material in 2050 under the hypothetical mDEP 2% and 5% sensitivities, as reflected in the following figure.[441]

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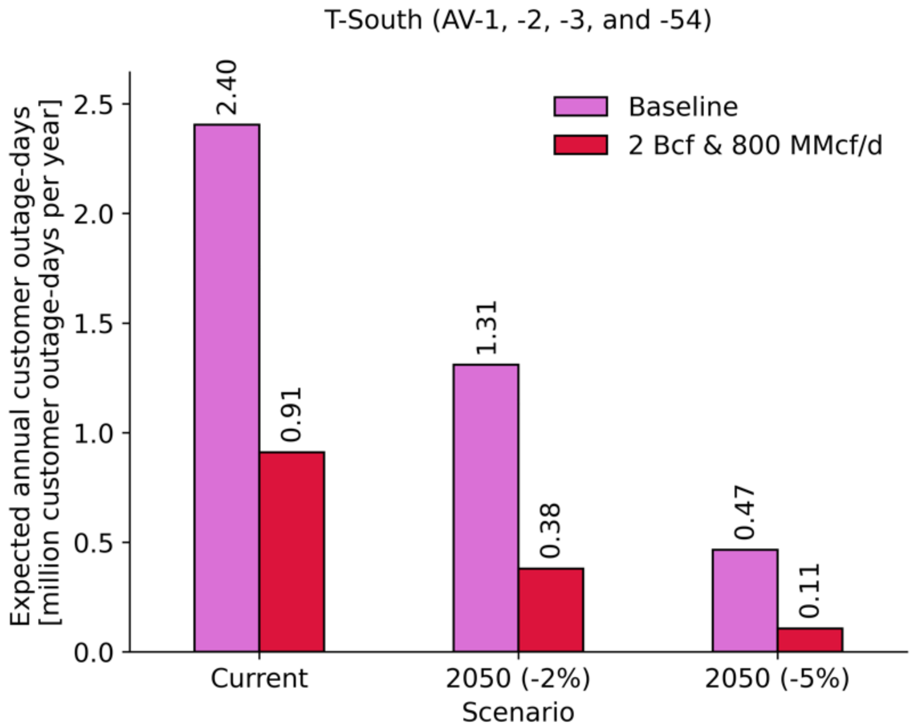
438 Note this also requires sufficient regasification capacity, which Supplemental Alternatives 8 and 9 provide.

439 Exhibit B-60, Supplemental Evidence, pp. 151-152.

440 Exhibit B-60, Supplemental Evidence, p. 152.

441 To simplify the analysis, FEI instructed Exponent to consider only the impact to the Lower Mainland due to a T-South failure: Exhibit B-60, Supplemental Evidence, Figure 4-17 (p. 153).

Figure 4-17: Expected Annual Customer Outage Days With and Without Mitigation from TLSE Project – Current and Hypothetical Future Adverse Load Sensitivities (mDEP 2% and 5%)



<u>"Bookend" Approach #2: Reallocating a Portion of the Resiliency Reserve to Gas Supply Creates Options to Avoid More Gas Costs in 2050</u>

333. The other "bookend" option if load on FEI's system declines in the future is electing to maintain the load support duration achieved at the in-service date (4.5 days at +4°C) and reallocating some of the resiliency reserve to gas supply. There is ample evidence for the BCUC to find that this approach would create opportunities for FEI to optimize its gas supply portfolio or generate significant mitigation revenues for the benefit of customers.[442]

334. The table below, based on FEI's transient modelling, shows what size of Tilbury resiliency reserve would be required in 2050 under the mDEP 2% and mDEP 5% scenarios to maintain the same support duration of 4.5 days that Supplemental Alternative 9 will provide at average winter temperatures for the approximately 600,000 customers currently in the Lower Mainland. It also shows the corresponding (post re-allocation) amount available for gas supply.[443]

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[442] Exhibit B-60, Supplemental Evidence, p. 153.

[443] Exhibit B-60, Supplemental Evidence, Figure 4-14 (p. 154).

Table 4-14: LNG Volume Required Under the 2050 mDEP (2% and 5%) Load – Resiliency Retention Approach (i.e., Maintain Equivalent Support Duration as Current Year)

Parameter	Alternative 8	Alternative 9
Support Duration Under Current Load +4°C	3 days and 8 hours	4 days and 13 hours
Current Load Resiliency Reserve Volume	1.4 Bcf	2.0 Bcf
Current Load Gas Supply Volume	0.6 Bcf	1.0 Bcf
Target Support Duration Under 2050 mDEP (2%) Load Sensitivity +4°C	3 days and 8 hours	4 days and 13 hours
2050 mDEP (2%) Load Sensitivity – Required Resiliency Reserve to Achieve Target Support	0.53 Bcf	0.76 Bcf
2050 mDEP (2%) Load Sensitivity – Resulting Gas Supply Volume	1.47 Bcf	2.24 Bcf
Target Support Duration Under 2050 mDEP (5%) Load Sensitivity +4°C	3 days and 8 hours	4 days and 13 hours
2050 mDEP (5%) Load Sensitivity– Required Resiliency Reserve to Achieve Target Support	0.39 Bcf	0.58 Bcf
2050 mDEP (5%) Load Sensitivity– Resulting Gas Supply Volume	1.61 Bcf	2.42 Bcf

335. As shown above, for Supplemental Alternative 9, FEI could increase its gas supply allocation in 2050 to 2.24 Bcf and 2.42 Bcf under the mDEP 2% and mDEP 5% sensitivities, respectively (vs. 1 Bcf today).[444] This re-allocation process could take place incrementally between 2030 and 2050 in response to declining load, thus increasing gas supply benefits across the TLSE Project's service life while maintaining the same resiliency risk mitigation. Supplemental Alternative 8 would also enable re-allocation, but to a lesser extent.

336. FEI would be able to use LNG volumes that have been re-allocated to gas supply in two distinct ways: (1) substituting other supply resources with Tilbury LNG; and/or (2) generating mitigation revenue by making Tilbury peaking supply available in the market. As explained below, both approaches would ensure that Supplemental Alternative 9 remains valuable for resiliency to the remaining customers until at least 2050, while also increasing gas supply benefits.

[444] Exhibit B-60, Supplemental Evidence, p. 154.

<u>Substituting Other Supply Resources with Tilbury LNG Would Maximize TLSE Utilization</u>

337. The BCUC recognized in the Adjournment Decision that a potential benefit provided by the TLSE Project is creating value by displacing other supply resources.[445] FEI has added to the evidence in that regard.

338. Each year, FEI undertakes gas supply portfolio optimization with the objective of developing a cost-effective portfolio to meet FEI's design load. The optimization is achieved by adjusting the supply resource mix (i.e., adding resources and de-contracting others).[446] FEI explained that, as supply resources come up for renewal, the flexibility provided by Supplemental Alternative 9 would allow FEI to adjust its portfolio over time to match changing customer demand and/or the resources available in the marketplace. For example, FEI could substitute Tilbury LNG for resources that are no longer needed to serve annual demand, while retaining the ability to serve the winter peak.[447]

339. Mr. Mason similarly identified the potential for resource substitution within the gas supply portfolio if the demand profiles of FEI's customers were to shift over time:[448]

> …while meeting the needs of FEI's customers for safe and reliable service, a proprietary LNG peaking facility will continue to carry long-term value for the utility and its customers. If the demand profiles of FEI's customers were to shift over time (i.e., lowering annual demand while maintaining the need for winter supply), the ease of de-contracting mainland transportation is more appropriate than shedding reliable on-system capacity as on-system storage is designed to be deployed only when it is required.

340. Mr. Mason also observed that the TLSE Project "would provide FEI with operational backup for disruption…to existing off-system storage and/or mainline transmission."[449]

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445 Adjournment Decision, p. 21.

446 Exhibit B-60, Supplemental Evidence, p. 154.

447 Exhibit B-60, Supplemental Evidence, p. 155.

448 Exhibit B-60, Supplemental Evidence, Appendix F, Raymond Mason Report, pp. 5 and 35. Mr. Mason also described the value (in terms of operational flexibility) of on-system peaking resources: Appendix F, Raymond Mason Report, p. 17.

449 Exhibit B-60, Supplemental Evidence, Appendix F, Raymond Mason Report, pp. 5 and 35.

<u>Mitigation Opportunities (Market Sales) Would Generate Value for Customers</u>

341. FEI routinely realizes gas supply mitigation revenues for customers from gas supply portfolio elements that it does not require on any given day. FEI's approach of using the gas supply portion of the TLSE tank would be no different. The evidence discussed below shows FEI could likely generate mitigation value from selling FEI's peaking supply in the region.

342. As described in Part Four, Section E above, the I-5 corridor and broader Western energy markets are increasingly turning to natural gas-fired power generation. Mr. Mason provided statistics demonstrating the rapid growth in demand for firm power generation and the strain on current electric resources in the region.[450] He also provided information from WECC and NERC that highlighted the extent of the pending capacity shortfall that will necessitate further investment in generation.[451]

343. Ultimately, Mr. Mason expressed confidence that the TLSE Project will continue to have financial value for FEI's customers in light of the regional market conditions. While acknowledging long-term price forecasts are inherently challenging, he illustrated the potential value with reference to 5-year forward prices. In his opinion, the market could absorb 3-4 Bcf of LNG volumes during the winter regardless of how FEI's own customer demand evolves:[452]

> 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. 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 reasonably absorb 300-400 MMcf/d [3-4 Bcf] of natural gas across multiple days (e.g., 10 days) during winter without influencing daily prices in a manner that could limit monetization values (i.e., materially decreasing the revenues generated through mitigation into the market).

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450 Exhibit B-60, Supplemental Evidence, pp. 88-89, Figure 3-24 and Appendix F, Raymond Mason Report, pp. 36-43; Exhibit B-63, BCUC IR5 129.5.

451 Exhibit B-60, Supplemental Evidence, pp. 89-90.

452 Exhibit B-60, Supplemental Evidence, Appendix F, Raymond Mason Report, pp. 6 and 36.

344. If FEI were able to sell 3 Bcf of Tilbury LNG over 10 peak days in the winter, Mr. Mason estimated that FEI could generate an average of $75.9 million for customers over a 5-year period. More conservatively, selling 3 Bcf of Tilbury LNG over 10 winter peak days in the first year and only 1.5 Bcf over 3 winter peak days in years 2-4 would generate an average of $37.95 million over a 5-year period.[453] These amounts do not account for potential additional revenue from a standing demand charge which Mr. Mason estimated could increase these amounts to $106.4 million and $68.7 million, respectively.[454]

345. 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 LNG supply while de-contracting other gas supply resources as contracts expire (as discussed above).[455]

346. In summary, the BCUC should find that there is very high potential that Supplemental Alternative 9 will continue to generate value for customers throughout its expected life.

G. <u>SUMMARY AND REQUESTED FINDING ON ALTERNATIVES ANALYSIS</u>

347. FEI submits, and the BCUC should find, that Supplemental Alternative 9 will provide FEI's customers with the greatest value among the viable alternatives and is in the public interest.

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[453] Exhibit B-60, Supplemental Evidence, Appendix F, Raymond Mason Report, p. 7.

[454] Exhibit B-60, Supplemental Evidence, Appendix F, Raymond Mason Report, pp. 7-8.

[455] Exhibit B-63, BCUC IR5 129.5.2 and 129.5.3.

PART SIX: PROJECT DESCRIPTION

A. INTRODUCTION

348. This Part supplements Part Six of FEI's Pre-Adjournment Final Submissions. There were very few IRs in rounds five and six related to the Project Description. The subsections in this Part make the following points:

- First, the TLSE Project remains largely unchanged since the Application was filed, although the schedule is delayed.
- Second, the scope of ground improvement work has changed in response to revisions to geotechnical requirements after the Application was filed. FEI has re-evaluated the geotechnical costs and has identified measures to mitigate the scope and costs of new ground improvement work.

349. FEI submits, and the BCUC should find, that FEI has appropriately defined the TLSE Project having regard to developments since the original Application. FEI's ongoing progress reporting, discussed in Part Six, Section B of FEI's Pre-Adjournment Final Submissions, will provide appropriate BCUC oversight during the development and construction phases.

B. PROJECT DESCRIPTION REMAINS LARGELY UNCHANGED SINCE THE APPLICATION

350. Much of the TLSE Project description detail in Section 5 of the Application remains current and applicable. The Project schedule has been delayed by approximately four years to the end of 2030,[456] but the project components and the Preferred Alternative remain unchanged following the supplemental alternatives analysis. All four of these project components are necessary to address the Project objectives:[457]

> **Regasification Capacity:** 800 MMcf/d of regasification capacity (4x200 MMcf/d) will replace the existing Tilbury Base Plant equipment that has reached end-of-life. Each unit is capable of an output range of 50 to 200 MMcf/d and will be capable of providing a quicker response time than the existing configuration. This is beneficial for both gas supply and resiliency.

[456] Table 5-2 of the Supplemental Evidence (Exhibit B-60, p. 191) provides a summary of the Project schedule and key milestones, with a comparison to the schedule and milestones from the Application.

[457] Exhibit B-60, Supplemental Evidence, Table 5-1 (pp. 188-189).

LNG Storage Tank: A 3 Bcf (142,400 m^3) tank will replace the Base Plant tank which was constructed to lower engineering and safety standards in place at the time of construction. The Base plant is impacted by seismic, environmental and flooding issues inherent to its design. For planning purposes, 2 Bcf of the tank will be allocated to a resiliency reserve and 1 Bcf will be allocated to gas supply as a peaking resource.
Addition or Modification of Auxiliary Systems: Power supply, utility pipe racks, in-tank pumps, piping, cable trays, instrument air compressors, boil-off gas compressors, connectivity to the Tilbury 1A LNG storage tank and connections to the sendout gas pipeline are all required to provide the necessary power, control, monitoring and interconnection systems to safely and reliably operate the facility.
Demolition of Existing Tilbury Base Plant: As part of replacing the existing Base Plant, the above-ground portion of the Base Plant tank and liquefaction facilities will be demolished. The liquefaction facilities are no longer functional and are already being decommissioned.

351. The IRs received in rounds 5 and 6 were primarily directed at clarifying aspects of the planned boil-off gas management system (part of the auxiliary systems). FEI explained that the purpose of the system is to avoid venting boil-off gases to the atmosphere. The proposed management system represents a very significant improvement over the existing Base Plant tank. The current design is very old. It vents to the atmosphere when pressure builds in the tank beyond the design range under minor upset conditions or during periods of compressor maintenance.[458] The new system will incorporate redundancy, consistent with current-day standards, and allows other options even if the entire boil-off gas management system were to become unavailable despite the built-in redundancy.[459] As such, FEI will only need to vent boil-off gas into the atmosphere if various options afforded by the new system do not stabilize the TLSE tank's operating pressure.[460]

C. GEOTECHNICAL WORK TO MEET NEW SEISMIC STANDARDS

352. Geotechnical work is one area where the scope of work has needed to change since FEI filed the Application in 2020.

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458 Exhibit B-63, BCUC IR5 133.1.

459 Exhibit B-63, BCUC IR5 133.2.

460 Exhibit B-63, BCUC IR5 133.2. If the liquefaction facility included in the Tilbury Phase 2 LNG Expansion project's scope is constructed, FEI could also direct the boil-off gas to that facility's flare system based on operational requirements, safety considerations, and emission regulations: Exhibit B-63, BCUC IR5 133.5.

353. The TLSE Project is being planned and constructed according to applicable safety standards and best practices, including seismic standards. Significant revisions to the seismic hazard and design criteria in the latest code CSA Z276:2022 (April 2023 version) have necessitated changes to the TLSE Project's geotechnical requirements and ground improvement work since the Application was filed.[461]

354. There has been a high degree of rigour in the analysis of the scope of geotechnical work and its costing. FEI retained independent experts, WSP, to review the associated design assumptions and ground improvements in order to prepare an updated Class 4 cost estimate.[462] WSP also consulted with a specialty ground improvement contractor to ensure the design requirements could be met.[463]

355. FEI has identified measures to mitigate potential increases to scope and costs of ground improvement work. These measures are informed by the lessons learned from constructing the Tilbury 1A tank .[464] FEI also identified a number of investigative tools that it can explore prior to commencing detailed design engineering,[465] and intends to carry out a Probabilistic Seismic Hazard Analysis (PSHA) and a ground response analysis to estimate the ground settlement.[466] Further discussions regarding ground improvement work and associated cost mitigations will also take place with the tank vendor once it has been retained.[467]

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461 Exhibit B-60, Supplemental Evidence, p. 189; Exhibit B-63, BCUC IR5 135.1.

462 A copy of WSP's report is provided as Confidential Attachment 135.1.1 (Exhibit B-63-1); Exhibit B-60, Supplemental Evidence, p. 189.

463 Exhibit B-60, Supplemental Evidence, p. 189.

464 These learnings primarily include how the existing ground improvements for Tilbury 1A have performed: Exhibit B-63, BCUC IR5 135.4.

465 The following measures will be used as inputs for the geotechnical analysis: (1) cone penetration tests (CPTs) to determine the geotechnical engineering properties of the soil; (2) boreholes to collect data that would be analyzed for determination of the properties of the subsurface; and (3) a shear wave velocity survey to measure the mechanical properties of the soil: Exhibit B-63, BCUC IR5 135.2.

466 Exhibit B-63, BCUC IR5 135.2.

467 Exhibit B-63, BCUC IR5 135.2 and 135.3.

PART SEVEN: FINANCIAL ANALYSIS

A. INTRODUCTION

356. This Part addresses financial matters related to the Preferred Alternative, focusing on the following points:

- First, FEI's updated Project cost estimate is a sound basis for the BCUC to assess the TLSE Project.
- Second, FEI's rate impact analysis adheres to the BCUC's CPCN Guidelines. While the TLSE Project remains viable and provides value to customers under a shorter levelized rate impact analysis period to 2050, a 67-year analysis period is appropriate.

B. THE UPDATED CAPITAL COST ESTIMATE IS A SOUND BASIS TO ASSESS THE PROJECT

357. The updated total cost estimate for the TLSE Project is $1,143.889 million in as-spent dollars, including AFUDC.[468] The estimate is a sound basis for the BCUC to assess this Application, as it reflects developments since the original 2020 estimate, incorporates further input from experts, and increases the contingency and allowance for escalation.

358. FEI provided a breakdown of the updated TLSE Project cost estimate in Table 6-1 of the Supplemental Evidence, which is reproduced below, in both 2023 and as-spent dollars.[469]

[468] Exhibit B-60, Supplemental Evidence, p. 193.

[469] Exhibit B-60, Supplemental Evidence, p. 195. Exhibit B-64, BCOAPO IR5 4.2 includes a similar table, with both the current and original cost estimates.

Table 6-1: Breakdown of the TLSE Project Cost Estimate ($ millions)

	2023 $	As-Spent $
LNG Tank (3 BCF)	359.749	423.480
Regasification Equipment	141.483	166.547
Ground Improvement	60.944	71.740
Auxiliary System	153.964	181.239
Base Plant Demolition	14.927	17.571
Subtotal Capital Cost	731.067	860.578
Contingency	135.800	160.749
Subtotal Project Capital Costs w/ Contingency	866.867	1,021.327
CPCN Application	4.945	4.945
CPCN Preliminary Stage Development	1.546	1.546
Subtotal w/ Deferral Costs	873.358	1,027.818
AFUDC	-	120.096
Tax Offset	-	(4.025)
TOTAL Project Cost	***873.358***	***1,143.889***

359. The updated total cost estimate meets the criteria for an AACE Class 3 Cost Estimate[470], in accordance with the BCUC's CPCN Guidelines. As with the original estimate completed in 2020, FEI developed the estimate with expert input from Linde, Horton CB&I (HCBI), WSP (previously Golder), and Solaris Management Consultants Inc. (SMCI) based on criteria from AACE International Recommended Practices 18R-97 and 97R-18.[471]

360. As shown above, the updated base capital cost estimate is $731.067 million in 2023 dollars (before contingency, deferred costs and financing costs), which represents an increase of approximately 38 percent from the original 2020 base capital cost estimate of $529.103 million.[472] The updated base cost estimate breakdown is included in Confidential Appendix G to the Supplemental Evidence.[473] The base cost increase is primarily due to inflationary increases in

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470 The typical variation in low and high accuracy ranges at an 80% confidence interval for an AACE Class 3 estimate fall between -10% to -20% on the low side and +10% to +30% on the high side.

471 Exhibit B-60, Supplemental Evidence, p. 193.

472 Exhibit B-60, Supplemental Evidence, p. 194.

473 Exhibit B-60-1, Confidential Supplemental Evidence, Confidential Appendix G.

material and equipment costs and, to a lesser extent, increased labour costs consistent with the increases experienced across the industry since 2020.[474]

361. The 3 Bcf LNG storage tank represents the largest component of the base capital cost estimate. An independent expert, HCBI, provided the updated estimate for the 3 Bcf tank. HCBI applied its global estimating guidelines and considered its previous experience in building LNG tanks.[475]

362. FEI re-engaged Validation Estimating to determine the appropriate level of: (1) contingency based on an updated quantitative analysis of Project-specific and systemic risks; and (2) escalation funding based on an updated escalation risk analysis. Validation Estimating made two recommendations, which are reflected in the updated Project cost estimate:

- **Increased Contingency:** Validation Estimating recommended a total capital budget at a P50 confidence level, resulting in a contingency estimate of $135.800 million in 2023 dollars, which is approximately 19 percent of the updated base capital cost estimate.[476]
- **Escalation to a Higher Confidence Level:** Validation Estimating recommended a higher (P70) confidence level for escalation, given that the Project's scale could put significant demands on local markets (thereby generating localized escalation) and the potential for a resurgence of inflation and/or competing capital spending.[477]

C. FEI'S UPDATED RATE IMPACT ANALYSIS IS APPROPRIATE

363. FEI's rate impact analysis adheres to the BCUC's CPCN Guidelines, using appropriate inputs described above in Part Five, Section F(d). While a 67-year analysis period is appropriate for the levelized rate impact analysis, even under a 20-year adverse sensitivity the TLSE Project remains viable and will, without question, provide value to 2050.

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[474] Exhibit B-60, Supplemental Evidence, p. 194.

[475] Exhibit B-63, BCUC IR5 134.3.1.

[476] Exhibit B-60, Supplemental Evidence, p. 194; Exhibit B-60-1, Confidential Supplemental Evidence, Confidential Appendix I.

[477] Exhibit B-60, Supplemental Evidence, p. 194; Exhibit B-60-1, Confidential Supplemental Evidence, Confidential Appendix J.

(a) Updated Rate Impacts Based on Expected Life of the TLSE Project (67-Year Horizon)

364. FEI performed the rate impact analysis using a 67-year analysis period, comprised of a 60-year expected life plus a seven-year construction period. Part Seven, Section C(b) of FEI's Pre-Adjournment Final Submissions explains why a 67-year analysis period is appropriate. Part Five, Section F(e) above demonstrates that the TLSE Project will continue to provide value throughout its 60-year expected life, given the flexibility it will offer in response to changes in load over time.

365. Based on the updated capital cost estimate and accounting for gas supply benefits, the proposed TLSE Project will result in an estimated levelized delivery rate impact of 2.45 percent over the 67-year analysis period.[478] For a typical residential customer with an average annual consumption of 90 GJ, this is equivalent to $0.228 per GJ, or a bill impact of approximately $20.55 per year.[479]

366. Although the TLSE Project will increase customer rates, as demonstrated in Parts Two and Five above, there is no "zero cost" option for customers to address the anticipated loss of the Base Plant. A bare minimum like-for-like replacement will still have rate impacts, without mitigating the severe risk of a winter T-South no-flow event and leaving FEI with a sub-optimal gas supply portfolio. The additional costs of the proposed Project relative to a like-for-like investment delivers significant additional value for customers.

(b) Updated Rate Impacts Based on Hypothetical Adverse Scenario (27-Year Horizon)

367. In response to BCUC commentary in the Adjournment Decision, FEI also provided an adverse sensitivity assuming a shorter financial analysis period of 27 years (7-year construction period plus a 20-year useful life).[480] Under this sensitivity, the TLSE Project assets would be fully depreciated by 2050, resulting in a levelized total rate impact of 3.56 percent. This is approximately 1.11 percent higher than the levelized total rate impact of 2.45 percent if the new assets are depreciated over the 67-year analysis period.[481] For a typical residential customer with

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478 See Part Five, Section F(d).

479 Exhibit B-60, Supplemental Evidence, p. 203.

480 Adjournment Decision, p. 21.

481 Exhibit B-60, Supplemental Evidence, p. 204.

an average annual consumption of 90 GJ, the adverse 2050 sensitivity has a levelized total bill impact of approximately $29.88 per year, which is approximately $9.34 per year higher than the $20.55 per year over the 67-year analysis period discussed above.[482]

368. While the TLSE Project remains viable and would provide value to customers under a shorter 27-year analysis period, the totality of the evidence on the record supports the assets remaining used and useful for the full 60-year expected service life, thus avoiding the higher levelized total rate impact associated with a far shorter service life.

369. Ultimately, FEI submits that a 67-year analysis period is appropriate for the levelized rate impact analysis in light of the resiliency and gas supply benefits the TLSE Project will provide.

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[482] Exhibit B-60, Supplemental Evidence, p. 204.

PART EIGHT: ENVIRONMENTAL AND ARCHAEOLOGICAL IMPACTS

A. INTRODUCTION

370. The TLSE Project will be constructed entirely within an existing brownfield site (as shown in the photograph below) that has hosted industrial operations for roughly half a century.[483] The TLSE Project is undergoing a separate comprehensive environmental assessment process as part of the Tilbury Phase 2 LNG Expansion Project, necessitating separate approvals from both the federal and provincial governments. Thus, although the BCUC is only assessing the TLSE Project as presented in the Application and Supplemental Evidence, the components will be subject to additional regulatory scrutiny to identify, evaluate and mitigate any potential impacts.[484]

371. Part Eight of FEI's Pre-Adjournment Final Submissions discussed the environmental assessment process applicable to the TLSE Project, and FEI's initial point-in-time assessment of the associated environmental and archaeological impacts . Over the past three years, FEI has undertaken additional activities to further understand the potential environmental and

[483] Exhibit B-44, Rebuttal Evidence to TWN, p. 22.

[484] Exhibit B-1-4, Application, p. 156.

archaeological impacts of the TLSE Project. In both cases, FEI's assessment is that, before taking into consideration mitigation measures, the potential impacts associated with the TLSE Project are lower than those identified in the Application (i.e., FEI has downgraded the TLSE Project's level of environmental and archaeological risk). It also remains the case that the potential impacts associated with the TLSE Project can be mitigated through additional assessments, permitting and standard protection and mitigation measures.[485]

372. The subsections in this Part demonstrate the following supporting points:

- First, additional environmental work supports a lower (pre-mitigation) environmental risk rating for the TLSE Project than what FEI originally presented in the Application, and that the risk can be mitigated.
- Second, the results of the Archaeological Impact Assessment (AIA), which identified no archaeological materials or features, supports a lower (pre-mitigation) archaeological risk rating for the TLSE Project than what FEI originally presented in the Application.

B. <u>ADDITIONAL ENVIRONMENTAL ASSESSMENT WORK SUPPORTS LOWER ENVIRONMENTAL RISK RATING</u>

373. Based on the additional information gathered, FEI has downgraded the potential environmental impacts of the TLSE Project, which were described as "moderate" in the Application, to "low to moderate".[486] That risk can be further mitigated.

374. The Application reflected the initial risk rating assigned to various biophysical receptors identified in the Environmental Overview Assessment (**EOA**) prepared for the Tilbury Phase 2 LNG Expansion Project. Since that time, FEI completed Technical Data Reports (**TDRs**) for the biophysical receptors identified in the EOA.[487] These reports included a Terrestrial Biophysical TDR, which included wildlife and wildlife habitat surveys, vegetation and invasive species surveys and wetlands characterization, and an Aquatic Biophysical TDR, which included fish and fish habitat surveys.

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485 Exhibit B-60, Supplemental Evidence, p. 206.

486 Exhibit B-60, Supplemental Evidence, p. 206.

487 See Appendix O to the Application (Exhibit B-1-4) for a copy of the EOA.

375. The table below summarizes the risk rating assigned to each biophysical receptor in the Application (Risk Rating in EOA) compared to the Supplemental Evidence (Risk Rating in TDRs).[488] Most of these risks were already "low" in the Application, but there has been a material improvement in the risk associated with the contaminated soil and/or groundwater biophysical receptor. That risk has been downgraded from a "medium to high" to a "negligible to low" risk due to the results of the Stage 1 and Stage 2 Preliminary Site Investigations (**PSIs**), which were undertaken to further understand the potential for contamination at the site. The PSI results were that 7 of the 8 areas of potential environmental concern (**APECs**) outlined in the EOA did not show contamination. The one APEC identified as having contaminated soil (a former sawmill site) has undergone a limited detailed site investigation (**DSI**) to further delineate the extent of soil contamination, and remediation works have been scheduled.[489]

Biophysical Receptor	Risk Rating in EOA	Risk Rating in TDRs
Surface water quality and quantity	Low	Low
Fish and fish habitat	Low	Low
Vegetation and wetlands	Low	Low
Wildlife and wildlife habitat	Low	Low
Land use	Low	Low
Atmospheric	Medium to High	Medium to High
Contaminated soils and/or ground water	Medium to High	Negligible to Low

376. As a result, all but one biophysical receptor now has a "low" risk or less.[490]

377. Any potential environmental impacts associated with the TLSE Project can be mitigated through permitting processes, including the environmental assessment process, and the

[488] Exhibit B-60, Supplemental Evidence, pp. 206-207.

[489] Exhibit B-60, Supplemental Evidence, p. 207.

[490] In the case of the atmospheric biophysical receptor, Metro Vancouver permitting is still considered a "medium to high" risk. Exhibit B-60, Supplemental Evidence, p. 207.

implementation of standard best management practices, which FEI will follow during construction. FEI will also prepare an Environmental Management Plan as part of the Project tendering process, followed by an Environmental Protection Plan specific to the TLSE Project. FEI has accounted for the costs to implement specialized mitigation measures or follow-up work (if any) as part of the TLSE Project contingency.

C. RESULTS OF ARCHAEOLOGICAL IMPACT ASSESSMENT SUPPORT LOWER ARCHAEOLOGICAL RISK RATING

378. Since completing the Archaeological Overview Assessment (**AOA**) for the Project, as discussed further in Part Eight, Section D of FEI's Pre-Adjournment Final Submissions, FEI has continued to progress archaeological assessment work. This included completing: (1) a detailed AIA of the TLSE Project area based on the recommendations of the AOA; and (2) development of a project-specific Chance Find Management Procedure, with input from Indigenous groups who requested to participate.[491] With the recommendations from the AIA and development of the Archaeological Chance Find Management Procedure, FEI has downgraded the Project's risk of archaeological impact from "moderate to low" to "low".[492]

379. The AIA was conducted under *Heritage Conservation Act* Permit #2020-137 and several Indigenous Cultural Heritage Investigation permits. It included 186 test pits with Indigenous in-field assistance and remote monitoring, as well as daily post-fieldwork summaries being provided to several Indigenous groups. No archaeological materials or features were identified as part of the AIA and no further archaeological work was recommended for the TLSE Project footprint or FEI property.[493]

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491 Exhibit B-60, Supplemental Evidence, pp. 207-208.

492 Exhibit B-60, Supplemental Evidence, p. 208.

493 The AIA also recommended that the Project-specific Archaeological Chance Find Management Procedure be available to contractors prior to undertaking ground-altering activities: Exhibit B-60, Supplemental Evidence, p. 208.

PART NINE: CONSULTATION AND ENGAGEMENT

A. INTRODUCTION

380. This Part addresses consultation with the public and Indigenous groups. It augments Part Nine of FEI's Pre-Adjournment Final Submissions, which addressed FEI's approach to consultation and engagement, the Tilbury Project Agreement with Musqueam Indian Band, and the nature of the duty to consult in this case. Those submissions remain relevant.

381. FEI has been consulting with the public, local governments and other stakeholders, and engaging with Indigenous groups throughout the development of the TLSE Project. FEI has solicited feedback and has responded to concerns raised. FEI's overall consultation and engagement approach to date has, in short, been meaningful, timely and sufficient. These activities will continue through the environmental assessment process for the Tilbury Phase 2 LNG Expansion Project and BC Energy Regulator (**BCER**) permitting processes.

382. This Part is organized around the following supporting points:

- First, synchronizing consultation and engagement for the TLSE Project with the ongoing environmental assessment process for the Tilbury Phase 2 LNG Expansion Project has been effective for soliciting and addressing comments. Coordination is both practical and respectful of Indigenous groups' capacity to participate.
- Second, FEI's consultation and engagement with potentially affected Indigenous groups, the public, governments and other stakeholders has been meaningful, timely and sufficient having regard to the approvals sought and current stage of Project development. It remains consistent with the requirements of the BCUC's CPCN Guidelines.
- Third, FEI's consultation and engagement activities will continue as the TLSE Project development progresses.

B. SYNCHRONIZED ENGAGEMENT WITH THE TILBURY PHASE 2 LNG EXPANSION PROJECT ENVIRONMENTAL ASSESSMENT PROCESS HAS BEEN BENEFICIAL

383. The environmental assessment process for the Tilbury Phase 2 LNG Expansion Project, which includes components of the TLSE Project, remains underway concurrently with this CPCN

Application. FEI has synchronized engagement activities between these regulatory processes where possible to limit consultation fatigue.[494]

384. A significant amount of engagement with the public, governments, stakeholders and Indigenous groups has taken place as part of the environmental assessment process. FEI applies all comments received through this synchronized process to all applicable aspects of the developments at Tilbury, including the TLSE Project. This ensures the comments are appropriately captured and addressed.[495]

385. Synchronization is also consistent with the BC Environmental Assessment Office (BC EAO)'s framework for consensus-seeking with Indigenous groups, as outlined in the Assessment Plan for the Tilbury Phase 2 LNG Expansion Project.[496]

C. FEI'S CONSULTATION AND ENGAGEMENT CONTINUES TO BE MEANINGFUL, TIMELY AND SUFFICIENT

386. FEI's ongoing consultation and engagement regarding the TLSE Project has been meaningful, timely and sufficient to date, reflecting the nature of the approvals sought and current stage of Project development. It remains consistent with the requirements of the BCUC's CPCN Guidelines.

(a) FEI Has Provided Additional Opportunities to Engage with the Public, Governments and Stakeholders

387. Part Nine of FEI's Pre-Adjournment Final Submissions summarized FEI's engagement activities with the public, governments and other stakeholders to July 2021. In Section 8.3 of the Supplemental Evidence,[497] FEI described how it has continued to inform these groups about the Project and afford meaningful additional opportunities to engage.[498]

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494 For further information regarding the synchronization between these regulatory processes, please refer to Exhibit B-1-4, Application, Section 8.2.2 (pp. 184-185) and Exhibit B-44, Rebuttal Evidence to TWN.

495 Exhibit B-60, Supplemental Evidence, p. 210.

496 Exhibit B-60, Supplemental Evidence, p. 210 and fn. 260; Exhibit B-63, BCUC IR5 137.4.

497 Exhibit B-60, Supplemental Evidence, pp. 214-219.

498 Exhibit B-63, BCUC IR5 138.2.

388. FEI has continued to provide stakeholders with opportunities, both within the Tilbury Phase 2 LNG Expansion Project environmental assessment process and outside of it, to learn more about the TLSE Project, to ask questions and to provide feedback.[499] For example, FEI has:[500]

- Conducted more than 75 site tours and 40 project meetings and presentations;
- Continued to share new project-related materials through various communication channels (e.g., a project-specific website and social media);
- Participated in BC EAO virtual and in-person open houses as part of the early engagement and process planning phases of the environmental assessment, in addition to other local community events; and
- As part of the environmental assessment public comment period in early 2025, responded to comments from 272 members of the public and 12 letters from organizations. These responses addressed a broad spectrum of themes, including environmental impacts, safety of the Tilbury LNG facility generally, project cost and associated rate impacts, the adequacy of Indigenous engagement, and the potential economic contributions of developments at Tilbury.[501]

389. FEI has also submitted its Public Engagement Report to the BC EAO, which provides a summary of engagement that took place during the Public Comment Period and FEI's responses to public comments, including how feedback has been addressed.[502]

390. Government representatives participated in some of the public engagement activities outlined above, and FEI has also engaged directly with local governments, provincial and federal government authorities and agencies. FEI has shared updates and sought feedback regarding the TLSE Project.[503] Government representatives are also on the Technical Advisory Committee (TAC) of the environmental assessment process for the Tilbury Phase 2 LNG Expansion Project. Government TAC members have filed 684 unique comments and/or information requests in that process.[504] FEI has responded to these information requests, many of which are specifically

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[499] Exhibit B-60, Supplemental Evidence, pp. 214-216.

[500] Exhibit B-60, Supplemental Evidence, pp. 215-216.

[501] See Exhibit B-63, BCUC IR5 138.2 for a summary of the issues raised during this public comment period.

[502] Exhibit B-69, BCUC IR6 160.2.

[503] Exhibit B-60, Supplemental Evidence, p. 216.

[504] Exhibit B-63, BCUC IR5 138.2; Exhibit B-69, BCUC IR6 160.2.

related to the draft environmental assessment application itself. FEI continues to engage with government representatives regarding specific concerns, issues and inquiries about: (1) project construction and operation of the facility (e.g., hydro-testing processes); (2) environmental impacts (e.g., proposed fish/wildlife impact mitigation and GHG emissions); (3) safety and emergency response procedures; (4) socio-economic impacts; (5) noise and traffic impacts; and (6) the use of RNG as a fuel for customers.[505]

391. Consultation is a long-term and ongoing process, but FEI's work to date has been effective. FEI has responded to all inquiries received from the public, governments and other stakeholders to date. In instances where the inquiries received have been beyond the scope of the TLSE Project, such as those related to upstream GHG emissions associated with natural gas extraction and production, FEI has still provided supplemental information to the best of its ability.[506]

(b) FEI's Indigenous Engagement Has Been Broad and Extensive

392. FEI has provided additional evidence on its Indigenous engagement since the Adjournment Decision, including updated Indigenous engagement logs covering the period of July 2021 to May 2025.[507] The evidence demonstrates that FEI's ongoing engagement with Indigenous groups that are potentially affected by the TLSE Project has been significant and meaningful to date, reflecting the nature of the approvals sought and current stage of Project development. FEI's engagement remains consistent with the requirements of the BCUC's CPCN Guidelines.

393. There are several notable features about FEI's Indigenous engagement since the Adjournment Decision. First, the scope of FEI's Indigenous engagement remains broad. In Section

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505 See Exhibit B-60, Supplemental Evidence, pp. 217-219; Exhibit B-63, BCUC IR5 138.2.

506 Exhibit B-60, Supplemental Evidence, p. 217.

507 See Exhibit B-63, Attachment 137.2 for an updated Indigenous engagement log covering the period of July 2021 to February 2025 and Exhibit B-69, Attachment 160.1 for the period covering March 2025 to May 2025.

8.2 of the Supplemental Evidence, FEI described how it has continued to engage the following 21 potentially affected Indigenous groups in relation to the TLSE Project:[508]

Table 8-1: Indigenous Groups Potentially Affected by the TLSE Project

Indigenous Groups		
Cowichan Tribes	Musqueam Indian Band	Soowahlie First Nation
Halalt First Nation	Penelakut Tribe	Squamish First Nation
Katzie First Nation	Seabird Island Band	Stó:lō Nation
Kwantlen First Nation	Semiahmoo First Nation	Stó:lō Tribal Council
Lake Cowichan First Nation	Shxw'ōwhámél First Nation	Stz'uminus First Nation
Lyackson First Nation	Skawahlook First Nation	Tsawwassen First Nation
Métis Nation British Columbia	Snuneymuxw First Nation	Tsleil-Waututh Nation

FEI has also engaged an additional 22 groups identified by the BC EAO as potentially affected "Indigenous Nations" in the Assessment Plan of the environmental assessment process for the Tilbury Phase 2 LNG Expansion Project.[509]

394. Second, to date, FEI has reached funding agreements to support the capacity of 15 Indigenous groups to participate in, and engage regarding, developments at Tilbury, including the TLSE Project.[510] These agreements enable resourced, equitable participation in the Project review process.

395. Third, FEI's TLSE Project-specific engagement has ensured that potentially affected Indigenous groups are kept informed about the Project as information becomes available, are able to identify issues and concerns, and have an opportunity to describe how the TLSE Project could interact with their interests.[511] Since July 2021, FEI has undertaken over 700 individual engagements with Indigenous groups related to the TLSE Project through various methods. FEI has, for instance:[512]

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508 Exhibit B-60, Supplemental Evidence, p. 210.

509 See Exhibit B-60, Supplemental Evidence, Table 8-2 for a list of additional Indigenous groups identified by the BC EAO; Exhibit B-63, BCUC IR5 137.1.

510 Exhibit B-60, Supplemental Evidence, p. 213.

511 Exhibit B-60, Supplemental Evidence, p. 211.

512 Exhibit B-60, Supplemental Evidence, pp. 211-212.

- Continued to discuss the TLSE Project through regular project meetings with Indigenous groups;

- Held 16 tours of the Tilbury site with Indigenous groups, which provide an opportunity to ask questions about the TLSE Project and to identify areas of concern, interest or opportunity relating to the Project; and

- Updated Indigenous groups regarding the status of this Application before the BCUC.[513]

396. Fourth, when FEI receives general comments from Indigenous groups in the environmental assessment process for the Tilbury Phase 2 LNG Expansion Project, FEI has been treating those comments as if they apply to all applicable aspects of the developments at Tilbury, including the TLSE Project.[514] This approach ensures FEI's engagement regarding the TLSE Project is robust and Indigenous groups have ample opportunity to engage in a process of dialogue and consensus-seeking over the course of project development and in a number of forums.[515] FEI has received feedback from Indigenous groups through a number of forums:

- Between January 2022 and January 2025, FEI and Indigenous groups have attended 11 TAC meetings held by the BC EAO as part of the environmental assessment process. These meetings have related to a range of topics relevant to Indigenous groups and the TLSE Project;[516]

- Indigenous groups have provided input into, or co-developed with FEI, comprehensive engagement summaries, which are included in Section 11 of the environmental assessment application;[517]

- Indigenous groups have had an opportunity to provide comments and ask questions during the comment process in the environmental assessment process. The six Indigenous groups[518] that participated in the comment process have submitted more than 855 unique comments and/or information requests to FEI to date, including: potential environmental impacts (e.g., cumulative effects), safety, economic opportunities, and clarifications regarding information in the

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513 Exhibit B-60, Supplemental Evidence, Appendix L.

514 Exhibit B-63, BCUC IR5 137.2.

515 Exhibit B-63, BCUC IR5 137.2.

516 See Exhibit B-63, BCUC IR5 137.3 for links to the TAC meeting notes.

517 See Exhibit B-63, BCUC IR5 137.3 for links to the engagement summaries.

518 These groups include: 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.

environmental assessment application.[519] This process remains ongoing, consistent with the defined phases of the environmental assessment process; however, FEI has responded to the comments raised by Indigenous groups regarding the TLSE Project to date; and

- FEI has met with Indigenous groups to discuss interests and issues raised during the application development and review phase, as well as to offer technical clarifications regarding the information, assessments and studies supporting the Tilbury Phase 2 LNG Expansion Project environmental assessment application.[520]

397. Fifth, FEI has entered into a project agreement with the Musqueam Indian Band (discussed further in Part Nine, Section B(b) of FEI's Pre-Adjournment Final Submissions) to work in close collaboration regarding projects at Tilbury Island.[521] FEI has also entered into an agreement with Snuneymuxw First Nation. Both agreements demonstrate the value of meaningful engagement and reflect FortisBC's collective efforts to build strong relationships with Indigenous groups and seek consent regarding the TLSE Project and other Tilbury projects.

D. FEI'S CONSULTATION AND ENGAGEMENT ACTIVITIES ARE ONGOING AND WILL REMAIN COMPREHENSIVE AND RESPONSIVE

398. FEI will continue to consult and engage with potentially affected Indigenous groups, the public, governments and other stakeholders during future phases of project development, construction, and operation.

399. FEI's consultation and engagement will continue to occur as part of the ongoing environmental assessment process, as well as through other future permitting processes.[522] FEI's efforts will evolve based on feedback to ensure that questions and input are addressed, including through:[523]

- **Public Comment Opportunities:** Additional environmental assessment public comment periods will be held during the Effects Assessment & Recommendation phases, which should include BC EAO-led in-person and virtual open houses;

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519 These comments are summarized in Exhibit B-63, BCUC IR5 137.4; see also Exhibit B-69, BCUC IR6 160.1.

520 Exhibit B-69, BCUC IR6 160.1.

521 Exhibit B-60, Supplemental Evidence, p. 214, fn. 264.

522 Exhibit B-60, Supplemental Evidence, pp. 214 and 219.

523 Exhibit B-63, BCUC IR5 138.3; Exhibit B-69, BCUC IR6 160.2.

- **Meetings, Workshops, Presentations & Notifications with Indigenous Groups, Government and Stakeholders:** Ongoing meetings to provide updates and address any emerging questions or concerns. In addition, Indigenous groups, government and other 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; and

- **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.

400. Once the TLSE Project has been approved through this process and the Tilbury Phase 2 LNG Expansion Project environmental assessment process, FEI will develop all necessary public consultation plans to support future permitting requirements and construction activities. This could include tailored plans such as a public impact mitigation plan and a traffic management plan, designed to meet local government, provincial, and federal requirements.[524]

401. FEI submits that there is ample evidence substantiating FEI's commitment to continued transparent, meaningful and respectful engagement with potentially affected Indigenous groups, the public, governments and other stakeholders.

[524] Exhibit B-63, BCUC IR5 138.3.

PART TEN: BC ENERGY OBJECTIVES AND LONG-TERM GAS RESOURCE PLAN

A. INTRODUCTION

402. Section 46(3.1) of the UCA states that the BCUC "must consider": "(a) the applicable of British Columbia's energy objectives" in section 2 of the *Clean Energy Act*,[525] and "(b) the most recent long-term resource plan filed by the public utility under section 44.1, if any." The subsections in this Part make the following points:

- First, "the applicable of British Columbia energy objectives" support the issuance of a CPCN for the TLSE Project. It will drive economic development and job creation while being consistent with the goal of reducing GHG emissions. This section also addresses the BCUC's question in its June 4, 2025, letter regarding GHG emissions.
- Second, this Application considers and is consistent with the outcome of the 2022 LTGRP proceeding.

B. TLSE PROJECT ADVANCES OR IS CONSISTENT WITH APPLICABLE ENERGY OBJECTIVES

403. "[T]he applicable of British Columbia's energy objectives" support the issuance of a CPCN for the TLSE Project. As discussed below, the TLSE Project is expected to drive economic growth and job creation, while being consistent with the goal of reducing GHG emissions.

(a) Most of the Energy Objectives Are Clearly Inapplicable

404. Most of the objectives are clearly inapplicable to the TLSE Project. Section 6 of the BCUC's CPCN Guidelines indicates that, if the nature of the project precludes a direct link to the energy objectives, the application should discuss how the project does not hamper other projects or initiatives undertaken by the applicant or others, from advancing these energy objectives.[526] In this regard, Table 9-1 of the Supplemental Evidence confirms that the TLSE Project does not conflict with any energy objectives.

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[525] SBC 2010, c. 22.

[526] CPCN Guidelines, p. 9.

(b) TLSE Project Will Drive Economic Development and Job Creation During Construction and Will Likely Prevent Billions of Dollars in Economic Harm

405. Section 2(k) of the *Clean Energy Act* is directly applicable to the TLSE Project: "to encourage economic development and the creation and retention of jobs". The TLSE Project promotes this objective in two ways.

406. First, constructing the Project will benefit the local economy by creating jobs in the province through FEI's contractors, as well as the procurement of goods and services from locally owned and operated vendors and subcontractors. FEI has committed to developing the local workforce, supporting local businesses, and connecting them to Project opportunities. FEI will work with Indigenous groups, community leaders and local organizations to implement this commitment.[527]

407. Second, as discussed in Part Three above, a key Project driver is to reduce the known potential for a winter T-South no-flow event to cause a customer outage with catastrophic socio-economic impacts.[528] The 2024 Resiliency Plan analysis confirms that losing T-South supply for less than a day during average winter conditions will, without question, result in many hundreds of thousands of natural gas customers losing access to gas for over two months. The outage will occur in the Lower Mainland, which represents the largest portion of the Provincial economy. PwC's analysis confirms that a single outage of this nature will cause billions of dollars of economic harm. Exponent's probability analysis indicates that we can expect an event like this at least once over the life of the Project, and probability calculations inherently obscure the reality that there could even plausibly be multiple events in quick succession. The following figure from the PwC Report shows the breadth of economic sectors that would be affected.[529]

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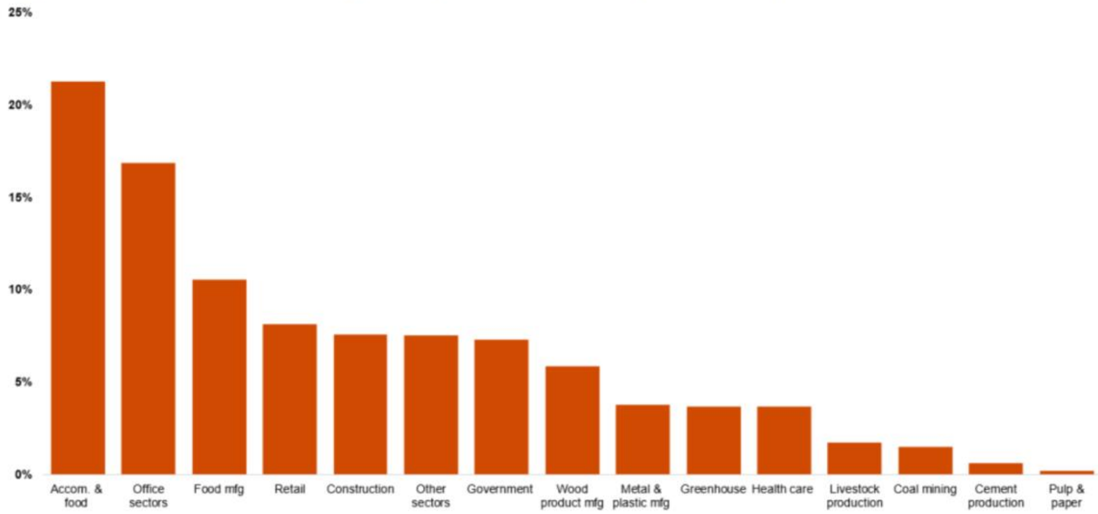
[527] Exhibit B-60, Supplemental Evidence, p. 223.

[528] Exhibit B-60, Supplemental Evidence, p. 223.

[529] See Exhibit B-60, Supplemental Evidence, p. 40; Exhibit B-61, 2024 Resiliency Plan, Appendix RP 3, PwC Report, p. 13.

Figure 6: Illustration of GDP impacts by sector, Percentage of total impact



Source: PwC analysis; breakdown based on AV-3 Reviewed Scenario; "Other sectors" category comprises the sum of the results across around 90 other sectors of the economy.

408. Recent CPCN decisions have recognized the benefits of project construction for economic development and job creation. Three examples are FEI's Coastal Transmission System and Interior Transmission System Transmission Integrity Management Capabilities projects and the Pattullo Gas Line Replacement project.[530]

(c) Project Aligns with GHG-Related Energy Objectives (Response to the BCUC Question)

409. The BCUC's letter of June 4, 2025 sought comments on the following topic:[531]

> How any incremental Greenhouse Gas (GHG) emissions that result from the TLSE Project impact the extent to which the TLSE Project aligns with BC's Energy Objectives. This should include incremental GHG emissions that result from the various phases of the TLSE Project (e.g. commissioning, normal operations, regasification), based on the relevant information included within the evidentiary record.

410. The TLSE Project is consistent with BC's energy objectives. As discussed below, the TLSE Project will not result in any sustained incremental GHG emissions and will reduce GHG emissions in some circumstances. In any event, as described further below, FEI is required to ensure the

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[530] See e.g., Decision and Order C-3-22, dated May 18, 2022, p. 56; Decision and Order C-1-24, dated January 15, 2024, p. 35; and Decision and Order C-2-21, dated June 30, 2021, p. 47.

[531] Exhibit A-52.

Tilbury Phase 2 LNG Expansion Project is capable of producing net-zero GHG emissions when it enters operation (i.e., net-zero ready).

The TLSE Project Provides Essential Storage and Regasification to Serve Existing Load

411. In considering this question, it is important to recognize what the TLSE Project is, and what it is not. The TLSE Project involves, in essence, replacing a pre-existing storage tank and regasification equipment that have been in place since 1971 to permit the continued provision of safe and reliable service. This is important when considering GHG emissions in several respects:

- First, the TLSE Project does not include new liquefaction, and is not being constructed to support exports.[532] This misapprehension is reflected in letters of comment filed in this process.[533]
- Second, the TLSE Project is sized based on customers' needs today, and does not to create capacity for load growth (see Part Five, Section F above). The peaking supply needs to come from somewhere. The TLSE Project is just avoiding the need for customers to pay more, and face greater deliverability risk, for the same amount of supply from an expanded regional pipeline or storage facility.
- Third, as described below, by virtue of being a peaking supply and resiliency asset, the tank is being depleted and refilled only very intermittently (particularly in the case of the "resiliency reserve" portion of the tank).
- Fourth, the TLSE Project is replacing a 1971 facility with a new facility that will be built to modern standards, which includes significantly reducing the current potential for GHG emissions through venting in normal operations (see Part Four, Section B(b) above).

GHG Emissions During Various Phases of the TLSE Project

412. **Commissioning:** The TLSE tank will be vented during the initial commissioning and cool down process as the boil-off compressors cannot accommodate the ambient temperature gases used for commissioning. This is a one-time event. This process will continue until the internal tank temperature is cold enough to allow for recompression into FEI's system.[534] FEI estimates

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[532] See Part 2, Section C of FEI's Pre-Adjournment Final Submissions.

[533] e.g., Exhibits E-15, E-20, E-21, E-22 and E-24.

[534] Exhibit B-18, BCSEA IR1 10.1.

that this single occurrence of venting will release approximately 6,500 tonnes of GHG emissions.[535] The liquefaction process to fill the TLSE tank is powered by electricity, thus reducing the carbon intensity of the LNG production process.[536]

413. **Normal Operations:** During normal operations, the main source of GHG emissions associated with the TLSE Project will come from the intermittent use of regasification equipment (vapourizers). The GHG emissions associated with regasification will not be significant. Use of the vapourizers will be infrequent, given that two thirds of the tank is set aside as a "resiliency reserve" and the remainder is a peaking gas supply that would normally only be used on a few days in the winter.[537]

414. Beyond regasification, there will be no continuous GHG emissions in normal operations as the TLSE Project incorporates modern design standards which make venting to the atmosphere very unlikely.[538] For example, as discussed in Part Six, Section B above, any boil-off-gas from stabilizing the tank's pressure will be contained by the boil-off-gas management system (which is electrically driven[539]) and returned to FEI's system, rather than being vented to the atmosphere.[540] The TLSE Project has also been designed with full secondary containment to prevent venting in the unlikely event of a breach.[541] In both respects, the TLSE Project is a significant improvement to the existing Tilbury Base Plant. In the unlikely event of an operational upset (e.g., FEI could not stabilize the tank pressure), the overpressure amount vented to the atmosphere is estimated to be only 1.7 MMcf/d.[542]

415. **Supply Emergency:** As a resiliency asset, the TLSE Project has the potential to avoid GHG emissions because of the avoided GHG emissions associated with preventing a widespread Lower

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535 Exhibit B-1-4, Application, Appendix Q-1, p. 6-1.

536 Exhibit B-44, Rebuttal Evidence to TWN, Appendix D, PDF p. 155.

537 Exhibit B-15, BCUC IR1 49.2; Exhibit B-18, BCSEA IR1 9.1.

538 Exhibit B-1-4, Application, pp. 101 and 130; Exhibit B-15, BCUC IR1 21.4.

539 Exhibit B-18, BCSEA IR1 10.6.

540 The boil-off gas system is designed for the maximum possible boil-off-gas rate and, as such, no GHG emissions are expected during normal operations: Exhibit B-63, BCUC IR5 133.1.

541 Exhibit B-60, Supplemental Evidence, pp. 79-80.

542 Exhibit B-1-4, Application, p. 127; Exhibit B-16, BCUC Confidential IR1 14.3; Exhibit B-18, BCSEA IR1 10.3.

Mainland outage. In an emergency event, FEI will need to run the regasification equipment, but the GHG emissions associated with that are relatively small. For instance, to take an extreme example of a peak day event, FEI expects GHG emissions at 800 MMcf/d to be limited to 37 tonnes per hour,[543] and at this rate of regasification FEI would fully consume the resiliency reserve within 2.5 days. But operating the TLSE Project regasification equipment allows the Lower Mainland system to remain pressurized, whereas today it is very likely that an uncontrolled depressurization will occur.[544] An uncontrolled depressurization results in GHG emissions because any air within the gas distribution system must be purged before it is repressurized. An air-gas mixture is expelled from the system and into the atmosphere as part of this process.[545]

TLSE Project GHG Emissions Are Accounted for in Environmental Assessment Net-Zero Planning

416. While the TLSE Project is not expected to contribute to sustained GHG emissions over the Project life, the full life-cycle GHG emissions of the TLSE Project will nonetheless be assessed as a component of the ongoing environmental assessment process for the Tilbury Phase 2 LNG Expansion Project.[546] Approximately 95 percent of the GHG emissions associated with the Tilbury Phase 2 LNG Expansion Project are associated with a liquefaction facility that is a non-regulated asset and not covered by this CPCN Application.[547]

417. FEI is required to ensure the Tilbury Phase 2 LNG Expansion Project is capable of producing net-zero GHG emissions when it enters operation (i.e., net-zero ready).[548] This aligns with governmental emissions reduction requirements, including the federal Strategic Assessment of Climate Change (SACC) and provincial Energy Action Framework which require a credible net-zero plan that describes how the Project will achieve net-zero emissions by 2050 and

543 Exhibit B-18, BCSEA IR1 9.1.

544 Exhibit B-60, Supplemental Evidence, Table 3-2 (p. 43) and Section 4.7.3.1 (pp. 175-176).

545 Exhibit B-1-4, Application, Section 3.3.3.2.1 (p. 34); Exhibit B-46-1, Rebuttal Evidence to RCIA, p. 36; Exhibit B-60, Supplemental Evidence, Section 4.7.3.1.

546 Exhibit B-44, Rebuttal Evidence to TWN, p. 29.

547 Exhibit B-44, Rebuttal Evidence to TWN, p. 29.

548 Exhibit B-63, BCUC IR5 137.4 and 138.2.

2030, respectively, in order to proceed through the environmental assessment process.[549] The development of a net zero GHG emissions plan for the Tilbury facility further advances British Columbia's energy objectives.[550]

A Resilient System Supports Decarbonization Efforts

418. More broadly, FEI submits that its system as a whole is playing an important role in advancing decarbonization. The resiliency driver behind the TLSE Project dovetails with FEI's planned transition to a low-carbon energy system. As FEI explains:[551]

> …the TLSE Project enables greater resilience of the gas energy delivery system, which as noted the [FortisBC's] *Clean Growth Pathway to 2050*, is expected to deliver an increasing proportion of renewable and low carbon energy into the future. The need for resilience is even greater as energy supply on both gas and electric systems shifts to incorporate intermittent sources. Accordingly, the TLSE plays a fundamental role in providing resilience to the energy system and supports BC's climate action framework.

Guidehouse's Pathways for British Columbia to Achieve its GHG Reduction Goals report (Guidehouse Pathways Report)[552] highlights the critical role that the gas system will have in the Province's decarbonization path. Guidehouse observes that decarbonizing BC's energy system cannot come at the cost of the system's resiliency and its ability to meet BC's energy requirements – particularly during extremely cold weather conditions.[553]

BCUC Has Determined that Prior Reliability Projects Support BC Energy Objectives

419. In the context of other CPCN applications where the project objective supports uninterrupted service to customers, rather than promoting load growth, the BCUC has been satisfied that the applicable British Columbia energy objectives supported the issuance of a CPCN. Three examples are the Coastal Transmission System and Interior Transmission System

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[549] Government of Canada, Strategic Assessment of Climate Change (2020); British Columbia, Energy Action Framework (2023): Exhibit B-63, BCUC IR5 137.4 and 138.2; Exhibit B-44, Rebuttal Evidence to TWN, p. 29.

[550] Exhibit B-44, Rebuttal Evidence to TWN, p. 24.

[551] Exhibit B-15, BCUC IR1 63.1.

[552] Exhibit B-15, Attachment 63.1.

[553] Exhibit B-15, BCUC IR1 63.1.

Transmission Integrity Management Capabilities projects, and the Pattullo Gas Line Replacement project.[554]

(d) The Requirement of "Must Consider" Does Not Mean "Prioritize Above Safe and Reliable Service"

420. The list of BC's energy objectives shows a clear intent to promote GHG reduction, among other objectives. However, it would be inconsistent with the wording and broader statutory framework, and the BCUC's core mandate to interpret section 46(3.1) of the UCA as establishing the promotion of a particular objective (e.g., GHG reduction) as a precondition to approval of a project.

421. The requirement in section 46(3.1) is that the BCUC "must consider" the applicable of British Columbia's energy objectives. "Must consider" is not synonymous with "must prioritize" or "must promote" or even "must not be contrary to". If the Legislature had intended that outcome, it could have explicitly said so.

422. The overarching requirement in sections 45-46 of the UCA is to apply a public interest test, and it is well-established that the public interest incorporates many considerations. Safe, reliable and cost-effective service, which is the driver of the TLSE Project, is clearly one of those considerations. There is default expectation in the UCA that FEI will provide just and reasonable service (sections 59-61), and that it will "maintain its property and equipment [which includes its LNG facilities] in a condition to enable it to provide, a service to the public that the commission considers is in all respects adequate, safe, efficient, just and reasonable" (section 38). The long-term resource planning framework (section 44.1) is predicated on having sufficient facilities and supply "in order to serve" post-DSM load.

423. A central element of the BCUC's core mandate is, according to the Supreme Court of Canada, "protecting the integrity and dependability of the supply system".[555]

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[554] See e.g., Decision and Order C-3-22, dated May 18, 2022, p. 56; Decision and Order C-1-24, dated January 15, 2024, p. 35; and Decision and Order C-2-21, dated June 30, 2021, p. 47.

[555] *ATCO Gas & Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, 2006 SCC 4 at para. 7.

424. The Tilbury facility is a critical piece of FEI's "property and equipment" necessary to provide reliable service to FEI's firm load net of FEI's extensive (and BCUC-accepted) DSM. The Tilbury Base Plant is old, obsolete and incapable of being "maintained" indefinitely. The evidence demonstrates that, until the Base Plant is replaced, the dependability of gas service in the Lower Mainland is exposed to unacceptable risk due to both: (1) the non-availability of alternative peaking supply in the market; and (2) the potential for a winter T-South no-flow event. It remains just and reasonable – as it has been for many years for all utilities in British Columbia – for FEI to have enough supply to serve firm customers in normal operations. It is similarly just and reasonable to mitigate an unacceptably severe customer outage risk.

425. Recent government policy statements also indicate that GHG reduction initiatives are not intended to result in British Columbians being left with their energy needs unmet, even if that means using natural gas. For instance, the "*Powering Our Future*" report states:[556]

> BC's gas system will also continue to play an important role for many years to come in order to maintain system resiliency, meet peak energy demand, and provide home heating in colder climates.

426. FEI respectfully submits that consideration of GHG emissions and economic development and jobs are important to consider, but the need to protect customers from known harm and provide dependable service must carry the day.

C. THE TLSE PROJECT IS CONSISTENT WITH FEI'S 2022 LONG-TERM GAS RESOURCE PLAN

427. This Application is consistent with the outcome of the 2022 LTGRP proceeding.

428. The TLSE Project was considered at length in the 2022 LTGRP proceeding as a means of enhancing the resiliency of FEI's gas system in response to the 2018 T-South Incident. As discussed in Part Three, Section B above, the 2024 Resiliency Plan is responsive to the additional analysis identified by the BCUC Panel in the Adjournment Decision. The BCUC Panel for the 2022 LTGRP proceeding agreed this additional analysis was needed to complete its review of the

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[556] Exhibit B-64, BCOAPO IR5 1.2. See also Exhibit B-66, CEC IR5 133.1.

Resiliency Plan and, ultimately, to make any decisions regarding the infrastructure needed to implement it.[557]

429. The 2022 LTGRP also explained the vital role of the existing Tilbury Base Plant in providing gas supply throughout the year and, in particular, during peak demand events. It noted that the attributes of, and peaking supply provided by, Tilbury LNG is difficult to replace with market alternatives.[558] This is one of the drivers behind the TLSE Project need, discussed in Part Four above.

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[557] Decision and Order G-78-24, dated March 20, 2024, p. 40; Exhibit B-60, Supplemental Evidence, p. 224.

[558] Exhibit B-60, Supplemental Evidence, p. 224 citing 2022 LTGRP, Exhibit B-1, Section 6.3.2, pp. 6-25.

PART ELEVEN: ADDITIONAL ORDERS AND TERMS

A. INTRODUCTION

430. This Part addresses the additional regulatory account approvals sought, progress reporting, acceptance of the 2024 Resiliency Plan, and terms addressing the allocation of the TLSE tank for planning purposes.

B. REGULATORY ACCOUNT PROPOSALS REMAIN REASONABLE

431. Part Seven, Section E of FEI's Pre-Adjournment Final Submissions explained why FEI's two proposed regulatory accounts – the "Application and Preliminary Stage Development Costs" deferral account and the "TLSE FX Mark to Market" deferral account – are just and reasonable and should be approved under sections 59-61 of the UCA. The original rationale for the accounts remains valid.

432. With respect to the Application and Preliminary Stage Development Costs, FEI provided an updated forecast of pre-tax deferral costs totalling $6.491 million.[559] FEI will record the actual Application and Preliminary Stage Development Costs in the proposed new non-rate base deferral account, attracting FEI's weighted average cost of capital until it enters rate base. Consistent with FEI's previous CPCN applications, FEI proposes to transfer the balance in the deferral account to rate base on January 1 of the year following BCUC approval of the Application and to commence amortization over a three-year period thereafter.[560]

C. PROGRESS REPORTING PROVIDES OVERSIGHT DURING DEVELOPMENT AND CONSTRUCTION

433. FEI's ongoing progress reporting, discussed in Part Six, Section B of FEI's Pre-Adjournment Final Submissions, will provide appropriate BCUC oversight during the development and construction phases.

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559 Exhibit B-60, Supplemental Evidence, Table 6-3 (p. 197).

560 Exhibit B-60, Supplemental Evidence, pp. 197-198.

D. BCUC SHOULD ACCEPT THE 2024 RESILIENCY PLAN

434. The considerations outlined above, as further developed in the following sections, support a finding that the 2024 Resiliency Plan forms a sound basis for determining this Application and should be accepted by the BCUC pursuant to section 44.1 of the UCA as part of granting a CPCN for the TLSE Project. In particular, given that the BCUC and interveners have had an opportunity to thoroughly test the Plan in this proceeding, FEI considers that a second review in the next LTGRP process would likely be inefficient.[561]

E. TERMS REGARDING TANK ALLOCATION (RESPONSE TO BCUC QUESTION)

435. On June 4, 2025, the BCUC requested that parties address the following issue:[562]

> Whether the BCUC is authorized to issue a CPCN for the TLSE Project subject to terms that specify how the TLSE Project LNG storage capacity can be allocated. For example, the ability of the BCUC to issue a CPCN for the TLSE Project subject to 2 billion cubic feet (BCF) of LNG storage capacity being allocated as a resiliency reserve and 1 BCF of LNG storage capacity being allocated for gas supply. If FEI considers that the BCUC is authorized to specify the use of a public utility asset in such terms, whether it's in the public interest to do so.

436. The BCUC has jurisdiction to include terms in its CPCN addressing the allocation of LNG storage capacity, pursuant to section 46(3) of the UCA. The BC Court of Appeal has confirmed the BCUC's jurisdiction to impose conditions under this section about matters related to its core mandate.[563]

437. FEI would not object to the BCUC specifying an allocation of the TLSE Project tank for planning purposes as between a "resiliency reserve" and FEI's gas supply portfolio. If the allocation is to be formalized in this manner, it is critical that the term is crafted very carefully to avoid inadvertently harming customers. First, the allocation serves an important role in planning, and that should be the focus of the term. FEI anticipates adhering to the allocation in normal circumstances, but it is conceivable that unforeseen adverse supply or operational circumstances

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561 Exhibit B-61, BCSEA IR5 21.1; Exhibit B-71, BCSEA IR6 27.1.

562 Exhibit A-52.

563 *Coquitlam v. British Columbia (Utilities Commission)*, 2021 BCCA 336 at para. 81.

could require real-time operational decisions to avoid potential harm to customers. In such cases, there is likely to be insufficient time to obtain prior BCUC approval to reallocate some LNG.

438. Second, it is important not to define the uses of the "resiliency reserve" too narrowly, such that it would inadvertently preclude some valuable resiliency uses. For instance, it would be contrary to the best interests of customers to reserve the LNG for something as specific as "for a winter T-South no-flow event", given that there are many possible causes of a supply emergency. The purpose of the "resiliency reserve" is best articulated broadly with reference to its true purpose: to be available for any circumstances where FEI believes, based on the available information, that the alternative to using it is the potential interruption of firm service.

439. Third, the term should explicitly recognize that FEI is at liberty to apply to change the allocation, although in practice changes are likely to be infrequent (e.g., where load changes materially).[564] It is useful for the BCUC to telegraph to all future stakeholders that the intent is not to lock in the allocation for all time, regardless of changing circumstances. The most efficient venue for FEI to make such a request is likely to be an ACP filing. FEI files ACPs annually for acceptance pursuant to section 14 of the BCUC Rules for Natural Gas Energy Supply Contracts. Each ACP will, as a matter of course, reflect a specific allocation of the TLSE tank to gas supply.

440. The following draft terms would address the issues noted above:

- Subject to further order of the BCUC, once the TLSE Project is in-service, FEI must:
  - include 1 Bcf from the TLSE tank in its subsequent ACPs; and
  - allocate 2 Bcf of the TLSE tank as a "resiliency reserve" that is set aside for addressing a potential interruption of firm service.
- For clarity, nothing in this order is intended to:
  - restrict FEI's use of the "resiliency reserve" to a no-flow event on T-South or otherwise,

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564 Exhibit B-63, BCUC IR5 129.3.

   - prevent FEI from using LNG allocated to gas supply for resiliency purposes where FEI believes, based on the available information, that the alternative to using it is the potential interruption of firm service.

- FEI may apply to the BCUC if it believes that the allocation for planning purposes should be changed.

PART TWELVE: CONCLUSION AND ORDER SOUGHT

441. In the six years since FEI filed this Application, FEI has done the work necessary to provide the BCUC with a sound evidentiary basis to evaluate the TLSE Project.

442. The evidence establishes a clear need for the TLSE Project. FEI recognizes that the TLSE Project is a significant investment and that the future is uncertain; however, there is no free option for customers and prolonging the *status quo* holds greater risk. A winter T-South no-flow event lasting less than a day will, without question, result in catastrophic harm. While the timing and frequency of these events is impossible to predict, we know that near misses have already occurred and there is a high probability that a no-flow event like the 2018 T-South Incident will occur again.

443. Irrespective of resiliency, the Base Plant has reached end-of-life after providing excellent value to customers for 55 years. FEI still needs dependable and rapidly deployable peaking gas supply to maintain firm service in normal operations. There is no available capacity in the market, such that a replacement facility is the only way to obtain the necessary peaking supply. LNG facility projects have long lead times,[565] such that the time is now to address these known resiliency and gas supply needs.

444. FEI's comprehensive alternatives analysis confirms that the Preferred Alternative will provide the greatest value to customers, having regard to a variety of measures, and is in the

[565] Exhibit B-60, Supplemental Evidence, pp. 80-81. FEI estimates that it would take 6 to 8 years to permit and construct a new tank and regasification equipment after deciding to build a new facility. Even a like-for-like replacement (0.6 Bcf tank and 200 MMcfd vaporization) would take over 4 years to engineer, procure and construct, assuming no further delays due to regulatory approvals, market conditions and other external factors.

public interest. FEI respectfully submits that the BCUC should approve the TLSE Project, as proposed, along with the other requested approvals discussed in Part Eleven above.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

Dated:	June 19, 2025	***[original signed by Matthew Ghikas]***
		Matthew Ghikas
		Counsel for FortisBC Energy Inc.
Dated:	June 19, 2025	***[original signed by Niall Rand]***
		Niall Rand
		Counsel for FortisBC Energy Inc.

APPENDIX A: MODELLING PARAMETERS THAT TEND TO UNDERSTATE CURRENT RISK AND THE PREFERRED ALTERNATIVE'S FINANCIAL BENEFITS

ITEM	ASSUMPTION	HOW DOES THE ASSUMPTION RESULT IN UNDERSTATEMENT OF CURRENT RISK AND FINANCIAL BENEFITS?	REFERENCE
1	***Risk Assessment Modelling Inputs Provided to PwC & Exponent***		
1.1	When determining the number of customer outages for a given pipeline AV, it was assumed that the pipeline failure occurred at the far downstream end of the pipeline.	The assumption has the effect of under reporting the number of customer outages that could be impacted by an AV. That is, for some AVs, if the failure occurred further upstream than has been assumed, more customers would be impacted than has been reported in the analysis.	Exhibit B-61, 2024 Resiliency Plan, Section 3.4.1.1
1.2	Following a no-flow event that results in a gas outage, 25 percent of customers will relight their own appliances.	The assumption results in a shorter Total Outage Duration. As the Total Outage Duration is an input to the risk calculation, the assumption results in a lower calculated risk. That is, if the risk calculation instead assumed that fewer customers relight their own appliances, the calculated risk would be higher. FEI's Rebuttal Evidence to RCIA (Exhibit B-46-1) explained the barriers to self-relights in the context of a widespread outage.	Exhibit B-61, 2024 Resiliency Plan, Section 3.4.1.2 FEI Pre-Adjournment Final Submissions, Part 3, Section F(b)
1.3	In the baseline scenario (i.e., without the TLSE Project), due to the location, it was assumed that two of the four AVs which represent T-South will result in a controlled shutdown.	A controlled shutdown is not assured. The assumption results in a shorter Total Outage Duration in the baseline scenario for these AVs. As the Total Outage Duration is an input to the risk calculation, the assumption results in a lower baseline risk for these AVs. Further, as the baseline risk is lower, the loss reduction provided by the Preferred Alternative for these AVs is also lower. That is, the benefit of the Preferred Alternative may be understated as a result of the assumption.	Exhibit B-61, 2024 Resiliency Plan, Section 3.4.1.2.2

ITEM	ASSUMPTION	HOW DOES THE ASSUMPTION RESULT IN UNDERSTATEMENT OF CURRENT RISK AND FINANCIAL BENEFITS?	REFERENCE
1.4	The relight rates assume that Lower Mainland private contractors and personnel from other operating companies (via mutual aid) will be available to assist FEI in the recovery effort following a widespread gas outage.	This may or may not be possible in reality. This assumption shortens the Total Outage Duration for AVs, like T-South, that result in a widespread gas outage. That is, since there are more personnel participating in the recovery effort, the time it takes to recover is shorter than it otherwise would be if only FEI personnel were available. As the Total Outage Duration is an input to the risk calculation, the assumption results in a lower calculated risk. Put another way, if the risk calculation instead assumed that private contractors and mutual aid resources failed to materialize, the calculated risk would be higher.	Exhibit B-61, 2024 Resiliency Plan, Section 3.4.1.3.2
2	***PwC Analysis***		
2.1	Where PwC did not interview any organizations in a sector, it was assumed that the sector would experience no direct economic impacts from the gas supply outage.	The assumption results in these sectors not contributing to the estimated GDP impact from the gas outage. As the GDP impact is one of the consequence metrics used in the risk calculation, an underestimated GDP impact results in a lower calculated risk.	Exhibit B-61, 2024 Resiliency Plan, Appendix RP 3 (PwC Report), Section 2.4, Table 3
2.2	The potential for a gas outage to cause brownouts in the electric system, and the associated negative GDP impacts from the brownouts, was not considered in PwC's analysis.	Widespread service disruption to the electric system can result in significant negative impacts to GDP. By excluding the potential impact to the electric system from a gas outage, the estimated GDP impact is likely underestimated. As the GDP impact is one of the consequence metrics used in the risk calculation, an underestimated GDP impact will result in a lower calculated risk.	Exhibit B-61, 2024 Resiliency Plan, Appendix RP 3 (PwC Report), Appendix 4
2.3	In PwC's analysis for hospitals, it was assumed that there would be no reduction in output in any scenario due to the availability of backup energy. This assumption was designed to be conservative and was founded on interview feedback that hospitals would likely be prioritized for fuel deliveries allowing continued operation even if the outage extended beyond the duration covered by their existing energy backup supplies. Therefore, the negative economic impacts in the health sector arise only in facilities which were reported to generally not have backup, such as at family doctors and outpatient clinics.	The assumption results in a lower GDP impact in the health sector, and thus a lower risk calculation.	Exhibit B-61, 2024 Resiliency Plan, Appendix RP 3 (PwC Report), Appendix 1 Exhibit B-75, CEC IR6 167.3

ITEM	ASSUMPTION	HOW DOES THE ASSUMPTION RESULT IN UNDERSTATEMENT OF CURRENT RISK AND FINANCIAL BENEFITS?	REFERENCE
2.4	PwC did not quantify the impacts of an outage on the residential sector. While the associated impacts would likely primarily include impacts on health, education (through school closures) and welfare effects resulting from inconvenience and disruption to everyday life, some of these impacts would have a negative economic impact.	Economic impacts to residential customers did not contribute to the estimated GDP impact from the gas outage. As the GDP impact is one of the consequence metrics used in the risk calculation, an underestimated GDP impact will result in a lower calculated risk.	Exhibit B-72, CEC IR6 160.4.
2.5	PwC did not take into account longer-term economic implications beyond the outage period, such as permanent business closures that would result in reduced GDP output.	Economic impacts beyond the outage period did not contribute to the estimated GDP impact from the gas outage. As the GDP impact is one of the consequence metrics used in the risk calculation, an underestimated GDP impact will result in a lower calculated risk.	Exhibit B-61, 2024 Resiliency Plan, Appendix RP 3 (PwC Report) p. 9.
2.6	PwC did not quantify the impacts of property damage and how this could impact an organization's ability to generate economic output after an outage.	Property damage did not contribute to the estimated GDP impact from the gas outage. As the GDP impact is one of the consequence metrics used in the risk calculation, an underestimated GDP impact will result in a lower calculated risk.	Exhibit B-61, 2024 Resiliency Plan, Appendix RP 3 (PwC Report), p. 9.
2.7	PwC did not assume any sectors were fully shutdown during an outage.	The estimated GDP impact from the gas outage may be underestimated. As the GDP impact is one of the consequence metrics used in the risk calculation, an underestimated GDP impact results in a lower calculated risk.	Exhibit B-72, CEC IR6 160.2.
2.8	PwC did not quantify the economic impacts beyond British Columbia because of an outage (e.g., supply chain disruptions across Canada).	Economic impacts outside of British Columbia did not contribute to the estimated GDP impact from the gas outage. As the GDP impact is one of the consequence metrics used in the risk calculation, an underestimated GDP impact will result in a lower calculated risk.	Exhibit B-61, 2024 Resiliency Plan, Appendix RP 3 (PwC Report), p. 9.
3	***Exponent Analysis***		
3.1	Exponent's calculation of the T-South failure probability did not consider cyberattack as a cause of a no-flow event.	As a potential cause of a T-South no-flow event is not accounted for, the T-South failure probability may be understated, and thus the calculated T-South risk may be understated.	Exhibit B-61, 2024 Resiliency Plan, Section 5.2
3.2	Exponent's calculation of the T-South failure probability did not consider 3rd party damage as a cause of a no-flow event.	As a potential cause of a T-South no-flow event is not accounted for, the T-South failure probability may be understated, and thus the calculated T-South risk may be understated.	Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2 (Exponent Report), p. 62, para. 146

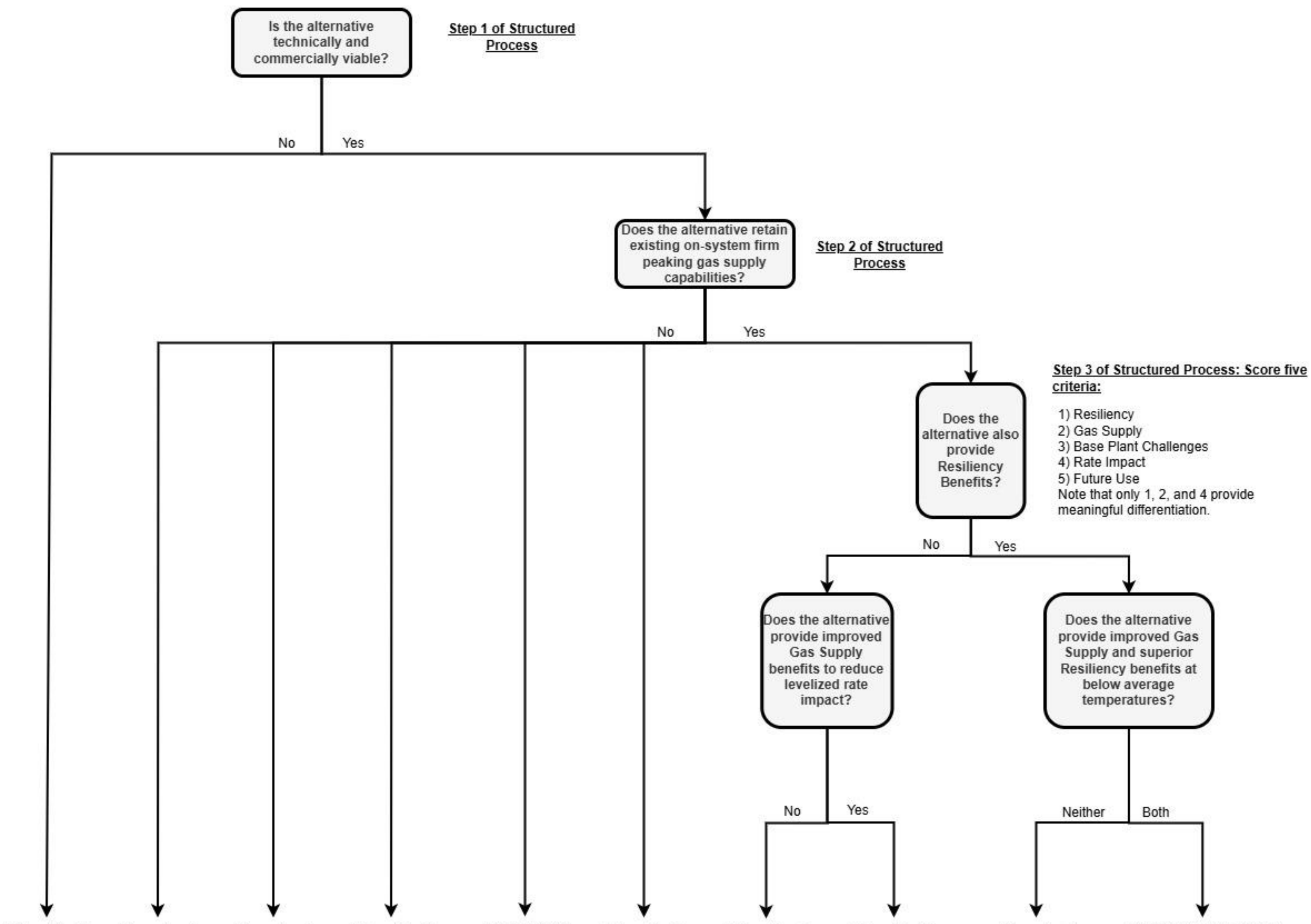
ITEM	ASSUMPTION	HOW DOES THE ASSUMPTION RESULT IN UNDERSTATEMENT OF CURRENT RISK AND FINANCIAL BENEFITS?	REFERENCE
3.3	In Exponent's calculation of the T-South failure probability, Exponent only considered failures on the pipeline component of the T-South system. Failures at T-South compressor stations were not considered as a potential cause of a T-South no-flow event.	As a potential cause of a T-South no-flow event is not accounted for, the T-South failure probability may be understated, and thus the calculated T-South risk may be understated.	Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2 (Exponent Report), Appendix N
3.4	Exponent's analysis did not consider volcanic eruptions as a hazard that could cause asset failure.	As a potential cause of a T-South no-flow event is not accounted for, the T-South failure probability may be understated, and thus the calculated T-South risk may be understated.	Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2 (Exponent Report), para. 119
3.5	Exponent's analysis did not consider avalanches as a hazard that could cause asset failure.	As a potential cause of a T-South no-flow event is not accounted for, the T-South failure probability may be understated, and thus the calculated T-South risk may be understated.	Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2 (Exponent Report), para. 117
3.6	Exponent investigated flooding and buoyancy as a hazard that could cause pipeline failure. The investigation found that pipeline failure rates due to flooding and buoyancy were negligible, therefore this hazard type was not considered in Exponent's risk calculation. An assumption made in the investigation, and that was key to the findings of the investigation, was that pipeline segments that cross wide crossings are adequately anchored.	The assumption resulted in off-ramping a potential cause of pipeline failure. As a potential cause of a T-South no-flow event is not accounted for, the T-South failure probability may be understated, and thus the calculated T-South risk may be understated.	Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2 (Exponent Report), Appendix J
3.7	Exponent investigated lightning as a hazard that could cause pipeline failure. The investigation found that rates of pipeline rupture due to lightning were low in comparison to the rates of other natural hazards considered. As a result, this hazard type was not considered in Exponent's risk calculation.	As a potential cause of a T-South no-flow event is not accounted for, the T-South failure probability may be understated, and thus the calculated T-South risk may be understated.	Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2 (Exponent Report), Appendix K
3.8	Exponent's analysis is only for a snapshot in time, and thus does not consider impacts that climate change may have on the failure rates for certain hazard types.	Over the long term, it is expected that failure rates for certain types of hazards will increase due to climate change. The calculated T-South failure probability, particularly when considering the longer-term time horizons of 20 and 60 years, may therefore be understated. As a result, the T-South risk calculation may be understated.	Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2 (Exponent Report), p. 66, para. 156

ITEM	ASSUMPTION	HOW DOES THE ASSUMPTION RESULT IN UNDERSTATEMENT OF CURRENT RISK AND FINANCIAL BENEFITS?	REFERENCE
3.9	In Exponent's analysis for failures due to earth movement related hazards for parallel pipelines (e.g., T-South), the calculation uses the maximum failure rate of the parallel pipelines instead of the sum of the failure rates from both pipelines.	The approach results in a lower failure rate for earth movement related hazards for AVs with parallel pipelines. As T-South is an AV with parallel pipelines, the approach results in an understated T-South risk.	Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2 (Exponent Report), Appendix P, p. P-4
3.10	Exponent's risk analysis is based on winter only failure rates. As such, the calculated annual failure rates are multiplied by a factor of 90 days / 365 days to represent the winter only failure rate.	It is possible that cold weather could occur outside of the 90-day winter period contemplated in Exponent's analysis. Thus, the use of the 90 days / 365 days factor may underestimate the T-South failure probability, and thus the T-South risk.	Exhibit B-61, 2024 Resiliency Plan, Appendix RP 2 (Exponent Report), Section 4.6
5	***Financial Evaluation***		
5.1	In the financial analysis, the gas supply benefits for the Supplemental Alternatives do not forecast any future escalation for the storage demand charges or transportation charges from 2035 onwards.	Any additional escalation for years beyond 2035 would have the effect of improving the levelized total rate impact of those Supplemental Alternatives that meet all of FEI's peaking gas supply requirements (i.e., Supplemental Alternatives 4A and 9) relative to those alternatives that do not (i.e., Supplemental Alternatives 1, 2, 3, 4, 5, 6, 7, and 8).	Exhibit B-60, Supplemental Evidence, Section 4.5.4.1.2, p. 136 Exhibit B-63, BCUC IR5 131.9

ITEM	ASSUMPTION	HOW DOES THE ASSUMPTION RESULT IN UNDERSTATEMENT OF CURRENT RISK AND FINANCIAL BENEFITS?	REFERENCE
5.2	In the financial analysis, FEI calculated the annual gas supply benefit of $7.9 million between 2031 and 2035 for Supplemental Alternatives 4A and 9. This benefit is based on Enbridge's T-South toll estimate of $0.95/GJ after the Sunrise Expansion project is completed in 2028 for contracting 52,000 GJ/d of T-South pipeline capacity.	As demonstrated in the response to BCUC IR5 131.4, FEI calculated the toll of $0.95/GJ based on the lowest toll impact in the five-year forecast from Enbridge's filing with the CER. However, inflation between now and 2028 could potentially increase the base toll. Further, as explained in Section 3.3.4.3.1 of the Supplemental Evidence, Enbridge's Sunrise Expansion project will only provide enough additional capacity to offset the needs of Woodfibre LNG. It is reasonable to assume there will be further regional infrastructure upgrades required which would result in an even higher toll beyond the current assumption of $0.95/GJ. Based on the capital cost of the Enbridge Sunrise Expansion project, FEI estimates that the T-South Long-Haul toll could increase to approximately $1.50/GJ (i.e., a 58 percent increase over the expected toll of $0.95/GJ by 2028) which FEI would have to pay year-round. Using a higher toll in the financial analysis would have the effect of increasing gas supply benefits between 2031 and 2035 for those Supplemental Alternatives where FEI no longer has to hold 52,000 GJ/d of year round pipeline capacity (i.e., Supplemental Alternatives 4A and 9).	Exhibit B-60, Supplemental Evidence, Section 3.3.4.3.1, p. 90 and Section 4.5.4.1.2, p. 133 Exhibit B-63, BCUC IR5 131.2, 131.3 & 131.4
5.3	FEI estimated that the annual cost for holding peaking gas supply of 1.0 Bcf and 200 MMcf/d could range from $63 million to $79 million (net of mitigation), depending on if the regional infrastructure upgrade is storage or pipeline. For the purpose of the financial analysis and comparing between all supplemental alternatives, FEI conservatively used the lower annual cost of $63 million which is for off-system storage for gas supply costs/savings.	Using the higher pipeline costs of $79 million annually (net of mitigation) would have the effect of improving the levelized total rate impact of those supplemental alternatives that meet all of FEI's peaking gas supply requirements (i.e., Supplemental Alternatives 4A and 9) relative to those options that do not (i.e., Supplemental Alternatives 1, 2, 3, 4, 5, 6, 7, and 8).	Exhibit B-60, Supplemental Evidence, Section 4.5.4.1.2, p. 136 Exhibit B-63, BCUC IR5 131.9

ITEM	ASSUMPTION	HOW DOES THE ASSUMPTION RESULT IN UNDERSTATEMENT OF CURRENT RISK AND FINANCIAL BENEFITS?	REFERENCE
5.4	In the financial analysis of Supplemental Alternatives 4 and 8 (both of which would maintain the existing 0.6 Bcf and 150 MMcf/d of regasification), FEI estimated that the annual gas supply costs to replace the existing 0.6 Bcf and 150 MMcf/d of peaking supply from the existing Tilbury Base Plant by 2035 could range from $46 million to $59 million (net of mitigation), depending on if the regional infrastructure upgrade is storage or pipeline. For the purpose of the financial analysis, FEI conservatively used the lower annual cost of $46 million which is for off-system storage for gas supply costs/savings for these two alternatives.	Using the higher pipeline costs of $59 million annually (net of mitigation) would have the effect of improving the levelized total rate impact of these two supplemental alternatives that partially meet FEI's peaking gas supply requirements relative to those options that do not provide any peaking gas supply (i.e., Supplemental Alternatives 1, 2, 3, 5, 6, and 7). However, the benefits for these two supplemental alternatives would still remain lower than Supplemental Alternatives 4A and 9 that meet all of FEI's peaking gas supply requirements, resulting in higher savings of $79 million outlined in 5.3 above.	Exhibit B-60, Supplemental Evidence, Section 4.5.4.1.2, p. 138 Exhibit B-63, BCUC IR5 131.9
5.5	In the financial analysis of the Supplemental Alternatives, FEI did not include costs for short-term contractual gas supply contracts that could be required between the time when FEI loses access to Tilbury and completion of regional infrastructure upgrades. FEI instead assumed that firm customers would be curtailed in peak periods because of the challenges of securing peaking supply, but curtailments also mean saving gas supply costs. As explained in Section 4.5.4.1.2 of the Supplemental Evidence, FEI has assumed 2035 to be the earliest time when the regional infrastructure upgrade could be completed, but FEI has no control over the timing or size of any upgrades.	Short-term contractual gas supply contracts expose FEI customers to extreme price volatility and price spikes during peak demand. FEI is unable to quantify these costs in the future but if FEI were to do so, that would have further improved the gas supply benefits for Supplemental Alternatives 9 and 4A over other alternatives that do not fully provide on-system peaking resource. This is assuming peaking supply would actually be available in the market on the cold days. Uncertain regional infrastructure expansions would involve the likelihood that FEI would have to curtail firm load in peak winter periods.	Exhibit B-60, Supplemental Evidence, Section 3.3.4.3.2, pp. 92 - 96

APPENDIX B: FIGURE 4-20 – STEP 3 SCORING RESULTS



	Alternative 1	Alternative 2	Alternative 3	Alternative 5	Alternative 6	Alternative 7	Alternative 4	Alternative 4A	Alternative 8	Preferred (Alternative 9)
Viability:	Not Viable	Not Viable	Not Viable	Not Viable	Not Viable	Not Viable	Viable	Viable	Viable	Viable
Levelized Total Rate Impact (%):	1.8%	3.3%	3.4%	4.4%	4.9%	5.6%	3.2%	3.0%	4.4%	4.2%
Levelized Total Rate Impact - Incremental to Alt 1 (%):	NA	1.57%	1.66%	2.68%	3.2%	3.84%	1.44%	1.27%	2.60%	2.45%
20-Year Expected GDP Loss Reduction ($millions):	0	0	0	41.6	642.7	3,311.2	0	0	3,246.8	3,311.2
60-Year Expected GDP Loss Reduction ($millions):	0	0	0	124.9	1,928.0	9,933.8	0	0	9,740.6	9,933.8
Expected Annual COD - Cold Weather (-1.4C):	NA	NA	NA	NA	NA	1,250,000	NA	NA	2,900,000	1,250,000
Scoring Results	NA	0.1	0.1	0.4	0.0	1.5	1.4	1.8	1.9	2.9