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September 13, 2021

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

Attention: Mr. Patrick Wruck, Commission Secretary

Dear Mr. Wruck:

Re: FortisBC Energy Inc. (FEI)

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

Response to the British Columbia Utilities Commission (BCUC) Information Request (IR) No. 1

FEI respectfully submits the attached response to BCUC IR No. 1 in the Application.

Treatment of Confidential Material

Due to the sensitive and confidential nature of some of the information in the Application, FEI is filing some responses and attachments to information requests on a confidential basis pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents, as set out in Order G-15-19. FEI's treatment of security-sensitive and commercially-sensitive information in these responses is consistent with BCUC Order G-161-21 and the Revised Confidential Application (Exhibit B-1-3). All of that information will be available to interveners who have previously signed and provided the BCUC Confidentiality Declaration and Undertaking form (Undertaking) and the revised non-disclosure agreement (NDA). In the case of interveners who have only provided the signed Undertaking, they will receive all commercially-sensitive information only.

While some parties submitted information requests on a confidential basis, in order to maximize the amount of information on the public record, FEI has reviewed the preambles, questions, responses, and related attachments and in instances where confidential information is not disclosed, FEI has filed the information publicly, redacting all confidential information (both commercially-sensitive and security-sensitive). In cases where the information requests were submitted publicly, if the responses or related attachments disclose security-sensitive or commercially-sensitive confidential information, FEI has redacted those portions for the public record.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

Table of Contents **Page no.**

A. PROJECT NEED

1.0 Reference: PROJECT NEED

Exhibit B-1-4 (Updated Public Application), pp. 20, 22, 38 – 40

Transportation Safety Board of Canada released Pipeline Transportation Safety Investigation P18H0088, pp. 31, 33, 34

Enbridge Projects and Infrastructure Growth Projects, *retrieved* from https://www.enbridge.com/projects-and-infrastructure/projects/tsouth-reliability-and-expansion-program

Westcoast T-South System

On page 22 of the Updated Public Application for a Certificate of Public Convenience and Necessity (CPCN) for the Tilbury Liquefied Natural Gas (LNG) Storage Expansion (TLSE) Project (Updated Public Application), FortisBC Energy Inc. (FEI) states:

> Guidehouse notes that building system redundancy is a key way to improve resiliency. This type of redundancy may not increase reliability performance in any given year, but will enable the utility to withstand system failures and unforeseen events and prevent disruptions to gas supply when such events occur. Redundancy can take the form of, for instance, redundant technology in a piece of infrastructure, excess capacity through larger sizing of a piece of infrastructure (e.g., a larger storage tank to supply more load if a pipeline fails), or duplicate infrastructure that can support loads in the event of one failing (e.g., two transmission lines or two pipelines to a source of supply).

On page 38 of the Updated Public Application, FEI states:

> The T-South system consists of two looped gas transmission pipelines operating as a single system. The T-South system connects production fields in northeast BC with the Lower Mainland (Huntingdon) and Williams Northwest Pipeline (NWP) at Sumas, Washington. The T South system flows north to south and runs approximately 916 km between Station 2 and Huntingdon.

On pages 39 to 40 of the Updated Public Application, FEI states:

> The T-South Incident, which occurred on October 9, 2018, brought into sharp focus the risk of supply interruption for FEI's customers. On that date, an NPS 36 natural gas pipeline forming part of the T-South system ruptured near Prince George, BC. The NPS 36 pipeline that ruptured shared the right-of-way with a second NPS 30 pipeline (as described above, the two pipelines are operated as part of a single system). While only the NPS 36 pipeline had ruptured, the natural gas escaping from that pipeline had ignited and Westcoast shut down the adjacent NPS 30 pipeline as a precaution and monitored it to evaluate its condition.

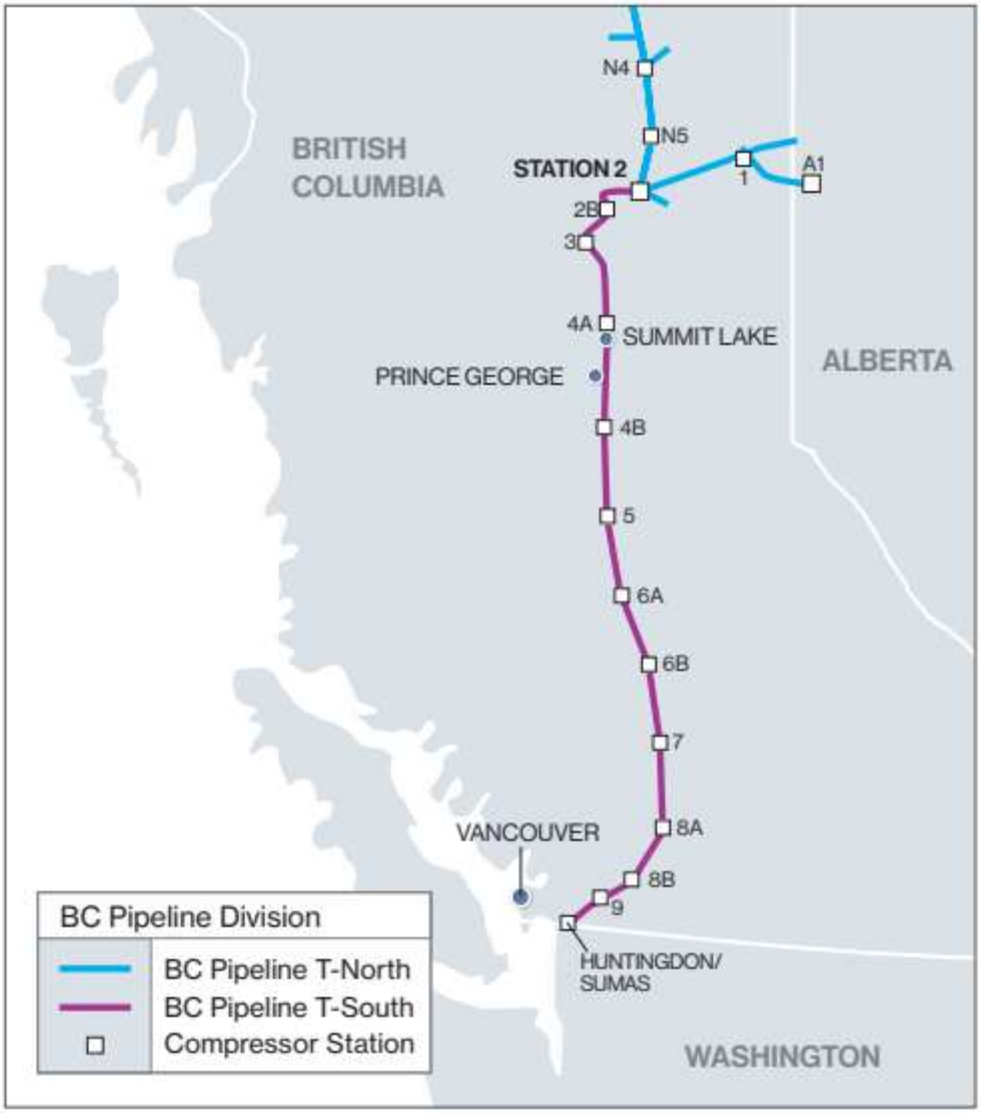
1.1 Please discuss the extent to which the two looped pipelines on the T-South system provide redundancy.

1.1.1 Please explain how this contributes to the resiliency of FEI.

Response:

The T-South system consists of two looped gas transmission pipelines operating as a single system with various interconnection points to FEI's delivery system (e.g., Savona, Kingsvale, Huntingdon, etc.). The T-South system has some inherent local redundancy along the pipeline and at compressor stations. For example, along the length of the pipeline, all river crossings consist of two separate crossings (i.e., one for each pipeline) with adjoining crossovers between the two pipelines before and after the river crossings. At compressor stations, Westcoast would have some excess and/or redundant compression capacity to accommodate the failures of individual compressor units. As such, should a compressor unit fail, Westcoast would likely be able to continue uninterrupted gas flow for most times of the year with its excess and/or spare compressor(s).

However, there are limits on the extent to which the T-South system can provide resiliency, and this is the risk that the TLSE Project addresses. The two lengthy pipelines comprising the T-South system are located in the same right-of-way, tied together by common headers and compressor stations, and hence are operated as a single pipeline, as the figure below (from Westcoast) illustrates. Therefore, a major incident on one of the pipelines could affect both, as was made evident during the T-South Incident. Further, a capacity reduction at any compressor station or pressure reduction of any segment of a pipeline between two valve stations reduces the capacity that can be delivered by the system. As such, the two looped pipelines on the T-South system provide some redundancy on the days of the year when the regional system load is less than the capacity of the T-South system when accounting for any compressor capacity or any pipeline pressure reductions. However, overall, the T-South system provides FEI and the region with limited resiliency.



1.2 Please confirm, or explain otherwise, that FEI's minimum resiliency planning objective assumes no-flow on both of the T-South pipelines for a period of at least three days.

<u>Response:</u>

Not confirmed. FEI clarifies that the Minimum Resiliency Planning Objective (MRPO) outlined in the Application assumes no-flow on both T-South pipelines into the Lower Mainland service area for a <u>maximum</u> of three days (as opposed to the statement in the question above that the MRPO assumes no-flow for a period of <u>at least</u> three days). In other words, meeting (but not exceeding) the MRPO would still leave FEI exposed to no-flow events longer than three days. For that reason, FEI is proposing a 3 Bcf tank, which provides a resiliency margin above the MRPO and the potential to realize ancillary benefits.

1.3 Please discuss the type of incident which may result in a supply interruption lasting longer than two days, with no flow on both pipelines on the T-South system.

Response:

At a high level, the potential sources of supply interruptions that could impact the T-South system include the following:

1. Integrity and/or reliability of the system (e.g., pipeline or equipment failures);
2. External forces (e.g., seismic, land movement, or wildfires); and
3. Intentional or unintentional external interference (e.g., malicious actors or third-party contacts).

Some detailed examples that may result in a supply interruption lasting longer than two days, with no-flow on both pipelines on the T-South system, include (but are not limited to):

- A pipeline rupture mid-span of an aerial crossing where the rupture of one pipeline causes a rupture or damage to the adjacent pipeline;
- A pipeline rupture of one pipeline causes a rupture or damage to the adjacent pipeline within the same right-of-way because of the presence of integrity issues (e.g., stress corrosion cracking, corrosion, etc.) on the adjacent pipeline;
- A precautionary shut-down of an adjacent pipeline (even if it is not necessarily ruptured or damaged) for other reasons (e.g., engineering assessments, police investigations, etc.);
- Any type of major facility or equipment failure at a compressor station and associated facilities where the two pipelines join together within a compressor station compound;
- A cyber-attack which disrupts Westcoast's ability to control or operate the T-South system resulting in a shutdown similar to that which caused a multi-day outage on the Colonial Pipeline oil pipeline in the eastern US;[1]
- A geohazard on or near a steep slope in mountainous terrain that results in a landslide that exposes and damages both pipelines; and
- A high water event that causes a washout of both pipelines under an active and fast moving creek/river, resulting in irreparable damage to one or both pipelines.

[1] https://www.reuters.com/business/energy/us-govt-top-fuel-supplier-work-secure-pipelines-closure-enters-4th-day-2021-05-10/.

1.3.1 Please discuss whether FEI is aware of any lessons learned or actions taken by Westcoast since the T-South Incident which would reduce the time needed to re-establish supply to one of the pipelines in the event of a rupture or other supply disruption.

<u>Response:</u>

The timing for re-establishing supply to a particular pipeline segment of the T-South system may vary considerably according to the type of incident and depending on several factors, including the following:

- cause/severity of the incident – whether it is a physical issue with the pipeline or a cyber-attack, and does the event require investigation and assessment by multiple authorities, including the Canada Energy Regulator (CER);
- time of year – incident occurring during favorable or unfavorable conditions for work to be done to resume gas flow; and
- incident location – ease of access to incident location.

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

On page 20 of the Updated Public Application, FEI states: "In the context of reliability and resiliency, the focus of integrity management on avoiding service disruption is key. Integrity management is concerned with avoiding incidents such as leaks or ruptures that would undermine the ability of the assets to deliver service."

On March 4, 2020, with respect to the T-South Incident, the Transportation Safety Board of Canada (TSB) released "Pipeline transportation safety investigation P18H0088" (TSB Report).[2] On page 31 of the TSB Report, TSB summarizes "findings as to causes and

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

contributing factors" which TSB notes "are conditions, acts or safety deficiencies that were found to have caused or contributed to this occurrence [of the T-South pipeline rupture]." TSB states in part:

> 6. Although Westcoast's Stress Corrosion Cracking Hazard Management Plan recognized the pipeline's susceptibility to near-neutral pH stress corrosion cracking, the extent of the existing cracking on this segment of pipe was not identified. 7. The crack growth model did not sufficiently reflect the uncertainties in the measured values or the increase in crack size as a result of crack coalescence. As such, the predicted growth that was used in the model was less than the actual crack growth. 8. The stress corrosion cracking electromagnetic acoustic transducer in-line inspection for the 4AL2 segment, scheduled for 2017, was deferred until fall 2018, resulting in the existing cracks remaining in the pipe undetected until failure.

On page 33 of the TSB Report, TSB states:

> On 11 July 2019, in response to Pipeline Safety Advisory 02/19, Westcoast advised the TSB that it had completed a review of its stress corrosion management practices used on the T-South natural gas pipeline system in British Columbia in January 2019, and had made several improvements to its SCC [stress corrosion cracking] management program.

The specific improvements are discussed further on pages 33 and 34 of the TSB Report.

1.4 Please discuss whether FEI took into account the findings by TSB and actions taken by Westcoast as outlined in the TSB Report in considering the need for the TLSE Project.

<u>Response:</u>

FEI has analyzed the TSB findings and actions taken by Westcoast as outlined in the TSB Report, both as part of its management review process for its Integrity Management Program for Pipelines (IMP-P) and in considering the need for the TLSE Project.

With respect to FEI's assessment of the need for the TLSE Project, FEI's learnings from the TSB findings and actions taken by Westcoast were primarily related to its broader understanding of potential supply interruptions that can occur following an integrity incident. This is highlighted by:

- Enbridge's proactive shut down of the NPS 30 L1 pipeline to monitor and evaluate its condition as a result of the rupture on the parallel NPS 36 L2 pipeline; and
- Enbridge's operation of the NPS 30 L1 and NPS 36 L2 pipelines at restricted operation pressures for extended periods.

The TSB findings and actions taken by Westcoast reinforce FEI's assertion that the risk of pipeline failures on the Westcoast T-South system cannot be reduced to zero, that no-flow events can occur if both pipelines are shut-in following a failure incident, and that an extended period of reduced pipeline flows may occur following pipeline repairs.

1.5 Please discuss whether FEI has undertaken any probability analysis of the expected frequency of a pipeline rupture on the T-South system.

1.5.1 If so, please provide a detailed explanation, including a description of the methodology, key assumptions, uncertainties, and the probability of different scale events (e.g. number of days of no flow, single pipeline, both pipelines etc.).

1.5.2 If not, please explain why not. Please discuss how the need for the TLSE Project can be examined in the absence of such analysis.

Response:

FEI believes that the potential for a widespread system collapse to result from a no-flow event on the T-South system, combined with the existence of a tangible example of a significant disruption on the T-South system, is a valid basis on its own to warrant investments in improved resiliency. A no-flow event on T-South is, without question, FEI's single greatest supply risk. However, FEI retained JANA Corporation (JANA) to conduct an independent, expert probabilistic analysis of a pipeline incident occurring on the Westcoast T-South system. JANA's analysis, discussed below, reinforces the case for investments to withstand a no-flow event on the T-South system.

JANA is a recognized pipeline industry expert, and has provided evidence in previous FEI CPCN applications related to integrity management, including the Inland Gas Upgrades, and the Coastal Transmission System - Transmission Integrity Management Capabilities projects. In support of those processes, JANA provided application content, responded to information requests, and appeared in a number of workshops with the BCUC and interveners. The *curriculum vitae* of Dr. Ken Oliphant and Wayne Bryce, principals of JANA, who are responsible for the response below, are provided as Attachments 1.5A and 1.5B to this response.

JANA has provided the following response:

> An assessment of the forecast cumulative probability of a pipeline rupture on the T-South system was conducted over the 67-year economic design live of the TLSE Project. The assessment is based on the estimated probability of failure for an average performing transmission pipeline system of the same length as the T-South system. The assessment is detailed in the attached white paper: Assessment of Outage Probability. Based on the analysis, the cumulative probability of a rupture event is forecast to be between 83.1% to 97.9% and the cumulative probability of an ignited rupture between 53.4% and 73.9% over the 67 year economic life of the TLSE Project.

Please also refer to Attachment 1.5C for JANA's *Assessment of Outage Probability – JANA Project 2347 White Paper*.

FEI has provided the following response:

FEI recognizes that, with respect to integrity-related hazards, the Canadian standard that applies to oil and gas pipeline systems throughout Canada (CSA Z662:19), requires that operators "monitor for conditions that can lead to failures" and "to eliminate or mitigate such conditions" (Clause 10.3.1 of CSA Z662:19). Further, the standard requires that "where hazards that might lead to failure or damage incidents are identified, the operating company shall […] implement and document measures for monitoring conditions that could lead to an incident with significant consequences and eliminate or mitigate such conditions […]" (Clause N.1.8.3). As such, FEI and other operators like Westcoast must monitor, and mitigate or eliminate, conditions that can lead to an incident with significant consequences. While integrity management practices can be highly successful in identifying and mitigating against integrity-related threats, FEI recognizes that residual integrity risk can never be zero. Similarly, FEI also recognizes that the potential for a no-flow or reduced-flow event can never be zero for transmission pipelines, whether resulting from a rupture or other cause. Both of these observations are supported by the JANA analysis, which is based on pipeline performance data from Canadian and US operators.

1.6 Based upon the findings as to causes and contributing factors identified in the TSB Report and the changes made to Westcoast's SCC management program, please discuss the extent to which FEI considers the risk of supply interruption on the T-South system has been mitigated.

Response:

Section 4.1.3 of the TSB Report states, "The NEB issued Notices to Resume Work or of Measures Satisfied after it was demonstrated that the relevant segments of the pipeline were fit for service to safely operate at their respective maximum operating pressures." On the basis that engineering assessments were completed by Westcoast and accepted by the Canada Energy Regulator, FEI accepts that the T-South system is fit for service and can safely operate at its respective maximum operating pressure(s).

However, as discussed in the response to BCUC IR1 1.5, the potential of a supply interruption on the T-South system resulting in a no-flow or reduced-flow event can never be zero for transmission pipelines.

1.6.1 Please provide any further information FEI is aware of, subsequent to the issuance of the TSB Report, respecting Westcoast's integrity management processes on the T-South system.

Response:

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

1.7 Please provide a summary of how Westcoast's current integrity management processes and capabilities compare to FEI's.

Response:

FEI has not compared its current integrity management processes and capabilities to that of Westcoast. The amount of information required for such a comparison would be extensive, and is also not publicly available to FEI.

Further, FEI would expect differences between operators' integrity management processes and capabilities depending on factors such as regulatory jurisdiction and the unique characteristics of each operator's pipeline system. Finally, CSA Z662:19 is not a prescriptive standard, meaning that there may be differences in how each operator interprets and applies the standard to their particular system and operations.

1.8 Please explain whether FEI has engaged in any discussions with Westcoast with respect to its integrity management processes since the T-South Incident.

Response:

Please refer to the response to BCUC IR1 1.6.1.

1.9 Please provide a detailed explanation of the different potential causes of supply disruption that FEI considers are a risk on the T-South system, and an assessment of the extent to which such causes are mitigated by Westcoast's integrity management or other processes.

Response:

FEI would expect that the threats that could potentially cause a supply disruption of Westcoast's T-South system are similar to those managed by FEI. This would include cyber-attacks, as well as disruption of physical infrastructure. In terms of the latter, FEI's IMP-P includes activities to mitigate the following threats:

- Third Party Damage: includes external interference such as third-party contact with the pipeline, or vandalism;
- Natural Hazards: includes geotechnical (e.g., landslide), hydrotechnical (e.g., flood), and seismic (e.g., earthquake) causes. Natural hazards can cause a pipeline to become exposed or move from its installation location;
- Pipe Condition: includes conditions such as metal loss (e.g., external corrosion) and cracking (e.g., stress corrosion cracking). These conditions are generally considered to be time-dependent, meaning they may have the potential to grow to failure during the operation of the pipeline, and must be monitored;
- Material Defects / Equipment Failure: includes features introduced during the pipe manufacturing process (e.g., a defective seam weld), and failures related to other equipment such as valves, gaskets, etc.; and
- Human Factors: includes hazards resulting from human error, such as construction errors (e.g., defective joint welds, dents, buckles) or operational errors.

However, FEI is unable to comment on the extent to which threats are mitigated by Westcoast's integrity management processes or other processes as FEI does not have access to the information required to make this assessment. Please also refer to the response to BCUC IR1 1.7.

1.10 Please discuss any other factors besides Westcoast's integrity management processes which might affect the likelihood of supply interruption on the T-South system over time.

Response:

Please refer to the response to BCUC IR1 1.3 for other factors beyond Westcoast's integrity management processes which might affect the likelihood of supply interruptions on the T-South system over time.

Enbridge is undertaking upgrades and a number of reliability enhancements on the southern portion of its natural gas transmission system which stretches from south of Chetwynd, British Columbia, to the southernmost point at the Canada/U.S. border at Huntingdon/Sumas. This program, known as the T-South Reliability and Expansion Program, is expected to be in-service late 2021.[3]

1.11 Please confirm, or explain otherwise, that FEI is aware of Enbridge's T-South Reliability and Expansion Program.

1.11.1 If confirmed, please discuss what undertakings from Enbridge's T-South Reliability and Expansion Program, FEI has taken into consideration in this Application.

Response:

FEI is aware of Westcoast's T-South Reliability and Expansion Program and included a discussion of this expansion in Section 4.3.4.2 of the Application.

FEI does not consider this expansion to have any impact on the Application because it will not enhance FEI's system resiliency. The expansion program primarily involves upgrading five compressor units at three existing compressor stations and equipment upgrades at three other existing compressor stations. These enhancements to T-South will not mitigate the risk of a no-flow or reduced-flow event, as discussed in the response to BCUC IR1 1.5. The expansion will allow Enbridge to provide shippers a further 90 MMcf/day in year-round firm capacity that has previously only been available on an interruptible basis, and an additional 100 MMcf/day in new firm year-round capacity. In effect, the expansion will result in an increased regional reliance on a single major pipeline, which is counter to FEI's resiliency goals. As stated in Section 4.3.4.2 of the Application, the "expansion provides very little new resiliency from FEI's perspective, since it does not reduce the current single point of failure risk and adds no pipeline diversity."[4]

1.12 Please explain whether FEI has had discussions with Enbridge as it relates to improving safety on the T-South system. If so, please provide a brief summary of the discussion, outcomes and plans for improved safety.

Response:

Please refer to the response to BCUC IR1 1.6.1.

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[3] *See* Enbridge Projects and Infrastructure Growth Projects, *retrieved from* https://www.enbridge.com/projects-and-infrastructure/projects/tsouth-reliability-and-expansion-program.

[4] TLSE Application, page 86.

2.0 Reference: PROJECT NEED

Exhibit B-1-4, p. 27

Causes of No-Flow Events

On page 27 of the Updated Public Application, FEI states:

> The ability of a natural gas system to withstand and recover from extreme or prolonged events is becoming increasingly relevant. Much of the infrastructure in the region is aging, which increases the risk of failures due to time-dependent threats. It is also possible that disruptive events, such as wildfires, landslides and floods, are becoming more frequent and severe, which increases the risk of damage to the pipeline infrastructure.

2.1 Please expand upon what FEI considers to be time-dependent threats to the T-South system.

Response:

FEI would expect that the time-dependent threats to the T-South system are similar to those managed by FEI's Integrity Management Program. FEI's Integrity Management Program for Pipelines (IMP-P) addresses time-dependent threats to its system, which consist primarily of metal loss (e.g., external corrosion) and cracking (e.g., stress corrosion cracking).

2.1.1 Please discuss the extent to which integrity management practices can identify and mitigate against time-dependent threats.

Response:

Integrity management practices can be highly successful in identifying and mitigating against integrity-related threats, including time-dependent threats; however, residual integrity risk can never be zero.

As an example, in-line inspection (ILI) is the primary method for transmission pipeline condition monitoring and is widely adopted by the industry for managing various integrity threats to pipelines; however, it is not without challenges. Even with ILI, the need for ongoing management of uncertainty and risk remains. With respect to the detection and sizing of imperfections, ILI vendor specifications are typically expressed with an explicit estimate of uncertainty. A typical metal loss specification is: "Depth sizing accuracy will be achieved to +/- 10% of pipe wall thickness, at 80% confidence." Integrity management processes are developed to account for uncertainty, including ILI tool performance specifications, to the extent practical but cannot reduce residual integrity risk to zero.

2.2 Please discuss whether FEI has undertaken any analysis of the T-South system's exposure to risks from events such as wildfires, landslides and floods.

2.2.1 Please discuss whether FEI has undertaken any analysis of the probability of supply disruptions caused by events such as wildfires, landslides and floods.

2.2.2 Please clarify the extent to which FEI considers the need for the TLSE Project is to mitigate against such events.

Response:

As explained in the response to BCUC IR1 1.9, FEI is well aware that supply disruptions can occur due to a variety of causes and the risk cannot be eliminated through an operator's integrity management programs alone. FEI has identified the conditions that can impact FEI's system with significant consequences (e.g. widespread and lengthy service outages), and has explained those conditions in Section 3 of the Application. Given the potential significant consequences, the TLSE Project is a reasonable and appropriate response to mitigate the risk of a pipeline failure resulting in a no-flow event and will significantly improve FEI's ability to maintain continuity of service to customers.

The JANA analysis discussed in the response to BCUC IR1 1.5 addresses the probability of rupture for a transmission pipeline of the length of the T-South system over a 67 year period, based on Canadian and US industry pipeline performance data. The JANA analysis includes transmission pipeline ruptures, regardless of cause.

3.0 Reference: PROJECT NEED

Exhibit B-1-4, p. 49; Appendix B, pp. 2, 17

2017 and 2018 PRMP proceeding, Exhibit B-11, Response to BCOAPO IR 1 on New Evidence

Pipeline Incidents

On page 49 of the Updated Public Application, FEI states: “The T-South Incident highlighted that, although supply emergencies are rare, they do occur.”

On page 2 of Appendix B, PricewaterhouseCoopers (PwC) states:

> Over the past decade, British Columbia (BC) has faced four natural gas pipeline incidents, including the Enbridge Alaska Highway pipeline fire in February 2009, the Enbridge valve enclosure fire in June 2012, and the Enbridge Nig Creek rupture in June 2012. The fourth incident took place most recently, on October 9th, 2018, when the Enbridge T-south pipeline ruptured near Prince George, BC.

On page 17 of Appendix B, PwC provides the following tables:

Overview of major natural gas disruption events

Table: British Columbia natural gas disruption events (2009 - 2019)

Date	Location	Description
Oct 9, 2018	Prince George, BC	Enbridge T-South rupture
Jun 28, 2012	Buick, BC	Enbridge Nig Creek rupture
Jun 23, 2012	Fort St. John, BC	Enbridge valve enclosure fire
Feb 20, 2009	Wonowon, BC	Enbridge Alaska Highway pipeline sending barrel rupture

Table: Rest of Canada natural gas disruption events (2009 - 2019)

Date	Location	Description
Jan 25, 2014	Otterbourne, MB	TC Canadian Mainline rupture
Oct 17, 2013	Fort McMurray, AB	TC NOVA rupture
Feb 19, 2011	Beardmore, ON	TC Line 100 explosion and fire
Sep 26, 2009	Marten River, ON	TC Line 100 rupture
Sep 12, 2009	Englehart, ON	TC Line 2 rupture and fire

Table: Northwest US (WA, OR, ID, MT) regional natural gas disruption events (2009 - 2019)

Date	Location	Description
Mar 9, 2016	Seattle, WA	Puget Sound Energy distribution line rupture
Mar 31, 2014	Plymouth, WA	Williams Plymouth LNG facility explosion and fire

In the 2017 Price Risk Management Plan (PRMP) and 2018 PRMP proceeding, in response to BC Old Age Pensioners' Organization et al. (BCOAPO) Information Request (IR) 1 on New Evidence (Exhibit B-11), FEI stated:

> FEI had not estimated the likelihood of this type of rupture reoccurring, given that an incident of this magnitude is extremely uncommon. FEI is not aware of this type and scale of incident occurring in the past on the Enbridge system. The overall integrity of the pipeline system in the region (i.e., British Columbia and the US Pacific Northwest) has been generally reliable.

3.1 Please provide a detailed history of any unplanned supply interruptions on the T-South system since it was commissioned. Please include the time of year, duration of the supply interruption, the extent to which supply was disrupted on both pipelines, a description of the cause, and any other relevant information about the downstream impact of the supply interruption to FEI and its customers.

Response:

Unplanned supply interruptions on gas transmission pipelines may be caused by a variety of factors. These supply interruptions may arise from factors such as production problems for upstream operators, operational upsets experienced by the pipeline itself, operating difficulties on downstream interconnecting pipelines, or because commercial arrangements fail.

Most of these incidents are managed on the day as part of routine business without significant impact and are not formally tracked. Generally, only more serious incidents that are attributable to the pipeline involve a record that can be tracked for a period of time.

The following table provides a list of unplanned equipment and pipeline segment failures experienced by Westcoast since 2000 on the T-South system. Westcoast provided this table in an information request response filed in 2019 as part of the review of its T-South Expansion and Reliability Program by the CER.[5] A list of T-South equipment and pipeline failures that may have occurred before 2000 is not available.

[5] https://docs2.cer-rec.gc.ca/ll-eng/llisapi.dll/fetch/2000/90464/90550/90718/3546473/3596844/3713803/3750759/A97849-12_Attachment_1_to_Powerex_IR_No._1.3.a_-_List_of_T-South_Pipeline_Failures_-_A6R9H7.pdf?nodeid=3754067&vernum=-2.

T-South Pipeline Failures

Year	Segment	Event	Description	Corrective Actions	Service Interruptions
2000	4BL2	Equipment failure	Flange/gasket leak	Replaced gasket	None
2000	8AL1	Pipeline failure	Hard spot (pipe manufacturing defect)	Repaired by cut-out	Yes
2001	5L2	First party damage	Excavator struck unused 3/4" tap off mainline	Tap repaired	None
2005	4BL1	Manufacturing defect	Pinhole leak in long seam when coating removed	Repaired by cut-out	None
2006	2L1/L2	Equipment failure	O-ring failure on 12" blowdown riser cap - on L2/L1 crossover.	Replaced O-ring	None
2007	2L1	Manufacturing defect	Pinhole leak in longseam when coating removed	Repaired by cut-out	None
2008	3L1	Manufacturing defect	Pinhole leak in long seam when coating removed	Repaired by cut-out	None
2015	5L2	Equipment failure	O-ring leak	Replaced O-ring	None
2016	2L2	Equipment failure	O-ring leak	Replaced O-ring	None
2018	8BL1	Mechanical damage	Bottom side dent leaked upon removal of indentor	Repaired by cut-out	None
2018	4AL2	Pipeline failure	Under investigation	Repaired by cut-out	Yes

While these kinds of failures are not uncommon, and they may cause a periodic reduction in operating capacity, very few are sufficiently serious to result in service interruptions that cause supply disruptions to both pipeline segments. These events also generally do not cause supply disruptions during the non-winter period because demand is generally well below pipeline capacity. However, during the winter period, this risk increases substantially because capacity is generally fully utilized. This risk can be managed to avoid supply disruptions depending on the location and severity of the incident and system load given regional temperature conditions prevailing at the time. That said, a more serious incident, such as one resulting in a no-flow event, could exceed FEI's current level of resilience.

Incidents that have caused a service interruption that disrupted supply on the T-South system are:

- August 7, 2000 – rupture on the NPS 30 pipeline between CS8A (Merritt) and CS8B (Hope). The NPS 36 pipeline was also isolated for a few hours before being placed back into service. This incident did not cause a commercial impact because of very low summer flows in 2000.
- The October 2018 T-South Incident: October 9, 2018 – rupture on the NPS 36 pipeline between CS4A and CS4B. T-South did not fully return to service until December 2019 for both pipe segments, although they were allowed to operate at a reduced operating pressure after inspection and repair (October 11, 2018 for the NPS 30 pipeline and November 1, 2018 for the NPS 36 pipeline). The Transportation Safety Board determined that the rupture was caused by stress corrosion cracking. The immediate impact of the rupture caused significant service interruptions and supply disruptions for all T-South shippers and interconnecting pipelines. While service on T-South resumed following the repair of the rupture, it continued to operate 15 percent below capacity until December 2019 when the CER provided approval to operate each of the 12 T-South segments at its maximum operating pressure.

Although the impact of failures of the type experienced in the past were managed so that service and supply interruptions were limited, the T-South load factor is now significantly higher than it has been historically. This, combined with the large increase in the number of end-use customers relying on the T-South system compared with those it served historically, has elevated the risk and the imperative for the TLSE Project.

3.2 Please discuss whether any of the other disruption events occurring in BC disrupted the flow of gas to FEI. Please discuss the magnitude, duration and impact of the disruption

Response:

None of the other three disruption events in BC referenced in the above preamble disrupted the flow of gas to FEI.

As a matter of clarification, the Nig Creek and Alaska Highway ruptures occurred on raw gas (sour) pipelines while the rest of the incidents involve residue gas pipelines that transport supply contracted for use by end-use markets.

3.3 Please discuss whether any of the disruption events identified in Appendix B resulted in a no-flow period of 3 days or greater.

Response:

The following response was provided by PwC.

Based on our review of publicly available information, we understand that:

- TC Mainline rupture (Jan 25, 2014) resulted in the loss of natural gas service to 9 rural Manitoba communities for ~80 hrs.
- A number of the other disruption events affected pipelines that were either already out of service or had multiple parallel lines in place (i.e., system resiliency) that were able to continue or resume operation in less than 3 days with at least partial flow rates.

Additional commentary:

- Natural gas disruption events are unique and their impact is influenced by a wide range of variables both known and unknown, precluding utility in comparison for purposes of impact assessment. Our report provided a list of recent natural gas disruption events for the purpose of highlighting that they do occur, and at a frequency that may not be widely understood.

Example: For illustrative purposes, FEIs Huntingdon facility represents a single connection point to upstream suppliers and in the event of disruption to it, supply of natural gas to hundreds of thousands of customers in BC would be at risk. In contrast, a similar disruption in a more resilient system may have an immaterial or no impact to consumers.

- 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.

3.4 Please discuss whether FEI considers it is possible to undertake a probability estimate of the occurrence of a disruption event occurring on a pipeline, based upon the frequency events outlined in the tables in Appendix B, the total length of pipelines in the regions reviewed, and the length of time.

3.4.1 Please discuss any limitations of this approach.

Response:

The following explanation was provided by PwC, with which FEI agrees.

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.

While likelihood was considered at the highest level (i.e., disruption events do happen periodically), we did not undertake an assessment of this type. The intent was that the study would assess the potential impact of natural gas disruption and provide the province and the energy industry with data to help weigh the costs and benefits of different infrastructure investments to enhance system resiliency in the province.

FEI also provides the following response:

Please refer to the response to BCUC IR1 1.5 where FEI has provided the cumulative probability of a disruption event based on Canadian and US industry pipeline performance data.

4.0 Reference: PROJECT NEED

Exhibit B-1-4, pp. 35, 41, 42

October 9, 2018 Incident (T-South Incident)

On page 41 of the Updated Public Application, FEI describes the T-South Incident, which occurred on October 9, 2018:

> The incident first affected communities such as Salmon Valley that were served from the segment of the T-South system that had been depressurized as a result of the rupture of the NPS 36 pipeline. System pressure south of the isolated and depressurized pipeline segment continued to drop in the hours that followed. As the timeline and content below demonstrates, there was a significant delay before reliable and actionable information was available following the pipeline rupture. The information delay was caused by a number of factors, including the relatively remote location of the rupture, as well as Westcoast's inability to physically inspect the site due to the fire that occurred. Approximately 24 hours passed before reliable information became available to FEI, preventing FEI from understanding and fully assessing the situation, including the status of Westcoast's NPS 30 pipeline adjacent to the ruptured pipeline.

On page 42 the Updated Public Application, FEI states:

> The length of the T-South Incident is known with hindsight, but FEI's system operations decisions are made in real time based on the information available. The speed with which FEI receives information about the nature and duration of the interruption is critical. Any resource that is sufficiently reliable so as to delay initiating a controlled shut-down has significant value from a resiliency perspective.

4.1 Please provide a summary of any lessons learned or actions taken by Westcoast that FEI is aware of, to enhance the speed and effectiveness of Westcoast's response to incidents such as pipeline ruptures on the T-South system.

<u>Response:</u>

Please refer to the response to BCUC IR1 1.3.1.

4.2 Please discuss any lessons learned or actions taken by FEI to enhance the speed and effectiveness of FEI's response to no-flow events following the T-South Incident.

Response:

As previously reported to the BCUC, in response to the 2018 T-South Incident FEI reviewed existing procedures and determined no process changes were required. However, this incident presented an opportunity to review and revisit existing mutual aid agreements with other regional stakeholders and to confirm communications protocols within that group.

The Northwest Mutual Assistance Agreement (NWMAA) member organizations met in 2019 to update the agreement, including revising the Executive Committee structure as well as Activation and De-activation protocols. The revised agreement (included as Attachment 4.2) was in place for the start of the November 2019 winter season.

Additionally, as part of its response to a potential severe supply shortage as a result of the T-South Incident, FEI prepared a System Preservation and Service Restoration (P&R) Plan (which was filed confidentially with, and reviewed by, the BCUC). The P&R Plan includes principles and strategies aimed at maintaining service to as many customers and areas as possible under evolving conditions.

Finally, FEI developed and exercised the "Third Party Natural Gas Systems Incidents (Upstream of FortisBC) Emergency Response Plan", dated May 2021. This plan outlines incident classifications which determines escalation and execution of the plan in phases, specifies roles, responsibilities of key personnel and communications protocols to address supply interruption scenarios. At a minimum, FEI intends to review this document annually to ensure it remains updated and relevant to the current operating environment.

On page 35 of the Updated Public Application, FEI states:

> It is unlikely that the end of a "no-flow" event on the T-South system will mean full resumption of supply for FEI. Rather, it can be expected that the pipeline system will continue to operate at significantly reduced capacity for an extended period. This occurred following the T-South Incident in 2018.

4.3 Aside from the experience in the 2018 T-South Incident, please explain, in detail, why FEI expects that a pipeline system would continue to operate at significantly reduced capacity following a no-flow event.

Response:

The 2018 T-South Incident demonstrated the operational steps, safety precautions, engineering assessments, and regulatory directives following a major pipeline failure that results in no-flow. While FEI recognizes that the individual circumstances of each no-flow event could be different, it is reasonable to expect that a no-flow event would trigger similar operational steps and assessments.

An extended period of reduced capacity could result from several potential stages following the incident itself:

- Initial pipeline shut-in which results in no-flow on the system.
- The parallel pipeline may also be shut-in, depending on the nature of the incident. For example, in the 2018 T-South Incident, the parallel pipeline was also shut-in as a safety precaution, due to its proximity to the explosion location.
- Immediately after an incident, the site may be in law-enforcement jurisdiction for investigative purposes and cannot be accessed.
- Regulatory directives may be issued that limit and restrict resumption of gas flow. In the 2018 T-South Incident these directives were accompanied by orders for completing engineering assessments and integrity verifications.
- The necessary engineering assessments and integrity verifications can take an extended period and require flow reductions to varying degrees. As an example, the 2018 T-South Incident resulted in ongoing flow reductions over the period of a year.

FEI reviewed the three most recent natural gas pipeline-related incident reports published by the Transportation Safety Board of Canada[6]. All incidents resulted in extended periods of reduced capacity.

- Incident date: 2018-10-09, Report release date: 2020-03-04, Westcoast Energy Inc., Prince George, BC
    - Described above
- Incident date: 2014-01-25, Report release date: 2015-07-28, TransCanada PipeLines Ltd., near Otterburn, Manitoba
    - Initial failure on 25 January 2014, two adjacent pipelines were shut down to enable assessment
    - 26 January 2014, two adjacent pipelines returned to service
    - 28 January 2014, normal gas delivery to affected communities resumed
    - October 2014, TransCanada submitted an assessment to the National Energy Board (now the Canada Energy Regulator) that a reduced pressure was warranted for the failed pipeline, there is no indication whether the pipeline was operated at such a reduced pressure since the initial failure in January 2014
- Incident date: 2013-10-17, Report release date: 2015-11-03, TransCanada PipeLines Ltd. (NOVA Gas Transmission Ltd.), near Fort McMurray, Alberta
    - Initial failure on 17 October 2013, and failed section of line was isolated (i.e., removed from service)

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[6] https://www.tsb.gc.ca/eng/rapports-reports/pipeline/index.html.

- Pipeline was returned to service on 21 November 2013 with a pressure restriction of 80 percent (7168 kPa) of a recorded pre-failure operating pressure (8960 kPa)
- October 2014, NEB issued Inspection Officer Order KF-001-2014 allowing the pipeline to operate at a maximum pressure of 7750 kPa (an increase of approximately 8 percent from the previous restricted operating pressure of 7168 kPa)

4.4 Please discuss whether FEI would still be at risk of either controlled or uncontrolled shutdowns during periods of reduced supply.

Response:

FEI would still be at risk of either controlled or uncontrolled shutdowns any time that customer demand exceeds available supply. Periods of reduced supply following a no-flow event can, for instance, leave FEI exposed during more common demand or supply events. However, the TLSE Project significantly improves FEI's ability to maintain continuity of service either by withstanding the supply disruption entirely or by "buying time" to shut down the system in a controlled manner. This is an important consideration for enhancing system resiliency, as discussed in Section 3.2.1.3 of the Application.

4.5 Please discuss whether FEI considered a minimum resiliency planning objective which contemplated reduced supply for a period of time following a no-flow event.

Response:

As discussed in Section 4.3.1.2 of the Application, FEI's MRPO is a short-duration objective. In other words, it is intended to address relatively short-duration supply disruptions in the Lower Mainland (i.e., a 3-day no-flow event). The Application demonstrates how on-system LNG storage at Tilbury best addresses FEI's short-duration resiliency objective.

The TLSE Project does take into consideration the potential supply reductions for a period of time following a no-flow event. In order to meet the MRPO, FEI would require 2 Bcf of LNG storage. FEI is proposing to exceed the MRPO by building a 3 Bcf LNG storage, in order to capture additional resiliency and ancillary benefits for customers. The incremental 1 Bcf of LNG storage will help FEI handle either a longer duration initial no-flow event or any reduced supply for a period of time following a no-flow event. The period of time that the TLSE Project will help following a no-flow event is limited by the storage tank size.

In Section 3.3.1.2 of the Application, FEI discussed how regional pipeline development, preferably constructed in different corridors from the T-South system, would help ensure that some pipeline supply is available during an event that involves a sustained loss of pipeline capacity. However, FEI would still require new storage to supplement the remaining pipeline flows during a no-flow event. As such, FEI considers additional pipeline infrastructure in the region to be a complementary resiliency investment, not an alternative to the TLSE Project.

4.6 Please provide an estimate of the financial impact upon FEI and its customers as a result of the T-South Incident, and explain how this amount was determined.

<u>Response:</u>

FEI has interpreted this question as being directed at costs to FEI and how that translates into rate and bill impacts for customers.

There are two types of impacts to be considered: incremental gas supply costs, and impacts to delivery margin resulting from customer load being lower than it otherwise would have been but for the T-South Incident.

The gas supply portfolio incremental costs resulting from the T-South Incident were approximately $140 million. These incremental gas supply costs, net of mitigation, were related directly to FEI securing natural gas supply resources incremental to the pre-incident Annual Contracting Plan (ACP) resources (2017/18 ACP for gas year ending October 31, 2018, and 2018/19 ACP for gas year starting November 1, 2018). The incremental resources were required to enable FEI to meet the Lower Mainland and Vancouver Island customer loads during the period following the October 9, 2018 pipeline rupture while T-South transportation capacity remained constrained, in particular during the winter 2018/19 period. This amount also includes atypical communication costs related to delivering key messaging to customers to conserve their use of gas during the period of restricted supply.

All of the incremental gas supply portfolio costs were captured in the Midstream Cost Reconciliation Account (MCRA) and recovered from FEI's core customers (i.e., RS 1 to 7 and 46) through midstream rates. For example, the table below presents the corresponding one-time midstream rate impacts for RS 1, 2, and 3 customers based on the incremental gas supply portfolio costs totaling approximately $140 million being fully recovered over a 12-month period through the storage and transport (i.e., midstream) charges.

<u>Midstream Rate Impacts Related to Gas Supply Portfolio Incremental Costs</u>

<u>Storage and Transport Charges</u>	**<u>RS-1</u>**	**<u>RS-2</u>**	**<u>RS-3</u>**
Rate Impact *(increase in $/GJ)*	$ 1.083	$ 1.086	$ 0.907
<u>Bill Impacts</u>	**<u>RS-1</u>**	**<u>RS-2</u>**	**<u>RS-3</u>**
Typical Annual Consumption *(in GJ)*	90	340	3770
Annual Bill Increase *(one-time)*	$ 97	$ 369	$ 3,419

As a result of the T-South Incident, customer load was lower than it would otherwise have been, resulting in increased delivery rates. It is not possible to calculate exactly what the load would have been; however, for the purpose of providing an estimate of delivery margin impacts in this information request, FEI has assumed the entire demand variances for certain months to be due to the T-South Incident, as set out below:

- For the residential (RS 1) and commercial (RS 2, 3, and 23) customers, FEI has assumed a T-South Incident impact equal to the variance in the weather-normalized demand between forecast and actual limited to the 2018/19 winter season (i.e., November 2018 to February 2019). FEI considers the small variances in demand during the spring and summer months of 2019 to be unrelated to the T-South Incident as FEI did not observe a significant drop in demand during this period; and
- For the industrial and transportation service customers (RS 4 to 7, 22, 25, and 27), FEI has assumed a T-South Incident impact equal to the variance in demand between forecast and actual for the entire period between November 2018 and November 2019. FEI believes much of this variance in demand was due to curtailments in November and December of 2018 and fluctuations in the market prices of natural gas following the T-South Incident until November 2019, which was immediately before the T-South system returned to full capacity. This fluctuation in the market prices of natural gas resulted in transportation customers reducing production and/or switching to alternative fuels, resulting in FEI's delivery margin losses.

FEI notes the delivery margin impact due to residential (RS 1) and commercial (RS 2, 3, and 23) customers are captured in the Revenue Stabilization Adjustment Mechanism (RSAM) deferral account and recovered through the RSAM rate rider from customers under RS 1, 2, 3 and 23 only. For the delivery margin impact due to industrial and transportation service customers (RS 4 to 7, 22, 25, and 27), the variance is captured in FEI's flow-through deferral account and recovered from all non-bypass customers through delivery rates. The table below provide the estimates of the delivery margin impact due to residential and commercial customers as well as the delivery margin impact due to industrial and transportation customers based on the assumptions discussed above. The table, as an example, also provides the corresponding bill impact to residential (RS 1) customers.

Line	Particular	Reference	Amount
1	**Residential and Commerical (RS 1, 2, 3, 23)**		
2	Assumed Reduction in Delivery Margin ($000s), Pre-Tax		5,386
3			
4	Residential and Commercial (RS 1, 2, 3, 23) Volume (TJ)	G-319-20	139,351
5	**Equivalent RSAM Rider ($/GJ)**	**Line 2 / Line 4**	**0.039**
6	Total Bill Impact to Average Residential (RS 1) @ 90 GJ ($)	**Line 5 x 90 GJ**	**3.48**
7			
8	**Industrial and Transportation Customers**		
9	Assumed Reduction in Delivery Margin ($000s), Pre-Tax		3,998
10	2021 Approved Delivery Margin ($000s)	G-319-20	879,479
11	% Delivery Rate Impact (via Flow-Through Amortization)	Line 9 / Line 10	0.45%
12			
13	2021 Approved Effective Delivery Rate ($/GJ)	G-319-20	4.510
14	**Equivalent Delivery Rate Impact ($/GJ)**	**Line 11 x Line 13**	**0.021**
15	Total Bill Impact to Average Residential (RS 1) @ 90 GJ ($)	**Line 14 x 90 GJ**	**1.85**

5.0 Reference: PROJECT NEED

Exhibit B-1-4, pp. 22,23

Hydraulic Collapse

On pages 22 to 23 of the Updated Public Application, FEI states:

> Resiliency, as the ability to prevent, withstand, and recover from system failures or unforeseen events, is critical for natural gas systems because the consequences of a lack of resiliency can be significant. Specifically, insufficient resiliency poses a risk of an uncontrolled shutdown of the distribution system (also called hydraulic collapse). An uncontrolled shutdown or hydraulic collapse occurs when parts or all of the gas distribution system are naturally lost due to a collapse of system pressure and gas supply. An uncontrolled shutdown is a serious scenario both in terms of service disruptions to customers as well as the potential for safety concerns:
>
> - When the pressure in a portion of the gas system experiences a hydraulic collapse, FEI is unable to directly determine which customers are receiving sufficient pressure to operate their appliances or equipment safely. These pressure variations can vary both in time (as the event progresses) and location (from area to area or even street to street). This uncertainty greatly complicates the ability of FEI to localize, manage and respond to the supply deficiency.

5.1 Please discuss whether FEI considers hydraulic collapse to be the most severe consequence to FEI's customers of a no-flow event on the T-South system.

Response:

FEI considers hydraulic collapse to be the most severe outcome of a no-flow event on the T-South system. An uncontrolled hydraulic collapse of the system would result in widespread and unpredictable outages such that it would take weeks or even months to restore service to all customers. FEI's service technicians would have to visit each customer premise to purge lines and relight appliances should this scenario occur.

Many gas customers and businesses rely on gas for necessities such as heating and cooking and cannot easily or quickly switch to an alternate energy source. Also, as detailed in Section 3.2.1.3 of the Application, hydraulic collapse could result in air being drawn into pipes, creating a combustible air-gas mixture. This represents a serious safety hazard to the public (please also refer to the responses to the RCIA IR1 8 series of questions). The PwC Report (Confidential Appendix B to the Application) addresses the severe consequences that an extended gas outage could have on customers and on society more broadly.

5.2 Please discuss whether FEI has ever experienced a hydraulic collapse on any part of its system. If yes, please provide a detailed explanation of the cause, impacts upon customers and FEI's response.

Response:

Widespread outages are rare and have never occurred on FEI's systems at the significant level that might have occurred if the 2018 T-South no-flow event had been longer in duration or occurred in colder weather. In the response to BCUC Confidential IR1 15.3, FEI describes the only two significant incidents where the outage involved an entire local system.

FEI experiences moderate-scale customer outages more regularly. These moderate-scale outages are typically caused by third-party damage to FEI's gas system, landslides, floods or wildfires. These events have led to the need to shut-in portions of the natural gas system in a controlled manner, isolating these areas from the rest of the system and cutting off gas supply to small pockets of customers. In the larger examples of these moderate-scale incidents, dozens to hundreds of customers and businesses have remained without gas for heat or cooking for several days while the system was restored. In some of these cases local, regional, or provincial emergency operations centres were activated to accommodate the needs of the residents in the neighbourhoods and communities affected.

5.2.1 Please also provide a summary of other instances of hydraulic collapse that FEI is aware of occurring in other gas utilities.

Response:

FEI is aware of examples of pipeline rupture incidents leading to hydraulic collapse and resulting loss of supply to customers. Additionally, FEI requested that Guidehouse provide examples of instances that it is aware of. FEI also notes that, as discussed in the responses to BCUC IR1 6.3 and BCUC Confidential IR1 15.3, it has experienced other instances of smaller-scale controlled shut downs resulting from third party damage within its distribution systems. The focus in this response is on failures of upstream supply in other gas utilities resulting in hydraulic collapse. These incidents are typically larger in scale.

The following response has been provided by Guidehouse:

Hydraulic collapses are rare in the natural gas utility sector in North America. This is because the North American natural gas system is inherently resilient through its intrinsic, physical, and operational properties that enable it to meet the volatile demand profiles resulting from resilience events. The sources of resilience include the ability to store natural gas, and the interconnectedness of the natural gas pipeline network. Most natural gas utilities can access these sources of resilience and have been able to avoid a system-wide collapse during an unforeseen supply shortage. However, we can identify some acute situations of smaller scale collapse.

Below are two examples of natural gas service disruptions caused by a lack of supply due to unforeseen upstream supply disruptions and two examples of natural gas service disruptions due to unforeseen outages on distribution systems.

Upstream Supply Disruption Examples

Example 1:

In February of 2011, New Mexico Gas Company and Southwest Gas Company experienced loss of gas service to more than 40,000 customers in New Mexico and Arizona.[7] At that time, the Southwest United States was experiencing record-setting cold weather. This resulted in well freeze-offs, gas processing plant shutdowns, and supply basin underperformance. The problem was impacted by increased peak demand from customers in Texas, New Mexico and Arizona.[8] Many customers were without gas service for a full week.

Example 2:

On January 25, 2014, a TransCanada Corporation gas transmission pipeline 762 mm (30-inch) Line 400-1 exploded and burned, near Otterburne, Manitoba, causing a natural gas shortage in Manitoba and parts of the United States. Natural gas burned for approximately 12 hours. Five residences in the immediate vicinity were evacuated, and Provincial Highway 303 was closed until the fire was extinguished. Officials identified natural gas outages affecting as many as 4,000 people in nearby communities, where temperatures dipped to near -20 degrees Celsius overnight. The Rural Municipality of Hanover declared a state of local emergency in a release that said the outage was expected to last 24 to 72 hours.[9]

Distribution System Disruption Examples

Example 1:

On January 21, 2019, National Grid was forced to shut down a significant portion of its natural gas distribution system on Aquidneck Island resulting in an outage to 7,455 customers. The outage lasted seven days and was due to a low-pressure condition caused by:[10]

1. Sudden high demand due to low temperatures;
2. Failure at an on-system LNG storage and vaporization facility in Providence; and
3. A malfunctioning valve.

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7 https://pscdocs.utah.gov/gas/19docs/1905713/307989DirTestFaustDEU4-30-2019.pdf.
8 https://www.azcc.gov/docs/default-source/utilities-files/gas/outages/southwest-gas.pdf?sfvrsn=4a761646_2.
9 https://www.cbc.ca/news/canada/manitoba/natural-gas-pipeline-explodes-near-otterburne-man-1.2510873.
10 http://www.ripuc.ri.gov/eventsactions/AI_Report.pdf.

Example 2:

On December 26, 2020, Aspen, Colorado experienced a gas outage that impacted 3,500 customers due to vandalism at three Black Hills Energy facilities. The company had to complete a manual shutdown of the system to prevent a total system collapse. This involved sending 150 technicians to the area to manually shut-off all 3,500 meters. The company was able to restore service within three days.

The following response has been provided by FEI:

FEI is aware of the following additional instances of hydraulic collapse caused by upstream supply disruptions that resulted in a loss of supply to customers served by the system.

Example 1:

On January 10, 2018, a rupture of a SaskEnergy (TransGas) NPS 6 transmission pipeline resulted in a loss of supply to approximately 4,500 customers' homes and business in Melfort, St. Brieux, and Kinistino, Saskatchewan and surrounding rural areas for approximately 2 days.[11]

Example 2:

On September 25, 1998, the supply to the Australian State of Victoria was interrupted after a fire at a gas plant jointly owned by Esso/BPH. Gas supply was restored on October 5, 1998. The losses to industry were reported at approximately $1.3 billion (Australian dollars).[12]

5.3 Please further explain why during a hydraulic collapse, FEI is unable to directly determine which customers are receiving sufficient pressure to operate their appliances or equipment safely.

Response:

Under normal operating conditions, FEI ensures that its pipeline systems (i.e., distribution and high pressure) have sufficient pressures and capacity in order to maintain tail end pressure levels. Pressures and flows are monitored at strategic locations throughout the system and used to infer and ensure minimum tail end pressures are maintained on a system by system basis. This indirect means of inferring minimum tail end pressures is not feasible during hydraulic collapse

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11 https://www.saskenergy.com/about-us/newsroom/natural-gas-system-outage-melfort-area.

12 https://www.aph.gov.au/About_Parliament/Parliamentary_Departments/Parliamentary_Library/pubs/rp/rp9899/99rp05#IMPACT.

scenarios because of the dynamic and unpredictable behaviour of the system load and resulting gas flows during upset conditions.

In order to determine the impacts on delivery pressure to customers during a hydraulic collapse, FEI would require real-time or on-demand pressure measurement widely distributed throughout FEI's distribution systems with the ability to monitor system pressure conditions. FEI's distribution systems do not have this real-time or on-demand pressure measurement capability distributed throughout the system at customers' premises; hence, FEI is not able to directly determine which customers are receiving sufficient pressure to operate their appliances or equipment during a hydraulic collapse.

6.0 Reference: PROJECT NEED

Exhibit B-1-4, pp. 23, 24

Controlled Shutdowns

On pages 22 to 23 of the Updated Public Application, FEI states:

> A controlled shutdown is a planned and safe depressurization of a part of the gas system using strategic control points, including stations and valves. It is far better from the perspective of customers, FEI, and society generally, if FEI has time to implement a controlled shutdown. In a controlled shutdown, FEI is aware of which areas and customers are no longer supplied with natural gas, which allows for safe regasification and relights of customer appliances and equipment. While a controlled shutdown is considered a measure of "last resort", it provides valuable flexibility to the operator when all supply options are exhausted, and improves customer service by minimizing the scale and duration of any necessary outages.
>
> Controlled shutdowns require time to implement. It is necessary to assess the supply shortfall, analyze and plan the extent of shutdown to meet the shortfall, and execute the plan. Guidehouse explains: …it would require significant time for FEI to ascertain the supply/demand on its system and develop the appropriate response, i.e., curtailment of customers, in order to mitigate long-term impacts, including catastrophic operational and economic failure. On-system storage would allow FEI to more effectively implement a controlled shutdown that minimizes the impact to at-risk customers if a major interruption event occurred.

6.1 Please further explain the time required by FEI to implement a controlled shutdown. Please include a discussion on whether the time required to implement a controlled shutdown changes depending on the scale of the shutdown required.

Response:

The time required by FEI to implement a controlled shutdown can be broken down into three phases:

The **first phase** is the planning phase where FEI defines the area that is to be shut down, and then determines the methods that will be used to achieve it. Based on the load that needs to be shed due to a supply shortfall, FEI identifies the geographic area(s), the number of customers, and the type of customers that are going to be impacted. This step of this phase takes about one hour. FEI has already prepared a detailed system shutdown plan as part of its emergency preparedness; to implement the plan, FEI selects a response based on the supply shortfall situation at hand. Once the geographic shutdown area has been confirmed, the next step is for FEI to identify the method that will be used to actually isolate the area from the rest of the FEI system. FEI can either use existing valves or pipe crimping[13] to achieve the required system

[13] Pipe crimping refers to using an external compression tool to squeeze the pipe thereby blocking the flow of gas within.

isolation. It could take FEI up to several hours to plan out the valves to be used and/or locations where pipe will be crimped taking into consideration the size of the area to be isolated, the accessibility of valves, the characteristics of the locations where pipe needs to be crimped, condition of the pipe to be crimped, etc.

The **second phase** is the actual field isolation of the system that needs to be shut down. Field staff, equipment, and support services are assembled and dispatched to execute the isolation plan. Valves are located in the field and closed by qualified field technicians. As required, crews locate the section of mains that need to be crimped, excavate the main, perform the crimp, and confirm the effectiveness of the crimp. Depending on the location of the main, support services such as traffic control, road cutters, etc. may be required to gain access to the main. The isolation phase of the controlled shutdown, could take up to several days depending on the number of valves to be closed, the number of locations where mains are to be crimped, and prevailing weather conditions.

The **third and final phase** is the shutting off of customer metersets within the isolated section of the system. In this phase, field technicians need to attend every meterset and use a hand wrench to turn off the meter cock – a valve on the meterset that stops the flow of gas into the customer's home or business. The time required to complete this phase is a function of the number of metersets that need to be turned off, the number of available field technicians, customer geographic density, weather conditions and traffic conditions. To isolate a few hundred customers at their premises could take several hours; in contrast, isolating tens of thousands of customers could take weeks to complete, dependent on the number of field technicians available.

6.2 Please provide a detailed explanation of the process to resume service to customers following a controlled shutdown.

Response:

The process to resume service to customers following a controlled shutdown has four distinct phases:

1. **Planning phase**: During this phase FEI determines how the isolated section of the system will be regasified and reconnected to the FEI system that was not part of the controlled shutdown. Depending on the size of the isolated section, detailed plans need to be developed as to the sequence in which isolation valves will be opened and crimped mains will be un-crimped. This planning is necessary to ensure that the gasification of the isolated section will not affect the hydraulic integrity of the larger FEI system.

2. **Integrity validation**: During this phase FEI verifies the integrity[14] of the section of the system that was isolated as part of the controlled shutdown. The larger the section of system that is isolated and the longer that it is isolated for, the greater the probability that

[14] In this context, integrity refers to the ability of the system to provide safe containment and flow of gas under pressure.

its integrity may have been compromised due to third-party damage. Should such third-party damage occur, FEI needs to locate it, assess the impact of the damage (i.e., confirm whether air may have entered the system, etc.), purge the affected system as required, and repair the damage.

3. **Gasification**: During this phase FEI restores gas flow into the previously isolated section. Field staff are dispatched to open the valves and un-crimp mains identified in the planning phase and to confirm the successful completion of these actions and the expected flow of gas into the system.

4. **Restore gas flow and relights**: This step requires a field technician to visit each customer's meterset, open the meter cock, and confirm the integrity of the meter set. Next, the field technician enters the customer's home or business, relights gas appliances as required, and confirms their safe operation. Finally, the field technician confirms the safe flow of gas through the meterset before leaving the premise and then moving on to the next customer or business.

6.3 Please discuss the historical frequency of controlled shutdowns implemented by FEI.

6.3.1 Please provide a summary of the circumstances which have historically caused FEI to implement a controlled shutdown.

<u>Response:</u>

Small-scale controlled shutdowns of up to several hundred customers occur periodically, primarily resulting from damage to FEI's system caused by third parties. Large-scale controlled shutdowns of up to several thousand customers occur much less frequently (about once every 5 to 10 years), again typically due to third-party damage to FEI's system. The most recent large-scale controlled shutdown occurred approximately three years ago when FEI was forced to shut down about 95 percent of the Revelstoke propane distribution system in response to a third-party line contact.

7.0 Reference: PROJECT NEED

Exhibit B-1-4, pp. 25, 26; Appendix A, p. 16

FEI General Terms and Conditions, Section 13

Customer Outages

On pages 25 to 26 of the Updated Public Application, FEI states:

> In general, gas transmission and distribution systems experience significantly fewer outages than electric networks. However, when gas customer outages do occur, they tend to be longer in duration (due to the need for purging and appliance relighting, as described above). Resiliency investments for the natural gas system are consequently focused on addressing low probability events. But events can and do occur, and they can give rise to significant consequences…
>
> The rates of reliability would suggest that, on average, a typical natural gas customer would expect 69 seconds of service outage per year, compared to almost four hours per year for a typical electric customer in BC (even with the high standards of redundancy on the electric system). In practice, the vast majority of FEI's customers have never experienced a single natural gas outage, other than for planned reasons such as a meter exchange.

7.1 Please provide a comparison of FEI's understanding of customers' acceptance of the average service outage per year for gas utilities compared to electric utilities. Please discuss if this is supported by evidence.

<u>Response:</u>

FEI believes that reliability of service is a fundamental customer expectation, regardless of whether the energy commodity provided is gas or electricity. Given the historical differences between gas and electric reliability, FEI considers that electric utility customers are generally more accepting of outages than are gas utility customers. As noted in the preamble, the vast majority of FEI's customers have never experienced a single, unplanned gas outage. Since most FEI customers have never experienced an unplanned outage, it is likely difficult for these customers to understand or relate to an event which has never occurred.

FEI periodically surveys a sampling of customers to gain insights on various topics. In March 2021, members of the FortisBC MyVoice community panel[15] were asked to provide feedback on FortisBC's gas and electric infrastructure resiliency. In total, 2,125 community panel members participated in the survey which is provided as Attachment 7.1. The survey results show that the majority of respondents feel reliability and resiliency are very important. 92 percent of respondents gave the reliability aspect an importance rating of eight or more. 87 percent of respondents gave the resiliency aspect an importance rating of eight or more.

Feedback from respondents included the following:

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[15] https://www.fortisbc.com/in-your-community/our-online-communities-myvoice-and-business-voice.

> "I rely on gas for heating, cooking, hot water and have only minimum electricity as a backup therefore gas service is extremely important to me."

> "I haven't experienced an extreme disruption so I can't rate that category. I would hope that you are well prepared for any event."

> "I lived through the ice storm in Ontario in 1998. I was without electricity for nine days and then it was sporadic after that for about two weeks. It was horrible and I never want to go through that again no matter what the cause."

> "Look what happened in Texas this winter... we don't want that to happen here."

Statements like those above, as well as other information in the survey, reaffirms FEI's understanding that customers view the provision of safe and reliable service as important.

7.2 In a hypothetical example of a 3 day customer gas outage due to a no flow event (with normal gas flows resuming after 3 days), please calculate the frequency of such an event that would equate to an average of four hours outage per year (assuming that other outages result in an average of 69 seconds per year).

7.2.1 Please compare this event frequency to the expected frequency of a 3 day no flow event.

Response:

FEI interprets the question to be seeking a comparison of outage frequencies in a purely mathematical sense as FEI is unaware of any outage frequency tables or figures that directly compare the frequency and probability of outages on the gas system.

- To achieve a total outage duration of 4 hours, it would take approximately 209 years of 69 second annual outages.
- A 3-day (i.e., 72-hour) outage occurring once every 18 years would result in an equivalent outage duration as compared to a 4 hour annual outage frequency.

However, FEI notes that it is not possible for this hypothetical 3-day outage scenario to occur. This is because it is currently not possible for FEI to experience a 3-day no-flow event followed by normal gas flows after those three days. In the scenario described, hundreds of thousands of customers in the Lower Mainland region would have their gas service interrupted at some point during the no-flow event and the system would depressurize. Consequently, as described in Section 3.3.3.2.1 of the Application, FEI would need to respond by visiting each customer premise to shut off the gas supply, followed by a progressive purge and repressurization of the system, and finally revisiting each customer premise to restore service and relight appliances. This restoration process could take days to months, depending on both the scale of outages and access to qualified resources.

This inability for widespread outages in the gas network to be confined to a short duration underscores the fundamental differences between gas and electric energy delivery. Unlike electricity where FortisBC Inc. (FBC) can rapidly restore service, it is not possible for FEI to rapidly restore supply to customers following a widespread outage. Instead, restoration of a significant number of gas customers following an outage is a necessarily slow and methodical event. As a result, attempting to compare the outage statistics between individual gas and electric outage events is not meaningful.

On page 16 of Appendix A, Guidehouse states:

> Given the obligation to serve, the natural gas utility does not curtail firm demand customers who cannot tolerate disruption to the service, unless it is an emergency or other circumstance identified in tariff provisions.

Section 13 of FEI's General Terms and Conditions[16] states:

> 13. Interruption of Service…
>
> 13.2 Right to Restrict
>
> FortisBC Energy may or may require any of its Customers to, at all times or between specified Hours, discontinue, interrupt or reduce to a specified degree or quantity, the delivery of Gas for any of the following purposes or reasons: (a) in the event of a temporary or permanent shortage of Gas, whether actual or perceived by FortisBC Energy; (b) in the event of a breakdown or failure of the supply of Gas to FortisBC Energy or of FortisBC Energy's Gas storage, distribution, or transmission systems; (c) in order to comply with any legal requirements; (d) in order to make repairs or improvements to any part of FortisBC Energy's Gas distribution, storage or transmission systems; (e) in the event of fire, flood, explosion or other emergency in order to safeguard Persons or property against the possibility of injury or damage. [Emphasis added]

7.3 Please confirm, or explain otherwise, that under the FEI's General Terms and Conditions, FEI has the right to restrict service to any of its customers under certain circumstances.

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16 https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/regulatory-affairs-documents/gas-utility/fortisbc_generaltermsandconditions.pdf?sfvrsn=202bc0bf_24.

Response:

FEI has the right to restrict service to its customers under FEI's General Terms and Conditions.[17]

7.3.1 Please discuss whether no-flow events on the T-South system could constitute an emergency.

Response:

FEI confirms that in certain circumstances a no-flow event on the T-South system could constitute an emergency.

7.3.2 Please discuss whether FEI considers that the General Terms and Conditions provide FEI the right to restrict service to any of its customers during an event such as the 2018 T-South Incident.

Response:

FEI's General Terms and Conditions provide FEI the right to restrict service to its customers during an event such as the 2018 T-South Incident.[18]

7.4 Please provide FEI's view of customers' acceptance of restricted service in rare, unforeseeable events that are outside of the direct control of FEI. Please discuss if this is supported by evidence.

Response:

Please refer to the responses to BCUC IR1 7.1 and 7.5.

[17] There are a limited number of customers whose contracts do not fall under FEI's General Terms and Conditions.

[18] There are a limited number of customers whose contracts do not fall under FEI's General Terms and Conditions.

7.5 Please discuss whether FEI has undertaken any studies, consultation, or other analysis with its customers to understand customers' willingness to pay for resiliency investments, and specifically willingness to pay for the costs of the TLSE Project.

7.5.1 If so, please provide a summary of such analysis.

7.5.2 If not, please explain how FEI has determined the TLSE Project is in the best interests of customers.

<u>Response:</u>

As discussed in the response to BCUC IR1 7.1, FEI explored customer attitudes about the importance of resilience investments in March 2021. At that time, FEI asked respondents from the Company's MyVoice Web panel to rate the relative importance of different service aspects. The stated importance results show that customers expect FEI to provide a reliable and resilient distribution system. The study did not explicitly research perceptions about cost. Following is a summary of the results and a discussion about customers' willingness to pay.

Table 1 below shows the percentage of respondents who rated the importance of service elements as eight, nine or ten, on a ten-point scale where one is "not at all important" and ten is "extremely important".

Table 1: Stated importance of service aspects

Energy service aspect - Importance	Importance ratings of 8-10
Having reliable energy service that can withstand and recover from minor disruption events	92%
Restoring service quickly after it has been disrupted	89%
Delivering your energy at a reasonable cost	89%
Having a resilient energy network that can withstand and recover from extreme disruption events	87%
Keeping you informed during service disruptions	84%

In the survey, a distinction was made between the reliability of FEI's energy service and the resiliency of FEI's energy network. A reliable energy service was defined as an energy service that can withstand and recover from minor disruption events (e.g., typical storms, minor system damage). A resilient energy network was defined as an energy network that can withstand and recover from extreme disruption events (e.g., severe weather-related disasters, deliberate systems damage or cyber-attacks). By these definitions, customers generally seemed more concerned about "reliability" than "resiliency", perhaps because reliability events are more probable. From FEI's perspective, the solutions to both reliability and resiliency events affecting the gas delivery system are similar.

Of the energy services rated by respondents, two of the top three were related to resiliency, with 92 percent of respondents scoring "having reliable energy service that can withstand and recover from minor disruption events" as having an 8-10 level of importance.

Overall, a significant proportion of customers were unable to provide an opinion regarding resiliency performance, presumably because disruptions of gas service are so rare. However, the very high importance scores of resiliency underscore the necessity of being able to maintain this key aspect of gas service delivery.

FEI did not directly evaluate customers' willingness to pay for additional resiliency investments. This is because a survey itself cannot provide sufficient context for respondents to meaningfully understand and evaluate the cost and benefits of resiliency alternatives and investments. This Application, for example, contains 150 pages explaining the Project's need, alternatives, costs and benefits (i.e., Sections 3 to 6). Consequently, FEI believes that direct pricing investigations on resiliency will not deliver meaningful insights.

FEI asked respondents to share the reasons they considered when rating the importance of "having a resilient energy network that can withstand and recover from extreme disruption events". Approximately 1,500 respondents shared their reasons.

Table 2: Stated reason for rating of importance of having a resilient energy network

Reason	Percentage of reasons cited
Comfort: heating, hot water, running appliances	25%
General need for consistent service with quick recovery after a disruption	22%
Concerns about weather, earthquakes, cyber-attacks, world disaster events	16%
Medical reasons, safety or security	8%
No past experience with service disruptions	5%
Important to be proactive, rather than reactive	4%
Consistent connection required for working at home and running businesses	3%
Want FortisBC to focus on improving infrastructure before preparing for rare catastrophic events	2%
Costs – do not want costs passed onto the consumer	2%
Experience with past service disruptions	2%
Low probability of disastrous events occurring	2%
Have access to alternate energy sources	1%

As shown in Table 2 above, the most common theme, cited by one-quarter of respondents, was centred on the importance of personal comfort and maintaining energy for heating, hot water and running appliances in their homes. One-fifth of respondents cited concerns about potential catastrophic events such as earthquakes and cyber-attacks, specifically noting the recent gas disruptions in Texas. Other mentions included medical and security issues. Respondents emphasized the importance for FEI to be proactive rather than reactive in their disaster response plan, and as such, expect FEI to make necessary and prudent infrastructure investments.

8.0 Reference: PROJECT NEED

Exhibit B-1-4, pp. 35, 51, 52; Appendix A, p. 45

Minimum Resiliency Planning Objective

On page 35 of the Updated Public Application, FEI states its Minimum Resiliency Planning Objective is:

> Having the ability to withstand, and recover from, a 3-day "no-flow" event on the T-South system without having to shut down portions of FEI's distribution system or otherwise lose significant firm load.

On page 51 Updated Public Application, FEI states:

> FEI's determination that three days is an appropriate minimum planning duration for a "no-flow" emergency event was informed by the experience with the T-South Incident. In particular, FEI considered: the length of the "no-flow" event in 2018; whether or not the T-South Incident occurred in favourable or unfavourable conditions from the perspectives of resuming flows and system demand and supply; and, the time that FEI required to assess the situation and re-establish a balance between supply and demand.

On page 52 Updated Public Application, FEI adds:

> In FEI's assessment, the very real potential exists under somewhat less favourable conditions for a "no-flow" supply emergency to last three days, and it could conceivably last longer.

On page 45 of Appendix A, Guidehouse states:

> FEI estimates that the most probable duration of total gas delivery outage in the LML is at least three days. FEI arrived at this estimate by evaluating the October 2018 Enbridge outage duration and response, weather, terrain variability factors, and time required for FEI operational teams to manage a controlled curtailment. The amount of load on the system and the time of year of the disruption are also key considerations when determining the minimum size of the tank, as these will impact how much gas is needed, and how much flexibility FEI has to refill the tank.

8.1 Please discuss whether FEI considered other forms of minimum resiliency planning objectives, for example: the ability to withstand a 1 in X years no-flow event; the ability to withstand a 3-day no-flow event on X% of days in a year; the ability to avoid a hydraulic collapse; maximum average outage time per customer per year. Please provide a discussion on the pros and cons of each example and any others explored by FEI, including why FEI rejected them.

8.1.1 Please discuss whether FEI considered the case for a minimum resiliency planning objective of a shorter or longer time period.

Response:

For clarity, the MRPO is simply a short-hand way of articulating the identified risk to the Lower Mainland service area associated with a no-flow event on the T-South system; it is not a general planning standard.

The Lower Mainland system configuration, load and geography are unique; therefore, the resiliency considerations for the Lower Mainland associated with a no-flow event on the T-South system do not necessarily apply to the Vancouver Island and the Interior service areas. The Lower Mainland customer load, which makes up the largest share (approximately 60 percent) of the demand on FEI's system, has the least amount of resiliency to upstream supply disruptions. In contrast,

- The Vancouver Island service area is at the end of FEI's system and is served by a submarine transmission pipeline, but also has access to the Mt. Hayes LNG Storage Facility. Mt. Hayes provides on-system storage resources to Vancouver Island for a duration of approximately 10 days and is sized appropriately to support Vancouver Island customer load during a potentially longer supply disruption or no-flow event.
- Interior customers have access to greater pipeline connectivity (i.e., multiple pipeline interconnections to T-South and TC Energy) compared to the Lower Mainland and Vancouver Island, which greatly increases system resiliency for the Interior region.

The MRPO was developed in consideration of FEI's significant operating experience, including its experience during the T-South Incident and the challenges that it experienced in maintaining service to customers during that time. Given the potential for future similar events (as discussed in the response to BCUC IR1 1.5), FEI considers the consequences for FEI and its customers if such an event were to occur to be too significant to accept.

Although the no-flow incident lasted two days, the speed with which Westcoast was able to resume service was a function of favourable conditions, as laid out in Section 3.4.4.1 of the Application. This factor, along with others described in Section 3 of the Application, support having a minimum objective for the Lower Mainland of being able to withstand a three-day no-flow event on T-South (i.e., the MRPO).

FEI considered the fact that a no-flow event could be longer than 3 days. However, FEI assessed that three days was a reasonable minimum amount of time for a pipeline operator to make an informed decision on next steps, which may include a controlled shutdown (as a worst case scenario). This is further discussed in Section 3.4.6 of the Application.

FEI emphasizes that there is no single approach for building resiliency. Each service region has its own unique needs depending on the region's accessibility to the three key elements that make up a resilient system (as FEI discussed in Section 3.3 of the Application - Diverse Pipelines & Supply, Ample Storage, and Load Management). The optimal amount of resiliency investments reflects the characteristics of FEI's supply portfolio, as illustrated in Figure 4-3 of the Application.

FEI also sought an external opinion from Guidehouse who confirmed that FEI's intended approach to addressing its resiliency needs was appropriate and provided information comparing how utilities in other jurisdictions considered resiliency needs.

FEI acknowledges that planning based on the MRPO alone leaves no margin after a 3-day no-flow event for managing through subsequent supply or demand events such as those that occurred following the T-South Incident. As explained in Section 4, FEI has chosen an approach (a 3 Bcf tank with 800 MMcf/day of regasification) that is reasonable given the alternatives available and considering the other complementary solutions to enhancing resiliency which FEI is also pursuing.

8.2 Please confirm, or explain otherwise, that FEI has not previously had a minimum resiliency planning objective. If confirmed, please explain why FEI considers it is necessary to implement a step change to an objective that assumes a 3-day period of no-flow.

8.2.1 Please discuss whether the step change to the 3-day minimum resilience objective precludes the consideration of incremental improvements to resiliency.

8.2.1.1 Please discuss whether FEI's approach constrains the evaluation of the cost-effectiveness of a wider range of alternatives which may be able to withstand shorter no-flow events.

Response:

FEI confirms that the MRPO was a concept developed for the purposes of this CPCN Application. It is simply a way of articulating or presenting the risk and resiliency need in the Lower Mainland associated with a no-flow event on the T-South system—the single largest supply risk facing FEI. It is not a general planning standard.

The T-South Incident brought into sharp focus the extent to which FEI's dependency on the T-South system represents a significant risk to FEI and its customers in the Lower Mainland. Given the potentially significant consequences that would impact a large number of customers resulting from a no-flow event on the T-South system, FEI considered it necessary to enhance resiliency in this portion of FEI's service area.

FEI notes that the BCUC also recognized this concern in Letter L-1-19 to FEI[19] dated February 5, 2019 (provided in Attachment 8.2), which states:

> Over the past year, British Columbia has experienced several extreme and unforeseeable events, including devastating wildfires and landslides, a rupture to the Enbridge Inc. Westcoast T-South pipeline and, most recently, severe windstorms. Further, British Columbia faces potential risks, such as earthquakes, ice storms or cybersecurity attacks. These events can damage

[19] This letter was sent from the BCUC to the "major utilities it regulates", including FEI, BC Hydro and Pacific Northern Gas.

> critical infrastructure and significantly restrict utilities' ability to provide safe and reliable energy services to customers, potentially leaving millions of British Columbians without access to essential energy for extended periods of time. This risk to safe and reliable energy is a significant concern to the British Columbia Utilities Commission (BCUC).
>
> To address this concern, the BCUC needs to better understand how the major public utilities plan for and manage operations during such events, and how they consider strategies that currently exist and those under development in relation to risk management and emergency preparedness. Further, we are interested in knowing how utilities plan to mitigate the potential impact on customers and stakeholders in response to emergency events.

In that letter, the BCUC specifically requested information on "[p]olicies and procedures in place to ensure reliability of both transmission and distribution of gas by the utility, and a comparison of these policies to Mandatory Reliability Standards where possible" as well as "[a]n inventory of assets and other tools that can be used by the utility to reduce risk, such as gas storage assets, and policies describing their management."

The MRPO is only a "step change" in the sense that it assumes that a no-flow event could last 24 hours longer than the no-flow period following the T-South Incident, which FEI believes is a reasonable expectation in light of the favourable circumstances in which the T-South Incident occurred. An "incremental" approach to resiliency improvements would imply that some level of load loss (potentially significant and lasting) would be acceptable during a plausible 3-day no-flow event. FEI believes it is appropriate to plan its system on the basis of making appropriate investments to avoid customer outages lasting weeks or months. Given that, FEI does not consider small incremental improvements for the Lower Mainland service area to be an appropriate approach to resiliency planning.

Through FEI's two-step evaluation process, FEI considered a variety of alternatives and determined that new on-system LNG storage at the existing Tilbury facility is the best option for withstanding shorter no-flow events.

8.3 Please provide a detailed explanation of the analysis and assumptions that led FEI to conclude that the most probable duration of total gas delivery outage in the Lower Mainland (LML) is at least three days. Please include a specific discussion on any probability analysis undertaken for an outage lasting one day, two days, three days, and more than three days.

8.3.1 Please explain how this is supported by the experience of the 2018 incident.

8.3.2 Please explain why the potential for a supply emergency lasting three days justifies a minimum resiliency planning objective based around a 3-day no-flow event.

8.3.3 Please discuss the extent to which the 3-day no-flow objective assumes the coincident occurrence of different worst-case or “unfavourable” variables.

Response:

Please refer to the response to BCUC IR1 8.1.

8.4 Please discuss whether the BCUC approval of the Project requires that the BCUC approve, in principle, the minimum resiliency planning objective.

Response:

FEI is not seeking approval of the MRPO in principle or for general application, and such approval is not required.

The MRPO is simply a useful way of conceptualizing or articulating the identified risk that FEI’s Lower Mainland system faces from a disruption on the T-South system based on FEI’s actual experience. FEI developed the MRPO based on the potential duration and impact of a no-flow event on FEI’s Lower Mainland system and as a means to explain the rationale for the Project. FEI is not implying that the MRPO is appropriate for broad application throughout FEI’s service territory or for other gas utilities as an industry standard. Rather, FEI would consider the unique characteristics of each region before developing and proposing resiliency projects for other areas of FEI’s system.

8.5 Please discuss whether the minimum resiliency planning objective is to be interpreted as “having the ability to withstand, and recover from, <u>any</u> 3-day “no-flow” event”, i.e. to withstand and recover from a 3-day no flow event during the coldest period of the year.

Response:

The MRPO and the resulting design of the TLSE Project have been selected to ensure that the system supplying customers in the Lower Mainland (LML) region could withstand and recover from a 3-day no-flow event on the T-South system during the coldest period of the year. As shown by the load-duration curve in Figure 4-12 and discussed in Section 4.4.2.2.1 of the Application, the TLSE Project has been sized to meet the LML customer peak demand for all days of the year, except for the single coldest design day. In other words, the TLSE Project will have sufficient capacity to meet forecast peak demand on all but one day of the coldest year in the 1 in 20 year forecast, irrespective of the cause of the no-flow event.

The TLSE Project is sized to achieve the MRPO during the coldest period of the year as this is when customers are most dependent on gas supply to heat their homes and businesses. As discussed in the PwC Report (Appendix B), supply disruptions during extremely cold weather could have significant customer impacts and result in serious societal harm, as was experienced in the state of Texas during the February 2021 winter storm.[20]

[20] https://www.dallasnews.com/news/weather/2021/04/30/number-of-texas-deaths-linked-to-winter-storm-grows-to-151-including-23-in-dallas-fort-worth-area/.

9.0 Reference: PROJECT NEED

Exhibit B-1-4, p. 36; Appendix A, pp. 20, 21 , 50, Workshop Transcript, March 11, 2021 (Transcript), p. 125

Risk Approach

On page 36 of the Updated Public Application, FEI states:

> Guidehouse characterizes resiliency investments as akin to insurance. It articulates a risk-based approach consistent with what FEI has applied to the Project. For example:
>
> … As a component of system redundancy in the form of reserve supply, the Tilbury Tank expansion project can be viewed as insurance that mitigates the risk of a significant supply disruption. The critical factors to consider when purchasing insurance include defining the risk, both in terms of the probability of the risk and the consequences of the risk and identifying prudent means to manage the risk. In other words, it is important to understand the likelihood, i.e., the probability of a major system disruption, and the significance, i.e. the potential cost and socio-economic implications of a major system disruption. Another critical consideration in managing risk is the cost to mitigate the risk, e.g. the cost of building infrastructure, or the cost of insurance.

On pages 20 to 21 of Appendix A, Guidehouse states:

> In terms of guiding system planning for resiliency, cost reasonableness is an important element that drives natural gas utility decision-making… Depending on the resiliency need, developing additional transportation or storage capacity may provide system redundancy and increased resiliency. These assets may be under-utilized for a period of time, creating a risk that these costs to customers could be viewed as unreasonable. However, weighed against the consideration is the potentially significant socio-economic consequences of a loss of service.

On page 50 of Appendix A, Guidehouse states:

> In the context of buying insurance, Guidehouse concludes that FEI has fittingly applied the appropriate risk management approach and chosen an effective and prudent solution in the form of the duration of supply that the proposed Tilbury Tank expansion will provide.

In the Transcript, on page 125, Mr. Moran states:

> And risk is -- and we'll talk about this in a moment, it's the ability -- risk is the impact of uncertainty on the ability of a company to fulfill its objectives. Or, it has also been described as the possibility of an event occurring that will significantly disrupt the ability of the company to fulfill its mission. So it's really less about the probability of an event, and it's more about the magnitude of the impact of that event.

9.1 Please explain how the Application provides an understanding of the likelihood / probability of a major system disruption.

9.1.1 Please discuss whether FEI has undertaken any analysis of the likelihood that the TLSE Project will be under-utilized for the duration of its expected useful life.

Response:

Given that the TLSE Project will provide ongoing and long-running resiliency and ancillary benefits, FEI does not consider there to be a risk of future under-utilization of the TLSE Project assets. Indeed, the cumulative probability analysis included in the response to BCUC IR1 1.5 demonstrates the high likelihood that the TLSE Project will be needed and used at least once over the 67-year analysis period for resiliency purposes.

The Application has described the need for the TLSE Project to provide resiliency in the Lower Mainland service area and address the current inability for that system to withstand a no-flow event of even a short duration for most of the year (including during cold winter conditions when reliable gas supply is most critical to customers) on the T-South system. In addition, the Application describes the ancillary benefits that are currently provided by the aging Tilbury Base Plant facility that will be replaced and expanded by installing a 3 Bcf tank as part of the Project.

Like most forms of insurance[21] against catastrophic events, FEI would prefer not to have to avail itself of the resiliency benefits afforded by the LNG storage provided by the Project. However, the magnitude of societal disruption and harm that could result if FEI does not have sufficient system resiliency to withstand a no-flow event would be unprecedented in BC and could result in outcomes that are irreversible.

Notwithstanding the preferred infrequent use of the resiliency benefits of the TLSE assets, the ancillary benefits provided by the additional 1 Bcf of storage volume will be available for the life of the facility. The ongoing benefits from these commercial opportunities will flow back to customers to help mitigate rates.

9.2 Please discuss what steps FEI has taken to consider cost-reasonableness in the context of mitigating the risk of a major supply disruption.

Response:

FEI considered cost-reasonableness in the context of mitigating the risk of a no-flow event by using the following analytical methods:

- Employing a portfolio approach which considers the three key elements that make up a resilient system (i.e., Diverse Pipelines & Supply, Ample Storage, and Load Management);

[21] Please refer to the response to BCSEA IR1 2.1 for the definition of “insurance” as it is used in this context.

- Identifying, screening, and evaluating all possible solutions to address the lack of resiliency in the Lower Mainland system; and
- Conducting an assessment of impacts on rates.

FEI has not identified a lower-cost or comparable solution that would provide the necessary resiliency and ancillary benefits. This analysis demonstrates that the TLSE Project will achieve FEI's resiliency objectives for a reasonable cost and is a prudent investment, which is in the public interest.

9.3 In the view of Guidehouse, please further elaborate on the conclusion that "FEI has fittingly applied the appropriate risk management approach." Please include a specific discussion on FEI's approach to defining the probability of a major system disruption.

Response:

The following response has been provided by Guidehouse:

Guidehouse observes that generally accepted definitions of risk include:

- The impact of uncertainty on objectives (ISO 31000)[22]; and
- The possibility that an event will occur and adversely affect the achievement of objectives (COSO ERM).[23]

It is not only the probability of a major system disruption that defines the level of risk, but also the significance, or impact of the event. In the example of FEI, it is the case that a major system disruption of its upstream supply delivery will severely impact the achievement of its objectives, which are FEI's ability to serve its customers.

Our key finding that "FEI has fittingly applied the appropriate risk management approach" is based on our evaluation of the analysis that FEI performed to understand the magnitude of impact to its ability to deliver gas in the event of a major system disruption during a period of peak demand. Although less likely to occur, low probability and high impact system disruptions result in the potential for extreme and/or catastrophic operational and financial loss that must be managed for.

[22] https://www.iso.org/iso-31000-risk-management.html.
[23] https://www.coso.org/Pages/erm.aspx.

9.4 Please further explain FEI's perspective on risk management as it relates to Mr. Moran's statement in the preamble. Does FEI consider probability of an event is relevant to risk management?

Response:

Please refer to the response to BCUC IR1 1.5 for FEI's perspective on risk assessment and management, and specifically the ability of the TLSE Project to address the probability of an event occurring that will significantly disrupt FEI's ability to serve its customers.

9.4.1 If possible, please explain how FEI is resilient to risks other than no-flow scenarios caused by a single-point-of-failure, such as earthquakes, malicious acts and dig-ins. In your response, please explain the probability of these other risks in comparison and the mitigation measures FEI takes to manage these other risks.

Response:

Widespread and lengthy system outages can result from a variety of causes. FEI mitigates conditions that may lead to system outages in the design, construction and operation of its assets where applicable and appropriate. For example, critical stations (i.e., Huntingdon and Fraser Gate Station) are designed, constructed and operated with appropriate levels of redundancy to minimize the potential for single-points-of-failure. Further, the TLSE Project is planned to allow FEI to continue to serve its customers during a 3-day no-flow event, regardless of the cause or source of supply disruption.

The probability of each type of risk depends on the type of risk. For example, seismic resiliency is mitigated such that FEI's transmission pipelines are expected to retain pressure containment following a 1 in 2,475 year event.

The following additional response has been provided by Guidehouse:

The scope of the Guidehouse engagement did not include an examination of the resilience of FEI to the probability of risks other than no-flow scenarios. The specific causes of the no-flow event were not relevant to Guidehouse's analysis, but rather the fact that the no-flow incident can occur. In this context, many other risk factors may be associated with or result in a no-flow event, including those noted in this question.

10.0 Reference: PROJECT NEED

Exhibit B-1-4, pp. 56 – 57; Appendix A, pp. 3, 24 – 26, 49

Other Jurisdictions

On page 56 of the Updated Public Application, FEI notes "The Guidehouse Report also identifies industry examples where utilities have used similar approaches to FEI in determining resiliency objectives. In particular, these utilities assessed on system storage as a tool for building resiliency with reference to duration and load and the potential consequences of an outage."

FEI summarizes an example from New Jersey Natural Gas (NJNG) on pages 56 to 57 as follows:

> New Jersey Natural Gas identified an objective of meeting customer load for a period of 5.88 days by adding new liquefaction to existing on-system storage:
>
> NJNG completed a Liquefaction Project in 2016 that allowed the company to convert natural gas to LNG and store the LNG at the company's existing tanks in Howell and Stafford, New Jersey. The project cost $36.5 million and was approved for rate recovery in 2016.48 The two LNG plants have an aggregate estimated maximum deliverability of approximately 170 MMcf/day and 1 Bcf of total storage. [Approximately 5.88 days]
>
> In 2019, NJNG applied to reconfigure its LNG assets to connect the Howell LNG facility directly to its natural gas transmission system. The stated intention of this project was to enhance system reliability and improve the Howell LNG facility's ability to provide peak-shaving supply and pressure support during periods of high natural gas demand, curtailments of pipelines or downtime due to maintenance and inspection.
>
> Footnote 48:
>
> http://investor.njresources.com/static-files/14a4896d-872a-45b1-9899-9d676093172a

On pages 25 to 26 of Appendix A, the NJNG example is described further by Guidehouse:

> New Jersey Natural Gas (NJNG) gained regulatory approval for multiple infrastructure projects designed to improve the resiliency of the state's natural gas system… The primary reason for the aforementioned infrastructure projects were five major storms that hit New Jersey in 2011 and 2012… These storms caused major issues for energy supply in the state, leading the New Jersey Board of Public Utilities (BPU) to start a Storm Mitigation Proceeding to investigate ways for New Jersey to protect and support its utility infrastructure to better-withstand extreme events in the future.

On page 57 of the Updated Public Application, FEI summarizes an example from Dominion Energy:

> Dominion Energy identified an objective of meeting customer load for a period of 8 days having regard to historical load data and consideration of the potential consequences of an adverse event:
>
> As summarized in Section 1.8, Dominion Energy Utah gained approval from the utility commission for an LNG facility for reliability purposes. Dominion used historical weather and supply limitation analysis to show that shortfalls of 100 million cubic feet (MMcf) were possible in the company's service territory. After determining that demand is expected to grow in the region, Dominion concluded that 150 MMcf for eight days of services (totalling 1.2 Bcf square feet [sic] of supply) was required for this facility.
>
> Dominion's project was also supported by several economic analyses, including one carried out by a third party, the Kem C. Gardner Policy Institute. The study analysed the impact of severe a natural gas system outage due to cold weather, under high and low scenarios. The study expects such an event would result in approximately 390,000 to 650,000 natural gas customers in Dominion's Utah service territory without power, some up to a period of 28 days. The overall impact to gross state product ranges from $1.45 billion to $2.38 billion in the low and high scenario respectively. Dominion's own analysis shows that restoring service to 650,000 customers would cost the utility between $10.45 million and $104.60 million.

On page 3 of Appendix A, Guidehouse states:

> It is Guidehouse's opinion that the North American gas delivery system is highly resilient due to the large network of interconnected natural gas transmission lines that span the continent and provide capacity to enable natural gas production to reach demand centres. However, we note that some individual natural gas utilities that do not have access to multiple transmission pipelines and rely on a single pipeline for the majority of their natural gas supply have less redundancy1, which is a key component of a resilient system.

On page 24, Guidehouse adds:

> for LDCs [local distribution companies] characterized as "end-of-pipe" utilities, there are often greater challenges associated with achieving multiple connections and access to physical resiliency. In these cases, where resiliency is identified as an issue, investments must be made to both enhance connectivity where possible and develop on-system storage options.

On page 49, Guidehouse states:

> There is no single industry standard approach to determine duration, i.e., the amount of natural gas required for a resiliency reserve… Although resiliency

reserve requirements differ on a case-by-case basis, we do note that the approach taken by FEI is similar to that of other utilities in determining the resiliency reserve requirement.

10.1 Please provide a working link or reference for footnote 48 on page 56 of the Updated Public Application.

Response:

The following response has been provided by Guidehouse:

This footnote references New Jersey Resource's 2016 annual report.[24] New Jersey Resources is the parent company of New Jersey Natural Gas.

10.2 Please discuss whether FEI and/or Guidehouse specifically reviewed other "end-of-pipe" utilities in North America with respect to their approach to addressing resiliency.

10.2.1 Please discuss whether FEI and/or Guidehouse is aware of resiliency objectives or investments implemented by other end-of-pipe utilities. Please specifically outline whether such objectives or investments were to address single point of failure risk comparable to those FEI is seeking to mitigate on the T-South System.

Response:

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

FEI would expect each end-of-pipe utility to have resiliency objectives and/or make investment decisions based on their own system configurations, unique characteristics, and operational challenges. As discussed in the response to BCUC IR1 8.1, there is no single approach for building resiliency; rather, it is dependent on the accessibility to the three key elements that make up a resilient system (Diverse Pipelines & Supply, Ample Storage, and Load Management).

[24] https://www.annualreports.com/HostedData/AnnualReportArchive/n/NYSE_NJR_2016.pdf.

10.3 Please discuss whether Guidehouse reviewed other examples of resiliency investments in addition to the NJNG and Dominion examples.

10.3.1 Please clarify whether Guidehouse's review was limited to a specific timeframe (e.g. in the past 5 years)

Response:

The following response has been provided by Guidehouse:

The Guidehouse review was not limited to a specific timeframe. The examples provided were identified through a search of publicly available information regarding resiliency investments by other natural gas utilities. Guidehouse observes that the North American natural gas system has demonstrated a high-level of resiliency over time. This trend provides an explanation of why there are so few gas system outages and why they have been limited in both frequency of occurrence and magnitude. In addition, Guidehouse observes that limitations in resiliency are most frequently revealed by an unforeseen event. For example, the impact to the energy delivery system in Texas across both electricity generation and production of natural gas that occurred in February 2021 due to Winter Storm Uri provides an illustration of how an unforeseen and low probability event, e.g., a historically rare extended period of extremely cold temperatures exacerbated by snow and ice that resulted in widespread and long duration power outages across Texas, can be of very high significance.

In addition to the NJNG and Dominion examples, Guidehouse has identified another example of a resiliency investment. In 2014, Southwest Gas, which serves Arizona, Nevada and portions of California applied for approval to construct an LNG storage tank. In its application to the Arizona Corporation Commission, Southwest Gas states that the primary purpose of the proposed LNG storage facility is to have readily available local gas supply to dispatch into Southwest Gas' distribution system during severe supply disruption events.

Southwest Gas received approval from the Arizona Corporation Commission in Docket No. G-01551A-14-0024 to construct an LNG storage facility near Tucson, AZ. One of the factors contributing to the approval decision was "service outages have demonstrated the need for natural gas storage, particularly Southwest Gas' 2011 southern Arizona outage, where Southwest lost service to almost 20,000 customers.[25]"

The loss of service to approximately 20,000 Southwest Gas customers in Arizona in February 2011 was due to an extreme winter event across the U.S. Southwest Region. This event contributed to natural gas well freeze-offs and shutdowns of gas processing plants during a time of peak gas demand. This resulted in pipeline demands exceeding available supplies. The Southwest Gas LNG facility is designed to mitigate the consequences of upstream supply disruptions due to extreme weather events.

[25] https://docket.images.azcc.gov/0000176126.pdf?i=1630443489033.

10.4 Please discuss whether NJNG or Dominion have established a formal minimum resiliency planning objective.

Response:

The following response has been provided by FEI:

FEI notes that the MRPO is simply a way of articulating the risk and resiliency need in the Lower Mainland associated with a no-flow event on the T-South system—the single largest supply risk facing FEI. It is not a general planning standard for FEI or other utilities.

The following response has been provided by Guidehouse:

Guidehouse is not aware whether NJNG or Dominion have established a formal minimum resiliency objective.

10.4.1 Please discuss if FEI or Guidehouse is aware of any other utilities that have established a formal minimum resiliency planning objective.

Response:

FEI is not aware of any other utilities that have established a formal minimum resiliency planning objective; however, it should be recognized that the MRPO is simply a means of presenting or articulating the risk that FEI has identified in relation to a no-flow event on the T-South system. The MRPO is not intended to be a system-wide standard, for FEI or any other operator. Given that there is no established industry standard for assessing resiliency, FEI expects that other gas utilities would develop similar objectives based on their own circumstances and available alternatives. Further, FEI expects they would develop their own approaches and/or methods for evaluating resiliency investments appropriate for their system. FEI would fully expect utilities to use different nomenclature to articulate the risks and needs.

The following response has been provided by Guidehouse:

Guidehouse is not aware of any other utilities that have established a formal minimum resiliency planning objective.

10.5 Please confirm, or explain otherwise, that the primary driver for the investments by NJNG and Dominion was extreme weather events.

Response:

The following response has been provided by Guidehouse:

The primary driver for the investments by NJNG and Dominion is not extreme weather events. The primary driver for the investments is to increase the capability to withstand the impacts of extreme weather events on the ability to source natural gas supply and deliver this natural gas supply to their customers.

10.5.1 If confirmed, please explain why these are relevant examples for the TLSE Project.

Response:

The following response has been provided by Guidehouse:

The examples provided by Guidehouse were selected because strengthening resiliency is specifically identified by NJNG and Dominion as a driver for their investment programs and key consideration in the decision-making process related to those investments.

10.5.2 Please compare the risk characteristics of extreme weather events and an unplanned disruption on the T-South system, in terms of frequency, severity and predictability.

Response:

FEI designs the capacity of its systems and contracts gas supply to sustain FEI's customers through extreme cold weather events that have a return period of 1 in 20 years. Given the return period, such events are relatively infrequent. In addition, while cold weather can be extended within a season, the duration of the extreme cold period within a peak event can be quite short. Since gas supply and pipeline capacity are established to meet the extreme peak requirements, the supply shortfall impact during an extreme weather event would be small and incremental in comparison to the prevailing demand. Further, to some extent, unpredictable extreme weather events come with some warning through long-term weather forecasts. As such, the risk for FEI customers related to extreme weather events is very small.

In contrast, an unplanned disruption on the T-South system, while also relatively unlikely, has a much higher potential for significant consequences than an extreme weather event. A T-South system disruption may occur without warning or time to prepare and could result in a significant loss of supply, leading to a widespread and lengthy system outage. As a result, FEI considers an unplanned disruption on the T-South system to pose a much higher risk for customers.

The following response has been provided by Guidehouse:

The scope of the Guidehouse engagement did not include a comparative analysis of the risk characteristics of extreme weather events and an unplanned disruption on the T-South system, related to extreme weather or not.

10.6 Please discuss whether FEI considered undertaking a suite of resiliency investments, as observed in the case of NJNG, rather than a single project to address resiliency.

Response:

FEI is pursuing a suite of resiliency investments. As discussed in Section 3 of the Application, FEI believes the three key elements that contribute to natural gas system resiliency (Diverse Pipelines and Supply, Ample Storage, and Load Management Capabilities) all require enhancing.

The TLSE Project addresses the Ample Storage element of resiliency by providing FEI with sufficient on-system storage to withstand and recover from short-duration, high-deliverability events while also realizing other ancillary benefits for its customers. FEI is also working on infrastructure options to address the other two elements:

- FEI filed a CPCN application with the BCUC for the implementation of Advanced Metering Infrastructure (AMI). A benefit of AMI is that it will improve FEI's ability to manage load on the system in the event of an emergency (i.e., Load Management Capability).
- FEI is completing the initial scoping and planning for a Regional Gas Supply Diversity (RGSD) solution which would entail building a new pipeline route to the Lower Mainland connecting to the Southern Crossing Pipeline (SCP) in the BC Interior (i.e., Diverse Pipelines). The design of the RGSD project would be optimally sized to form a cost-effective resiliency solution in combination with FEI's other gas supply assets. The RGSD project would enhance gas supply resiliency by providing needed pipeline diversity in the region, as well other benefits, including helping to serve load growth in the region and assisting with the transition to a lower carbon energy future.

In summary, RGSD, AMI and the TLSE Project in combination are required to meet FEI's long-term resiliency needs; however, the TLSE Project is the most cost-effective and optimal solution to address the risk of a no-flow event underlying the MRPO.

10.7 Please clarify whether the Dominion example is a primarily a reliability or resiliency investment.

10.7.1 If reliability, please explain why this is a relevant example for the TLSE Project.

Response:

The following response has been provided by Guidehouse:

The Dominion example is primarily a resiliency investment. In its approval of the request by Dominion for a voluntary resource decision to construct an LNG facility[26], the Public Utility Service Commission of Utah (PSC-Utah) identified that Dominion had experienced unanticipated supply disruptions upstream of the company's distribution system and outside of the company's ability to control or manage explicitly. In addition, the PSC-Utah stated that "if these shortfalls had lasted for an extended period (multiple days), occurred during extremely cold periods (when supply disruptions are most likely to occur), or on a Design Day, they would have impacted the Company's ability to provide safe and reliable service to its customers and, in fact, could have resulted in a significant loss of service to customers in Dominion Energy's demand center."

It is the opinion of Guidehouse that the type of situation that the PSC-Utah is describing in its approval for the asset fits the description of an investment designed to primarily provide resiliency service, which Guidehouse defines as the ability of the natural gas system to prepare, withstand and recover from unforeseen events.

10.8 Please clarify the difference between a "resiliency reserve" and a "minimum resiliency planning objective".

Response:

The following response has been provided by Guidehouse:

A resiliency reserve is an amount of natural gas that can provide protection against an unforeseen, yet possible, eventuality. It is an undefined amount of natural gas that can be used to mitigate the undefined impact of an undefined amount of supply disruption for an undefined amount of time.

Guidehouse understands that FEI has defined a minimum resiliency planning objective to articulate its specific requirements to avoid a supply disruption on the T-South pipeline.

FEI adds:

[26] https://pscdocs.utah.gov/gas/19docs/1905713/307951RedactAppVlntryReqforApprvlRsrcDec4-30-2019.pdf.

The MRPO is simply a way of articulating the risk and resiliency need in the Lower Mainland associated with a no-flow event on the T-South system—the single largest supply risk facing FEI. It is not a general planning standard.

10.8.1 Please summarize other examples of approaches taken in the industry to determine the amount of natural gas required for a resiliency reserve.

Response:

The following response has been provided by Guidehouse:

The approach taken by Dominion is very similar to the approach used by FEI. In the situation of Dominion, the minimum resiliency reserve was identified as a vaporization rate of 150 MMcfd (approximately 150,000 Dth/day), for eight days, meaning that the LNG facility would be able to provide an additional 150,000 Dth/day of natural gas to Dominion Energy's system in the event of a supply shortfall. The chosen rates of vaporization and storage coincide with the curtailed volumes of the supply shortfall incidents that Dominion sought to mitigate.

10.8.1.1 Please further explain how the approach undertaken by FEI is similar to that of other utilities.

Response:

The following response has been provided by Guidehouse:

The approach undertaken by FEI is very similar to the approach undertaken by Dominion, which consists of determining load requirements and estimating the amount of supply buffer (daily requirement and number of days) required to mitigate the supply shortfall.

Dominion deployed a similar framework to that of FEI in examining possible solutions to its resilience issue. This included examining the opportunity to connect to additional upstream pipelines and off-system storage options to increase diversity of supply and/or acquire incremental storage and transportation services. A key determination made by Dominion is that off-system storage is not a reliable means to resolve a supply shortfall because Dominion cannot control its access to these resources. Instead, they are dependent on the availability of these assets that are controlled and operated by third parties and would be vulnerable to the same risks that Dominion sought to mitigate with an on-system LNG storage facility. In addition, third party off-system storage was not available in the marketplace. Dominion also examined demand response as an option. Similar to FEI, Dominion's analysis identified the critical limitations of demand response. Dominion arrived at a similar conclusion to FEI: demand response is very unreliable and unpredictable.

11.0 Reference: PROJECT NEED

Exhibit B-1-4, Section 3.4.6, p. 56; Section 3.5 pp. 57-74, 94-95

Exhibit B-4 (Workshop Presentation), slide 39

Workshop Transcript, March 11, 2021, pp. 130, 174, 178, 234

Adequacy of Current Resources

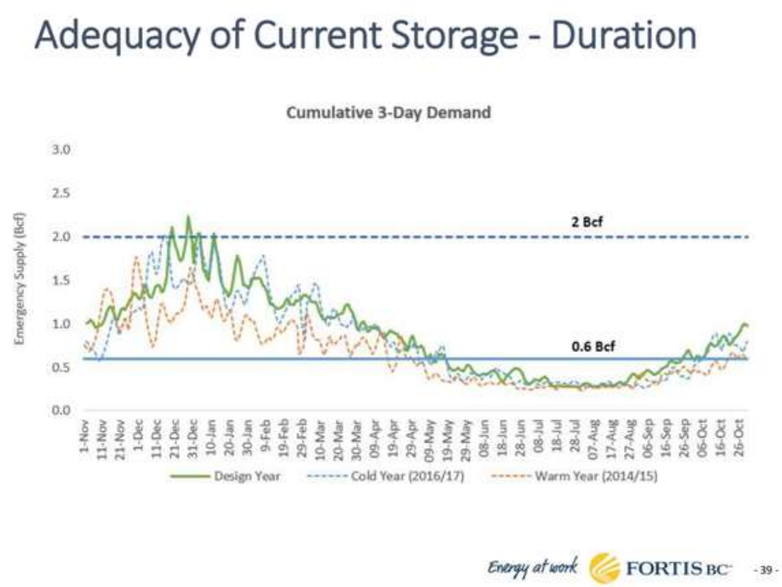
On pages 57 to 74 of the Updated Public Application, FEI describes its current resources to support resiliency as:

- Mount Hayes LNG storage facility
- Tilbury base plant tank
- Tilbury 1A tank
- Off-system storage at JPS and Mist
- Line pack
- Interruptible customers
- Requesting customer conservation
- Incremental supply from available purchases
- Mutual aid agreements

On pages 94 to 95 of the Updated Public Application, FEI states:

> The maximum calculated cumulative design load over a 3-day period (extrapolated from FEI's load duration curve) is approximately 2.2 Bcf, while the maximum actual cumulative load over a 3-day period during the coldest winter in the past 10 years (i.e., the 2016/17 winter) was approximately 2.0 Bcf. This analysis reinforces that, even when using actual demand values that provide a lower level of resiliency than those based on the design curve, the minimum storage capacity to serve the Lower Mainland can be no less than 2.0 Bcf in order to meet FEI's 3-day Minimum Resiliency Planning Objective.

On slide 39 of the Workshop Presentation, FEI provides the following diagram:



On page 57 of the Updated Public Application, FEI states: “FEI will examine each of its tools in detail to demonstrate that its current capability is limited to withstanding a 3-day outage in only the most favourable summer conditions. FEI has excluded available purchases from this analysis because they are unlikely to be available during the ‘no-flow’ portion of an incident.”

11.1 Please clarify whether FEI has based the minimum tank size on the cumulative 3-day demand in the design year, the coldest year in the last ten years, or otherwise. Please provide the rationale for this approach.

Response:

FEI based the minimum tank size on the cumulative 3-day demand in the 2019/20 design year for the Lower Mainland (LML). The minimum resilience supply requirement was validated with the actual demand of the coldest year (2016/17) that the LML experienced in the past ten years. Please also refer to the response to BCUC IR1 8.5.

The rationale for this approach is to have the ability to withstand, and recover from, a 3-day no-flow event on the T-South system without having to shut down portions of FEI’s distribution system or otherwise lose significant firm load.

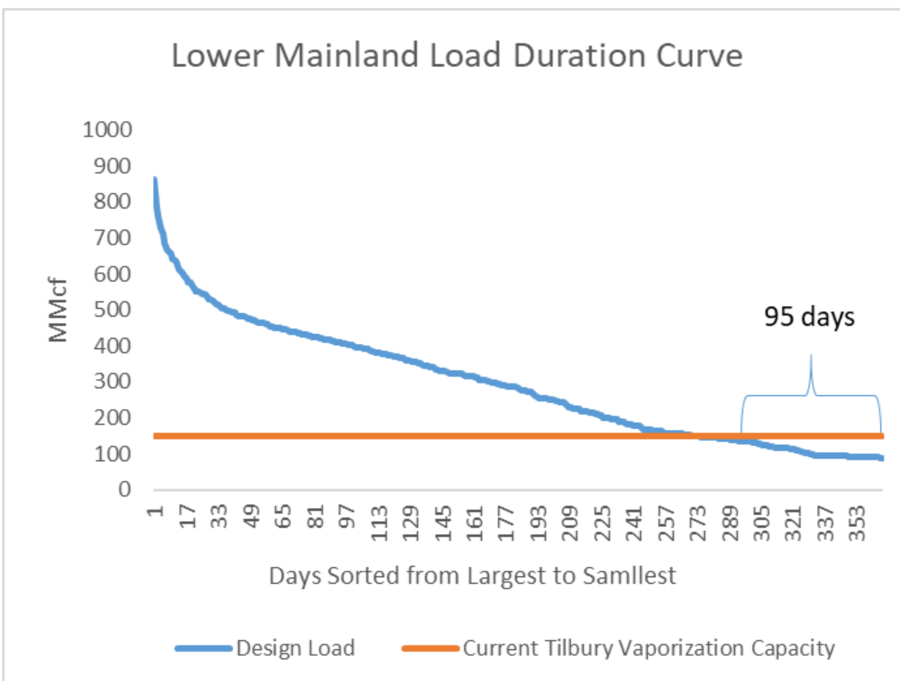
11.2 Please explain which days, or periods, of the year FEI can currently withstand a 3-day outage in the LML, as referred to in the quote in the preamble, using all of its available tools except available purchases.

11.2.1 Please provide a summary of the number of days in a year when FEI would have no other LML supply resources besides the Tilbury Base Plant available during a no-flow event on T-South. Please provide supporting assumptions. If feasible, please illustrate on the load duration curves.

<u>Response:</u>

If purchases are excluded, the only remaining tool available to support the LML load is the Tilbury Base Plant.

The Base Plant is designed with a storage size of 0.6 Bcf and a vapourization capacity of 150 MMcf/day. The daily sendout is limited by the vapourization capacity. As the following graph shows, except for the 95 days in the summer where demand is the lowest, the current vapourization capacity is inadequate to meet the <u>single-day</u> load requirements of the LML. Outside of this 95 day period, FEI would have insufficient gas supply to meet the LML load (without additional off-system purchases). If the outage occurs in the winter, the Tilbury Base Plant could only support a small portion of the daily LML load.



Even if (hypothetically) the plant was not constrained by the vapourization capacity, the 0.6 Bcf storage would not provide sufficient supply to the LML during a no-flow event. The cumulative 3-day demand in the LML increases from 0.27 to 2.21 Bcf from summer to winter. As the chart below shows, the total inventory (0.6 Bcf) at the Base Plant can withstand a 3-day outage if it occurred during summer months, but does not provide sufficient supply for the remaining months of the year.

11.3 Please confirm the number of days of the year the existing 0.6Bcf Tilbury storage tank can provide 3-days of supply to the LML in each of (a) the design year; (b) the cold year; (c) the warm year.

Response:

The following table provides the number of days in the year the existing 0.6 Bcf Tilbury storage tank would be expected to provide 3-days of supply to the LML under various weather conditions.

	Number of Days of the Year
2019/20 Design Year	137
The Cold Year (2016/17)	149
The Warm Year (2014/15)	183

11.4 Please provide versions of the diagram on page 39 of Exhibit B-4 “Adequacy of Current Storage – Duration” showing the adequacy of current storage for:

a) Cumulative 1-Day Demand

b) Cumulative 2-Day Demand

c) Cumulative 4-Day Demand

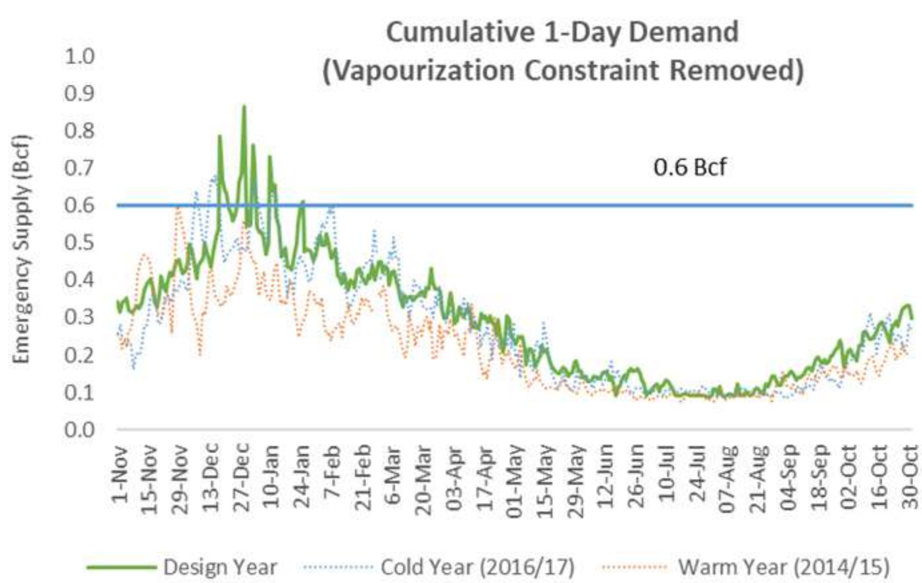
11.4.1 Please also provide a version of the diagram on page 39 of Exhibit B-4 with the demand values on the load duration curve arranged from largest to smallest. Please include percentage intervals on the x axis to show the cumulative percentage of days in the year.

Response:

The Base Plant's ability to provide supply in an outage is actually constrained by the vapourization capacity, such that FEI would not be able to meet the single-day requirements in much of the year (see the response to BCUC IR1 11.2). However, since the above questions relate to the storage size and duration of supply, the following analysis assumes the hypothetical scenario that the daily send out is not constrained by the current vaporization capacity (i.e., such that it is assumed the entire single-day demand can be met on the first day, rather than only a fraction of it).

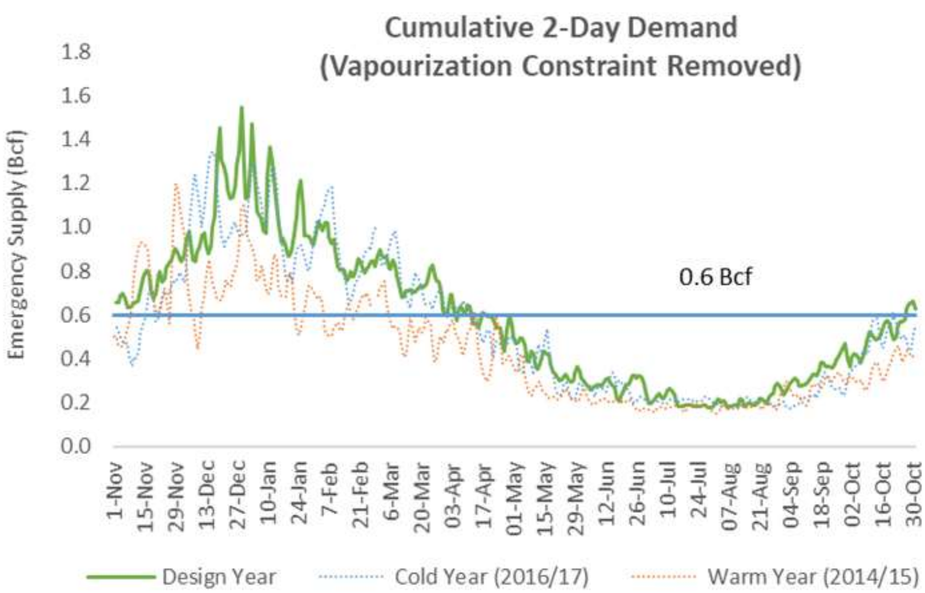
Cumulative 1-Day Demand

In the hypothetical case of the vapourization constraint being removed, the current Base Plant storage (0.6 Bcf) could provide adequate one-day demand in the summer as well as most days in the winter except the 15 coldest days in a design year:



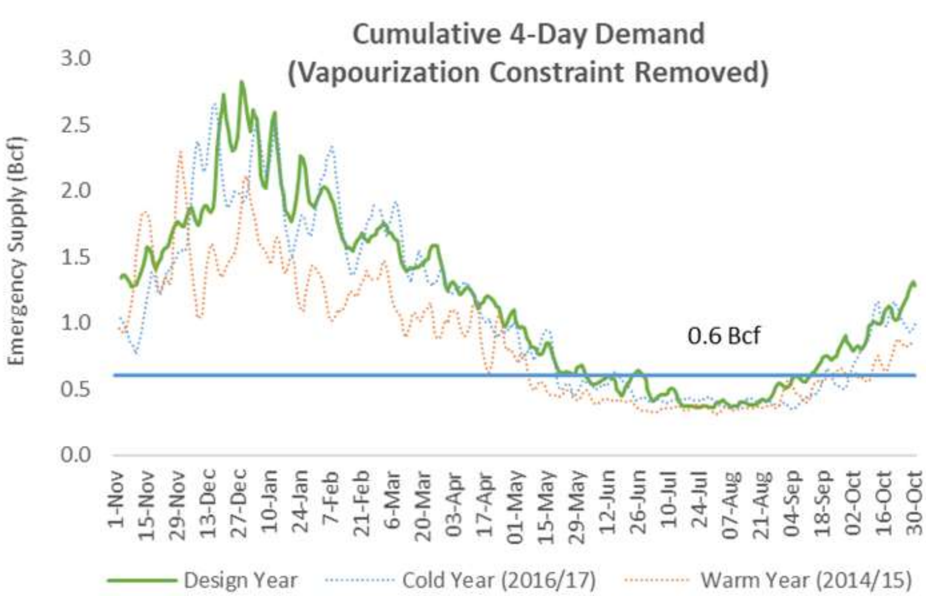
Cumulative 2-Day Demand

In the hypothetical case of the vapourization constraint being removed, current storage (0.6 Bcf) can provide adequate 2-day demand for the majority of the summer but does not meet the winter load of the design year:



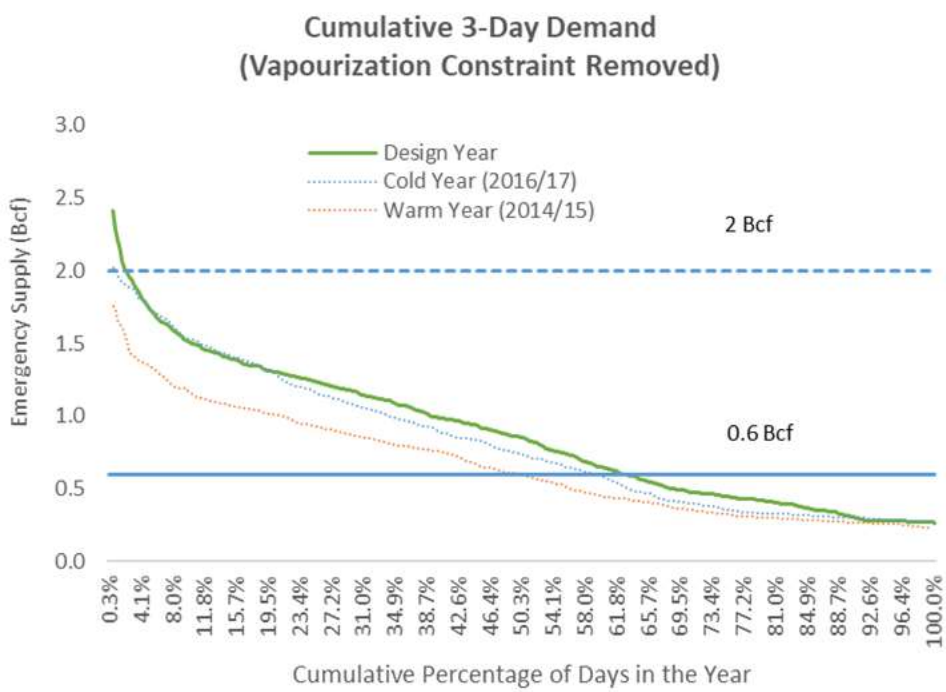
Cumulative 4-Day Demand

Current storage can only provide adequate 4-day demand for some days in the summer but does not meet the majority of the daily load requirements of the design year:



Cumulative 3-Day demand arranged from largest to smallest

In the hypothetical case of the vapourization constraint being removed, the following chart shows the Lower Mainland load values sorted from largest to smallest. The cumulative percentage of days in the year is displayed on the X axis.



11.5 Based on the figure in the preamble, please confirm, or explain otherwise, that assuming a no-flow event occurs in a given "cold year," the probability of requiring a 2Bcf tank is approximately 1-in-365.

Response:

Assuming a 3-day outage occurred in 2016/17 (the coldest year in the past 10 years), the probability of requiring a 2 Bcf tank is approximately 1 percent. The following table provides the probability of requiring 3-day supply at 2 Bcf, 1.5 Bcf, and 1 Bcf separately under the 2019/20 design year and the cold year (2016/17).

	Probability of Requiring Each Tank Size*		
	>= 2 Bcf	>= 1.5 Bcf	>= 1 Bcf
Design Year 2019/20	2%	10%	39%
Cold Year 2016/17	1%	11%	34%

** Design year 2019/20 and the cold year 2016/17 demand includes Rate Schedule 1 to 6, Rate Schedule 23, and Rate Schedule 25.*

11.5.1 Please discuss whether FEI has any evidence to suggest that the likelihood of an unplanned pipeline disruption is affected by time of year.

Response:

FEI is not aware of any evidence to suggest that the likelihood of an unplanned pipeline disruption is affected by time of year.

In reference to the T-South Incident, on page 57 of the Updated Public Application, FEI explains the results of asking its customers to curtail their usage: "FEI has estimated that natural gas use reduced by approximately 39 MMcf/day (approximately 20 percent of expected load of 193 MMcf/day) on October 10, 2018 for customers in Rate Schedules 1 through 7 within the Lower Mainland."

On page 56 of the Updated Public Application, FEI states: "For example, the interruptible volumes represent only approximately 10 to 15 percent of FEI's load when the temperature is below minus 5 degrees Celsius."

On page 63 of the Updated Public Application, FEI provides Table 3-2:

Table 3-2: Summary of Tilbury LNG Facility Design Capabilities

Plant	Liquefaction	Storage	Regasification	LM Peak Design Load
Base Plant	5 MMcf/day 120 days to fill	0.6 Bcf 0.69 days reserve	150 MMcf/day	871 MMcf/day
Tilbury 1A	28 MMcf/day 36 days to fill	1.0 Bcf Storage reserve to support RS 46 sales only	Zero	N/A - Facility designed to support RS 46 sales only

On page 67 of the Updated Public Application, FEI provides a summary of the Mount Hayes facility in Table 3-3:

Table 3-3: Summary of Mt. Hayes LNG Facility Design Capabilities

Plant	Liquefaction	Storage	Regasification[60]	VI Peak Design Load
Mt. Hayes	8 MMcf/day 200 days to fill	1.5 Bcf 10 days reserve	150 MMcf/day 100% of VI daily design load	150 MMcf/day

On page 74 of the Updated Public Application, FEI provides a summary of the line pack resource:

> The T-South Incident provided a best-case scenario from a line pack perspective. Demand was low and the incident occurred in the north. FEI could continue to

access gas held in the T-South system to the south of where the incident occurred. During the winter load period, the quantity of expected line pack would only serve a small fraction of a single day's load.

On page 74 of the Updated Public Application, FEI discusses the mutual aid response following the T-south incident: "There is a mutual interest in avoiding a hydraulic collapse in one area that could affect the entire regional system. During the T-South Incident, FEI received an extraordinary response from the NWMAA [Northwest Mutual Assistance Agreement]."

11.6 With all potential resiliency resources available to FEI today taken into account (interruptible loads, customer voluntary curtailment, LNG storage tanks, off-system storage, line pack, mutual aid agreements, purchases), please estimate how much energy remains to be supplied to the LML during a 3-day no-flow event without hydraulic collapse:

(a) during the coldest period;

(b) during an average winter period;

(c) during an average period in the year;

(d) during the warmest period of the year.

Please also include a breakdown of the energy supplied or curtailed by resource. If the situation varies depending on the location of the no-flow incident or other factors, please provide a range of alternative scenarios.

Response:

While the resources set out in the preamble above support resiliency, the majority of these resources are not sufficiently certain to be relied upon when planning for the risk of a no-flow event or other supply emergencies. For instance, Section 3.5.4.3 of the Application explains that off-system storage and line pack can be of limited assistance when pipeline flows are disrupted in an emergency. Further, Section 3.5.6 discusses that mutual aid agreements do not provide FEI with any supply certainty in the event of a supply disruption.

As the supply and demand balance for any given day is dependent on many factors, FEI is unable to estimate the amount of energy demand it would be unable to meet during a 3-day outage under each of the four times of year listed in the question. FEI can say that it is not able to withstand a 3-day outage in the LML during the winter season with the aforementioned potential resources. During the summer months (May to September), there is a greater likelihood that FEI could withstand a 3-day outage because the load in the Pacific Northwest region is significantly lower, which provides FEI a greater chance to access supply through mutual aid and to curtail interruptible loads.

On page 45 of the Updated Public Application, FEI states with respect to the T-South Incident:

> Given the low Vancouver Island load associated with mild weather, FEI's Mt. Hayes LNG on-system storage facility was able to supply all of the demand for the Vancouver Island system while also providing some supply to the Lower Mainland (by physically reversing flow as compared to normal operations);

On page 174 of the Transcript, the following exchanges takes place:

> "THE CHAIRPERSON: In terms slide number 38, which shows the regasification requirements in the Lower Mainland load duration curves, is it feasible for you to use the regasification facilities at Mt. Hayes, for instance, at the LNG facility there to serve the load from the Lower Mainland?
>
> MR. HILL: Physically we isolated the Lower Mainland and the Vancouver Island system. Basically, the main restriction to that is in cold events we cannot backflow gas at a V1 compressor station, basically to get gas back into the Lower Mainland, if you will."

11.7 Please explain why in cold events FEI cannot backflow gas at a V1 compressor station.

Response:

The Mt. Hayes facility was designed to support Vancouver Island (VI) requirements. The transmission system to VI was designed with compressors at Eagle Mountain (V1), Port Mellon (V3), and Texada Island (V4) to move gas from east to west (i.e., from the LML to the VI). The existing compressors are not configured or located for effective flow from west to east. The reverse flow delivery capability from Mt. Hayes is limited to a maximum of approximately 64 MMcf/day in the summer, which is constrained by the lower maximum sendout pressure at Mt. Hayes, and the lack of compression to restore pressure loss in the reverse direction. In the winter, the Mt. Hayes sendout is delivered in increasingly large volumes directly to VI customers as temperatures decrease, and only the excess above VI demand could possibly supply the LML at V1. Ultimately, under peak conditions there is no reverse flow capability because the full capacity of Mt. Hayes is required to supply VI peak demand.

11.8 Please explain whether the Mt. Hayes facility can be used to support the resiliency in the Lower Mainland during warmer times of the year.

11.8.1 If yes, please explain the weather restrictions for the Mt Hayes facility to provide Lower Mainland support and the number of days in a year it can act as a resource.

11.8.2 If no, please explain what level of capital investment would be required to allow the Mt. Hayes facility to support resiliency in the Lower Mainland (i.e. backflow gas).

Response:

In the event of a supply disruption, FEI would use the Mt. Hayes facility to support the Vancouver Island (VI) system as a priority because VI customers have no other source of supply. Any storage consumed from Mt. Hayes to support the Lower Mainland (LML) system would reduce the survival time of the VI system. Further, the limited volumes that the reverse flow can provide are insignificant relative to the LML requirements, especially during the winter. As a result, while FEI cannot provide a precise estimate of the number of days of support, there would be large portions of the year when the VI system would provide no material support as a resource to the LML during a no-flow event on the T-South system.

Notwithstanding this, the VI system and the Mt. Hayes facility have some ability to support resiliency in the LML during warmer times of the year. Under favourable weather conditions (i.e., warmer periods), Mt. Hayes can provide up to 60 MMcf/day of supply to the LML by reversing the gas flow in the VI system. This was demonstrated during Phase 1 of the T-South Incident, as depicted in Figure 3-7 of the Application.

It would be a significant and very costly undertaking to enable the inventory of Mt. Hayes such that the excess above the VI system's need could be made fully available to the LML. Assuming an amount equivalent to the proposed 800 MMcf/day into the LML is required, and assuming the existing sendout capability of 150 MMcf/day at Tilbury is retained, an additional 650 MMcf/day in regasification capacity would be required to be built at Mt. Hayes. In addition, the maximum pipeline capacity with compression in the existing VI system is approximately 155 MMcf/day. FEI would need to build new pipeline and compression facilities in the reverse direction equivalent to more than four times the capacity of the existing VI pipeline. The current VI pipeline extends more than 350 km from Mt. Hayes near Ladysmith to Eagle Mountain in Coquitlam, traversing the Coquitlam watershed, with two marine crossings of the Salish Sea along the way. The pipeline cost alone would far exceed the TLSE Project cost, in the billions of dollars.

On page 178 of the Transcript, in response to a question about whether the Tilbury T1A tank can provide resiliency in the event of an emergency, Mr. Leclair stated: "it's really about whether or not there will be any LNG in the tank when its required. We can't count on it being there."

11.9 Please confirm, or explain otherwise, that FEI would use the Tilbury T1A tank in the event of a no-flow event on T-South system, if required, to support resiliency in the Lower Mainland to avoid a pressure collapse.

11.9.1 Please confirm, or explain otherwise, that FEI may curtail service to Rate Schedule 46 customers served by the Tilbury T1A tank in an event such as the T-South Incident.

Response:

FEI would use the Tilbury 1A tank in the event of a no-flow event on the T-South system, if required, to support resiliency in the Lower Mainland to avoid a pressure collapse. However, as explained below, FEI has no certainty that it will have access to stored LNG in the Tilbury 1A tank for resiliency purposes.

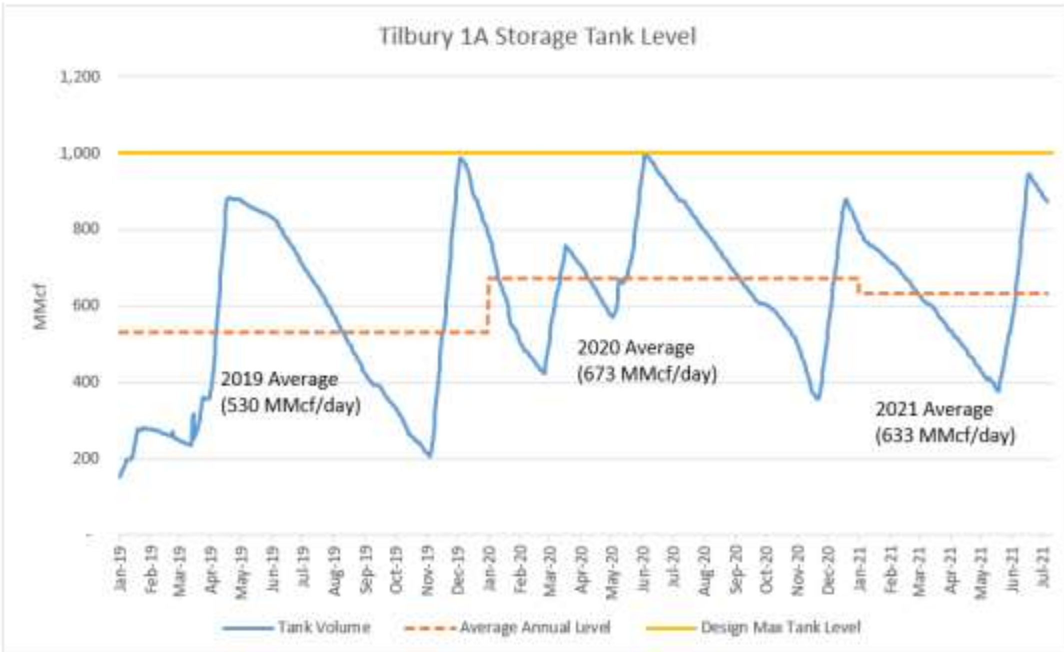
As discussed in Sections 3.5.4.1.2 to 3.5.4.1.6 of the Application, in a supply emergency, the Tilbury site configuration will provide access to storage from the Tilbury 1A tank. However, from a planning perspective, FEI cannot rely on Tilbury 1A storage to meet the MRPO. The Tilbury 1A tank was built to support LNG sales, and FEI provides LNG service under a BCUC-approved rate schedule. Due to Tilbury 1A's use in the ordinary course of business for LNG sales, there is no certainty that the tank will contain sufficient stored LNG at the time of a supply disruption. Moreover, many LNG sales customers are firm customers, with similar expectations to natural gas customers for firm service. These customers include BC Ferries, Seaspan, Ledcor, and trucking companies that provide essential services in the Lower Mainland.

In any event, the Tilbury 1A storage tank's maximum capacity is far below what is required to meet the MRPO.

11.9.2 Please explain the average level of LNG stored in the T1A tank for each year since start of operation

Response:

The figure below provides the level of storage in the Tilbury 1A tank since the start of operation, including the average level of LNG storage for each year.



As the figure illustrates, the 2019 average was the lowest at 530 MMcf/day, which is reasonable given the expected challenges and delays associated with the first year of operations. For instance, as the figure illustrates, the storage tank level dropped to approximately 200 MMcf/day in early November 2019. This was during the final operational handover from the Tilbury 1A Engineering, Procurement and Construction (EPC) contractor to FEI that resulted in several delays to the start-up of the production run at that time.

The average storage volume increased to 673 MMcf/day for 2020. The 2021 average provided in the above figure is for the period of January 1, 2021 to July 6, 2021. Although the year is not completed, the average amount is consistent with the 2020 average. Going forward, FEI expects to manage the tank levels to match expected LNG sales and maintenance activities.

11.9.3 Please provide a graph showing the level of storage in the T1A tank over the course of each year since start of operation. Please discuss any annual trends in storage levels and any anticipated future changes in storage levels.

Response:

Please refer to the response to BCUC IR1 11.9.2.

11.9.4 Please explain whether FEI could manage the amount of LNG in the T1A tank to provide potential resiliency over the coldest periods of the year, in order to support resiliency in the LML.

Response:

The Tilbury 1A facilities are intended to serve LNG customers (i.e., RS 46), and FEI is providing LNG service under a BCUC-approved rate schedule in the ordinary course of business that requires FEI to draw down the volume in the LNG tank. Please refer to Section 3.5.4.1.2 of the Application for more details.

If there is available LNG in the Tilbury 1A tank at the time of a no-flow event, it could provide some additional resiliency, but would still not withstand a 3-day outage over the coldest periods of the year. Please refer to the response to BCUC IR1 11.4 for further discussion.

On page 39 of the Updated Public Application, FEI states:

> Approximately 105 MMcf/day of east to west connectivity from SCP can also be utilized to provide gas supply to customers in the Lower Mainland, via FEI's interconnect with the T7 South system at Kingsvale. However, 105 MMcf/day represents [REDACTED] of the total Lower Mainland design day demand for 2019/2020. The SCP pipeline system has limited capacity at this time, and also relies on a 172 km segment of the T-South system (Kingsvale to Huntingdon) to deliver gas to the Lower Mainland.

11.10 Please clarify whether FEI assumes that it could rely on 105 MMcf/day from SCP to serve LML demand in the event of a no-flow event on the T-South system.

11.10.1 If yes, please explain how this has factored into the TLSE Project minimum tank size of 2 Bcf and regasification capacity of 800 MMcf/day.

11.10.2 If not, please explain why not.

Response:

FEI has not assumed 105 MMcf/day from SCP to serve LML demand because a future no-flow event could occur south of Kingsvale (the location where the SCP interconnects with T-South system). In this scenario, gas supply from Kingsvale via the SCP would be disrupted to the Lower Mainland.

Further, because of its location, the TLSE Project could also mitigate the risk of a pipeline disruption on FEI's transmission system from Huntingdon into the LML system.

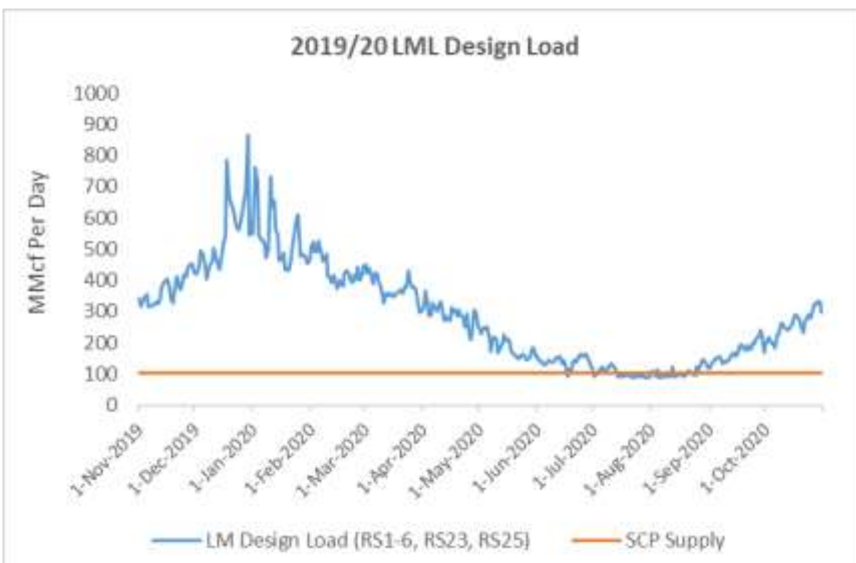
11.11 Please discuss whether 105 MMcf/day from Southern Crossing Pipeline (SCP) could serve LML demand in the event of a no-flow event on the T-South system occurring North of Kingsvale.

Response:

If a no-flow event on the T-South system occurs north of Kingsvale, the supply from SCP could serve some LML demand. This was shown during the T-South Incident, as Figure 3-7 illustrated in the Application. However, the portion of the 105 MMcf/day that could serve the LML would depend on the following factors:

- the status of Westcoast's T-South to Savona or other delivery points north of Kingsvale;
- the load requirements of the Interior system; and
- the operating conditions of the T-South system south of Kingsvale.

Even if the 105 MMcf/day is available to supplement LML demand, it is still well below the daily requirements for most days (except the 40 lowest demand days in the summer) in the design year 2019/20. The following graph plots LML daily demand in comparison with maximum available SCP supply.



12.0 Reference: PROJECT NEED

Exhibit B-1-4, Section 3.5, pp. 59-60

Interruptible Load

On pages 59-60 of the Updated Public Application, FEI discusses its strategy to shed interruptible customer load in the event of a rupture. On page 59, FEI states: "the interruptible volumes represent only approximately 10 to 15 percent of FEI's load when the temperature is below minus 5 degrees Celsius."

12.1 Please explain whether FEI has explored the feasibility of moving additional customers to an interruptible rate.

12.1.1 If not, please explain why.

Response:

FEI has not explored moving additional customers to an interruptible rate as this is ultimately the customer's choice. FEI presents its rate options (both firm and interruptible) to customers and it is the customer that ultimately determines the type of service that is most appropriate for their business. Customers consider a multitude of factors when making these decisions and some may be unique to their business. FEI would expect that, since interruptible service is cheaper than firm service, eligible customers who could accept interruptible service would have done so.

12.2 Please explain whether moving additional customers to an interruptible rate would mitigate some of the resiliency risk from a pipeline rupture event.

Response:

FEI does not see this as a feasible approach to addressing the risk posed by a no-flow event on the T-South system.

The choice of adopting firm or interruptible service rests with the customer. Interruptible rate schedules are intended for, and attractive to, customers who have short-term storage of alternative sources of energy onsite and who are able to use those alternate sources when capacity or energy is constrained due to cold weather. Interruptible customers receive advance warning through weather forecasts and are able to plan and prepare their facilities, energy storage inventories, and equipment for the temporary change in their energy sources. Since interruptible rates are lower than firm rates, FEI expects that eligible customers whose business allows for interruptible service (including the ability to manage and switch to alternate fuels) will have already taken interruptible service.

Forcing customers to move from a firm service to an interruptible service as a preemptive resiliency measure would be ineffective and have undesirable consequences for customers. First, given the very significant gap between FEI's existing on-system storage in the Lower Mainland and the forecast peak demand during winter conditions, moving some of FEI's customers to an interruptible rate would not change the need for the TLSE Project during a no-flow event. Second, the customers who were forced to take interruptible service would also be exposed to curtailment for gas supply (commercial) reasons, which may be highly undesirable to those customers and potentially impact the ongoing viability of their businesses. Third, other things equal, the lower rates associated with interruptible service would generate lower revenues and result in higher rates for all customers.

13.0 Reference: PROJECT NEED

Exhibit B-1-4, Section 3.5, p. 60

Customer Self-Curtailment Request

On page 60 of the Updated Public Application, FEI states "FEI has estimated that natural gas use reduced by approximately 39 MMcf/day (approximately 20 percent of expected load of 193 MMcf/day) on October 10, 2018 for customers in Rate Schedules 1 through 7 within the Lower Mainland….It is reasonable to expect that the customer response to public appeals for conservation would have been materially reduced had the event occurred during cold winter weather."

13.1 Please explain whether FEI considers a 20 percent reduction in load in Rate Schedules 1 through 7 in the Lower Mainland to be significant.

Response:

A 20 percent reduction in load can be considered significant on its own, but the situation in which the reduction is occurring must be considered. For example, the 20 percent reduction in load referenced above would have been smaller in proportion to overall energy use during colder temperatures and would not have generated a large enough reduction over a short enough period of time to avoid a widespread system collapse on its own following the T-South Incident.

While FEI estimated a 20 percent reduction in load on October 10, 2018, public appeals for conservation are not a resiliency resource, as the public's response and conservation of their demand cannot be relied upon, particularly during cold winter weather. Ultimately, FEI needs to be able to balance the supply/demand scenario in a timely manner to avoid widespread system failure. While load shedding via public appeals for conservation can result in a decrease in demand, it cannot address the fundamental problem during a no-flow event, which is a lack of gas supply.

13.2 Please discuss whether FEI has any other experience with voluntary customer conservation.

Response:

FEI has no other relevant experience with voluntary customer conservation.

13.2.1 Please provide a summary of any examples from other gas utilities with respect to voluntary customer conservation during supply shortages that FEI is aware of.

Response:

FEI has not studied any voluntary customer conservation programs from other gas utilities during supply shortages. Any industry examples would be highly specific and dependent on the utility location, regulatory environment, system configuration, customer makeup, prevailing weather conditions at the time of the incident, etc.

13.3 Please explain whether FEI has any evidence that customers would not respond to public appeals for curtailment in cold winter weather.

Response:

While some customers may respond to public appeals during cold winter weather, for the majority of FEI's customers, the energy used for space heating and hot water is vital to their health and safety; therefore, the non-discretionary nature of this load imposes inherent limitations on the extent to which load can be managed and relied upon during a supply emergency.

Customer behavior suggests that, unless the customer understands the nature of the emergency and how their actions could help, the customer will be less likely to take action. Customers' knowledge of energy usage and energy systems, specifically the gas system and how it functions, is low and as such, while FEI saw reductions in gas usage following initial public appeals, customers quickly reverted back to their previous energy consumption patterns. Further, public appeals had a diminishing effect the longer the appeals continued as customers became fatigued with repeated requests for conservation.

Further, the primary energy sources in BC for cooking, space heating, and hot water are natural gas and electricity. If large amounts of gas load temporarily switched to electricity during public appeals for curtailment, this could overload the electrical grid, which could lead to brownouts or blackouts.

Please also refer to the responses to RCIA IR1 10.1 and MS2S IR1 4iii.

13.4 Please discuss whether FEI has considered any further actions to enhance the effectiveness of voluntary customer conservation as a result of the T-South Incident.

Response:

FEI has not considered any other actions to enhance the effectiveness of voluntary customer conservation, as this action has inherent limitations as discussed in the section referenced in the preamble. While any reduction in demand is helpful, voluntary customer conservation cannot be relied upon. However, as discussed in the response to BCUC IR1 10.6, FEI has filed an application with the BCUC for the implementation of AMI, which FEI believes is a more effective means of managing load during an emergency.

14.0 Reference: PROJECT NEED

Exhibit B-1-4, p. 29

Impact of Concurrent FEI Capital Projects on Resiliency

On page 29 of the Updated Public Application, FEI states: "FEI's own transmission system has a degree of resiliency due to the redundancy incorporated into its design. This redundancy has been incorporated as the need arose for additional system capacity to supply customers during peak load periods."

FEI's projects currently before the BCUC requiring CPCN approval include: Pattullo Gas Line Replacement, Okanagan Capacity Upgrades, Transmission Integrity Management Capabilities (Coastal Transmission System and Interior Transmission System), TLSE, and Automated Metering Infrastructure.

In 2020, the BCUC granted a CPCN for the Inland Gas Upgrades project, which is under construction.

FEI's major projects which have been directed by Order in Council include: Coastal Transmission System Expansion, Tilbury Phase 1A and Tilbury Phase 1B.

14.1 Please explain whether FEI has considered an approach of contemplating resiliency investments as part of other infrastructure projects when such projects are needed.

14.1.1 Please discuss whether FEI considers significant cost savings may be available with this approach.

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

FEI does consider building additional resiliency into its system where possible to achieve this as an ancillary benefit though its major projects. However, any incremental resiliency that could be gained through other projects would not alleviate the need for the TLSE Project.

For example, many of FEI's major system upgrades such as the recent Coastal Transmission System (CTS) and Lower Mainland Intermediate Pressure System Upgrades (LMIPSU) projects have allowed FEI to add redundancy to its pipeline systems, which have provided some increased local system resiliency (i.e., against events occurring within FEI's own system). Please refer to Section 3.3.1.1 in the Application for a discussion of the resiliency benefits of some recent major projects.

Other recently filed or upcoming infrastructure projects may continue to provide resiliency benefits to FEI. For example, the AMI project will improve FEI's load management capabilities, which is a key aspect of resiliency. As discussed in the Application, appropriate load management can allow for controlled load shedding in the event of a system failure. In addition, transmission pipeline upgrades could provide local resiliency benefits similar to those discussed in Section 3.3.1.1, via the addition of redundant flow pathways in FEI's system. Potential regional pipeline infrastructure projects (discussed in Section 3.3.1.2 of the Application) may also provide FEI with the opportunity to diversify supply to its system.

While these projects can provide local improvements to resiliency (such as the benefit provided by the OCU Project), upgrades are required to address the potential for supply disruptions upstream of FEI's system. FEI's analysis indicates that a large-scale increase in on-system storage is required. No other FEI major project includes on-system storage within its scope; therefore, while many of FEI's major projects do improve local resiliency, no combination of these other ongoing and/or potential projects would allow FEI to withstand a 3-day no-flow event on the T-South system. A dedicated resiliency project with on-system storage (i.e., the TLSE Project) is therefore required to meet this need.

In summary, FEI does not consider relying on other major projects for resiliency benefits to be a viable alternative to the Project; thus, cost savings are not enabled by such an approach.

14.2 Please explain the impact of the Okanagan Capacity Upgrade Project on FEI's system resiliency.

Response:

The Okanagan Capacity Upgrade Project (OCU Project) will provide some regional resiliency benefits in Kelowna, Vernon, and the surrounding areas. As defined in Section 3 of the Application, resiliency refers to "the ability to prevent, withstand, and recover from system failures or unforeseen events."

The proposed OCU Project will provide a parallel path for gas to flow north to Kelowna and Vernon via an extension of the existing OLI PEN 406 pipeline. Currently, during high demand scenarios associated with cold weather conditions, capacity constraints limit the gas flowing north to Kelowna through the existing VER PEN 323 pipeline. Following completion of the OCU Project, the looped portion of the VER PEN 323 pipeline will no longer be the primary source of supply to the Kelowna and Vernon load centres. As such, should a pipeline failure or unforeseen event occur on the looped section of the VER PEN 323 pipeline, FEI will be able to maintain gas flow via the new OLI PEN 406 extension while repairs to the VER PEN 323 pipeline are completed. Consequently, FEI's ability to maintain uninterrupted supply to the Okanagan region will be improved by the completion of the OCU Project, thereby improving FEI's "ability to prevent, withstand, and recover from system failures or unforeseen events", albeit in a localized area of the system.

For clarity, as suggested by the project name, the Okanagan Capacity Upgrade is intended to increase capacity for the Okanagan region. While there is also an inherent resiliency benefit (as described above) associated with the OCU Project, it does not materially improve FEI's ability to withstand a disruption to upstream supply on the T-South system.

14.3 Please explain the impact of the Inland Gas Upgrade and Transmission Integrity Management Capabilities projects have on the likelihood of a rupture in the FEI system.

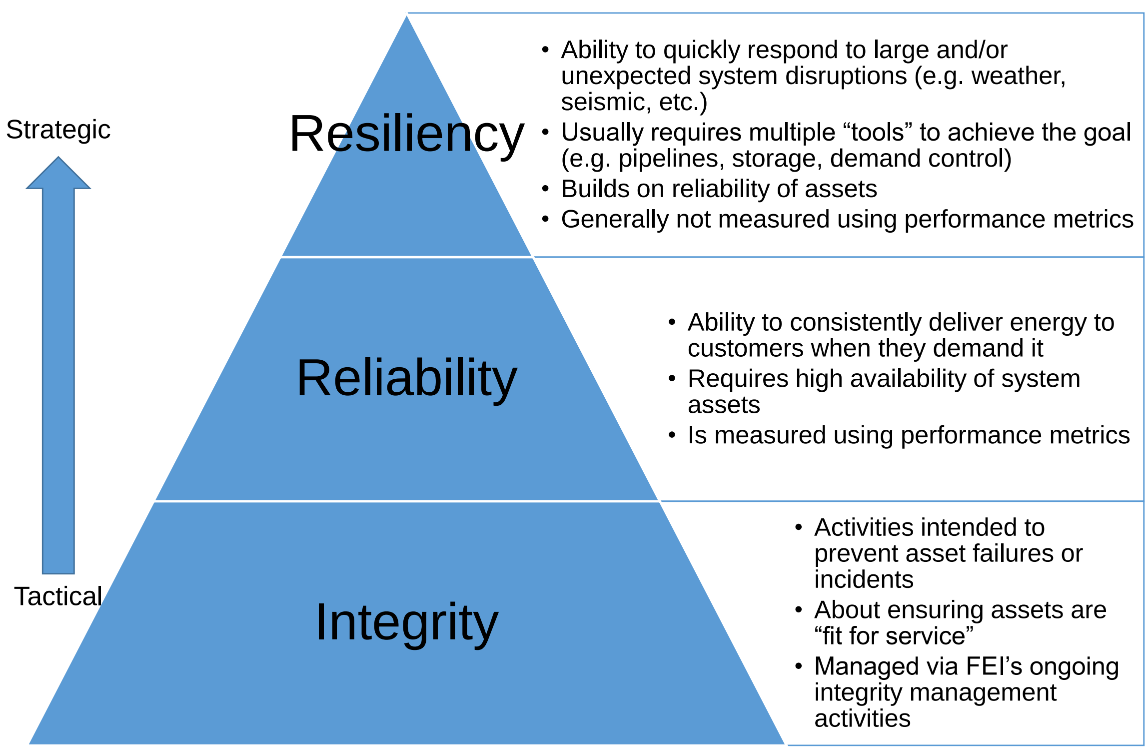
14.3.1 Please explain whether these integrity management projects mitigate some of the need for the TLSE Project.

Response:

The Inland Gas Upgrade (IGU) and Transmission Integrity Management Capabilities (TIMC) projects, in conjunction with each other, will improve FEI's ability to inspect its pipelines using in-line inspection (ILI) technologies. The IGU project will allow FEI to run ILI tools in smaller diameter lateral pipelines to identify external corrosion that may impact the pipeline integrity. The TIMC project will allow FEI to run newer ILI tools to detect stress corrosion cracking and crack-like features. As a result, FEI will be better able to assess and manage the integrity of its system, decreasing the likelihood of a potential rupture on its transmission pipelines.

The IGU and TIMC projects are integrity projects. While they will provide benefits to FEI and its customers, they do not address the same need as the TLSE Project. As illustrated in Figure 3-1 of the Application (reproduced below), integrity projects are foundational for building and operating a reliable and resilient system.

Figure 3-1: Integrity, Reliability and Resiliency as Building Blocks of Customer Service



In short, the IGU and TIMC projects will reduce the risk of a pipeline rupture within FEI's system, but will do nothing to address the risk faced by FEI of a rupture upstream of FEI (i.e., on the T-South system) resulting in a no-flow supply disruption.

14.4 Assuming BCUC approval and completion of the five projects listed above, coupled with FEI's existing resiliency measures, please explain whether the need for the TLSE Project would be different, when compared to FEI's need today.

Response:

The need for the TLSE Project, as described in the Application, will still exist once the five projects are completed, and taking into account FEI's current and planned resiliency measures. Each of the five projects listed is driven by a different need, which is outlined in detail in each project's respective CPCN application. FEI undertakes a rigorous capital planning process when assessing both its short and long-term capital needs to ensure it proposes and constructs prudent projects with a holistic view of its system. Thus, while the proposed projects in some cases complement each other, no single project could be eliminated from FEI's portfolio without leaving the specific need for that project unaddressed.

14.5 In light of the other FEI major capital projects currently underway, please explain how FEI prioritized the need for the TLSE Project when contemplating the timing of all of its planned capital projects.

14.5.1 Please explain why FEI has chosen to do the TLSE Project now, and whether FEI considers the TLSE Project could be delayed.

Response:

Each of FEI's major capital projects are necessary, and have their own unique drivers which contribute to the need and timing for these projects. The CPCN applications filed for the Pattullo Gas Line Replacement Project, the Okanagan Capacity Upgrade Project, the Transmission Integrity Management Capabilities Project, and the Automated Metering Infrastructure Project provide detailed explanations of the need and required timing for each Project. Please refer to the respective CPCN applications for these justifications, and to the transcript of the CTS TIMC project workshop[27] for a summary of FEI's prioritization of these projects.

The TLSE Project is driven by specific system resiliency needs, which were underscored by the 2018 T-South Incident. Until this Project is complete, FEI's customers remain at risk of widespread and extended gas outages in the case of a supply disruption on the T-South system. Such a

[27] CTS TIMC Workshop Transcript, pp. 12-14.

disruption could occur without warning at any time, as demonstrated by the T-South Incident. By completing the TLSE Project as soon as possible, the least cumulative risk is incurred by FEI's customers. Delaying the TLSE Project would leave the system vulnerable to hydraulic collapse for a longer period of time, without decreasing the overall cost of the Project. With the risk identified, and recognizing the associated significant consequences of a hydraulic collapse (as quantified in the PwC report), FEI believes it is important to improve system resiliency at this time.

From FEI's perspective, all of the projects listed above should proceed as proposed and without undue delay. The TLSE Project should proceed as proposed as FEI has no alternate means of mitigating the risk associated with upstream supply disruptions.

14.6 Please discuss the estimated cumulative rate impact of all of FEI's anticipated major projects listed above and include any major projects which may not have been listed which are expected to have an impact on rates over the next 10 years.

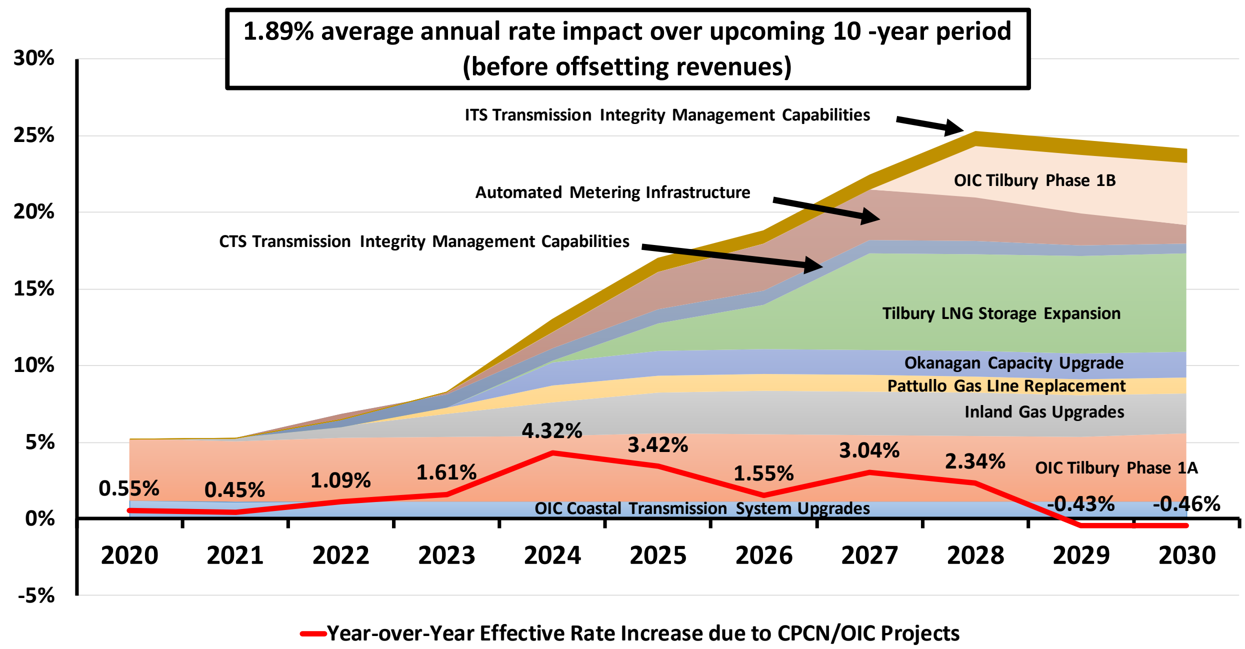
Response:

FEI notes similar information was recently requested in the Coastal Transmission System Transmission Integrity Management (CTS TIMC) CPCN application proceeding, first in the CTS TIMC Workshop held on May 13, 2021, and subsequently in BCUC IR1 29.1, filed on July 27, 2021. The figure below is the same as the one provided in the CTS TIMC CPCN proceeding, which shows the estimated cumulative rate impact of the following major projects:

- Inland Gas Upgrades (IGU) CPCN;
- Pattullo Gas Line Replacement (PGR) CPCN;
- Okanagan Capacity Upgrade (OCU) CPCN;
- Tilbury LNG Storage Expansion (TLSE) CPCN;
- Advanced Metering Infrastructure (AMI) CPCN;
- CTS TIMC CPCN;
- Interior Transmission System (ITS) TIMC CPCN;
- OIC Tilbury Phase 1A (OIC-T1A);
- OIC Tilbury Phase 1B (OIC-T1B); and
- OIC Coastal Transmission System Upgrade (OIC-CTS).

As discussed in the response to BCUC IR1 29.1 in the CTS TIMC CPCN proceeding, FEI has not yet fully developed or committed to the OIC-T1B project, and the ITS TIMC project is still being developed; thus, FEI does not have an estimate of these projects' costs or timing. As such, the rate impact of the OIC-T1B project was preliminarily estimated based on the rate impact of OIC-T1A, and the rate impact of the ITS TIMC project was preliminarily estimated based on the rate impact of the CTS TIMC project.

Also as discussed during the CTS TIMC Workshop and in the response to BCUC IR1 29.1 in the CTS TIMC proceeding, the cumulative rate impact shown in the figure below does not include any offsetting revenues resulting from increased capacity/demand or Rate Schedule 46 revenues that would offset the rate impact of Tilbury Phase 1A and Phase 1B. FEI also notes the actual rate impact will not be dependent on these projects alone; there are various factors beyond the OIC and CPCN projects that will affect FEI's revenue requirement, such as the demand forecast, taxes, O&M expenses, and other capital additions. As such, the figure below is illustrative only and does not represent FEI's estimated rate increase for the years shown.



B. DESCRIPTION AND EVALUATION OF ALTERNATIVES

15.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

FEI 2017 Price Risk Management Plan (PRMP), Exhibit B-11 Response to BCOAPO IR1 on New Evidence[28];

Pipeline redundancy to address upstream rupture risk

In response to BCOAPO IR1 on New Evidence in the FEI 2017 PRMP proceeding, when asked how it would mitigate the risk from a future Enbridge rupture event, FEI stated:

> Considerations would include additional infrastructure to help build more redundancy in the region. This is important because even if FEI could have foreseen the rupture in the summer of 2018 (i.e., prior to the rupture), FEI's action in terms of physical supply would be limited given that the resources in the region are fully contracted and constrained during the winter. Therefore, building redundancy in the region by adding more infrastructure will help mitigate the risk of future situations, such as the one that occurred on the T-South pipeline system. Given that the resources in the region are interconnected and that market participants in the region typically dictate how much redundancy is required, a long term solution in the region will mostly require the participation by all regional stakeholders and utilities, not just FEI.

15.1 Please explain when and why FEI changed its mitigation strategy to building LNG storage instead of additional pipeline infrastructure to address resiliency.

Response:

The response cited in the preamble was submitted on January 9, 2019, only three months after the T-South pipeline ruptured and during the period of significant ongoing supply constraints. At the time of the PRMP proceeding, FEI was focused on managing through the event, and had not fully developed its long-term mitigation strategy to improve gas system resiliency. After FEI was able to manage through the 2018/19 winter season, FEI initiated an internal working group to study and identify strategies that would improve gas system resiliency. Through the working group, FEI identified the three key elements that help enhance gas system resiliency (Ample Storage, Diverse Pipelines and Supply, and Load Management Capabilities), as depicted in the diagram below. FEI presented this slide to BCUC staff on September 24, 2019.

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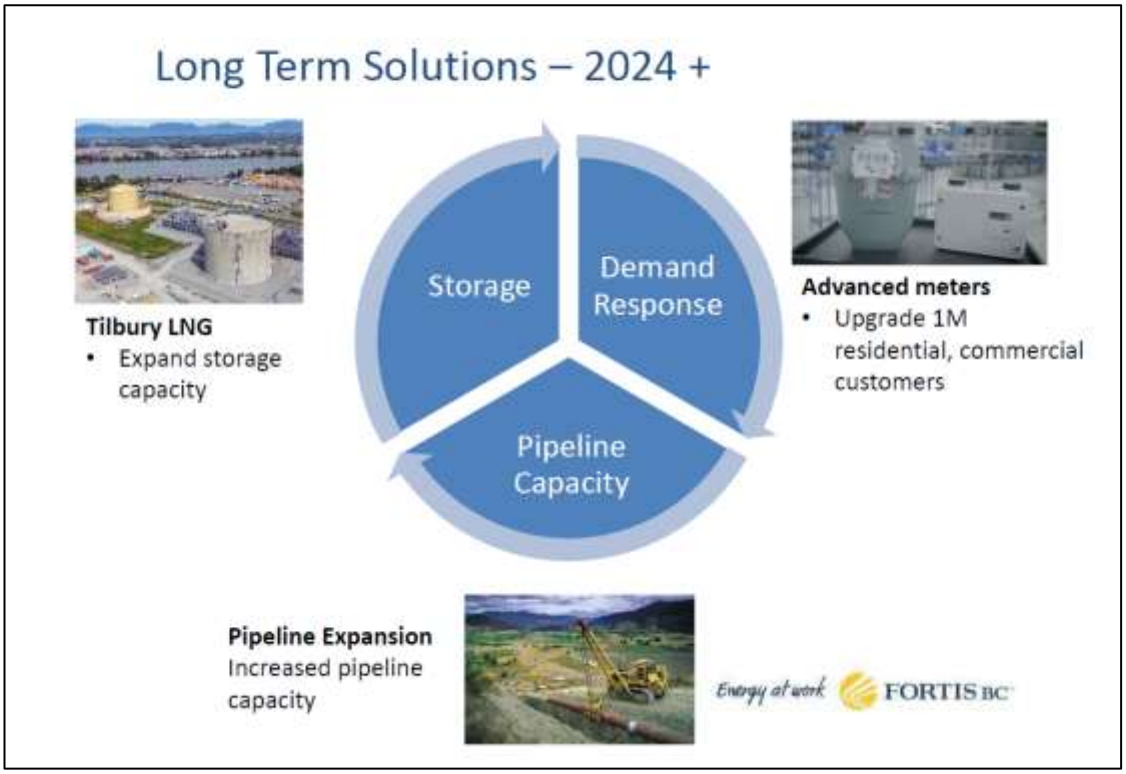
[28] https://www.bcuc.com/Documents/Proceedings/2019/DOC_53177_B-11-FEI-IR1-Response-to-BCOAPO-on-NewEvidence.pdf.



Long Term Solutions – 2024 +
Storage
Demand Response
Pipeline Capacity
Tilbury LNG
• Expand storage capacity
Advanced meters
• Upgrade 1M residential, commercial customers
Pipeline Expansion
Increased pipeline capacity
Energy at work
FORTIS BC

16.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1-4, Section 4.3, pp. 81-100; FEI Application for a CPCN for Approval of the Advanced Metering Infrastructure (AMI) Project (AMI Application), p. 41

Workshop Transcript March 11, 2021, pp. 188-192

Evaluation of Step One Alternatives

On pages 81-82 of the Updated Public Application, FEI shows Table 4-1: Summary of Step One Alternatives Considered to Meet Minimum Resiliency Planning Objective.

On pages 82-83 of the Updated Public Application, FEI discusses the Automated Metering Infrastructure (AMI) alternative. On page 83 of the Updated Public Application, FEI states: “AMI will also help FEI keep the natural gas system pressurized, thereby reducing recovery time for customers that experience service interruption.”

On page 41 of the AMI Application, FEI states:

> Depending on the form of Automation, there are benefits for customers in the long term as well as immediate opportunities in the operation of the gas distribution system. In particular, Automation provides the opportunity to improve the resiliency of FEI’s gas system in the event of a gas supply emergency. Increasing the resiliency of FEI’s gas system is a key need that Automation would support in three distinct ways:
>
> • by allowing near real-time visibility of the load on the system;
>
> • by providing FEI the ability to strategically disconnect gas remotely in an emergency situation; and
>
> • by providing the ability to keep pressure in the system to minimize time for customer reconnections.

16.1 Please explain whether implementation of AMI would give FEI enough added operational flexibility to avoid a pressure collapse in the event of a no-flow event in the absence of the TLSE Project. Please discuss if there are any circumstances where FEI considers there would be a remaining risk of a pressure collapse.

<u>Response:</u>

AMI will provide complementary resiliency benefits to the TLSE Project. However, AMI alone would not prevent a pressure collapse in all scenarios, nor would it prevent wide-scale customer outages.

As discussed in Section 4.3.3 of the Application, the TLSE Project would be used in conjunction with AMI’s ability to collect system supply and demand information, identify where in the system the most significant loads are occurring, and perform remote disconnects if necessary.

AMI provides FEI with a technology platform that will allow the economic installation of additional mid-point pressure and flow sensors, and tail-end pressure sensors. With this technology, FEI will be able to monitor, in near-real time, the performance of all stations throughout FEI's system. To support monitoring and forecasting the total system demand, AMI will provide FEI with the ability to monitor, in near real-time, all customer consumption. This means all meters[29], no matter the size, will be connected to the AMI network. As customer consumption information is collected throughout each hour, FEI will aggregate the total system demand and will be able to determine the granular demand in specific parts of the system. This near-real time aggregated total demand on the system of interest, and supply performance, will be used by FEI to determine which parts of FEI's system are vulnerable to a pressure collapse.

AMI will also provide the ability to remotely disconnect residential and small commercial customers, in order to decrease the possibility of a pressure collapse. Large commercial and industrial customer meters will not be equipped with remote shutoff valves, and so FEI will continue to rely on slower, manual processes to curtail these customers.

Regardless, FEI does not view temporarily shutting-off service to customers as a preferred option as it would still result in a customer outage and the need for a subsequent customer visit for appliance relighting. The preferred option is to utilize the TLSE Project storage to meet all customer demand during the no-flow event. By allowing FEI to strategically disconnect customers in a timely manner, AMI will decrease the possibility of a pressure collapse and allow for critical customers to remain connected. However, while AMI provides complementary functionality to TLSE, AMI alone will not stop a pressure collapse from occurring in all scenarios.

16.2 Please provide a detailed discussion of any other anticipated resiliency benefits from the implementation of AMI, including but not limited to how AMI could impact FEI's ability to:

- Ascertain the supply/demand on the system;
- Curtail customers/Implement a controlled shutdown; and
- FEI's process and timelines to resume service.

Response:

Please refer to the response to BCUC IR1 16.1 for details of how AMI supports ascertaining system supply/demand, accurately forecasting load for the duration of a gas supply emergency, and curtailing customer demand.

AMI is not a supply-side solution, so by definition would not add any supply or storage in the Lower Mainland region; hence, AMI would not contribute to meeting the MRPO. The only supply-side options that would provide FEI with the capability to withstand and recover from a no-flow

[29] Except for a small number of non-communicating meters as explained in the AMI CPCN Application.

event would be a combination of new storage and/or pipeline(s). As such, AMI is complementary to the TLSE Project, and is not a replacement or alternative for the Project.

Should all other gas transportation or storage options be exhausted and FEI is forced to disconnect customers, AMI would allow for a more timely resumption of service. The amount of time to reconnect customers in a large scale outage would vary and still be significant; however, AMI's capability of effectively tracking which customers were disconnected enhances the efficiency of the relight process.

AMI's ability to remotely disconnect customers to prevent a system pressure collapse would help minimize the number of customers that are disconnected from the system. As a result, FEI would have fewer customers to relight and would be able to complete the relight process more efficiently. Accordingly, the overall time to re-establish service to customers would decrease.

Once FEI secures a sufficient supply of gas, disconnected customers would be reconnected. This process would involve FEI calling the disconnected customers and arranging for a relight appointment. FEI is assessing the feasibility of using AMI to provide customers the additional option of a remote reconnect. If feasible, the remote reconnect option could involve asking customers pre-screening questions (over the phone) to confirm they are capable of safely relighting their appliance(s). If the customer wants to relight their appliance(s) and demonstrates the necessary knowledge, FEI would send a command, via the AMI network, for the meter to perform a remote dial test to confirm the integrity of the customer's house piping and appliance(s). If the meter passes its remote dial test, the customer would be informed that the appliances would be ready to be relit.

Manually relighting all Lower Mainland customers would take months to complete, even with all available FEI and provincial resources, local gas contractors, and mutual aid agreements. However, if FEI can use AMI to remotely disconnect customers and prevent a pressure collapse, this would result in fewer customers requiring a relight and save potential days to weeks required to repressurize a collapsed system. If a pressure collapse is averted but a large number of customers were disconnected, it could still take months to relight all these disconnected customers. If the remote reconnect option is available, FEI would have greater flexibility to relight customers. This greater flexibility should decrease the overall amount of time to relight customers disconnected from FEI's system, however FEI is unable to quantify this reduction in advance. The total time should decrease by approximately the same percentage of customers who successfully relight their appliances via the remote reconnect option.

On pages 85-86 of the Updated Public Application, FEI explains the T-South Expansion alternative. FEI states: "The expansion provides very little new resiliency from FEI's perspective, since it does not reduce the current single point of failure risk and adds no pipeline diversity."

16.3 Please explain the additional resiliency benefits the T-South Expansion alternative would add compared to FEI's resiliency capability today.

16.3.1 Please explain whether there are circumstances where the T-South Expansion would prolong FEI's ability to withstand a no-flow event.

Response:

FEI discusses below the resiliency benefits and cost considerations pertaining to the T-South Expansion alternative. FEI also provides an explanation as to why a pipeline solution and on-system storage need to be viewed as complementary assets that are necessary to address infrastructure resiliency, which provides relevant context for FEI's responses to BCUC IR1 16.3 to 16.11. By doing so, FEI hopes to clarify several questions from the BCUC and interveners regarding the potential for a pipeline expansion in the region to replace the need for the TLSE Project.

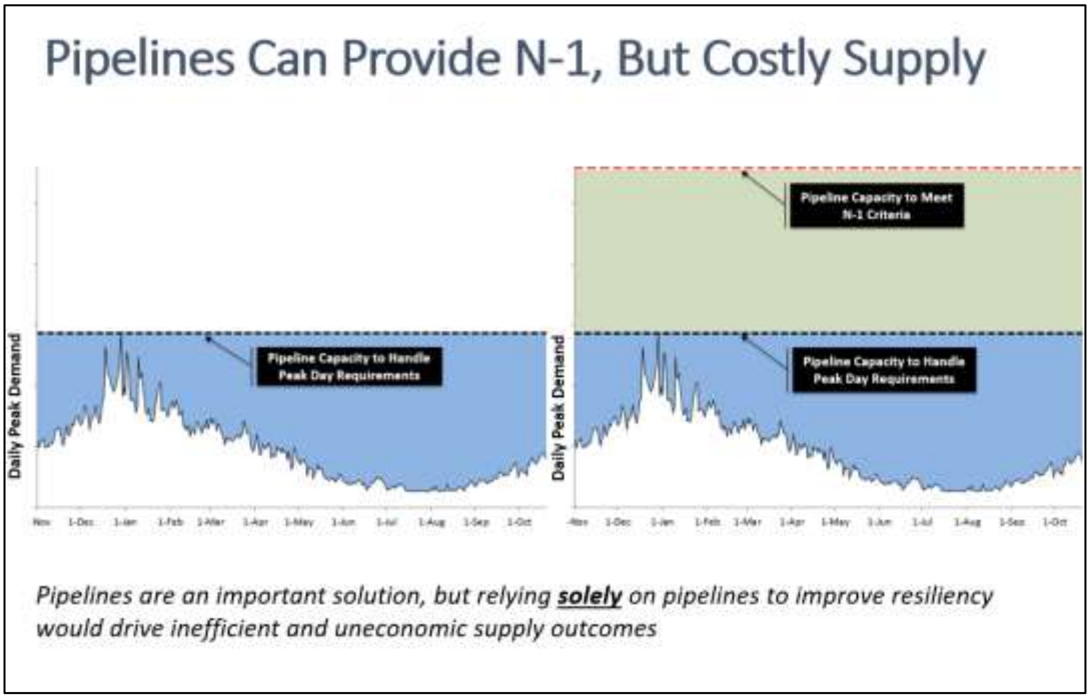
FEI believes additional pipeline infrastructure in the region is important for enhancing system resiliency. Depending on the pipeline infrastructure option, to varying degrees it would also facilitate load growth opportunities, generate additional gas supply benefits, and support the transition to cleaner energy. The resiliency benefits that any pipeline expansion can bring to the region (as described in the Application and in the responses to BCUC IR1 16.3 to 16.11), would be dependent on the pipeline size (capacity per day), market interest, and the proposed pipeline route.

Section 4.3.4.5.2 of the Application provides an example of doubling the optimal amount of pipeline capacity on two pipelines (T-South system and SCP Expansion to Huntingdon) within FEI's existing ACP portfolio of resources[30] as an alternative to forego an expansion of on-system storage. Within this example, FEI's customers would be paying higher annual costs due to the pipeline demand charges, compared to the portfolio approach that FEI is proposing with the TLSE Project.

If FEI proposed enhancing system resiliency in the Lower Mainland with a pipeline-only solution with no associated on-system storage support, any pipeline expansion would have to be along a different corridor than the existing T-South pipeline (to avoid the risk of common-mode failures), and be sized for at least 800 MMcf/day to provide full replacement capacity for T-South if that system was not available for any reason.

While building a new pipeline this size may be technically possible, this option would ultimately be more costly for customers. It would come at a higher cost than FEI's portfolio approach to resiliency, given that FEI would be holding excess total capacity (i.e., 800 MMcf/day on both pipelines). This would result in FEI's customers paying demand charges for capacity on two pipelines with a significant portion going unused. This point was explored in the March 11, 2021 TLSE Workshop in the discussion associated with the figure below.[31]

[30] This includes the utilization of the Tilbury Base Plant.
[31] TLSE Workshop Transcript, pp. 161-162 and Exhibit B-4, FEI Workshop Presentation.



Additionally, the size of a pipeline expansion into the region would depend on potential interest from third-party shippers. Although the market requires additional pipeline to satisfy growing gas demand and diversified market access especially during the winter, as well as to provide much needed gas supply resiliency to the region, at this time FEI does not believe there is enough support from third-party shippers to build an 800+ MMcf/day pipeline.

Based on the above considerations, and as further discussed in Section 4.3.1.2 of the Application, the pipeline expansion alternatives do not replace the need for the TLSE Project:

> It is unlikely to be efficient, or in the interest of customers, to try to build resiliency by holding year-round diverse pipeline resources in quantities that would only be required if a “no-flow” event occurred during a short duration peaking period. Conversely, it is unlikely to be feasible or economic to attempt to manage long-duration supply events or exposures with on-system LNG storage, since the amount of storage required would be too large.[32]

FEI believes on-system LNG and pipeline expansions provide critical interrelated resiliency benefits that jointly address short- and long-duration supply issues in a cost effective manner. As such, they need to be viewed as complementary assets that form the foundation of an efficient resiliency portfolio (as shown in Figure 4-3 of the Application). A pipeline expansion in the region would be optimally sized to manage any long-duration supply disruption (i.e., Phases 2 and 3 of the T-South Incident[33]) while also meeting the commercial needs of the region. For additional details regarding FEI’s optimal approach to resiliency with enhancements to pipeline redundancy and the TLSE Project, please refer to Sections 5 and 6 of Appendix C (ACP Compliance Report).

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[32] TLSE Application, p. 80.

[33] The T-South phases are laid out in Sections 3.4.2.2.1, 3.4.2.2.2, and 3.4.2.2.3 of the Application.

With respect to the T-South Expansion alternative specifically, Westcoast has not publicly disclosed if and/or when an expansion of the T-South system would be considered. Based on the fact the pipeline is built on one single major corridor for a distance of 916 km and operated as a single system, it is highly unlikely an expansion of T-South would materially prolong FEI's ability to withstand a no-flow event. FEI expects that a future T-South expansion likely includes pipeline looping and compressor upgrades along the same corridor. However, it is also possible, but less likely, that Westcoast would consider an expansion along an entirely different right-of-way. Given these uncertainties, the potential size of a T-South expansion[34] and its costs are unknown at this time.

These considerations are important when taking into account estimated pipeline costs as well as potential circumstances where FEI would be able to withstand a no-flow event. For example, an expansion that entails pipeline looping along the same corridor as the existing T-South system would come at a lower cost than the option for Westcoast to build a new pipeline along an entirely different right-of-way. However, this lower cost option provides minimal resiliency benefits to FEI. This is because any future no-flow event could still disrupt the entire path in the common corridor.

In contrast, an expansion along a new pipeline corridor would provide several resiliency benefits, while also meeting the commercial needs of the region and FEI specifically. This would include mitigating the risk of a prolonged supply disruption of the nature that occurred in Phases 2 and 3 of the T-South Incident. Further, an expansion along a new corridor could enhance FEI's ability to withstand a no-flow event depending on several factors, including demand of the system and the new pipeline size. For comparison purposes, the distance to complete a Southern Crossing Expansion to Huntingdon is approximately 240 km. This type of expansion could prolong FEI's ability to withstand a no-flow event beyond three days.

16.4 Please provide the estimated cost of the T-South Expansion alternative.

Response:

Please refer to the response to BCUC IR1 16.3.

On pages 86-87 of the Updated Public Application, FEI explains the Expansion to Northwest Pipeline's (NWP) Gorge Capacity alternative. FEI states:

> Expanding the NWP Gorge capacity would allow gas to flow west into the Seattle and Portland region and decrease demand at Huntingdon/Sumas. While this project has merit and would provide increased physical supply into the region, it

[34] The potential size of any pipeline expansion would depend on what capacity the pipeline operator can offer, as well as the level of interest from third-party shippers.

would not be FEI's preferred choice for a new pipeline into the region because of the limited resiliency benefits it would provide to FEI directly…. FEI's storage and regasification needs would, from a resiliency standpoint, remain unchanged under this scenario.

16.5 Please explain the additional resiliency benefits the Expansion to NWP Gorge Capacity alternative will add compared to FEI's resiliency capability today.

16.5.1 Please explain whether there are circumstances where the Expansion to NWP Gorge Capacity alternative would prolong or otherwise enhance FEI's ability to withstand a no-flow event on the T-South system.

16.5.2 Please provide the estimated cost of the Expansion to NWP Gorge Capacity alternative.

<u>Response:</u>

FEI understands that considerations for a potential expansion of the Gorge pipeline have not advanced to a point where NWP is able to provide reasonable expansion scenarios and their estimated costs. FEI expects that any such expansion would likely follow the same right-of-way as the existing Gorge pipeline and would include a combination of pipeline and compression upgrades. However, FEI is unable to determine the size of the expansion because that would depend on what NWP can offer as well as the interest from third-party shippers in the region.

Regardless of these factors, this type of expansion would provide limited benefits to enhancing FEI's system resiliency because of the physical gas flows. As discussed in Section 4.3.4.3, FEI would still need to rely on displacement[35], which is dependent on physical gas flow on the T-South system to Huntingdon, and would be reliant on the cooperation and effort of mutual aid partners to physically flow gas northward during a no-flow or emergency event.

As a result, it is highly unlikely that during the winter season there is any scenario whereby a Gorge expansion could prolong FEI's ability to withstand both a long-duration supply disruption and/or a no-flow event on the T-South system. For example, if there is a no-flow event on T-South, the gas supply from the Gorge would be physically used for the load requirements in Washington before it could make its way up to the Lower Mainland.

The only circumstance where a Gorge expansion could help is during a no-flow event on the T-South system under favourable conditions (i.e., low regional demand). This was demonstrated during the T-South Incident, as FEI was able to physically access supply through mutual aid agreements because load demand in Washington and Oregon was sufficiently low that some of the physical flow could be reversed northwards across the border. This is not possible during the winter season, when regional demand is at its highest. Please refer to Figure 3-7 of the Application for an illustrative diagram showing how supply that physically moved northwards helped meet FEI's load requirements on October 10, 2018.

[35] The displacement process is detailed in Section 3.5.4.3 of the Application.

Ultimately, whether a Gorge expansion could help a prolonged supply disruption is outside of FEI's control, as it would depend on how long the favourable conditions last in the region and whether the mutual aid agreement remains effective during the supply disruption event.

On page 87 of the Updated Public Application, FEI explains the SCP Expansion to Kingsvale alternatives. FEI states:

> An expansion of SCP to Kingsvale, with some of FEI's required supply being shifted from the T-South system to SCP, would mitigate a significant portion of FEI's reliance on the T-South system. However, it would not provide redundancy for the 172 km section of the T-South system between Kingsvale and Huntingdon, since all of the gas from SCP would have to travel on that segment to reach the load centre in the Lower Mainland. As a result of this exposure, an expansion of SCP to Kingsvale would not change FEI's storage requirements from a resiliency standpoint.

16.6 Please explain the additional resiliency benefits the SCP Expansion to Kingsvale alternative will add compared to FEI's resiliency capability today.

Response:

As the preamble notes, an SCP expansion to Kingsvale would mitigate FEI's reliance on the T-South system, except for failures along the section of T-South between Kingsvale and Huntingdon. Therefore, the additional resiliency benefits from this expansion would be dependent on the location of a future supply disruption event.

A T-South disruption between Kingsvale and Huntingdon would result in limited or no-flow to the Lower Mainland; therefore, the resiliency benefits of this expansion are limited to a restricted flow event only. However, if the rupture occurred north of Kingsvale, similar to the T-South Incident, Westcoast may continue operating the T-South pipeline capacity between Kingsvale and Huntingdon at a reasonable pressure. In such an event, the resiliency benefits would include mitigating the risk of a no-flow event during the summer period, as well as the potential prolonged disruption of supply on T-South, similar to Phases 2 and 3 of the T-South Incident. As discussed in the response to BCUC IR1 16.3, such an expansion would not meet the MRPO during the winter period.

Although this option provides some benefits, development of such an alternative has not advanced to a point where the scope of work is sufficiently defined to support a cost estimate.

16.7 Please explain whether there are circumstances where the SCP Expansion to Kingsvale alternative would prolong or otherwise enhance FEI's ability to withstand a no-flow event on the T-South system.

Response:

Please refer to the response to BCUC IR1 16.6.

16.8 Please provide the estimated cost of the SCP Expansion to Kingsvale alternative.

Response:

Please refer to the response to BCUC IR1 16.6.

On pages 87-88 of the Updated Public Application, FEI explains the SCP Expansion to Huntingdon alternative. FEI states:

> An expansion of SCP to Huntingdon would be FEI's preferred choice of pipeline development from a resiliency standpoint, given that this solution would entail an entirely different path from the T-South system and would allow FEI to split the optimal amount of pipeline capacity between T-South and the new pipeline.…This project would amplify the resiliency benefits of the SCP expansion to Kingsvale.

16.9 Please explain the additional resiliency benefits the SCP Expansion to Huntingdon alternative will add, compared to FEI's resiliency capability today.

Response:

As cited in the preamble, an SCP expansion to Huntingdon would create a flow path separate from the T-South system, thus providing a new route to supply the Lower Mainland. This expansion would provide the greatest resiliency benefits as compared to the other pipeline expansions described in the responses to BCUC IR1 16.3, 16.5, and 16.6.

An SCP expansion to Huntingdon would be able to mitigate the risk of a no-flow event during low-demand (i.e., summer) periods, as well as help address the risks of a prolonged supply disruption similar to Phases 2 and 3 of the T-South Incident. However, it is unlikely to be feasible or economic that this pipeline expansion alone would be able to fully withstand a no-flow event on the T-South system during the winter season. Section 4.3.4.5.1 of the Application provides a hypothetical gas flow scenario that includes FEI contracting pipeline capacity on a new corridor pipeline to the Lower Mainland. This scenario shows that the FEI system demand would still far exceed the available pipeline capacity during the winter, such that on-system storage would still be required. This reinforces FEI's view that a pipeline expansion in the region is complementary to—but not a replacement for—the TLSE Project.

As discussed in the response to BCUC IR1 10.6, FEI is completing initial scoping work and is planning to proceed with development of the SCP expansion to Huntingdon as its preferred pipeline solution. After this work is complete, FEI will be able to provide the estimated cost of this expansion.

16.10 Please explain whether there are circumstances where the SCP Expansion to Huntingdon alternative would prolong or otherwise enhance FEI's ability to withstand a no-flow event on the T-South system.

<u>Response:</u>

Please refer to the response to BCUC IR1 16.9.

16.11 Please provide the estimated cost of the SCP Expansion to Huntingdon alternative.

<u>Response:</u>

Please refer to the response to BCUC IR1 16.9.

On page 98 of the Updated Public Application, FEI explains Underground On-System Storage in the Fraser Valley alternative. FEI states: "Since 1997, the regulations under the Petroleum and Natural Gas Act do not allow for the exploration of or the granting of a lease for an underground natural gas storage reservoir in the Fraser Valley." FEI provides Figure 4-7 showing the exclusion zone.

16.12 Please explain whether there are potential areas for On-System underground storage near the Lower Mainland, adjacent to FEI's pipelines and outside the exclusion zone, such as Chilliwack, Hope or Howe Sound.

Response:

FEI is not aware of potential areas for on-system underground storage near the Lower Mainland, adjacent to FEI's pipelines, and outside the exclusion zone, such as Chilliwack, Hope or Howe Sound. Even if there were such underground storage areas, their value would be limited to FEI because they would not be adjacent to FEI's pipelines and hence would likely require extensive pipeline infrastructure to connect the underground storage to the Coastal Transmission System.

16.13 If yes, did FEI consider underground storage outside the exclusion zone? If not, why not?

Response:

FEI did not consider underground storage outside the exclusion zone because it considered this alternative to be highly uncertain from a technical standpoint, and almost certainly impossible to implement due to the expected public and governmental response. The cost of determining the technical feasibility would also likely be high; simply ascertaining feasibility would require extensive exploratory drilling and engineering assessment of the geological formations which may (or may not) be found. Given the lack of identified benefits compared to the high expected costs of this alternative, FEI did not consider this to be a prudent use of development funds and therefore did not pursue this alternative further.

On pages 81-82 of the Updated Public Application, FEI shows Table 4-1: Summary of Step One Alternatives Considered to Meet Minimum Resiliency Planning Objective, including the Contract Additional Off-System Storage alternative.

16.14 Please further explain the scope, benefits and drawbacks of the Contract Additional Off-System Storage alternative.

Response:

As discussed in Section 3.5.4.3 of the Application, contracting for additional off-system storage would still leave FEI subject to a single point of failure risk, since FEI would remain dependent on the T-South system to access the storage resources. Access to the JPS and Mist storage facilities in the US is only by displacement, and is dependent on gas physically flowing on T-South. For this reason, FEI discarded contracting for additional off-system storage as an alternative early in the screening process. This alternative provides limited benefits from a resiliency perspective because, as Guidehouse explains, "off-system natural gas storage is dependent on the transmission system for delivery to the natural gas system and provides less resiliency to an LDC than on-system storage."[36]

16.15 Please explain the additional resiliency benefits the Contract Additional Off-System Storage alternative will add, compared to FEI's resiliency capability today.

Response:

Contracting additional off-system storage provides no additional resiliency benefits compared to FEI's resiliency capability today. Please also refer to the response to BCUC IR1 16.14.

16.16 Please explain whether there are circumstances where the Contract Additional Off-System Storage alternative would prolong or otherwise enhance FEI's ability to withstand a no-flow event on the T-South system.

Response:

FEI is unable to identify any circumstances where the Contract Additional Off-System Storage alternative would prolong or otherwise enhance FEI's ability to withstand a no-flow event on the T-South system. FEI has already contracted for off-system storage resources at JPS and Mist through its Annual Contracting Plan. Contracting additional storage from these facilities would not result in more supply during a no-flow event because the availability of these resources depends on both mutual aid assistance and the timing of the event. For instance, the T-South Incident occurred when demand was low in Washington and Oregon. This allowed for gas to physically flow northwards into BC for use by FEI. However, the amount of supply that was available and provided was under the mutual aid agreement from partners. FEI would not expect this mutual aid capability to be available during high demand conditions associated with cold winter temperatures. Please also refer to the response to BCUC IR1 16.14.

16.17 Please provide the estimated cost of the Contract Additional Off-System Storage alternative.

[36] TLSE Application, Appendix A (Guidehouse Report), p. 14.

Response:

FEI is unable to develop an estimated cost for this alternative because the Company is unable to identify a contractual method of achieving the resiliency benefits necessary to meet the identified risk of a T-South no-flow event underlying the MRPO.

On page 99 of the Updated Public Application, FEI explains the On-System Storage at a New Site alternative:

> The combination of existing infrastructure located on a developed site already purposed for LNG service with available space is unique. The additional costs required to acquire land, extend gas supply and power and construct liquefaction capacity to supply the LNG would render a new site uneconomic and challenging relative to a project at the Tilbury site.

16.18 Please explain the additional resiliency benefits the On-System Storage at a New Site alternative could add, compared to FEI's resiliency capability today.

Response:

On-system storage and regasification capacity at a new site could allow FEI to store a sufficient LNG volume to meet the MRPO. Provided the new site were located at an appropriate injection location, the resiliency benefits a new LNG storage site could have for FEI are identical to the resiliency benefits FEI will realize with the TLSE Project. However, there would be no added resiliency benefit from construction of a new on-system storage facility at a new site when compared to the proposed TLSE Project, assuming a comparable tank size.

In order to provide the same benefits that FEI will realize with the TLSE Project, any new site would need to be located near the center of the transmission system. Should the new site be located at the periphery of the Lower Mainland system (for example, near Huntingdon), its resiliency benefit would be lessened due to its reliance on the pipelines connecting it to the rest of the system. Additionally, as discussed in the response to BCUC IR1 24.3, the existing Tilbury LNG facility is already in a very good location from a hydraulic perspective for injection of gas into the Lower Mainland system. Other greenfield locations with similar hydraulic advantages would be unsuitable for the construction of any major facilities as the associated region is a highly developed and densely populated urban area.

Finally, a new facility site would require new land acquisition, site preparation, power, and pipeline infrastructure in excess of what is required for the TLSE Project. It would also require the construction of liquefaction capacity for the production of LNG, unlike at the proposed Tilbury site, where existing liquefaction capacity will be utilized. This would add significant additional costs to the Project while providing no added resiliency.

16.19 Please explain whether there are circumstances where the On-System Storage at a New Site alternative would prolong or otherwise enhance FEI's ability to withstand a no-flow event on the T-South system.

Response:

More LNG storage at a greenfield site could prolong FEI's ability to withstand a no-flow event on the T-South system. However, this would not be a practical or cost-effective approach to enhancing system resiliency, given the presence of the existing Tilbury facility and the much higher costs of constructing a greenfield facility compared to the TLSE Project, as discussed in the response to BCUC IR1 16.18.

16.20 Please provide the estimated cost of the On-System Storage at a New Site alternative.

Response:

FEI has not developed a detailed cost estimate for on-system storage at an alternative site to the existing Tilbury site. The design, equipment, and construction costs for a new 3 Bcf LNG storage tank and associated regasification equipment as well as foundation work would not be significantly different between a new site and at the existing Tilbury facility. However, as discussed in Section 4.3.5.5 of the Application, the alternative site option would be significantly more costly because of the additional costs required to acquire new land, and to construct the necessary interconnecting pipelines, electrical power supply, and the new liquefaction capacity for LNG production. These would all result in significantly higher capital costs with resulting higher rate impacts to FEI customers. As such, there is no benefit to acquiring a new site in order to construct new on-system storage, as it is more economical to leverage the current land and infrastructure already available at the existing Tilbury site.

While FEI has not performed a cost estimate for the on-system storage at a new site alternative, given the factors discussed, the cost would be significantly higher than the proposed TLSE Project.

On page 100 of the Updated Public Application FEI discusses the Combination of Existing Base Plant and New Tank alternative. FEI states: "the Tilbury Base Plant is currently 50 years old and is approaching the end of its useful life… While FEI expects the tank to last beyond 55 years, it makes economic and practical sense to replace the tank now to capture available economies of scale in the construction of a single, larger tank."

On page 100 of the Updated Public Application, FEI provides Table 4-4, Comparison of the Capital Costs to Build a Single, Larger Tank. The table shows a comparison between building a new 2.0 Bcf tank and 800 MMcf/d regasification, and building 1.4Bcf tank and 650MMcf/d regasification now then replacing the Base tank at some point in the future. Several different scenarios are provided with end of life for the existing tank in different years, ranging from 55 to 70 years.

16.21 Please explain how FEI determined the remaining lifespan of the existing 0.6 Bcf tank at Tilbury, including reference to recent maintenance activities.

16.21.1 Please explain the likelihood of the existing base tank reaching a 70-year life, or longer.

Response:

FEI did not determine the remaining lifespan of the 0.6 Bcf tank as it was not necessary to do so for evaluating the alternative of constructing a new 2 Bcf tank now versus constructing a new 1.4 Bcf tank now and replacing the existing Base Plant tank at a later date. In Table 4-4 of the Application, FEI provides a range of financial comparisons (i.e., 55 to 70 years) which shows that even if the Base Plant tank could remain in service for another 20 years (at which time it would be 70 years old), it is still financially beneficial to FEI's customers to replace the Base Plant tank now with a new larger storage tank.

FEI notes the financial comparison discussed in Section 4.3.5.6 and in Table 4-4 of the Application reflects the very conservative (unrealistic) assumption that no further capital maintenance activities for the Tilbury Base Plant would be required. Even with this assumption of no future capital maintenance costs, the Base Plant would have to remain in service until at least 94 years old to be financially beneficial versus the alternative of constructing a new 2 Bcf tank and regasification capacity now. In reality, there would be capital maintenance activities required for the Tilbury Base Plant to continue to extend its service life; however, this would make the option of continuing operation of the Base Plant even more uneconomical than what is shown in Table 4-4. From both a technical and financial perspective, FEI believes it is unreasonable to rely on the Base Plant to operate for at least another 50 years (at which time the Base Plant would be 100 years old). As shown in Table 4-4, it makes more sense financially to replace the Base Plant with a new tank and regasification capacity now, regardless of whether additional capital maintenance activities are performed on the Base Plant.

16.22 Please further explain any drawbacks or benefits of the Combination of Existing Base Plant and New Tank project alternative.

Response:

As outlined in Section 4.3.5.6 of the Application, there are several drawbacks to the Combination of Existing Base Plant and New Tank alternative, which is why FEI discarded this alternative in Step 1 of its two-step alternatives analysis.

As shown in Table 4-4 of Section 4.3.5.6, even under a scenario where the Base Plant tank reaches a 70-year service life, it is more economical to construct a new 2 Bcf tank now as opposed to constructing a 1.4 Bcf tank now and continuing to utilize the Base Plant tank. FEI also notes that the analysis in Table 4-4 does not include any sustaining capital spending for the Base Plant tank, which, given the tank's age and current condition, is very unlikely. Should the Base Plant tank require sustaining capital expenditures, the Combination of Existing Base Plant and New Tank alternative becomes even less economical compared to constructing a new 2 Bcf tank.

FEI has determined that 2 Bcf of storage is the minimum amount needed in order to withstand and recover from a 3-day no-flow event. Given this minimum need, and as the analysis in Table 4-4 shows, it does not make economic sense to build a new storage tank that is less than 2 Bcf, irrespective of whether the Base Plant tank is replaced now or sometime in the future. However, there are added benefits to removing the Base Plant facilities as part of the TLSE Project, as the demolition activities can be planned and synchronized as part of the overall Project execution, thus allowing for a more efficient and streamlined process. Additionally, continuing to operate the Base Plant facilities would increase the operation and maintenance costs for the overall Tilbury facility, as FEI would be operating and maintaining three storage tanks (the Base Plant tank, Tilbury 1A tank, and the new TLSE tank); in particular, the maintenance requirements for the Base Plant tank would be different from the other newer tanks due to the Base Plant tank's age and design.

The only benefit of the Combination of Existing Base Plant and New Tank alternative is that it provides increased resiliency relative to today; however, it is more costly than constructing a new 2 Bcf tank. Please refer to the response to BCUC IR1 16.23 for a discussion and quantification of the additional resiliency provided by a new 1.5 Bcf storage tank relative to today.

On page 94 of the Updated Public Application, FEI states: "At 2 Bcf, the storage would provide minimal margin to assist in responding to any supply or demand events occurring during the period following resumption of flows (as occurred following the T-South Incident)."

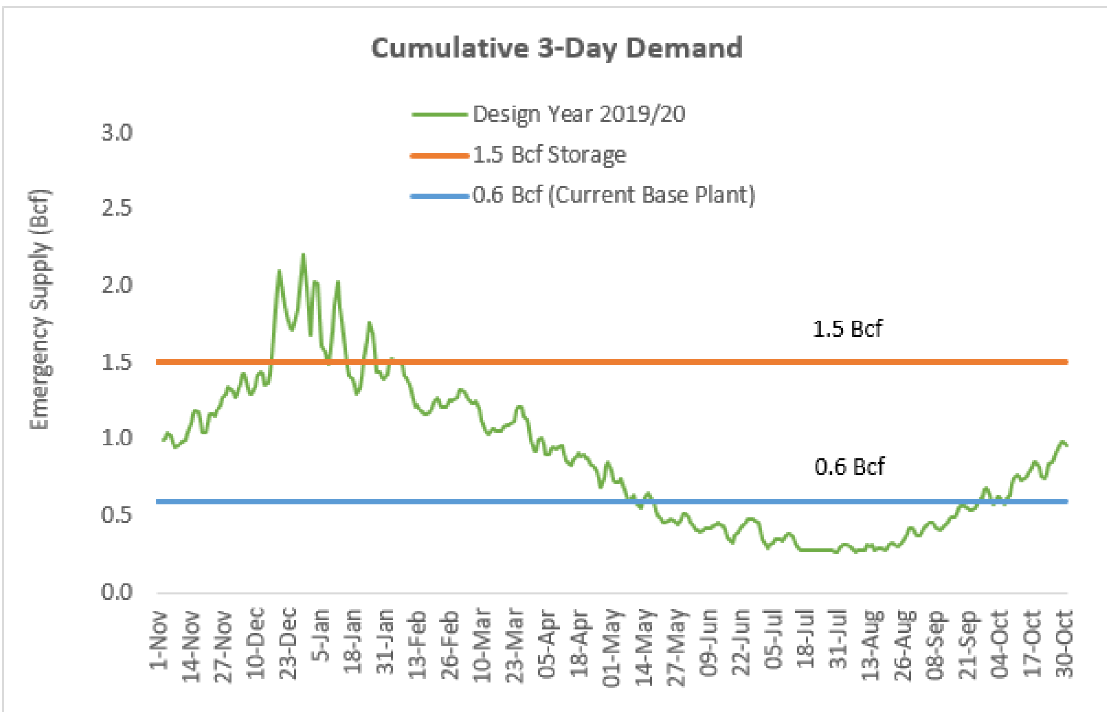
On pages 188 to 192 of the Transcript, Mr. Chernikowsky explains several ancillary operational benefits from the Project, including extending available gas supply and deferring a future $20-30 million compression project in the Okanagan region. Also discussed are adjusting gas flows in the CTS pipeline system to facilitate integrity management inspection tools and reduction of operating pressures to repair any issues found during pipeline inspections. Further, Mr. Chernikowsky states benefits of the AMI project of real-time customer consumption information and remote shut-off capability.

16.23 Please explain the additional resiliency benefits the On-System Storage at a Tilbury (<2Bcf) would add, given a tank size of 1.5Bcf, compared to FEI's resiliency capability today.

Response:

If the TLSE Project was built with a storage tank size of 1.5 Bcf, the additional resiliency benefits compared to FEI's resiliency capability today would include the ability to:

- withstand a 2-day no-flow event in the winter, except for the two-day coldest period of the year; and
- withstand a 3-day no-flow event on T-South for 326 days in a year, as illustrated in the figure below.



These benefits are all based on the 2019/20 design load forecast for RS 1 to 6, 23 and 25 Lower Mainland customers, which is consistent with the analysis provided in the Application.

As FEI explained in the response to BCUC IR1 16.22, a tank size of less than 2 Bcf was discarded in Step One of FEI's two-step alternatives analysis because it does not address the identified risk underlying the MRPO.

16.24 Please explain whether the project benefits described by Mr. Chernikowsky in the Workshop (deferring Okanagan compression project, adjusting gas flows in the CTS pipeline system for integrity management tools, remote shut-off capability) would occur if FEI built a smaller tank, such as the 2 Bcf tank considered in the project alternatives. If not, please explain why not.

Response:

The project benefits discussed in the preamble would not occur if FEI built a smaller tank such as 2 Bcf. This is because the objective of the TLSE Project is to have 2 Bcf reserved for resiliency purposes at all times so as to position FEI to withstand a 3-day no-flow event, with the incremental 1 Bcf providing a resiliency margin above that minimum and flexibility to pursue additional gas supply and operational benefits (such as deferring the Okanagan compression project or adjusting gas flows in the CTS pipeline system for integrity management tools).

16.25 Please explain how long of a no-flow scenario in winter could be withstood under the On-System Storage at Tilbury (<2 Bcf) alternative with a 1.5Bcf tank size.

Response:

Please refer to the response to BCUC IR1 16.23.

16.26 Please explain how many days of the year this alternative scenario could withstand a three-day no-flow event on T-South system.

Response:

Please refer to the response to BCUC IR1 16.23.

16.27 Please provide the estimated cost of the On-System Storage at Tilbury (<2 Bcf) alternative, given a tank size of 1.5Bcf.

Response:

Please refer to the table below for a comparison of the estimated capital costs as well as the financial evaluation of on-system storage at Tilbury with a tank size of 1.0 Bcf, 1.5 Bcf, 2.0 Bcf, 3.0 Bcf, and 3.5 Bcf. In addition to the 1.5 Bcf tank size, the 1.0 Bcf and 3.5 Bcf tank size estimates have been provided in the table below as that information was requested in other BCUC information requests. The financial evaluations for the 2.0 Bcf and 3.0 Bcf storage tank are from Table 4-6 of the Application, and are included in the table below for comparison purposes.

For the 1.0 Bcf, 1.5 Bcf and 3.5 Bcf storage tanks, the estimates were discounted/prorated from the TLSE Project Class 3 estimate (i.e., storage tank, ground improvement, regasification, auxiliary systems and owner's costs) that were presented in the Application for the 2.0 Bcf and 3.0 Bcf storage tanks. FEI also updated the contingency and escalation factors based on the discounted/prorated cost estimates. FEI notes that it has assumed a regasification capacity of 800 MMcf/day for all tank sizes.

	1.0 BCF & 800 MMcf/d	1.5 BCF & 800 MMcf/d	2 BCF & 800 MMcf/d (Table 4-6 of Application)	3 BCF & 800 MMcf/d (Table 4-6 of Application)	3.5 BCF & 800 MMcf/d
Total Project Capital Costs, 2020 dollars ($ millions)	492	547	588	637	713
Capital Cost per unit of storage ($ millions/BCF)	492	365	294	212	204
PV of Incremental Revenue Requirement 67 years ($ millions)	861	918	951	1,042	1,105
Levelized Delivery Rate Impact 67 years (%)	5.51%	5.88%	6.09%	6.67%	7.07%
Levelized Delivery Rate Impact 67 years ($/GJ)	0.249	0.265	0.275	0.301	0.319
Average Residential Use per Customer (GJ)	90.0	90.0	90.0	90.0	90.0
Average Annual Residential Bill Increase ($)	22.4	23.9	24.8	27.1	28.7
Average Annual Residential Bill Increase (%)	3.71%	3.95%	4.10%	4.49%	4.76%

16.28 Please provide the estimated cost of the On-System Storage at Tilbury (>3 Bcf) alternative, given a tank size of 3.5Bcf.

Response:

Please refer to the response to BCUC IR1 16.27.

16.29 If the minimum resiliency planning objective criteria were changed to a two-day no-flow event, please provide a table ranking the Step 1 Alternatives based on cost, benefits, drawbacks and ability to withstand a no-flow event.

16.29.1 Please explain, in FEI's view, which of the Step 1 Alternatives would merit further consideration, given the costs and benefits.

Response:

A revised table ranking the Step One Alternatives is provided below, with FEI's assessment of each alternative based on a 2-day MRPO. In almost all scenarios, a change to the MRPO does not change the feasibility of the Step One Alternatives.

Even with a 2-day MRPO, no alternative would allow FEI to meet the MRPO without construction of additional on-system storage. By altering the MRPO, only the volume of on-system storage required is reduced. Thus, the only alternatives that would become feasible based on a change to the MRPO are "Use the Existing Base Plant Storage (including regasification) and Add Additional Storage" and "On-System Storage at Tilbury (<2 Bcf)".

However, as stated above and in the Application, FEI does not consider a 2-day MRPO to be sufficient. The T-South Incident resulted in a 2-day no-flow scenario, despite favourable weather and pipeline access conditions at that time. Under more severe conditions, such a rapid repair of the ruptured pipeline may not have been possible. Please also refer to the response to MS2S IR1 4.i.

Also, due to inherent economies of scale, the cost savings from reducing the size of the on-system storage tank is limited. As previously noted, construction of LNG storage becomes less expensive in dollars per unit volume as the storage volume increases (up to an inflection point where cost per unit volume begins to increase due to constructability issues).

Further, reducing the size of the on-system LNG storage tank does not provide the additional benefits that the 3 Bcf option provides, which were shown in Table 4-5 of the Application. The gas supply benefits alone associated with having the "third Bcf" of storage exceed the incremental cost of building the "third Bcf", as discussed in FEI's response to BCUC IR1 46.2; it is significantly more costly to contract for a peaking resource than using the storage available from the proposed 3 Bcf storage tank.

As such, construction of more than 2 Bcf of storage provides greater resiliency benefits and reduces the cost per Bcf of storage. Both overall system resiliency and cost efficacy would be reduced by the proposed change to the MRPO.

FEI also notes that the required regasification capacity is unchanged by the altered MRPO.

Table 1: Revised Step One Screening Assuming a 2-day MRPO

Resiliency Elements	Alternatives	Assessment – 2-day Condition	Ranking
Load Management	Advanced Metering Infrastructure (AMI)	• The revised 2-day MRPO does not change FEI's assessment of this alternative. • AMI remote shut-off capability will add resiliency by reducing the potential for an uncontrolled shutdown, but is best viewed as complementing supply-side solutions. Without additional supply during a no-flow event, large scale load shedding would be required, leaving many non-interruptible customers without service.	N/A
Diversified Pipeline Supply	T-South Expansion	• The revised 2-day MRPO does not change FEI's assessment of this alternative. • Expansion in the same corridor would still leave FEI subject to single point of failure risk, such that new storage would still be required to meet FEI's MRPO even if the pipeline was constructed. Recall that the rupture of the 30" Enbridge pipeline resulted in a requirement to reduce the pressure on the parallel 36" pipeline. The amount of new storage required would be reduced based on the 2-day MRPO.	N/A
	Expansion to Northwest Pipeline's (NWP) Gorge Capacity	• The revised 2-day MRPO does not change FEI's assessment of this alternative. • Expansion would add little resiliency for FEI. FEI must rely on displacement to access Gorge capacity, such that T-South gas must be physically flowing. Even if the Gorge expansion was constructed, new storage would still be required to meet FEI's MRPO. The amount of new storage required would be reduced if FEI adopted a 2-day MRPO.	N/A
	SCP Expansion to Kingsvale (i.e., interconnecting with the T-South system 172 km north of FEI's Lower Mainland system)	• The revised 2-day MRPO does not change FEI's assessment of this alternative. • New regional pipeline would add resiliency by reducing single point of failure risk north of Kingsvale on the T-South system. Even if constructed, new storage would still be required to address single point of failure risk for the 172 km south of Kingsvale on the T-South system. The amount of new storage required would be reduced if FEI adopted a 2-day MRPO.	N/A
	SCP Expansion to Huntingdon	• The revised 2-day MRPO does not change FEI's assessment of this alternative. • New regional pipeline adds resiliency by diversifying supply into the Lower Mainland. Some gas will still be available if there is a failure on one pipeline system (T-South or expanded SCP). However, even if constructed, new storage would still be required to supplement remaining pipeline flows and avoid significant load shedding. The amount of new storage required would be reduced if FEI adopted a 2-day MRPO.	N/A

Resiliency Elements	Alternatives	Assessment – 2-day Condition	Ranking
Storage	Contract Additional Off-System Storage	• The revised 2-day MRPO does not change FEI's assessment of this alternative. • Required off-system storage would be less with 2-day MRPO, but the remaining single point of failure risk is unchanged. • Contracting additional off-system storage would still leave FEI subject to single point of failure risk, since FEI would remain dependent on the T-South system to access the storage resource. (Access to JPS and Mist is only by displacement and the displacement commercial transactions require physical flows on the T-South system.)	N/A
	On-System Underground Storage	• The revised 2-day MRPO does not change FEI's assessment of this alternative. • This alternative is not feasible within the FEI service territory.	N/A
	On-System Storage at a New Site	• The revised 2-day MRPO does not change FEI's assessment of this alternative. • The required storage would be less with 2-day condition, but the drawbacks to this alternative are unchanged. • This alternative would provide resiliency but is more costly than expansion at an existing brownfield site, and would require construction of liquefaction in addition to storage and regasification. FEI does not think that further development of this alternative, when compared to the options on the existing Tilbury site, would be a prudent use of funds or resources.	N/A
	Use the Existing Base Plant Storage (including regasification) and Add Additional Storage	• This alternative would potentially meet the revised 2-day MRPO; however, this alternative would not leverage the economies of scale of a single, larger tank. It would be more costly over time because the existing Base Plant facilities would still require replacement within the useful life of the new tank.	2
	On-System Storage at Tilbury (<2 Bcf)	• On-System storage at Tilbury (<2 Bcf) would meet the revised 2-day MRPO. • It would, however, provide less of a resiliency benefit compared to the proposed TLSE Project with only marginal cost savings.	1
	On-System Storage at Tilbury (>3 Bcf)	• The revised 2-day MRPO does not change FEI's assessment of this alternative. • The 2-day condition does not change FEI's assessment that there are diminishing economies of scale beyond 3 Bcf due to constructability challenges.	N/A

1

As altering the MRPO does not change the feasibility of most of the Step One Alternatives, FEI does not believe any alternative merits further consideration. The only alternatives which would become feasible from a resiliency perspective due to the changed MRPO are "Use the Existing Base Plant Storage (including regasification) and Add Additional Storage" and "On-System Storage at Tilbury (<2 Bcf)".

The former alternative would potentially meet the revised 2-day MRPO; however, the costs and drawbacks remain unchanged. In particular, the requirement to replace the existing Base Plant tank during the life of the new storage tank makes this alternative more costly overall than constructing a new, larger storage tank.

The latter alternative would provide less of a resiliency benefit with only marginal cost savings, and would not allow for ancillary benefits.

16.30 If the minimum resiliency planning objective criteria were changed to avoiding a pressure collapse in the LML, please provide a table ranking the Step 1 Alternatives based on cost, benefits drawbacks and ability to withstand pressure collapse during a no-flow event.

16.30.1 In this scenario, please explain which of the Step 1 Alternatives would merit further consideration, given the costs and benefits.

Response:

FEI considers "avoiding a pressure collapse in the LML" to be the same as the MRPO. The MRPO was defined by considering the length of a no-flow event which FEI must be able to withstand to prevent a pressure collapse on its system. Therefore, this does not entail an actual change to the MRPO, but simply re-states it. For this reason, the feasibility and ranking of Step 1 Alternatives would be unchanged; only the Step Two alternatives (i.e., on-system LNG storage tank sizes between 2 and 3 Bcf) can meet the MRPO.

17.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1-4, Section 1.2.2.1, p. 7; Section 4.3.3, p. 83

Combinations of Step 1 Alternatives

On page 7 of the Updated Public Application, FEI shows Table 1-1: Summary of Step One Alternatives Considered to Meet Minimum Resiliency Planning Objective.

17.1 Please explain whether any combinations of the non-feasible alternatives listed in Table 1-1 would meet the minimum resiliency planning objective.

17.1.1 If yes, please provide an estimated cost of the combined alternatives.

17.1.2 If not, please explain which combination of the non-feasible alternatives would get closest to meeting the minimum resiliency planning objective and how close it would be. Please also provide an estimated cost of this combined alternative.

<u>Response:</u>

FEI has not identified a combination of non-feasible alternatives that would meet or almost meet the MRPO at a lower cost than the proposed TLSE Project.

Load Management alternatives (such as Advanced Metering Infrastructure) are not supply-side solutions, so by definition would not add any supply or storage in the Lower Mainland region; hence, load management would not contribute to meeting the MRPO. As such, the only remaining options would be a potential combination of new storage and/or pipeline(s).

During the Step 1 screening of feasible alternatives to meet the MRPO, FEI took into account that the MRPO applies to a specific service area (the Lower Mainland), which has unique constraints associated with its upstream supply resources. Given the configuration of the T-South system, FEI does not consider the T-South Expansion or the SCP Expansion to Kingsvale to be viable ways to meet the MRPO as the Lower Mainland would still be exposed to significant customer outages due to T-South no-flow events occurring between Huntingdon and Kingsvale.

As such, the only remaining alternatives that would enable FEI to meet the MRPO would be the proposed TLSE Project, the On-System Storage at a New Site alternative, or the SCP to Huntingdon pipeline alternative. The latter two alternatives are more costly and more complex than the TLSE Project, and thus are considered uneconomic in meeting the MRPO. An SCP to Huntingdon pipeline solution is better suited for providing resiliency in the period following a no-flow event, rather than as a means of withstanding the no-flow period itself.

On page 83 of the Updated Public Application, FEI states: “In 2021, FEI expects to file an application for a CPCN to install AMI. The AMI project would implement an AMI network that will deliver improved information about natural gas consumption and pipeline operating conditions to FEI and its customers… AMI will also help FEI keep the natural gas system pressurized, thereby reducing recovery time for customers that experience service interruption."

17.2 If FEI's Application for the AMI project were approved by the BCUC, please provide a discussion of whether any of the remaining Step One alternatives, or combination of alternatives, would meet the minimum resiliency planning objective.

Response:

If the proposed AMI project is approved by the BCUC, several resiliency benefits will be realized, including the ability to:

- provide near real-time demand information while also improving the ability to forecast demand through the duration of an emergency;
- monitor interruptible customers' contractual compliance to curtailments;
- monitor the impact of appeals for voluntary reductions of gas use;
- monitor distribution system endpoint pressures;
- monitor station flows and pressures and downstream demand;
- decrease demand by strategically removing firm customers from FEI's affected system to balance supply and demand and therefore reduce the risk of a pressure collapse; and
- improve the ability to re-establish service to customers once adequate supply of natural gas is made available for the gas system.

However, the capability to monitor and strategically decrease demand does not assist in meeting the MRPO because it would still require FEI to shut down portions of the FEI distribution system during supply emergencies, resulting in customer outages. For this reason, the availability of AMI infrastructure would not change the analysis of the Step One alternatives provided in Section 4 of the TLSE CPCN Application.

17.2.1 If none of the remaining project alternatives meets the minimum resiliency planning objective, please explain which alternative is closest to meeting the minimum resiliency planning objective and the size of the remaining gap.

Response:

As discussed in the response to BCUC IR1 17.2, AMI is not a supply-side solution, and so will not add any additional supply or storage in the Lower Mainland region, and hence would not contribute to meeting the MRPO. As such, the only remaining options for meeting the MRPO would be a potential combination of new storage and/or pipeline(s), as discussed in the response to BCUC IR1 17.1.

Consequently, the remaining gap in the resiliency of gas supply into the Lower Mainland service area would essentially be unchanged regardless of whether the AMI solution is approved or not.

18.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Workshop Transcript March 11, 2021, pp. 81, 125

Exhibit B-1-4, Section 3.4.4, p. 51; Section 5.2, p. 121

Tank Sizing and Minimum Resiliency Planning Objective

On page 51 of the Updated Public Application, FEI states:

> FEI's Minimum Resiliency Planning Objective incorporates the concept of "Having the ability to withstand, and recover from, a 3-day "no-flow" event on the T-South system without having to shut down portions of FEI's distribution system or otherwise lose significant firm load." FEI's determination that three days is an appropriate minimum planning duration for a "no-flow" emergency event was informed by the experience with the T-South Incident. In particular, FEI considered: the length of the "no-flow" event in 2018; whether or not the T-South Incident occurred in favourable or unfavourable conditions from the perspectives of resuming flows and system demand and supply; and, the time that FEI required to assess the situation and re-establish a balance between supply and demand.

On page 81 of the Workshop Transcript from March 11, 2021, Mr. Sam states:

> We have chosen a minimum three-day no-flow event based on the T-South event. Although the actually[sic] no-flow event was two days in that case, we've effectively added an additional day to our planning objective. To recognize that that event happened during relative mild weather with the associated lower system demand and the actual location of the event in favourable weather conditions at the time resulted in relatively easy access to the site to access and take the appropriate measures.

In Table 5-1 on page 121 of the Updated Public Application, FEI describes the LNG storage tank component of the project: "A 3 Bcf tank provides sufficient LNG supply at the above regasification rate to serve FEI's Lower Mainland winter design load for 3 days without depleting the entire inventory of LNG."

18.1 Please explain what size of tank would be required if the minimum resiliency planning objective was changed to:

a) a three-day no flow event on the T-South system during an average-weather three-day period (i.e. spring or fall).

b) A one-day no flow event on the T-South system, during the coldest day.

c) a two-day no flow event on the T-South system during the coldest two-day period.

d) a four-day no flow event on the T-South system during the coldest four-day period.

For each alternative, please explain the impacts to the cost of the project, at a high level.

Response:

For each of the storage size alternatives below, FEI has assumed that sufficient vapourization capacity (800 MMcf/day) is installed to meet peak load demands. As such, the four scenarios only differ in the length of time for which they would be able to meet the cumulative customer demand during the requested period.

a) If the MRPO was changed to a three-day no-flow event on the T-South system during an average-weather three-day period (i.e., spring or fall), the required tank size would be approximately 1 Bcf. However, as the table below shows, FEI would have to curtail a significant portion of the Lower Mainland demand if a three-day no-flow event occurred in the winter season.

(Bcf)	Average 3-Day Demand (2019/20 Design Year)
Spring (Mar to May)	0.89
Summer (Jun to Aug)	0.33
Fall (Sep to Nov)	0.76
Winter (Dec to Feb)	1.43

b) If the MRPO was changed to a one-day no-flow event on the T-South system during the coldest day (i.e., peak day), the required tank size would be approximately 1 Bcf, based on the 2019/20 design load forecast.

(Bcf)	The Coldest Day Demand (2019/20 Design Year)
Peak Day	0.86

c) If the MRPO was changed to a two-day no-flow event on the T-South system during the coldest two-day period, the required tank size would be slightly greater than 1.5 Bcf, based on the 2019/20 design load forecast.

(Bcf)	2-Day Demand (2019/20 Design Year)
Coldest 2-Day Period	1.55

d) If the MRPO was changed to a four-day no-flow event on the T-South system during the coldest four-day period, the required tank size would be around 3 Bcf, based on the 2019/20 design load forecast.

(Bcf)	4-Day Demand (2019/20 Design Year)
Coldest 4-Day Period	2.83

The table below provides a comparison of estimated capital costs for each of the tank sizes described in the scenarios above. Please refer to the response to BCUC IR1 16.27 for the complete financial comparison in terms of cost of service for each tank size over a 67-year period. Please also refer to BCUC IR1 46.2 for discussion on the benefits from the additional 1 Bcf of storage (i.e., the "third Bcf") in terms of avoided gas supply costs from the market through commercial arrangements.

Tank Size	1 Bcf	1.5 Bcf	3 Bcf
Total Project Capital Costs, 2020 dollars ($ millions)	492	547	637

18.2 In the event of a no-flow event on T-South system lasting greater than 3 days, please discuss how FEI would respond if the tank was sized at (i) 2 Bcf and (ii) 3 Bcf.

18.2.1 In the event of a no-flow event on T-South system lasting greater than 3 days, please discuss when hydraulic collapse would be expected to occur if the tank was sized at (i) 2 Bcf and (ii) 3 Bcf.

Response:

FEI would respond similarly whether the tank was sized at 2 or 3 Bcf.

One of the key benefits of the TLSE Project is that it "buys time" for FEI to gather information, assess the situation, and make and execute a plan to address the emergency event. The only difference between a 2 and 3 Bcf tank, in terms of resiliency, is the amount of time the tank would provide before FEI would be forced to execute a controlled shutdown. Given that the exact circumstances (e.g., available gas supply, customer demand, subsequent weather forecast, etc.) for a given no-flow event would not be known until the event occurs, it is difficult for FEI to determine exactly how much longer that supply to customers could be maintained. However, assuming a no-flow event occurs during near design day temperatures, the 3 Bcf tank would be able to meet the Lower Mainland load by one additional day compared to the 2 Bcf tank, before the potential of a hydraulic collapse.

Notwithstanding these uncertainties, a 3 Bcf tank would be preferred to a 2 Bcf tank from a resiliency standpoint because it would provide 50 percent more storage and allow FEI to maintain service to customers for as long as possible.

19.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1-4, Section 4.3, pp. 94, 103, 117

Workshop Transcript March 11, 2021, pp. 173, 223, 225

Gasification Capacity

On page 94 of the Updated Public Application, FEI explains regasification sizing:

> Regasification should be determined with reference to peak demand: System capacity planning for infrastructure is typically done with reference to the design peak demand to ensure adequate delivery to the customer. In this case, "capacity" refers to the capability of regasification equipment to convert stored LNG back into gas for use by customers. This conversion rate is driven by the need to serve the customer's peak demand and hence, regasification capacity is directly related to the overall design peak demand. For this reason, the discussion of regasification capacity focuses on the extent to which it can serve overall design peak demand in the Lower Mainland.

Footnote 87 on page 94 of the Updated Public Application defines the term 'design year': "Design demand represents the expected customer demand in a very cold year. The coldest day in a design year is referred to as the peak day.

On page 103 of the Updated Public Application, FEI states its optimal sizing of regasification: "800 MMcf/day significantly reduces the risk of widespread outages by covering the Lower Mainland daily demand on all but one day in the design year."

On page 117 of the Updated Public Application, FEI states: "The load duration curves for sales customers (Rate Schedule 1 to 7 customers plus Firm Rate 14 Schedules 23 and 25) were used to assess the required emergency supply from Tilbury LNG. A load duration curve is a graphic representation of customer daily demand over a weather year."

19.1 Please explain why FEI included Rate Schedule 7 customers in its calculation of load duration curves for the required emergency supply for Tilbury LNG.

19.1.1 Please explain how the load duration curves would alter if Rate Schedule 7 customers were excluded.

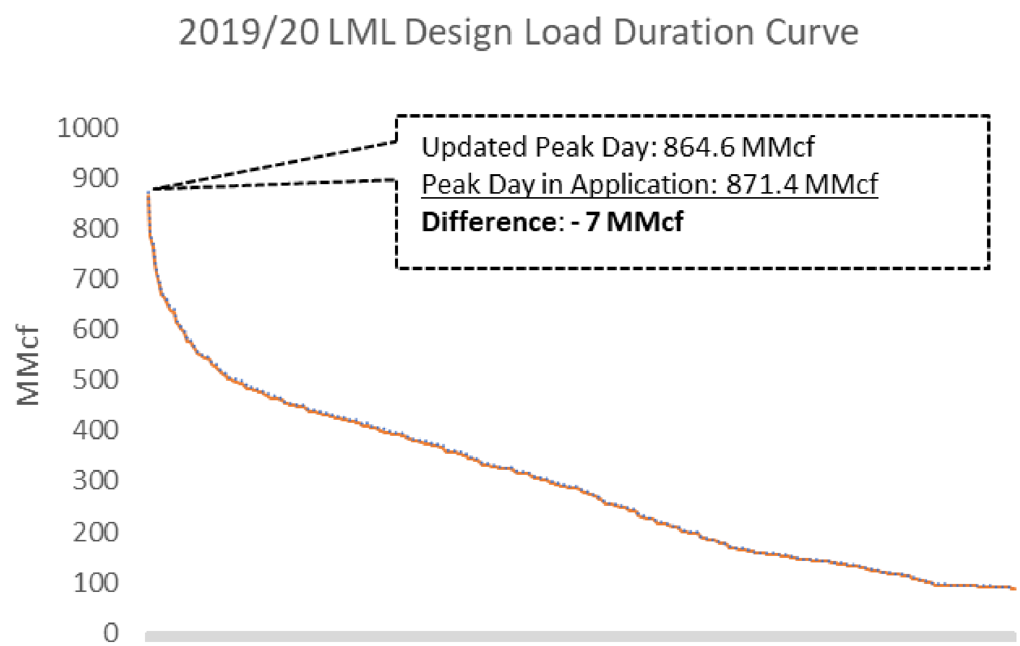
Response:

FEI confirms that the inclusion of Rate Schedule (RS) 7 and Whistler demand in the load duration curves does not result in a material change. Nonetheless, FEI explains why RS 7 and Whistler were included and quantifies the impact of excluding that demand below.

FEI's design load forecast is developed for sales customers (Rate Schedules 1 through 7) as one group, and does not separate RS 7 customers from the load duration curve, which is why RS 7 load was included in the calculation of the load duration curves. FEI noted in the TLSE Workshop that the design load duration curves included in the Application contained RS 7 as well as Whistler demand and that it would address the inclusion of RS 7 and Whistler demand in the IR process.[37]

For context, the design load forecast used for the TLSE Project contained in the Application was developed at the beginning of 2019, which includes an immaterial amount of RS 7 demand and a minor amount of Whistler demand. Based on the average load from the gas year 2015/16 to 2017/18, FEI estimates the daily load for RS 7 customers to be between 0.08 and 0.92 MMcf per day and the daily load for Whistler customers to be between 1 and 7 MMcf per day.

FEI has provided a revised load duration curve below which shows the updated design load forecast for the gas year 2019/20 excluding RS 7 and Whistler customers. The revised design load forecast shown below is slightly lower than the previous forecast. The daily load difference is in the range of 1 to 7 MMcf per day. The peak day forecast for the Lower Mainland is approximately 7 MMcf lower than the previous forecast used in the Application.



19.2 Please explain whether FEI considers it would be reasonable to size regasification capacity for peak load minus voluntary curtailment.

19.2.1 Please explain what size of regasification would be required in the above scenario.

[37] Transcript Volume 1, pp. 175-176.

Response:

FEI did not consider it reasonable to rely on voluntary curtailment in sizing the regasification capacity for the TLSE Project because (a) it would mean disrupting customers who require firm service (i.e., need a consistent gas supply) and (b) FEI cannot plan on the assumption that voluntary curtailment will be successful. As discussed in the response to BCUC IR1 13.3, the majority of FEI's customers' energy use during cold weather is for space heating and hot water, which is vital to their health and safety. Therefore, the non-discretionary nature of this load imposes inherent limitations on the extent to which load can be managed and relied upon during a supply emergency.

Given the uncertainties in how much load could or would be voluntarily curtailed, and whether it would be curtailed quickly enough, FEI does not consider it reasonable to size regasification capacity for peak load minus voluntary curtailment.

Regarding sizing of the regasification capacity, in the Workshop Transcript from March 11, 2021 on page 173, Mr. Hill states: "We did look at in the application the 600 range, but we decided in the end to go to the 800. The main reason for that is consistently we have days in the winter period over the 600. And, as an example, in the 2016/2017 year, which is close to our design year, we had 15 days or 16 days above 600."

On page 223 of the Transcript, Mr. Leclair states: "TLSE does require the CTS expansion in order to inject energy back into our system. And in addition, the Tilbury 1B expansion also requires the CTS expansion in order to deliver the natural gas to the facility in order to liquefy at that capacity."

And on page 225 of the Transcript, Mr. Leclair states: "So the CTS, the two to three kilometre CTS expansion was previously approved, I believe through the 2015 OIC amendment."

19.3 Please explain whether a 600 MMcf/day regasification could support the Lower Mainland during a three-day no flow event on T-south during (a) the coldest days of the design year; (b) the average days of the design year; (c) the coldest day of an average year; (d) the coldest day of a warm year; (e) the average day of an average year.

Response:

For context, as discussed in greater detail in Section 4.4.2 of the Application, FEI determined that 800 MMcf/day of regasification capacity is sufficient to cover the Lower Mainland daily load in a design year except for the peak day. In addition to daily load requirements, FEI also determined the regasification capacity based on the optimal number of vaporizers (four 200 MMcf/day units) to provide necessary coverage during a complete T-South outage and to provide ancillary benefits to support future load growth. Further, four units provides reliability benefits if there is a problem/issue with one of the regasification units.

In response to scenario (a), the following table indicates that 600 MMcf/day of regasification capacity could not support the Lower Mainland if a no-flow event on T-South occurred on the coldest days of the design year 2019/20.

(MMcf/day)	2019/20 Design Load (LML RS1-6, RS23, RS25)	Tilbury Regasification Capacity	Deficiency
Peak Day	865	600	(265)
2nd Coldest Day	786	600	(186)
3rd Coldest Day	762	600	(162)
4th Coldest Day	730	600	(130)
5th Coldest Day	711	600	(111)
6th Coldest Day	686	600	(86)
7th Coldest Day	669	600	(69)
8th Coldest Day	662	600	(62)
9th Coldest Day	656	600	(56)
10th Coldest Day	640	600	(40)
11th Coldest Day	637	600	(37)
12th Coldest Day	636	600	(36)
13th Coldest Day	614	600	(14)
14th Coldest Day	610	600	(10)
15th Coldest Day	601	600	(1)

In response to scenario (b), FEI considers the median load to be a reasonable characterization of the average load for each season of the design year 2019/20. The following table shows that 600 MMcf/day of regasification capacity could support the Lower Mainland on average days of the design year 2019/20 during a 3-day no-flow event on the T-South system.

(MMcf/day)	2019/20 Design Load (LML RS1-6, RS23, RS25)	Tilbury Regasification Capacity	Adequacy
Median Load (Dec to Feb)	481	600	119
Median Load (Mar to May)	294	600	306
Median Load (Jun to Aug)	113	600	487
Median Load (Sep to Nov)	259	600	341

In response to scenario (c), FEI considers a normal year to be a reasonable characterization of the average year. The following table shows that 600 MMcf/day of regasification capacity could not support the Lower Mainland on the coldest days of the 2019/20 normal year during a 3-day no-flow event on the T-South system.

(MMcf/day)	2019/20 Normal Load (LML RS1-6, RS23, RS25)	Tilbury Regasification Capacity	Deficiency
The Coldest Day	673	600	(73)
2nd Coldest Day	646	600	(46)
3rd Coldest Day	633	600	(33)
4th Coldest Day	616	600	(16)
5th Coldest Day	612	600	(12)

In response to scenario (d), FEI identified 2014/15 as a warm year in the past 10 years. The following table shows that 600 MMcf/day of regasification capacity could support the Lower Mainland on the coldest days of a warm year during a 3-day no-flow event on the T-South system. However, the actual load of the coldest two days of the 2014/15 gas year (i.e., a “warm year”) was very close to 600 MMcf/day.

(MMcf/day)	2014/15 Actual Load (LML RS1-6, RS23, RS25)	Tilbury Regasification Capacity	Adequacy
The Coldest Day (Warm Year 2014/15)	599	600	1
2nd Coldest Day (Warm Year 2014/15)	597	600	3

In response to scenario (e), FEI considers a normal year to be a reasonable characterization of the average year. The following table shows that 600 MMcf/day of regasification capacity could support the Lower Mainland on the average days of the normal year 2019/20 during a 3-day no-flow event on the T-South system.

(MMcf/day)	2019/20 Normal Load (LML RS1-6, RS23, RS25)	Tilbury Regasification Capacity	Adequacy
Median Load (Dec to Feb)	438	600	162
Median Load (Mar to May)	259	600	341
Median Load (Jun to Aug)	97	600	503
Median Load (Sep to Nov)	229	600	371

19.4 Please explain whether a 600 MMcf/day regasification at Tilbury would require the expansion to the CTS pipeline quoted in the preamble.

Response:

An expansion of the CTS pipeline quoted in the preamble is required. The existing sendout pipeline connecting the Tilbury site to the FEI transmission system is a 323 mm pipeline. With the proposed Tilbury vapourizers injecting at the maximum operating pressure of 4020 kPa, this pipeline could only deliver just over 350 MMcf/day into the CTS. Above that rate the gas velocity in the existing pipeline would be unacceptably high. To deliver more gas volume would require exceeding the MOP of the pipeline at the Tilbury Site.

Under the CTS Tilbury Expansion approved under Direction No. 5, the following was approved:

> (d) the project to expand the transmission facilities of FortisBC Energy Inc. at and between the Tilbury Gate Station and Tilbury LNG Facility

Execution of this portion of the CTS Tilbury Expansion Project, the construction of a new 762 mm pipeline connecting Tilbury Gate Station and the Tilbury LNG Facility, will be required to support either 600 MMcf/day or the full 800 MMcf/day regasification at Tilbury.

19.5 Please explain the impact to the project costs if a 600 MMcf/day regasification was used instead of the proposed 800 MMcf/day.

Response:

The cost reduction associated with reducing the regasification capacity from 800 MMcf/day to 600 MMcf/day would be the reduction of one vapourizer and sendout pump plus the electrical components associated with the single vaporizer.

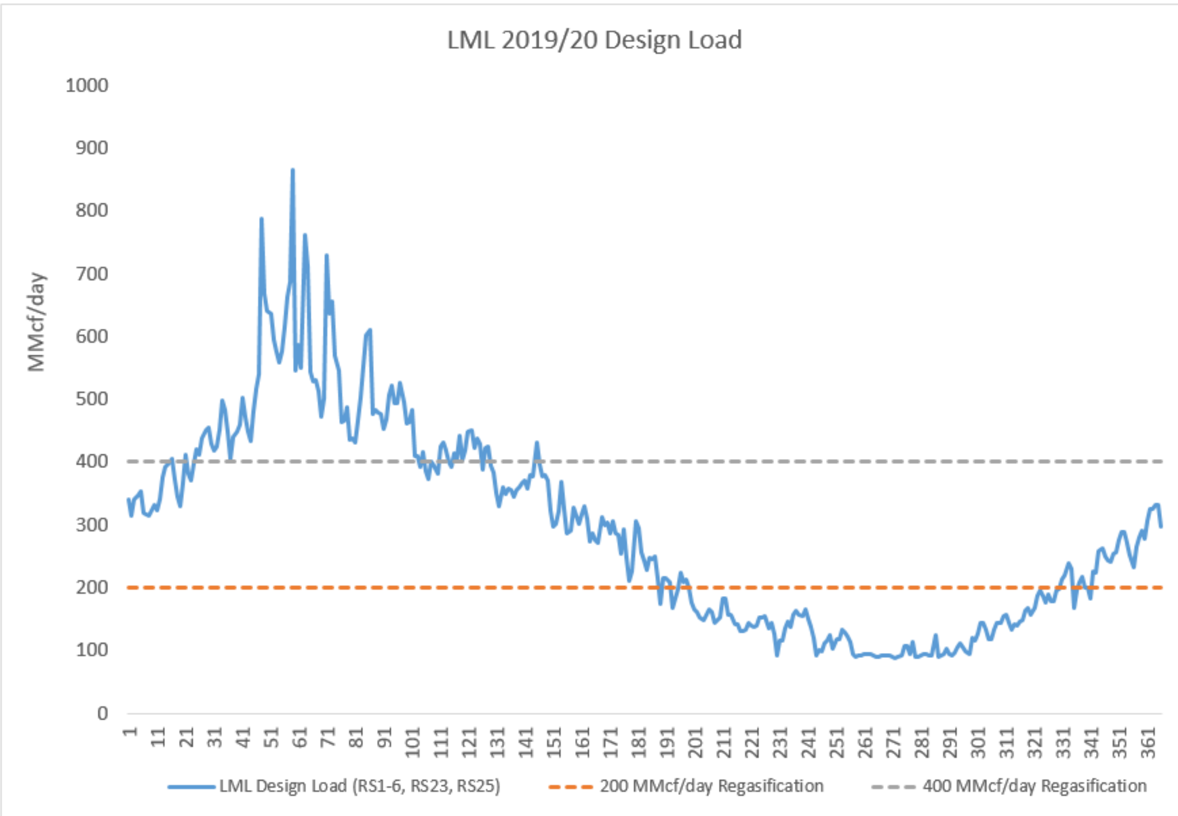
The estimated cost reduction is shown in the following table.

Description	Total ($ millions)
200 MMcf/day Vaporizer	
Vaporizer Equipment and Materials including Send out pump	11.0
Vaporizer Installation	2.3
Electrical/ Instrumentation and Controls	0.5
Indirect Costs	2.9
AFUDC	1.4
TOTAL	**18.1**
High Range (+30%)	**23.5**
Low Range (-20%)	**14.5**

19.6 Please explain whether smaller capacities, such as 200 MMcf/day or 400 MMcf/day, regasification were considered. If not, please explain why.

Response:

As the following figure illustrates[38], a lower regasification capacity (such as 200 or 400 MMcf/day) would not meet the load requirements during a significant part of the year, and would therefore not provide resiliency to the system.



FEI undertook a capacity analysis to determine the optimal sizing of the regasification for the TLSE Project. As stated in Section 4.4.2.2 of the Application, design demand represents the expected customer demand in a very cold year. The coldest day in a design year is referred to as the peak day. FEI used design demand over the last 10 years to determine the design regasification capacity. FEI selected this criterion as the intent is to ensure that peak demand can be served without having to resort to firm customer curtailments or load shedding.

As discussed in the response to BCUC IR1 19.1, the updated design peak demand for the Lower Mainland is 865 MMcf/day for 2019/20. FEI notes that the load duration curve declines, such that the second coldest day on the design load duration curve is 786 MMcf/day. These figures demonstrate that a regasification capacity of 800 MMcf/day is adequate to support the Lower Mainland load during a T-South no-flow event even if it occurred on the coldest days of the winter, with the exception of the single peak design day. Regasification capacity at this level is reasonable given the remote probability of a no-flow event occurring simultaneously with the design peak day.

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[38] Note that interruptible customers (i.e., Rate Schedule 7, 27, 22) are not included in the referenced demand curves.

20.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1-4, Section 1.4, pp. 8–9

Alternatives Not Considered

Recent developments in LNG storage and regasification options are emerging, for example, as outlined in an Econnect Energy Article[39]:

> In 2017, the PFLNG [Petronas Floating LNG] Satu became the world's first water-based combined production, liquefaction, storage and transfer plant. Since first introduced, the capacity of LNG transferring ships have also seen huge development, now ranging up to Qmax size. The most common process in FLNGs is the PRICO process, using a single mixed refrigerant to achieve train sizes that are as small as 0,6mtpa and easy to modularize. The process is used both in Exmar Tango FLNG, the Golar Hilli Episeyo FLNG in Cameroon and in the new Tortue project for Mauritania... Floating storage and regasification units (FSRU) have been operating since the mid-2000s but experienced a major increase in fleet size since 2015. They receive, store, and regasify LNG before transferring it in a gaseous state to the consumers.

20.1 Please explain whether FEI has considered the feasibility any of the below alternatives to address system resiliency. Please also discuss the pros and cons of each alternative.

a) Floating LNG storage and regasification (FSRU) or Floating LNG storage (FLNG) and land-based regasification;

Response:

FEI did not consider FLNG or FSRU as viable alternatives.

Floating LNG facilities are often used to take advantage of offshore natural gas fields. These facilities can process, liquefy, store and transfer LNG, which would otherwise be difficult to access. In this case, however, FEI plans to liquefy natural gas from its own transmission system. It is far more efficient to store LNG at or near the location that it is produced, and FEI has adequate space at its existing Tilbury site to construct a new storage tank adjacent to its liquefaction facilities. Similarly, it is more efficient to regasify LNG in close proximity to both the LNG storage and to the system into which the gas will be injected. FEI's Tilbury site is adjacent to its transmission pipeline system and near major load centers, making it an optimal location for storage and regasification.

An expansion of FEI's land-based facility, which will occur entirely on FEI's existing property, will be much less expensive and less complex than construction of a new, floating facility with LNG and natural gas transportation to and from the offshore structure. FEI sees no benefits to this

[39] https://www.econnectenergy.com/articles/how-can-we-expect-lng-technology-to-change-during-the-next-decade.

approach but only significant added costs, complexity, and risk to the Project. For these reasons, FEI does not consider this alternative to merit further investigation.

b) LNG storage tank facility located in the Okanagan; and

Response:

A new LNG storage tank facility in the Okanagan region could help to support peak load in the Okanagan, but would not provide any resiliency benefits for the Lower Mainland service area. LNG storage in the Okanagan would still be reliant on the T-South system to transport this gas to the Lower Mainland. Since no-flow events can occur on the T-South system between the Okanagan and the Lower Mainland, storage in the Okanagan may not be accessible during a supply disruption event.

c) 0.6 Bcf replacement storage tank when existing Tilbury base storage tank is at end of life with new 200MMcf/d gasification (like for like replacement).

Response:

FEI clarifies that the existing Tilbury Base Plant has 150 MMcf/day of regasification capacity (refer to Figure 3-13 of the Application), not 200 MMcf/day as suggested by the question.

FEI does not consider a "like for like" replacement of the existing Base Plant to be a viable alternative to the TLSE Project. Neither the storage capacity nor the regasification capacity of FEI's existing Base Plant addresses the identified risk of a no-flow event that underlies the MRPO. The existing 150 MMcf/day of regasification capacity was designed and is sufficient to provide peak shaving to the system when required during cold winter conditions. It was not designed, and is not sufficient, for a no-flow event in cold weather, as this would supply less than a quarter of the peak demand, which is not enough to prevent a hydraulic collapse of the system.

20.1.1 For the alternative of an LNG storage tank facility in the Okanagan, please explain whether this alternative could also support peaking the Okanagan region, similar to the Okanagan Capacity Upgrade Project.

Response:

Please refer to the response to 20.1b).

21.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1-4, Section 4.4.1.4, p. 110; FEI 2017 Long Term Gas Resource Plan (LTRP) proceeding, Exhibit B-1-4, Appendix E, pp. 2-3

Renewable Natural Gas and LNG

On page 110 of the Updated Public Application, FEI states:

> Additionally, the 2017 LTGRP examined the impact of a number of technology advancements that could lead to a substantially decarbonized energy system, utilizing the natural gas infrastructure within the Province to continue delivering gas in a diversified energy future. A range of demand growth opportunities that reduce global GHG emissions through conversion from higher carbon emitting fuels in the transportation sector, improved energy efficiency within the built environment and lower carbon gas supplies, all in varying amounts, will make up such a low carbon energy future while maintaining a diverse and robust energy system in BC. There are a wide range of combinations of these resources that could be employed to help meet Provincial emission reduction targets, making a flexible natural gas storage and distribution system essential long into the future. A 3 Bcf tank maximizes the opportunity to meet Provincial energy needs in a cost-effective way by accommodating future growth and expanding FEI's ability to store and deliver renewable natural gas.

On pages 2-3 of Appendix E of FEI's 2017 LTGRP Application presents the following GHG reduction scenarios:

> Renewable Natural Gas (RNG) Impact
>
> This appendix assumes four speculative maximum RNG levels to be achieved by 2036. The first level assumes that FEI will reach its maximum allowance under the GGRR (5 percent of FEI's 2015 non-bypass annual demand, or approximately 8.88 million GJ at up to $30 per GJ energy supply cost) by 2036. The second through fourth levels assume that new technologies, such as cellulosic biogas, will expand the maximum attainable RNG supply up to approximately 94 million GJ by 2036…The second through fourth levels represent between approximately 25 and 46 percent of FEI's forecast 2036 Reference Case annual demand.
>
> Power-To-Gas Impact
>
> This examination assumes that electrolysers generate hydrogen which is injected into the FEI gas supply…Industry research reflects a broad range of potential maximum power-to-gas levels among the natural gas supply to be viable without significantly increasing risks to end-use appliances, public safety, or the durability and integrity of the existing pipeline networks. These levels approximately extend from 5 percent to 15 percent by volume and depend on the specific infrastructure and end-use characteristics of each jurisdiction which can vary significantly. This

appendix assumes two maximum power-to-gas levels: (1) 5 percent of 2036 forecast scenario annual demand by 2036, and (2) 15 percent of 2036 forecast scenario annual demand by 2036.

21.1 Please explain the impact of increasing hydrogen content in FEI's gas supply network on FEI's liquefaction and regasification processes.

Response:

FEI does not anticipate impacts on the TLSE Project, nor on its liquefaction process, as a result of increasing hydrogen content in the gas stream as hydrogen can be separated if introduced upstream of the Tilbury facility.

There are two potential options available to mitigate the impact on LNG operations from increasing hydrogen content in the gas system:

- hydrogen would be removed by separating it from the gas supply upstream of the LNG facility and then redirected to a different part of the gas network; or
- hydrogen would enter the LNG facility but would be extracted prior to liquefaction and stored separately onsite for use in gaseous or liquid form (e.g., for fuel cell electric vehicle refueling).

This would mitigate:

- Impacts on the rate of boil-off gas generation from the LNG storage tank;
- The risk of stratification within the LNG storage tank; and
- The impact on FEI's long-term LNG storage operations.

Both options would remove the hydrogen from the gas stream prior to liquefaction and hence the LNG tank would continue to only store liquid natural gas. As such, there are no increased capital or operating costs included in the TLSE Project associated with the future use of hydrogen in FEI's gas supply network.

21.2 Please explain the impact of increasing hydrogen content in FEI's gas supply network on FEI's long-term LNG storage operations.

21.2.1 Please discuss how increased hydrogen content in FEI's gas supply network impacts the rate of boil-off gas generation from the LNG storage tank.

21.2.2 Please explain the impact increased hydrogen content in FEI's gas supply network has on the risk of stratification within the LNG storage tank, and how FEI has accounted for this in its design.

21.2.3 Please explain whether the capital and operating costs presented in this Application account for any impact of increased hydrogen content in FEI's gas supply network.

Response:

Please refer to the response to BCUC IR1 21.1.

21.3 Please explain how the overall gas composition within FEI's gas supply network is expected to change as the supply of RNG increases.

21.3.1 Please discuss whether FEI expects a greater concentration of nitrogen in its gas supply network as the supply of RNG increases.

21.3.1.1 If so, please discuss the impact of increasing nitrogen content in FEI's gas supply network on FEI's liquefaction and regasification processes.

21.3.1.2 Please discuss the impact of increasing nitrogen content in FEI's gas supply network on FEI's long-term LNG storage operations.

21.3.1.3 Please discuss how increased nitrogen content in FEI's gas supply impacts on the rate of boil-off gas generation from the LNG storage tank.

21.3.1.4 Please explain the impact increased nitrogen content in FEI's gas supply network has on the risk of stratification within the LNG storage tank and how FEI has accounted for this in its design.

21.3.2 Please explain whether the capital and operating costs presented in this Application account for any potential impacts of increased nitrogen content in FEI's gas supply network.

Response:

Currently, conventional natural gas can contain approximately 0.3 percent nitrogen by volume. Nitrogen content in RNG (biomethane) can vary and those sources with more than 1 percent nitrogen could create an issue for LNG processes if the nitrogen reached high enough concentrations; however, FEI does not expect nitrogen content to become an issue for a number of reasons, including:

- First, nitrogen content above 1 percent by volume is limited to landfill gas projects whereas other existing and future biomethane facilities are able to produce RNG with less than 1 percent nitrogen content by volume.
- Second, there are limited landfill gas projects in the vicinity of the Tilbury LNG facility and the gas from those projects is not expected to reach the plant. The City of Vancouver landfill is the largest in BC and FEI expects to acquire RNG from two planned biomethane facilities at that landfill that would be injected into the local transmission pressure network but the RNG will not physically flow across the gas system to the Tilbury LNG facility. Therefore, considering there are only a few other relatively small landfills in BC there is very low risk of RNG constituents such as nitrogen changing the overall gas composition within FEI's gas supply network as the supply of biomethane increases.
- Third, FEI manages nitrogen content within its biomethane (RNG) specification, which is intended to ensure the chemical composition and constituent breakdown of RNG supplied on-system is compatible with conventional natural gas. The biomethane specification is an important technical reference in terms of FEI's renewable gas supply growth strategy going forward. It allows up to 4 percent by volume inert gases in the final RNG from biomethane facilities; nitrogen is included within this limit.

FEI considers the risk of increased nitrogen to be negligible, including:

- Greater concentration of nitrogen in its gas supply network as the supply of RNG increases;
- Any impact of increasing nitrogen content in FEI's gas supply network on FEI's liquefaction and regasification processes;
- Any impact of increasing nitrogen content in FEI's gas supply network on FEI's long-term LNG storage operations;
- Any impact from increased nitrogen content in FEI's gas supply on the rate of boil-off gas generation from the LNG storage tank; and
- Any impact from increased nitrogen content in FEI's gas supply network on the risk of stratification within the LNG storage tank and how FEI has accounted for this in its design.

As such, there are no increased capital or operating costs included in the TLSE Project associated related to the presence of nitrogen in FEI's gas supply network.

21.4 Please elaborate on how the TLSE Project will reduce greenhouse gas (GHG) emissions by providing specific examples of reductions that will result from the TLSE Project.

Response:

As discussed in Section 4.3.5.6 of the Application, the TLSE Project will incorporate modern design standards which minimize the potential for venting of methane to the atmosphere, thus decreasing the potential release of greenhouse gases. Please also see Sections 5.3.1.3 and 5.3.2.5 which discuss venting in more detail.

The primary purpose of the TLSE Project is to enhance the resilience of FEI's gas delivery system and as such, the Project on its own will not significantly reduce greenhouse gas emissions in BC.

However, the TLSE Project is a key addition to FEI's gas delivery system, which has a significant role in reducing emission in BC. FortisBC's climate plan, the *Clean Growth Pathway to 2050*[40] defines the actions which FortisBC is taking to reduce emissions in BC, including supporting the conversion from higher carbon emitting fuels in the transportation sector, improving energy efficiency within the built environment and increasing renewable gas supply. As noted in the preamble and as discussed in more detail in the response to BCUC IR1 63.1, the TLSE Project is capable of storing and delivering renewable gas to its customers. As noted in Section 4.4.1.5.1 of the Application, FEI believes energy storage is an increasingly valuable function, particularly as both gas and electric grids incorporate increasing amounts of renewable energy from intermittent sources.

[40] clean-growth-pathway-brochure.pdf (fortisbc.com).

22.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1-4, Section 4.4.1.5.3, pp. 112-113, Section 5.3.1.4, p. 127

Ancillary Benefits – Daily Balancing Capability

On pages 112 and 113 of the Updated Public Application, FEI states:

> One of four things must happen to keep the system in balance: (1) Westcoast refrains from enforcing the 5 percent limit; (2) FEI sheds load by interrupting service to interruptible customers; (3) FEI isolates the VITS to reduce flow and uses limited line pack to meet the load; or (4) FEI injects supply from Tilbury or Mt. Hayes…
>
> FEI has received occasional requests from Westcoast to reduce peak hourly flows to keep within the 5 percent rule… Short of shutting-in customers to reduce demand, the use of on-system supply from Tilbury would be the preferred and most reliable solution to address this operational need. Therefore, the construction of storage above the minimum requirement at Tilbury enhances FEI's ability to meet OBA balancing obligations.

On page 127 of the Updated Public Application, FEI states:

> Construction of additional liquefaction is not within the scope of the TLSE Project. Rather, the 3 Bcf LNG tank will be filled using reserve capacity (approximately 5 MMcf/day) from the Tilbury 1A LNG liquefaction system, which has been reserved for utility use, including for peak shaving, emergency depletion, and replacement of LNG lost as boil off gas.

22.1 Please clarify how FEI prioritizes the four methods for daily balancing listed above.

Response:

There are a number of variables that contribute to the daily decisions made by FEI in order to balance the system. Under normal operating and weather conditions, FEI's off-system storage resources (Aitken Creek, JPS, and Mist) are prioritized first in managing the daily balancing requirements of the system. FEI's on-system LNG resources can help with daily balancing; however, given the smaller storage size of these assets, their utilization is prioritized for cold weather events and/or emergency purposes.

The four load balancing scenarios cited in the preamble above come into consideration during periods of operational constraints (i.e., supply reductions) or extreme cold weather conditions. There is no single method of prioritization. Decisions are dependent on a number of factors, including but not limited to the:

- time of year;
- off-system storage inventory levels from an FEI and regional perspective;
- operational constraints; and
- location of the extreme weather condition.

22.2 Please discuss the approximate LNG regasification capacity (in MMSCFD) currently required to accomplish daily balancing by injecting supply from Tilbury and/or Mt. Hayes.

Response:

FEI does not have the approximate amount of LNG regasification capacity required to accomplish daily balancing from Tilbury and Mt. Hayes, because that is not the primary purpose for these resources. The Tilbury Base Plant and Mt. Hayes facilities were designed and intended primarily for peak weather events and/or operational purposes such as emergency events. As discussed in the response to BCUC IR1 22.1, FEI prioritizes its off-system resources for daily balancing purposes over on-system LNG.

22.2.1 Please provide the approximate maximum LNG regasification capacity required to accomplish daily balancing over the next 10 years, assuming FEI proceeds with its preferred and most reliable daily balancing solution.

Response:

Please refer to the responses to BCUC IR1 22.1 and 22.2.

22.3 Please explain whether the existing regasification capacity at Mt Hayes and Tilbury are adequate to meet maximum daily balancing supply over the next 10 years.

Response:

Under normal operating conditions such that all supply resources in the region are available, the existing regasification capacity at Mt. Hayes and at Tilbury are adequate to meet maximum daily balancing supply over the next 10 years. This is because FEI has other resources in its gas supply portfolio to help balance supply, including off-system storage. If supply resources are disrupted, and FEI only has the Tilbury Base Plant to balance the daily Lower Mainland supply, the limitation would be the amount of energy available in the 0.6 Bcf storage tank. Under this type of scenario, the limited storage volume at Tilbury would play a more significant role than FEI's existing regasification capacity.

22.4 Please explain to what degree FEI's minimum resiliency planning objective can be met if a new 2 BCF LNG tank is constructed and volume from this tank is used to meet daily balancing needs.

Response:

If a 2 Bcf LNG tank were constructed instead of 3 Bcf, there would be no volume available for daily balancing needs. This is because from a planning perspective the entire 2 Bcf will be reserved and retained in the tank for resiliency purposes only. The incremental 1 Bcf of storage that FEI is proposing will provide a margin above the 2 Bcf minimum resiliency requirement, and flexibility to pursue additional gas supply and operational benefits, which may include enhancing daily balancing capabilities.

22.5 Please clarify whether additional liquefaction capacity will need to be reserved for the TLSE Project should FEI pursue its preferred solution to meet daily balancing needs from the Tilbury site.

Response:

Additional liquefaction capacity will not need to be reserved. There will be an interconnection between the Tilbury 1A tank and the TLSE tank that allows FEI to utilize 5 MMcf/day of liquefaction from the new Tilbury 1A liquefier to refill the Base Plant. Given that the daily balancing from the TLSE Project would only come from the "third Bcf" of storage, the 5 MMcf/day of liquefaction will be sufficient for refilling purposes.

22.6 Please discuss whether FEI's ability to generate revenue as part of the Gas Supply Mitigation Incentive Program (GSMIP) would be affected as a result of the TLSE project.

22.6.1 Please compare the additional revenue generated as part of the GSMIP as result of a 2 Bcf tank vs a 3 Bcf tank.

Response:

The TLSE Project will reserve 2 Bcf of storage for resiliency purposes at all times, with the incremental 1 Bcf providing a margin above the minimum resiliency requirements and flexibility to pursue additional gas supply and operational planning benefits. The 2 Bcf for resiliency purposes will not generate revenue because this inventory will be held for an emergency event.

The remaining 1 Bcf of the TLSE storage may be able to generate revenue; however, FEI is unable to speculate on this opportunity at this time as it is subject to multiple factors, including the following:

- FEI has no historical data to utilize because FEI has not generated a significant amount of GSMIP revenue from the Tilbury Base Plant due to its relatively small tank size and its storage being primarily reserved for managing customer load on the coldest days of the winter or for emergency situations; and
- Market conditions in the region that help generate revenue as part of the GSMIP are constantly changing, making it difficult to foresee what revenue could be generated.

The TLSE Project is based on an identified need for system resiliency in the Lower Mainland region, and the GSMIP was not a factor in FEI proposing the need for the Project.

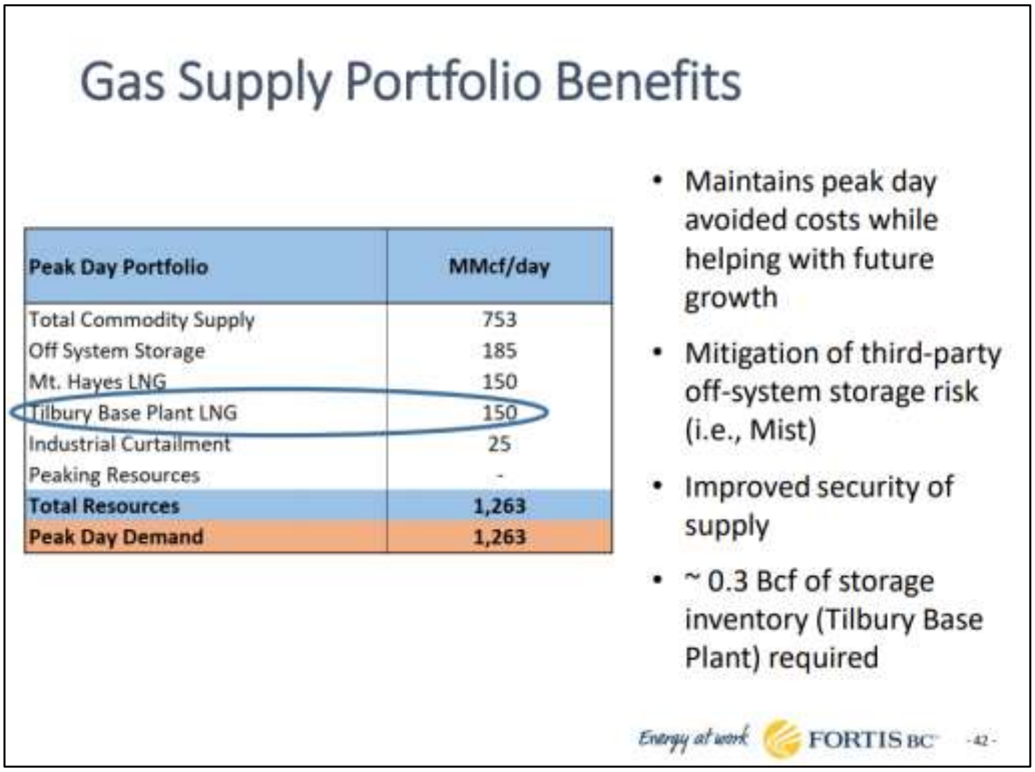
22.7 Please explain whether the proposed 3 BCF tank and regasification capacity will be used for the purposes of peak shaving. Please confirm the peak shaving capacity that is envisioned for the proposed 3 BCF tank.

Response:

The TLSE Project is a resiliency investment; therefore, the LNG storage volume and regasification capacity are intended for resiliency purposes. From a planning perspective, FEI will reserve 2 Bcf in the tank at all times. As described in Section 4.4.1.5 of the Application, the incremental 1 Bcf will provide a margin above the minimum resiliency requirement while also providing some flexibility for gas supply and operational purposes. The TLSE Project also proposes replacing the Tilbury Base Plant, which is currently part of FEI's gas supply portfolio.

As discussed at the TLSE Workshop, approximately 0.3 Bcf of storage and 150 MMcf/day of regasification capacity is currently part of FEI's gas supply resource stack (refer to the presentation slide from the Workshop below). As FEI explained at the Workshop, absent the Base Plant resource, FEI would have to find a replacement in the open market.[41] Contracting for a 150 MMcf/day peaking asset in the open market would be challenging and costly, absent new infrastructure being built, which is discussed further in the response to BCUC IR1 46.1. Given that 0.3 Bcf of storage will be required for FEI's existing gas supply portfolio, the remaining 0.7 Bcf of storage could be used to access ancillary gas supply and operational benefits in the future.

[41] Transcript Volume 1, p. 182.



Gas Supply Portfolio Benefits

Peak Day Portfolio	MMcf/day
Total Commodity Supply	753
Off System Storage	185
Mt. Hayes LNG	150
Tilbury Base Plant LNG	150
Industrial Curtailment	25
Peaking Resources	-
Total Resources	**1,263**
Peak Day Demand	**1,263**

- Maintains peak day avoided costs while helping with future growth
- Mitigation of third-party off-system storage risk (i.e., Mist)
- Improved security of supply
- ~ 0.3 Bcf of storage inventory (Tilbury Base Plant) required

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23.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1-4, Section 4.4.1.5.5, p. 115; Appendix Q-1, p. 2-1; BCUC FEI AES Inquiry, Final Report, pp. 61-62

Ancillary Benefits – Other Services

On page 115 of the Updated Public Application, FEI states:

> The construction of a new pipeline in BC will proceed when supported by load growth in the region. Additional pipeline capacity into the region could provide the opportunity for further expansion of the Tilbury site with additional liquefaction to support LNG for export…
>
> This potential scenario provides significant future optionality and a potential reduction in FEI's customer rates in the scenario where a new pipeline into the Lower Mainland is constructed that follows an entirely separate corridor from the T-South system along with an expansion at the Tilbury site…
>
> With the additional pipeline supply into the Lower Mainland, as discussed in Section 4.2.4.5 above, FEI could potentially further reduce its storage needs by entering into commercial arrangements to provide access to other contingency resources. This could potentially allow FEI to lease storage space to the export entity, thereby recovering a portion of the cost of service of the Project while maintaining an enhanced level of resiliency. Should this opportunity materialize, there is the potential to reduce FEI customers' costs; however, it is unlikely that a 2 Bcf tank under this scenario would free up enough space to take advantage of such an opportunity.

On page 2-1 of Appendix Q-1 "Initial Project Description," FEI states:

> The LNG storage tank is needed to provide security of public utility service and resiliency against possible interruptions of natural gas supply to the Region (as occurred in the winter of 2018-2019) but will also be sized and designed to have capacity to meet the future demands of the LNG bunkering and export markets. The LNG production will be built in phases of one or more 'liquefaction trains' to meet market demand. The proposed Project, also referred to as Tilbury "Phase 2", is detailed in Table 2-1 and shown in Figure 2-1.

Table 2-1 of Appendix Q-1 is reproduced below:

Table 2-1. Tilbury Proposed Phase 2 Facilities

Phase	Description	In-Service Date	Size	Owner	Key Regulator
Tilbury 2 Tank	LNG storage tank	2024	Tank: up to 162,000[1] m^3 (4.0 PJ)	FortisBC or FEI	BC EAO / IAAC Threshold: 136,000 m^3
Tilbury 2 Liquefaction	LNG liquefaction trains	2024-2028	Up to 11,000 t/d	FortisBC	IAAC Threshold: 3,000 t/d

On pages 61 to 62 of the BCUC's FEI AES Inquiry Report states:

> In the case of LNG activities, other than for a Prescribed Undertaking, the Commission recommends that that if FEU [FortisBC Energy Utilities] wish to participate in this market, they do so through a separate Non-Regulated Business. The Commission Panel considers that the public interest will be best served by ensuring that all participants in the nascent LNG market (other than utility participants doing so as Prescribed Undertakings) be non-regulated entities so the existence of a dominant player and the additional costs which flow from regulation do not impede the competitive market. The Panel further finds that public interest considerations in respect of LNG include protection of the traditional natural gas distribution customers from excessive rates that may result from cross-subsidization and from taking business risks which ought to be borne by participants in a competitive market. The potential risks from LNG Service are exacerbated by the large capital investment required for LNG infrastructure…
>
> In all cases, if FEU have excess capacity to supply LNG and/or tanker service, the FEU should supply that LNG at the higher of the market price or the fully allocated cost of service. This upholds the guideline that "[a]n approved Code of Conduct and Transfer Pricing Policy should govern interactions between the Regulated Business and any Unregulated Affiliated Business and should include the following features:
>
> a. minimal sharing of resources – at the level of corporate services only; and
>
> b. use of the full cost to provide the service or market pricing, whichever is higher.

23.1 Please confirm, or explain otherwise, that the 3 BCF tank being proposed as part of the TLSE Project is the storage tank for the Tilbury Phase 2.

23.1.1 If yes, please discuss the volume from the proposed 3 BCF LNG storage tank that will be required to accommodate Tilbury Phase 2 liquefaction capacity.

<u>Response:</u>

FEI confirms that the 3 Bcf tank proposed as part of the TLSE Project is the same storage tank described in the Initial Project Description (IPD) for the Tilbury Phase 2 Expansion Project Environmental Assessment (EA). The Tilbury Phase 2 Expansion Project has two components: (i) the 3 Bcf storage tank, and (ii) a liquefaction facility. To facilitate understanding, when referring to the liquefaction facility component of the Tilbury Phase 2 Project EA, FEI will use the naming convention "Liquefaction Facility".

As discussed in the response to BCUC IR1 23.2, it would be incorrect to characterize the TLSE Project as being required to support the Liquefaction Facility. The Liquefaction Facility may or may not require storage, and if the TLSE Project were unavailable the storage could be constructed by the party developing the Liquefaction Facility. There is, however, a potential benefit to FEI customers of using the TLSE Project to provide storage for LNG from the Liquefaction Facility.

Of the 3 Bcf of storage provided by the proposed new TLSE Project storage tank, 2 Bcf is required to address the risk reflected in the MRPO. Accordingly, from a planning perspective, FEI will reserve 2 Bcf in the tank solely for resiliency purposes. The remaining 1 Bcf of storage will also provide resiliency benefits. However, because it is in excess of the MRPO, the remaining 1 Bcf can be used more flexibly. It would be available to provide either resiliency or the ancillary benefits to FEI and its customers described in Section 4.4.1.5 of the Application, including accommodating LNG from the Liquefaction Facility, in certain circumstances.

As described in Section 4.4.1.5.5 of the Application, the timing for the expansion of the Tilbury site to include a new liquefaction capacity (i.e., the Liquefaction Facility) is uncertain and contingent on market events. Irrespective of the potential future development of the Liquefaction Facility, the 3 Bcf storage tank proposed as part of the TLSE Project is needed to provide resiliency to FEI's existing customers and will provide a number of ancillary benefits, as described in Section 4.4.1.5.

23.2 Please clarify how the TLSE Project and Tilbury Phase 2 are connected and which facility resources would be shared.

Response:

As explained in the response to BCUC IR1 23.1, the 3 Bcf storage tank proposed as part of the TLSE Project is a component of the Tilbury Phase 2 LNG Expansion Project that is the subject of the EA process. The other component of Tilbury Phase 2 is the Liquefaction Facility.

The 3 Bcf storage tank proposed in the TLSE Project and the Liquefaction Facility would be physically connected through piping. The proposed 3 Bcf storage tank requires both BCUC and EA approval. However, the TLSE Project tank and the Liquefaction Facility have different purposes.

The purpose of the TLSE Project is to address the resiliency needs of FEI customers. The TLSE Project components are summarized in Table 5-1 and described in detail in Section 5 of the Application.

The purpose of the Liquefaction Facility is to provide LNG as a transportable and storable low carbon-intensity fuel for use in the marine fueling or export markets. This may ultimately require some form of LNG storage, which may be provided by the TLSE tank if approved. If the TLSE tank is not approved, and if LNG storage is required to support the Liquefaction Facility, the LNG storage could be built and paid for by the entity developing the Liquefaction Facility.

In other words,

- The TLSE Project is a resiliency investment and the need for it is not dependent on the Liquefaction Facility;
- The Liquefaction Facility component of Tilbury Phase 2 is not dependent on the approval or construction of the TLSE tank;
- However, the TLSE Project does offer some flexibility where FEI could provide a portion of the storage to support the Liquefaction Facility. If the TLSE tank is used in this way it would provide benefit to FEI's customers through payments back to FEI made by the entity developing and operating the Liquefaction Facility.

As stated above, the primary resource which could be shared if the entire Tilbury Phase 2 LNG Expansion Project (both the TLSE Project and Liquefaction Facility) is completed is the new storage tank; however, as discussed in the response to BCUC IR1 23.1, 2 Bcf of the storage tank will be reserved at all times for minimum resiliency requirements. In order for this sharing to occur, the Liquefaction Facility would be interconnected to the 3 Bcf storage tank so that it could produce LNG and also accept boil-off gas from the 3 Bcf tank for reprocessing.

The Liquefaction Facility would also need to connect to other resources at the Tilbury site, including utilities (power supply, etc.), plant control systems and other common facilities located at the Tilbury site.

As discussed in the response to BCUC IR1 23.1, the timing of the expansion of the Tilbury site to include the Liquefaction Facility is an uncertain and contingent event. If construction of the Liquefaction Facility proceeds, sharing of the aforementioned TLSE resources would be subject to BCUC oversight.

23.2.1 Based on the extent of shared resources, please discuss the pros/cons of sharing the construction costs of the TLSE Project LNG storage tank between FEI and FortisBC.

<u>Response:</u>

With respect to the construction of the TLSE Project, if a situation were to arise where construction of the TLSE Project and the Liquefaction Facility occurred simultaneously, FEI would seek opportunities to share resources and optimize construction costs.

23.2.2 Please discuss the need to establish a specific Tilbury LNG Storage Code of Conduct and Transfer Pricing Policy as described in the preamble.

Response:

A Code of Conduct and Transfer Pricing Policy would only be applicable to a situation where there was sharing of resources with an FEI Affiliate. FEI does not believe there is a need to establish a Code of Conduct and Transfer Pricing Policy specifically for this scenario because it has an existing BCUC-approved FEI All Inclusive Code of Conduct (COC) and Transfer Pricing Policy (TPP) effective March 1, 2017, which is applicable to FEI's interactions with all affiliates including non-regulated FortisBC affiliates. FEI notes that for export sales of LNG using ISO[42] containers, the sales are provided as a regulated service offering by FEI under the existing Rate Schedule 46 (RS 46) and are not subject to the FEI COC and TPP.

Since the AES Inquiry Report was issued on December 27, 2012 containing the language outlined in the preamble to this question, there have been two significant developments. First, Direction 5 specified that activities related to FEI's LNG business from the existing Tilbury 1A and under RS 46 should be reflected in rates for the overall natural gas class of service, such that some of the commentary from the AES Inquiry directed at segregating FEI's own LNG offerings other than prescribed undertakings is no longer valid.

Second, and more directly relevant to the specific question being asked, at the direction of the BCUC,[43] FEI developed an All Inclusive COC and TPP approved by the BCUC that addresses its interactions with its affiliates including an Affiliated Natural Monopoly Utility, an Affiliated Regulated Business Operating in a Non-Natural Monopoly Environment, and an Affiliated Non-Regulated Business.

The need for an All-Inclusive COC/TPP was decided in Order G-143-14 dated September 18, 2014 where the BCUC stated that:

> ...ultimately there should be only one integrated document" for the FEI All-Inclusive CoC/TPP, "making it easier to compare practices between entities of different natures". A single combined document would also, in the BCUC's assessment, "make it easier to keep track of any changes occurring over time and ensure consistency.[44]

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42 "ISO container" refers to LNG storage tanks fabricated in a standard-size shipping container package.

43 BCUC Directive from the AES Inquiry Report (p. 23) recommended that FEI engage in a collaborative process to initiate a process to prepare an updated COC and TPP:

> *The Panel recommends that the FEU initiate a process to prepare an updated Code of Conduct and Transfer Pricing Policy in respect of the interaction between the regulated utilities and related non-regulated businesses. This should be done through a collaborative process, carried out in an expeditious manner, involving the utilities, stakeholders (including interveners in this proceeding) and Commission staff.*

44 Appendix A to Order G-143-14, p. 3.

For reference, provided below are excerpts from the existing BCUC approved FEI COC and TPP outlining the rules and language governing FEI's interactions with its affiliates. Additionally, an initial assessment of how the FEI COC and TPP language would be applied to the Tilbury LNG Non-Regulated business is provided below to demonstrate that the existing FEI COC and TPP provides sufficient guidance regarding its potential interactions with the Tilbury LNG Non-Regulated business.

Requirements	FEI COC and TPP	Tilbury Non-Regulated Business
Shared Services and Personnel	b) FortisBC Energy will only share its services and non-executive personnel with Affiliates in circumstances where: 1. the services can be identified and tracked effectively and there are other appropriate safeguards in place as discussed in Section 7 of this document; 2. there is limited potential for disclosure of confidential information; and 3. there are benefits to FortisBC Energy Customers. FortisBC Energy may also share its services and non-executive personnel with an AU where there is no detriment to FortisBC Energy.	Applies to Tilbury Non-Regulated business.
	c) Business Development Personnel FortisBC Energy will not share business development personnel with an Affiliate where the Affiliate is carrying out business development activities to acquire Customers seeking energy products and services available in a competitive marketplace and where FortisBC Energy is providing similar energy solutions. FortisBC Energy and an AU can share business development personnel.	Applies to Tilbury Non-Regulated business. As the Tilbury Non-Regulated business is focused on the export market only, it is not carrying out business development activities to acquire Customers seeking energy products and services available in a competitive marketplace and where FEI is providing similar energy solutions.
	d) Natural Gas Portfolio, Mitigation and Contract Negotiation Personnel FortisBC Energy will not share personnel directly responsible for natural gas portfolio planning and mitigation activities and related contract negotiations with Aitken Creek Gas Storage ULC and FortisBC Midstream Inc. Refer to Appendix A for the relevant positions.	The Tilbury Non-Regulated business does not intend to share such FEI personnel.
	e) Directors and officers/executives with dual management roles in FortisBC Energy and an Affiliate are required to execute a non-disclosure agreement. In the situation of an AU, a non-disclosure agreement is not required.	There may be directors and officers/executives with dual management roles in FEI and the Tilbury Non-Regulated business. The directors and officers/executives with dual management roles will execute a non-disclosure agreement.

Requirements	FEI COC and TPP	Tilbury Non-Regulated Business
Provision of Information	a) Individual Customer Information must be treated as required by the *Personal Information Protection Act* (PIPA). Subject to subsection (b) below, the Customer Information should only be released with the written consent of the Customer or representative of the Customer. b) FortisBC Energy may disclose to a party that requests Customer Information that is aggregated or summarized in such a way that confidential or individual information would not be ascertained by third parties. A written consent will be not required for the release of aggregated or summarized Customer Information. c) If a Customer requests their information be provided to a specific party, only that party may receive the information. If a Customer agrees to a general release of their information, or if the aggregated or summarized Customer Information is released, that information must be made available to all interested parties who request it, without discrimination as to access, timing, cost or content. When the Customer Information or Commercial Information is provided, the requesting party must pay a reasonable price that allows FortisBC Energy to recover the cost of extracting and providing the information. All parties should pay the same price for the same information. d) FortisBC Energy will not provide Commercial Information to an Affiliate except in the case of an AU.	The Tilbury Non-Regulated business and FEI will comply with the existing language for Provision of Information in FEI's COC and TPP.
Preferential treatment and equitable access to service	FortisBC Energy will not state or imply that favoured treatment will be available to Customers of FortisBC Energy as a result of using any service of an Affiliate. In addition, no Company personnel will condone or acquiesce in any other person stating or implying that favoured treatment will be available to Customers of the Company as a result of using any product or service of an Affiliate. This section on Preferential Treatment is not applicable to an AU. Except as required to meet acceptable quality and performance standards, and except for some specific assets or services which require special consideration as approved by the Commission, FortisBC Energy will not preferentially direct its Customers to an Affiliate. In discussing energy alternatives with a Customer, or a potential Customer, FortisBC Energy personnel may not preferentially direct Customers to an Affiliate. If a Customer, or potential Customer, requests from FortisBC Energy information about products or services offered by an Affiliate, FortisBC Energy may provide such information, including a directory of suppliers of the product or service, but shall not promote any specific supplier in preference to any other supplier. This section on Equitable Access to Services is not applicable to an AU.	The Tilbury Non-Regulated business and FEI will comply with the existing language for Preferential treatment in FEI's COC and TPP.
Use of FortisBC name	The use of the FortisBC name by an Affiliate is an acceptable business practice. FortisBC Energy will exercise care in distinguishing between services provided by FortisBC Energy and services offered by an Affiliate except in the situation of an AU. The name FortisBC is owned by Fortis Inc.	The Tilbury Non-Regulated business and FEI will comply with the existing language for Use of FortisBC's name.

Requirements	FEI COC and TPP	Tilbury Non-Regulated Business
Financing and other risks	FortisBC Energy will not normally provide financing, or any form of financial assistance including co-signing of loans, to an Affiliate. No FortisBC Energy financing or other financial assistance, including cross-guarantees, can occur under any circumstances without advance Commission approval.	The Tilbury Non-Regulated business will not receive any financing assistance from FEI under any circumstances without advance BCUC approval.
Transfer Pricing Scope	The Transfer Pricing mechanism should provide a fair and transparent mechanism to FortisBC Energy's Customers, and after having considered the interests of FortisBC Energy's Customers, may consider the potential interests of the Customers of an Affiliate. Costs to be allocated from FortisBC Energy to an Affiliate are on the basis of the higher of market price or fully allocated cost as set out in the FortisBC Energy Transfer Pricing Policy. FortisBC Energy is to seek advance approval from the Commission prior to charging a price that is other than as outlined. Where there is an agreement between FortisBC Energy and its Affiliate with respect to the sharing or provision of services, resources, or personnel that has been reviewed by the Commission, the terms of that agreement will govern. Allocation of costs to an Affiliate will reflect appropriate compensation for any benefit derived as a result of its affiliation with the FortisBC Energy or other businesses. This will include compensation for additional cost or risk related to the addition of incremental debt to FortisBC Energy for the new products or services. FortisBC Energy will ensure that it receives appropriate compensation for the resources and services provided, in order to protect its Customers from subsidizing the activities of Affiliates as required by the Code of Conduct for Affiliates and this Transfer Pricing Policy.	As outlined in the Application, FEI will be allocating costs to the Tilbury Non-Regulated business based on the higher of market price or fully allocated cost and FEI would seek advance approval from the BCUC prior to charging a price that is other than as outlined.
Pricing rules	i. If an applicable FortisBC Energy tariff rate exists, the Transfer Price to an Affiliate will be set according to the tariff. ii. Where no tariff rate exists, the Transfer Price will be set on the basis of the higher of market price or the fully allocated cost iii. Where there is no market price or a market price is not readily discernable, the Transfer Price will be set on the basis of fully allocated cost iv. In situations where it can be shown that an alternative Transfer Price will provide greater benefits to the FortisBC Energy Customers, FortisBC Energy must apply to the Commission for a variance from the pricing rules i, ii, or iii v. If there is an agreement between FortisBC Energy and an Affiliate that has been reviewed by the Commission, that agreement applies.	See comments in Transfer Pricing scope above.

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23.3 Please discuss whether the leasing of LNG storage to a separate export entity to be a regulated activity. Please discuss how FEI anticipates leasing charges would be set.

Response:

This response addresses BCUC IR1 23.3, 23.3.1, and 23.3.2.

In the event an opportunity were to arise for a separate entity to contract space in the tank to generate benefits for FEI customers, the BCUC would have oversight. For the setting of any charges for the LNG storage space, FEI would consider existing guidelines for addressing the pricing of resources and services based on the higher of market price or fully allocated costs. Fully allocated costs represent the sum of the direct costs and overhead costs required to provide the product or service.

Any activity undertaken by FEI in relation to the TLSE Project would be regulated. Due to the changes that have occurred since the AES Inquiry was issued, FEI does not believe it is necessary to determine at this time whether the activity takes place in a competitive market or whether it is a “new” service offering. These issues can be explored at the time arrangements are entered into with knowledge of the facts at that time, at which time they would come before the BCUC.

23.3.1 Please explain whether the leasing of LNG storage space for the purposes of export or marine bunkering to be a service offering within a competitive market.

Response:

Please refer to the response to BCUC IR1 23.3.

23.3.2 Please explain whether the leasing of LNG storage space for the purposes of export or marine bunkering to be a new service offering by FEI.

Response:

Please refer to the response to BCUC IR1 23.3.

23.3.3 Please describe FEI's understanding of the current and forecasted Pacific NorthWest marine bunkering market.

Response:

FEI notes that the TLSE Project is a resiliency project. The marine bunkering market is being served by the existing Tilbury 1A facility, which was developed for LNG sales.

The global LNG bunkering market is predicted to grow to between $8.3 to $10.2 billion dollars of annual revenue within the next five years (2023) as the marine shipping sector moves to lower emissions.[45] Global marine shipping is overseen by the International Maritime Organization (IMO), which has established ambitious requirements to mitigate the environmental impact of international marine shipping. The IMO has adopted an initial strategy to reduce Greenhouse Gas (GHG) emissions from international shipping. This strategy aims to reduce international shipping Carbon Dioxide (CO2e) emissions by at least 40 percent by 2030 and 70 percent by 2050, and total annual GHG emissions by at least 50 percent by 2050 (from 2008 levels). As a relatively low CO2e (and overall GHG) intensive fuel source, these regulations and guidelines position LNG fuel as one of the potential contributors to achieving IMO's long-term emissions reduction targets and as a key factor in supporting a global transition to a cleaner international shipping sector.

Based on FEI's experience and knowledge of the industry, the demand for LNG fueled vessels continues to increase. Importantly, the number of LNG fuelled vessels continues to climb in all shipping segments. In total, 522 vessels have been ordered as of July 2021 with the largest number of orders placed between the 2020/2021 period. By far the largest segment is the container industry, with 82 vessels on order. This trend will correlate to a rapid increase in LNG demand over the next few years due to the larger volume of LNG required. FEI's vision is that the Vancouver Fraser Port Authority (VFPA) will become the west coast port of call for LNG refueling (bunkering) with low carbon LNG from Tilbury. Capitalizing on the LNG marine bunkering[46] opportunity is an integral part of FEI's long term strategy (the Clean Growth Pathway) to support the Province's CleanBC plan of lowering emissions from the transportation sector while generating significant economic opportunity for the province of BC.

There are two key marine segments that FEI is targeting: short sea, and trans-Pacific. FEI has made significant progress in the short sea market segment with current commitments for a total of nine short sea marine vessels (five from BC Ferries, and four from Seaspan). The Truck-to-Ship fueling method currently used works well for regional ferry and small vessel operators with relatively small fuel capacities. FEI anticipates additional growth in this segment with adoption of LNG for additional BC Ferries vessels in the next four to five years.

Trans-Pacific vessels require larger LNG transfer volumes and will need a Ship-to-Ship LNG fueling method, which is the current method used to fuel trans-Pacific vessels with traditional

[45] Mordor Intelligence (2018),"Global LNG Bunkering Market 2018-2023 & Allied Market Research (2017), *Global LNG Bunkering Market: Opportunities and Forecasts 2017-2023*.

[46] Bunkering is the act of supplying a marine vessel with fuel.

marine fuels. FEI is continuing to focus market development activities on the trans-Pacific vessels that regularly call at west coast ports from Asia; however, FEI has not executed any LNG supply contracts with trans-Pacific vessel operators to date.

23.3.3.1 Please compare the ability of storage operators to exert market power in the Pacific NorthWest marine bunkering market to the ability of storage operators to exert market power in other gas storage markets, such as the one in which FMI's (FortisBC Midstream Inc.) Aitken Creek Gas Storage operates.

Response:

The comparison between Aitken Creek and the TLSE Project is inapt. Aitken Creek is market area storage. As stated in the Application, the TLSE Project is a resiliency investment that will significantly improve FEI's ability to maintain continuity of service in the event of a disruption in the supply of natural gas to FEI's system.

As discussed in the FortisBC Midstream Inc. (FMI) Application for Approval of the Acquisition of the Shares of Aitken Creek Gas Storage ULC proceeding (FMI response to BCUC IR1 12.2), Aitken Creek and FEI do not have the ability to exercise market power with any of their assets.

Although FEI will have some flexibility to use the "third Bcf" of TLSE storage for bunkering sales (among other ancillary benefits in Section 4.4.1.5 of the Application), the services provided under RS 46 for bunkering will be regulated by the BCUC in accordance with Direction No. 5 to the British Columbia Utilities Commission.

23.3.4 Please discuss the rationale and appropriateness of FEI investing in the design and construction of the capacity for such storage services.

Response:

As stated in the Application, the TLSE Project is a resiliency investment that will significantly improve FEI's ability to maintain continuity of service in the event of a disruption in the supply of natural gas to FEI's system.

23.4 Please provide an update on the anticipated in-service date for Tilbury Phase 2.

Response:

As explained in the response to BCUC IR1 23.1, Tilbury Phase 2 as presented in the EA includes two components: (i) the 3 Bcf storage tank which is included as part of the TLSE Project, and (ii) the Liquefaction Facility. This CPCN Application is in respect of the TLSE Project.

A summary construction and in-service schedule for the TLSE Project, which includes construction of the new 3 Bcf storage tank, is provided in Table 5-9 of the Application. A more detailed schedule is included within Confidential Appendix L. This schedule is contingent on many factors and should not be seen as final; however, it is indicative of the expected sequence and overall duration of the design, construction and commissioning period. As noted in the response to CEC Confidential IR1 84.1, the in-service date for the TLSE Project is now expected to be in Q2 of 2027 as a result of some delays in both the BCUC and EA regulatory processes.

The capacity and construction sequence of the Liquefaction Facility will be dependent on the LNG market. While the timing is subject to commercial uncertainty, the currently anticipated in-service date is 2028. As an indication, should the Liquefaction Facility be constructed to furnish the maximum envisioned size, the projected design and construction timeline is approximately 60 months from the beginning of Front-End Engineering (FEED). FEED would be undertaken when and if commercial agreements are in place.

23.5 Please explain whether ownership of Tilbury 2 Tank (FortisBC or FEI) is still under consideration as described in Table 2-1 above.

Response:

The "Tilbury 2 Tank" discussed in the cited reference is the 3 Bcf tank included as part of the TLSE Project. FEI confirms that it is the entity requesting BCUC approval to construct and operate the tank as part of this Application.

23.5.1 Please discuss the pros/cons of FEI leasing LNG storage space for resiliency purposes from a FortisBC owned LNG storage tank until such time that "a new pipeline into the Lower Mainland is constructed that follows an entirely separate corridor from the T-South system."

Response:

As explained in response to BCUC IR1 16.3, on-system storage and new pipeline infrastructure need to be viewed as complementary assets that are necessary to address infrastructure resiliency in the region, as each separately addresses short duration and long duration supply issues in a cost effective manner. Neither is a substitute for the other. This is why FEI is requesting approval of a new 3 Bcf storage tank as part of this Application and is also separately investigating a pipeline solution. Further, the development of a pipeline solution is still in the very early stages and FEI's need for resiliency is immediate and can be addressed through completion of the TLSE Project.

There is no reason for a FortisBC entity other than FEI to construct a new storage tank at this time and no affiliated FortisBC entity currently has a need for LNG storage for bulk export of LNG. If another FortisBC entity were to construct and own a new storage tank, it would require a long-term contract from FEI to justify making such an investment now or in the future. The addition of a new regional pipeline is uncertain, but if successful does not, in itself, create a non-regulated need for LNG storage at Tilbury.

The pros and cons of a FortisBC entity other than FEI owning a tank that is then contracted to FEI would depend on how the arrangement was structured; however, this arrangement has not been considered in detail as FEI is the only entity with a need for a new LNG storage tank at this time. A potential pro for FEI could be cost certainty if an arrangement were structured with a fixed price contract; however, the price would still need to cover all of the cost of service of the asset until there were other users. A potential con for FEI could be that FEI would be limited in its flexibility to use the asset which would reduce operational benefits. As noted in the Application, the primary purpose of the 3 Bcf LNG storage tank for the TLSE Project is for FEI to meet its resiliency needs; however, the new storage tank also provides ancillary benefits to FEI's customers.

FEI would still be required to construct the 800 MMcf/day of new regasification capacity in order to meet its resiliency needs. Additionally, if FEI were only able to contract for 2 Bcf of the FortisBC affiliate-owned storage tank, at some point in time FEI would need to obtain additional storage for peak shaving to replace the Tilbury Base Plant facilities, which are reaching the end of their useful life.

In summary, FEI is the entity in need of a new LNG storage tank to meet a critical resiliency need. It is needed in the public interest and as such it is appropriate for FEI to advance the LNG storage tank as part of the TLSE Project.

23.6 Please discuss whether any components of the TLSE Project are currently "sized and designed to have the capacity to meet the future demands of the LNG bunkering and export markets".

23.6.1 Please list the components of the TLSE Project sized and designed to meet the future demands of the LNG bunkering and export markets.

23.6.1.1 Please provide a breakdown of the cost impact to size and design these TLSE Project components for LNG bunkering and export market purposes.

Response:

The TLSE Project components, as described in Table 5-1 of the Application, are as follows:

- Regasification capacity of 800 MMcf/day;
- LNG storage tank of 3 Bcf; and
- Addition or modification of any necessary auxiliary systems including power supply, utility pipe racks, in-tank pumps, piping cable trays, instrument air compressors, boil-off gas compressors, connectivity to Tilbury 1A LNG storage tank, and connections to the sendout gas pipeline.

The proposed regasification capacity of 800 MMcf/day is sized and designed solely for resiliency purposes, not to meet the future demands of the LNG bunkering and export markets.

The 3 Bcf storage tank is sized and designed for resiliency purposes while providing FEI with the flexibility to access numerous ancillary benefits as described in Section 4.4.1.5 of the Application. The gas supply benefits associated with the “third Bcf” alone outweigh the incremental costs of a larger tank, making the 3 Bcf tank ultimately less costly for FEI’s customers (please refer to FEI’s response to BCUC IR1 46.2). As explained in Section 4.4.1.5 of the Application, one of the ancillary benefits is the opportunity to potentially reduce FEI customer rates through LNG sales and/or storage contracting opportunities. The other ancillary benefits include operational flexibility and efficiency, enhanced daily balancing, security of supply and mitigation of third party storage risk.

Some minor design components associated with the auxiliary systems that cannot be retrofitted later (i.e., after the TLSE Project assets are in service) have been included within the TLSE Project design to realize the future benefits of the Liquefaction Facility. The cost impact of these items is minimal compared to the overall TLSE Project cost. When it comes time to set rates, FEI will ensure that only costs for providing utility service are included in FEI’s revenue requirements when these assets come into service. Please refer to BCUC Confidential IR1 8.2 for additional details.

24.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1-4, Section 4.4.2.2.1, pp. 117-118; FEI Pattullo Gas Line Replacement CPCN proceeding, Exhibit B-1-4, Section 3.2, p. 15

Regasification Capacity

On pages 117 to 118 of the Updated Public Application, FEI states:

> …the design peak demand for the Lower Mainland is 871 MMcf/day for 2019/20. FEI notes that the load duration curve declines steeply, such that the second coldest day on the design load duration curve (blue) is 793 MMcf/day. The figures above demonstrate that a regasification capacity of 800 MMcf/day is adequate to cover Lower Mainland load during a complete T-South outage if it occurred on the coldest days of the winter, with the exception of the single peak design day…Further, regasification capacity at this level will allow FEI to supply enough load so as to make it more realistic to balance the system through targeted load shedding or other emergency measures at times when it is colder.

On page 15 of the Pattullo Gas Line Replacement CPCN Application, FEI provides Figure 3-1 which is titled “Overview of FEI’s CTS [Coastal Transmission System] and Distribution System.” This figure is reproduced below:

Source: FEI data overlaid on Google Earth mapping

24.1 Please describe the results of any FEI assessments into the hydraulic capabilities of FEI’s transmission and distribution system to deliver 800 MMSCFD of gas from the Tilbury Site to customers throughout the Lower Mainland.

Response:

FEI’s Coastal Transmission System (CTS) has been designed to deliver natural gas from the Huntingdon Control Station in Abbotsford. In other words, Huntingdon is normally where the gas supply delivered to FEI for the Lower Mainland and Vancouver Island is received from the

Westcoast System. However, the CTS pipelines are bi-directional and can also deliver natural gas from the Tilbury Site back into the system towards Coquitlam, Surrey, Langley and other communities as far east as Abbotsford and Mission in the eastern portion of the CTS nearest the Huntingdon Control Station.

FEI has modelled the capacity of the CTS receiving gas from the Tilbury Site, injected at the maximum operating pressure of 4020 kPa (583 psig) into a new NPS 30 pipeline connecting the plant site to the existing CTS pipelines at the Tilbury Valve Station. FEI determined that given a hypothetical unlimited vaporization capacity at the Tilbury site, the CTS could deliver more than 1435 MMcf/day in this reverse flow configuration, which is well in excess of the proposed 800 MMcf/day, while maintaining the necessary inlet pressure to all gate stations within the CTS. In this configuration, the lowest pressure in the CTS would be in the gate stations in the Abbotsford area serving Abbotsford and Mission. With all gate stations in the CTS receiving sufficient inlet pressure, FEI is able to maintain the normal distribution system delivery pressures. As a result, the distribution system would not be impacted by the change in delivery of gas from Huntingdon to the Tilbury Site.

24.1.1 Please describe any bottlenecks identified in FEI's Lower Mainland transmission and distribution system which would limit the delivery of gas from the Tilbury Site to customers throughout the Lower Mainland.

Response:

FEI's distribution system is not impacted by the pressure distribution of the transmission system. As long as FEI's gate stations receive adequate upstream (transmission) pressure, the distribution system will be unchanged by the majority of CTS supply originating at the Tilbury Site.

As discussed in the response to BCUC IR1 24.1, FEI's existing transmission infrastructure is capable of supporting delivery of gas from the Tilbury Site to Lower Mainland customers. The only bottleneck identified is the connection between the Tilbury Plant and the Tilbury Gate Station. The existing 168 mm and 323 mm interconnecting pipelines between these two locations are not large enough to carry 800 MMcf/day of sendout. However, the 168 mm pipeline will be replaced by a 762 mm pipeline by the time the TLSE Project is complete. This pipeline upgrade project is already approved under an OIC. Please also refer to the response to BCUC IR1 19.4.

24.1.2 Please provide a figure, similar to the transmission and distribution network Figure 3-1 above, which shows the flow of 800 MMSCFD of gas from the Tilbury Site out to Fraser Gate Station, Coquitlam Gate Station and the urban centers throughout the Lower Mainland.

Response:

The diagram below illustrates the flow of gas (in MMcf/day) for the transmission system when there is no flow into the system at Huntington Control Station and a flow of 800 MMcf/day from [redacted]

24.2 Please explain whether FEI anticipates any capital projects, such as modifications to transmission and/or distribution networks, in order to deliver 800 MMSCFD of gas from the Tilbury Site to customers throughout the Lower Mainland.

Response:

Please refer to the response to BCUC IR1 24.1.1. The only required upgrade is the pipeline upgrade project referenced in that response. No other capital projects are required.

24.3 Please explain the optimal location, based on existing network hydraulic capacity, to inject 800 MMSCFD of gas into the Lower Mainland transmission and distribution network in the event of a complete T-South outage.

Response:

Hydraulically, the optimal location to inject 800 MMcf/day of gas into the Lower Mainland transmission and distribution network in the event of a complete T-South outage would be near some central point along the large transmission pipelines that form the backbone of the Coastal Transmission System (CTS). Such a location would minimize the distance the injected gas would travel from the injection point to the major demand centers in the Lower Mainland and would therefore minimize the pressure drop incurred in delivering gas. Such a location would have greater capacity to service high-demand loads compared to other less optimal locations.

The figure below shows the approximate area that FEI considers to be an optimal location from a purely hydraulic perspective. The location shown is close to the larger system loads and is near where the major transmission pipelines in the CTS diverge. However, from a practical perspective the location shown (centered around 140th Street and 92nd Avenue in central Surrey) is unsuitable for the construction of any major facilities such as a greenfield LNG plant. The surrounding region is a highly developed and densely populated urban area.

The existing Tilbury LNG facility is also a very good location hydraulically. The site is near existing major transmission pipelines that head north from the Tilbury Valve Station delivering gas to Richmond and Vancouver and other large pipelines that deliver gas from the Tilbury Site eastward toward the rest of the Lower Mainland. The Tilbury Site is also close to the major demand centers of Metro Vancouver and Surrey/Delta, making it a hydraulically better option than the Huntingdon Control Station in Abbotsford.

25.0 Reference: PROJECT DESCRIPTION

Exhibit B-1-4, Section 5.3, p. 121

Design Standards

On page 121 of the Updated Public Application, FEI states:

> FEI will develop the Project in accordance with all applicable statutory codes and standards, including FEI's internal standards, and all British Columbia Oil and Gas Commission (BCOGC) regulations.

25.1 Please provide a list of FEI's internal standards which are applicable to this Project.

Response:

A list of the latest internal FEI specification/standards are provided below:

Project Specifications

Description	Document No.
Fire & Gas Detection System Requirements for LNG Facilities	90500-I-RPT-00003-R3
Emergency Shutdown Philosophy for LNG Storage and Production Facilities	90500-I-RPT-00001-R3
Isolation Philosophy for LNG Storage and Production Facilities	90500-X-RPT-00002-R3
Piping Material Specifications for LNG Storage & Production Facilities	90500-M-SPC-00001-R5
Instrument and Controls Design Criteria for LNG Storage and Production Facilities	90500-I-RPT-00002-R1
Instrument and Control System Specification for LNG Storage and Production Facilities	90500-I-SPC-00001-R1
Process Design Criteria for LNG Storage and Production Facilities	90500-X-RPT-00001-R1
Process Hazard Analysis Procedure for LNG Storage and Production Facilities	90500-X-PRC-00001-R0
Tag Numbering Specification for LNG Storage and Production Facilities	90500-X-SPC-00002-R3
Engineering Drawing and Documentation Specification for LNG Storage and Production Facilities	90500-X-SPC-00001-R6
Electrical Design Criteria for LNG Storage and Production Facilities	90500-E-RPT-00001-R1
Site Preparation for LNG Storage and Production Facilities	90500-C-SPC-00001-R2
Site Survey for LNG Storage and Production Facilities	90500-C-SPC-00002-R1
Mechanical Insulation - Above Ground (Insulation Above Ground for LNG Storage and Production Facilities)	90500-M-SPC-00002-R1
Mechanical - External Painting and Coating (External Painting and Coating for LNG Storage and Production Facilities)	90500-M-SPC-00003-R1
Steel Buildings for LNG Storage and Production Facilities	90500-C-SPC-00007-R1
Reinforced Concrete for LNG Storage and Production Facilities	90500-C-SPC-00006-R1

Description	Document No.
Grouting for LNG Storage and Production Facilities	90500-C-SPC-00005-R1
Coatings for Structural Steel for LNG Storage and Production Facilities	90500-C-SPC-00004-R1
Chain Link Fencing for LNG Storage and Production Facilities	90500-C-SPC-00003-R2
Guidelines for Piping Pressure Testing Procedures for LNG Storage and Production Facilities	90500-M-PRC-00001-R2
Structural Steel for LNG Storage and Production Facilities	90500-C-SPC-00008-R1
Geotechnical Design Criteria For LNG Projects At Tilbury Site	90500-C-RPT-00002-R1
Codes and Standards for LNG Storage and Production Facilities	90500-X-STD-00006-R1
Tilbury Site Data	90500-X-SPC-00003- R4
Design and Construction for Roads and Paving for LNG Storage and Production Facilities	90500-C-SPC-00009-R0
Structural Design Criteria for LNG Storage and Production Facilities	90500-C-REP-00003-R0
Civil Design Criteria for LNG Storage and Production Facilities	90500-C-REP-00004-R0

Standard Drawings

Item	Specification/Guideline Doc No.	Description
1	90500-M-STD-00005-R0 90500-M-STD-00006-R0 90500-M-STD-00007-R0 90500-M-STD-00008-R0 90500-M-STD-00009-R0 90500-M-STD-00010-R0 90500-M-STD-00011-R0	Piping Design Standard Details
2	90500-M-STD-00001-R0 90500-M-STD-00002-R0 90500-M-STD-00003-R0 90500-M-STD-00004-R0	Pipe Spacing Charts
3	90500-M-PDD-00001-R0 90500-M-PDD-00002-R1 90500-M-PDD-00003-R1 90500-M-PDD-00004-R0 90500-M-PDD-00005-R1 90500-M-PDD-00006-R0 90500-M-PDD-00007-R0 90500-M-PDD-00008-R0 90500-M-PDD-00009-R0 90500-M-PDD-00010-R0 90500-M-PDD-00011-R0 90500-M-PDD-00012-R0 90500-M-PDD-00013-R0 90500-M-PDD-00014-R0 90500-M-PDD-00015-R1	Pipe Support Details

Item	Specification/Guideline Doc No.	Description
	90500-M-PDD-00016-R1 90500-M-PDD-00017-R1 90500-M-PDD-00018-R1 90500-M-PDD-00019-R1 90500-M-PDD-00020-R1 90500-M-PDD-00021-R1 90500-M-PDD-00022-R1 90500-M-PDD-00023-R1 90500-M-PDD-00024-R1 90500-M-PDD-00025-R1 90500-M-PDD-00026-R1 90500-M-PDD-00027-R1 90500-M-PDD-00028-R1 90500-M-PDD-00029-R1 90500-M-PDD-00030-R1 90500-M-PDD-00031-R1 90500-M-PDD-00032-R1 90500-M-PDD-00033-R1 90500-M-PDD-00034-R1 90500-M-PDD-00035-R1 90500-M-PDD-00036-R1 90500-M-PDD-00037-R1 90500-M-PDD-00038-R1 90500-M-PDD-00039-R0 90500-M-PDD-00040-R0 90500-M-PDD-00041-R1 90500-M-PDD-00042-R1 90500-M-PDD-00043-R1 90500-M-PDD-00044-R0 90500-M-PDD-00045-R1 90500-M-PDD-00046-R1 90500-M-PDD-00047-R1 90500-M-PDD-00048-R1 90500-M-PDD-00049-R1 90500-M-PDD-00050-R1 90500-M-PDD-00051-R1 90500-M-PDD-00052-R1 90500-M-PDD-00053-R0 90500-M-PDD-00054-R0 90500-M-PDD-00055-R0 90500-M-PDD-00056-R0 90500-M-PDD-00057-R0 90500-M-PDD-00058-R1 90500-M-PDD-00059-R0 90500-M-PDD-00060-R0 90500-M-PDD-00061-R0	

Item	Specification/Guideline Doc No.	Description
4	90500-M-LST-00001-R1	Mechanical Standard & Specification Index (Pipe Support Index)
5	90500-X-LGN-00001_R1 90500-X-LGN-00002-R0 90500-X-LGN-00003-R0 90500-X-LGN-00004-R0	Piping & Instrumentation Symbols and Legend Sheets for LNG Storage and Production Facilities
6	90500-E-LST-00001-R1 90500-E-LGN-00001-R1 90500-E-STD-00001-R1 90500-E-STD-00002-R1 90500-E-STD-00003-R1 90500-E-STD-00004-R1 90500-E-STD-00005-R1 90500-E-STD-00006-R1 90500-E-STD-00007-R1 90500-E-STD-00008-R1 90500-E-STD-00009-R1 90500-E-STD-00010-R1	Electrical Standard Details
7	90500-C-LST-00001-R1 90500-C-STD-00005-R1 90500-C-STD-00006-R2 90500-C-STD-00007-R2 90500-C-STD-00008-R1 90500-C-STD-00009-R1 90500-C-STD-00010-R1 90500-C-STD-00011-R0 90500-C-STD-00012-R0 90500-C-STD-00013-R4 90500-C-STD-00014-R0 90500-C-STD-00015-R0 90500-C-STD-00016-R0 90500-C-STD-00017-R0 90500-C-STD-00018-R0 90500-C-STD-00019-R0 90500-C-STD-00020-R0 90500-C-STD-00021-R0 90500-C-STD-00022-R0 90500-C-STD-00023-R0 90500-C-STD-00001-R1 90500-C-STD-00002-R1 90500-C-STD-00003-R0 90500-C-STD-00004-R1	Civil & Structural Steel Standard and Typical Details
8	90500-I-LST-00001-R0 90500-I-ISD-00001-R0 90500-I-ISD-00002-R0 90500-I-ISD-00003-R0	Instrumentation Standard and Typical Details

Item	Specification/Guideline Doc No.	Description
	90500-I-ISD-00004-R0 90500-I-ISD-00005-R0	

25.2 In the case where there is disagreement between any applicable statutory codes or standards, please describe which code or standard takes precedence by providing a hierarchy of design documents.

Response:

In the event of any conflict or inconsistency between any applicable statutory codes or standards, the following order of precedence will be applied:

a) requirements of governmental authorities including Canadian federal and provincial laws and regulations; the latest version of CSA Z276 Liquefied natural gas (LNG) - Production, storage, and handling shall be used;

b) FEI and project specifications and standards (engineering code requirements as minimum);

c) Industry codes and standards; and

d) Industry best practices.

In general, European Standards (EN) will not be adopted. However, FEI may use EN standards where CSA/ASME/ANSI standards either do not address an issue or do not cover specific design requirements. FEI will ensure that these EN standards are accepted by the BCOGC, Technical Safety BC, and other technical regulators, as appropriate.

26.0 Reference: PROJECT DESCRIPTION

Exhibit B-1-4, Section 5.3.1, p. 122

Site Layout

On page 122 of the Updated Public Application, FEI states: "The 3 Bcf tank will be constructed on the existing Tilbury site in the location shown in Figure 5-2."

26.1 Please provide a high-resolution copy of Figure 5-2.

Response:

Please refer to Attachment 26.1 for a high-resolution copy of Figure 5-2.

26.2 Please explain whether the siting of the 3 Bcf tank as shown in Figure 5-2 adheres to the tank spacing requirements of applicable codes and standards (e.g. CSA Z276)

Response:

The siting of the 3 Bcf tank adheres to the tank spacing requirements of CSA Z276-18, Table 3. The requirements for minimum inter-tank distance, as well as the minimum distance from tank to property line are met. Please also refer to Attachment 26.1 for a drawing showing the tank spacing.

26.2.1 Please confirm the separation distance between the proposed 3 Bcf tank and other existing LNG tanks at the Tilbury site.

Response:

At this phase of design, FEI has specified a separation distance of 33 metres from the closest tank (i.e., the T1A LNG Storage Tank). CSA Z276-18 provides that the minimum inter-tank distance should be one quarter of the sum of the diameters of adjacent containers, which in this case is approximately 30 metres.

26.2.2 Please confirm whether FEI has conducted an engineering analysis to assess the radiant heat flux in the vicinity of the proposed 3 Bcf tank in the case of a fire within the tank.

26.2.2.1 If so, please discuss the results of the analysis.

26.2.2.2 If not, why not?

Response:

The latest version of the code CSA Z276-18 Table 7 does not consider a fire within a "full containment" tank with a reinforced concrete roof to be a credible scenario. As a result, FEI has not carried out an engineering analysis to assess the radiant heat flux in the vicinity of the proposed 3 Bcf tank, which is a full containment tank with a concrete roof.

27.0 Reference: PROJECT DESCRIPTION

Exhibit B-1-4, Section 5.3.1.1, pp. 124, 125

Tank Design

On page 124 of the Updated Public Application, FEI states:

> In general terms, the tank assembly will consist of a double-wall, insulated storage tank. A cryogenic steel inner vessel will contain the LNG liquid. This will be further enclosed by a concrete outer tank, also lined with steel, which will provide protection from the environment and external elements. The space between the two tanks will be filled with thermal insulation to maintain the LNG storage temperature of approximately minus 168 degrees Celsius. This design is consistent with current world-wide practices for construction of above-ground LNG storage tanks.

Further on page 125, FEI lists details of the design of the proposed 3 Bcf tank, including the following:

> This is a full-containment LNG tank designed in accordance with CSA Z276, API 625 and ACI 376. Full containment refers to the ability of the tank to contain the entire volume of stored LNG even in the event of a breach of the inner steel tank;

27.1 Please explain whether FEI considered LNG storage tank designs other than above-ground full containment type.

27.1.1 If confirmed, please discuss the pros/cons of each type of LNG storage tank design considered and the reasons why an above-ground LNG storage tank was selected. Please include comparisons of design complexity, capital cost, construction schedule and site spacing requirements.

27.1.2 If not, why not?

Response:

The most common industry practice in North America for storing large volumes of LNG is by means of above-ground, double-wall, flat-bottom LNG storage tanks. For sites with limited area and close property lines, full containment tanks with a 9 percent nickel inner tank and pre-stressed concrete outer tank is conventional practice and is the proposed design for the TLSE Project.

This LNG tank design is a safe, proven, and cost-effective configuration that CB&I has been constructing for over 40 years including 50 full containment LNG tanks worldwide.

Buried LNG tanks are not typical and would be significantly more expensive to construct at the existing Tilbury site (which is located immediately adjacent to the Fraser River) considering:

- An extensive excavation would be required with a significantly larger footprint required for construction;
- A heavy foundation would be required to counteract the buoyancy from the high water table and for the loss of overburden from the deep excavation; and
- Ongoing dewatering would be required due to the high water table.

Given the significantly higher construction costs, with few discernable offsetting benefits, a buried LNG tank was not considered for the TLSE Project.

28.0 Reference: PROJECT DESCRIPTION
Exhibit B-1-4, Section 5.3.1.1, p. 126
Boil-off Rate

On page 126 of the Updated Public Application, FEI states:

> The insulation system will be designed to produce a boil-off rate of less than 0.05 percent per day of the tank gross volume based on pure methane, constant pressure, and ambient environmental conditions. This will minimize the boil-off of natural gas and therefore the need to expend energy to recompress or re-liquefy this gas.

28.1 Please provide the rate of boil-off in MMSCFD units, based on a maximum rate of 0.05 percent per day of the tank gross volume. Please compare this to the liquefaction capacity reserved for the TLSE project.

Response:

The boil-off rate due to tank heat gain is approximately 1.7 MMcf/day.

5 MMcf/day of liquefaction capacity will be reserved for utility use, including for LNG refilling due to usage for peak shaving, emergency depletion, and the replacement of LNG lost as boil-off gas.

29.0 Reference: PROJECT DESCRIPTION

Exhibit B-1-4, Section 5.3.1.3, p. 127

Venting Design

On page 127 of the Updated Public Application, FEI states:

> During normal operations, venting to the atmosphere is expected to be a very unlikely event. Any vapour or boil off gas (BOG) from the tank will be contained by the boil off gas system and returned to the pipeline. However, in the event that there is an upset condition that exceeds the capability of the boil off gas system, the overpressure will be released to the atmosphere through pressure safety valves on the tank top. This is considered standard industry design. The other operating condition that may require minimal venting to the atmosphere would occur during maintenance activities, where equipment intended to capture the boil off gas is required to be out of service. The Project is being designed from a reliability perspective such that there is redundant equipment to prevent situations where any venting to the atmosphere would be required. As such, venting to the atmosphere is expected to be a very unlikely event.

29.1 Please explain the sizing basis for the boil off gas system and confirm the maximum capacity in MMSCFD.

<u>Response:</u>

The controlling case for sizing of the boil-off gas (BOG) system is the transfer of LNG to the 3 BCF tank at a rate of 2000 m^3/hr while a high pressure pump is recycling from the regasification system. The sizing of the BOG compressor will be finalized after the regasification system design is complete. An appropriate level of conservatism has been applied such that there is no venting under any operating scenario.

The capacity of the larger compressor is estimated to be 16 MMcf/day.

29.1.1 Please provide the rate of boil off when the regasification system is operating at its maximum design capacity (e.g. gas sendout capacity of 800 MMSCFD).

<u>Response:</u>

Based on the sendout capacity of three vapourizers, the net boil-off gas generation from the tank is estimated to be 0.15 MMcf/day. Operating four vaporizers would further reduce the boil-off gas generation and would not impact the boil-off gas handling capacity.

29.1.2 Please provide the rate of boil off during normal operations, when no LNG is being sent out from the tank.

Response:

The boil-off rate during normal operations when no LNG is being sent out of the tank is the same as the boil-off rate due to tank heat gain. The boil-off rate is estimated to be approximately 1.7 MMcf/day. Please also refer to the response to BCUC IR1 28.1.

29.1.3 Please discuss whether there are any other operating modes which impact the required capacity of the boil off gas system.

Response:

All operating modes that impact the capacity of the boil-off gas compressors have been included in the boil off gas calculations.

29.2 Please explain the level of redundancy currently designed for in the boil off gas system.

Response:

Two boil-off gas compressors will be provided. The larger compressor will be used for LNG transfer operations; however, as this is an intermittent operation, no spare is required. The smaller compressor will be used for heat gain losses on a day-to-day basis. Redundancy for this compressor will be provided by the larger compressor.

29.3 Please describe any limitations (e.g. regulatory) imposed on FEI with respect to venting natural gas to atmosphere.

Response:

FEI is not currently aware of any regulatory limitations that may be imposed with respect to venting natural gas to the atmosphere. The Tilbury 1A plant is currently operating under Metro Vancouver Permit #GVA1104. This permit limits the total annual methane emissions from the Tilbury 1A facility. A permit amendment will be submitted for the TLSE Project once the detailed design has been completed and accurate modeling of any potential air emissions impacts have been completed. As noted, venting to atmosphere is expected to be a very unlikely event and therefore should not adversely affect the ability to obtain an air emissions permit.

30.0 Reference: PROJECT DESCRIPTION

Exhibit B-1-4, Section 5.3.1.4, p. 127

Workshop Transcript, pp. 130, 234

Filling methodology

On page 127 of the Updated Public Application, FEI states:

> Construction of additional liquefaction is not within the scope of the TLSE Project. Rather, the 3 Bcf LNG tank will be filled using reserve capacity (approximately 5 MMcf/day) from the Tilbury 1A LNG liquefaction system, which has been reserved for utility use, including for peak shaving, emergency depletion, and replacement of LNG lost as boil off gas.

On page 234 of the Transcript, in response to a question on how much of the new Tilbury LNG tank storage capacity is reserved for resiliency in the event of an emergency, Mr. Leclair stated: "we'll always have three days of minimum supply reserved for our customers so then the incremental sort of differential to fill is far less."

On page 130 of the Transcript, Mr. Moran states: "Winter demand [is] almost three times as high as summer demand."

30.1 Please describe how the reserved 5 MMSCFD liquefaction capacity from the Tilbury 1A LNG liquefaction system is adequate for the purposes of the proposed 3 Bcf tank.

Response:

There is a range of time that could be required for filling the 3 Bcf TLSE tank, depending on the amount of liquefaction capacity available at the time of filling. The initial fill will rely on a combination of the 5 MMcf/day reserved from Tilbury 1A along with any available excess capacity from Tilbury 1A and 1B (if the latter is constructed and in service in time).

Theoretically, if utilizing only the 5 MMcf/day capacity from Tilbury 1A, it would require approximately 600 days to fill the tank. However, in the timeframe of the TLSE Project, it is expected that the LNG fuel sales volumes will still be ramping up; as such, excess liquefaction capacity may be available to accelerate the initial filling of the TLSE tank considerably. If FEI is able to utilize the full Tilbury 1A liquefaction capacity of 33 MMcf/day, it would take approximately 95 to 100 days to complete the initial fill. Under Direction No. 5 to the BCUC, FEI has approval to proceed with installation of a second liquefaction train (Tilbury 1B) to support additional LNG sales under RS 46, making additional liquefaction potentially available beyond the 33 MMcf/day currently at Tilbury 1A which could shorten the time. Since the total amount of excess capacity available is unknown at this time, FEI is unable to determine the exact time it will take to complete the initial fill.

As discussed in the response to BCUC IR1 22.7, following the initial fill of the TLSE tank, there will always be 2 Bcf available in the tank for resiliency purposes. The remaining 1 Bcf tank capacity will be filled from the 5 MMcf/day liquefaction capacity outside of peak winter conditions.

In the event of a supply disruption and the 3 Bcf tank is emptied, the tank will be refilled by any surplus capacity in the T1A tank or T1B liquefaction and the 5 MMcf/day liquefaction.

30.2 Please explain how long it will take FEI to fill the tank to a level of 2 Bcf and 3 Bcf from empty.

Response:

As explained in the response to BCUC IR1 30.1, the time to fill the 3 Bcf tank will be between 95 and 600 days depending on the available LNG liquefaction capacity. For a 2 Bcf tank, the fill time would be between 39 and 400 days. These durations do not include any potential liquefaction capacity at Tilbury 1B, which could shorten the fill time.

30.3 Please provide further explanation of FEI's plans for minimum supply in the tank reserved for resiliency purposes. Please clarify whether FEI intend to have a minimum of 2 Bcf in the tank at all times for resiliency purposes.

Response:

Please refer to the response to BCUC IR1 22.7.

30.3.1 Please discuss any anticipated seasonal variations in storage levels.

Response:

Please refer to the response to BCUC IR1 22.7. FEI is planning to retain 2 Bcf so as to be able to withstand the 3-day no-flow event contemplated in the MRPO, with the remainder providing a resiliency margin above the minimum and being available for gas supply and/or operational requirements as described in Section 4.4.1 of the Application. The seasonal variation may come from the incremental 1 Bcf of storage available for gas supply and/or operational requirements. This may include peak days during the winter or for an operational issue. The seasonal variation of the 2 Bcf of storage would depend on whether there is a future no-flow or a supply disruption event.

30.3.2 Please discuss how FEI plans to refill the tank in the event LNG is used for non-resiliency purposes and depleted below 2 Bcf.

Response:

FEI will reserve 2 Bcf of LNG at all times for resiliency purposes.

30.4 Please explain the liquefaction capacity required in order for FEI to take advantage of the five ancillary benefits described in Section 4.4.1.5 of the Application.

Response:

The existing Tilbury 1A liquefaction of 5 MMcf/day reserved for FEI's non-RS 46 customers will be sufficient to take advantage of the five ancillary benefits described in Section 4.4.1.5 of the Application. This is because only 1 Bcf of the TLSE Project may be used for these benefits. If FEI uses all of the 1 Bcf during the winter period, the 5 MMcf/day of liquefaction will allow FEI to replenish the storage during the summer period.[47]

[47] 5 MMcf/day X 214 (summer days) = 1,070 MMcf or 1.07 Bcf.

31.0 Reference: PROJECT DESCRIPTION

Exhibit B-1-4, Section 5.3.2, p. 128

Regasification System

On page 128 of the Updated Public Application, FEI states: "Vapourizers utilizing submerged combustion bath heater technologies which convert the LNG back into a gaseous state."

31.1 Please discuss other regasification technologies considered by FEI other than submerged combustion bath heaters.

Response:

As part of the early engineering, a number of regasification technologies were considered and assessed. The following table provides the summary of the findings:

Technology	Source of heat	Comments
Open Rack Vapourizer	Water (seawater commonly used).	Rejected – due to environmental concerns, it is preferred not to use river water as heat medium.
Submerged Combustion Vapourizers (SCV)	Exhaust gas from burner sparged into water bath, which vapourizes the LNG.	Shortlisted – existing Base Plant vapourizers are SCV type; only 4 units would be required for 800 MMcf/day sendout.
Indirect Fired Water Bath (IFWB)	Vapourizer tube bundle submerged in a water bath; water bath is indirectly heated.	Shortlisted – limitation on the maximum size and multiple units.
Ambient Air Vapourizers (AAV)	Direct air or indirect air	Rejected – due to the potential for fog formation, icing, and supplementary heating to meet required gas temperature
Shell and Tube Vapourizer (STV)	Water (seawater commonly used in heat exchanger; a variant uses water-glycol)	Rejected – although the Mt. Hayes facility utilizes shell-tube type heat exchangers using glycol-water as heat medium, this system has a longer start-up time compared to SCV. Due to environmental concerns, it is preferred not to use river water as heat medium and additionally the equipment would be spread out at site due to code spacing requirements leading to a larger footprint which would increase cost and operational complexity
Water Bath Vapourizer Using Intermediate Fluid	Intermediate heat transfer fluid (e.g. glycol-water)	Shortlisted – Longer start-up time compared to SCV; additional utility requirements for glycol pumps.
Intermediate Fluid Vapourizer (IVF) - Variant	Variant which uses hydrocarbon as heat transfer fluid (e.g. seawater, butane)	Rejected – due to environmental concerns, it is preferred not to use river water as heat medium.

From the shortlisted technologies, it was determined that:

- The Water Bath Vapourizer Using Intermediate fluid (e.g., glycol-water) would be expected to have a longer response time for start-up. Also, the equipment is spread-out (e.g., the gas-fired heaters are located in a different area and large pipes and pumps are required to bring in the intermediate fluid) and hence would require additional site space driving additional cost and operational complexity. Additional electricity load would be required for the water-glycol pumps.
- The Indirect Fired Water Bath (IFWB) option was a potential solution, but there are limitations on the largest available size of the units. A total of approximately ten units would be required to meet the required 800 MMcf/day sendout and this would increase process complexity and maintenance issues.

For the above reasons, it was considered that the alternative technologies led to increased process complexity or did not provide significant benefit over the conventional SCV technology for the 800 MMcf/day scale of the TLSE Project.

31.1.1 Please explain why submerged combustion bath heater technology was selected over alternative regasification technologies.

Response:

Please refer to the response to BCUC IR1 31.1.

31.1.2 Please discuss the cost effectiveness of the submerged combustion bath heater technology in comparison to other regasification technologies (e.g. capital costs, operating costs).

Response:

Only one technically viable vapourization technology was identified during the FEED phase. As a result, cost effectiveness was not a differentiating factor between options. While not a factor in the selection of the technology, preliminary capital costs were obtained for the vapourizer equipment. The four SCV packages (to provide 800MMcf/day of regasification) were approximately 15 percent lower in cost than ten IFWB packages that would deliver the same capacity. Reducing the number of packages also reduces the amount of equipment requiring maintenance, and therefore also reduces operating costs.

31.1.3 Please explain the rate of fuel gas supply required to operate the selected vapourizers at their design capacity (e.g. 800 mmscfd regasification capacity).

Response:

At 800 MMcf/day regasification capacity, the vapourizer fuel gas consumption is estimated to be 12 MMcf/day. At start up, the supply will come from pipeline gas however following initial start-up vapourized LNG will be used as fuel gas for the vapourizers.

31.2 Please discuss whether FEI considered any energy recovery opportunities as part of the regasification system design.

31.2.1 Please discuss the pros/cons of incorporating energy recovery into the regasification system design for this Project.

Response:

Incorporation of energy recovery as part of the regasification system has not been investigated during the preliminary engineering phase. FEI will consider incorporating energy recovery into the regasification system during the detailed design if the benefits (e.g., increased regasification efficiency) outweigh the expected increased capital cost when considering the low frequency of operation.

31.3 Please discuss lessons learned from the design of the regasification system at Mt Hayes, and how these were incorporated into the design of the proposed Project.

Response:

As discussed in the response to BCUC IR1 31.1, FEI has selected a different vapourization technology for the TLSE Project than was used for the Mt Hayes regasification system. Therefore, no specific lessons learned were applied to the TLSE Project design.

On page 128 of the Updated Public Application, FEI states: “The new regasification facility will be designed for fast start-up (within 2 hours of an initial call for sendout) to be able to accommodate the full capacity gas sendout.”

On pages 129 and 130 of the Updated Public Application, FEI states:

> The regasification package will be designed for rapid start-up and supply of natural gas in the event of a sudden disruption to the upstream gas transmission system. A key design consideration to allow for this rapid response is to ensure necessary LNG piping and HP sendout pumps are kept continuously cold and hence, ready for immediate operation. This will be accomplished by circulating LNG from the storage tanks though this key equipment….To ensure full sendout capacity is achieved rapidly, the regasification system will need to be designed to heat the water baths of all four vapourizers simultaneously.

31.4 Please discuss the optimal time to achieve full capacity gas sendout following an initial call.

31.4.1 Please discuss the pros/cons of designing the regasification facility for fast start-up within 2 hours of an initial call for sendout.

31.4.2 Please explain the impacts on day-to-day operations (e.g. rate of boil-off, rate of site power consumption, etc.) of designing for sendout of gas following an initial call within a time greater than 2 hours.

<u>Response:</u>

The regasification system has been optimized to support the fastest reasonable start-up time (other than running the system continuously, which would have zero start-up time). The regasification system will be designed for full capacity sendout within two hours of the initial call for sendout. Additional incremental improvements to response times may be possible, however they will be dependent on operational practices once the facility is placed in service.

It is not expected that there would be an impact on day-to-day operations by designing the system to sendout gas in a time greater than two hours.

On page 128 of the Updated Public Application, Table 5-4 specifies the regasification system design parameters. Table 5-4 is reproduced below:

Table 5-4: Regasification System Design Parameters

Parameter	Value
Total sendout capacity	800 MMcf/day
Number of vapourizers	4
Sendout capacity per vapourizer	200 MMcf/day
Number of HP sendout pumps	4
Rated capacity of HP sendout pump	473 m^3/hr
In-tank pump capacity	1,600 m^3/h

31.5 Please confirm the "Rated capacity of HP sendout pump" provided in Table 5-4 is the capacity per each HP sendout pump to be installed.

31.5.1 Please provide the rated capacity of HP sendout pump in equivalent MMSCFD units.

31.5.2 Please provide the cumulative capacity of the four HP sendout pumps in equivalent MMSCFD units.

Response:

The rated HP Sendout Pump capacity of 473 m^3/h is the capacity per HP sendout pump to be installed.

The rated pump capacity of 473 m^3/h would result in a sendout capacity of 240 to 250 MMcf/day depending on the LNG composition.

The overall capacity of the pumps would result in a cumulative capacity of 960 to 1000 MMcf/day (FEI standards incorporate a 10 percent design margin). Additionally, approximately 10 MMcf/day of gas is consumed as fuel for vaporization resulting in a net sendout capacity of approximately 815 to 817 MMcf/day.

31.6 Please describe the sparing philosophy for the HP sendout pumps.

31.6.1 Please discuss the need for any HP sendout pumps to be stored on-site as warehouse spare and whether the current Project Cost estimate accounts for this.

Response:

At full sendout rates of 800 MMcf/day, all four HP sendout pumps would be in operation. At times when gas sendout demand is 600 MMcf/day or less, one pump will act as a standby pump. An allowance has been made for warehouse spares as part of the Class 3 cost estimate.

31.7 Please confirm the In-tank pump capacity listed in Table 5-4 is the capacity per each In-tank pump to be installed.

31.7.1 Please confirm the number of in-tank pumps to be installed.

31.7.2 Please provide the in-tank pump capacity in equivalent MMSCFD.

31.7.3 Please provide the cumulative capacity of all installed in-tank pumps in MMSCFD.

<u>Response:</u>

There will be two in-tank pumps installed, each with a capacity of 800 MMcf/day. The cumulative in-tank pump capacity is 1600 MMcf/day; however, one pump is intended to act as a spare, so the operating capacity will be 800 MMcf/day.

32.0 Reference: PROJECT DESCRIPTION

Exhibit B-1-4, Section 5.3.3.5, p. 132

Utilities

On page 132 of the Updated Public Application, FEI states:

> Electrical power, including 13.8 kV and 4.16 kV feeder lines to supply the LNG storage tank systems, BOG compressors, and regasification package… An emergency generator to provide electric supply for critical loads to ensure operations even during a site-wide power failure. At a minimum, these critical loads will include one in-tank LNG pump, three HP send-out pumps, three vapourizers, and instrument air compressors, as required.

32.1 Please clarify whether the TLSE Project electricity will be supplied from British Columbia Hydro and Power Authority (BC Hydro) or from on-site power generation during normal operation.

<u>Response:</u>

The power for the TLSE Project will be supplied from BC Hydro during normal operation. BC Hydro owns and operates a 69-kV transmission line to an existing FEI substation located on the southeast corner of the Tilbury site which provides the power supply for all onsite equipment.

32.2 Please provide the sizing basis for the emergency generator.

32.2.1 Please confirm whether the emergency generator is sized to provide electric supply to the BOG compressors.

32.2.2 If not, please explain how venting is handled in the event of a site-wide power failure.

<u>Response:</u>

The sizing basis for the emergency generator is as follows:

- two in-tank LNG marine loading pumps;
- four LNG HP send out pumps;
- four vaporizers;
- auxiliary systems;
- BOG compressor; and
- the tank foundation heating.

The sizing will be finalized during the detailed design phase.

FEI confirms that the emergency generator has been designed to start and run the BOG compressor in the event of a site-wide power failure.

33.0 Reference: PROJECT DESCRIPTION

Exhibit B-1-4, Section 5.3.4, p. 133

Site Grade

On page 133 of Updated Public the Application, FEI states "The site grade will be increased by approximately 3.5 m to mitigate any risk of equipment or site damage due to flooding of the adjacent Fraser River."

33.1 Please discuss how increasing the site grade by approximately 3.5 m aligns with local municipal diking and sea level rise adaptation planning.

<u>Response:</u>

The City of Delta Policy Statement pertaining to Flood proofing requirements (see page 94, excerpted below) indicates that, in the event of a dyke breach to an elevation of 2.9 metres above GSC (Geodetic Survey Canada) flooding would occur and recommends the elevation be increased to 3.5 metres above GSC.

> Any applicant for a building permit or subdivision approval shall be informed that, in the event of a dyke breach, flooding to an elevation of 2.9 metres G.S.C., could occur and construction with major habitable areas above elevation of 3.5 metres G.S.C. is recommended.
>
> -94- ...continued...

Extract from: City of Delta Policy Statement pertaining to flood-proofing requirements.

During the detailed design of Tilbury 1A and the building permit application process, elevations were negotiated with the City of Delta and it was agreed that any critical equipment would be elevated to 3.5 metres above GSC, with non-critical equipment being elevated to 2 metres above GSC. Covenant CA3723021 was agreed to in November of 2013 (see Attachment 33.1) which stipulated the conditions for placing structures on the Tilbury property. FEI will continue to work with the City of Delta throughout the permitting process for the TLSE Project.

33.2 Please clarify whether site grading is currently under review as part of any other on-going permitting process.

33.2.1 If so, please discuss the risk that an increase in site grade above 3.5m may be required.

<u>Response:</u>

The stripping, grading, and surface water management plans are part of the development that is assessed through the Provincial Environmental Assessment process and the Federal Impact Assessment process. Once the assessments are completed, the site stripping and grading plan will also be subject to a City of Delta Development Permit. While the 3.5 metre grade elevation is based on the best available information, and FEI is confident that it will protect site assets in the event of a flood, the assessments and subsequent permitting process may identify a different appropriate grade elevation.

34.0 Reference: PROJECT DESCRIPTION

Exhibit B-1-4, Section 5.5.1, pp. 144-145; Section 5.5.3.1, p. 147; Section 5.5.3.3, p. 147

EPC Contractor

On pages 144 and 145 of the Updated Public Application, FEI states:

> Construction for the Project is divided into the following five main sub-projects:
>
> • Ground Improvement and Early Works;
>
> • Regasification Package;
>
> • Auxiliary Systems (Utility Pipe Rack and Equipment);
>
> • 3 Bcf LNG Storage Tank; and
>
> • Base Plant Demolition.

On page 147 of the Updated Public Application, FEI states:

> Given the size and complexity of the Project and the multiple interfaces between the work, FEI intends to initiate a competitive process to select and award the work to a single EPC contractor for the entirety of the scope. However, this would need to include a balance of risk and cost acceptable to both parties. FEI will also consider the possibility of awarding multiple contracts if required to properly manage the risk profile for the Project.

Further on page 147 of the Updated Public Application, FEI states:

> A consulting engineering firm selected through an appropriate sourcing process will complete the engineering detailed design activities, preferably as part of an EPC contract structure. Detailed design activities encompass all engineering calculations, validations, preparation of drawings and bid packages required to cover the project needs.

34.1 Please discuss how FEI will determine whether to proceed with a single EPC contractor for the entirety of the scope or proceed with awarding multiple contracts.

34.1.1 Please clarify the timing of FEI's decision regarding how to proceed.

Response:

FEI's preference is to award the TLSE Project scope to a single EPC contractor, or more likely a single consortium of contractors who will share management of the Project execution. This has several advantages, primarily:

- Reduces the overall Project risk by minimizing the interfaces that FEI may need to manage as owned risks as the Project progresses; and

- Reduces the number and cost of the FEI project management resources needed to execute the TLSE project.

There are scenarios in which this strategy may not be feasible, however they are considered unlikely:

- No acceptable bids are received by a single contractor/consortium; or
- The bidding process reveals significant advantages to splitting the contract.

FEI will select the contractor(s) based on overall value to the project, i.e., the proponent(s) who best demonstrate a thorough understanding of the scope, commercial terms and conditions, execution strategy, and are best suited (by way of experience of company and personnel) to perform the Project scope.

FEI's evaluation criteria will include the following general categories (and others that may be identified as development of the bidding process progresses):

- LNG storage and regasification experience at scale;
- Safety and environmental management planning;
- Contractor reputation (performance);
- Commercial favourability;
- Diversity management planning;
- Indigenous and local inclusion planning;
- Contractor team;
- Geographic location;
- Brownfield site development experience;
- Canadian and BC construction experience; and
- Contractor financial strength.

Exact weighting and ranking procedures for these criteria will be established once the TLSE Project scope and timing has been finalized following BCUC approval.

The final selection of the successful EPC contractor (or consortium of contractors) will take approximately 6 to 9 months following CPCN approval.

On page 147 of the Updated Public Application, FEI states:

> The preference will be to award the contract(s) to a proven contractor(s) with a high level of experience in LNG and natural gas engineering projects, and a recent successful track record of execution. The successful contactor(s) will be chosen according to established procurement procedures.

34.2 Please provide the evaluation criteria for selection of the EPC contractor should FEI initiate a competitive process for award of this contract.

Response:

Please refer to the response to BCUC IR1 34.1.

35.0 Reference: PROJECT DESCRIPTION

Exhibit B-1-4, Section 5.5.3.8, p. 149

Commissioning

On page 149 of the Updated Public Application, FEI states:

> A methodical and reasoned commissioning plan will be drafted, reviewed, and adopted well in advance of construction completion. Part of the EPC selection process will include the requirement to demonstrate ample experience in LNG plant start-ups to ensure FEI has a sound commissioning plan for the start up of the new assets.

35.1 Please explain whether the EPC contractor will be responsible for the commissioning and start-up of the TLSE Project equipment.

35.1.1 If so, please explain at what point in the commissioning and start-up process will operating responsibility be handed over to FEI.

35.1.2 Please discuss the pros/cons of the selected approach with respect to EPC contractor commissioning and start-up responsibilities.

<u>Response:</u>

FEI anticipates that the EPC contractor will perform the commissioning and start-up scopes. After the performance and operability of the equipment has been demonstrated according to a negotiated set of criteria, FEI will accept the systems and assume responsibility for operation. The conditions for acceptance will be agreed during the EPC contract drafting and negotiation. This arrangement strongly incentivizes the contractor to construct and commission systems such that startup and initial operations are safe, efficient, and reliable as possible.

During the construction, commissioning, and startup of the systems, FEI's owner's team will provide oversight of these activities to ensure safe, responsible management and to ensure FEI's due diligence obligations are met. FEI's commissioning and operations personnel will be integrated into most activities to aid in timely and safe startup, and to gain experience on the equipment before acceptance.

Commissioning and start-up is an important aspect of the planned scope and will be the subject of detailed negotiations with prospective contractors. It will represent considerable value and risk to the cost and timing of the Project's completion, and as such will be scrutinized carefully before award to promote the most favourable outcome for FEI and its customers.

The option to contract these scopes to some entity other than the EPC contractor, or to self-perform them as FEI, will be retained until award of the EPC contract. FEI historically has not used this approach, nor is it considered likely in this case as it would introduce further risk and complication to the Project, and would not be considered unless some offsetting advantage is identified, or if no suitable EPC bidder offers to take it on.

35.2 Please provide the details of the performance test requirements that will be expected of the successful EPC contractor.

Response:

No details of the performance test requirements have yet been developed.

The overall design requirements for the TLSE Project as recommended by FEI are described in the Project Basis of Design, and will be finalized during the detailed design phase which will occur following BCUC approval.

The general performance test requirements and general performance characteristics to be tested will be discussed and agreed between FEI and the EPC contractor during the EPC bidding phase. It is FEI's intention that overall performance aspects such as maximum regasification capacity, energy use, LNG specifications, etc. will be agreed upon before the contract is awarded.

Detailed performance specifications and test requirements for the various systems and major equipment packages will be finalized during detailed design when specifications for all equipment will be completed.

35.3 Please provide a description of lessons learned from the commissioning and start-up of Mt Hayes LNG Facility and Tilbury Phase 1A LNG Facility.

Response:

Learnings from the Mt. Hayes LNG project were incorporated into the development of the Tilbury 1A contract. A comprehensive lessons learned workshop was held following the Tilbury Phase 1A construction and commissioning/start-up phases to gather lessons and recommend enhancements to processes and practices for future projects such as the TLSE Project.

A number of opportunities were identified for future projects. The key actionable learnings for the Commissioning and Start-up phases applicable to the TLSE Project were:

- Establish clear expectations within the EPC contract terms for the development and handover of operations manuals and procedures, critical spares lists (including criteria), and maintenance planning;
- Establish methods for handover of permits and transfer of environmental data specifically for use during the commissioning and startup phases; and

- Planning and delivery for training of FEI personnel on key equipment procedures should be enhanced as part of all future projects.

These learnings have been incorporated into the TLSE Project planning process, and specific actions and programs will be put in place and managed under the Operational Readiness organization within the Project team.

36.0 Reference: PROJECT DESCRIPTION

Exhibit B-1-4, Section 5.8.1.1, p. 156

Canadian Impact Assessment Agency

On page 156 of the Updated Public Application, FEI states:

> Given that both the Federal and Provincial Environmental Assessment (EA) processes (see Section 5.8.1.2 below) are triggered, FEI asked that the Province request the Federal Minister of Environment and Climate Change to approve the substitution of the BC EA process for the Federal IA process. If substitution is approved for the proposed Project, it is expected that the British Columbia Environmental Assessment Office (BC EAO) will conduct the EA/IA in accordance with the conditions set out in the Substitution Decision, and at the end of the assessment process the BC EAO will provide its report to both the Provincial and Federal Ministers for their consideration.

On page 156 of the Updated Public Application, FEI states that an initial project description and engagement plan was filed in February 2020 with the BC EAO, and the public comment period was from June 1, 2020 until July 16, 2020.

36.1 Please provide an update on FEI's request to have the BC EAO process substitute the Federal IA process.

Response:

The Tilbury Phase 2 LNG Expansion Project has entered the environmental assessment process administered by the BC EAO and the impact assessment process administered by the Impact Assessment Agency of Canada (IAAC). The project is currently in the Early Engagement Phase (provincial) and the Planning Phase (federal). These are the same phases of the assessment process that the Project was in at the time of filing the Application.

As part of the assessment process, the Government of British Columbia has requested that the conduct of the federal impact assessment process be substituted to the province. The BC EAO and IAAC jointly administered a public comment period from June 1 to July 26, 2020 to facilitate feedback from the public and Indigenous groups on the substitution request. A decision on the substitution request is expected later in 2021.

More detail on the BC EAO review process can be found in the EAO User Guide.[48]

[48] https://www2.gov.bc.ca/assets/gov/environment/natural-resource-stewardship/environmental-assessments/guidance-documents/2018-act/eao_user_guide_v102_april_2021.pdf.

36.2 Please provide an update regarding the BC EAO process, including requirements for and status of public and Indigenous consultation if applicable.

Response:

Please refer to the response to BCUC IR1 36.1.

37.0 Reference: PROJECT DESCRIPTION

Exhibit B-1-4, Section 5.8.1.2, p. 157

BC Environmental Assessment Office

On page 157 of the Updated Public Application, FEI states:

> FEI notes that the Tilbury Phase 2 LNG Expansion under review by the BC EAO and the IAAC encompasses a larger expansion of the Tilbury site than what FEI is seeking approval for as part of this Application, as components of the larger project will not be owned by FEI.

37.1 Please clarify whether a separate BC EAO review shall be required for the TLSE Project scope, or whether the BC EAO review of the Tilbury Phase 2 LNG Expansion currently underway includes all of the scope of the TLSE Project.

Response:

The TLSE tank component is included as part of the reviewable scope of the Tilbury Phase 2 LNG Expansion Project EA. For clarity, no separate BC EAO review is required for the TLSE Project scope.

37.2 Please explain whether the TLSE Project, which FEI is seeking approval for as part of this Application, will require any additional review by the BC EAO should the Tilbury Phase 2 LNG Expansion project not proceed.

Response:

BC EAO review is required of any project that exceeds the trigger for assessment under the *Reviewable Projects Regulation* outlined in BC's *Environmental Assessment Act.* The TLSE Project includes an LNG storage tank that triggers a Provincial EA and is therefore subject to BC EAO review. This LNG storage tank is subject to BC EAO review as part of the Tilbury Phase 2 LNG Expansion and cannot be constructed without approval of a Provincial EA Certificate.

37.3 Please provide an update on the status of the BC EAO review of the Tilbury Phase 2 LNG Expansion.

Response:

Please refer to the response to BCUC IR1 36.1.

38.0 Reference: PROJECT DESCRIPTION

Exhibit B-1-4, Section 5.8.2, p. 157; Appendix O, p. 3-6

BC Oil and Gas Commission Approvals

On page 157 of the Updated Public Application, FEI states:

> The Oil and Gas Activities Act governs the construction and operation of the Project. The Project will require Facility Amendments for each of the Project Components. A Facility Amendment is a significant process with considerable technical scrutiny on the Project by the BCOGC. Indigenous and public consultation, archaeological requirements, design reviews, and environmental permits/approvals for work in and around fish bearing streams are all components of the Facility Amendment. Each component must receive BCOGC approval prior to commencing construction. Since the proposed Project is within the existing facility boundaries, the current schedule assumes a six-month approval period from the time of filing.
>
> In addition to the Facility Amendments, the Project may require a waste discharge authorization and heritage permits from the OGC.

In Table 5-9 FEI notes a key milestone of June 2023 for BC OGC permits.

38.1 Please clarify if the June 2023 milestone represents the filing date with the BC OGC, or the date by which FEI expects to receive the relevant permits.

Response:

The most recent Project permitting schedule anticipates submission of the BCOGC Facility Amendment in mid-2023 with approval anticipated by the end of 2023.

38.2 If applicable, please provide an update with respect to the current status of BC OGC permit applications.

Response:

The BCOGC permit applications are currently in the planning phase and will be further developed as the Project planning and design advances.

38.2.1 Please clarify how many separate BC OGC applications FEI expects to file as part of this Project.

Response:

FEI is still discussing the overall permitting approach with the BCOGC and has not yet determined how many amendments (applications) FEI will file for the TLSE Project.

38.3 Please provide an update regarding Indigenous and public consultation as they relate to FEI's application to the BC OGC for this Project.

Response:

FEI has not yet submitted an application to the BCOGC for the TLSE Project. The Company is currently engaging with the BCOGC to determine permitting requirements, which will inform the required Indigenous and public consultation.

FEI together with FortisBC Holdings Inc. has developed an overarching Engagement Plan to ensure Indigenous groups and stakeholders are informed and engaged about the TLSE Project holistically and to allow for synchronized consultative activities with the parallel Provincial EA and Federal IA processes, which involve significant engagement. Please also refer to the response to BCUC IR1 58.1 for an updated engagement log with Indigenous groups.

With respect to FEI's application to the BCOGC for the TLSE Project, FEI will use the same synchronized approach to ensure that FEI meets the consultation and notification requirements of the BCOGC.

38.4 Please explain, in FEI's experience, the typical length of time required by the BC OGC to review and approve permits for a Project of this scope.

Response:

In FEI's experience, the review and approval of LNG Facility Permit Amendments by the BCOGC could take between 6 to 12 months. As a planning assumption, the Project permitting schedule provided as part of the Application assumes 6 months from submission to approval of the BCOGC facility permit amendment.

38.5 Please explain whether FEI is submitting separate permit applications to the BC OGC for the TLSE Project and the Tilbury Phase 2 LNG expansion project.

Response:

The Tilbury Phase 2 LNG Expansion Project EA includes two separate components, namely the 3 Bcf LNG storage tank included in the TLSE Project, and additional liquefaction capacity (the Liquefaction Facility). Since the Liquefaction Facility is contingent on market factors it is unclear when construction would commence or the new capacity brought into service. In contrast, the 3 Bcf LNG storage tank has been identified as a critical component of FEI's system resiliency and as such FEI plans to execute this TLSE Project upon receipt of BCUC approval as well as successful conclusion of the required environmental assessment process.

FEI expects to file a permit application to the BCOGC for the TLSE Project. The liquefaction component of the Tilbury Phase 2 LNG Expansion Project will also require a BCOGC permit which will be submitted by the proponent who develops the Liquefaction Facility.

38.5.1 Please explain how FEI will apply for BC OGC permits for any Project components which are shared between the TLSE Project and the Tilbury Phase 2 LNG expansion project, including how Indigenous and public consultation will be adequate for these permits.

Response:

For clarity, the TLSE storage tank is a component of the Tilbury Phase 2 LNG Expansion Project that is being assessed under the provincial Environmental Assessment (EA) and Federal Impact Assessment (IA) processes, with the other major component being the Liquefaction Facilities.

As discussed in the response to BCUC IR1 38.5, FEI expects to submit a permit application for the TLSE Project. A separate permit application will be required for the Liquefaction Facilities component of the Tilbury Phase 2 LNG Expansion Project. The permit application for the storage tank would include any changes to the site required to support the TLSE Project. This application will include aspects of interconnections to the existing Tilbury 1A facility and existing shared utilities at the site.

A similar process would likely be followed for the Liquefaction Facility component of the Tilbury Phase 2 LNG Expansion Project and any interconnections with existing equipment at the site.

As previously discussed in the response to BCUC IR1 38.2.1, there are ongoing discussions with the BCOGC to determine the exact details of how this permitting will proceed.

With respect to Indigenous and public consultation, FEI and FortisBC Holdings Inc. have developed an overarching Engagement Plan to ensure Indigenous groups and stakeholders are informed and engaged about the TLSE Project and to allow for synchronized consultative activities with the parallel Provincial EA and Federal IA processes, both of which involve significant engagement. For further detail, please refer to the updated Table 8-5 in the response to BCUC IR1 58.1. FEI will initiate the same synchronized approach to ensure that it meets the consultation and notification requirements of the BCOGC.

On page 3-6 in Table 3-1 of Appendix O states:

> An amendment to the existing Facility Permit or New Facility Permit is required for the construction and operation of the expansion. The amendments could be completed in phases to align with the construction phases. Requires site-specific environmental baseline fieldwork, detailed engineering information, and consultation with Indigenous groups and public stakeholders prior to EA Application submission.

38.6 Please clarify if FEI intends to apply for the amendments in phases. If yes, please clarify the projected timing of each phase, and the requirements for environmental, archeological and consultation at each stage.

<u>Response:</u>

The TLSE Project and the Liquefaction Facility are both subject to BCOGC amendment processes. FEI or FortisBC Holdings Inc. intends to apply for BCOGC amendments in phases, with the TLSE Project portion proceeding first. At the current phase of development, the schedule is uncertain and therefore, it is difficult to provide projected timing for each phase including environmental, archaeological, and consultation. However, FEI has started preliminary discussions with the BCOGC about permitting projects at the Tilbury site. As schedule certainty increases, FEI and FortisBC Holdings Inc. will re-engage permitting authorities to develop a detailed permitting plan for each phase.

39.0 Reference: PROJECT DESCRIPTION

Exhibit B-1-4, Section 5.8.3, p. 157

Municipal Approvals

On page 157 of the Updated Public Application, FEI states:

> Municipalities have bylaws and guidelines related to construction and installation of facilities of this nature. FEI is currently in the process of identifying all municipal permit requirements and will determine requirements during detailed design. FEI will acquire permits and approvals and adhere to conditions during construction, subject to FEI exercising rights under section 121 of the Utilities Commission Act in the event requirements are expected to supersede or impair the Project or a power conferred on the BCUC.

39.1 Please provide any updates on FEI's progress in identifying all municipal permit requirements.

Response:

FEI has created a list of all the municipal permits required for the TLSE Project, including their application requirements. The list is based on the currently available design information and will be revised as more detailed engineering information becomes available. In addition, the permitting list and requirements will be developed and refined in collaboration with municipal staff responsible for permitting.

During the Tilbury Phase 2 LNG Expansion Project Environmental Assessment process, FEI and FortisBC Holdings Inc. consulted with local governments and governmental agencies including Metro Vancouver and the City of Delta. FEI will validate the list of required municipal permits for the TLSE Project during the consultation process.

39.1.1 Please explain why identification of municipal permitting requirements is deferred until the detailed design phase of the TLSE Project.

Response:

Identification of the TLSE Project municipal permitting requirements is a collaborative effort between FEI and respective municipalities. Further, the process of determining municipal permitting requirements is informed by engineering details that can only be determined during the detailed design phase, as was done during the Tilbury 1A project.

C. PROJECT COSTS, ACCOUNTING TREATMENT AND RATE IMPACT

40.0 Reference: PROJECT COSTS, ACCOUNTING TREATMENT AND RATE IMPACT

Exhibit B-1-4, Section 4.3.5.6, p. 100; Section 6.4.1, p. 163; Section 6.4.3, p. 165

LNG Tank Depreciation

On page 163 of the Updated Public Application, FEI states:

> FEI consulted with Concentric, who recommended the average service life of a new 3 Bcf LNG tank would be 60 years (i.e., 1.67 percent = 1 / 60 x 100) based on recent experience, with a net salvage rate determined to be 40 percent of the capitalized value of the LNG tank over 60 years (i.e., 0.67 percent = 0.4 / 60 years x 100).
>
> FEI currently has a depreciation rate of 1.23 percent (equivalent to 81 years) and a net salvage rate of 1.12 percent approved by the BCUC for the Tilbury LNG tank (Account Class 44300). This rate is primarily determined based on historical assets (i.e., Tilbury Base Plant and Tilbury 1A facilities) within the same class that includes accumulated gains or losses embedded within the depreciation rates that existed at the time of the depreciation study.

40.1 Please discuss what the estimated average service life and net salvage rate of the existing Tilbury LNG tank are when the accumulated gains or losses are excluded, and how these compare to the proposed 3 Bcf LNG tank's estimated average service life (i.e. 60 years) and net salvage value (i.e. 0.67 percent), respectively.

40.1.1 If the estimated average service life and net salvage rate of the existing Tilbury LNG tank, as calculated in response to the preceding IR, differs from 60 years and 0.67 percent, respectively, please explain why. As part of the response, please explain if differences in tank usage purpose is attributable to the different service lives.

<u>Response:</u>

While responding to this information request, FEI noted page 163 of the Application, as referenced in the preamble, incorrectly implied that the currently approved depreciation rate of 1.23 percent and net salvage rate of 1.12 percent for the Tilbury Base Plant tank (i.e., the “Tilbury LNG tank”) were determined based on both the Tilbury Base Plant and Tilbury 1A facilities. FEI clarifies that the currently approved depreciation and net salvage rates of 1.23 percent and 1.12 percent, respectively, were determined based on the Tilbury Base Plant facilities only.

FEI's currently approved depreciation and net salvage rates are based on its 2017 Depreciation Study, which was approved by Order G-165-20 and decision regarding FEI's 2020-2024 Multi-Year Rate Plan (MRP) Application. The 2017 Depreciation Study included FEI's assets in rate base up to and including December 31, 2017. As the Tilbury 1A facilities first entered rate base in 2018, the 2017 Depreciation Study did not include the Tilbury 1A facilities. Therefore, the current depreciation and net salvage rates of 1.23 percent and 1.12 percent, respectively, were determined based on the Tilbury Base Plant facilities only.

Based on the 2017 Depreciation Study, the average service life and the net salvage rate for the Base Plant tank (Asset Class 44300) is 40 years and 0.5 percent, respectively, when the accumulated gains or losses are excluded[49]. The net salvage rate was determined based on a net salvage percentage of 20 percent for Asset Class 44300 (i.e., 0.5 percent = 0.2 / 40 years x 100).

The Base Plant tank has been in service since 1971, which is 50 years ago. The life of the tank has been extended due to the capital maintenance activities over the years that have involved replacing and repairing major components of the tank. However, the use of the estimated 40-year average service life has resulted in the remaining original assets that have not been replaced and retired now being over-depreciated, and the replacement assets being depreciated based on a renewed 40-year average service life at the time of installation. All of the gains and losses are being recorded to the accumulated depreciation account; therefore, by taking into account these historical gains and losses in the depreciation rate calculation, the apparent financial 81-year average life estimate (100/1.23 = 81) is not a true reflection of the estimated asset life.

The estimated average service life of 60 years for the proposed 3 Bcf tank is recommended by Concentric based on the newer Mt. Hayes LNG storage tank, which entered service in 2011. The Mt. Hayes storage tank has been recorded under a separate asset class (44305) and is included in FEI's 2017 Depreciation Study with the estimated average service life determined to be 60 years. Concentric advised that using a 60 year average service life, consistent with the Mt. Hayes tank, to calculate the depreciation and salvage rates for the proposed new TLSE tank is reasonable and appropriate given the similarity of materials and construction technology between the Mt. Hayes tank and the proposed TLSE tank. The TLSE tank is considered to be more comparable to the Mt. Hayes tank than the Tilbury Base Plant tank due to the relative age of the tanks and the resulting changes in materials, technology and construction over time. As described above, the use of the tank was not a consideration in the service life of the Base Plant tank compared to the proposed new TLSE tank.

40.2 Please provide the rate impact of using the existing Account Class 44300 depreciation and salvage rates for the proposed 3 Bcf LNG tank.

<u>Response:</u>

The following table compares the present values of the incremental revenue requirement and the levelized delivery rate impact (in percentage and in $ per GJ) over the 67-year analysis period between the proposed depreciation and salvage rates in this Application and the currently approved depreciation and salvage rates for Account Class 44300.

---

49 MRP Application, Appendix D2-1, pp. 8-7.

As the table below shows, the change in the present value of incremental revenue requirements is minimal and has no impact on the levelized delivery rate impact over the 67-year analysis period when rounded to two decimal places in percentage or to three decimal places in $ per GJ. FEI notes the decrease in the depreciation rate (1.67 percent to 1.23 percent) is offset by the increase in the salvage rate (0.67 percent to 1.12 percent).

	Proposed Depreciation Rate of 1.67% and Salvage Rate of 0.67%	Current Depreciation Rate of 1.23% and Salvage Rate of 1.12%
PV of Incremental Revenue Requirement 67 years ($ million)	1,041.925	1,041.963
Levelized Delivery Rate Impact 67 years (%)	6.67%	6.67%
Levelized Delivery Rate Impact 67 years ($/GJ)	0.301	0.301

40.3 Please confirm all assets which are included in Account Class 44300 apart from Tilbury Base Plant and Tilbury 1A facilities. As part of the response, please discuss whether the Mt. Hayes LNG facility is included.

Response:

Asset Class 44300 only contains the costs for the Tilbury Base Plant and Tilbury 1A facilities. The costs for the storage tank for the Mt. Hayes facility are recorded in a separate Asset Account (i.e., 44305). Please also refer to the response to BCUC IR1 40.1 clarifying the assets which were used to determine the currently approved depreciation and net salvage rates for the Tilbury Base Plant tank.

On page 165 of the Updated Public Application, FEI states:

> Once the Base Plant has been demolished, the assets will be retired following normal asset retirement accounting by crediting plant in service and debiting accumulated depreciation,
>
> […]
>
> FEI's next depreciation study will be completed prior to 2025, and, if approved, this retirement will be known, future depreciation rates for the impacted asset classes will take the retirement of the Base Plant into account. All else equal, this retirement will result in an increased depreciation rate for the impacted accounts in order to recover the remaining net book value of the retired assets. FEI has not forecast a change to the depreciation rate in the financial analysis, as the impact of the

retirement on future depreciation rates is unknown and will be confirmed with the next depreciation study.

40.4 Please provide the factors that FEI considers when seeking a change in the depreciation rate to recover the remaining net book value of retired assets. As part of the response, please discuss the appropriateness of recovering the entire remaining net book value of the retired assets as an expense in the year that retirement occurs (as opposed to recovering the remaining net book value through increased future depreciation rates).

Response:

As background on the treatment of retired assets under utility group accounting practices, FEI provides below its response to BCUC IR1 104.1 in the 2020-2024 MRP Application proceeding. It was in this proceeding that FEI's current depreciation rates were approved.

> 104.1 Please explain how FEI currently accounts for gains or losses on retirements. Do these amounts appear in this study?
>
> Response:
>
> Gains and losses resulting from historical assets retirements are recorded as a credit or debit, respectively, in accumulated depreciation for the specific asset class to which they relate. This treatment is discussed in the BCUC Uniform System of Accounts for Gas Utilities pages 17 through 21.
>
> When a depreciation study is conducted on a three to five year cycle, the revised depreciation rates will reflect the unwinding of the difference between the net book value of assets and the value realized at retirement that is embedded in accumulated depreciation. This is accomplished by setting depreciation rates to true up the depreciation reserve, if required. This mass property accounting methodology for gains and losses on retirements is consistent with the group method of depreciation adopted by many utilities (including FortisBC) and is also discussed on pages 23 through 26 in the BCUC Uniform System of Accounts for Gas Utilities.
>
> In the FEI 2017 Depreciation Study, on pages 5-2 and 5-3 of Appendix D2-1 in the Application, the gains and losses are included in column 5, labelled Book Depreciation Reserve. Note that the majority of the Book Depreciation Reserve is representative of the accumulated depreciation collected in customer rates, with a portion representing gains and losses on retirements. The unwinding of the accumulated gains and losses included in the Book Depreciation Reserve were taken in consideration when the recommended depreciation rates, on pages D-3 to D-7 in Section D2.2.1 of the Application, were developed.

Overall, the review and update of the depreciation rates takes into account a number of factors and considerations including adjusting the recommended depreciation rates for the remaining net book value of any retirement losses as described above.

In arriving at the recommended depreciation rates (with the assistance of an external depreciation specialist, which is accepted practice for utilities including FEI), the depreciation specialist performs a number of activities. These include reviewing FEI's assets and retirement transactions, conducting operational interviews with FEI staff, and comparing the results to FEI's industry peers. The retirement transactions and any related early retirements (i.e., actual service life versus original estimated service life) help to inform the decision on the estimated remaining useful life, which affects the proposed depreciation rates. The depreciation rates are then adjusted to factor in the recovery of any existing retirement losses (or gains) that may be included in the accumulated depreciation account balance over the remaining lives of the existing assets and the final depreciation rates are subject to review by the utility's regulator.

Recommendations for revised depreciation rates are not designed to recover existing "loss" balances all at once. Under FEI's approved group accounting method, depreciation rates are designed to recover existing amounts of unrecovered depreciation over the remaining service lives of the assets that remain in the asset class. There will continue to be assets in Asset Class 44300 after the Base Plant is retired; therefore, the accepted regulatory accounting practice is to recover any remaining net book value over the life of the remaining assets in the class.

40.5 Please provide a detailed description of any past examples of where FEI was approved to recover the remaining net book value of retired plant assets through increased depreciation rates.

Response:

The subject of retirement losses and their recoverability in depreciation rates and subsequently through customer rates has been thoroughly explored in past FEI regulatory proceedings. Each time FEI files a depreciation study (every three to five years), the approved depreciation rates are designed to recover the remaining net book value of retired plant assets, as described in the response to BCUC IR1 40.4. This is accepted utility group accounting practice and accords with the BCUC Uniform System of Accounts.

The most recent example of this is FEI's 2017 Depreciation Study. In FEI's 2017 Depreciation Study, on pages 5-2 and 5-3 of Appendix D2-1 in the 2020-2024 MRP Application, the gains (over-recovered depreciation) and losses (under-recovered depreciation) are included in column 5, labelled Book Depreciation Reserve. Note that the majority of the Book Depreciation Reserve is representative of the accumulated depreciation collected in customer rates, with a portion representing gains and losses on retirements. The unwinding of the accumulated gains and losses included in the Book Depreciation Reserve was taken in consideration when the recommended depreciation rates, on pages D-3 to D-7 in Section D2.2.1 of the 2020-2024 MRP Application, were developed.

The issue was canvassed extensively in FEI's 2012-2013 RRA. In its decision on the 2012-2013 RRA, the BCUC approved the recovery of under-recovered depreciation (referred to as" Asset Losses"):[50]

> The Commission Panel notes that in this case a number of factors resulted in the Asset Losses and there was no evidence of asset misuse by the Utilities. **Therefore, the Panel directs that the Asset Losses be recovered from ratepayers, as proposed, in current depreciation rates.**

FEI's current practice as described above remains consistent with the 2012-2013 RRA decision and the BCUC Uniform System of Accounts, and is appropriately applied to the Tilbury Base Plant as well. Please refer to the response to BCUC IR1 40.4 for further explanation of FEI's approved group accounting methodology.

40.6 Please discuss the delivery rate impact of recovering the remaining net book value of the retired assets over the following periods: (i) one year, (ii) 5 years, and (iii) 10 years.

<u>Response:</u>

As discussed in the response to BCUC IR1 40.4, adjusting the depreciation rate during a depreciation study on a regular basis to reflect retirements (early or at the end of life) and to recover the retirement losses over the remaining service life of the asset class is a common and normal practice for utilities.

FEI does not believe it is appropriate to recover the remaining net book value of the Tilbury Base Plant over (i) 1 year, (ii) 5 years, or (iii) 10 years through the use of a deferral account. However, in order to be responsive, FEI has provided the following table showing the levelized delivery rate impact in $ per GJ for FEI's non-bypass customers and the equivalent annual bill impact for the average residential customer with consumption of 90 GJs per year, based on amortizing the deferral account over 1, 5, and 10 years. FEI notes that if the remaining net book value of the retired assets is recovered through adjustment of the depreciation rates in a future depreciation study, as proposed in the Application, the retirement losses will be recovered over the estimated average service life of the individual asset accounts. Using the asset account for the storage tank of the Tilbury Base Plant, which has an estimated average service life of 40 years, the delivery rate impact would be significantly lower than recovering the remaining net book value over 1, 5, or 10 years.

[50] FEU 2012-2013 RRA Decision, p. 88: https://www.bcuc.com/Documents/Proceedings/2012/DOC_30355_04-12-2012-FEU-2012-13RR-Decision-WEB.pdf.

	Amortization Period		
	1 Year	5 Years	10 Years
Levelized Annual Delivery Rate Impact ($/GJ)	0.133	0.029	0.018
Equivalent Annual Average Residential Bill Impact ($)	11.93	2.65	1.64

40.7 Please provide the remaining net book value of the Base Plant in year 2025 when the Base Plant is expected to be demolished and the assets will be retired.

Response:

The forecast remaining net book value of the Base Plant assets in 2025 is $18.366 million. Please refer to Section 5.3.5 of the Application for a description of the Base Plant assets which will be retired.

On page 100 of the Updated Public Application, FEI states:

> While FEI expects the tank to last beyond 55 years, it makes economic and practical sense to replace the tank now to capture available economies of scale in the construction of a single, larger tank.

40.8 Please provide examples where FEI, or utilities in other jurisdictions, conducted similar asset retirements for the purposes of achieving economies of scale that are recoverable in rates.

Response:

FEI is not aware of any situations where asset retirements specifically for the purposes of achieving economies of scale were evaluated for rate setting. However, FEI disagrees with the characterization in this IR that the “purpose” of the asset retirement is to achieve economies of scale. As discussed in Section 4.3.5.6 of the Application, achieving the desired storage capacity with a combination of the existing 0.6 Bcf Tilbury Base Plant tank and a new storage tank is not the preferred alternative, from both a technical and economic perspective, which is why FEI dismissed this alternative in Step 1 of its two-step alternatives analysis. Please also refer to the response to BCUC IR1 16.22 where FEI discusses the rationale for retiring the Base Plant facilities as part of the TLSE Project.

41.0 Reference: PROJECT COSTS, ACCOUNTING TREATMENT AND RATE IMPACT
Exhibit B-1-4, Section 6.3, p. 163
Future Capital Replacement

On page 163 of the Updated Public Application, FEI states:

> The average service life for the regasification equipment and auxiliary system is both 40 years, which is shorter than the 60-year post-Project period used for the financial analysis. As such, FEI's financial analysis includes future replacement of the regasification and auxiliary systems at the end of their average service life at 40 years. The future capital replacement does not include the replacement of ground improvement work related to stone columns as discussed in Section 5.3.4. FEI does not expect the stone columns will need to be replaced within the 60-year post Project period.

41.1 Please confirm, or explain otherwise, that the 40-year average service life for the regasification equipment and auxiliary system was recommended by Concentric.

Response:

FEI did not seek a separate recommendation from Concentric regarding the average service life for the regasification equipment and auxiliary system. FEI utilized the approved rates from FEI's 2017 Depreciation Study, which was developed by Concentric and approved by Order G-165-20. Both regasification equipment and auxiliary systems are recorded under the asset account LNG Send Out Equipment (44840); per the 2017 Depreciation Study the estimated average service life for assets under this account is 40 years.[51]

41.2 Please confirm, or explain otherwise, that FEI's financial analysis includes future replacement of the ground improvement work that is not related to stone columns.

41.2.1 If not confirmed, please provide the delivery rate impact of including the future replacement of the ground improvement work that is not related to stone columns.

Response:

There is no ground improvement work that is not related to the installation of stone columns. FEI clarifies that all ground improvement work discussed in Section 5.3.4 of the Application as well as all capital costs shown in Line 3 of Table 6-2 of the Application are related to installation of stone columns.

[51] MRP Application, Appendix D2-1, FEI Depreciation Study, pp. 8-12.

42.0 Reference: PROJECT COSTS, ACCOUNTING TREATMENT AND RATE IMPACT

Exhibit B-1-4, Section 5.5.3.6, p. 148; Section 6.3, p. 163

Stone Columns

On page 148 of the Updated Public Application, FEI states that "over 4,200 stone columns will be required to support the LNG tank and other equipment such as pipe rack modules and the regasification area."

On page 163 of the Updated Public Application, FEI states that it "does not expect the stone columns will need to be replaced within the 60-year post Project period."

42.1 Please provide the typical useful life of a stone column. If it is less than 60 years, please explain why FEI does not expect the stone columns will need to be replaced within the 60-year post Project period.

42.1.1 Please provide an estimate of the cost to replace the stone columns during the 60-year post Project period and the delivery rate impact. Please provide any assumptions used.

Response:

The stone columns are considered to have an indefinite life. The only situation where new stone columns might be needed is if the structure above (i.e., the LNG tank) is removed and a new structure that is installed above requires more stone columns than those already installed.

Given that it is not necessary to replace the stone columns, nor is it possible to replace the columns without removing the structure above it (i.e., the LNG tank), FEI has not provided an estimate to replace the stone columns.

42.2 Please discuss whether FEI's expectation of not needing to replace the stone columns within the 60-year post Project period is consistent with industry experience with using stone columns in similar construction projects.

Response:

FEI confirms that its approach is consistent with industry experience with using stone columns in similar projects.

42.3 Please confirm, or explain otherwise, that Concentric has agreed with FEI's view that the stone columns would not need to be replaced within the 60-year post Project period.

Response:

Not confirmed. FEI did not seek a recommendation from Concentric regarding the stone columns. As discussed in the response to BCUC IR1 42.1, from a technical perspective, it is not necessary to replace the stone columns, nor is it possible to replace the columns without removing the structure above them (i.e., the LNG tank). Further, as confirmed in BCUC IR1 42.2, FEI's approach is consistent with industry experience.

FEI clarifies that the stone columns are recorded in asset account 44200 "LNG Gas Structures & Improvements". This is also the asset account for structures/buildings (except for the LNG tank) at the Tilbury facilities, and includes various components such as utilities, drainage, fencing, landscaping, railroad trackage, roads, sewer system, as well as the cost of clearing, leveling, grading, and surveying land before and after construction. The current estimated average service life of this asset account is 25 years with an approved depreciation rate of 2.2 percent per FEI's 2017 Depreciation Study approved by Order G-165-20.

FEI notes it is normal practice in group asset accounting for assets within the same class to have a range of useful lives. The stone columns in asset account 44200 will be depreciated financially based on the asset account's approved depreciation rate, and a future depreciation study will consider any gains or losses embedded within accumulated depreciation and will adjust the depreciation rate accordingly to reflect the over/under depreciation of all assets within the same account, including the stone columns.

43.0 Reference: PROJECT COSTS, ACCOUNTING TREATMENT AND RATE IMPACT

Exhibit B-1-4, Section 6.3, p. 162

Operation and Maintenance (O&M)

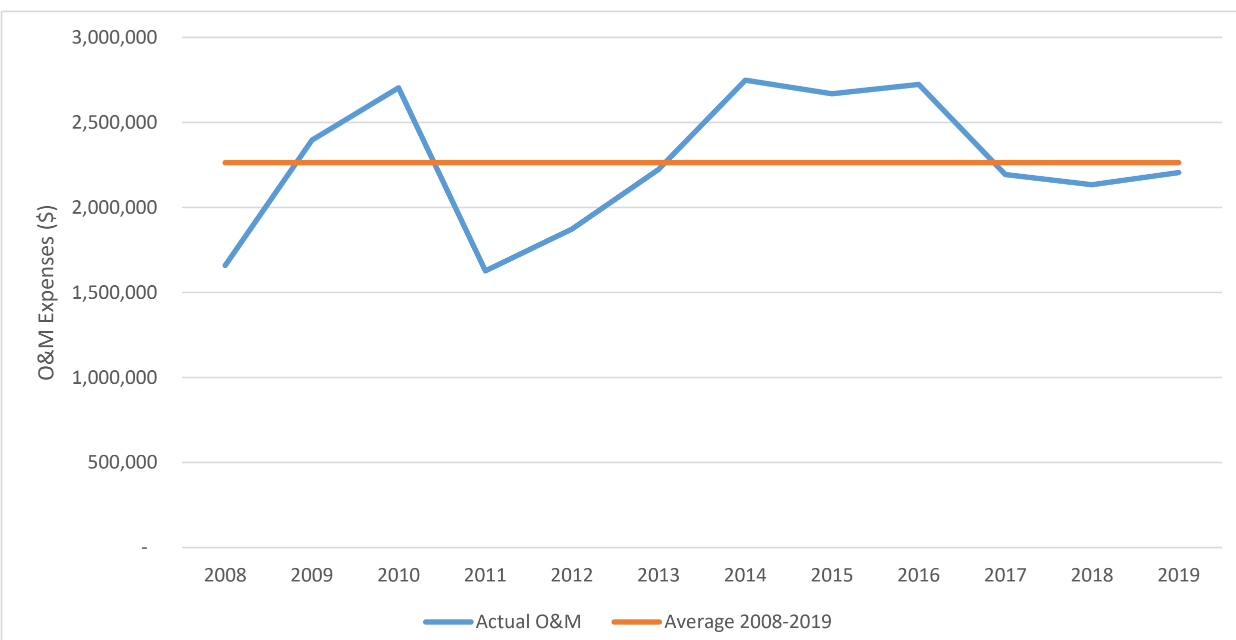
On page 162 of the Updated Public Application, FEI states: “The offsetting savings reflect the average of historical O&M costs for the Tilbury Base Plant from 2008 to 2019.”

43.1 Please explain why the historical period 2008 to 2019 was chosen to estimate historical O&M costs for the Tilbury Base Plant.

Response:

FEI clarifies that the average of actual O&M expenses for the Tilbury Base Plant from 2008 to 2019 were used to estimate what the annual O&M expenses would be in 2020 if the Tilbury Base Plant continues operations without the proposed TLSE Project. FEI has not used the actual O&M expenses from 2008 to 2019 to estimate historical O&M expenses for the Tilbury Base Plant as suggested by the question.

FEI used an average of actual 2008 to 2019 O&M expenses to estimate what the annual O&M expenses would be in 2020 for the Tilbury Base Plant because there is no particular trend shown from the actuals in those years. The figure below shows the actual O&M expenses from 2008 to 2019 (i.e., the blue line) which, on average, result in an annual O&M expense of $2.263 million. As the figure shows, the historical O&M expenses fluctuate significantly from year to year, and absent any trend, it is reasonable to use the average O&M expenses from 2008 to 2019 to estimate the costs of continuing to operate the Tilbury Base Plant.



43.2 Please discuss what the annual operating costs would be if the Tilbury Base Plant continued operating until the end of its life. Please provide any assumptions used.

Response:

Please refer to the response to BCUC IR1 43.1.

44.0 Reference: PROJECT COSTS, ACCOUNTING TREATMENT AND RATE IMPACT

Exhibit B-1-4, Section 6.4.4, p. 165

Application and Preliminary Stage Development Costs Deferral Account Amortization Period

On page 165 of the Updated Public Application, FEI states: "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 commence amortization over a three-year period thereafter."

44.1 Aside from consistency with FEI's previous CPCN applications, please provide the rationale for a three-year amortization period.

Response:

FEI evaluated amortization periods of 1 though 7 years for the deferral account because FEI considers it appropriate to amortize the deferral account for the TLSE Project in 7 years or less as the Project is forecast to be undertaken over a 7-year period.

The following table summarizes the levelized annual delivery rate impact in $/GJ and the levelized annual bill impact for a residential customer with an average consumption of 90 GJs per year for each of the amortization periods evaluated.

	Amortization Period						
	1 Year	2 Years	3 Years	4 Years	5 Years	6 Years	7 Years
Levelized Annual Delivery Rate Impact ($/GJ)	(0.003)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)	(0.001)
Levelized Annual Bill Impact for Residential, 90 GJs ($)	(0.27)	(0.09)	(0.09)	(0.09)	(0.09)	(0.09)	(0.09)

With the exception of the 1-year amortization period, there is no difference in the annual delivery rate impact for amortization periods of 2 to 7 years when rounded to 3 decimal places. Given there is essentially no difference in terms of annual delivery rate impact when rounded to 3 decimal places, FEI ultimately considers that there is no basis on which to deviate from prior practice for this Project, and as such selected an amortization period of 3 years, which is consistent with recent BCUC approvals for FEI's CPCN applications:

- Order C-2-21 for the Pattullo Gas Line Replacement Project approved a single Application and Preliminary Stage Development Costs deferral account with a three-year amortization period;
- Order G-12-20 for the Inland Gas Upgrades Project approved a single Application and Preliminary Stage Development Costs deferral account with a three-year amortization period;
- Order C-11-15 for the Lower Mainland Intermediate Pressure System Upgrade Project approved two separate deferral accounts for the Application and Project Development costs, both with three-year amortization periods; and

- Order C-2-14 for the Muskwa River Crossing Project for the Fort Nelson Service Area approved a single Application and Project Development Cost deferral account with a three-year amortization period.

44.2 Please discuss whether any alternative amortization periods were considered by FEI.

44.2.1 If so, please discuss these alternatives including why they were not chosen.

44.2.2 If no alternatives were considered, please discuss why not.

Response:

Please refer to the response to BCUC IR1 44.1.

44.3 Please provide the delivery rate impact if the deferral accounts are amortized over a one-year period and a two-year period, respectively.

Response:

Please refer to the response to BCUC IR1 44.1.

45.0 Reference: PROJECT COSTS, ACCOUNTING TREATMENT AND RATE IMPACT

Exhibit B-1-4, Section. 6.4.5, pp. 166-167

TLSE Foreign Exchange (Fx) Mark to Market Valuation Deferral Account

On page 166 of the Updated Public Application, FEI states: “A portion of the price of the Project may include US Dollar (USD) payments to the main Project contractor, giving rise to exchange rate risk.”

45.1 Please provide the expected portion of the estimated Project costs that may include USD payments.

Response:

Please see the table below which shows that approximately 27.8 percent of the total Project capital cost of $769.379 million in as-spent dollars (Table 6-2 of the Application, Line 7, Column 5) is expected to include USD payments. The table below also provides the USD/CAD exchange rates used by the consultants that developed the individual components of the cost estimates.

Partcular	Total As-spent ($ millions)	Portion USD ($ millions)	Exchange Rate (USD/CAD)	Source
LNG Tank	$ 401.272	$ 137.636	0.744	Horton CBI, Limited
Regasification Equipment	143.855	41.718	0.708	Linde
Ground Improvement	55.661	-		
Auxiliary System	151.461	34.836	0.735	Clough Enercore
Subtotal Addition to Plant	$ 752.249	$ 214.190		
Base Plant Demolition	17.129	-		
Subtotal Project Capital Cost	$ 769.379	$ 214.190		
Project Capital Cost in USD (%)		**27.8%**		

45.2 Please provide the foreign exchange rate that was used to prepare the Project cost estimate for the Application and the source of this foreign exchange rate forecast.

Response:

Please refer to the response to BCUC IR1 45.1.

On page 166 of the Updated Public Application, FEI states that it is seeking approval for a deferral account "to capture the mark-to-market valuation of any foreign currency forward contracts entered into related to construction of the Project. The deferral account is an important tool to avoid uncontrollable external income statement volatility, as well as to avoid additional exposure to foreign currency exchange rate risk during the Project."

On page 167 of the Updated Public Application, FEI states:

> The deferral account will not attract a financing return, as the mark-to-market adjustments are non-cash.
>
> […]
>
> The deferral account treatment of the mark-to-market adjustments related to the foreign exchange rate hedging for the Project will have no impact on customer rates. The use of the requested deferral account will not increase or decrease the expected cost of the Project because the hedging fixes the exchange rate for the USD denominated cost components and thus mitigates the foreign exchange risk upon settlement, or payment.

45.3 Please confirm, or explain otherwise, that in addition to having no impact on customer rates nor attracting financing return, the TLSE Fx Mark to Market deferral account will not result in any incremental costs or revenue requirement impacts.

<u>Response:</u>

Confirmed.

45.4 Please explain why FEI expects "uncontrollable external income statement volatility" in the absence of the deferral account.

<u>Response:</u>

The nature of foreign exchange rate changes are outside of the control of FEI since they are generally driven by macroeconomic factors. In Section 6.4.5 of the Application, FEI did not intend to indicate it expects uncontrollable external income statement volatility. Rather, in the absence of a deferral account, if there are movements in foreign exchange rates, there would be external income statement volatility if no hedging structure was implemented.

45.4.1 Please discuss the impact to FEI, its shareholders, and its ratepayers if the deferral account is not approved and, as a result, there is "uncontrollable external income statement volatility." As part of the response, please discuss the impact to shareholder earnings and shareholders' equity.

<u>Response:</u>

If the deferral account is not approved and the utility were to still enter into foreign currency forward contracts related to the construction of the Project, mark-to-market adjustments on the forward contracts would have no impact on ratepayers, as they are treated as a non-regulated item, which may settle to shareholders' equity each year. Over time and assuming the hedging arrangements are approved by the BCUC, any shareholder earnings impacts related to the mark-to-market adjustments would cumulatively net to zero; however, these adjustments could create year to year income statement volatility, which is not preferable from an investor/shareholder perspective when evaluating the utility's performance.

Alternatively, if the deferral account is not approved, FEI could choose not to enter into foreign currency forward contracts related to the construction of the Project, thereby eliminating the need to record mark-to-market adjustments. This would eliminate the risk to the shareholder related to income statement volatility, but create foreign exchange risk for ratepayers on the total Project costs that would ultimately end up in rates at the completion of the Project.

Ultimately, the use of the regulatory account ensures the fair treatment of both customers and the Company.

45.5 Please discuss whether FEI would hedge its USD denominated payments for the TLSE Project if the deferral account is not approved. Please explain why or why not.

<u>Response:</u>

If the deferral account is not approved, FEI would still attempt to manage its exposure to foreign exchange, but may not make use of hedging with foreign currency forward contracts as the use of such instruments may result in external income statement volatility arising from mark-to-market adjustments on the forward contracts.

Further on page 167 of the Updated Public Application, FEI states: "At the end of the Project, the amount of the deferral account will be zero, since the deferral account only captures any unrealized gains and losses related to the requirement to mark-to-market the foreign exchange derivative contracts."

45.6 Please discuss whether there would be any issue with the BCUC directing this account be closed at the end of the construction of the TLSE Project in year 2025.

Response:

FEI would not have an issue with this direction; however, as the account is intended to be used until the completion of the Project's construction period, if the construction timeline is delayed or extended, the deferral account would also need to remain open until the completion of construction. Therefore, if the BCUC were to direct the closure of the deferral account, FEI recommends that the closure be tied to the completion of Project construction and not a specific year.

46.0 Reference: PROJECT COSTS, ACCOUNTING TREATMENT AND RATE IMPACT

Exhibit B-1-4, Section 4.4.1.5.2, p. 111, Section 4.4.1.5.5, p. 115; Terasen Gas Inc. Certificate of Public Convenience and Necessity for the Tilbury Property Purchase Application, Exhibit B-1-4, Section 6.3, pp. 30 – 31 (TGI CPCN for Tilbury Property Purchase)[52]

Rate Impact

On page 111 of the Updated Public Application, FEI states:

> […] FEI has recently experienced a rise in costs to renew its market area storage resources. Going forward, it is reasonable to expect that contracting peaking resources could be challenging and costly absent new infrastructure being built.

46.1 Please provide supporting evidence to the above statement. As part of the response, please discuss why it is reasonable to expect that contracting peaking resources is challenging and costly.

Response:

As discussed in Section 4.4.1.5.2 of the Application (Table 4-7), the key pipeline and off-system storage resources in the region are fully contracted, which is having a significant effect on regional constraints. These assets are essential to managing the winter conditions in the region, including the coincidental peak demand from the natural gas and electric utilities in the region. Therefore, the existing assets will likely remain fully contracted until new infrastructure in the region is added. As a result, if a shipper such as FEI needs to contract additional resources, it will have to pay some premium to a counterparty to obtain such an asset.

The cost of the premium will likely reflect forward market prices in the region. The forward market price curve reflects information that is known to the market at the time. Figure 1 below shows the forward prices as of July 21, 2021 for Station 2 plus the associated Westcoast T-South Huntingdon Delivery Capacity toll and variable costs, compared to the Sumas forward price at the delivered market (Huntingdon). The figure reflects the market view that there is value for regional parties to hold firm resources (pipeline or off-system storage) to manage their winter load requirements, instead of purchasing Sumas-priced supply at the Huntingdon market. Thus, there is a premium to secure resources if a counterparty willing to sell such resources can be found. For example, the forward market prices as of July 7, 2021 show that if FEI or any counterparty in the region requires seasonal supply for November 1, 2021 to March 31, 2022 at Sumas (either a Sumas hedge or a T-South capacity release), they may have to pay a 0.90 CAD/GJ premium over the T-South Huntingdon Delivery Capacity toll.

[52] https://www.bcuc.com/Documents/Proceedings/2009/DOC_23705_B-1_PUBLIC-Tilbury-Property-CPCN-Application.pdf

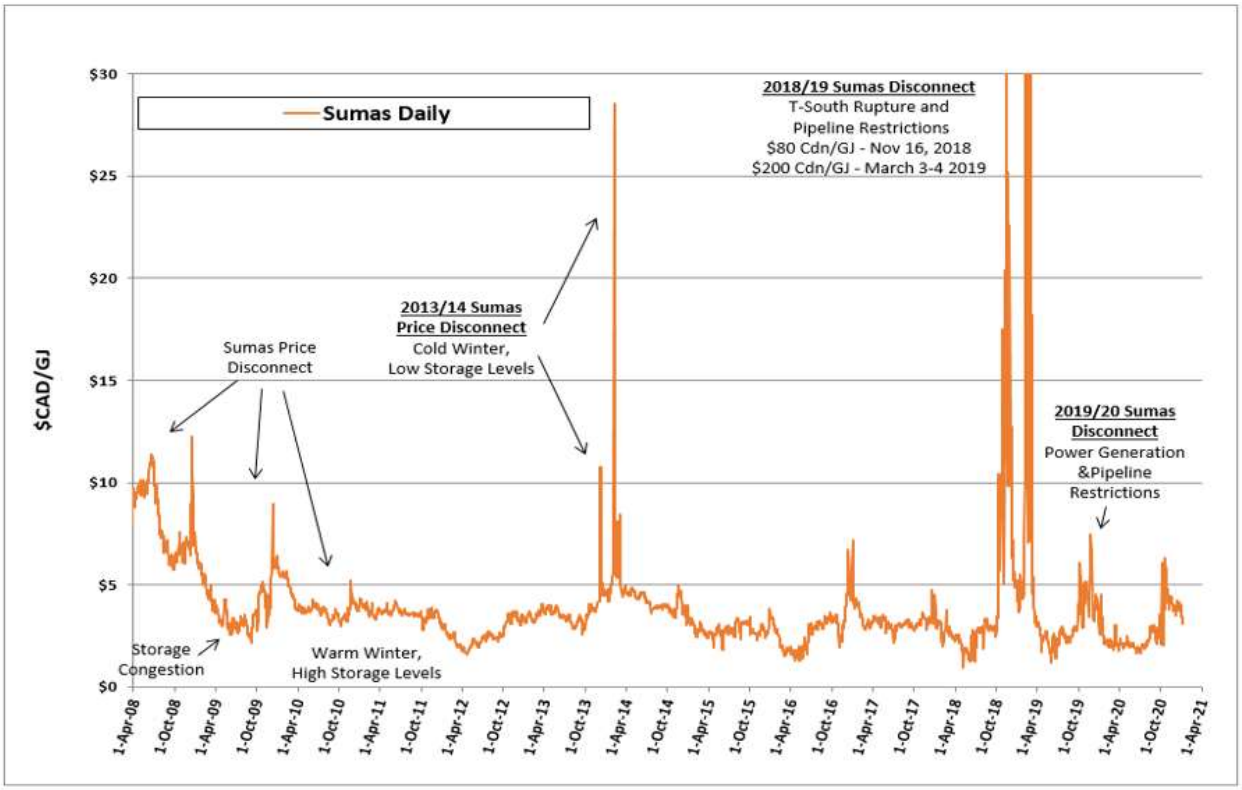
Figure 1: Forward Market Prices (as of July 7, 2021)[53]

From an Annual Contracting Plan standpoint, the evidence supporting the fact that resources are becoming costlier has been through the renewals of off-system storage assets at JPS and Mist. Since the region became fully contracted in 2013, the demand charges that FEI has negotiated have steadily increased. For instance, the annual demand capacity charge for FEI's most recent off-system storage renewal increased by 0.75 USD per dekatherm.

With respect to the challenge for contracting peaking resources, FEI is aware of only a few counterparties that would be willing to structure a peaking arrangement deal because the market risk for these arrangements is extremely high, as evident in the Sumas daily price volatility (see Figure 2 below).

[53] Graph is based off indicative forward pricing provided by Amerex on July 21, 2021. Station 2 full costs include Station 2 forward monthly price, Westcoast 2021 Final Tolls, and the estimated T-South fuel, Motor Fuel and Carbon Tax. Although the graph shows the current spread is slightly narrowing and curve slightly declining, the Sumas forward price for the winter season is still well above the Station 2 plus the associated Westcoast T-South Huntingdon Delivery Capacity toll and variable costs.

Figure 2: Sumas Daily Prices (2008-21)



This type of deal structure would have no long-term commitment, as the counterparties will likely only contract for terms up to five years, given the uncertainty in the regional marketplace. This is important to take into account, as the TLSE Project will provide a long-term commitment that no other alternative peaking resource in the market can provide.

FEI also believes that it could only secure a portion of what the Tilbury Base Plant currently provides (i.e., 150 MMcf/day) through commercial arrangements. This is because the 150 MMcf/day of the Tilbury Base Plant's existing deliverability is a large supply resource in the regional context. For example, the Tilbury deliverability is about 9 percent of the Westcoast T-South Capacity to Huntington, which is 1.7 Bcf/day. Further, even if FEI was able to structure a peaking deal, it would not only be costly but would also provide no assurances that the counterparty would be able to deliver the gas if FEI calls upon it. For these reasons, FEI's strategy has been to contract for resources directly with pipeline or storage facilities for its gas supply requirements.

46.2 Please discuss whether FEI has conducted a cost / benefit analysis for the alternative of contracting for peaking resources.

46.2.1 If so, please provide the economic analysis, the cumulative Delivery Rate Impact (over the 6-year period between 2022 – 2027), along with any assumptions made.

46.2.1.1 Please discuss where the peaking resources would come from, at what costs and at what commitment levels.

46.2.2 If no economic analysis was conducted, please explain why not.

Response:

Table 1 below provides an economic analysis and comparison between the following two scenarios:

- Construction of the proposed TLSE Project with 3 Bcf of storage and 800 MMcf/day of regasification capacity; and
- Construction of 2 Bcf of storage and 800 MMcf/day of regasification capacity, plus 150 MMcf/day of capacity contracted from T-South.

FEI considers both scenarios would meet FEI's MRPO, as well as maintaining FEI's current level of supply capacity provided by the existing Tilbury Base Plant. The supply capacity provided by the existing Tilbury Base Plant would be replaced with either the additional 1 Bcf of storage (scenario 1) or the 150 MMcf/day of peaking capacity from the marketplace[54] (scenario 2).

As shown in Table 1, although the alternate scenario of constructing a 2 Bcf tank (i.e., scenario 2) has a present value (PV) cost that is approximately $91 million less than the proposed 3 Bcf tank (in terms of PV of incremental revenue requirement over a 67-year analysis period), this is <u>entirely offset</u> by the additional annual costs required to secure the 150 MMcf/day of capacity from the market. When factoring in the additional annual costs required to secure capacity from the market, the total PV of incremental revenue requirement over a 67-year period for scenario 2 would be $313 million higher than the proposed TLSE Project. This alternative scenario would also result in a higher levelized delivery rate impact over 67 years by approximately 2.01 percent and a higher cumulative delivery rate impact from 2022 to 2027 by approximately 2.68 percent.

[54] Please refer to the response to BCUC IR1 22.7 for more details.

Table 1: Financial Comparison between 3 Bcf of Storage and 2 Bcf of Storage with 150 MMcf/day of Contracted Supply[55]

	3 BCF (Preferred Alternative)	2 BCF & plus T-South 150 MMcf/d Contract	Difference (3 Bcf - 2 Bcf)
Total Project Capital Costs, 2020 dollars ($ millions)	637	588	50
PV of Incremental Revenue Requirement 67 years -w/o T-South Contract ($ millions)	1,042	951	91
PV of T-South Contract; $30 million (2021 $) per year ($ millions)	-	405	(405)
Total PV of Incremental Revenue Requirement 67 years ($ millions)	**1,042**	**1,355**	**(313)**
Levelized Delivery Rate Impact 67 years (%)	**6.67%**	**8.68%**	**(2.01%)**
Levelized Delivery Rate Impact 67 years ($/GJ)	0.301	0.391	(0.090)
Cumulative Delivery Rate Impact (2022 to 2027)	**9.07%**	**11.75%**	**(2.68%)**

This comparison assumes the Tilbury Base Plant is demolished by 2025 and replaced with 150 MMcf/day of T-South Huntingdon delivery capacity at the same time. FEI notes that even if the Base Plant is able to continue operating for an additional 20 years before removal in 2040 (i.e., the Base Plant would be 70 years old), at which time the Base Plant gas supply capacity is replaced with T-South capacity, the PV of incremental revenue requirement would still be approximately $71 million higher than constructing a 3 Bcf storage tank now.

As such, this comparison demonstrates that it is significantly more costly to contract for a peaking resource than using the storage available from the proposed 3 Bcf storage tank. The additional 1 Bcf of storage capacity from the proposed TLSE Project will benefit FEI's customers with lower rate impacts when compared to the alternative of securing the equivalent gas supply capacity of 150 MMcf/day from the market through commercial arrangements.

Scenario 2 described above also assumes that FEI is able to contract T-South Huntingdon Delivery capacity for 150 MMcf/day, which is the equivalent to the existing Tilbury Base Plant capacity currently included in FEI's gas supply portfolio through the Annual Contracting Plan. As discussed in the TLSE Workshop,[56] FEI estimated the cost for 150 MMcf/day of capacity would be approximately $30 million per year in 2021 dollars. Since the TLSE Workshop, FEI has conducted further cost analysis that takes into account the potential costs to acquire this capacity, and the potential mitigation value for holding this capacity. This analysis was important because, as discussed in the response to BCUC IR1 46.1, resources are fully contracted in the region, therefore FEI would likely have to pay a premium over the Westcoast toll to acquire the capacity. Based off recent commercial transactions and the forward prices (Figure 1 of the response to BCUC IR1 46.1), FEI has placed the value to acquire this capacity at $0.86 Mcf/day. If FEI is able to acquire this capacity, there will be mitigation opportunities during the winter season to reduce the toll exposure for FEI's customers. FEI has placed this value at $0.75/Mcf, based off

[55] FEI assumed the annual costs for the supply contract would be $30 million per year without escalation or inflation. For the calculation of the $30 million, please refer to Table 2.

[56] TLSE Workshop Transcript, p.182.

current market conditions. The analysis is shown in Table 2 below, which further validates the $30 million per year in 2021 dollars.

Table 2: Huntingdon Delivery Capacity at Market Value (Including Winter Mitigation)

Daily Deliverability/Tilbury Regasification	(Mcf/day)	150,000
Pipeline Value (Cost to Acquire Incremental Capacity)	($/Mcf/day)	$0.86
Duration	(Days)	365
Annual Fixed Cost	($/Year)	$47,085,000
Winter Mitigation Revenue ($0.75/Mcf)	($/151d)	(16,987,500)
Annual Cost Incl. Winter Mitigation		**$30,097,500**

On page 115 of the Updated Public Application, FEI states:

> […] FEI could potentially further reduce its storage needs by entering into commercial arrangements to provide access to other contingency resources. This could potentially allow FEI to lease storage space to the export entity, thereby recovering a portion of the cost of service of the Project while maintaining an enhanced level of resiliency. Should this opportunity materialize, there is the potential to reduce FEI customers' costs;

46.3 Please provide an estimate of the reduction in FEI customers' costs as it relates to potentially leasing storage space. As part of the response, please quantify the impact on delivery rates and identify any assumptions used.

<u>Response:</u>

Please refer to the response to BCUC IR1 23.3 for a discussion of the provision of storage space to a third-party or affiliate. Although FEI cannot quantify the impact on rates of such an arrangement at this time given that no contract terms have been developed, FEI can provide an example of a scenario where an entity contracts for 20 percent of the storage capacity and 20 percent of the fully allocated cost of service was recovered from that entity. This would result in a reduction in the levelized delivery rate impact of the TLSE Project over the 67-year analysis period by 20 percent, or a decrease from 6.67 percent to 5.33 percent.

Any arrangement to contract storage would be subject to BCUC oversight.

46.4 Please discuss whether FEI has had discussions with any third parties to lease storage space.

Response:

FEI has not had discussions with any third parties to provide LNG storage space at this time.

On page 31 of the TGI CPCN for Tilbury Property Purchase, FEI stated that one of the potential opportunities for other uses of the purchasing of the property known as the Northwest Hardwoods Site was "to earn revenue from low impact activities on the Property, such as third party storage."

46.5 Please discuss whether FEI has leased the storage space referenced above.

46.5.1 If so, please quantify the revenue offset FEI has received since leasing the storage space and identify the time period.

Response:

For clarity, the initiative referenced above was related to providing space on the Tilbury property for the third party to store items, not LNG storage. Between 2010 and 2013, FEI received lease revenue of $1,581,937 through low impact third-party storage at Tilbury, as detailed in the Compliance Filing to the BCUC pursuant to Order G-68-10, dated June 28, 2013. This amount was subsequently returned to FEI customers. FEI has not received any additional third-party lease revenue for the Tilbury property past 2013.

47.0 Reference: PROJECT COSTS, ACCOUNTING TREATMENT AND RATE IMPACT

Exhibit B-1-4, Section 8.2.2, p. 184

Cost Allocation

On page 184 of the Updated Public Application, FEI states:

> FEI is engaged in consultation with the same Indigenous groups and stakeholders under the BC EA and Federal IA processes for concurrent developments at the Project site. The Project Engagement Plan synchronizes these consultation efforts.
>
> As noted above, the Tilbury Phase 2 LNG Expansion Project is also being developed concurrently at the Tilbury site.
>
> […]
>
> FEI notes that the Tilbury Phase 2 LNG Expansion under review by the BC EAO and the IAAC encompasses a larger expansion of the Tilbury site than what FEI is seeking approval of as part of the CPCN, as components of the larger project will not be owned by FEI.

47.1 Please discuss how FEI ensures costs that are related to assets at the Tilbury site that are not FEI-owned are segregated from those that are FEI-owned. As part of the response, please discuss the allocation of consultation costs to the TLSE Project.

47.1.1 Please discuss the allocation of any costs FEI ratepayers are being charged that are partially attributable to the non-regulated operations of the Tilbury site.

Response:

Currently, all assets at the Tilbury site are FEI-owned; therefore there is no need to segregate costs.

With regard to the development of the projects included in the Tilbury Phase 2 LNG Expansion Environmental Assessment (EA) (i.e., the TLSE Project storage tank and the Liquefaction Facility), FEI has a process in place to ensure costs are properly segregated. To date, applicable costs include EA-related costs, which include any consultation costs for the EA. FEI and its affiliated companies utilize internal orders within their accounting systems to allocate costs as between companies and as between regulated and non-regulated activities. At this time, minimal costs have been directly attributable to the Liquefaction Facility; FEI will monitor and allocate EA-related costs as the EA process proceeds.

47.2 Please discuss the integration risks of constructing the TLSE tank concurrently with the execution of other Tilbury LNG projects. As part of the response, please describe any increased execution complexity with respect to project coordination.

Response:

As discussed in the TLSE Workshop, there are other Tilbury projects being considered that could be developed at the same time as the TLSE Project if the development timelines coincide. For example, this could occur if market conditions favour the start of construction on the Liquefaction Facility (please refer to BCUC IR1 23.1).

Should projects be required to be executed concurrently, there will be increased execution complexity due to space constraints at the Tilbury site. Work fronts and laydown areas will be required to be carefully managed to avoid overlap and ensure site safety.

To minimize the interface risks associated with the potential for concurrent projects, FEI intends to design a competitive process to seek a single EPC contractor for the concurrent projects with demonstrated competence and experience in completing similar scale projects. This is advantageous because there would be one point of responsibility. These entities bring proven systems and processes for management of complex worksites and optimization of procurement, logistics, and construction activities so that execution, safety, cost, and schedule risk is minimized. Once designed, the competitive process will look to leverage the capabilities and expertise of the EPC, minimize risks to FEI and its customers, and seek to capitalize on economies of scope or scale to the benefit of the projects.

D. ENVIRONMENT AND ARCHEOLOGY

48.0 Reference: ENVIRONMENT AND ARCHEOLOGY

Exhibit B-1-4, Section 7.1, pp. 169, 170, 175

Impacts of the TLSE Project relative to the Tilbury Phase 2 LNG Expansion Project

On page 169 of the Updated Public Application, FEI states:

> the Tilbury Phase 2 LNG Expansion Project, of which the TLSE Project is a component, triggers the requirements for both a Federal Impact Assessment and a Provincial Environmental Assessment. … Accordingly, the Project will undergo a rigorous assessment of its environmental and other impacts, beyond the scope of assessment discussed in this Section. As part of that process, FEI will be undertaking detailed environmental assessment work, including vegetation, fish/fish habitat, and wildlife/wildlife habitat surveys, as well as surface and ground water resource investigations. Ultimately, the environmental assessment process will provide further opportunity to understand Project impacts and assess the suitability of any proposed mitigations. [Emphasis added]

On page 170 of the Updated Public Application, FEI states:

> FEI retained Jacobs Consultancy Canada Inc. (Jacobs) to conduct a preliminary environmental assessment of the Project. The results and conclusions from Jacobs' preliminary environmental assessment are outlined in the FortisBC Tilbury LNG Phase 2 Expansion Project Environmental Overview Assessment report (Environmental Overview Assessment or EOA), a copy of which is attached as Appendix O. [Emphasis added]

48.1 Please confirm, or explain otherwise, that Appendix O addresses the environmental impacts of the TLSE Project only.

Response:

FEI confirms that the Environmental Overview Assessment included as Appendix O in the Application identifies the environmental sensitivities of the Tilbury property as a whole, but addresses only the potential environmental impacts of the TLSE Project.

48.2 Please confirm if "the Project" referred to in both above extracts refers to the same project, or explain otherwise.

Response:

On page 169 and 170 of the Updated Public Application, the references to “the Project” and “Project” are referring to the TLSE Project.

49.0 Reference: ENVIRONMENT AND ARCHEOLOGY

Exhibit B-1-4, Section 7.2.1, pp. 174; 175; Appendix O, p. ES-1 to ES-2; p. 6-1

Atmospheric impacts and permitting requirements

FEI state on page 174 of the Updated Public Application:

> While impacts to the atmospheric environment associated with this Project are expected to be minimal, the risks associated with Metro Vancouver permitting under the Greater Vancouver Regional District Air Quality Management Bylaw No. 1082, 2008 are considered medium to high. The potential risk associated with the permitting under this bylaw will be further assessed during the detailed engineering phase through air dispersion modelling and working through the Metro Vancouver permitting process.

On page ES-1 of Appendix O states:

> This EOA concludes that each of the three Project alternatives, have the same potential effects, mitigation / follow-up actions and overall risk rating for all environmental receptors.
>
> ….
>
> The atmospheric environment receptor was determined to have a medium to high risk rating. A medium to high risk rating was determined because additional assessment is recommended to predict emissions to determine whether emissions are within applicable Ambient Air Quality Objectives and to obtain a Metro Vancouver Air Permit. Pending the outcomes of further emissions modeling, additional cost for the implementation of specialized mitigation measures or follow-up work are expected.

In Table 6-1 on page 6-1 of Appendix O, Jacobs notes: “Additional cost for the implementation of specialized mitigation measures or follow-up work are expected. The regulatory process is well-defined and associated costs are predictable.”

49.1 Given that Jacobs states associated costs are predictable, please confirm to what extent (if any) the costs of possible mitigation measures have been factored into the project contingency.

Response:

Financial costs associated with mitigation measures specific to ambient air quality were not identified as individual line items in the cost estimate prepared by Jacobs because the scope of the mitigation required is dependent on the outcome of the emissions modeling. The TLSE Project-wide contingency was estimated as 20 percent of the overall cost; this includes the cost for the implementation of specialized mitigation measures or follow-up work, if required.

On page 175 of the Updated Public Application, FEI states: “In addition, a cumulative impact assessment will be undertaken with regard to the atmospheric environment for the entire Tilbury site, including air dispersion modelling to facilitate permitting through Metro Vancouver.”

49.2 Please explain the nature and scope of a cumulative impact assessment, and the potential implications for the TLSE Project in terms of cost and timing.

Response:

FEI does not expect the cumulative impact assessment related to emissions to significantly impact the cost or timing of the TLSE Project.

The scale of the TLSE Project means that some of the components of the Project, specifically the LNG storage tank, trigger both the Provincial Environmental Assessment (EA) and the Federal Impact Assessment (IA) processes. The LNG storage tank is a component of the Tilbury Phase 2 LNG Expansion Project and subject to an EA and IA. The scope of the cumulative effects assessment related to emissions (eCEA) will be determined through ongoing discussions development of the Application Information Requirements required by the Provincial and Federal regulators for the Tilbury Phase 2 LNG Expansion Project.

Currently, it is expected that the greater portion of the emissions being assessed in the EA/IA would result from the proposed liquefaction. The main source of emissions associated with the TLSE Project are related to the occasional use of the vaporizers, and their operation will be infrequent. Given this, FEI anticipates the eCEA will have little to no impact on the cost or timing of the TLSE Project.

50.0 Reference: ENVIRONMENT AND ARCHEOLOGY

Exhibit B-1-4, Section 7.2, p. 172; Appendix O, p. ES-2 , p. 6-1,

Contaminated Soils and Groundwater Impacts - APECs

Page ES-2 of Appendix O states:

> The contaminated soils and groundwater environmental receptor were determined to have a medium to high risk rating. A medium to high risk rating was determined because there are eight APECs identified on the Tilbury site and further assessment (i.e., a Stage 1 and Stage 2 Preliminary Site Investigation (PSI)) is recommended to characterize and manage the potential adverse effects. Pending outcomes of the Stage 1 and Stage 2 PSI, <u>low to considerable additional cost</u> for the implementation of specialized mitigation measures or follow-up work are expected. [Emphasis added]

On page 172 of the Updated Public Application, FEI states that it will be undertaking Stage 1 and/or Stage 2 PSIs as the need is triggered by Project activities.

On page 6-1 in Table 6-1 of Appendix O states the risk rating for contaminated soils and groundwater receptors is Medium to High. Regulatory approvals are required to carry out the Project; however, Jacobs notes the regulatory process is well-defined and associated costs are predictable. [Emphasis added]

Mitigation/follow-up activities noted in Table 6-1 include the following:

- Finalize Stage 1 PS.I
- Work with BC ENV to unfreeze any permits that may be caught under the Site Profile-Site Disclosure Statement Process.
- Complete Stage 2 PSI work on all APECs for soil and groundwater to determine if contamination exists and to provide additional information for quantifying expected volumes of contaminated soils and/or groundwater.
- Preparation of a Soil Management Plan so that movement of soils during construction is already mapped out to reduce construction Delays.
- Liaise with BC ENV to discuss potential obligations and timing of remediation requirements.

50.1 Please clarify if any of the above mitigation/follow-up activities have taken place since the application was submitted. If yes, please provide an updated assessment of the TLSE Project related risks rating for the contaminated soils and groundwater receptors.

Response:

The Stage 1 Preliminary Site Investigation (PSI) is the only item that has been completed from the list of mitigation / follow-up activities listed in Table 6-1 of Appendix O. The findings of the finalized Stage 1 PSI did not alter the risk ratings, which remain as medium to high for contaminated soils and groundwater receptors.

The Stage 2 PSI was initiated in June 2021. Once the final report is produced (expected in early September 2021), more detailed information will be available to adjust the risk ratings for contaminated soil and groundwater.

50.2 Please clarify what "considerable" additional costs to implement specialized mitigation measures may be incurred, and if these have been included in the project contingency for the contaminated soils and groundwater receptors.

Response:

The removal of large volumes of contaminated soil and or contaminated ground water could require considerable additional cost and this is included in the overall contingency. The contingency quantification methodology employed by FEI is aligned to AACE recommended practices and referenced in the Validation Estimating LLC report. The methodology does not quantify or allocate contingency by individual risk events. Instead, the overall contingency for the TLSE project of $108.2 million includes sufficient funds should the risk occur and ground improvement mitigation activities are required.

50.3 Please provide an update of the BC ENV permit review process, or clarify when the review period would begin.

Response:

FEI has not engaged with BC ENV on the permit review process to date. FEI will engage with BC ENV when the Stage 1 and 2 PSI results are available.

51.0 Reference: ENVIRONMENT AND ARCHEOLOGY

Exhibit B-1-4, Section 7.3, pp. 176, 180; Appendix P, p. 28, p. i

Archeology Overview Assessment (AOA)

Page i of Appendix P states that Golder Associates Ltd. was retained to undertake an archaeological overview assessment of the FortisBC Tilbury LNG Production and Storage Facility Expansion (the Study) on Tilbury Island, Delta, BC.

On page 176 of the Updated Public Application, FEI states that the AOA is based on both a desk-top review of available information and a preliminary field reconnaissance (PFR).

On page 180 of the Updated Public Application, FEI states that an invitation to participate in the PFR was extended to the following Indigenous communities:

- Katzie First Nation
- Kwantlen (Seyem' Qwantlen) First Nation
- Musqueam Indian Band
- Semiahmoo First Nation
- Stó:lō
- Squamish Nation
- Tsawwassen First Nation
- Tsleil-Waututh Nation

During the PFR, the archaeological field crew consisted of one qualified archaeologist and one community member from Katzie First Nation, Seyem' Qwantlen First Nation, and Tsawwassen First Nation.

Page 28 of Appendix P states that the PFR was conducted through the morning and early afternoon of 21 of November 2019.

51.1 Please explain if the scope of the AOA covers the impacts from both the Tilbury Phase 2 LNG Expansion Project, and the TLSE Project.

<u>Response:</u>

For clarity, the TLSE storage tank is part of the Tilbury Phase 2 LNG Expansion Project, contrary to what is implied by the question. The scope of the AOA includes the entire Tilbury site, with the exception of the Tilbury 1A area that was investigated in an AIA conducted by Stantec in 2013 (and reported in 2014). A review of the entire site was necessary for the TLSE Project alone because there is the potential for ground disturbance within the existing property footprint, but is also sufficient to encompass the Phase 2 LNG Expansion Project and has been used in the EA/IA processes.

51.2 Please provide a copy of the invitation to participate in the PFR referenced in the preamble to the above mentioned groups.

Response:

FEI's consultant (Golder) has confirmed that it sent invitations to the Indigenous communities listed above in October 2019 (via individual emails to representatives from each Indigenous community). In addition, Golder sent follow-up email notifications to the Indigenous communities stating that the PFR was postponed in late-October, and then again in mid-November.

Golder has informed FEI that it did not retain all of the individual invitation emails. As such, FEI is unable to provide copies of the invitations.

51.3 Please provide any relevant, non-confidential written documentation from any Indigenous communities following the PFR, such as notes or minutes of meetings or phone calls, or letters received from or sent to the First Nation.

Response:

No comments were received specific to the PFR; however, FEI did receive one comment in relation to the AOA, which contains the results of the PFR. On February 26, 2021, Cowichan Tribes requested Tilbury Island be replaced with a Hul'q'umi'num place name as per the Cowichan Nation Use and Occupancy Study for Tilbury Island (September 9, 2019).

52.0 Reference: ENVIRONMENT AND ARCHEOLOGY

Exhibit B-1-4, Section 7.3, p. 181

BC OGC Archeological Review Processes

On page 181 of the Updated Public Application, FEI states:

> All oil and gas development proposed in BC requires that an Archaeological Information Form (AIF) be submitted to the BCOGC. The AIF indicates whether the proposed development will require a further AIA. Major projects that cover substantial areas typically require an AIA. An AIA was conducted on the Tilbury 1A portion of the Tilbury site in 2013. The AIF can be completed prior to finalizing the AIA; however, the approval would be conditional on completion of an AIA. [Emphasis added]
>
> Where an AIA is recommended, subsurface archaeological tests may proceed following the issuance by the Archaeology Branch (FLNRORD) of an HCA Section 12.2 permit. In the event that an archaeological site is discovered, then a HCA Section 12.4 permit (from BCOGC) may also be required. In addition, any Indigenous heritage investigation permits that are applicable at the time of the AIA will be obtained. Currently the Indigenous communities that have permitting processes in place are Musqueam, Seyem' Qwantlen, Squamish, Stó:lō and Tsleil-Waututh.
>
> Potential impacts to archaeological and historic heritage sites will be further assessed during the Project AIA. Archaeological permits will be obtained prior to conducting the AIA field work, which will be undertaken during the detailed engineering phase of the Project and, if necessary, during the construction phase of the Project. Indigenous communities will be invited to participate in the AIA field work.
>
> The AIA will be conducted where Project-related impacts to areas identified in the AOA as having archaeological potential are unavoidable. FEI anticipates that the majority of AIA work will be completed prior to construction during the detailed engineering phase of the Project. In addition, portions of the AIA may be completed concurrent with construction (e.g., in areas with potentially deep buried resources, areas with access constraints, or areas where ground conditions are not suitable for manual testing).

52.1 Please explain which approval is referred to in the 1st paragraph of the above preamble.

<u>Response:</u>

The approval referred to in the first paragraph is the BCOGC *Oil and Gas Activities Act* (OGAA) permit approval.

52.2 Please confirm, or explain otherwise, if FEI has obtained the required heritage investigation permits from the Musqueam, Seyem' Qwantlen, Squamish, Stó:lō and Tsleil-Waututh.

Response:

Confirmed. FEI's consultant, Golder, obtained the following heritage investigation permits:

- Musqueam Indian Band Heritage Investigation Permit MIB-2019-177-AOA;
- Seyem' Qwantlen Heritage Investigation Permit SQ 2020-47;
- Squamish Nation Archaeological Investigation Permit 19-0183;
- Stó:lō Heritage Investigation Permit 2019-252; and
- Tsleil-Waututh Nation Cultural Heritage Investigation Permit 2019-172.

52.3 Please provide an update with respect to progress on the AIA.

Response:

The AIA fieldwork was completed in Q2 2021. The reporting is underway with the draft interim report expected in Q3 2021 for review by Indigenous groups.

52.4 Given that portions of the AIA may be complete concurrent with construction, please explain the timing of the approval process with respect to the AIA.

Response:

The AIA field work was completed in April and May 2021 in all areas where access was possible; a small portion in the NE corner of the operating facility still requires AIA field work. The Interim AIA report is currently being drafted and will be provided to Indigenous groups for review and comment before it is finalized and submitted to the Archaeology Branch for approval. Depending on Indigenous group review, the submission to the Archaeology Branch is likely to occur in late Q4 2021 or early 2022.

53.0 Reference: ENVIRONMENT AND ARCHEOLOGY

Exhibit B-1-4, Appendix P, pp. 31-32; p. 595 of pdf

AOA Recommendations

Figure 11 in Appendix P illustrates the extents of four different areas with specific recommendations:

- Conduct an AIA in larger portions of assessment areas K, L and M prior to construction;
- In much of the area that has been previously developed (including parts of assessment areas A, B, C, D, F, G, H, Ia, Ib, K and L, and all of area E) the chance of encountering archaeological remains at least in the upper layers of fill is low. A chance find management plan (CFMP) should be implemented prior to ground disturbance to provide workers with the steps to follow should suspected archaeological materials be encountered during construction when an archaeologist is not present.
- In most of the area offshore of the dyke (area A), due to reported depths of fill or sediments, a CFMP should be implemented during work conducted in this area. If the proposed work extends below 4.0 m dbs, monitoring should be conducted (providing material from the depths where archaeological potential is anticipated will be exposed on the surface and available for observation).
- Where no archaeological potential has been assessed due to distance from water, previous subsurface excavations, or previous archaeological investigations (including parts of areas A, B, C, D, F, G, H, Ia and Ib, and all of area J) a CFMP should be implemented during work conducted in this area.

A summary map of the archeological recommendations is shown on page 595 of the pdf (shown below):

53.1 Please explain if all of the archeological assessment areas (A through M) are related to the TLSE Project. If not, please clarify.

Response:

Not all of the areas shown on the AOA figure are related to the TLSE Project. Areas A, K, L and M are not expected to be impacted by the TLSE Project but could be impacted by other FEI and FortisBC Holdings Inc. projects and were assessed by the archaeologists at the same time. All other areas identified on the figure could potentially be impacted by the TLSE Project depending on the final TLSE Project layout.

E. CONSULTATION

54.0 Reference: CONSULTATION

Exhibit B-1-4, Section 8.2, pp. 185; 198-199, Appendix Q-1, p. 1-1; Appendix Q-2,

pp. 15, 23 Synchronisation of CPCN Consultation with Environmental and Impact Assessment Processes

On page 185 of the Updated Public Application, FEI states:

> Given the BC EAO and IAAC assessment is occurring concurrently with the CPCN Application, and involves overlapping stakeholders and Indigenous groups, FEI's approach has been to synchronize consultation activities for both the Tilbury Phase 2 LNG Expansion Project and the TLSE Project in order to ensure engagement is robust, efficient and transparent. Combining consultation ensures interested parties are able to provide input through a single medium. This improves accessibility and mitigates against the risks of confusion and consultation fatigue that could result from engaging on each project separately. Further, this approach reduces the overall burden placed on Indigenous groups by removing the duplicative efforts that would otherwise be required to review each project separately.
>
> As part of the assessment process for the Tilbury Phase 2 LNG Expansion Project, FEI submitted an Initial Project Description (Appendix Q-1) and Engagement Plan (Appendix Q-2), which the BC EAO and IAAC accepted on February 27, 2020. This filing initiated the provincial Early Engagement phase and the federal Planning Phase of the assessments.

On page 198 to 199 of the Updated Public Application, FEI states:

> In order to limit consultation fatigue and recognizing the resource constraints within Indigenous groups, FEI has sought to combine engagement activities where possible. Rather than solicit feedback from Indigenous groups on each distinct Project component, FEI sought to provide a holistic picture as part of transparent information sharing. Comments received through consultation with Indigenous groups are applied to all applicable aspects of the Project to ensure they are appropriately captured and addressed.
>
> … To date, comments received have been related to the broader Tilbury Phase 2 LNG Expansion Project, and have not been specific to the TLSE Project. The one exception was a question regarding decommissioning of the existing infrastructure and related permitting requirements. [Emphasis added]

54.1 Please confirm if FEI has received any further comments from Indigenous groups, the general public or stakeholders specific to the TLSE Project since the filing of the Application.

Response:

Further comments specific to the TLSE Project since the filing of the Application are included in the table below.

Topic	Question
Project purpose	The proponent states that 'the LNG storage tank is needed to provide security of public utility service and resiliency against possible interruptions of natural gas supply to the Region but will also be sized and designed to have capacity to meet the future demands of the LNG bunkering and export markets'. [The Indigenous group] is in the opinion that improving the resiliency of the energy system that supplies BC homes' local supply and meeting market demands (LNG export market) do not justify the expansion in the same way. Please clarify how the Phase 2 expansion serves the BC public interest. In addition, what proportion of the increased production and the accompanying infrastructure for liquefaction from the Tilbury Expansion site will go through the TJLP marine jetty? Please clarify.
Accidents and malfunctions	Consider specific malfunctions and accidents associated with facility commissioning and LNG tank cool down
Decommissioning	[The Indigenous group] would like more details about the process for decommissioning and demolition of the old plant.

A number of additional comments, while not specific to the TLSE Project, are relevant to the project. The comments include topics such as:

- Alternative means;
- Alternatives to the Tilbury Phase 2 LNG Expansion Project;
- Purpose and need for the Tilbury Phase 2 LNG Expansion Project;
- Accidents, malfunctions, and public safety;
- Effects of the environment on the Tilbury Phase 2 LNG Expansion Project;
- Geology, geochemistry, and geological hazards;
- Acoustic environment;
- Visual environment;
- Vegetation;
- Groundwater and surface water; and
- Economic conditions.

In addition, FEI is aware that Tsleil-Waututh Nation has submitted comments directly to the BCUC regarding the consultation requirements for a CPCN and is in ongoing discussions with the Province about the application of DRIPA legislation to the *Utilities Commission Act*.

54.2 Please provide copies of any materials used by FEI in its consultation activities to explain the difference between the TLSE Project and the broader Tilbury Phase 2 LNG Expansion Project.

<u>Response:</u>

FEI's primary tool for major project communications is its website TalkingEnergy.ca[57]. Please refer to Attachment 54.2a.

As part of the Provincial Environmental Assessment, the project team conducted a workshop on the development history of the Tilbury site for Indigenous groups and government agencies. Please refer to Attachment 54.2b for a copy of the presentation.

An information sheet that provided a background of the TLSE CPCN process was shared with the BC EAO in February 2021. The BC EAO then shared the information sheet with Indigenous groups who requested further information about the process. This document provided further information on why FEI applied for a CPCN for the TLSE project, how FEI has been conducting engagement for TLSE, and a timetable for CPCN procedural-related activities. Please refer to Attachment 54.2c for a copy of the information sheet.

[57] https://talkingenergy.ca/.

55.0 Reference: CONSULTATION

Exhibit B-1-4, Section 8.4.5, pp. 204-205

Indigenous Consultation and Engagement Timing

On page 204 of the Updated Public Application, FEI states:

…

- FEI will continue to engage Indigenous groups through the BC Environmental Assessment and Canada's Impact Assessment process to gather and incorporate Project feedback, address concerns, and provide information on upcoming business opportunities. These regulatory processes will address some of the preliminary concerns raised by Indigenous groups including greenhouse gas emissions and air quality;
- During the BCOGC permitting process for this Project, more detailed Project information will be available to Indigenous groups for review and comment. This process will include up-to-date shape files, maps, and environmental management plans. FEI will support the BCOGC consultation process by responding to technical questions and attending meetings where appropriate. The BCOGC process will encompass the comments raised by Indigenous groups around tank demolition; and
- Finally, FEI anticipates that there will be extensive engagement with Indigenous groups in the coming years for the Project through the concurrent regulatory processes underway with the BC EAO and IAAC, and the future BCOGC process. This includes Indigenous participation in planning of the Environmental Assessment, contribution of Indigenous knowledge into the Assessment materials, and the potential for elements of Indigenous-led assessment.

55.1 Please provide an update with regard to the status of consultation with Indigenous groups through the EA/IA and BC OGC processes.

<u>Response:</u>

The processes cited in the question are applicable to the Tilbury Phase 2 LNG Expansion Project, one component of which is the TLSE storage tank (the other component is the Liquefaction Facility).

FEI and FortisBC Holdings Inc. continue to engage with Indigenous groups that have an asserted interest in the Tilbury Phase 2 LNG Expansion Project area through the Provincial EAA and Federal IAA processes. The purpose of this ongoing engagement is to provide opportunities for input on the Tilbury Phase 2 LNG Expansion Project, including the storage portion addressed in this CPCN application, and to gain an understanding of the interests of Indigenous groups and how they may be affected by the proposed work.

Specifically, Indigenous groups have provided their feedback on the draft Detailed Project Description for the Tilbury Phase 2 LNG Expansion Project. Feedback received has informed the final Detailed Project Description, which has been filed to initiate the Readiness Decision, the next step in the assessment process.

If the Tilbury Phase 2 LNG Expansion Project proceeds past the Readiness Decision, the intention is to synchronize engagement between the BCOGC and ongoing EAA and IAA processes to ensure Indigenous groups are informed and engaged about the TLSE Project holistically and to ensure that FEI meets the consultation and notification requirements of the BCOGC.

56.0 Reference: CONSULTATION

Exhibit B-1-4, Table 8-2, p. 191

Provincial and Local Government Communications Log

Table 8-2 on page 191 of the Updated Public Application contains a summary of government communications from October 2019 to June 2020.

56.1 Please provide an updated table covering the period from October 2019 to the present.

<u>Response:</u>

As described in Section 8.2.2 of the Application, consultation and engagement activities for the TLSE Project were synchronized with the parallel Provincial EAA and Federal IAA processes. Most communications with Provincial and Local Governments touched upon both the TLSE Project and these parallel processes. The updated Table 8-2 below includes additional meetings and communications that took place after filing from November 2020 to June 2021, where the TLSE Project was specifically discussed.

Meetings and communications below took place *after* filing: Nov 2020 to June 2021				
Nov 19, 2020	Video conference	FEI former VP External Relations; VP External & Indigenous Relations; Director External & Indigenous Relations; Community Relations Manager	Delta Mayor; Delta City Councillor; City Manager of Delta;	Purpose of meeting was to introduce FortisBC's new VP to the Mayor and staff, as well as provide an update on the Tilbury Expansion Program, including the TLSE Project. FEI committed to keeping them informed throughout the process. Note: Due to the COVID-19 pandemic, this meeting was a video conference call.
Feb 9, 2021	Conference call	VP External & Indigenous Relations; Government Relations Manager; Community Relations Manager	MP Delta; MP's Constituency Manager	Provided an update on the Tilbury Expansion, primarily on components other than TLSE. TLSE was briefly mentioned in the context of regulatory timelines. FortisBC committed to keeping the constituency manager informed, during any upcoming public comment periods, as they indicated that is when they see an increase in emails from constituents about the Project. Note: Due to the COVID-19 pandemic, this meeting was a conference call.
Feb 10, 2021	Email	Community Relations Manager	Federal Provincial Municipal	Notified stakeholders (see Appendix Q-3 for recipients) via email (Please refer to Attachment 56.1a) that the CPCN Application was filed. Also informed them that the EA process was continuing in parallel.

Meetings and communications below took place *after* filing: Nov 2020 to June 2021				
Feb 11, 2021	Conference Call	Community Relations Manager; Community Relations Liaison	MLA Delta South	Provided MLA with an overview of the Project, and committed to keeping him informed as the Project progresses. No specific feedback about the Project that requires a response was expressed at that time. Note: Due to the COVID-19 pandemic, this meeting was changed from an in-person meeting to a conference call.
April 16, 2021	Video Conference	VP External & Indigenous Relations; VP Major Projects; Government Relations Manager, Community Relations Manager	MLA Richmond South Centre	Provided MLA with an overview of the Tilbury expansion, including the TLSE Project, and committed to keeping him informed as the Project progresses. He expressed specific interest in the areas of LNG safety, and renewable gas, and FortisBC provided him with follow up information by email accordingly after the meeting. Note: Due to the COVID-19 pandemic, this meeting was a video conference call.
May 4, 2021	Video conference presentation	Please see Attachment 56.1b for list of attendees.	Please refer to Attachment 56.1b for list of attendees.	BC EAO requested that FortisBC present on the development history of the Tilbury site for Indigenous groups and government agencies to provide them with an opportunity to ask questions. Please refer to Attachment 54.2b for a copy of presentation.
June 16, 2021	Video conference workshop	Please refer to Attachment 56.1c for list of attendees.	Please refer to Attachment 56.1c for a list of attendees.	As part of the Early Engagement process, BC EAO requested FortisBC provide a presentation of the draft Detailed Project Description to Indigenous groups and government agencies. This provided them with another opportunity to ask questions and provide feedback. Please refer to Attachment 56.1d for a copy of the presentation.

57.0 Reference: CONSULTATION

Exhibit B-1-4, Section 8.3.7, p. 190; Appendix Q-6

Local Landowner Notifications

On page 190 of the Updated Public Application FEI states that it mailed 667 notification letters (Appendix Q-6) to businesses and residents within a two kilometre radius of the Tilbury LNG facility on May 29, 2020. The letters informed them of the start of the IAAC and BC EAO processes and upcoming BCUC regulatory process, and provided instructions on how they could ask for more information and provide feedback.

57.1 Please explain why a 2km radius was deemed appropriate for local landowner notifications.

Response:

FEI selected a two-kilometre radius based on its previous experience sending notifications to landowners in proximity to the Tilbury LNG facility in compliance with the BCOGC Consultation and Notifications (C&N) requirements for an LNG facility. As of June 1, 2021, the BCOGC updated its C&N distances to 1,300 metres for consultation, and 1,800 metres for notification, measured from the centre point of the facility.

58.0 Reference: CONSULTATION

Exhibit B-1-4, Section 8.2, pp. 184, 197; Appendix Q-1, pp. 11-10 to 11-12

Indigenous Consultation Log

On page 184 of the Updated Public Application, FEI states: "The Company began engagement with Indigenous groups specific to the Project in 2018 with preliminary discussions focused on outlining the proposed Project and listening to comments or concerns."

On page 197 of the Updated Public Application, FEI states that preliminary engagement activities occurred from July 2019 to July 2020, followed by a list of the Indigenous communities that have engaged in two-way communication with FEI during the preliminary engagement period.

Table 8-4 on page 197 of the Updated Public Application provides a log of consultation with indigenous groups covering the period July 2019 to June 2020.

Table 11-2 on pages 11-10 to 11-12 of Appendix Q-1 contains a summary of engagement with Indigenous Groups, with the latest entry of December 5, 2019.

58.1 Please provide an updated version of Table 8-4.

Response:

FEI confirms there have been no changes to Table 8-4 regarding the Indigenous groups that are potentially affected by the Project. However, FEI interprets the question and preamble as seeking an update to Table 8-5 - Indigenous Engagement Log, which FEI has provided below.

As described in Section 8.2.2, consultation and engagement activities for the TLSE Project were synchronized with the parallel CPCN Application and Provincial EAA / Federal IAA processes. Most of the communications with Indigenous groups touched upon both projects. Included in the updated table below are engagement activities where aspects of the TLSE Project were referenced or discussed.

For added clarity, FEI has excluded the following out of scope items from the list:

- FEI has not included correspondence or activities related to EA process elements (for example, comments on draft Valued Components or Application Information Requirements).
- Through the EA process, there are additional engagement requirements for the Tilbury Phase 2 LNG Expansion Project that extend to a broader list of Indigenous groups. FEI has not included correspondence or activities related to those Indigenous groups not identified in Table 8-4, as populated by the consultative areas database (CAD) list and referenced in 8.4.2 of the Application.

The table below starts after the last entry (June 1, 2020) in the original Table 8-5 from the Application.

Date	Method of Contact	Indigenous Group	Notes
August 25, 2020	Email	• Ts'uubaa-asatx Nation (Lake Cowichan First Nation) • S'ólh Téméxw Stewardship Alliance • Musqueam Indian Band • Cowichan Tribes • Halalt First Nation • Stz'uminus First Nation • Lyackson First Nation • Penelakut Tribe • Katzie First Nation • Kwantlen First Nation • Tsawwassen First Nation • Tsleil-Waututh Nation	Email sent to Indigenous groups requesting to meet on the Project, introduce the Tilbury Phase 2 LNG Expansion, discuss next steps.
September 22, 2020	Online meeting	• Cowichan Tribes • Penelakut Tribe • Stz'uminus First Nation • Lyackson First Nation • Halalt First Nation	The purpose of the meeting was to discuss project updates, overview and EA process materials.
October 7, 2020	Online meeting	• Ts'uubaa-asatx Nation	The purpose of the meeting was to have an introduction to the Tilbury Phase 2 Project. The main topics discussed were introductions, Project overview, issues/concerns.
October 15, 2020	Online meeting	• Tsawwassen First Nation	Met with Tsawwassen First Nation for project updates and the next steps in the Tilbury Phase 2 LNG Expansion Project.
October 15, 2020	Email	• Kwantlen First Nation • S'ólh Téméxw Stewardship Alliance	Requested meetings with each Nation to discuss the project and review project documents and comments.
October 21, 2020	Online meeting	• Musqueam Indian Band	The topics discussed in the meeting were introductions to the FortisBC team, project updates and timelines, and Indigenous Knowledge.
October 27, 2020	Online workshop	• Cowichan Tribes • Halalt First Nation • Kwantlen First Nation • Musqueam Indian Band • Tsawwassen First Nation • Tsleil-Waututh Nation • S'ólh Téméxw Stewardship Alliance	Workshop held jointly with the BC EAO and IAAC to present the draft Detailed Project Description.
October 28, 2020	Email	• Tsleil-Waututh Nation	FortisBC provided written responses to TWN comments on the Initial Project Description.
October 29, 2020	Online meeting	• Tsleil-Waututh Nation	The topics discussed in the meeting were introductions, project updates, Indigenous Knowledge, TWN comments and action items, and next steps in the Project.

Date	Method of Contact	Indigenous Group	Notes
October 29, 2020	Online meeting	• Kwantlen First Nation	The purpose of the meeting was to provide a team introduction and project background. The main topics discussed in the meeting was Kwantlen First Nation and FortisBC's past work, the Tilbury Phase 2 LNG Expansion Project background, key issues, the EA process, use of the Fraser River, questions from the Detailed Project Description and follow-up meetings.
November 12, 2020	Email	• S'ólh Téméxw Stewardship Alliance	S'ólh Téméxw Stewardship Alliance provided FEI with comments on the draft Detailed Project Description and draft Valued Components documents.
December 8, 2020	Online meeting	• Musqueam Indian Band	The purpose of the meeting was to follow-up on action items from the previous meeting and discuss Musqueam's comments. The main topics discussed were Musqueam Indian Band's comments on project, next steps and Indigenous Knowledge.
January 8, 2021	Online meeting	• Cowichan Tribes • Penelakut Tribe • Stz'uminus First Nation • Lyackson First Nation • Halalt First Nation	Purpose of the meeting was to review schedule updates, action items, and to review comments.
January 11, 2021	Online meeting	• S'ólh Téméxw Stewardship Alliance	The purpose of the meeting was to introduce team members and to provide Project introductions and updates.
January 21, 2021	Online meeting	• Tsawwassen First Nation	The topics discussed in the meeting were introductions, project updates, action items, and next steps in the Project.
January 28, 2021	Email	• Musqueam Indian Band • Kwantlen First Nation • Tsleil-Waututh Nation	FortisBC provided project follow-up and asked for any feedback or comments from the Indigenous groups.
February 11, 2021	Email	• Semiahmoo First Nation • Squamish Nation • Soowahlie First Nation • Kwantlen First Nation • Cowichan Tribes • Penelakut Tribe • Stz'uminus First Nation • Lyackson First Nation • Halalt First Nation • Katzie First Nation • Tsleil-Waututh Nation • Ts'uubaa-asatx Nation • Skawahlook First Nation • Seabird Island Band • Metis Nation BC • Shxw'ōwhámél First Nation • Musqueam Indian Band • Tsawwassen First Nation • S'ólh Téméxw Stewardship Alliance	Sent a letter providing project updates, specifically related to the regulated utility review process conducted by the British Columbia Utilities Commission (BCUC).

Date	Method of Contact	Indigenous Group	Notes
February 12, 2021	Email	• S'ólh Téméxw Stewardship Alliance • Ts'uubaa-asatx Nation • Cowichan Tribes • Penelakut Tribe • Stz'uminus First Nation • Lyackson First Nation • Halalt First Nation • Tsawwassen	FortisBC provided project follow-up and asked for any feedback or comments from the Indigenous groups.
March 3, 2021	Online meeting	• Cowichan Tribes • Penelakut Tribe • Stz'uminus First Nation • Lyackson First Nation • Halalt First Nation	Purpose of the meeting was to review schedule updates, action items, and to walk through follow-up comments.
March 8, 2021	Email	• Cowichan Tribes • Penelakut Tribe • Stz'uminus First Nation • Lyackson First Nation • Halalt First Nation	Cowichan Tribes provided comments on the draft Detailed Project Description.
March 16, 2021	Email	• Lyackson First Nation	Lyackson First Nation provided comments on the draft Detailed Project Description.
April 8, 2021	Email	• Cowichan Tribes • Penelakut Tribe • Stz'uminus First Nation • Lyackson First Nation • Halalt First Nation	FortisBC provided responses to Cowichan Tribes' comments on the draft Detailed Project Description.
April 9, 2021	Email	• Cowichan Tribes • Penelakut Tribe • Stz'uminus First Nation • Lyackson First Nation • Halalt First Nation	FortisBC provided responses to Lyackson First Nation's comments on the draft Detailed Project Description.
April 12, 2021	Online meeting	• Cowichan Tribes • Penelakut Tribe • Stz'uminus First Nation • Lyackson First Nation • Halalt First Nation	Purpose of the meeting was to review schedule updates, action items, and to walk through follow-up comments on Detailed Project Description.
April 22, 2021	Email	• Ts'uubaa-asatx Nation • S'ólh Téméxw Stewardship Alliance • Musqueam Indian Band • Cowichan Tribes • Penelakut Tribe • Halalt First Nation • Stz'uminus First Nation • Lyackson First Nation • Katzie First Nation • Kwantlen First Nation • Tsawwassen First Nation • Tsleil-Waututh Nation	FortisBC emailed Indigenous groups to inform and provide information related to field work for the TLSE Project at the Tilbury site in spring 2021 to respond to Indigenous communities' areas of interest.

Date	Method of Contact	Indigenous Group	Notes
May 4, 2021	Online workshop	• Cowichan Tribes • Halalt First Nation • Katzie First Nation • Kwantlen First Nation • Semiahmoo First Nation • S'ólh Téméxw Stewardship Alliance • Tsawwassen First Nation • Tsleil-Waututh Nation	Tilbury History Presentation – held jointly with the BC EAO.
May 13 & 14, 2021	Field studies – remote monitoring	• Tsleil-Waututh Nation • Cowichan Tribes	Representatives attended remote monitoring for field studies being conducted for the project.
May 31, 2021	Email	• Ts'uubaa-asatx Nation • S'ólh Téméxw Stewardship Alliance • Musqueam Indian Band • Cowichan Tribes • Penelakut Tribe • Halalt First Nation • Stz'uminus First Nation • Lyackson First Nation • Katzie First Nation • Kwantlen First Nation • Tsawwassen First Nation • Tsleil-Waututh Nation	FortisBC provided updated schedule and information about proposed acoustic monitoring sites for review.
June 3, 2021	Email	• Cowichan Tribes • Penelakut Tribe • Stz'uminus First Nation • Lyackson First Nation • Halalt First Nation	Cowichan Tribes provided comments on the draft Detailed Project Description.
June 16, 2021	Online workshop	• Cowichan Tribes • Halalt First Nation • Kwantlen First Nation • Kwikwetlem First Nation • Musqueam Indian Band • Penelakut Tribe • Tsawwassen First Nation • Tsleil-Waututh Nation	Workshop held jointly with the BC EAO and IAAC to present on the draft Detailed Project Description.
June 16, 2021	Email	• Cowichan Tribes • Halalt First Nation • Stz'uminus First Nation • Lyackson First Nation • Penelakut Tribe • Kwantlen First Nation • Tsawwassen First Nation	FortisBC emailed Indigenous groups to follow up on workshop and request meetings to discuss the draft Detailed Project Description.
June 25, 2021	Email	• Tsleil-Waututh Nation	FortisBC provided information about field studies and an invitation to participate remotely.
June 29, 2021	Email	• Musqueam Indian Band • Ts'uubaa-asatx Nation	FortisBC provided information about field studies and an invitation to participate remotely.

Date	Method of Contact	Indigenous Group	Notes
June 30, 2021	Online meeting	• Musqueam Indian Band	The purpose of the meeting was to review the draft Detailed Project Description and discuss Musqueam's initial comments.
June 30, 2021	Online meeting	• Ts'uubaa-asatx Nation	The purpose of the meeting was to review the draft Detailed Project Description and discuss Ts'uubaa-asatx Nation's comments.
July 5, 2021	Email	• Cowichan Tribes • Halalt First Nation • Stz'uminus First Nation • Lyackson First Nation • Penelakut Tribe • Katzie First Nation • Kwantlen First Nation • Tsawwassen First Nation	FortisBC provided information about field studies and an invitation to participate remotely.

58.2 Please provide copies of any relevant, non-confidential written documentation regarding consultation, such as notes or minutes of meetings or phone calls, or letters received from or sent to the First Nation.

Response:

The following correspondence from FEI specific to the TLSE Project was sent to Indigenous groups:

- FEI sent a letter to Indigenous groups on June 1, 2020 providing an update on both the Environmental Assessment process and the CPCN process for the TLSE Project. This letter indicated FEI's intent to submit a CPCN application for the TLSE Project to the British Columbia Utilities Commission in late-2020. Please refer to Attachment 58.2a.
- A second letter was sent on February 11, 2021 which provided Indigenous groups with an update to both regulatory processes. This letter notified groups that FEI had filed the CPCN application for the TLSE Project on December 29, 2020. It also outlined ways for Indigenous groups to participate in the BCUC process including the link to sign up as an Interested Party or Intervener along with the registration deadline. Please refer to Attachment 58.2b.

Further, as part of the Early Engagement phase, FEI (together with FortisBC Holdings Inc.) is currently in discussion with a number of Indigenous groups about capacity funding agreements to support engagement in the regulatory processes. At this time, these agreements, and the confidentiality provisions therein, are in various stages of negotiation. FEI will continue to treat specific information shared by Indigenous groups through engagement activities as confidential until the agreements and their confidentiality terms have been agreed. However, FEI has provided an outline of issues or concerns identified to date in the response to BCUC IR1 59.1.

59.0 Reference: CONSULTATION

Exhibit B-1-4, p. 203

Indigenous Issues and Concerns Raised

Table 8-6 on page 203 of the Updated Public Application summarises concerns raised by Indigenous groups during FEI's engagement into three themes, namely: business opportunities; potential environmental impacts; and economic viability.

59.1 Please identify any new specific issues or concerns that have been raised by any Indigenous groups.

Response:

The following table outlines issues raised to date by Indigenous groups during engagement. The right-hand column provides FEI's, together with FortisBC Holdings Inc's, responses to how those issues will be addressed or assessed within the environmental assessment application.

Issues Raised	FortisBC Response
Potential effects of the proposed Project on fish and fish habitat, including migratory habitats and shoreline habitats near the proposed Project Site.	Potential effects to fish and fish habitat for all project phases will be assessed in the Application under the Fish and Fish Habitat Valued Components (VC). Details of the effects assessment requirements are provided in the draft Application Information Requirements (AIR) that is appended to the Detailed Project Description (DPD).
Use of present day conditions, rather than historical or pre-contact conditions, to characterize baseline conditions.	The current version of the draft AIR uses existing conditions as baseline conditions. FortisBC will engage with the BC EAO, IAAC and Indigenous groups when developing a methodology for assessing pre-baseline historical conditions in the assessment of cumulative effects on Indigenous Interests. FortisBC will present the methodology at a future meeting with Indigenous groups.
Changes in air quality and the potential effects to human health, wildlife, cultural continuation, and subsistence and cultural use of the proposed Project Area.	FortisBC acknowledges the importance of air quality. The EA application will consider a project case and cumulative case for air quality emissions. These assessments will use the latest available air quality monitoring data from the vicinity of the proposed Project for the background and existing conditions. The methodology used in the Air Quality assessment of the Assessment will satisfy the requirements of Metro Vancouver, BC EAO, IAAC, and the Strategic Assessment of Climate Change.

Issues Raised	FortisBC Response
Potential effects to the accessibility and availability of Traditional Lands and resources during the construction and operations phases.	FortisBC acknowledges Indigenous groups' concerns regarding Project-related activities that could affect rights to access Traditional Lands and resources. Effects to local vegetation and harvesting sites will be assessed in the Vegetation section of the proposed project application. Effects on wildlife habitat will be included in the Wildlife and Wildlife Habitat section.
Concerns with increases in noise and the potential effects to human health, wildlife, including marine mammals, cultural continuation, and subsistence and cultural use of the proposed Project Area.	Environmental noise is included in the draft AIR. Human health effects from environmental noise will be assessed using Health Canada's 2017 'Guidance for Evaluating Human Health Impacts in Environmental Assessment: Noise'. FortisBC will determine location of the sound level meters in consultation with Indigenous groups and the Technical Advisory Committees as part of the EA process. Potential noise effects will be assessed in the proposed project application under the Acoustic VC. Potential effects to marine mammals will be evaluated in detail in the project application under the Wildlife and Wildlife Habitat VC, including potential impacts as a result of noise. Each Indigenous group will also have a subsection within Section 11, Indigenous Interests that will speak to that Indigenous group's specific issues including cultural continuation, and subsistence and cultural use. The assessment of effects on Indigenous Interests will be informed by the Human Health VC.
Sufficient capacity funding to enable meaningful participation within the EA process.	FortisBC has been engaging with Indigenous groups regarding capacity funding.
Human Health VC should consider Indigenous health determinants and VCs linked to human health should include indicators of risks to Indigenous health that can be used to assess effects to cultural use and cultural continuation.	Indigenous health will be considered separately in the proposed project application under the Human Health VC. The information is aggregated in the VC assessment and is applicable to all Indigenous groups that are potentially affected by the proposed project. Each Indigenous group will also have a subsection within Section 11, Indigenous Interests that will speak to that Indigenous group's specific issues and unique information.
Disturbance of or damage to archaeological or historical sites, features, and objects as a result of proposed Project activities.	FortisBC acknowledges that a new archaeological assessment is required for the locations that will be disturbed during construction and operations of the proposed Project. An AOA was completed for the whole Tilbury site and will conduct an AIA for the Phase 2 LNG Expansion Project activities.
Project's GHG emissions, including cumulative contributions to Provincial, National, and sector GHG emissions.	The Detailed Project Description includes a preliminary GHG estimate for the proposed project and a discussion and comparison against Provincial and Federal targets. FortisBC will address GHG emissions and cumulative effects in the proposed project application and will include a detailed GHG analysis with an updated comparison to Provincial and Federal targets.

59.2 Please provide a description of how the specific issues or concerns raised by the First Nation will be avoided, mitigated or otherwise accommodated, or explain why no further action is required to address an issue or concern.

Response:

Please refer to the response to BCUC IR1 59.1.

60.0 Reference: CONSULTATION

Exhibit B-1-4, Section 8.2, p. 184; Appendix Q-4

Summary of Email and Telephone Inquiries

Appendix Q-4 contains a summary of email and telephone inquiries and responses for the period up to August 2020.

60.1 Please provide an updated version of Appendix Q-4, covering the period July 2020 to the present.

Response:

Since filing the CPCN application, FEI has received one email inquiry from the public. While the question is not specific to the TLSE Project, it could be considered relevant to the Project. The question was received on March 20, 2021, and the inquiry was as follows:

> I would like to know the estimate of the workforce required for the Tilbury LNG Facility Expansion project if possible the number of person years estimated to construct the expansion project.

FEI responded by email on April 1, 2021 with the following response:

> Thank you for your questions and interest in our Tilbury liquefied natural gas (LNG) facility expansion.
>
> Our Tilbury LNG facility has been at the heart of British Columba's energy system for 50 years. Our expansion program will improve the resiliency of our gas system – ensuring we can deliver natural gas to our customers when they need it most, like on the coldest days of the year. We are committed to creating jobs for local workers through education and training programs, as well as direct and indirect opportunities.
>
> Our proposed Tilbury expansion project could create over 6,500 jobs during construction and over 100 new long-term jobs once construction is complete. Construction could start as early as 2022 and be completed by 2028. The project's economic benefits will be distributed not only in the LNG industry, but also to the industries that support it, including everything from manufacturing to engineering to professional services. Economic benefits will go beyond the Lower Mainland to the energy heartland in northeastern BC where gas is produced.

61.0 Reference: CONSULTATION

Exhibit B-1-4, Appendix Q-2, pp. 15, 18

Capacity Funding

On page 15 of the Appendix Q-2, FEI states that Preliminary engagement activities occurred from July to December 2019, in advance of filing the IPD.

In Appendix Q-2, page 15 of the Engagement Plan states that FortisBC has negotiated and signed capacity funding agreements with Indigenous Groups. These include agreements with Musqueam First Nation (2015, 2018) and the Cowichan Tribes (2018) specific to the Project. No other communities have signed a capacity funding agreement with FortisBC.

On page 18 of the Appendix Q-2, FEI states that FortisBC has executed capacity funding agreements with First Nations during the preliminary engagement phase. FortisBC will discuss capacity funding needs during Early Engagement Phase with those Indigenous Groups that reasonably identify areas within the Early Engagement Phase where additional support is needed.

61.1 Please clarify which capacity funding agreements with First Nations were executed during the preliminary engagement phase.

Response:

Capacity funding agreements were signed with Musqueam First Nation and Cowichan Tribes prior to entering the Early Engagement phase of the EA.

61.2 Please provide an update on the status of any capacity funding agreements which have been executed since the submission of the Application, or are being negotiated.

Response:

Please refer to the response to BCUC IR1 61.1 regarding the funding agreements that are being presently negotiated. A capacity funding agreement has been executed with Chawathil First Nation.

61.3 Please explain the different phases of consultation (e.g. such as preliminary and early consultation), specifying the current phase.

Response:

Preliminary engagement activities occurred prior to the start of the BC EA process.

The Early Engagement phase is the start of the regulatory process with the BC Environmental Assessment Office (BC EAO). Early Engagement is an important preparatory phase where meaningful conversations among participants begin about the proposed project to identify engagement approaches, potential interests, issues, and concerns early in the EA process and to provide the BC EAO with information to set the technical requirements of the assessment.

The Early Engagement phase concluded in September 2021. The next phases includes the regulator-led Readiness Decision and Process Planning phases, which are conducted by the BC EAO.

Using the foundation provided by the Early Engagement phase, a decision is made by the regulators on whether a project should proceed to an EA during the Readiness Decision. Following a positive Readiness Decision, the Process Planning phase formalizes how the EA must be carried out, including: identifying the required information; defining who does what, when, and how; and determining how participants work together for the rest of the EA and future engagement approaches.

A similar process is conducted in parallel in the federal impact assessment. In that process early engagement and then the setting of technical requirements are conducted in the "planning phase".

Once the provincial Process Planning phase and federal planning phase are completed the technical requirements of both the provincial and federal assessment will be issued. FEI and FortisBC Holdings Inc. will continue engagement with Indigenous groups in the provincial "Application Development" phase. During Application Development, the proponent works with Indigenous groups and participants to develop the Application for an EA Certificate.[58] FEI and FortisBC Holdings Inc. will also be required to submit an "impact assessment" report for the federal assessment. FEI anticipates that a single report will be prepared for both the federal and provincial assessments, and will consult with Indigenous groups on the report for the purposes of both the federal and provincial assessment decisions.

61.3.1 Please clarify which phases of consultation any current capacity funding agreements (both executed and in negotiations) are intended to cover.

[58] https://www2.gov.bc.ca/gov/content/environment/natural-resource-stewardship/environmental-assessments/the-environmental-assessment-process/2018-act-environmental-assessment-process.

Response:

The purpose of capacity funding agreements is to support meaningful engagement in regulatory processes by Indigenous groups. Based on current information, FEI expects capacity funding for Indigenous groups will be required for the Early Engagement Phase and Application Development and Review. More detail about the assessment process and engagement needs will become available following Process Planning.

Please also refer to the response to BCUC IR1 61.3 for details about the EA process phases.

62.0 Reference: CONSULTATION

Exhibit B-1-4, Appendix Q-7, Table 4-2, p. 16

Open House Questions

Appendix Q-7 includes a summary of open house questions. Several of these comments appear to have been truncated.

62.1 Please provide a corrected version of Appendix Q-7, showing all questions in full.

<u>Response:</u>

Please refer to Attachment 62.1 for a corrected version of Appendix Q-7.

F. PROVINCIAL POLICY AND ENVIRONMENTAL OBJECTIVES

63.0 Reference: PROVINCIAL GOVERNMENT 1 ENERGY OBJECTIVES AND POLICY CONSIDERATIONS

Exhibit B-1-4, Section 9.2, p. 206;

BC Energy Objectives

On page 206 of the Updated Public Application, FEI states:

> British Columbia's energy objectives are defined in section 2 of the CEA. Based on the results of the socio-economic evaluation described below, the Project will support the British Columbia energy objective in section 2(k) of the CEA "to encourage economic development and the creation and retention of jobs" in two ways: through construction and through reducing the risk of a supply disruption.

Section 2 of BC's Clean Energy Act outlines BC's energy objectives, including:

> (b) to take demand-side measures and to conserve energy,…
>
> …
>
> (g) to reduce BC greenhouse gas emissions
>
> …
>
> (iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,
>
> (iv)by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and
>
> (v)by such other amounts as determined under the Climate Change Accountability Act;
>
> (h)to encourage the switching from one kind of energy source or use to another that decreases greenhouse gas emissions in British Columbia;
>
> (i)to encourage communities to reduce greenhouse gas emissions and use energy efficiently;

63.1 Please discuss the extent to which FEI considers the TLSE Project is consistent with and will advance the BC government's energy objectives as set out above.

<u>Response:</u>

The TLSE Project is consistent with and will advance the BC government's energy objectives, as set out above.

FEI sees a continued and growing role for its existing and proposed infrastructure, including the TLSE Project, to achieve the BC government's energy objectives to strengthen its economy while driving the transition to a low-carbon energy system, as identified in its legislated GHG emissions reduction targets.

FortisBC's *Clean Growth Pathway to 2050* describes measures that FEI will take to align its investments, program offerings, and energy supply to achieve CleanBC's identified GHG emission reduction goals. FortisBC's 30BY30 target is enabling the reporting and accountability framework by which to achieve the goals of its Clean Growth Pathway. More specifically, the TLSE Project enables greater resilience of the gas energy delivery system, which as noted the *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. FEI explains in more detail below.

Informing FEI's look to the future of its infrastructure and BC's energy system in the low-carbon transition is the Guidehouse report *Pathways for British Columbia to Achieve its GHG Reduction Goals* (Pathways report). The Pathways report, provided in Attachment 63.1, highlights the critical role that the gas system will have in the Province's decarbonization path because of: i) the significant GHG reduction potential embedded in the gas system both in the form of introducing high blends of renewable gases to supply, and to displacing more carbon intensive fuels like refined petroleum products in commercial transport; ii) lower costs of decarbonization when using gas system solutions; and iii) the heightened resiliency and reliability of using low-carbon solutions from both gas and electric infrastructure.

The report also highlights some key challenges to achieving BC's GHG reduction goals. 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. Expanding peak electrical generating capacity to meet load growth as some end-uses electrify (e.g. light duty transportation) is one of the primary cost-drivers of decarbonization where there are significant electric capacity constraints. However, the gas and electric systems are able to complement each other. Meeting peak thermal requirements and providing resiliency and reliability from the gas system is essential for moderating electric peak load growth and ensure an overall smoother low-carbon transition for BC's energy consumers.

The TLSE Project is a key addition to the resiliency and integrity of BC's gas distribution system and strengthens the overall Provincial energy system as it decarbonizes in line with Provincial targets. The Pathways report demonstrates that serving peak demand periods will require low-cost storage and low-carbon fuels in the form of renewable gases. The TLSE Project improves the gas system's ability to meet peak periods and to help moderate peak load growth on the gas system. Furthermore, FortisBC's success in meeting the CleanBC objectives depends on the use of the entire gas system across all regions of the Province.

G. APPENDIX B – PRICEWATERHOUSE COOPERS ECONOMIC ASSESSMENT

64.0 Reference: PRICEWATERHOUSE COOPERS ECONOMIC ASSESSMENT

Exhibit B-1-4, p. 50; Appendix B-Redacted, p. 17

Overview of major natural gas disruption events

On page of the Updated Public Application, FEI states:

> FEI retained PricewaterhouseCoopers (PwC) to provide information and analysis that would inform future resiliency investment decisions. A copy of the PwC report is attached confidentially as Appendix B. PwC noted that the T-South Incident was not an isolated incident. <u>Although relatively rare</u>, PwC identified three additional incidents of a similar nature to the T-South Incident that have occurred in BC over the past decade. PwC identified an additional five natural gas disruption events which occurred in other Canadian jurisdictions and two in US jurisdictions over the same period. [emphasis added]

Page 17 of the PWC Report provides an overview of several major natural gas disruption events.

64.1 Please provide the following additional information for all 11 events:

- Description of nature of disruption (e.g. was some interruptible demand met, only firm demand met, restrictions applied to firm demand, or no demand met);
- Number of customers affected;
- Geographic area impacted by the disruption (community or regional disruptions);
- Duration of disruption; and

<u>Response:</u>

The following response has been provided by PwC:

Table 1: British Columbia natural gas disruption events (2009 - 2019)

Date	Location	Description
Oct 9, 2018	Prince George, BC	Enbridge T-South rupture **Nature of Disruption**: Major consumers curtailed (force majeure, no distinction between interruptible vs firm service) **Customers Affected**: 1 million BC, 0.8 million US **Geographic Area**: System disruption (BC and US Pacific Northwest) **Duration of disruption**: Curtailment lifted Dec, 2018 (>6 weeks), Full operational capacity resumed Dec 1, 2019 (> 1 year)

Date	Location	Description
Jun 28, 2012	Buick, BC	Enbridge Nig Creek rupture **Nature of Disruption**: N/A (Pipelines were not operating at time of incident due to unplanned outage elsewhere in the system) **Customers Affected**: No relevant information found **Geographic Area**: Community disruption (BC) **Duration of disruption**: Full operational capacity resumed Sep 21, 2012 (85 days)
Jun 23, 2012	Fort St. John, BC	Enbridge valve enclosure fire **Nature of Disruption**: N/A (Was not operating at time of incident due to planned outage) **Customers Affected**: No relevant information found **Geographic Area**: Community disruption (BC) **Duration of disruption**: Full operational capacity resumed Jul 16, 2012 (23 days)
Feb 20, 2009	Wonowon, BC	Enbridge Alaska Highway pipeline sending barrel rupture **Nature of Disruption**: No relevant information found **Customers Affected**: No relevant information found **Geographic Area**: Community disruption (BC) **Duration of disruption**: No relevant information found **Note:** Incident is believed to have occurred on non-critical system support assets (i.e., pipeline pig launcher) with limited impact to core system operations.

1

2 **Table 2: Rest of Canada natural gas disruption events (2009 - 2019)**

Date	Location	Description
Jan 25, 2014	Otterbourne, MB	TC Canadian Mainline rupture **Nature of Disruption**: No demand met **Customers Affected**: 9 rural MB communities **Geographic Area**: Community disruption (MB) **Duration of disruption**: Consumer supply interrupted for ~80 hrs, Engineering assessment demonstrated safe operation at reduced pressure in Oct, 2014 (>120 days)

Date	Location	Description
Oct 17, 2013	Fort McMurray, AB	TC NOVA rupture **Nature of Disruption**: No demand met for two (2) major industrial consumers **Customers Affected**: Two (2) industrial consumers **Geographic Area**: Community disruption (AB) **Duration of disruption**: No relevant information on duration of customer impact, Operations resumed Nov 21, 2013 at reduced capacity (35 days), Full operations resumed Oct, 2014 (~1 year)
Feb 19, 2011	Beardmore, ON	TC Line 100 explosion and fire **Nature of Disruption**: No interruption of service to consumers (multiple parallel lines) **Customers Affected**: N/A **Geographic Area**: Community disruption (ON) **Duration of disruption**: Operations resumed Feb 20, 2011 at reduced capacity (1 day), Full operations resumed Aug 23, 2011 (185 days)
Sep 26, 2009	Marten River, ON	TC Line 100 rupture **Nature of Disruption**: No interruption of service to consumers (multiple parallel pipelines) **Customers Affected**: N/A **Geographic Area**: Community disruption (ON) **Duration of disruption**: Operations resumed immediately (multiple parallel pipelines), Full operations resumed Nov 4, 2009 (39 days)
Sep 12, 2009	Englehart, ON	TC Line 2 rupture and fire **Nature of Disruption**: No interruption of service to consumers (multiple parallel pipelines) **Customers Affected**: N/A **Geographic Area**: Community disruption (ON) **Duration of disruption**: Operations resumed immediately (multiple parallel pipelines), Full operations resumed Dec 12, 2009 (91 days)

Table 3: Northwest US (WA, OR, ID, MT) regional natural gas disruption events (2009 - 2019)

Date	Location	Description
Mar 9, 2016	Seattle, WA	Puget Sound Energy distribution line rupture **Nature of Disruption**: No demand met **Customers Affected**: Three (3) businesses destroyed and 36 damaged **Geographic Area**: Community disruption (WA) **Duration of disruption**: No relevant information found

Date	Location	Description
Mar 31, 2014	Plymouth, WA	Williams Plymouth LNG facility explosion and fire **Nature of Disruption**: No interruption of service to consumers (incident occurred within peak shaving LNG facility) **Customers Affected**: LNG peak shaving facility shut down **Geographic Area**: Regional disruption (WA / Canada) **Duration of disruption**: Full LNG operations expected to resume Apr, 2016 (>2 years)

Additional commentary:

- Publicly available data tends to be focused on immediate health and safety impacts (i.e., injuries and fatalities) as well as incident cause. We found limited publicly available information that would specifically characterize and allow quantification of the disruption (e.g., nature and duration of disruption, and number of customers affected).
- Although a disruption may have affected a specific asset for an extended period of time (e.g., loss or reduction of service), system resiliency allowed customer impact to be negligible. Our assessment scenarios make no assumption around the inherent level of resiliency in a given system.
- Interruptible service is a contracting mechanism generally intended to facilitate system load balancing during peak consumption periods and over short periods of time. From our research, it is our understanding that interruptible service does not imply that consumers are prepared or able to manage extended periods of interruption. Additionally, natural gas disruption events represent emergency, force majeure situations. Under these circumstances, system operators will tend to prioritize speed of response and curtailment of the largest volume consumers in order to mitigate potential system imbalances. For these reasons, we do not view the type of service (firm vs interruptible) as being relevant to assessing impact.

65.0 Reference: PRICEWATERHOUSE COOPERS ECONOMIC ASSESSMENT

Exhibit B-1-4, pp. 1, 3; Appendix B-Redacted, pp. 4, 5

Scenario Development

Page 4 of the Appendix B states:

> In order to assess the potential impact that a natural gas disruption could have on BC, we developed three scenarios for evaluation. The scenarios are hypothetical events used to evaluate potential impacts of supply disruption and were designed to be both realistic (i.e. a mix of less extreme to more extreme scenarios, but ensuring that all are real possibilities), while also considering an exhaustive range of parameters (see below). In analyzing the impacts of these scenarios, <u>we did not consider possible causes, likelihood or readiness to respond</u>. (emphasis added)

> In order to develop the scenarios, we identified four key dimensions that would drive scenario impact, including 1) the duration of the disruption, 2) the temperature and environmental conditions at the time of the hypothesized event, 3) the geographic area impacted by the disruption, and 4) the magnitude of the supply / demand imbalance. Once these were defined, we developed the upper and lower bound variable ranges for each dimension. These bounds were defined based on our research, which included working with FEI to define the appropriate scenario parameters, with input about system and stakeholder constraints from stakeholder interviews. This enabled us to identify actual conditions that reflect critical threshold values that would drive scenario impact.

On page 1 of the Updated Public Application, FEI provides its determination of a specific minimum resiliency objective for prospective planning: Having the ability to withstand, and recover from, a 3-day "no-flow" event on the T-South system without having to shut down portions of FEI's distribution system or otherwise lose significant firm load.

65.1 Please confirm, or explain otherwise, that the probability of the 3 scenarios occurring was not assessed.

<u>Response:</u>

The following response has been provided by PwC:

We confirm that the probability of the 3 scenarios occurring was not assessed.

Additional commentary:

- 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.

65.2 Please explain whether the scenario bounds were based on data from any major natural gas disruption events that have occurred to date, and if so, provide the underlying data.

Response:

The following response has been provided by PwC:

Scenario bounds were not explicitly based on data from any major natural gas disruption events that have occurred to date. This is intentional, as the conditions under which FEI operates its natural gas infrastructure, and the nature of the impacts that would be felt, are unique.

Instead, scenario bounds were defined based on the notable conditions that would create a material step change in impact for one or more stakeholder groups in BC. These were identified by collecting information from external (impacted sectors / stakeholder groups) and internal (FEI) interviews, but may inherently be informed by previous disruption events that stakeholders have identified and considered in their own risk management plans. Our analysis did not then explore the efficacy of stakeholder risk management plans which may or may not present risk similar to FEI's system resiliency.

For example:

- Our stakeholder interviews indicated that major hospitals are mandated to have a three (3) day back up heating source, yet some critical systems / capabilities for full operations (e.g., sterilization) may be limited.
- Information gathered from internal interviews included FEI's operational experience in outages and bringing systems back online, which played a part in informing the "Duration" and "Magnitude" scenario bounds.

65.3 Please explain if and how the 3 scenarios relate to FEI's minimum resiliency planning objective.

Response:

The following response has been provided by PwC:

PwC was not engaged in FEI's minimum resiliency planning.

As described in our response to question [BCUC IR1] 65.2, the 3 scenarios were not defined based on, or in relation to, FEI's minimum resilience planning objective. Scenario bounds were defined based on the notable conditions that would create a material step change in impact for one or more stakeholder groups in BC. These were identified by collecting information from external (impacted sectors / stakeholder groups) and internal (FEI) interviews, but may indirectly be informed by previous disruption events that stakeholders have identified and considered in their own risk management plans.

The following response has been provided by FEI:

FEI considers that the three scenarios illustrate the consequences that could result from a supply disruption to customers, ranging from relatively small-scale, through medium-scale, to large-scale outages. The primary scenario relevant to the TLSE Project and the development of FEI's MRPO is Scenario 3. This scenario is the most representative of a gas supply disruption affecting all Lower Mainland customers. Although this may be a relatively low probability event, the severe consequences which would result led FEI to develop its MRPO to mitigate the risk of this scenario occurring.

Page 5 of the Appendix B states: "The notable conditions were defined intentionally, based on the insights from interviews and research on system and stakeholder constraints. These helped to ensure that scenarios developed were realistic and reflected real thresholds that lead to material changes to economic, social or environmental impact between scenarios."

65.4 Please provide more details on the nature of the research used to identify the notable conditions, in particular the lower and higher impact notable conditions. Please provide any relevant examples from major natural gas disruption events that have occurred to date globally.

Response:

The following response was provided by PwC:

In order to identify the notable conditions used to describe each of the three scenarios, research was conducted, supported by interviews with both external (impacted sectors and other stakeholders) and internal (FEI resources). Examples of the research undertaken are provided below:

- Research included literature review to identify such things as mandated OH&S workplace temperatures, temperature effects on morbidity and mortality, natural gas demand patterns, and associated segmentation of stakeholders.
- 22 external interviews were conducted with a range of representative natural gas consumers and government actors. Key interview questions included: experience of past natural gas disruptions (notably the Enbridge event), the impact of an outage on

operations, mitigation processes in place (e.g. backup systems), costs incurred due to the disruption, and social and environmental implications.

- 18 internal interviews were conducted across several FEI departments to learn about the province's network operations, capacity levers and constraints.

Taken together, the information collected in these interviews enabled us to understand how the range of conditions across each scenario dimension (Duration, Temperature, Area, Magnitude) would impact each stakeholder group. We noted that significant "step changes" in impact, across stakeholder groups, coalesced across certain thresholds in the range of possible conditions.

- For example, almost all stakeholders reported they would experience an economic impact if a disruption were to occur when atmospheric temperature is below 16ºC, the BC health & safety minimum for the workplace. This was therefore defined as a 'notable condition' for the temperature dimension.

Three (3) relevant examples from major natural gas disruption events that have occurred to date globally include:

Disruption Example 1

Scenario Dimensions: Duration (~80 hrs) / **Temperature (extreme cold ⇒ Jan 25, 2014)** / Area (Community) / **Magnitude (No demand met)**

Note: **Bold** denotes higher / lower notable condition

Source: TSB


TC Canadian Mainline rupture

Date of Incident: Jan 25,2014

Location: Otterbourne, MB

Geographic area of disruption: Community disruption

Number of Customer affected: 9 rural communities in Manitoba

Nature of Disruption: No demand met for 80 hours

Duration of Disruption: >120 days (Eng assessment demonstrated safe operation at reduced pressure in Oct, 2014)

Background

A natural gas pipeline rupture and ignition occurred on TransCanada PipeLines Limited 762 mm (30-inch) Line 400-1 at the site of Mainline Valve 402 near Otterburne, Manitoba. A crater measuring approximately 24 metres long by 12.5 metres wide was created, and debris was ejected approximately 100 metres from the rupture site. Natural gas burned for approximately 12 hours.

Line was shutdown at the time of incident, but as a precaution, two adjacent pipelines, lines 400-2 and 400-3, were shut down, assessed, and returned to service on 26 January 2014. This resulted in the loss of natural gas service to 9 rural communities in Manitoba for approximately 80 hours.

Disruption Example 2

Scenario Dimensions: Duration (~1 day) / **Temperature (extreme cold ⇒ Dec 12, 2017)** / **Area (System)** / Magnitude (Some demand met through alternate sources)

Note: **Bold** denotes higher / lower notable condition

Source: The Guardian, Gas Connect Austria

Baumgarten site explosion & fire

Date of Incident: December 12, 2017

Location: Slovakia, Austria

Geographic area of disruption: System disruption

Number of Customer affected: Sufficient information not available

Nature of Disruption: No international demand met through facility for ~1 day (overall system resiliency mitigated consumer impact)

Duration of Disruption: 119 days (Full facility operation restored Apr 10, 2018)

Background

An explosion and fire that ripped through Austria's main gas pipeline hub killed one person and injured 21 others, prompting Italy to declare a state of emergency as flows from the strategic site were cut off for most of the day.

The Baumgarten site in eastern Austria, near Slovakia, is a major regional transfer node, taking natural gas from as far away as Russia and pumping it towards neighbours including Germany and Italy, Baumgarten's biggest recipient.

The part of the site affected by the fire was 100 metres (330 feet) by 100 metres at a site that covers 17 hectares (42 acres). That part is not used for international pipelines.

Disruption Example 3

Scenario Dimensions: Duration (Service maintained) / Temperature (moderate ⇒ Sep 9, 2010) / Area (Community) / Magnitude (All demand is met via parallel line)

Note: **Bold** denotes higher / lower notable condition

Source: PHMSA, WSJ

PG&E - San Bruno Pipeline rupture and explosion

Date of Incident : September 9, 2010

Location: San Bruno, California

Geographic area of disruption: Community disruption

Number of Customer affected: Sufficient information not available

Nature of Disruption: Parallel line was used to continue supply of natural gas

Duration of Disruption: >120 days (only 1 of 38 destroyed homes had been rebuilt after 1 ½ years)

Background

The San Bruno pipeline explosion occured at 6.11 pm PDT, when a 30-inch (76 cm) diameter steel natural gas pipeline owned by Pacific Gas & Electric exploded into flames in the Crestmoor residential neighborhood 2 miles (3.2 km) west of San Francisco International Airport near Skyline Boulevard and San Bruno Avenue

The United States Geological Survey registered the explosion and resulting shock wave as a magnitude 1.1 earthquake. Around 8 people were killed, and 58 injured due to the accident, and >100 homes damaged / destroyed.

During the first 50 hours following the incident, over 500 firefighters and 90 apparatus responded, involving 42 fire agencies

Additional commentary:

- Natural gas disruption events are unique and their impact is influenced by a wide range of variables both known and unknown, precluding utility in comparison for purposes of impact assessment. Our report provided a list of recent natural gas disruption events for the purpose of highlighting that they do occur, and at a frequency that may not be widely understood.

  Example: For illustrative purposes, FEIs Huntingdon facility represents a single connection point to upstream suppliers and in the event of disruption to it, supply of natural gas to hundreds of thousands of customers in BC would be at risk. In contrast, a similar disruption in a more resilient system may have an immaterial or no impact to consumers.

- 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.

On page 3 of the Updated Public Application, FEI states that a major disruption on the T-South system would leave FEI with insufficient supply to meet the daily Lower Mainland load at most times of the year, and leave the system vulnerable to a hydraulic collapse (i.e., an uncontrolled, total depressurization).

65.5 Please clarify what is meant by a "imbalance" in the duration component of the disruption scenarios, specifying the assumptions made around the assumed duration of the disruption, and the form it takes e.g. the period for which there is hydraulic collapse or uncontrolled loss of pressure, a controlled no flow situation, or reduced flow (and to what extent flow is reduced), and .

Response:

The following response has been provided by PwC:

Imbalance refers to supply not meeting demand as a result of disruption, ranging from all demand is met to no demand is met within the context of the other scenario parameters. The scenarios generally entail an initial full or partial outage, followed by a ramp up back to normal supply conditions over the remaining duration. No attempt was made to characterize the form of the disruption as this was not relevant to the analysis of impact. PwC was not engaged in FEI's resiliency planning.

Scenario bounds were defined based on the notable conditions that would create a material step change in impact for one or more stakeholder groups in BC. These were identified by collecting information from external (impacted sectors / stakeholder groups) and internal (FEI) interviews, but may inherently be informed by previous disruption events that stakeholders have identified and considered in their own risk management plans.

For example:

- Our stakeholder interviews indicated that major hospitals are mandated to have a three (3) day back up heating source, yet some critical systems / capabilities for full operations (e.g., sterilization) may be limited. Interviewed industrial consumers indicated that production could typically continue for a short term (approximately 6 weeks) following a natural gas disruption event.
- Information gathered from internal interviews included FEI's operational experience in outages and bringing systems back online, which played a part in informing the "Duration" upper scenario bounds.

65.6 Please explain to what extent the TLSE project would help to avoid the imbalances assumed in the 3 scenarios.

Response:

The following response has been provided by PwC:

The intent of the study was to assess the potential impact of natural gas disruption and provide the province and the energy industry with data to help weigh the costs and benefits of different infrastructure investments to enhance system resiliency in the province. PwC was not engaged in FEI's resiliency planning.

The following response has been provided by FEI:

As discussed in the response to BCUC IR1 46.5, the scenarios generally entail an initial full or partial outage, followed by a ramp-up to normal supply conditions over the remaining duration. The TLSE Project would avoid the imbalances assumed during the initial full or partial outage for the three scenarios (i.e., short duration supply disruption). The period of time that the TLSE Project will help following a ramp-up back to normal supply conditions is limited by the storage tank size. This was discussed in the response to BCUC IR1 4.5.

Attachment 1.5a

Ken Oliphant, Ph.D., P.Eng.

Executive Vice President & Chief Technology Officer
JANA Corporation

PROFILE

Dr. Ken Oliphant is Executive Vice President and Chief Technology Officer of JANA. Ken received his undergraduate degree in Chemical Engineering from the University of Toronto and his Ph.D. in Chemical Engineering from Queen's University. Prior to co-founding JANA, he spent his career at Rohm & Haas and AT Plastics. Ken's specific focus is piping system risk assessments, performance validation and lifetime forecasting. Under Ken's technical leadership, JANA's Risk Technologies Team partners with gas pipeline operators to develop Integrity Management strategies based on JANA's mechanistic-probabilistic risk modeling, allowing pipeline operators to make fully-informed business decisions.

EXPERIENCE

JANA Corporation
1999 > Current

Executive Vice President & Chief Technology Officer

JANA was founded in 1999 as a testing laboratory for plastic piping systems. Over the next 15 years, JANA grew to be the largest hydrostatic testing lab in North America and the largest oxidative resistance testing lab in the world. In 2014, JANA sold its laboratory assets to NSF International and turned its entire focus to JANA's risk models for gas pipeline systems. Emerging from JANA's 300,000,000 hours of plastic pipe testing experience, advanced reliability engineering tools from the aerospace and nuclear industries, and the performance modelling tools developed at JANA over the last two decades, JANA's risk models are used by North American gas pipeline operators to create Risk Assessments customized to an operator's specific piping network. JANA is proud to have made an impact on the integrity of natural gas pipelines serving over 51 million homes in the US and Canada.

Responsibilities:

- Builds an innovative technological roadmap by setting short and long-term technical goals while ensuring alignment with JANA's strategy
- Leads all aspects of JANA's technology development
- Directs JANA's technology strategic direction, development and future growth for platforms, partnerships and external relationships
- Provides leadership to a rapidly expanding Risk Technologies Team in a fashion that supports JANA's culture, mission and values
- Actively researches leading edge technologies, conducts case studies and makes determinations on the direction of new technologies
- Outlines technical opportunities and risks to deliver technologies and identifies new innovations
- Collaborates with pipeline operators to develop high-level risk strategies to allow optimal integration of risk assessments into corporate decision-making processes

EDUCATION

Queen's University 1994	Ph.D. Engineering Chemistry
University of Toronto 1989	B.A.Sc. Chemical Engineering

INDUSTRY PARTICIPATION

Over his career, Dr. Oliphant has participated in the industry as follows:

Industry Associations

- Professional Engineers of Ontario (PEO)
- Association of Professional Engineers and Geoscientists of Saskatchewan
- Plastic Pipe Institute (PPI)
- Canadian Standards Association (CSA)
- American Gas Association (AGA)
- Canadian Gas Association (CGA)
- ISO TC138 (Plastics pipes, fittings and valves for the transport of fluids)
- ISO TC 251 (Asset Management)

Technical Leadership

- ISO TC138 Co-Chair, Canada
- ISO TC251 Subcommittee
- CSA B137 Distribution Subcommittee
- PPI Hydrostatic Stress Board
- CSA Z662

Regulatory Influence

JANA has supported its clients and their communities in the following regulated jurisdictions:

- Alberta
- California
- Virginia
- British Columbia
- Ontario
- Canadian Federal Code
- US Federal Code

PUBLICATIONS

- "A Risk-Based Approach to Stress Corrosion Cracking Integrity Management" Paul Chernikhowsky, Bryan Balmer, Ken Oliphant, James DuQuesnay, 2020.
- "Integrating QRA Outputs into Pipeline Integrity Management Decision-Making", Dr. K. Oliphant, P.Eng. and W. Bryce, P.Eng., JANA Corporation, 2019.
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- "Modeling Risk for Optimal Legacy Cross Bore Inspections", D. Joyal and K. Oliphant, JANA Corporation, American Gas Association, Nashville, 2019.

- “Implementing Probabilistic/Quantitative Absolute Risk Models in Natural Gas Utilities”, R. Gardner, Xcel Energy, W. Luff and K. Oliphant, JANA Corporation, American Gas Association, Nashville, 2019.
- “A Risk-Based Approach to Legacy Cross Bore Inspection Optimization”, D. Joyal and K. Oliphant, JANA Corporation, Canadian Gas Association, Ottawa, 2019.
- “Risk-Based Inspection Optimization for Valve Inspections”, P. Vibien, P.Eng., D. Joyal, Dr. K. Oliphant, P.Eng. and W. Luff, JANA Corporation, 12th International Pipeline Conference, Calgary, September 24-30, 2018.
- “A Framework for Pipeline and Storage Facilities Risk Modeling”, Dr. K. Oliphant, P.Eng. and W. Bryce, P.Eng., JANA Corporation, 2018.
- “Integrating QRA Outputs into Pipeline Integrity Management Decision-Making”, Dr. K. Oliphant, P.Eng. and W. Bryce, P.Eng., JANA Corporation, 2019.
- “OPEX Savings through Risk-Based Inspection Optimization”, W. Luff and K. Oliphant, JANA Corporation, American Gas Association, Washington, DC, 2018.
- “Pipeline Risk Modeling – How Much Data do I Need?”, W. Bryce P.Eng., Dr. K. Oliphant, P.Eng., JANA Corporation, American Gas Association, Orlando, 2017.
- “Power Law Analysis Implications of the San Bruno Pipeline Failure”, Dr. K. Oliphant, P.Eng., W. Bryce, P.Eng., W. Luff, JANA Corporation, 11th International Pipeline Conference, Calgary, September 26-30, 2016.
- “RCA Framework for Gas Distribution Piping Assets”, Dr. K. Oliphant, P.Eng., Sarah Chung, P.Eng., Bonnie Ng, JANA Corporation, American Gas Association, Phoenix, 2016.
- “Non-Destructive Inspection of Polyethylene Fusions and Electrofusions”, Dr. Ken Oliphant, P.Eng. and Dalton Crosswell, JANA Corporation, American Gas Association, Phoenix, 2016.
- “Modeling the Consequences of Pipeline Risk”, Dr. K. Oliphant, W. Bryce and W. Luff, JANA Corporation, American Gas Association, Phoenix, 2016.
- “A Critical Review of Pipeline Risk Modeling Approaches”, William Luff, Dr. Ken Oliphant, Wayne Bryce and James DuQuesnay, JANA Corporation, American Gas Association, Phoenix, 2016.
- “Bowtie Risk Assessment of Electrofusion Fitting Installations”, Dr. Ken Oliphant, P.Eng., James DuQuesnay, William Luff, JANA Corporation, American Gas Association, Phoenix, 2016.
- “An Absolute Risk Model Framework for Gas Pipelines”, K. Oliphant, Ph.D., P.Eng., W. Luff, M.A.Sc., W. Bryce, P.Eng., JANA Corporation, American Gas Association, Phoenix, 2016.
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- “Long-Term Performance of Polyethylene Piping Materials in Potable Water Applications”, Patrick Vibien, M.Sc., P.Eng., Sarah Chung, M.A.Sc., P.Eng., Sheyla Fong, Ken Oliphant, Ph.D., P.Eng., Jana Laboratories Inc., American Water Works Association, 2015.
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- "Melt Grafting of a Basic Monomer onto Polyethylene in a Twin Screw Extruder", K. Oliphant and W.E. Baker, Paper Presented at the 1994 Annual Technical Conference of the Society of Plastics Engineers, San Francisco, May 1-5, 1994.
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- "Recycling of Ground Rubber Tires in Polymer Blends using Reactive Compatibilization", K. Oliphant and W.E. Baker, Proceedings, Polymer Processing Society, 7th Annual Meeting, Hamilton, Ontario, Canada, April 22-24, 1991.

Attachment 1.5b

Wayne Bryce, P.Eng.

President & Chief Executive Officer
JANA Corporation

PROFILE

Wayne Bryce is President & CEO of JANA. Wayne is a Mechanical Engineer from McGill University in Montreal and has spent his entire career in the field of piping systems. Joining DuPont out of University, Wayne led the team that developed proprietary process technology saving $20 million in capital and reducing operating costs by over 30% annually. Following that success, Wayne launched a completely new product for DuPont and grew the market penetration of an established product line by 42%. In 1999, Wayne co-founded JANA, with a mission to ensure Better Pipelines for a Better World. Under Wayne's leadership, this Mission defines, directs and drives JANA. Wayne ensures that JANA invests deeply in developing the absolute best technology that empowers gas pipeline operators to genuinely manage their assets in a risk-informed manner and profoundly mitigate the inherent risks of operating pipeline assets.

EXPERIENCE

JANA Corporation
1999 > Current

President & Chief Executive Officer

JANA was founded in 1999 as a testing laboratory for plastic piping systems. Over the next 15 years, JANA grew to be the largest hydrostatic testing lab in North America and the largest oxidative resistance testing lab in the world. In 2014, JANA sold its laboratory assets to NSF International and turned its entire focus to JANA's risk models for gas pipeline systems. Emerging from JANA's 300,000,000 hours of plastic pipe testing experience, advanced reliability engineering tools from the aerospace and nuclear industries, and the performance modelling tools developed at JANA over the last two decades, JANA's risk models are used by North American gas pipeline operators to create Risk Assessments customized to an operator's specific piping network. JANA is proud to have made an impact on the integrity of natural gas pipelines serving over 51 million homes in the US and Canada.

Responsibilities:

- Directs the creation and implementation of strategic corporate business plans including financial goals and controls, product development and defined focus and value-added initiatives
- Sets direction with Executive Team in planning new business strategies
- Evaluates and advises on the impact of long-range planning, introduction of new programs/strategies and regulatory action
- Participates in the development of the corporation's plans and programs as a strategic partner
- Represents the company as required, including attendance of important functions, industry events and public meetings
- Builds strong relationships with key players (early adopters, thought leaders) in the various geographies and industries

AT Plastics
1995 - 1999

Business Development Manager

DuPont
1989 - 1995

Business Manager

EDUCATION

McGill University — B.Sc. Mechanical Engineering

1989

INDUSTRY PARTICIPATION

Over his career, Mr. Bryce has participated in the industry as follows:

Industry Associations

- Professional Engineers of Ontario (PEO)
- Institute of Asset Management (IAM)
- Canadian Standards Association (CSA)
- ISO TC 138 (Plastics pipes, fittings and valves for the transport of fluids),
- ASME B31.8
- Canadian Gas Association (CGA)
- American Gas Association (AGA)
- Western Energy Institute (WEI)
- Plastics Pipe Institute (PPI)

Technical Leadership

- ISO TC138 Co-Chair, Canada
- Board of Directors, IAM Canada
- Gas Piping Technology Committee (GPTC)

Regulatory Influence

JANA has supported its clients and their communities in the following regulated jurisdictions:

- Alberta
- California
- Virginia
- British Columbia
- Ontario
- Canadian Federal Code
- US Federal Code

PUBLICATIONS

- "Integrating QRA Outputs into Pipeline Integrity Management Decision-Making", Dr. K. Oliphant, P.Eng. and W. Bryce, P.Eng., JANA Corporation, 2019.
- "Incorporating Low Probability High Consequence Events into Risk Models", Dr. K. Oliphant, P.Eng., W. Bryce, P.Eng. and Dr. Vida Meidanshahi, JANA Corporation, American Gas Association 2019 Pipeline Risk Data Workshop, Albuquerque, 2019.
- "Probabilistic Risk Models for DIMP", R. Gardner, Xcel Energy, W. Bryce, P.Eng. and Dr. K. Oliphant, P.Eng., JANA Corporation, American Gas Association 2019 Pipeline Risk Data Workshop, Albuquerque, 2019.
- "A Framework for Pipeline and Storage Facilities Risk Modeling", Dr. K. Oliphant, P.Eng. and W. Bryce, P.Eng., JANA Corporation, 2018.
- "Pipeline Risk Modeling – How Much Data do I Need?", W. Bryce P.Eng., Dr. K. Oliphant, P.Eng., JANA Corporation, American Gas Association, Orlando, 2017.
- "Power Law Analysis Implications of the San Bruno Pipeline Failure", Dr. K. Oliphant, P.Eng., W. Bryce, P.Eng., W. Luff, JANA Corporation, 11th International Pipeline Conference, Calgary, September 26-30, 2016.

- “Modeling the Consequences of Pipeline Risk”, Dr. K. Oliphant, W. Bryce and W. Luff, JANA Corporation, American Gas Association, Phoenix, 2016.
- “A Critical Review of Pipeline Risk Modeling Approaches”, William Luff, Dr. Ken Oliphant, Wayne Bryce and James DuQuesnay, JANA Corporation, American Gas Association, Phoenix, 2016.
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Attachment 1.5c

Assessment of Outage Probability

JANA Project 2347
White Paper

Confidentially submitted to FortisBC Energy Inc.

September 9, 2021

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CONTENTS

1.0 OVERVIEW

An assessment of the cumulative probability of an outage event on the T-South system over the economic life of the TLSE Project (67 years) was conducted. The assessment is based on the estimated probability of failure for an average performing transmission pipeline the length of the T-South system. The assessment considered the probability of both a rupture[1] and an ignited rupture based on two different sources of pipeline performance data:

- The PHMSA (Pipeline and Hazardous Materials Safety Administration) average reported rupture rates through the last 10 years
- The TSB (Transportation Safety Board of Canada) average reported rupture rates through the last 10 years

These numbers represent rupture probabilities for North American pipeline operators employing currently available integrity management practices and are considered to provide a reasonable basis for estimating future potential ruptures. While ruptures are not the only event that could drive a loss of supply situation (e.g., compression station failure), they are considered to represent a key component of potential loss of supply situations.

Based on the rupture rates, the cumulative probabilities of at least one rupture and at least one ignited rupture of a transmission pipeline the length of the T-South pipeline occurring over the 67-year economic design life of the TLSE Project were forecast.

2.0 BACKGROUND

2.1 Enbridge BC Pipeline T-South System

Two pipelines make up the Enbridge BC Pipeline T-South system (see Figure 1):

- NPS 36 L2
- NPS 30 L1

Length

The total length of the T-South system (L1 and L2 combined) is approximately 1834 km (= 2 × 917 km). The T-South system extends 917 km from Compressor Station 2 to the Huntingdon Meter Station in Huntingdon, BC.[2] The NPS 36 L2 pipeline parallels the NPS 30 L1 pipeline in the same right-of-way throughout the T-South system.

Age

Construction of the NPS 36 L2 pipeline was completed in 1972. T-South system has been in service since 1957.[3]

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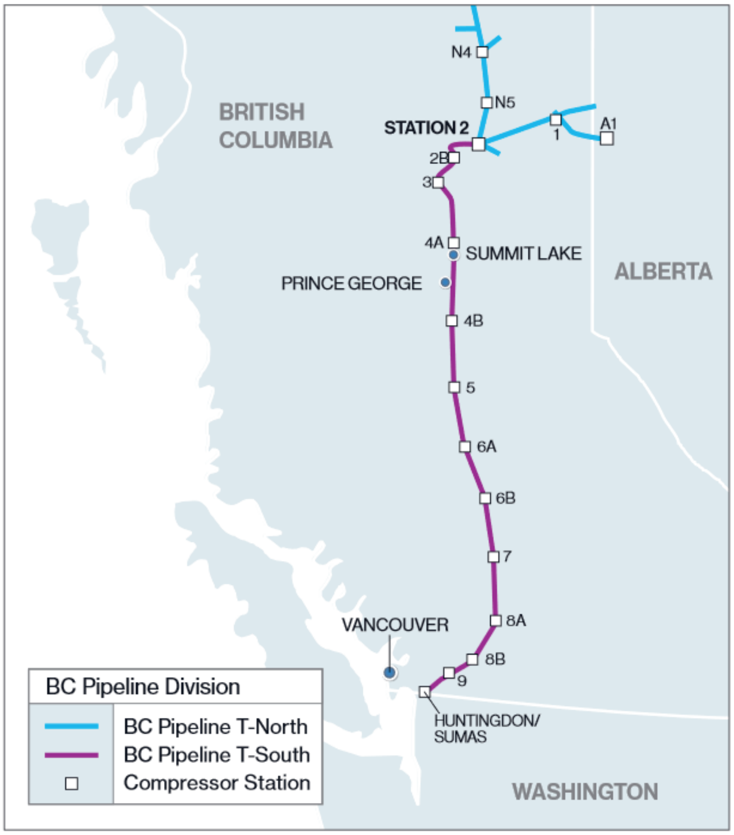
[1] Ruptures are through wall failures of the pipeline where the stress within the pipeline extends the through wall defect during the failure event, resulting in unstable failure and gas release. They are distinguished from "leaks" where the release is from a stable through wall defect.

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

[3] https://www.enbridge.com/~/media/12016B2E981A419D97C19039E552E797.ashx

Figure 1: T-South Pipeline System



3.0 HISTORICAL RUPTURE RATE

A loss of supply event could arise due to many potential causes (loss of compressor stations, pipeline failure, etc.). This analysis considered the probability of a loss of supply event due to pipeline rupture only. To estimate the future cumulative probability of a rupture event on the T-South pipeline over the economic lifetime of the TLSE Project (67 years), a reasonable estimate of the annual rupture probability for the pipeline is needed. The assessment considered the estimated probability of failure for an average performing transmission pipeline the length of the T-South system. Given the limited length of the T-South pipeline system (approximately 1,843 km in total) more comprehensive datasets on pipeline rupture performance were assessed. A set of rupture rates for onshore natural gas transmission pipelines was calculated from two industry data sources:

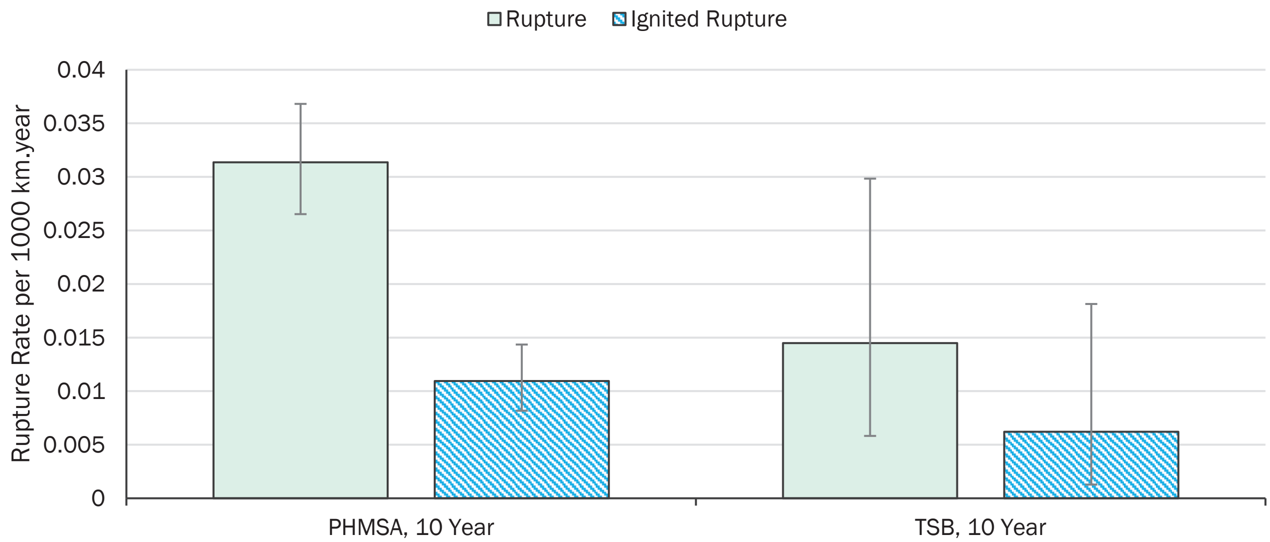
- PHMSA (10 year average)
- TSB (10 year average)

These datasets represent roughly 476,366 km and 48,388 km of transmission pipelines, respectively. The data represent the collective pipeline performance for North American pipeline operators employing currently available integrity management practices and are considered to provide a reasonable basis for estimating future potential ruptures. There are potential factors that could, overtime, cause these number to decrease (e.g., evolving integrity management practices, regulatory changes, etc.) or increase (e.g., increasing age of the pipelines, increasing frequency of extreme weather events, etc.) that were not considered in this analysis.

While ruptures are not the only event that could drive a loss of supply event (e.g., compression station failure), they are considered to represent a key component of potential loss of supply situations and, therefore, are considered a reasonable basis for estimating the cumulative probability of loss of supply. Any pipeline rupture is a serious event that would result in temporary pipeline shutdown until repairs could be affected, the cause of the rupture identified and the integrity of the pipeline verified. Given the two pipelines that make up the T-South system are in close proximity, a rupture of one of the pipelines would likely result in at least a temporary shut-down of both lines. Not all pipeline ruptures result in ignition of the gas released. Ignited ruptures are more serious incidents with a higher probability of an extended outage. For this reason, the analysis considered both the rupture potential and the ignited rupture potential. A rupture of the pipeline without ignition could result in an extended loss of supply depending on the rupture cause, specific location, regulatory response, etc. The overall rupture rate is, therefore, considered to be a higher end bound for a potential loss of supply event due to pipeline failure. An ignited rupture would be expected to result in an extended loss of supply and is considered to represent the lower end bound of outage probabilities.

The data from the two sources are summarized in Figure 2. The two sources provide similar rupture rate forecasts (overlapping 95% confidence bounds). The 95% confidence bounds are smaller for the PHMSA data due to the greater volume of data in the dataset. The rupture rate and ignited rupture rate for the T-South pipeline observed since installation fall between the PHMSA and TSB rupture rates.

Figure 2: Transmission Pipeline Failure Rates for Ruptures and Ignited Ruptures



	RUPTURE RATE (PER 1000 KM.YEAR)			IGNITED RUPTURE RATE (PER 1000 KM.YEAR)		
	Mean	Lower Limit*	Upper Limit*	Mean	Lower Limit*	Upper Limit*
PHMSA, 10 Year	0.031	0.027	0.037	0.011	0.008	0.014
TSB, 10 Year	0.014	0.006	0.030	0.006	0.001	0.018

* Limits are for a 95% confidence level

4.0 PROBABILITY OF RUPTURE EVENT OVER TIME INTERVAL

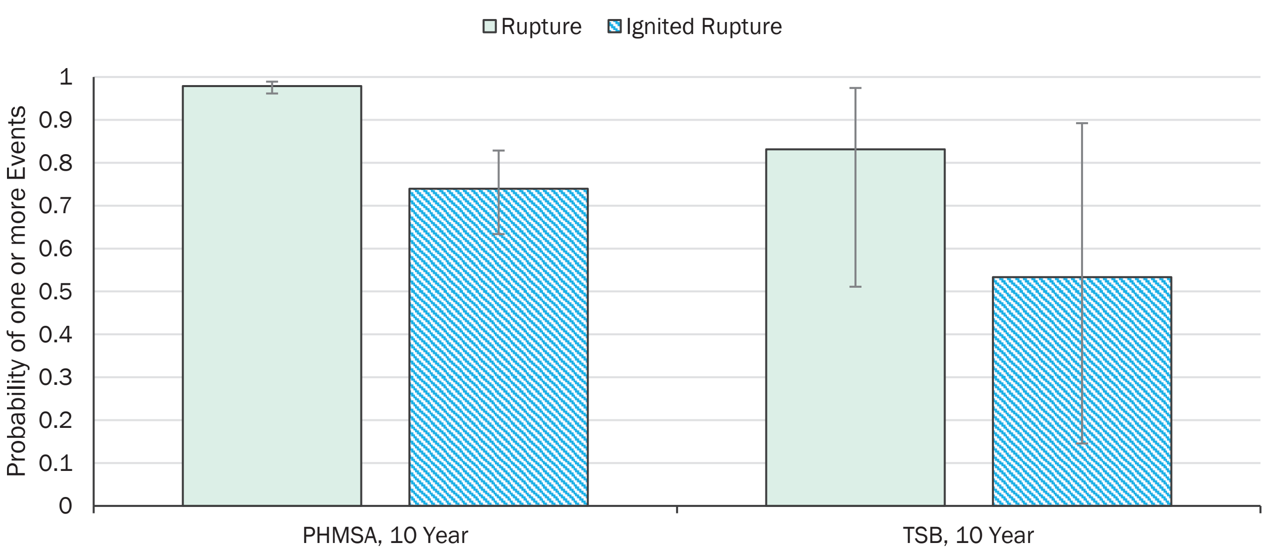
The estimated cumulative probabilites of at least one rupture event and at least one ignited rupture event throughout the economic life of the TLSE Project (67 years) were calculated for the two different rupture rate sources.

The calculated rupture rates were applied to a 1,834 km length of pipe (representing the total length of the T-South system). This was done to account for the fact that rupture of either pipeline would likely result in temporary shutdown of both pipelines, as was done in response to the October 9th, 2018 rupture.

The probablities of one or more events in time intervals over the range from 0 to 67 years were calculated using the Poisson distribution (See Appendix D) and are sumarized in Figure 3.

Based on the analysis, the cumulative probability of a rupture event is forecast to be between 83.1% to 97.9% and the cumulative probability of an ignited rupture between 53.4% and 73.9% over the 67 year economic life of the TLSE Project.

Figure 3: Cumulative Probability Estimates for Rupture of an 1,834 km long Transmission Pipeline



	PROBABILITY OF ONE OR MORE RUPTURES (%)			PROBABILITY OF ONE OR MORE IGNITED RUPTURES (%)		
	Mean	Lower Limit*	Upper Limit*	Mean	Lower Limit*	Upper Limit*
PHMSA, 10 Year	97.9	96.2	98.9	73.9	63.4	82.9
TSB, 10 Year	83.1	51.1	97.4	53.4	14.6	89.2

* Limits are for a 95% confidence level

Statement of Confidentiality

This report is intended for FortisBC Energy Inc. (**"Client"**) and its employees. The information contained in this document is proprietary and confidential. No part of this document or the information contained in this document may be used, disclosed, published or redistributed without the prior written consent of JANA.

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APPENDIX A: OCCURRENCE RATE CALCULATION BASIS

Occurrence rate is the number of events observed in a time interval divided by the total exposure in that time interval. For pipelines, the exposure is the sum of the length of in-service pipe for each year in the time interval.

$$r = \frac{n}{E}$$

r occurrence rate (events per km·year)
n number of events (e.g., ruptures)
E total exposure (km·year)

Confidence Interval

Assuming the occurrence of incidents follows the law of rare events, a Poisson distribution can be used. The confidence interval for a Poisson distribution can be calculated using following relationships:[4]

Occurrence Lower Limit

$$n_{LL} = \frac{1}{2}\left(\chi^2\left(\nu = 2n, p = \frac{\alpha}{2}\right)\right)$$

Occurrence Upper Limit

$$n_{UL} = \frac{1}{2}\left(\chi^2\left(\nu = 2n + 2, p = 1 - \frac{\alpha}{2}\right)\right)$$

n	Number of occurrences
$\chi^2(\nu, p)$	chi-squared quantile function
ν	degrees of freedom
p	right tail probability
$1 - \alpha$	confidence level (e.g., for 95% confidence, $\alpha = 0.05$)

[4] Sahai, H. and Khurshid, A. (1993), Confidence Intervals for the Mean of a Poisson Distribution: A Review. Biom. J., 35: 857-867. https://doi.org/10.1002/bimj.4710350716

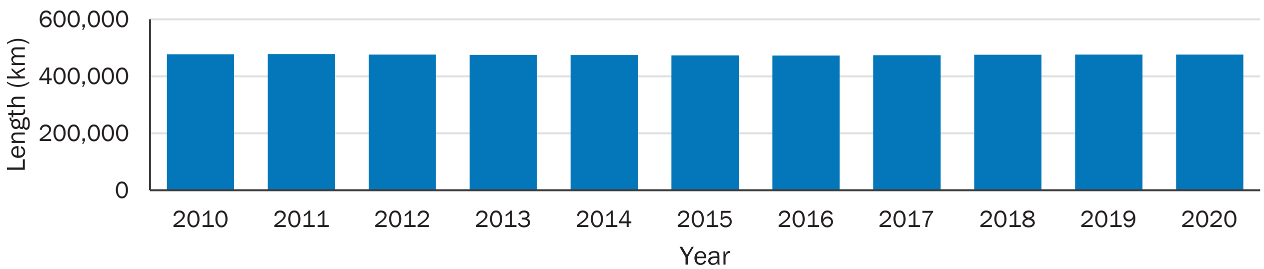
APPENDIX B : INDUSTRY RUPTURE DATA SOURCES

B1 PHMSA

United States Department of Transportation (US DOT), Pipeline and Hazardous Materials Safety Administration (PHMSA)

B1.1 US Federal/State-Regulated Onshore Natural Gas Transmission Pipelines

Length of US Federal/State-Regulated Gas Transmission and Gathering pipelines is available from PHMSA Annual Reports.

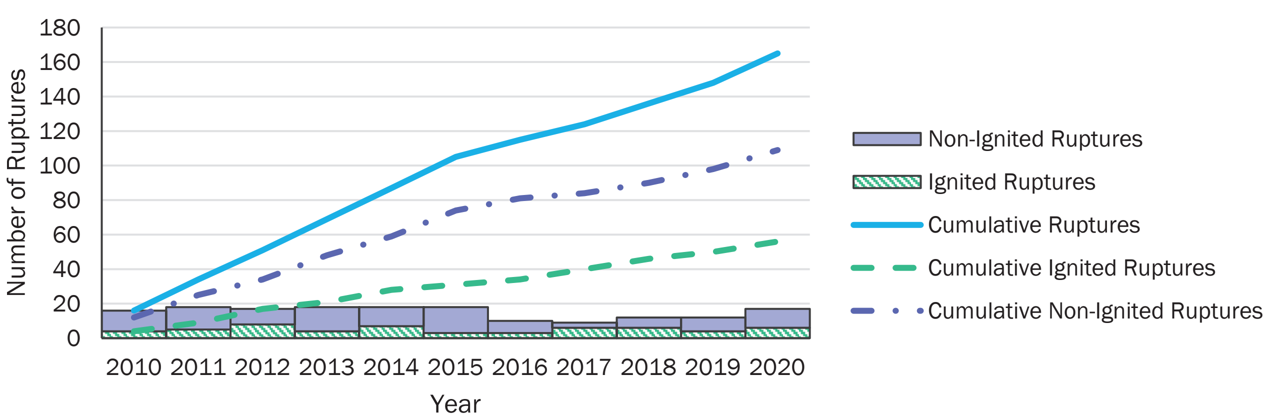


Data Filter: Commodity='Natural Gas', Onshore, Transmission

B1.2 PHMSA Incident Data for Onshore Natural Gas Transmission Pipelines

PHMSA incident reports (gas transmission and gathering) 2010 – Present (accessed September 4th, 2021).

B1.3 Rupture Incidents on Onshore Natural Gas Transmission Pipelines



Data Filter(s): ON_OFF_SHORE = 'ONSHORE', COMMODITY_RELEASED_TYPE = 'NATURAL GAS', RELEASE_TYPE = 'RUPTURE', and PIPELINE_FUNCTION LIKE '%TRANSMISSION%'

B2 TSB (CER)

Transportation Safety Board of Canada (TSB)

Canada Energy Regulator (CER)

B2.1 CER Regulated Natural Gas Transmission Pipelines:

REGION	APPROX. LENGTH (KM)	SOURCE
All	48 338	CER Natural Gas Pipeline Transportation System
Westcoast	2 900	CER Pipeline Profiles: Westcoast or BC Pipeline

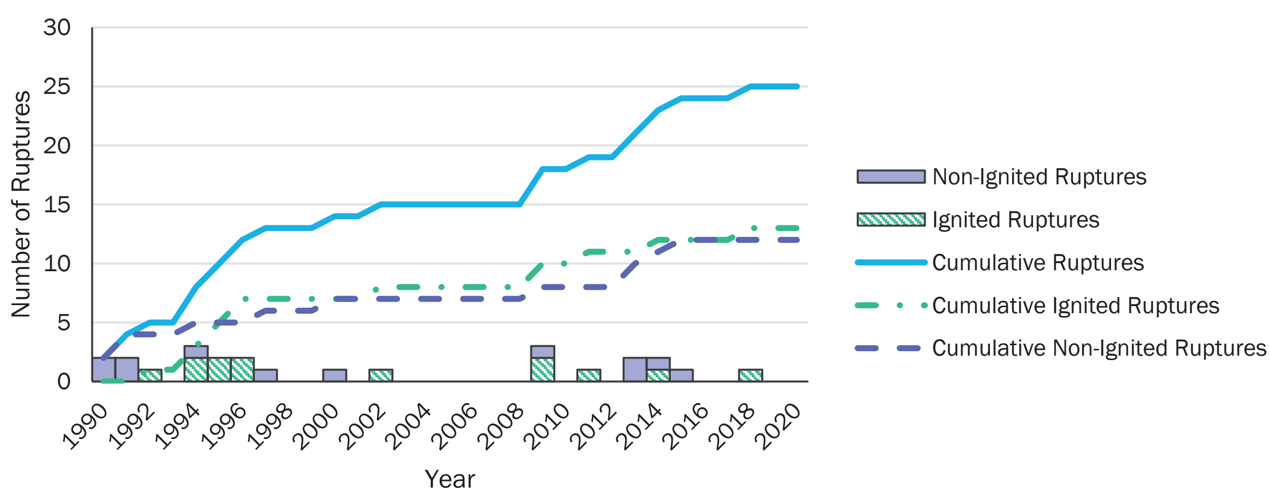
B2.2 Incident Data for CER Regulated Pipelines

Transportation Safety Board of Canada (TSB) Pipeline Occurrence Database System:

Pipeline occurrence datasets from January 1979 http://www.tsb.gc.ca/eng/stats/pipeline/data-2.html

Accidents and incidents[5] are reported in accordance with the TSB Regulations that were in effect at the time of the occurrence.

B2.3 Rupture Incidents on CER Regulated Pipelines



Data Filter(s): product = 'Natural Gas', rupture_ind = 'True', and facility_type = 'Transmission Line'

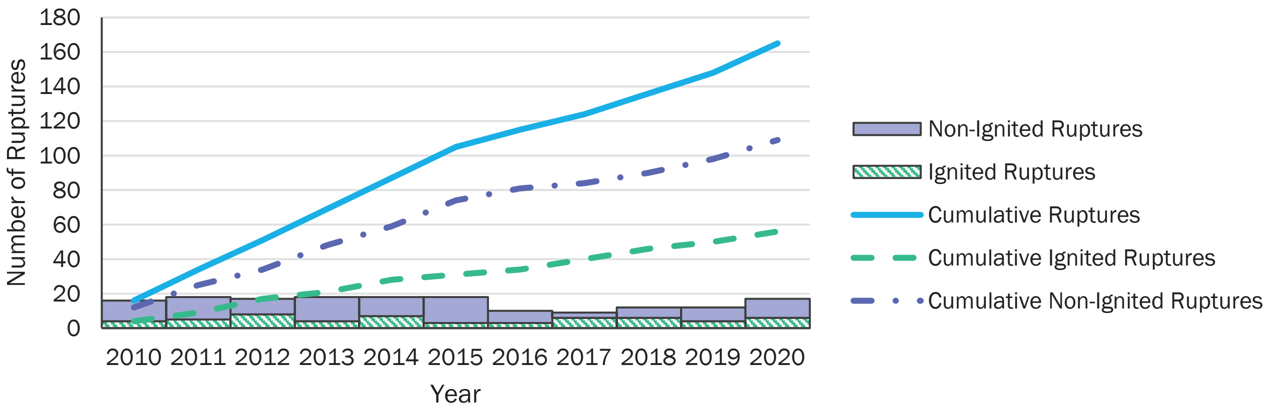
[5] Accidents are more severe than incidents.

B2.4 Rupture Incidents on the T-South System

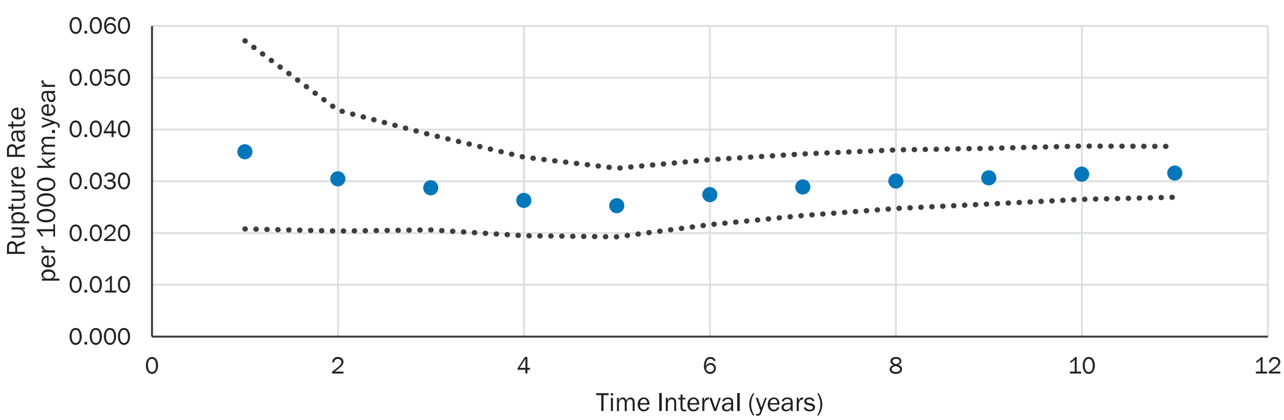
TSB OCCURRENCE NUMBER	OCCURRENCE DATE	TSB REPORT	SUMMARY	FIRE
P18H0088	2018-10-09	http://www.tsb.gc.ca/ENG/rapports-reports/pipeline/2018/P18H0088/P18H0088.html	Rupture of NPS 36 L2 on section 4A	Yes
P00H0037	2000-08-07	http://www.tsb.gc.ca/ENG/rapports-reports/pipeline/2000/P00H0037/P00H0037.html	Rupture of NPS 30 L1 on section 8A	No

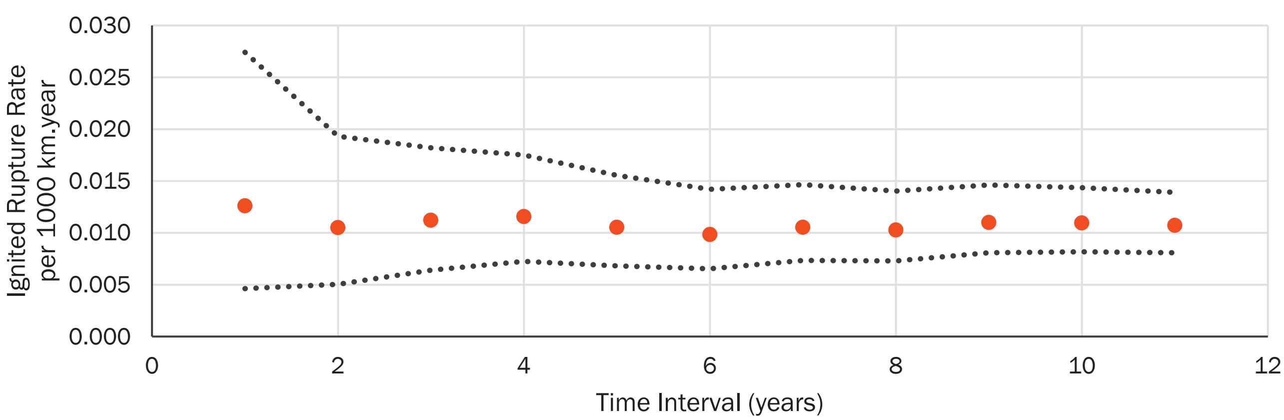
APPENDIX C: PHMSA HISTORICAL RUPTURE RATE

Reported rupture incidents



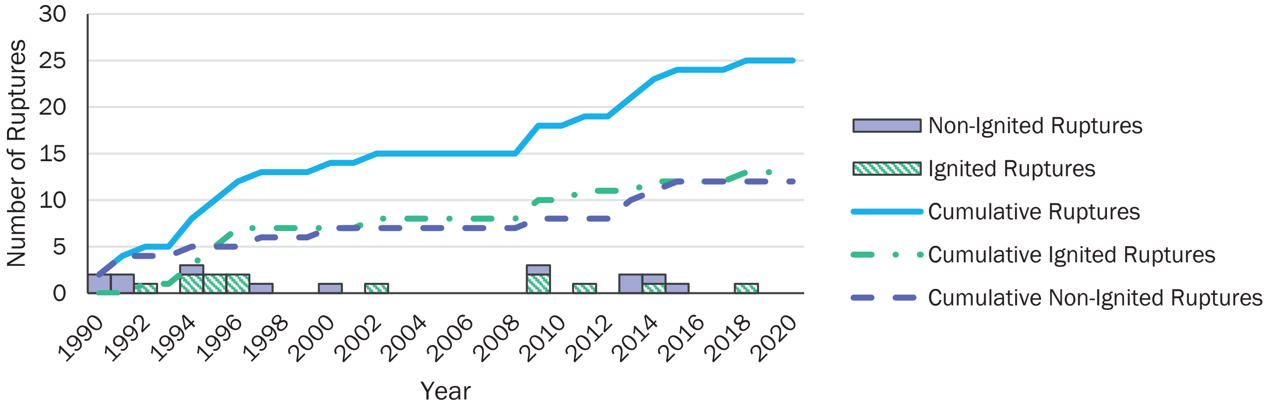
Reported ruptures from 2010 to 2020 (11 years). A plot of the historical rupture rate over time intervals looking back from 2020 (inclusive), 1 to 11 years. Dotted lines are the upper/lower 95% confidence limits.



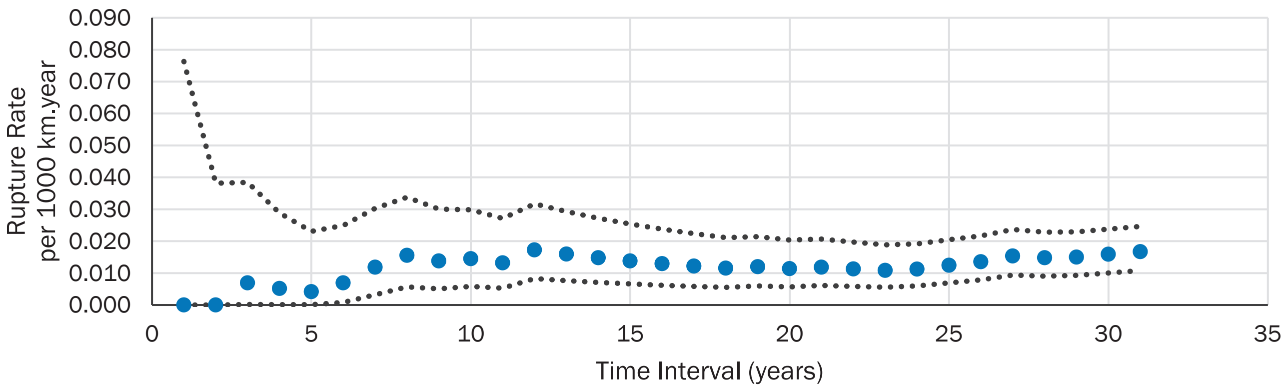


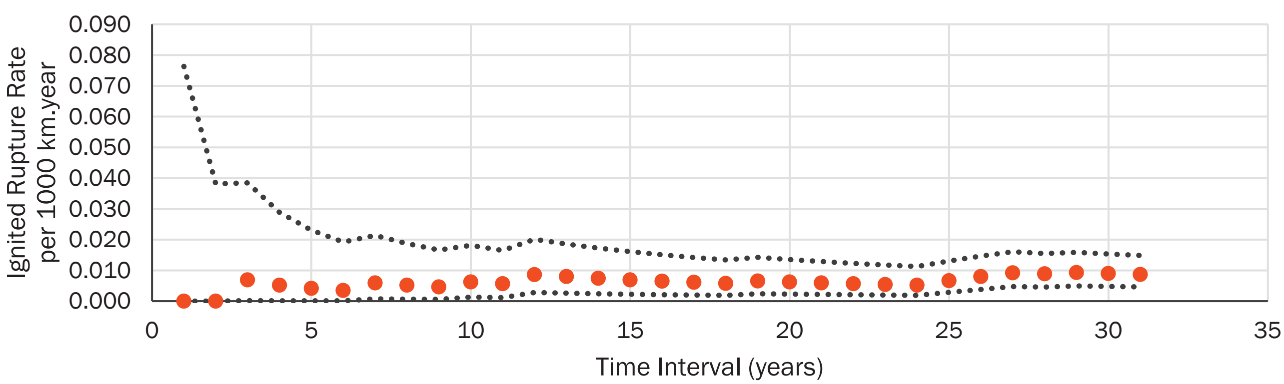
APPENDIX D: TSB HISTORICAL RUPTURE RATE

Reported rupture incidents



Reported ruptures from 1990 to 2020 (31 years).[6] A plot of the historical rupture rate over time intervals looking back from 2020 (inclusive), 1 to 31 years. Dotted lines are the upper/lower 95% confidence limits.



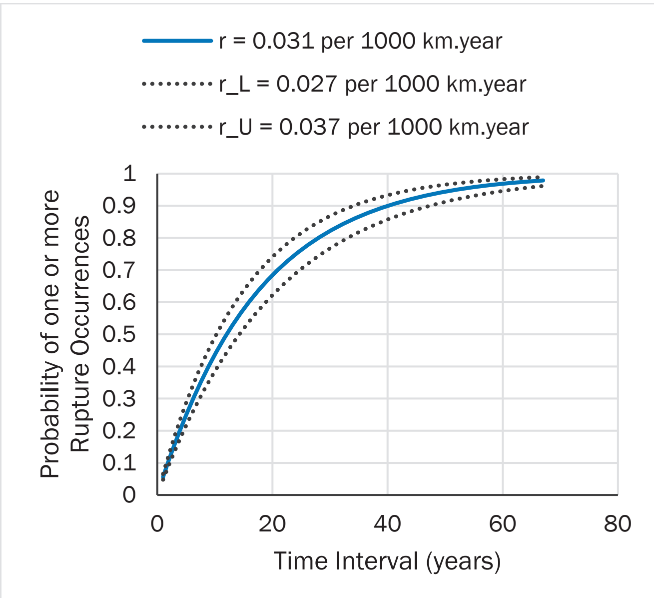


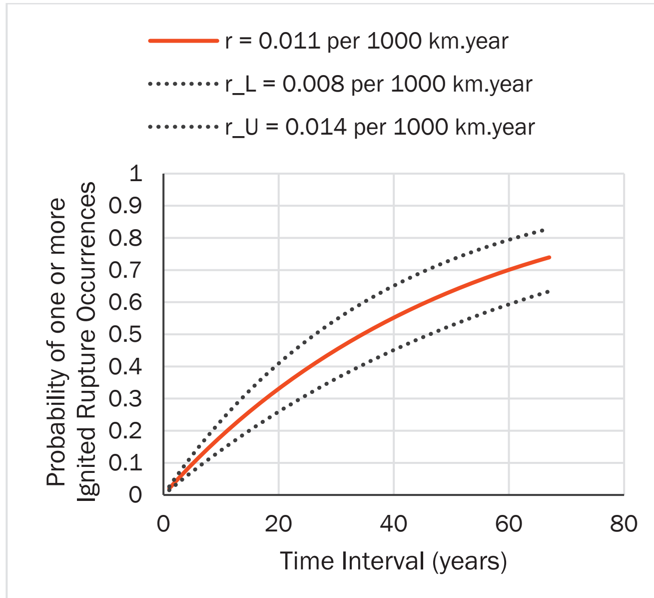
[6] This assessment used the current length of CER natural gas pipelines for the entire history since historical data from CER was not readily available. This assumption will likely be more significantly off from the actual length for the time intervals longer than 10 years.

APPENDIX E: PROBABILITY OF RUPTURE EVENTS USING HISTORICAL DATA

E1 PHMSA Historical Rupture Rate

Using an occurrence rate based on the past 10 years of data (from 2011 through 2020)





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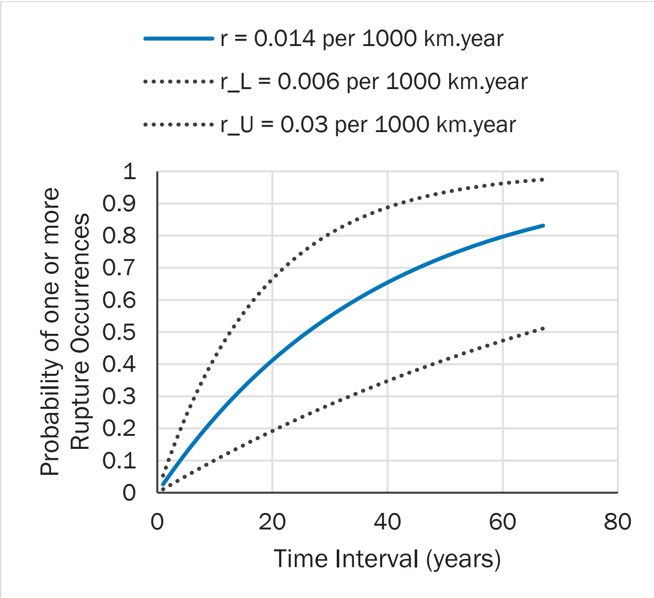
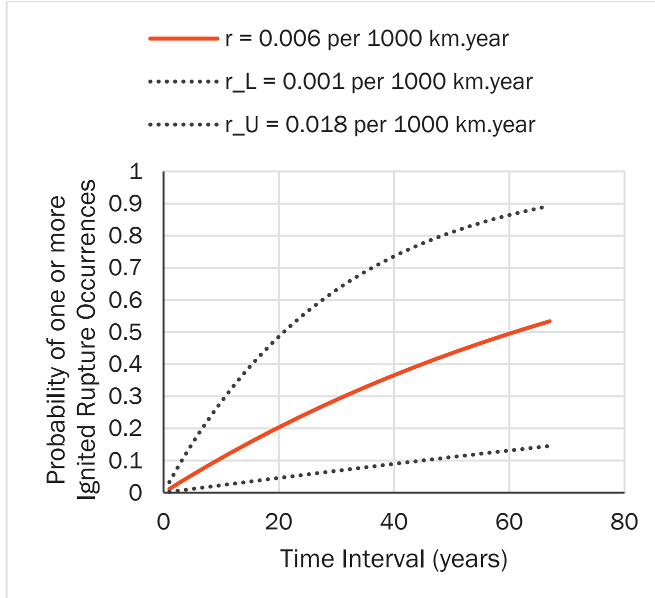
E2 TSB Historal Rupture Rate

Using an occurrence rate based on the past 10 years of data (from 2011 through 2020)





Attachment 4.2

Northwest Mutual Assistance Agreement

(FORTISBC ENERGY INC.)

Table of Contents

Introduction

Each signatory to this Agreement ("Member" or collectively "Members") is an entity that controls assets that utilize, operate, or control natural gas transportation or storage facilities in the Pacific Northwest (British Columbia, Alberta, Washington, Oregon, Nevada, and Idaho). Each Member has an interest in exercising due diligence in its operations and planning to be able to provide and maintain firm natural gas supply, storage, or transportation service during emergency conditions or events and to restore normal service to customers as quickly as possible after such events occur. All Members have an interest in maintaining a safe, secure, reliable regional natural gas system.

This Agreement defines the terms and conditions of voluntary cooperation and assistance between the Members in a natural gas system emergency if such aid is requested, offered, and accepted. Another objective is to maintain and improve communication between the Members regarding emergency planning and incident response. The Agreement does not impose any obligation whatsoever on the Members to provide or continue cooperation, aid, or assistance.

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

There is no membership (i.e. signatory) limitation to this Agreement and membership is voluntary. The emergency responses which Members are asked to provide to other Members needing assistance are emergency supply and/or emergency service or request for deviation from existing normal activities.

Definitions

1. Member: A Pacific Northwest entity with controlling interest in assets that may provide assistance in an Emergency Condition that is a signatory to this Agreement.
2. Pacific Northwest: Washington, Oregon, Idaho, Nevada, Alberta, and British Columbia
3. Affected Member: A Member experiencing an Emergency Condition.
4. Assisting Member: A Member providing Emergency Service to the Affected Member.
5. Emergency Condition: That situation which exists when an unplanned event causes, or is likely to cause, a supply shortfall to firm customers or markets beyond the ability of a Member to manage.
6. Emergency Service: The service (and/or actions) provided, by mutual agreement, from an Assisting Member to an Affected Member during an Emergency Condition.
7. Northwest Mutual Assistance Agreement ("Agreement" or "NWMAA"): The pre-arrangements as set out herein to assist in the management of an Emergency Condition.
8. Custodian: A contracted service provider that supports the maintenance and implementation of the Agreement.

Executive Committee

Each natural gas pipeline and each Local Distribution Company ("LDC") will have one representative on the Executive Committee ("EC"). The EC will operate by majority rule with each representative having one vote. The EC representatives (which may be changed from time to time by notifying the Co-Chair and the Custodian) are listed in Appendix B. Each EC representative shall have the authority from their company to make decisions that may be required under this NWMAA.

The EC will plan to hold two meetings annually. A spring meeting will be held in the second quarter of the calendar year to review the previous winter operations, make recommendations to revise the agreement, as necessary, and make plans to implement the changes prior to the following winter season. A fall meeting will be held to review the changes and discuss the upcoming winter season. Meeting notes from the spring and fall meetings will be distributed to the Members by the Secretary of the EC, who will be selected as described below.

To facilitate communication among the Members, the Custodian will maintain a listing of contact information for all Members' gas acquisition, scheduling, gas control, and public relations representatives, and others as the EC may deem appropriate, as Appendix D to this Agreement.

Two Co-Chairs, a Vice-Chair, and a Secretary will be selected from the EC representatives and will serve without remuneration. These positions will serve on a rotational business for two years, defined as November 1 to October 31. EC representatives will rotate through these roles as Secretary, Vice-Chair, and Co-Chair, in that order. Co-Chairs will be seated on a staggered basis, such that one Co-Chair is in their first year and the other is in their second year.

The Co-Chairs, with assistance from the Custodian, will administer the EC, which will include organizing meetings, ensuring the Member and EC contact list is reviewed and updated, and overseeing changes to the Agreement, as agreed upon, prior to the start each winter operating season.

The Vice-Chair, with assistance from the Custodian, will facilitate the annual spring meeting to review the past winter season operation and suggest changes to improve the Agreement, as well as facilitate an after action review ("AAR") in the event assistance is activated (that is, the triggers for activation defined on page 5 are met).

The Secretary, with assistance from the Custodian, shall keep and distribute minutes for all meetings conducted under this Agreement. The Secretary will review and maintain the Member contact list and distribute updates to the Member as appropriate.

The Custodian will maintain the official Agreement and appendices, including updates to the contact information for Member representatives. When the Agreement is activated, the

Custodian will host Joint Conference Calls in execution of this Agreement including establishing secure communications and protocols.

The Co-Chairs, Vice-Chair, and Secretary will not be held liable for any matters whatsoever arising from their involvement in these positions, the actions or arrangements between or among Members, or implementation of any plan.

Any amendments to this Agreement must be evidenced in writing and signed by each of the Members.

Underlying Emergency Service Expectations

1. Notwithstanding any other terms or conditions in the Agreement or Appendices, any activity performed under this Agreement by an Affected or Assisting Member shall:
   1.1. Be agreed upon by the Affected and Assisting Members.
   1.2. Be subject to the Members' contractual and operational limitations.
   1.3. Be subject to all applicable tariffs, regulations, and policies.

2. Each Affected Member shall be responsible for initiating requests for assistance and for detailing requirements, expected duration, and such other information reasonably needed to determine the severity of the Emergency Condition.

3. Each Assisting Member will notify the Affected Member of the level of Emergency Service that can be made available.

4. Terms and conditions for Emergency Services shall be mutually agreed between the Affected Member and the Assisting Member.

5. The transporting pipeline(s) and storage plan operators will use reasonable efforts, within their existing tariffs, agreements, and applicable regulations, to facilitate the necessary services.

Activation and Mobilization

Activation Criteria

Activation of the NWMAA Executive Committee should meet the following criteria based on the actual/forecasted event and scope of work.

1. The event is expected to or has impacted one or more Members that are seeking mutual assistance and support.
2. The resource requirements are greater than the Member-to-Member coordination can offer or that of any other state or regional association.
3. At the discretion of the NWMAA Co-Chairs.

NWMAA Activation

The activation triggers of the NWMAA are:

1. **A requesting utility or pipeline Member will contact the either of the Co-Chairs to discuss the need for NWMAA activation.**
2. **The NWMAA Custodian will host a joint conference call with the requesting Member and the Co-Chair to discuss the requesting Member's request.**
3. **Either of the Co-Chairs will:**
   a. **Decide to activate the NWMAA.**
   b. **Decide not to activate the NWMAA.**
   c. **Reassess depending on resource needs.**

Activation steps of the NWMAA Co-Chairs:

1. **Maintain situational awareness; stay well-informed of incidents of potential significance; and may communicate with NWMAA Members at their discretion.**
2. **Inform the NWMAA Executive Committee and the NWMAA Custodian of the activation.**
3. **Work with the NWMAA Custodian to notify Members and state and national consortiums of the activation.**
4. **Work with the NWMAA Custodian to set up conference calls, as needed, to support activation and coordination efforts.**
5. **Establish cadence and operational period timeframes for conference calls, operational briefings, and updates.**

Joint Conference Call Procedures

Because emergency events could expand and impact more than one Member over time, joint conference calls will be used to encourage the following:

1. **Provide Members with the opportunity to understand the entire scope of the emergency, including the number of entities and customers expected to be impacted and the potential damage to each.**
2. **Allow Members to discuss and evaluate options, such as weather forecasts for different sources and/or what changes in operations that may help minimize the impact of the emergency.**
3. **Efficient, effective, and equitable allocation of available resources while mitigating the financial risk associated with the early mobilization of resources.**

The following protocols will be followed while participating in or conducting a Joint Conference Call:

1. **Members understand and agree that participation on Joint Conference Calls is restricted to employees of Member entities of the NWMAA, unless by invitation of Executive Committee representatives.**
2. **Members understand and agree that conversations between Member entities during Joint Conference Calls shall be confidential and proprietary. Therefore, with the exception of general response data/information, Members agree not to share or release any information shared between Members during the Joint Conference Calls unless**

otherwise mutually agreed. Provided, however, that a Member shall not be prevented from making public disclosure of information related to its assets where such Member, acting in good faith, makes such public disclosure to comply with applicable regulatory requirements, including, but not limited to, regulations of the Federal Energy Regulatory Commission.

3. Members understand and agree that all conversations and information shared between Member entities during Joint Conference Calls is subject to all compliance and market manipulation regulations applicable under emergency conditions. Each Member is responsible for maintaining compliance with all applicable regulatory obligations related to their entity and shall not be liable to any Member for public disclosure of information obtained during joint Conference Calls to the extent such disclosing party's actions are based on its good faith belief that public disclosure is required by compliance and market manipulation regulations applicable under emergency conditions.
4. Secretary will provide minutes to the membership, as soon as reasonably possible, after the completion of each joint conference call.

Deactivation and Demobilization

Once coordination of Joint Conference Calls have concluded, coordination of mutual assistance engagement has been handed off with confidence to requesting and responding utilities, and ancillary support and needs have been satisfied, the Co-Chairs will decide to or initiate the demobilization/deactivation of the NWMAA.

As part of the demobilization process, the NWMAA Secretary or Custodian will compile all key documentation related to the mutual assistance engagement and ensure latest versions are archived to a records repository.

After Action Review

After each NWMAA activation, the Co-Chairs will call for an after action review ("AAR") to be conducted with the key participants in the mutual response engagement. The purpose of this review is to assess the response and identify any practices to sustain as well as potential improvement opportunities.

The AAR will be facilitated by the NWMAA Vice Chair with support from the Secretary and Custodian to record any resulting action items to be assigned as agreed upon by the NWMAA Executive Committee and Members. AAR results will be made available for review either by email or an in-person meeting.

The Secretary or Custodian has the responsibility for tracking the completion of the action items and assuring distribution and posting of any resulting reports. The AAR and other related reports may be publicly disclosed by the Executive Committee.

Applicable Law and Dispute Resolutions

Nothing in this Agreement is intended to modify or change the terms of the underlying enabling agreements between the Members, or between an Assisting Member and an Affected Member including, but not limited to the applicable law and dispute resolution provisions of such underlying enabling agreement.

Each Member agrees that its activities pursuant to this Agreement will and are intended to comply with all applicable laws, including all applicable antitrust laws.

Limitations of Liability

Under no circumstances whatsoever shall a Member be liable to any other Member for any losses or damages resulting from or arising out of any action taken or not taken by the Member with respect to this Agreement, any alleged or actual default by the Member with respect to this Agreement or any failure to performance related hereto, howsoever caused, including without limitation, any lost or prospective profits or any other special, indirect, incidental or consequential losses or damages.

Appendices

A: Executive Committee contact information
B: Member Entities and Representatives
C: Joint Conference Call Agenda Template
D: Custodial Duties

Appendix D: NWMAA Custodial Duties

1. Maintain the Official Agreement and appendices, including updates to the contact information for Member representatives.

2. Once a year updates membership, mailing list, & manages notification system.

3. Once a year organizing a spring review of the past heating season.

4. In October, organizes a desktop exercise to practice the NWMAA.
    a. Schedule, conference call, keep notes, distribute notes.

5. Coordinate the emergency conference calls using secure communications & protocols.

NWMAA Member Company Signature Page

Company Name: FortisBC Energy Inc.

Signature: ______________________

Title: Vice President Energy Supply & Resource Development

Date: October 3, 2019

Attachment 7.1

Infrastructure Resiliency – MyVoice Panel Survey Results

April 28, 2021

In March 2021, members of the FortisBC MyVoice community panel were asked to provide feedback on FortisBC infrastructure resiliency. 2125 members participated in the survey. The findings of the survey are presented here.

Analysis of survey responses

Overall satisfaction

The majority of respondents are satisfied with FortisBC's service overall. Seventy-nine percent of respondents gave FortisBC a rating of eight or higher on a ten-point scale, where one is "not at all satisfied" and ten is "fully satisfied."

Importance - energy service

Respondents were asked to rate the importance of several service aspects, using a ten-point scale, where one is "not at all important" and ten is "extremely important". Two of the service aspects respondents were asked to rate were the reliability of FortisBC's energy service and the resiliency of FortisBC's energy network. A reliable energy service was defined as an energy service that can withstand and recover from minor disruption events (e.g., typical storms, minor system damage). A resilient energy network was defined as an energy network that can withstand and recover from extreme disruption events (e.g., severe weather-related disasters, deliberate systems damage or cyber-attacks). The survey results show that the majority of respondents feel reliability and resiliency are very important. Ninety-two percent of respondents gave the **reliability** aspect an importance rating of eight or more. Eighty-seven percent of respondents gave the **resiliency** aspect an importance rating of eight or more.

Table 1 below shows the percentage of respondents who rated the importance of the noted FortisBC energy service aspects, as eight, nine or ten, on a ten-point scale where one is "not at all important" and ten is "extremely important".

Energy service aspect - Importance	Importance ratings of 8-10
Having reliable energy service that can withstand and recover from minor disruption events	92%
Restoring service quickly after it has been disrupted	89%
Delivering your energy at a reasonable cost	89%
Having a resilient energy network that can withstand and recover from extreme disruption events	87%
Keeping you informed during service disruptions	84%

Table 1. Ratings - Importance - Energy Services: 8 + 9 + 10 ratings combined; Scale: 1=not at all important, 10 = extremely important; Total sample; Unweighted; base n = 2125

Performance - energy service

Respondents were asked to rate FortisBC's performance on several energy service aspects, using a ten-point scale, where one is "very poor" and ten is "very good". Two of the notable service aspects rated were the **reliability** of FortisBC's energy service and the **resiliency** of FortisBC's energy network. A reliable energy service was defined as an energy service that can withstand and recover from minor disruption events (e.g., typical storms, minor system damage). A resilient energy network was defined as an energy network that can withstand and recover from extreme disruption events (e.g., severe weather-related disasters, deliberate systems damage or cyber-attacks). The survey results show that about a quarter of respondents are not familiar with FortisBC's performance on these aspects.

Two-thirds, or sixty-six percent, of respondents gave FortisBC a rating of eight or more on their ability to provide **reliable** energy service. Twenty-one percent of respondents did not know, or were unsure, of FortisBC's performance on reliability. One half, or fifty percent, of respondents gave FortisBC a rating of eight or more on their ability to provide a **resilient** energy network. Over a third, or thirty-five percent, did not know or were unsure of FortisBC's performance on resiliency. Three percent of these respondents noted that they have not experienced such service disruptions in the past so were unable to comment on FortisBC's performance or preparation for extreme disruption events. Some respondents commented:

- *I have not experienced an extreme disruption event in order to see what FortisBC would actually do to recover from it.*
- *I haven't experienced an extreme disruption so I can't rate that category. I would hope that you are well prepared for any event.*
- *Not sure what kind of network is provided in the case of extreme disruption events. More info to the customers would be appreciated.*

Table 2 below shows the percentage of respondents who rated the performance of the noted FortisBC energy service aspects, as eight, nine or ten, on a ten-point scale where one is "very poor" and ten is "very good". The table also shows the percentage of respondents who do not know, or are not sure, of FortisBC's performance on the noted energy service aspects.

Energy service aspect – Performance	Performance ratings of 8-10	Don't know / unsure
Having reliable energy service that can withstand and recover from minor disruption events	66%	21%
Restoring service quickly after it has been disrupted	60%	26%
Delivering your energy at a reasonable cost	53%	5%
Having a resilient energy network that can withstand and recover from extreme disruption events	50%	35%
Keeping you informed during service disruptions	49%	29%

Table 2. Service quality ratings - Energy services: 8 + 9 + 10 ratings combined; Scale: 1=very poor, 10 = very good; Total sample; Unweighted; base n = 2125

Risk – Past and present

Respondents were asked to consider this question: *Comparing today to ten years ago, do you feel energy utilities are facing more or less risk from extreme events like severe weather, deliberate system damage and cyber-attacks?*

The majority of respondents (66%) feel that energy utilities are facing more, or much more, risk today than 10 years ago. Figure 1 is a graphical representation of the respondents' ratings on risk levels faced by energy utilities today, compared to ten years ago.

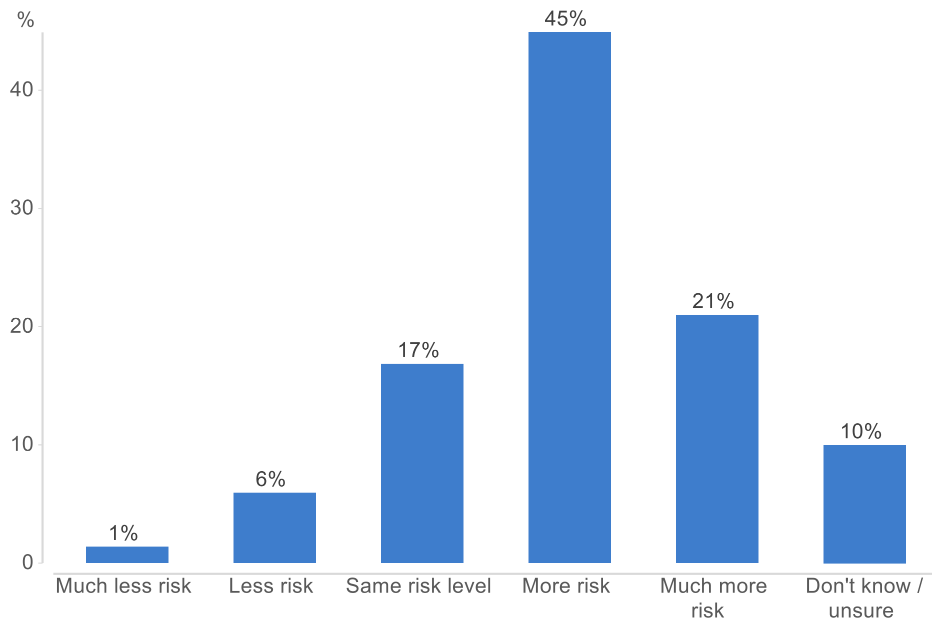


Figure 1. Comparing risk past and present
Total sample; Unweighted; base n = 2125

Gap Analysis

A gap analysis was conducted to determine how well FortisBC is performing the surveyed service aspects. This is done by calculating mean rating scores for the performance and importance of each service aspect surveyed. The difference, or “gap”, between the scores shows how well FortisBC is performing each service aspect in relation to the respondents’ rating of its importance.

Table 3 shows that respondents rated the importance of all energy service aspects more than nine points on a ten point scale. Performance was rated slightly less for most aspects, meaning that FortisBC is underperforming these aspects relative to customers’ expectations. However, the underperformance is minimal for most aspects, as the gaps are small. The exception is the service aspect “delivering your energy at a reasonable cost”, where customers feel that the cost of energy is too high, in relation to the services they receive.

Service aspect	Performance mean rating	Importance mean rating	Gap	Performance level
Delivering your energy at a reasonable cost	7.51	9.36	-1.86	Underperforming
Keeping you informed during service disruptions	8.82	9.19	-0.37	Underperforming
Having reliable energy service that can withstand and recover from minor disruption events	9.19	9.48	-0.28	Underperforming
Restoring service quickly after it has been disrupted	9.24	9.53	-0.28	Underperforming
Having a resilient energy network that can withstand and recover from extreme disruption events	9.35	9.47	-0.12	Underperforming

Table 3. Gap analysis measuring performance level

Correlation Analysis

This correlation analysis shows how customer perceptions about individual service aspects are influencing their overall service rating. As noted earlier, the majority of respondents are satisfied with FortisBC's service overall, with seventy-nine percent of respondents giving FortisBC a rating of eight or higher on a ten-point scale, where one is "not at all satisfied" and ten is "fully satisfied."

The first column in the matrix in Figure 2 shows the strength of the relationship between the respondents' opinion of the overall service provided by FortisBC, and their opinion of FortisBC's performance of each of the service aspects surveyed. The correlation for all aspects fall between .05 and .06, meaning that the measured services aspects are all equally impacting respondents' rating of FortisBC services overall. No one service aspect stands out as having a more positive impact on the overall service rating.

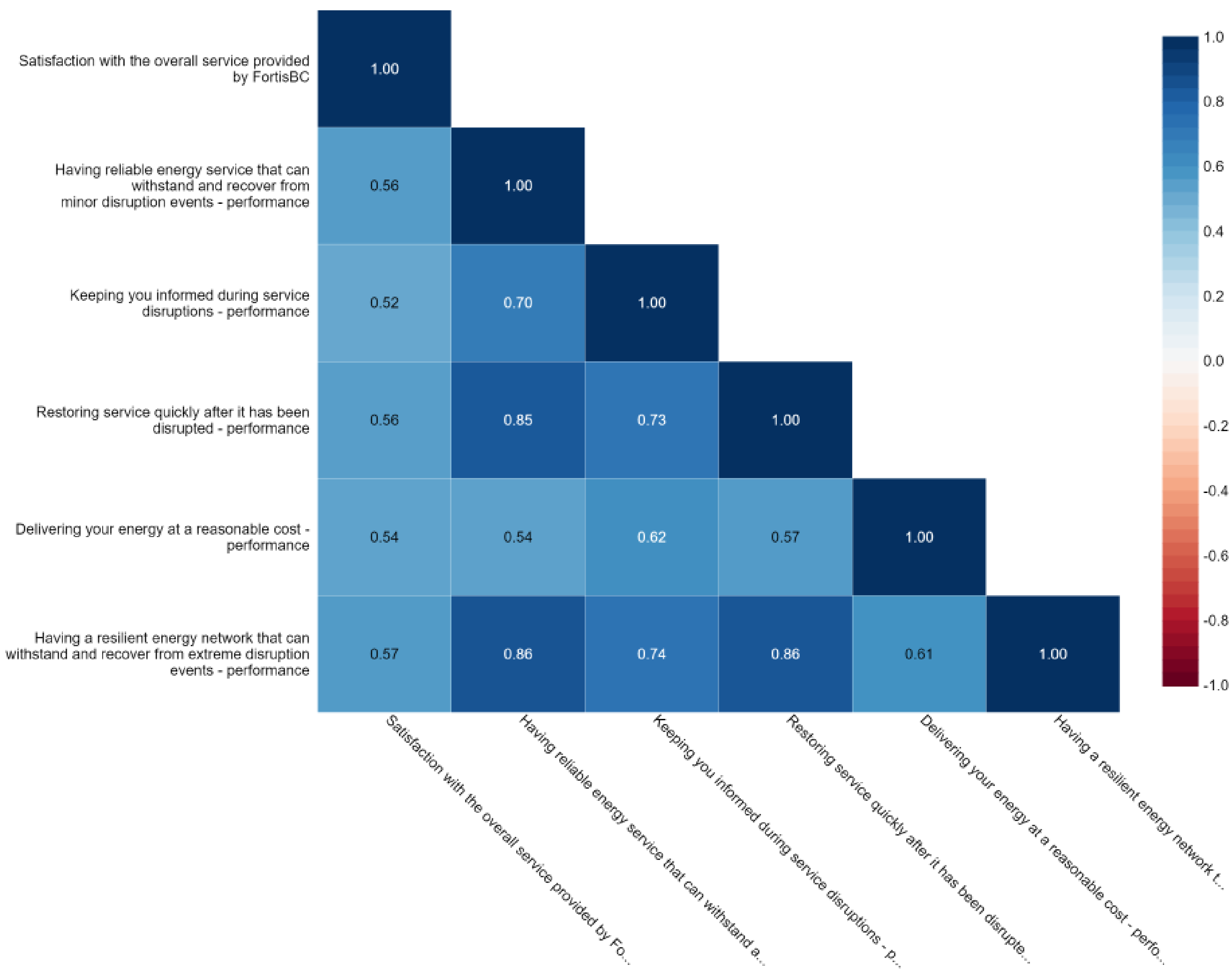


Figure 2. Correlation matrix; excludes "don't know/unsure" responses.

Verbatim Analysis

Respondents were asked to share the reasons they considered when rating the **importance** of "having a resilient energy network that can withstand and recover from extreme disruption events". Approximately fifteen hundred respondents shared their reasons. The most common theme, cited by one quarter of respondents, was centered on the importance of personal comfort and maintaining energy for heating, hot water and running appliances in their homes. One fifth of respondents cited concerns about potential catastrophic events such as earthquakes and cyber-attacks, specifically noting the recent gas disruptions in Texas. Other concerns included medical and security issues. Respondents noted the importance for FortisBC to be proactive rather than reactive in their disaster response plan. A number of respondents noted the low probability of disastrous events occurring and preferred FortisBC to focus on improving current infrastructure before preparing for rare catastrophic events. Some respondents did not feel spending on resiliency was warranted based on the risk, and did want these costs passed onto consumers.

Table 4 shows the common themes from the responses and the percentage of responses with each theme.

Reason	**Percentage of reasons cited**
Comfort: heating, hot water, running appliances	25%
General need for consistent service with quick recovery after a disruption	22%
Concerns about weather, earthquakes, cyber-attacks, world disaster events	16%
Medical reasons, safety or security	8%
No past experience with service disruptions	5%
Important to be proactive, rather than reactive	4%
Consistent connection required for working at home and running businesses	3%
Want FortisBC to focus on improving infrastructure before preparing for rare catastrophic events	2%
Costs – do not want costs passed onto the consumer	2%
Experience with past service disruptions	2%
Low probability of disastrous events occurring	2%
Have access to alternate energy sources	1%

Table 4. Reasons for rating importance of having a resilient energy network
Total sample; Unweighted; base n = 1502; total n = 2125; 623 missing

The following is a sample of verbatim feedback from the respondents**:**

- *I rely on gas for heating, cooking, hot water and have only minimum electricity as a backup therefore gas service is extremely important to me.*
- *For us it is health related, if we have no power, heat etc. we would be very compromised. My husband is in a hospital bed and needs a ceiling lift to get to his wheelchair. Without power we would be in trouble, so having a good network to recover from disasters is very important.*
- *I rely on power to work from home, dealing with customers online and cannot have disruptions during calls.*

- *I lived through the ice storm in Ontario in 1998. I was without electricity for nine days and then it was sporadic after that for about two weeks. It was horrible and I never want to go through that again no matter what the cause.*

- *Extreme disruptions are no longer as uncommon as they once were. It seems that almost monthly, somewhere across North America, there is some sort of extreme disruption or another. An energy network that is both resilient and recoverable is getting to be a higher and higher priority.*

- *Look what happened in Texas this winter... we don't want that to happen here.*

- *I don’t think cyber disruption is prioritized nearly enough by many organization leaders.*

- *Even though it is important to be able to recover in a timely manner, it is also understandable that an unreasonable amount of money should not be invested to withstand an event that is unlikely to occur.*

Attachment 8.2

bcuc
British Columbia
Utilities Commission

Patrick Wruck
Commission Secretary

Commission.Secretary@bcuc.com
bcuc.com

Suite 410, 900 Howe Street
Vancouver, BC Canada V6Z 2N3
P: 604.660.4700
TF: 1.800.663.1385
F: 604.660.1102

February 5, 2019

Sent via email

Letter L-1-19

Ms. Doug Slater
Director, Regulatory Affairs
Fortis BC Energy Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8
gas.regulatory.affairs@fortisbc.com

Mr. Fred James
Chief Regulatory Officer,
British Columbia Hydro and Power Authority
16th Floor-333 Dunsmuir Street
Vancouver, BC V6B 5R3
bchydroregulatorygroup@bchydro.com

Ms. Janet P. Kennedy
Vice President, Regulatory Affairs & Gas Supply
Pacific Northern Gas Ltd.
Pacific Northern Gas (N.E.) Ltd.
2550–1066 West Hastings Street
Vancouver, BC V6E 3X2
jkennedy@png.ca

Re: Response plans for Emergency Events

Dear Stakeholders:

Over the past year, British Columbia has experienced several extreme and unforeseeable events, including devastating wildfires and landslides, a rupture to the Enbridge Inc. Westcoast T-South pipeline and, most recently, severe windstorms. Further, British Columbia faces potential risks, such as earthquakes, ice storms or cybersecurity attacks. These events can damage critical infrastructure and significantly restrict utilities' ability to provide safe and reliable energy services to customers, potentially leaving millions of British Columbians without access to essential energy for extended periods of time. This risk to safe and reliable energy is a significant concern to the British Columbia Utilities Commission (BCUC).

To address this concern, the BCUC needs to better understand how the major public utilities plan for and manage operations during such events, and how they consider strategies that currently exist and those under development in relation to risk management and emergency preparedness. Further, we are interested in knowing how utilities plan to mitigate the potential impact on customers and stakeholders in response to emergency events.

As such, the BCUC asks the major utilities it regulates, including your utilities, to provide the following information:

1) Emergency response plans and other relevant contingency-type plans to facilitate or coordinate operations, restore service or secure assets in the event of a significant risk to its infrastructure.
2) Assessments of key safety risks faced by the utility and plans or strategies to mitigate those risks.

3) Assessment of key reliability risks faced by the utilities at both a transmission and distribution level and strategies or plans to mitigate those risks.
4) Policies and procedures in place to ensure reliability of electricity distribution, and a comparison of these policies to Mandatory Reliability Standards applicable to the utility's electrical transmission system.
5) Policies and procedures in place to ensure reliability of both transmission and distribution of gas by the utility, and a comparison of these policies to Mandatory Reliability Standards where possible.
6) An inventory of assets and other tools that can be used by the utility to reduce risk, such as gas storage assets, and policies describing their management.
7) Confirmation that the utility has adopted and implemented all Canadian Safety Association (CSA) standards and best practices, and if not, provide a listing of standards not in place and with an explanation.
8) Policies and procedures in place to ensure timely and relevant plans are made or updated to address utility safety and reliability risks.
9) Internal or external audit reports or documents that have resulted from assessing or testing any of the above mentioned items.
10) Any further materials or information the utility believes is relevant to the consideration of either safety or reliability of energy in British Columbia.

When faced with similar concerns regarding public utility safety, the California Public Utilities Commission (PUC) set out on a regulatory process to address this risk - the Safety Model Assessment Proceeding. That process, concluded in December 2018, resulted in the California PUC establishing a new risk evaluation framework. The goal of the California PUC's new approach is to make utility decision-making about weighing and mitigating safety risks more quantitatively rigorous and transparent. As British Colombia faces many similar safety risks to California, a similar approach may be of value when evaluating utility safety risks here in British Columbia.

We appreciate that safety and reliability are important concerns for public utilities in British Columbia and we look forward to gaining a better understanding of how our major public utilities address these concerns. Prior to filing any documents, we encourage you to contact our staff to discuss this letter and seek clarity on any items outlined above.

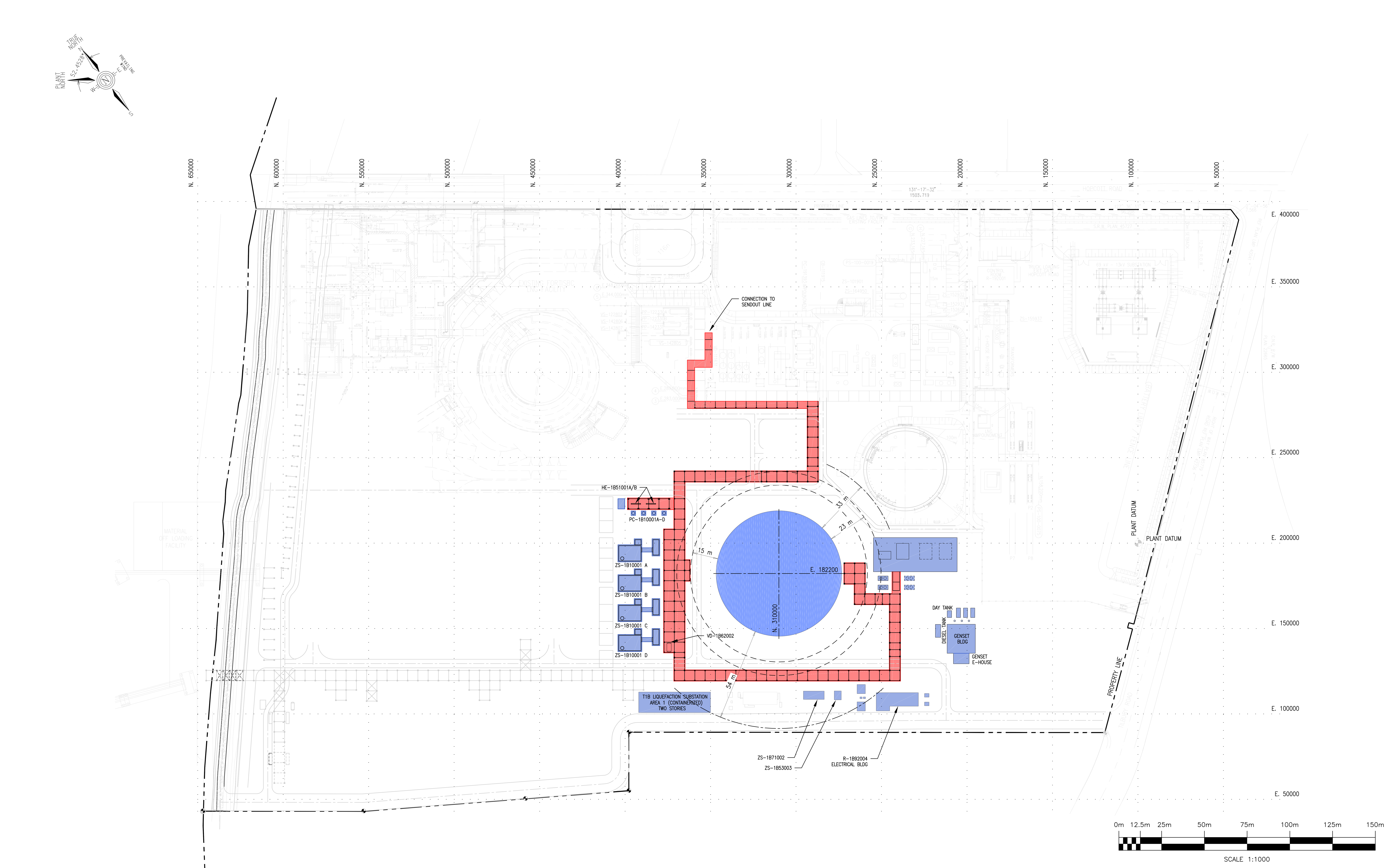
Sincerely,

Original Signed by Ian Jarvis for:

Patrick Wruck
Commission Secretary

KB/aci

Attachment 26.1



REFERENCE DRAWINGS:

43116-M-SPL-1B-00001-R0-F

SOLARIS MANAGEMENT CONSULTANTS INC.

CLOUGH ENERCORE

BY	No.	REVISION	DESIGNED	CHECKED	APPROVED	DATE(YYYY-MM-DD)
SOLARIS-MCI	A	ISSUED FOR INFORMATION	PML	BSP	DLM	2020-09-11

PREVIOUS DR. NO.- SCALE- 1:1000

FORTIS BC

ENGINEER SEAL

TILBURY LNG STORAGE EXPANSION (TLSE)

TILBURY LNG STORAGE EXPANSION
SITE LAYOUT

DRAWING NUMBER 43116-M-SPL-1B-SK003-B

Attachment 33.1

FORM_C_V19 (Charge)

NEW WESTMINSTER LAND TITLE OFFICE

May-14-2014 10:12:17.003

CA3723021

LAND TITLE ACT
FORM C (Section 233) CHARGE
GENERAL INSTRUMENT - PART 1 Province of British Columbia

PAGE 1 OF 7 PAGES

Your electronic signature is a representation that you are a subscriber as defined by the Land Title Act, RSBC 1996 c.250, and that you have applied your electronic signature in accordance with Section 168.3, and a true copy, or a copy of that true copy, is in your possession.

Christina Lynn Reed I5S5W2

Digitally signed by Christina Lynn Reed I5S5W2
DN: c=CA, cn=Christina Lynn Reed I5S5W2, o=Lawyer, ou=Verify ID at www.juricert.com/LKUP.cfm?id=I5S5W2
Date: 2014.05.06 16:54:48 -07'00'

1. APPLICATION: (Name, address, phone number of applicant, applicant's solicitor or agent)

Christina Reed, Barrister & Solicitor
YOUNG ANDERSON
1616 - 808 Nelson Street
Vancouver BC V6Z 2H2

Phone: (604) 689-7400
File: 76-920
LU006898

Document Fees: $73.50

Deduct LTSA Fees? Yes ☑

2. PARCEL IDENTIFIER AND LEGAL DESCRIPTION OF LAND:

[PID] [LEGAL DESCRIPTION]

029-263-301 **LOT 1, EXCEPT: PART DEDICATED ROAD ON PLAN EPP36476, DISTRICT LOT 135 GROUP 2 NEW WESTMINSTER DISTRICT PLAN EPP28232**

STC? YES ☐

3. NATURE OF INTEREST CHARGE NO. ADDITIONAL INFORMATION

Covenant s.219 - Flood

4. TERMS: Part 2 of this instrument consists of (select one only)

(a) ☐ Filed Standard Charge Terms D.F. No. (b) ☑ Express Charge Terms Annexed as Part 2

A selection of (a) includes any additional or modified terms referred to in Item 7 or in a schedule annexed to this instrument.

5. TRANSFEROR(S):

FORTISBC ENERGY INC., INC. NO. 778288

6. TRANSFEREE(S): (including postal address(es) and postal code(s))

THE CORPORATION OF DELTA
A MUNICIPAL CORPORATION INCORPORATED UNDER THE LOCAL GOVERNMENT ACT
4500 CLARENCE TAYLOR CRESCENT
DELTA BRITISH COLUMBIA
V4K 3E2 CANADA

Incorporation No
N/A

7. ADDITIONAL OR MODIFIED TERMS:

N/A

8. EXECUTION(S): This instrument creates, assigns, modifies, enlarges, discharges or governs the priority of the interest(s) described in Item 3 and the Transferor(s) and every other signatory agree to be bound by this instrument, and acknowledge(s) receipt of a true copy of the filed standard charge terms, if any.

Officer Signature(s)	Execution Date Y	M	D	Transferor(s) Signature(s)
Colleen Lorraine Bohun Commissioner for Taking Affidavits in BC FORTIS ENERGY INC. 16705 Fraser Highway Surrey, BC V4N 0E8 (as to all signatures)	14	01	10	FORTISBC ENERGY INC. by its authorized signatory(ies): Name: Christopher Coady

OFFICER CERTIFICATION:

Your signature constitutes a representation that you are a solicitor, notary public or other person authorized by the *Evidence Act*, R.S.B.C. 1996, c.124, to take affidavits for use in British Columbia and certifies the matters set out in Part 5 of the *Land Title Act* as they pertain to the execution of this instrument.

FORM_D1_V19

LAND TITLE ACT
FORM D

EXECUTIONS CONTINUED

Officer Signature(s)	Execution Date Y	M	D	Transferor / Borrower / Party Signature(s)
Sandra MacFarlane Commissioner for Taking Affidavits in BC 4500 Clarence Taylor Crescent Delta, BC V4K 3E2	14	02	25	THE CORPORATION OF DELTA by its authorized signatory(ies): Name: Lois E. Jackson Mayor
(as to the signature of Robyn Anderson)	14	02	21	Name: Robyn Anderson Acting Municipal Clerk

OFFICER CERTIFICATION:
Your signature constitutes a representation that you are a solicitor, notary public or other person authorized by the *Evidence Act*, R.S.B.C. 1996, c.124, to take affidavits for use in British Columbia and certifies the matters set out in Part 5 of the *Land Title Act* as they pertain to the execution of this instrument.

TERMS OF INSTRUMENT - PART 2

COVENANT

(Section 219 *Land Title Act*)

THIS AGREEMENT made the 4th day of November, 2013.

BETWEEN:

FORTISBC ENERGY INC., Inc. No. 778288
1000 1111 West Georgia Street
Vancouver, BC V6E 4M3

(hereinafter called the "Grantor")

AND:

THE CORPORATION OF DELTA, a Municipal
Corporation under the *Community Charter*
4500 Clarence Taylor Crescent,
Delta, BC V4K 3E2

(hereinafter called the "Municipality")

WHEREAS:

A. The Grantor is the owner of, or has an equity of redemption in, certain land and premises situate in the Municipality of Delta, in the Province of British Columbia, and more particularly described as:

Parcel Identifier: 029-263-301
Lot 1, Except: Part Dedicated Road on Plan EPP36476, District Lot 135 Group 2 New Westminster District Plan EPP28232

(hereinafter called the "Lands");

B. The Lands are located in the floodplain of the Fraser River and, although they are located behind a dyke, they are, or could reasonably be expected to be, subject to flooding, erosion, wave action or tsunami; and

C. The Grantor proposes to build upon the Lands at an elevation below the level for which the Municipality's storm drainage system was designed;

D. The Grantor has voluntarily agreed to enter into this agreement and to permit it to be registered against the title to the Lands; and

E. Section 219 of the *Land Title Act* provides, inter alia, that a covenant, whether of a negative or positive nature, may be registered as a charge against the title to land in favour of a Municipality or the Crown.

NOW THEREFORE THIS AGREEMENT WITNESSES that, pursuant to Section 219 of the *Land Title Act*, and in consideration of the premises and the sum of One Dollar ($1.00) now paid to the Grantor by the Municipality (the receipt and sufficiency of which is hereby acknowledged by the Grantor), the parties hereto covenant and agree each with the other as follows:

1. THE GRANTOR COVENANTS, ACKNOWLEDGES AND AGREES with the Municipality that:

   (a) the Lands shall not be built upon except in accordance with this Agreement;

   (b) hereafter, no building or structure or any part thereof shall be located, constructed, reconstructed, moved or extended on the Lands such that the underside of the floor system of any area used for habitation, business or the storage of goods damageable by floodwaters or, in the case of a mobile home or modular unit, the ground level or the top of the concrete or asphalt pad on which the mobile home or modular unit is located, is lower than 2.74 metres Geodetic Survey of Canada (G.S.C.) datum;

   (c) in this Agreement the phrase “area used for habitation” means any room or space within a building or structure which is or may be used for human occupancy, commercial sales, business or storage of goods, but does not include an entrance foyer or parking facility;

   (d) the above required elevation may be achieved by structural elevation of the said habitable, business or storage area or by adequately compacted landfill on which the said building or structure is to be located, constructed, reconstructed, moved or extended, or by any combination of both structural elevation and adequately compacted landfill. No area below the required elevation shall be used for the installation of furnaces or other fixed equipment susceptible to damage by floodwaters. Where landfill is used to achieve the required elevation, the face of the landfill slope shall be adequately protected against erosion;

   (e) hereafter, no building or structure or any part thereof shall be located, constructed, reconstructed, moved or extended on the Lands such that any part of the building or structure is located within 7.5 metres from the natural boundary of any tidal area or the inboard toe of any dyke, or within 6 metres from the natural boundary of any swamp, slough, pond or ditch;

(f) the Municipality may refuse, but shall in no case be obligated to refuse, to issue a building permit or final inspection for any building or structure on the Lands if any of the restrictions or conditions contained herein have not been complied with;

(g) neither the Municipality nor any of its officials, officers or employees have represented to the Grantor or any other person that any building or structure located, constructed, reconstructed, moved or extended on the Lands will not be damaged by flooding or erosion, whether or not the provisions of this Agreement are complied with;

(h) the Grantor will pay to the Municipality the legal fees incurred by the Municipality in the review, preparation and registration of this Agreement, and will deposit with the Municipality, immediately upon execution of this Agreement, the estimated amount of such legal fees; and

(i) the Grantor will, at the expense of the Grantor, do or cause to be done all acts reasonably necessary to grant priority to this Agreement over all charges and encumbrances which may have been registered against the title to the Lands in the New Westminster Land Title Office save and except those specifically approved in writing by the Municipality or in favour of the Municipality.

2. THE GRANTOR FURTHER COVENANTS AND AGREES with the Municipality that:

(a) the Grantor has been advised that:

(i) the Lands are located behind a dyke and that in the event of a failure of the dyke they are, or could reasonably be expected to be, subject to flooding and erosion; and

(ii) the proposed building elevation is below 3.5 metres and below the level for which the Municipality's storm drainage system was designed and consequently buildings or structures constructed on the Lands may be subject to flooding;

(b) the Grantor hereby releases the Municipality and its elected officials, officers and employees from liability for and agrees to save harmless and effectually indemnify the Municipality and its elected officials, officers and employees against all actions and proceedings, costs, damages, expenses, claims and demands whatsoever and by whomever brought by reason of:

(i) the issuance of a building permit covering the Lands and the construction, reconstruction, alteration or placement of any building or structure upon the Lands and, without limiting the generality of the foregoing, for any damages to the premises or their contents or any personal injury caused directly or indirectly by flooding or erosion; and

(ii) any act or omission carried out by or not carried out by the Municipality, its elected officials, officers, servants, agents or employees in the exercise or purported exercise of any of the rights or compliance or attempted compliance with any obligations granted or imposed by this Agreement, or arising from the restrictions imposed on the use of the Lands or the construction of any buildings or structures thereon by this Agreement; and

(c) in the event any person is injured, or the Lands, or any building or structure or any part or contents thereof located on the Lands is damaged, by flooding or erosion, the Grantor shall not commence any legal proceedings or third party proceedings against the Municipality or its elected officials, officers or employees related to such injury or damage.

3. IT IS MUTUALLY UNDERSTOOD, agreed and declared by and between the parties hereto that:

(a) the Municipality has made no representations, covenants, warranties, guarantees, promises or agreements (oral or otherwise) with the Grantor other than those contained in this Agreement;

(b) nothing contained or implied herein shall:

(i) constitute a Highway Use Permit or other approval to carry out any works within any road or any lands owned or occupied by the Municipality;

(ii) prejudice or affect the rights and powers of the Municipality in the exercise of its functions under any public and private statutes, bylaws, orders and regulations, all of which may be fully and effectively exercised in relation to the Lands as if this Agreement had not been executed and delivered by the Grantor; or

(iii) exempt the Grantor from any duty to comply with any enactment of the federal, provincial or regional government or to obtain any approval or consent required by any of them or their respective agencies;

(c) the covenants set forth herein shall charge the Lands pursuant to Section 219 of the *Land Title Act* and shall be covenants the burden of which shall run with the Lands. It is further expressly agreed that the benefit of all covenants made by the Grantor herein shall accrue solely to the Municipality and that this Agreement may be modified by agreement of the Municipality with the Grantor, or discharged by the Municipality, pursuant to the provisions of Section 219(9) of the *Land Title Act* without giving notice to or obtaining the consent of the owner of any other portion of the Lands and without affecting the rights and obligations of the owner of any other portion of the Lands;

(d) the Municipality may, but shall in no way be obligated to, enforce any or all of the provisions of this Agreement and may waive any requirements contained herein without giving notice to or obtaining the consent of the owner of any other portion of the Lands and without affecting the rights and obligations of the owner of any other portion of the Lands;

(e) no failure by the Municipality in exercising its rights hereunder or enforcing the Grantor's obligations hereunder and no waiver of any of the requirements herein shall in any way limit the Municipality in, or prevent the Municipality from, later exercising its rights herein, or enforcing the Grantor's obligations in respect of any breaches of this Agreement which have occurred or which may occur, nor shall the Municipality be deemed to have waived or become estopped from thereafter exercising any of its rights or enforcing any of the Grantor's obligations under this Agreement;

(f) wherever the singular or masculine is used herein, the same shall be construed as meaning the plural, feminine or the body corporate or politic where the context or the parties so require; and, where the Grantor consists of more than one person, the term "Grantor" shall mean all such persons jointly and severally;

(g) this Agreement shall enure to the benefit of and be binding upon the parties hereto and their respective heirs, executors, administrators, successors and assigns; and

(h) the parties hereto shall do and cause to be done all things and execute and cause to be executed all documents which may be necessary to give proper effect to the intention of this Agreement.

IN WITNESS WHEREOF the parties have executed this Agreement on Forms C and D, which are attached to and form part of this Agreement.

END OF DOCUMENT

Attachment 54.2a

FORTIS BC Energy at work

Tilbury Phase 2 LNG Expansion project

Overview Updates Q&A's Community

About this project

For 50 years, the Tilbury liquefied natural gas (LNG) facility has been at the heart of BC's energy system, providing natural gas on the coldest days of the year. Now we're planning to expand our facility to meet increasing demand for liquefied natural gas (LNG) into the future and help us reach our 30BY30 target to reduce our customers' greenhouse gas emissions 30 per cent by 2030.

LNG is natural gas that has been cooled to -162C, becoming a clear, non-toxic and non-flammable liquid. We use LNG to supplement the Lower Mainland gas supply when you need it most – on days of high demand like when the temperature drops.

The Tilbury Phase 2 LNG Expansion project will improve the resiliency of the gas system – ensuring we have the natural gas supply our customers need, in the event of an emergency. It will also help us advance LNG as a marine fuel or meet demand from overseas customers. The project will include the construction of:

FORTIS BC Energy at work

- a new liquefaction unit with capacity of up to 2.5 million tonnes per year to produce LNG for marine fuelling or overseas export

Ship owners are responding to new sulphur emission regulations from the International Maritime Organization by adopting LNG as a marine fuel. Traditionally, about 86 per cent of ocean-going ships have used heavy fuel oils to power their engines, but these oils can be harmful to the environment. As of 2020, an estimated 10-20 per cent of new ships on order will be LNG fuelled. At the same time, there is growing interest from overseas customers looking to buy LNG from Canada to lower their carbon footprint.

Our Tilbury LNG facility is ideally positioned to meet these opportunities and we're aiming to elevate Tilbury's role in the global transition to lower carbon energy. Tilbury is powered by renewable hydroelectricity, which means it can produce a cleaner marine fuel than other LNG facilities.

Next steps

Rendering of potential Tilbury Phase 2 LNG Expansion project

Impact Assessment/Environmental Assessment

committed to ongoing engagement throughout the project.

The project is now in the Early Engagement phase, which gives the public, Indigenous Groups and stakeholders an opportunity to learn more and provide feedback to the regulatory agencies. Virtual open houses were held in June 2020.

For more information on the regulatory process please visit:

Impact Assessment Agency of Canada

Environmental Assessment Office of BC

Certificate of Public Convenience and Necessity

The Tilbury LNG Storage Expansion project is subject to regulation by the BC Utilities Commission (BCUC). In December 2020, we filed our project application for a Certificate of Public Convenience and Necessity with the BCUC. The project will include the construction of the new LNG storage tank and equipment to increase our capacity to flow gas from the Tilbury LNG facility back into our system that serves BC.

While preparing to submit our application, we've been engaging local governments, Indigenous communities, landowners, and area residents to share details on the project and obtain feedback. Anyone interested in getting involved with the process can visit the BCUC website.

We're pleased to be one step closer to ensuring we have an additional backup source of natural gas in the event of a gas supply disruption. If approved, construction of the Tilbury LNG Storage Expansion project could start in 2023 and be completed by 2026.

Community and Indigenous engagement

FortisBC is committed to continuing engagement with the local community, including opportunities for dialogue throughout these regulatory processes. The feedback we receive will form part of our

If approved, construction of the Tilbury Phase 2 LNG Expansion project could start as early as 2023 and be complete as early as 2028.

Project highlights

A new storage tank would improve system resiliency during a supply shortage and meet customer demand.

LNG-powered ships help reduce nitrogen oxides by up to 95%, particulate matter by up to 99% and sulphur oxides to almost zero, which translates into much cleaner exhaust emissions compared to other marine fuels.

LNG can reduce GHG emissions by up to 27% over the entire lifecycle compared to other marine fuels, depending on the engine used.

Creating jobs and economic opportunities

Employment, training and contractor opportunities will be available throughout project planning and construction, and approximately another 110 new long-term jobs will be created once construction is complete. Job postings will be added to our career postings when they are available. You can also apply to become a supplier or vendor for the project.

We are working closely with local businesses like Ideal Welders to create local jobs and put money back into the BC economy. Learn about the work we're doing with Ideal Welders.

FORTIS BC Energy at work

Working with our community

our major projects, including the expansion of our Tilbury LNG facility in Delta.

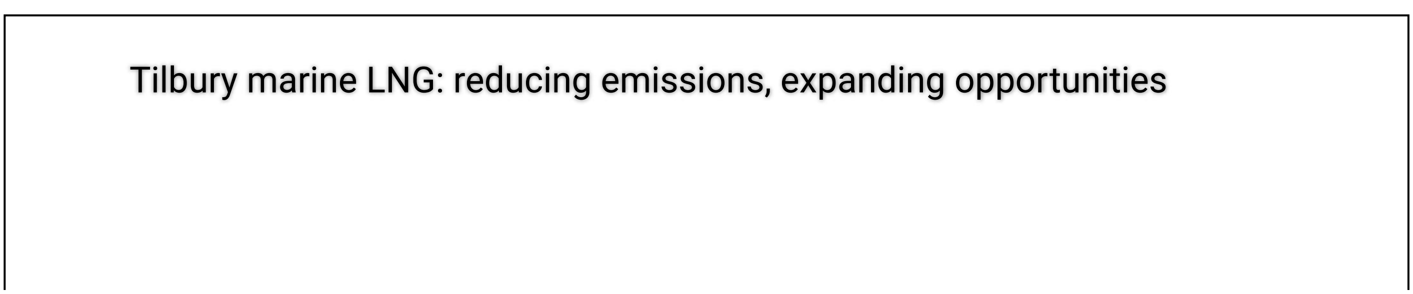
1 / 5

About LNG

What is LNG?

Our LNG storage facilities are monitored 24/7 year-round by highly trained site personnel who have been producing LNG for decades. Within its double-walled insulated storage tank, LNG is maintained in liquid form, without air, and will not burn.

Tilbury marine LNG: reducing emissions, expanding opportunities



Liquefied natural gas (LNG) from our Tilbury facility is helping marine industry partners reduce greenhouse gas emissions by up to 27%. Through industry-leading initiatives, and continued investment in our LNG infrastructure, our vision of Vancouver as a global LNG marine hub is becoming a reality.

CALL US

(855) 576-7133

EMAIL US

tilbury.info@fortisbc.com

ASK US

Ask a question

About us Contact us

Privacy Policy

Attachment 54.2b

Tilbury LNG Facilities

Development & Permitting History

March 18, 2021

Tilbury LNG Facilities

Agenda

- Introductions
- Tilbury LNG Facilities Current State
- Development & Permit History

FortisBC Holdings Inc. (“FHI”) is the proponent of the Tilbury Phase 2 LNG Expansion. Its affiliates include FortisBC Energy Inc. (the regulated gas utility and holder of the OGC Facility Permit), Fortis LNG Limited Partnership (the holder of the CER Export Permit), and Tilbury Jetty Limited Partnership (the owner of the Tilbury Marine Jetty Project).

For the sake of simplicity this presentation refers to FortisBC; however this is not intended to convey ownership or operatorship of any given piece of infrastructure or business.

Tilbury LNG Facilities

The BCUC & “Facility Regulation” Processes

BCUC

The BCUC is an economic regulator and regulates what a regulated utility is able to recover through the “rate base”

In effect it “approves” a business investment.

Any investment (e.g. facility, upgrade, etc.) is still subject to regulation and approval by the appropriate regulator.

Tilbury Facility Regulators

The OGC regulates the construction, operation, and expansion of Tilbury as an LNG Facility through the LNG Facility Regulation.

Metro Vancouver regulates the air emissions generated by the Tilbury LNG Facility.

Tilbury LNG Facilities

Tilbury Developments

Liquefaction unit
0.25 MTPA

Storage tank
1.1 petajoules

Truck loading expansion
2 new loading bays

Phase 1 in service (Liquefaction unit, Storage tank)

Phase 1 in Execution (Truck loading expansion)

Liquefaction unit (Phase 1B)
up to 0.65 MTPA

Power line
6 km

Phase 1 in development

Phase 1

Storage tank
up to 3.7 petajoules

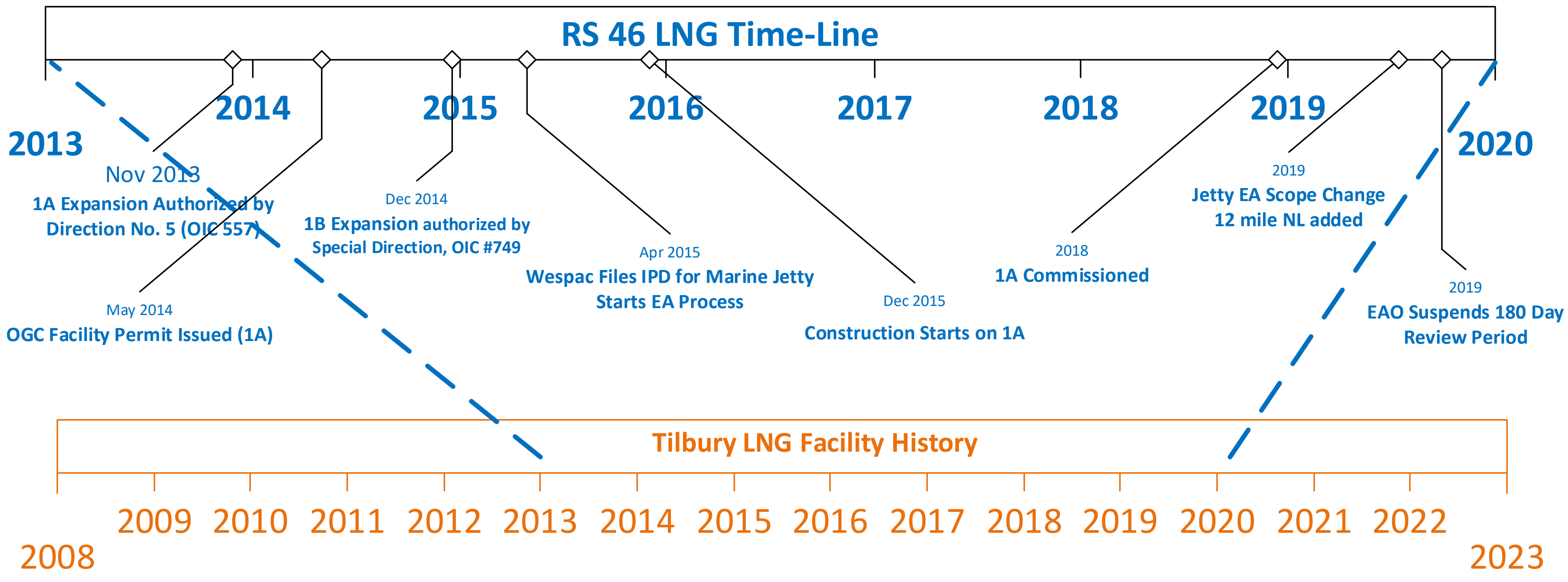
Liquefaction units
up to 2.5 MTPA

Phase 2 in environmental assessment

Phase 2

Tilbury LNG Facilities

Timeline of Phase 1 Milestones



<u>Rate Schedule 46 Business</u>

- 1A & 1B Liquefaction Plants
- Power supply for E-Drive
- Improved gas supply
- 1A Storage Tank

NOTE – FortisBC is waiting on receipt of the Tilbury Marine Jetty EAC before proceeding with the remaining Phase 1 investments

Tilbury LNG Facilities

Current State (c. 2021)

Base Plant

1971: Begins peak shaving service

2010: First fuelling of local trucks

2017: First fuelling of local ferries, produces LNG for global market

Phase 1A Expansion

2012: Indigenous and community engagement begins

2013: Direction 5 to the BCUC, rezoning approved by City of Delta

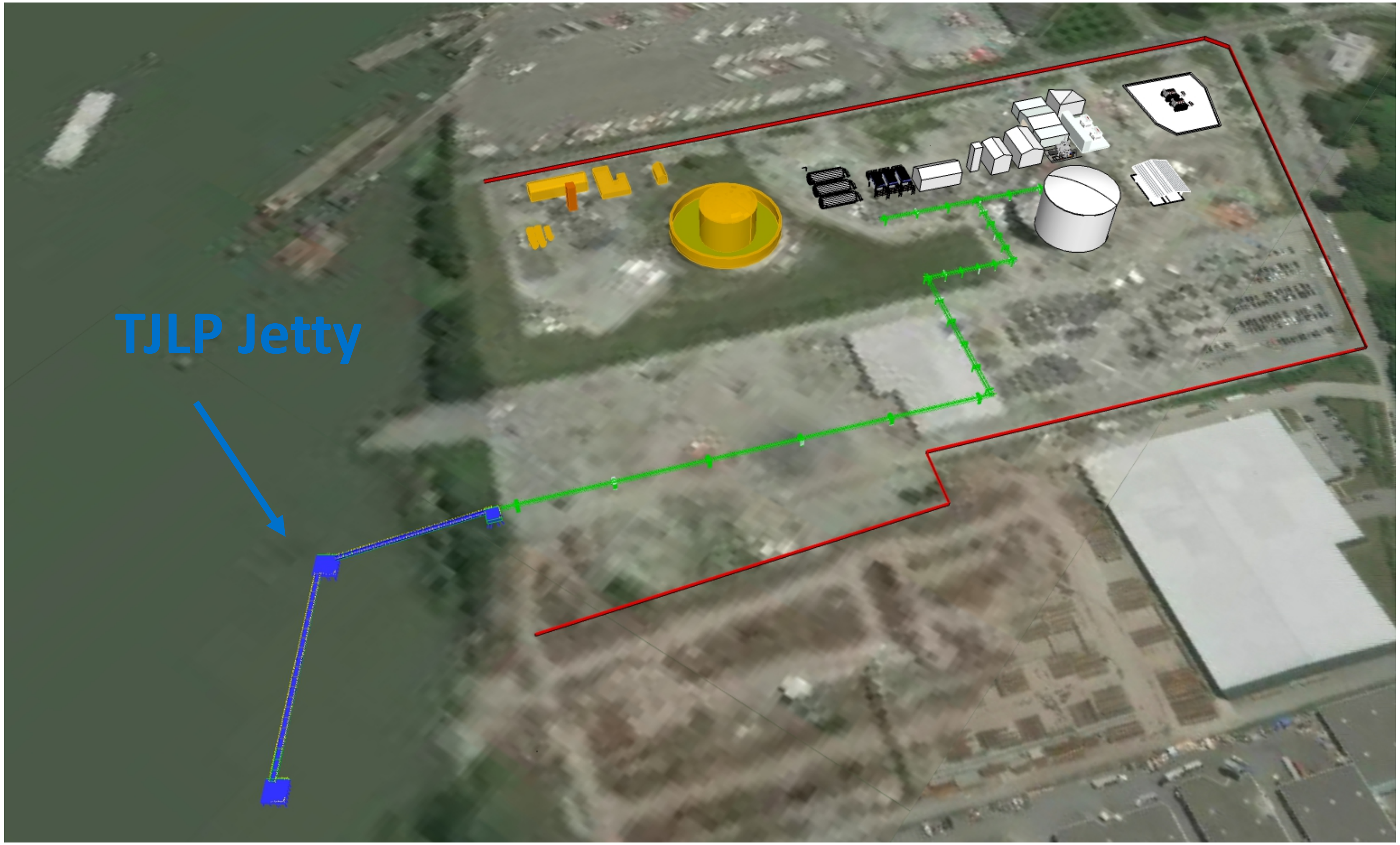
2015: Facility permit from OGC

2019: Commissioning and Operations

2021: Two bays to be installed under GGRR

Tilbury LNG Facilities

Tilbury Marine Jetty



Marine Jetty/Onshore

2012: Initial Engagement by Wespac

2015: Project description

2016: Export License obtained by Wespac (CER GL-310) to export up to 3.5 MTPA

2019: Project (EA) Application

2020: Change of ownership, acquired by TJLP

2020: Export permit transferred from Wespac to Fortis LNG Limited Partnership

~2021: EA decision

Tilbury LNG Facilities

Coastal Transmission System 30” Gas Line Upgrade

Gas Line Upgrade

December, 2014: Authorized by 1st amendment to Direction 5 to the BCUC as one of 4 Coastal Transmission System (CTS) upgrades; the other 3 upgrades have been completed

Permitting: OGC

Consultation: as per OGC Permit requirements

Tilbury LNG Facilities

1B Liquefaction including 230 kV Power Supply

Phase 1B Liquefaction

2014: Authorized by 1st amendment to Direction 5 to BCUC

Permitting: Permit amendment of OGC required, not yet started

Permit amendment required from Metro Vancouver (air quality),

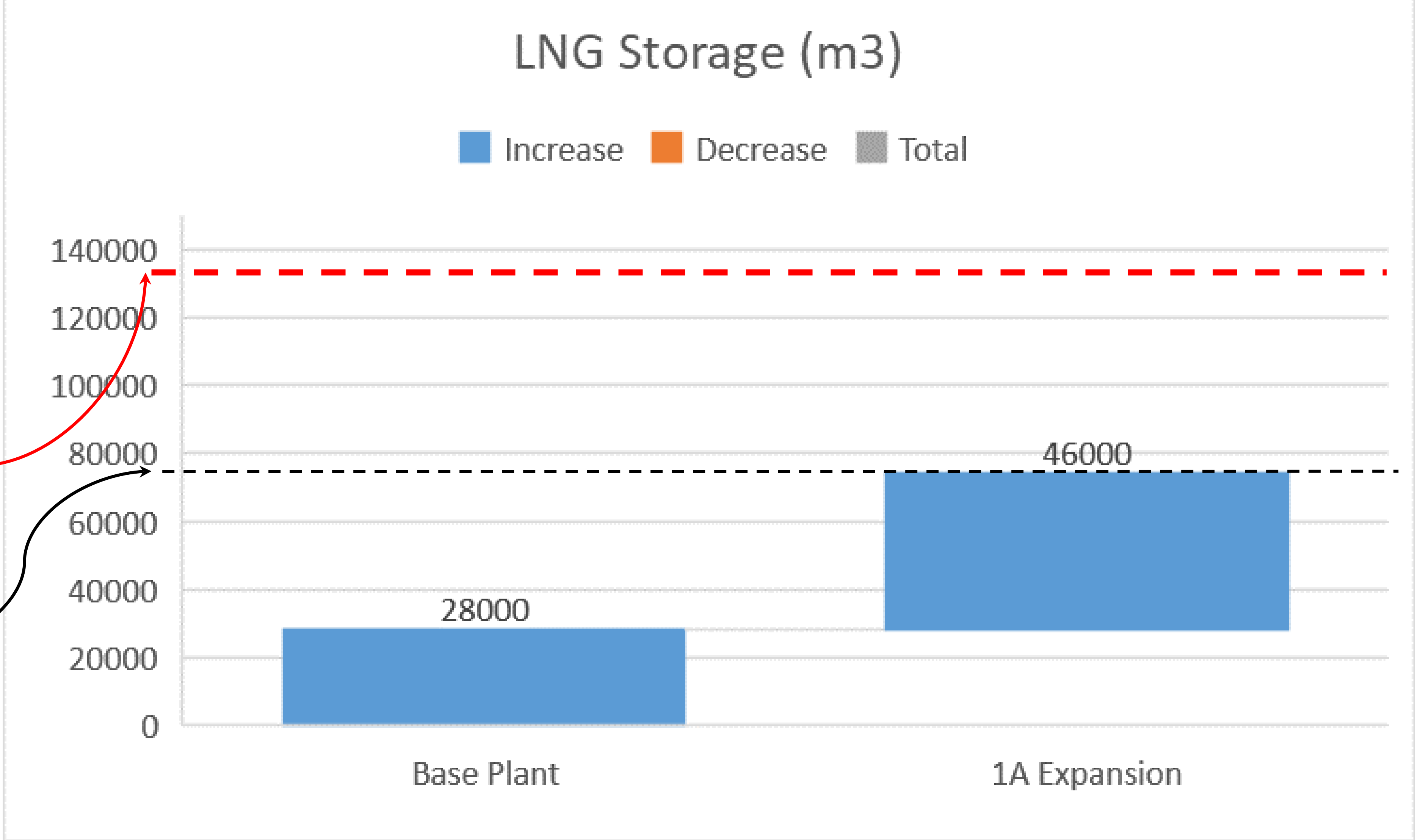
Development Set Back Variance by Delta

Consultation: Both the OGC, Metro Van processes involve consultation

Set Back Variance is a public process which the public can comment on.

Tilbury LNG Facilities

Tilbury Phase 1 LNG Storage Capacity & EA/IA Threshold



136,000 m3 LNG storage, Provincial Environmental Assessment Threshold

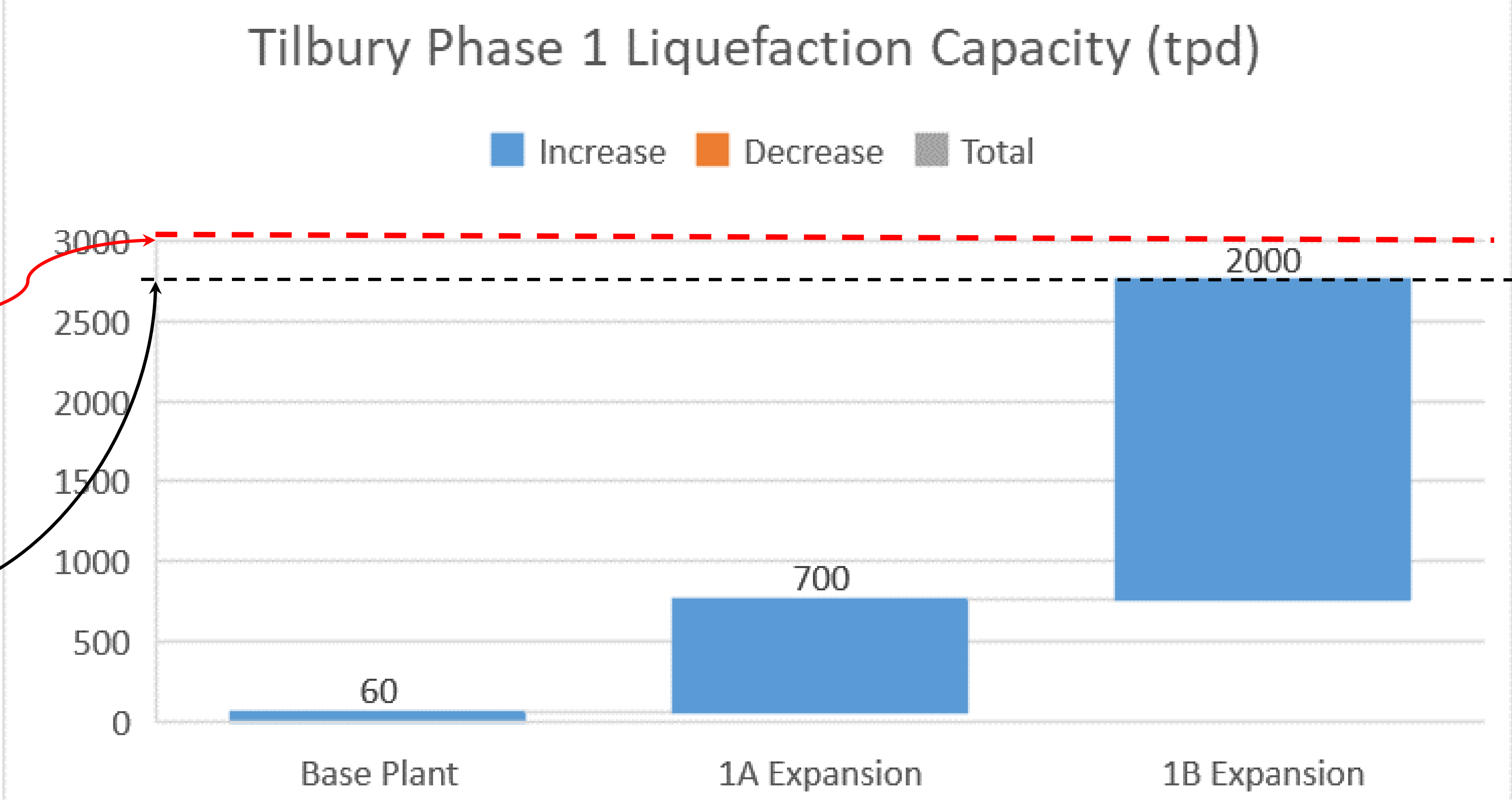
74,000 m3 total LNG Storage (installed)

Tilbury LNG Facilities

Phase 1 Liquefaction Capacity & IA Threshold

3000 t/day Federal Impact Assessment Threshold

2,760 t/day planned total Phase 1 Liquefaction capacity, based on highest planned capacities



Tilbury LNG Facilities

2018 Supply Disruption - Unanticipated Event Precipitating a Shift in Priority

VANCOUVER SUN

Local News / Energy

B.C. pipeline rupture causes natural gas shortage, soaring gasoline prices

British Columbians should brace for possible loss of natural gas service and soaring gasoline prices after an Enbridge natural gas line ruptured north of Prince George.

Randy Shore

Oct 11, 2018 • October 11, 2018 • 5 minute read • Join the conversation

The incident is ongoing in the community of Shelley, northeast of Prince George. PHOTO BY GREG N/@GREGNOEL /Twitter

Only On-System LNG (and Load Shedding) Can Be Relied Upon

Maintaining Service Depends on Partial Pipeline Flows and Off-System Storage, Plus LNG to Manage Short Duration Events

ZERO FLOW SUPPLY EMERGENCY

REMAINDER OF WINTER - SUPPLY CONSTRAINT AND PERIODIC SUPPLY/PEAKING EVENTS

Pipeline Supply Disrupted

Partial Restoration of Pipeline Flows but at Very Restricted Capacity

(~2 days after 2018 Incident)

Flows on Pipeline Increased but Capacity Still Well Below Normal

(~2.5 weeks after 2018 Incident)

Full Restoration of Pipeline Capacity to Normal Operations

(~14 months after 2018 Incident)

Tilbury LNG Facilities

Phase 2 Development – Increased Regasification Capacity

Regasification

2020: BCUC application to add 800 mmscf/d of regasification capacity

Permitting: OGC (facility), Metro Vancouver (air permit)

Consultation: Began in 2020, supports CPCN processes; future consultation with OGC Facility Approval Amendment and Metro Vancouver Air Emissions Permit Amendment

Tilbury LNG Facilities

Phase 2 Development – 3 Bcf LNG Storage Tank

Tilbury LNG Storage Expansion

2020: BCUC application to add 3 bcf of storage.

Described in the Initial Project Description filed with EAO and IAAC

Permitting: EAO/IAAC, OGC (facility), Metro Vancouver (air permit)

Consultation: Began in 2020, supports EA & CPCN processes; future consultation on Management Plans and permits

Tilbury LNG Facilities

Phase 2 Development - Future Liquefaction

Contingent Development

- FortisBC has no firm plans for additional liquefaction; need will be determined by marine fueling demand growth and global market demand
- The IPD includes the potential of adding up to 3.5 MTPA (11,000 tpd) of liquefaction capacity. This has been revised to 7,700 tpd in the DPD.
- This has been included in the scope of the EA to reflect future development in any Cumulative Effects Assessments.

Tilbury LNG Facilities

Phase 1 & Phase 2 facilities overview

Component	Existing / Planned	Description	In-service date	Size	Key Regulator
Tilbury base plant	Existing	LNG storage tank	1971	Tank: 28,000 m^3 (0.69 PJ) LNG: 60 t/d	BCUC / BC OGC
Tilbury 1A	Existing	Storage tank, load-out facilities, and liquefaction	2018	Tank: 46,000 m^3 (1.1 PJ) LNG: 700 t/d	BCUC / BC OGC / Metro Vancouver (air quality)
Tilbury 1B	Planned	Liquefaction, and gas send-out facilities	2024 - 2025	LNG: up to 2,000 t/d	BCUC / BC OGC / Metro Vancouver (air quality)
Tilbury 1B - Power line	Planned	Additional power supply from BC Hydro's Arnott substation	2023 - 2024	6 km of 230 kV power line	BCUC
Tilbury Phase 2A Storage Tank	Planned	LNG storage tank	2026	Tank: 142,400 m^3 working capacity (~3.7 PJ)	EAO / IAAC
Tilbury Phase 2B Liquefaction	Contingent	LNG liquefaction trains	Consistent with DPD (2028+)	Up to 7,700 t/d design capacity (revised in DPD)	EAO/IAAC

Tilbury LNG Facilities

Attachment 54.2c

Backgrounder: Tilbury LNG Storage Expansion CPCN

On Dec. 29, 2020, FortisBC Energy Inc. (FEI) filed an application with the BC Utilities Commission (BCUC) for approval of the Tilbury LNG Storage Expansion (TLSE) project. TLSE is being proposed to strengthen the resiliency of FEI's gas system in order to enhance its response to unforeseen supply shortages. TLSE includes the construction of an LNG storage tank, regasification equipment and the demolition of the original 50-year-old Tilbury facility. It does not involve the construction of any incremental liquefaction as this is not currently needed for resiliency. This note provides an overview of the CPCN process and related engagement.

CPCN process

As a regulated utility, FEI must apply to the BCUC for approval to construct and/or operate new facilities or extensions of existing facilities. Through the Certificate of Public Convenience and Necessity, the proponent identifies the need for a project and confirms its technical, economic and financial feasibility. The proponent also assesses feasible alternatives to the project, including an overall assessment of the social and environmental impact of the project relative to the overall impact of the alternatives. FEI has extensive experience in this BCUC process and operates a number of projects approved by CPCN, including the Mt. Hayes LNG facility on Vancouver Island.

Project engagement

TLSE is being developed concurrently with the Tilbury Phase 2 LNG Expansion and both projects include the proposed LNG storage tank in its scope. As a result, FEI's approach has been to synchronize engagement activities in recognition that the projects share many of the same interested parties. This approach helps mitigate the risk of confusion and fatigue among Indigenous groups and stakeholders, while still meeting the requirements of the BCUC, BC Environmental Assessment Office (EAO) and Impact Assessment Agency of Canada (IAAC). This approach includes a shared project web page, combined project notifications and meetings covering both projects. The public can also attend virtual open houses to learn more and ask questions about both projects.

Timetable

FEI will participate in a number of activities required as part of the CPCN process. The activities begin with notifications to stakeholders and Indigenous groups, print ads and social media by February 14. A timetable of the CPCN procedural-related activities is included below.

ACTION	DATE (2021)
BCUC Issues Procedural Order	Tuesday, January 26
FEI Publishes Notice by	Sunday, February 14
Intervener Registration	Thursday, February 25
Workshop	Thursday, March 11
BCUC and Intervener Information Request No. 1	Thursday, March 25
FEI Response to Information Request No. 1	Monday, April 26
Procedural Conference	Thursday, May 12
Further process	TBD
BCUC decision	As early as January 2022

Attachment 56.1a

From:	Hodson, Courtney
To:	mayorandcouncillors@richmond.ca
Subject:	FortisBC Tilbury LNG Storage Expansion Project Update
Date:	Wednesday, February 10, 2021 9:22:00 AM

Hello Mayor & Councillors,

I'm reaching out today to share another important milestone for the Tilbury LNG Storage Expansion Project. We filed an application to the British Columbia Utilities Commission (BCUC) for a Certificate of Public Convenience and Necessity (CPCN) for the Tilbury Liquefied Natural Gas (LNG) Storage Expansion Project on December 29, 2020, to seek approval to construct a new LNG storage tank and equipment to increase our capacity to provide natural gas to our customers. The project would enhance Tilbury's ability to provide energy to the Lower Mainland in the event of a gas supply disruption.

As a regulated utility, FortisBC's projects are reviewed and approved by the BCUC. If you are interested in registering to participate in the BCUC process, you can find information on how to get involved at bcuc.com. The registration deadline is set for February 25, 2021 and all related documents can be found here on the BCUC's website.

Separately, the environmental assessment process for the Tilbury Phase 2 LNG Expansion project continues to proceed with the British Columbia Environmental Assessment Office and the Impact Assessment Agency of Canada. This project encompasses a larger expansion of the Tilbury site, including the new storage tank as well as more LNG production capacity, than what FortisBC is seeking approval of as part of the CPCN as components of the larger project are not currently needed to respond to a gas supply outage.

FortisBC is dedicated to ensuring engagement is robust, efficient and transparent, including participating in open houses, to give the opportunity for our customers and the community to learn more about the project, ask questions and provide feedback.

If the CPCN application is approved, construction could start as early as 2022 and be completed by 2026. If you would like to be kept informed of the project's progress, visit our website at talkingenergy.ca/tilburyphase2, or you can subscribe to receive regular updates at subscriptions.fortisbc.com/subscribe.

In the meantime, I would welcome the opportunity to share more about the expansion with you by email or conference call at your convenience. Please let me know if you have any questions or would like any more information.

Best regards,

Courtney Hodson
Community Relations Manager, Major Projects
Tel: 604.592.7603

Mobile: 778.580.5717
courtney.hodson@fortisbc.com

Attachment 56.1b

Meeting Minutes

Subject **Tilbury LNG - Development History Presentation**

Project Tilbury Phase 2 LNG Expansion Project

Date/Time Tuesday May 4, 2021
10:00 am to 12:00 pm

Participants

Indigenous Nations and Their Representatives
Candace Charlie (Cowichan Tribes)
Raven August (Halalt)
Kimberly Armour (Katzie)
Drew Atkins (Kwantlen)
Steven Harris (Kwantlen)
Tanner Timothy (Kwantlen)
Lyackson
Leeann Wells (Semiahmoo)
Shana Roberts (Sto:Lo)
Sheila Williams (TFN)
Maria Du Monceau (TWN)
Deanna Shrimpton (TWN)
Annie Chalifour (LGL representing TFN)
Megan Mathews (LGL representing TFN)
Mike Demarchi (LGL representing TFN)
Kirsten Barnes (Lawyer representing Cheam)

Municipal and Regional Governments
Leeann Graham (City of Delta)
Mike Brotherston (City of Delta)
Chad Paulin (City of Richmond)
Curtis Tillyer (City of Richmond)
Kathy Preston (Metro Vancouver)
Clare Zemcov (Metro Vancouver)
Darren Lee (Metro Vancouver)
Jean Lawson (Metro Vancouver)
Catherine Braun Rodriguez (Metro Vancouver)
Erin Hogg (Metro Vancouver)
Nicole Chan (Metro Vancouver)
Shelina Sidi (Metro Vancouver)

Provincial Agencies
Suzanne Mathews (BC OGC)
Garth Thoroughgood (BC OGC)
Marc Chawrun (BC OGC)
Ian Swan (BC OGC)
Theodore Back (CAS)
Leith Anderson (EAO)
Amber Pauson (EAO)
Fern Stockman (EAO)
Amy Thede (EAO)
Jennifer Davison (EMLI)
Duane Chapman (EMLI)
Sebastian Blackthorne (FLNRORD)
Goran Krstic (Fraser Health)
Mikayla Roberts (MAFF)
Devon Carter (MIRR)
Nedinska Donaldson (MIRR)
Cara Lachmuth (Ministry of Health)
Lindsey Huebel (FLNRORD)

Federal Government
Stephanie Russo (DFO)
Kevin DeBoer (DFO)
Yee Ting Choy (ECCC)
Robynn McLean (ECCC)
Hsin-Ming Yeh (Health Canada)
Yota Hatziantoniou (Health Canada)
Vivian Au (IAAC)
Katherine Zmuda (IAAC)
Daisy Hsu (IAAC)
Dylan Joyce (IAAC)
Gia Kim (IAAC)
Zoltan Fabian (IAAC)
Kenneth Law (IAAC)
Christal Nieman (IAAC)
Shannon Potter (IAAC)
Paulo Eusebio (INAC)
Joseph Whiteside (Indigenous Services Canada)
Anica Madzarevic (NRCAN)
Eric Leung (Transport Canada)
Elizabeth Harries (Transport Canada)
Sumandeep Atwal (Transport Canada)
Catherine Adams (Women and Gender Equity Canada)
Emily Robinson (ECCC)

FortisBC and Their Representatives
Ian Finke (FEI)
Andrew Hamilton (FEI)
Courtney Hodson (FEI)
James Humble (FEI)
Scott Neufeld (FEI)
Roger Ord (FEI)
Hailey Robinsmith (FEI)
Olivia Stanley (FEI)
Will Zylmans (FEI)
Sarah Durham (Jacobs)
Matt Mosher (Jacobs)
Julie Swinscoe (Jacobs)
Tara Lindsay (Jacobs)
Sang Vo (Jacobs)
Trish Wiegele (Jacobs)

Purpose of Meeting	To provide additional background for Technical Advisors and Indigenous nations about the history and planned developments at the Tilbury LNG site.
Topics Discussed	1. Introduction 2. FortisBC Presentation on Tilbury LNG development history (1 hour) 3. Q&A 4. Closing/next steps
Actions	• Fern Stockman, EAO to provide participants with a copy of FortisBC's PowerPoint presentation
Key Issues Raised / Discussed	1. What does the acronym BCUC stand for? 2. Are you sharing the presentation/slides with participants? 3. How is the pipe infrastructure from Tilbury 2? How could it disseminate from Tilbury 2 to the city? Is there going to be more beefing up of the pipe in the City of Vancouver? 4. Do your GHG calculations involve the upstream portion of the GHG process? 5. Can you please describe how much of an impact the increased capacity of the Fortis Facility will have on the demand/capacity for Natural Gas production on the Enron Supplier up North. Will it lead to more Fracking up North? 6. What is the estimated capital cost of Phase 1? 7. Has an economic cost benefit analysis been done for the project? 8. Can you comment on the reasoning for storage of LNG or now RNG for emergency situations vs exporting RNG for profit. It seems that storage is being used as a catalyst for capital progress of the company. Is the global market, which is changing rapidly with the immediate and long term climate challenges, actually needing RNG exported from BC? BC wants to decrease emissions by 40% by 2030, whereas fortis is aiming for 30%, how can we keep under that target with increased production and export

	9. Could someone from EAO or IAAC give an update on the assessment process for this project, please? 10. Thank you for responding, I will have to review the CPCN. I want less carbon in our atmosphere too but I also worry about methane. Methane, I believe, is a stronger GHG than carbon i.e. stays in the atmosphere longer and captures greater amounts of solar energy . Which means methane emissions may be more sensitive than C02, methane is a main component of RNG, right? I see the upstream portion of where this RNG comes from to Tilbury can hinder the atmospheric health of the province. 11. Does BCUC have a requirement under BC legislation to consult First Nations - especially under new legislation of DRIPA? 12. If there was a disruption to the supply line of Natural Gas to Fortis, would Fortis Halt the export of LNG to foreign markets to ensure the priority of the BC residents. 13. Is there any discussion for upgrades needed between project itself and upstream transmission lines itself? Any clarity on whether anything needed there? 14. Has the resiliency component considered future reductions in municipal household use? (I'm thinking of municipalities' climate plans i.e. Vancouver indicating a desire to transition away from natural gas for household usage) 15. Does the Tilbury facility do any NGL removal of incoming gas supply? 16. As part of the Tilbury Jetty Expansion EAO it was advised that custom sized vessels would be constructed for the export to foreign markets. Is the development of these ships still being managed by WesPac, or would this fall to the new Fortis/Seaspan Partnership?

Attachment 56.1c

FORTIS BC

Meeting Minutes

Subject **Tilbury LNG – Detailed Project Description Part 2**

Project Tilbury Phase 2 LNG Expansion Project

Date/Time Wednesday June 16, 2021
10:00 am to 12:00 pm

Participants

Indigenous Nations and Their Representatives
Rose Peters (Chawathil)
Candace Charlie (Cowichan Tribes)
Raven August (Halalt)
Caitlin Kenny (PGL representing Halalt)
Drew Atkins (Kwantlen)
Steven Harris (Kwantlen)
Tanner Timothy (Kwantlen)
Hirmand Saffari (Kwikwetlem)
Lyackson representatives
Tanya Faire(Musqueam)
Chris Raftis (Musqueam)
Josh James(Penelakut)
Sheila Williams (TFN)
Annie Chalifour (LGL representing TFN)
Megan Mathews (LGL representing TFN)
Mike Demarchi (LGL representing TFN)
Maria Du Monceau (TWN)
Deanna Shrimpton (TWN)

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Catherine Braun Rodriguez (Metro Vancouver)
Nicole Chan (Metro Vancouver)
Shelina Sidi (Metro Vancouver)

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Amy Thede (EAO)
Leith Anderson (EAO)
Andrea Orellana (BC ENV)
Jennifer Davison (EMLI)
Lindsey Huebel (FLNRORD)
Goran Krstic (Fraser Health)

Federal Government
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Kevin DeBoer (DFO)
Elizabeth Blanchette (DND)
Yee Ting Choy (ECCC)
Robynn McLean (ECCC)
Snehal Lakhani (ECCC)
Tasha Gallagher (ECCC)
Kathryn Marshall (ECCC)
Rachel Canham (ECCC)
Lillian Cesh (ECCC)
Graham Irvine (Health Canada)
Hsin-Ming Yeh (Health Canada)
Yota Hatziantoniou (Health Canada)
Katherine Zmuda (IAAC)
Dylan Joyce (IAAC)
Kenneth Law (IAAC)
Shannon Potter (IAAC)
Danielle Jeddore (INAC)
Nancy Xue (INAC)
Paulo Eusebio (INAC)
Joseph Whiteside (INAC)
Jacob Ediza (NRCAN)
Susan Hwang (NRCAN)
Anica Madzarevic (NRCAN)
Eric Leung (Transport Canada)
Sumandeep Atwal (Transport Canada)
Chris Bishop (Vancouver Fraser Port Authority)
Tim Blair (Vancouver Fraser Port Authority)
Megan Kirby (Women and Gender Equality Canada)

FortisBC and Their Representatives
Ian Finke (FEI)
Andrew Hamilton (FEI)
Courtney Hodson (FEI)
James Humble (FEI)
Scott Neufeld (FEI)
Roger Ord (FEI)
Hailey Robinsmith (FEI)
Olivia Stanley (FEI)
Matt Mosher (Jacobs)
Julie Swinscoe (Jacobs)
Tara Lindsay (Jacobs)
Trish Wiegele (Jacobs)

Purpose of Meeting	To provide an update on the Project, timelines and the regulatory processes. To provide an overview of changes made to the Detailed Project Description, draft Application Information Requirements and Valued Component Selection document. To provide an opportunity for Technical Advisors and Indigenous nations to ask questions and seek clarification.
Topics Discussed	1. Welcome and introductions 2. Process Update 3. Next Steps and Timelines for Review 4. Project Update and DPD Overview • Overview of DPD, dAIR and VC selection updates • Commonly requested clarifications in DPD • Common issues and concerns raised during early engagement and discussions • Providing DPD feedback 5. DPD Discussion / Q&A 6. Closing
Actions	• None identified

Key Issues Raised / Discussed	Q: How does that compare to Methane intensity which is a primary GHG, and arguably stronger in terms of how long it stays in the atmosphere and how much solar energy it absorbs/refracts? Q: Could the proponent comment on whether an upstream GHG assessment will be completed? I don't believe it was included in the DPD. Using the maximum capacity off 7,700 tonnes/day of LNG production and the lifecycle GHGi of BC natural gas, the upstream emissions would likely exceed the 500 ktonne threshold. Q: I understand the need for resiliency within the energy system writ large, but isn't a viable alternative to the project (specifically in regards to the goal of increasing resiliency) to diversify the energy sources for British Columbians to include small scale renewables? I'm curious about whether the storage increase under discussion is necessary with increasing trends in the use of heat pumps, solar installations etc. Q: In addition to the comment and question above, what is the balance between Tilbury expansion for "cold snaps" vs exporting LNG with the proposed jetty to international markets? Is the additional storage a catalyst for exporting LNG for profit . Q: How many modules will be coming through riverside, what are the sizes of these modules? Q: To what degree are the two separate EA processes coordinated? Will any of the proposed scope changes alter the scope of the Marine Jetty EA? For example: projections of shipping traffic. Are there intentions of providing greater coordination between the two assessment processes as they progress? Q: For the in-water works, is the proponent aware of the requirement to submit an application to the Navigation Protection Program at Transport Canada? Q: Will dredging be required for the MOF? Q: Is the MOF to be shared with Tilbury Marine Jetty or is this a separate piece of infrastructure? Q: Further to my earlier question, could the IACC provide guidance on when they would make a decision on whether an upstream GHG assessment is required and how that fits into the process presented by the EAO? From our preliminary calculations, upstream emissions would likely exceed 500 kT.

	Q: Have the updated VCs been included in the DPD sent to reviewers this month? Q: Would potential LNG exports to overseas markets through the Phase 2 project depend on the Tilbury Marine Jetty project? What upgrades to TMJ, if any, would need to be made for LNG exports?

Attachment 56.1d

Tilbury Phase 2 LNG Expansion Project

Detailed Project Description Workshop 2

June 16, 2021

Tilbury Phase 2 LNG Expansion

Energy at work FORTISBC

Project need

- FortisBC provides energy to over 1.2 million customers
- On the coldest days of the year, we can deliver up to half of BC's energy demand.
- Tilbury has provided backup energy supply to British Columbians for 50 years
- FortisBC is aiming to modernize and expand Tilbury to continue meeting BC's energy needs into the future

Tilbury has evolved since 1971 from providing LNG to meet peak energy demand in BC to also providing LNG as a fuel for local transportation.

Tilbury Phase 2 LNG Expansion

Energy at work FORTIS BC

Project purpose: Resiliency

FortisBC's system is tied in to the broader Pacific Northwest regional gas system, which relies on the T-South transmission line flowing from northern BC to the US for most of its supply.

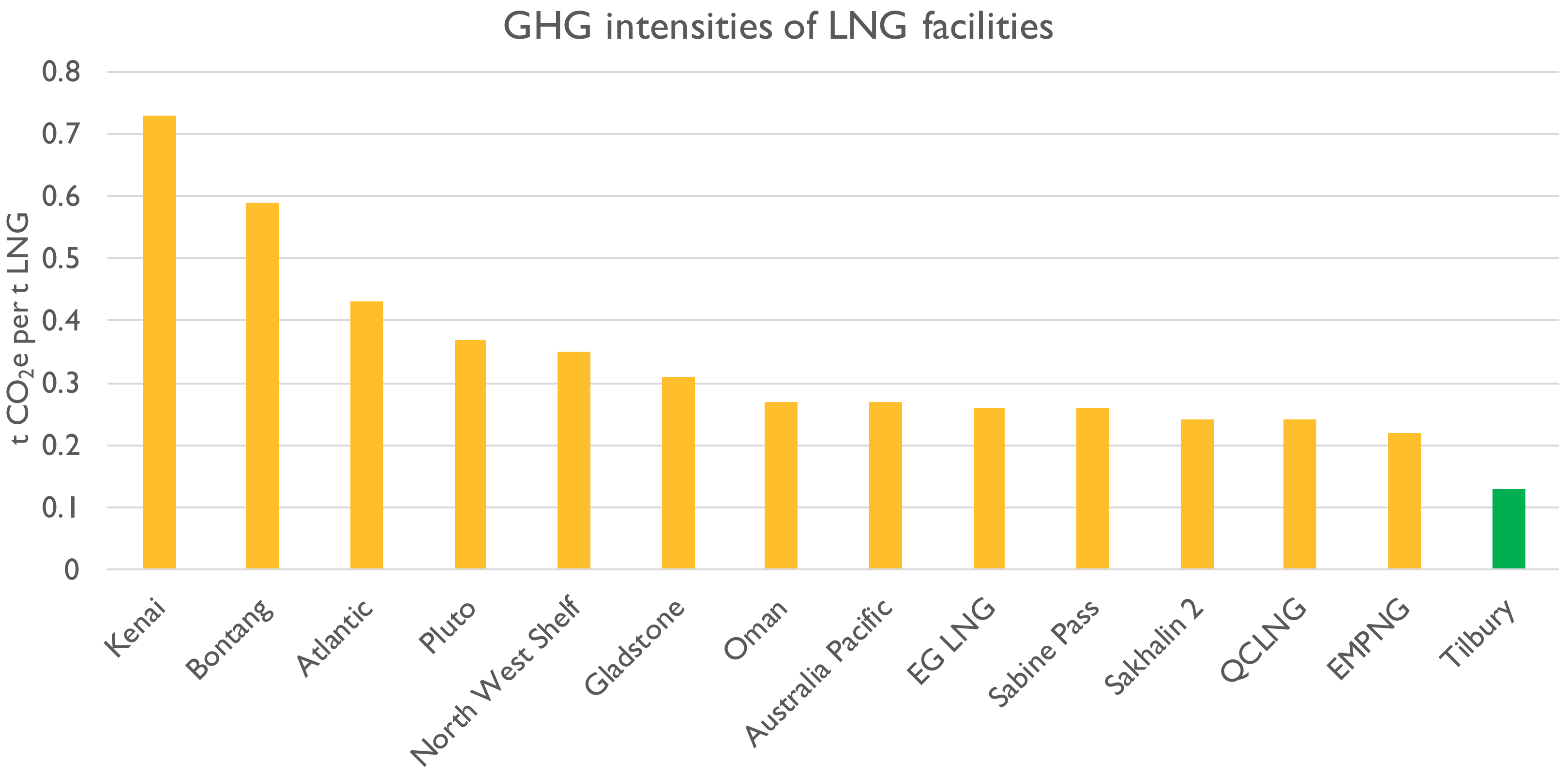
- The project will serve two purposes.
- The first purpose of the project is to enhance the resiliency of the gas system and maintain reliable energy service to customers.
- The objective is to withstand a 3-day gas supply disruption to the Lower Mainland
- Consequences of a supply disruption could be significant for FortisBC customers and the province as a whole

Tilbury Phase 2 LNG Expansion

Energy at work FORTIS BC

Project purpose: Liquefaction

- The other purpose is to displace higher carbon fuel with LNG to reduce GHG and air pollutant emissions.
- The project would produce LNG with a low carbon intensity because it would be powered by renewable energy.
- Tilbury is close to key regional and international markets.
- New liquefaction capacity would be built as market demand is realized.



Our current e-drive facility can produce LNG with low carbon intensity

Tilbury Phase 2 LNG Expansion

Energy at work FORTIS BC™

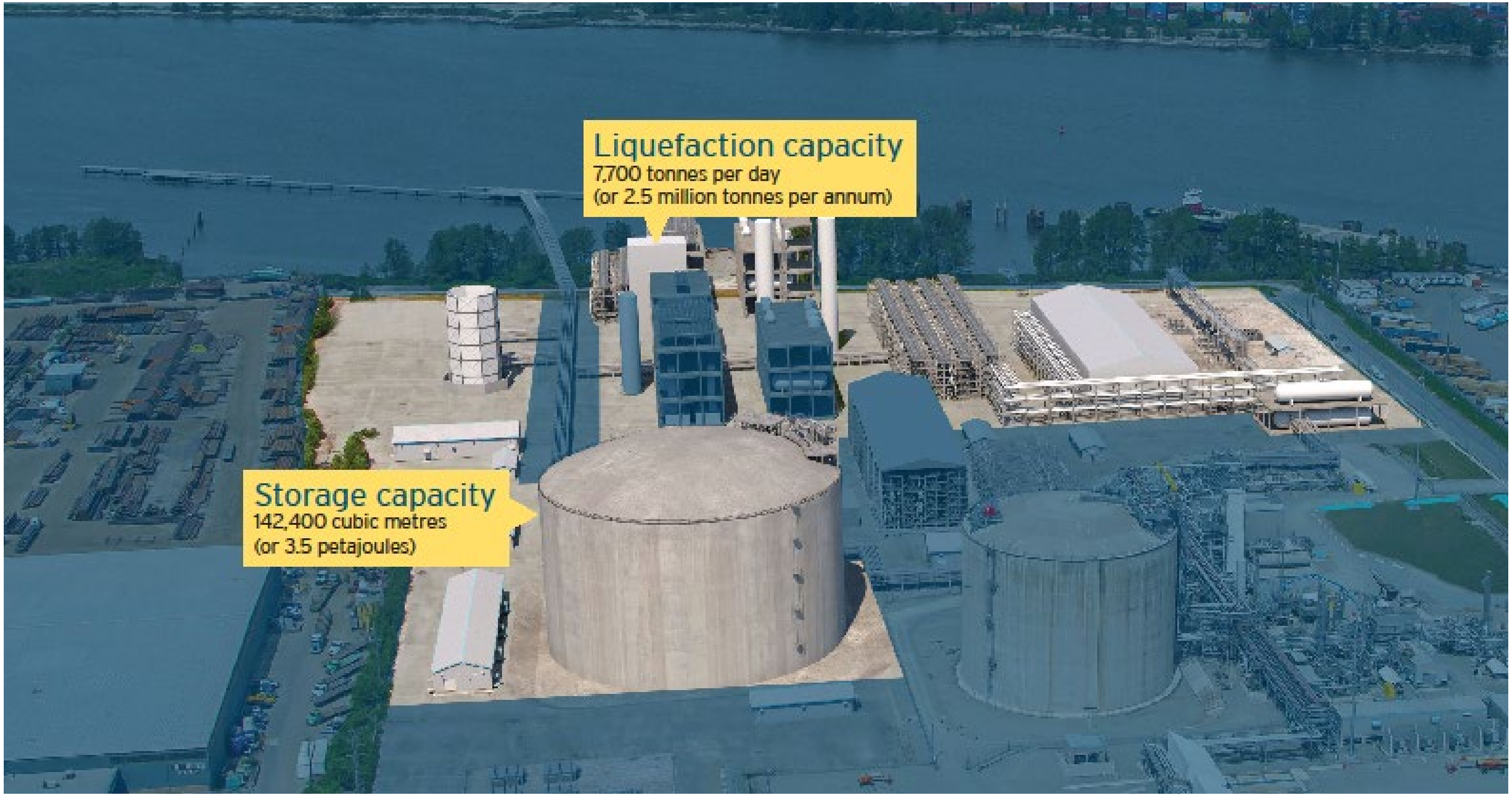
Project benefits

Reliable energy supply	• Enhance the gas system's capability to withstand unforeseen events and maintain reliable service to B.C. homes and businesses
Greenhouse gas emissions reductions	• Equivalent to removing more than **1.5 million cars** off the road or **5 million tonnes** of CO2 equivalent
Air pollution reductions	• LNG can reduce emissions such as up to **99% less particulate matter, 99% less Sulphur oxides** and **95% less nitrogen oxides** than petroleum-based fuel
Economic opportunities	• About **$1.7B** could be added to B.C.'s GDP during construction, an estimated **$700M** could be added annually during operations
Job opportunities	• Construction could create more than **6,000** direct, FTE jobs and **110** FTE jobs during operations
Tax revenue	• Construction could generate **~$300M** in tax revenues for local government and **~$280M** annually for federal and provincial governments in operation

Tilbury Phase 2 LNG Expansion

Energy at work FORTIS BC

Project scope changes



Tilbury Phase 2 LNG Expansion

Energy at work FORTIS BC™

Project Update: Indigenous Engagement

Meetings and Other Engagement

- Meeting and corresponding since July 2019
- Tailoring approach based on Indigenous Nations preferences
- Engagement approach adapted due to COVID19
- Topics being engaged on include:
  - Project overview and updates
  - Schedule
  - Indigenous Interests
  - Assessment methods
- Received and responded to 300+ written comments on project documents

Field Studies/Verification

- Virtual participation due to COVID-19
- Upcoming opportunities for future studies/verification

Tilbury Phase 2 LNG Expansion

Energy at work FORTIS BC

Project update: Engagement

Public & Local Stakeholder Engagement

- Ongoing project overview presentations to new community stakeholder groups
- Participation in local industry and community virtual events
- Notifications and follow-up communications with stakeholders, including the bi-monthly Tilbury e-newsletter
- Sharing new LNG videos on FortisBC social channels to increase public knowledge
- Host a live LNG demonstration once public health guidelines allow
- Responded public concerns raised in summary of engagement

Technical Advisor Engagement

- Meetings and workshops with Local Governments, Technical Advisors, EAO and IAAC
- Ongoing communications and support for review of draft Part 1 DPD, dAIR & VC documents
- Received and responded to 400+ written comments on project documents

Tilbury Phase 2 LNG Expansion

Energy at work FORTIS BC™

Common issues and concerns raised in Early Engagement

Topics in our October 2020 workshop:

- Accidents, Malfunctions and Public Safety
- Human Health and Well-Being
- Indigenous People's Rights & Interests
- Fish and Fish Habitat and Marine Mammals
- Infrastructure and Services
- Cumulative Effects

Tilbury Phase 2 LNG Expansion

Energy at work FORTIS BC™

Common issues and concerns raised in Early Engagement

Topics in this workshop

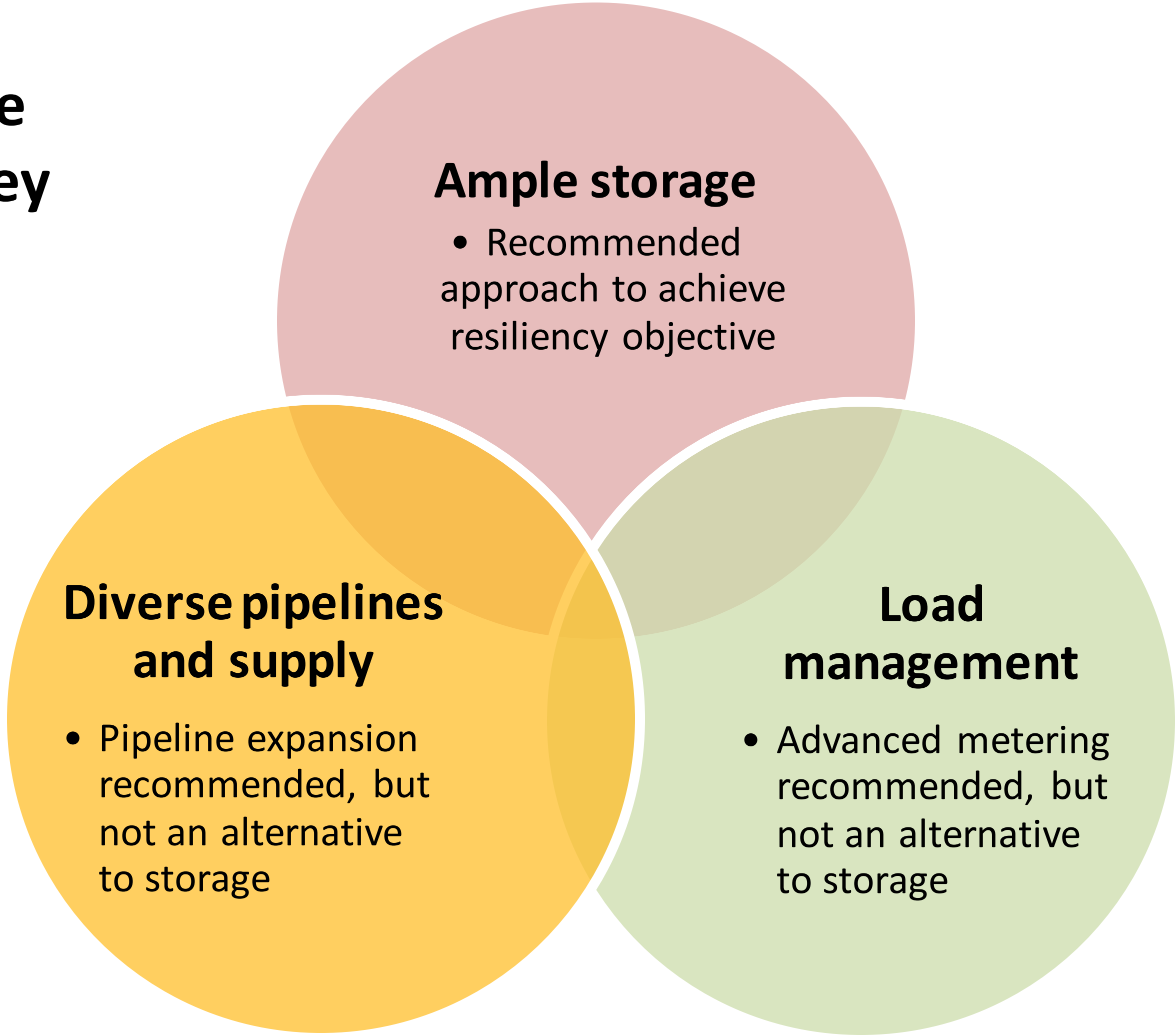
- Alternatives to the Project
- Alternative Means of Carrying Out the Project
- Material offloading facility
- Atmospheric Environment
- Climate Change and Greenhouse Gas

Tilbury Phase 2 LNG Expansion

Energy at work FORTIS BC

Alternatives to the Project

System resilience requires three key elements



Tilbury Phase 2 LNG Expansion

Energy at work FORTIS BC™

Alternative means: Flexibility of location and design

Fixed characteristics

- **Project location** (Preferred option: Brownfield site in the Lower Mainland)
- **Storage technology** (Preferred option: On-system above ground storage)
- **Storage volume** (Preferred option: 3 bcf capacity)
- **Liquefaction driver selection** (Preferred option: Electric Drive)
- **Cooling technology** (Preferred option: Air cooling)
- **Construction methods** (Preferred option: Off-site modularized construction)

Flexible characteristics – to be decided

- Single or multi-train liquefaction
- Liquefaction volume
- Flare technology

Tilbury Phase 2 LNG Expansion

Energy at work FORTIS BC™

Material Offloading Facility (MOF)

Update options

- Riverbed densification / ground improvement
- Piling
- Shoreline armour (rip rap / stabilization)
- Demolition of existing construction dock
- Scour protection on river bed

Upland work

- Flood defence crossing, grading, and clearing
- Deck expansion

Tilbury Phase 2 LNG Expansion

Energy at work FORTIS BC™

Atmospheric environment

Assessment approach

- Comprehensive AQ studies of construction, operation, and decommissioning emissions will be undertaken; predicted emissions will be modelled and compared to Metro Vancouver's ambient air quality objectives (AAQOs), Canadian Ambient Air Quality Standards (2020 and 2025 CAAQS), BC Provincial AAQOs.
- A cumulative effects assessment will be undertaken that considers Project sources, baseline, and reasonably foreseeable developments in the area.
- The evaluation will consider normal operating conditions as well as upset conditions (maintenance, malfunctions, accidental releases)
- Compressor drive emissions are typically the major source of operational SOx, NOx and GHG emissions at such facilities.
- Pre-selected E-drive technology emits no direct GHG, NOx or SOx.
- Best available technology (BAT) studies will include an assessment of the implications of the technology on air quality

Tilbury Phase 2 LNG Expansion

Energy at work FORTIS BC™

Atmospheric environment - greenhouse gas emissions

Preliminary Estimates of Direct and Acquired Energy GHG emissions

Phase	Duration (years)	Direct Emissions (tCO_2e/year)	Acquired Energy Emissions (tCO_2e/year)	Net Emissions (tCO_2e/year)
Construction	3	5,000	0	5,000
Operations	40	190,000	43,000	233,000
Decommissioning	2	N/A	0	N/A

- The decision to use e-drive compression has reduced emissions by approximately 200,000 tonnes per year relative to gas-fired compression.

Preliminary Project GHG Contribution Context

	Reduction Target (%)	Annual Emissions ($ktCO_2e$/year)	Project Contribution (%)
Project Annual Net Emissions	n/a	233	n/a
Federal 2005 Baseline	n/a	730,000	0.032
Federal 2030 Target	30	511,000	0.046
BC 2007 Baseline[b]	n/a	61,000	0.38
BC 2030 Target	40	37,000	0.64
BC 2040 Target	60	24,000	0.96
BC 2050 Target	80	12,000	1.9

Tilbury Phase 2 LNG Expansion

Energy at work FORTIS BC™

Atmospheric environment – Strategic Assessment of Climate Change

Our assessment will meet **Strategic Assessment of Climate Change** requirements:

1) A GHG-specific BAT requirement

Scope	SACC BAT	Provincial BAT
GHG	✓ +	Not explicit
AQ		✓

"+" The SACC also requires an "**Emerging Technology Assessment**"

2) "Climate Lens" Adaptation Assessment

3) Net Zero (GHGs) by 2050 Plan

Tilbury Phase 2 LNG Expansion

Energy at work FORTIS BC™

dAIR / VC Overview and Updates

Valued Component (VC) Selection Document

- Updated VCs (Project specific changes, changes as a result of engagement)
- Ongoing considerations that may influence VC selection (e.g., Indigenous nation specific VCs)
- Capturing Indigenous interests and bringing them into the VC doc as required
- Guidance developed to capture Interests or Issues raised and to track them through the assessment process (Issues and Interests Tracker)

Tilbury Phase 2 LNG Expansion

Energy at work FORTIS BC™

dAIR / VC Overview and Updates

Draft Application Information Requirements (dAIR)

- Federal requirements (IAAC) have been incorporated into the dAIR
- Section 22 (IAAC) and 25 (EAO) requirements incorporated into dAIR
- Study Areas Updated (Local Assessment Area and Regional Assessment Area)
- Indigenous nations effects assessment

Tilbury Phase 2 LNG Expansion

Energy at work FORTIS BC™

Providing feedback

- When providing feedback on the DPD or other Tilbury Phase 2 Expansion deliverables please use the comment tracking sheet provided

Tilbury Phase 2 LNG Expansion Comment Tracking Sheet		
Project: Tilbury Phase 2 LNG Expansion		
Document: DPD		
Document Version: Draft 1		
Date of Review: (date)		
Reviewer: (name)		
Document Section	**Topic**	**Reviewer Comments**

Thank you

Energy at work FORTIS BC™

For further information, please contact:

Phone: 1-855-576-7133

Email: Tilbury.info@FortisBC.com

Website: Talkingenergy.ca/tilburyphase2

Find FortisBC at:

Fortisbc.com

604-676-7000

Attachment 58.2a

16705 Fraser Highway
Surrey, B.C. V3L 5R7
Fortisbc.com

June 1, 2020

[redacted]

Via email: [redacted]

Dear [redacted],

RE: ***PUBLIC COMMENT PERIOD COMMENCING FOR FORTISBC TILBURY PHASE 2 LNG EXPANSION PROJECT***

FortisBC would like to update [redacted] regarding the Tilbury Phase 2 LNG Expansion Project ("Tilbury Project"). FortisBC is proposing to expand LNG storage and LNG production capacity at its existing facility located at 7651 Hopcott Road, on Tilbury Island in the City of Delta.

Environmental Review Process

The Tilbury Project is a reviewable project under the *Environmental Assessment Act* (2018) regulated by the British Columbia Environmental Assessment Office (BCEAO) and the *Impact Assessment Act (2019)* regulated by the Impact Assessment Agency of Canada (IAAC).

The Tilbury Project entered the provincial Early Engagement phase and the federal Planning Phase on February 27, 2020. Due to the COVID-19 pandemic, FortisBC requested two 30-day extensions of this Early Engagement phase bringing the total phase from 90 days to 150. In addition, FortisBC requested two 30-day suspensions of the 180-day Planning Phase. The provincial and federal regulators have decided to commence a 45-day public comment period on June 1, 2020. The feedback received from this comment period will help inform our Detailed Project Description, expected to be filed in late-2020.

Regulated Utility Review Process

As a regulated utility, FortisBC also requires a Certificate of Public Convenience and Necessity (CPCN) from the British Columbia Utilities Commission. We are aiming to submit a CPCN application to the Commission later this year. At that time, we will notify you of additional opportunities to participate in the CPCN process. If the application is approved, we estimate that construction could begin as early as 2022 with projected completion by 2028.

FortisBC recognizes that the Tilbury Project is located within the traditional territory of [redacted], and we strongly believe in transparent, meaningful engagement with rights holders such as yourselves. We would like to continue ongoing dialogue with your community as we move forward in this process.

In addition to the comment period, FortisBC would be happy to meet with you at your convenience to discuss comments or questions related to the Tilbury Project prior to the submission of the Detailed Project Description and CPCN application.

Sincerely,

Olivia Stanley
Indigenous Relations Manager
FortisBC

Attachment 58.2b

16705 Fraser Highway
Surrey, B.C. V3L 5R7
Fortisbc.com

February 11, 2021

[redacted]

Via email: [redacted]

Dear Chris,

RE: ***FORTISBC TILBURY LNG STORAGE EXPANSION PROJECT UPDATE***

FortisBC would like to update [redacted] regarding the regulated utility review process for the Tilbury Phase 2 LNG Expansion Project. This letter is a follow up to the one you received in June 2020 regarding FortisBC's filing of a Certificate of Public Convenience and Necessity (CPCN) with the British Columbia Utilities Commission (BCUC).

Regulated Utility Review Process

As a regulated utility, FortisBC requires a CPCN from the BCUC for major projects that may affect rates paid by FortisBC customers. On December 29, 2020, FortisBC filed the CPCN for the Tilbury Liquefied Natural Gas (LNG) Storage Expansion Project with the BCUC to seek approval for the construction of a new LNG storage tank. With a new LNG storage tank, FortisBC will be able to ensure an additional backup source of natural gas for our customers in the event of a gas supply disruption. If the CPCN is approved, we estimate that construction of the storage tank could begin as early as 2022 with projected completion by 2028.

Indigenous groups and members of the public are able to participate in the BCUC process by registering as an Interested Party or as an Intervener. An Interested Party receives email notification of all non-confidential evidence presented in the proceeding and has their name appear on the public evidentiary record. Interveners are active participants in the process. Further information on participation in the BCUC process can be found at www.bcuc.com/get-involved. The BCUC registration deadline is set for February 25, 2021.

Environmental Review Process

The broader Tilbury Phase 2 LNG Expansion Project continues to proceed through the environmental assessment process led by the British Columbia Environmental Assessment Office and the Impact Assessment Agency of Canada. This project encompasses a larger expansion of the Tilbury site, including the new storage tank as well as more LNG production capacity, than what FortisBC is seeking approval of as part of the CPCN as components of the larger project are not currently needed to respond to a gas supply outage. As the next step in this process, FortisBC is anticipating submission of the Detailed Project Description in mid-May 2021 and will continue to engage with [redacted] to discuss comments and feedback throughout the environmental assessment.

16705 Fraser Highway
Surrey, B.C. V3L 5R7
Fortisbc.com

FortisBC has and will continue to synchronize consultation activities for both projects in order to ensure engagement is robust, efficient and transparent, including participating in more open houses, giving the opportunity for our customers and the community to learn more about the project, ask questions and provide feedback.

If you have any questions regarding the Tilbury Project or the BCUC process, please contact me at [redacted], or by phone at [redacted].

Sincerely,

H. Robinsmith

Hailey Robinsmith
Indigenous Relations Liaison
FortisBC

Attachment 62.1

Appendix Q-7: Open House Questions and Comments (*Corrected Version*)

Questions & Comments from Virtual Open House – June 18, 2020	
1	Wanted to know how many people are calling in on real time
2	How does FortisBC reconcile building new fossil fuel infrastructure in a climate emergency?
3	The 2018 IPCC report states that natural gas can only increase production if it is coupled with carbon capture and storage. What is FortisBC planning to ensure this project is net zero by 2050?
4	How is mining, pipelining and selling to customers 5 million tonnes of liquefied fracked gas (which will, when burned, produce at least 14 million tonnes of GHGs- over 100% of BC's 2050 Clean BC target for the whole province) in any way consistent with FortisBC's "30by30" plan to reduce customer emissions 30% by 2030?
5	The lack of transparency in this public engagement process is concerning. We do not trust that people that are writing supportive comments for LNG projects like this are real. We believe they may be paid by FortisBC to influence the "optics" of support for this project.
6	Skype is not a good platform for hosting this kind of event. This is not meaningful public engagement.
7	We do not support LNG projects in BC. FortisBC is not reconciling building new projects with climate in a responsible way.
8	What is the estimated vessel traffic during operations for both marine fueling and overseas export? The initial project assessment discusses vessel traffic for construction, but not operations.
9	Currently, the spot price of LNG in a glutted Asian market is around US $2.10 (averaging less than $6 over the past 5 years), while, according to the Canadian Energy Research Institute (CERI), the full cost of BC-produced LNG is over US $8 (both per million British Thermal Units (mmBTU)). How does Fortis plan to profit from this dismal scene?
10	Turning LNG tankers (which can only be filled on one side of the vessel) and barges in a busy, narrow river channel will be problematic. SIGTTO recommends a turning circle of at least 5 times the ship's length (about 1,500m. for a full-sized LNG tanker). How will that be possible in the narrow, busy Fraser navigation channel?
11	Will the Tilbury project incorporate any carbon capture and storage technology?
12	Currently, the spot price of LNG in a glutted Asian market is around US $2.10 (averaging less than $6 over the past 5 years), while, according to the Canadian Energy Research Institute (CERI), the full cost of BC-produced LNG is over US $8 (both per million British Thermal Units (mmBTU)). How does Fortis plan to profit from this dismal scene?
13	How is the Tilbury LNG Phase 2 project connected to the WesPac Marine Jetty Project? Will this project utilize the marine shipping assessment from WesPac's Marine Jetty project or conduct its own marine shipping assessment?
14	Burning 5 million tonnes of LNG will produce at least 14 million tonnes of GHGs. That is more than 100% of BC's legislated 2050 Clean BC target for the whole province. How can this be aligned with the objectives of "CleanBC"?
15	You should also know that the audio quality is very poor, and is cutting out often.
16	FortisBC is a regulated utility whose charges to Customers are based on recovering its expenses for service. Building a 5 megatonne LNG plant will cost in excess of $5 Billion. Won't financing for this come out of our (i.e. customers') pockets and raise our heating and food preparation costs through the roof (as happened with Australian LNG developments, which tripled gas bills for locals)?
17	How does FortisBC plan to get the gas from N.E. BC to Delta? (Enbridge's Spectra pipeline does

	not have the capacity to supply a domestic market with the 5 MTPA volume needed for Tilbury LNG). Does FortisBC plan to expand Spectra, build a new pipeline, or utilize the (leaky, 66-year old) 24" Trans Mountain line if/when the new 36" dilbit pipeline is operational?
18	Why not move away from fossil fuel entirely for our future
19	Recognizing that the production of natural gas will have a carbon impact here in BC, what is the potential global net reduction of carbon gas emissions as a result of moving our global neighbours off of coal and on to LNG instead?
20	Outline the risks of locating an LNG plant in the area of the Lower Mainland most impacted by a significant seismic event. Japanese LNG import facilities, post-Fukishima, are required to sink their storage tanks so their tops are at ground level – why are Tilbury's overground and lacking any secondary containment?
21	Continuing to burn fossil fuels as a solution to climate change is insane!
22	We support LNG projects in BC.
23	Burning 5 million tonnes of LNG will produce at least 14 million tonnes of GHGs. That is more than 100% of BC's legislated 2050 Clean BC target for the whole province. How can this be aligned with the objectives of "CleanBC"?
24	FortisBC gives LNG bunkering of ships in Port of Vancouver as a justification for this multi-million tonne expansion. But- the PoV's 2017 LNG bunkering report predicts an optimistic bas- case bunkering demand of just 129,000 tonnes by 2035, and an PoV owner's survey demand of just 43,000 tonnes, also by 2035. Can you explain these demand discrepancies?
25	FortisBC 30by30 target: Your IPD suggests that you are counting, toward that target, GHG reductions achieved by Asian Customers substituting LNG for coal in electricity generation plants. How do you know that will happen; how to do you propose BC validates it; and how would those Asian customers be FortisBC's (i.e. not WesPac's or a third-party marketer's)?
26	Will upgrades be required to the current infrastructure leading to Tilbury?
27	We support LNG in BC and believe that the show stoppers in this discussion are paid by non Canadian factors to sabotage projects in Canada the economy of Canada.
28	We support LNG projects in BC. FortisBC is doing a great job in reconciling building new projects with climate in a responsible way.
29	You have talked about natural gas being cleaner to burn than oil and gas. Could you acknowledge the hugely damaging impacts of fracking for the gas.
30	Describe the public liability insurance arrangements for the LNG carriers /barges which will pass close by heavily-populated areas of Richmond and Delta? (we appreciate that most vessels carry cargo and hull insurance – this is about the public liability coverages, where there is no in-force international insurance agreement for LNG such as exists for oil spills).
31	If there will be no vessel traffic during operations of Phase 2, then why does the project description state there will be increased liquefaction capacity for overseas export?
32	Is the planned expansion for export or domestic use? How will it compete with the LNG Canada? Or Woodfibre LNG?
33	Trust you are taking care of safe connections of big gas pipelines? If it explodes, will it impact us at Richmond area?
34	I am a contractor, how can I get some business from this opportunity? Whom should I contact and what is the process?
35	Will it be possible to minimize light pollution from the facility at night?
36	Is there opportunity to enhance shoreline vegetation and foreshore fish habitat at the site? Are offsite enhancement projects being considered as mitigation?
37	Audio is understandable but somewhat distorted. Might help if presenters speak a little slower.

38	Describe the public liability insurance arrangements for the LNG carriers /barges which will pass close by heavily-populated areas of Richmond and Delta? (we appreciate that most vessels carry cargo and hull insurance – this is about the public liability coverages, where there is no in-force international insurance agreement for LNG such as exists for oil spills).
39	Will there be local job opportunities?
40	Will Messy Tunnel be removed as told by previous government?
41	Is there evidence that China would prefer to use LNG or is open to switching to it? Would mean job loss for them.
42	Is the existing pipeline enough in size or will there be a new pipeline? This project is in high urban spaces.
43	LNG IS NOT a simple “coal out, natural gas in” process -it does not "replace" fossil fuel

Questions & Comments from Virtual Open House – June 23, 2020	
1	Not a question, just wanted to thank you for your presentations and say that Tilbury has operated safely for many years and that this expansion represents a great opportunity for BC. It's clear that it is being held to the highest regulatory standards and will be an important contributor in a world where we are recovering from the COVID 19 crisis.
2	Thank you for the presentation. What specific efforts will been put into staff training?
3	Will the climate test that is part of federal assessment include upstream emissions from fracking?
4	FortisBC’s proposal is silent on the local public benefits of this LNG development (to date, the BC-LNG industry has contributed not a dime in public benefits). Please detail the local socio-economic benefits of this project?
5	How will you consider the Clean B.C. targets for carbon emissions and how the carbon emissions built into the decades of operation of this project will impact those targets?
6	Tilbury Pacific LNG Jetty is a proposed jetty (nearing the end of its EA) that will exist only to support the Tilbury LNG Phase 2 Expansion (which is just starting its EA). It seems that if the jetty is approved, then Tilbury Phase 2 LNG Expansion must be approved as to not render the jetty useless. How will the EA for Tilbury LNG Phase 2 Expansion consider the outcome of Tilbury Pacific LNG Jetty? Why has the EAO/Agency allowed for these two projects to be split and submitted at different times, as opposed to being submitted at the same time to allow for a full review of cumulative effects?
7	How does FortisBC plan to get the gas from N.E. BC to Delta? (Enbridge’s Spectra pipeline does not have the capacity to supply a domestic market with the 5 MTPA volume needed for Tilbury LNG). Does FortisBC plan to expand Spectra, build a new pipeline, or utilize the (leaky, 66-year old) 24” Trans Mountain line if/when the new 36" dilbit pipeline is operational?
8	How is mining, pipelining and selling to customers 5 million tonnes of liquefied fracked gas (which will, when burned, produce at least 14 million tonnes of GHGs- over 100% of BC’s 2050 Clean BC target for the whole province) in any way consistent with FortisBC’s “30by30” plan to reduce customer emissions 30% by 2030?
9	The site is only ~ 1 metre above current sea-level. Won't flooding due to sea-level rise (caused in part by GHGs emanating from burning LNG) be an issue?
10	LNG is classified as a HNS (Hazardous and Noxious substance) cargo rated second only to explosives as a shipping risk by the International Maritime organization (IMO). Prone to equipment malfunction and human caused accidents and terrorist actions, how does FortisBC plan to eliminate such risks with this project?

11	Seems that Indigenous Nations are required to say yay/nay on a Project within 90 days of the start (Early Engagement) of a project. That seems awfully short/rushed, when the details of the mitigation needs and actions have not yet been defined, let alone agreed.
12	There have been many instances of earthquakes caused by hydraulic fracturing and deep-well injection of waste in Canada. Please outline the risks of locating an LNG plant in the area of the Lower Mainland that would be most impacted by a significant seismic event. Japanese LNG import facilities, post-Fukishima, are required to sink their storage tanks so their tops are at ground level – why are Tilbury's tanks over ground and lacking any secondary containment?
13	Radioactivity levels in the gas: What assurances can you give that the fracked gas is not contaminated with excessive levels of radioactive substances (especially radon)?
14	I am concerned about investing in continued fossil fuel infrastructure, when it is clear, that around the world, we should be moving onto renewables. How does this fit into Canada's goals of lowering carbon emissions?
15	Fighting a fire at a LNG facility on a waterway (opposite a jet-fuel terminal and near fire-prone Burns Bog, where a fire three Summers ago triggered the complete evacuation of Tilbury Island) requires special equipment, such as foam retardant and fire-boats, of which Richmond and Delta have neither. Will Fortis be compensating these Councils for the expense of providing publicly-funded emergency response and security capabilities?
16	Both industry-group SIGTTO (Society of International Gas Tanker and Terminal Operators) and U.S. DHS Regulations strongly argue against locating LNG plants near human populations and/or in narrow inland waterways with significant aircraft, ferry, freighter and recreational traffic. This is a good description of the Tilbury site. Why would you choose to deny the good sense and experience of these regulatory bodies?
17	All LNG plants have tall flares to burn boil-off gases and the impurities in the feed gas. What will/would Tilbury have and how tall would the flare stack, the flame be?
18	Will there be local job opportunities on the project?
19	The creation of this project will de facto create more shipping (that's the goal!) Will the government be able to consider this increase in shipping with this project, or must it remain separate to the actual terminal expansion?
20	Has consultation with Indigenous Nations already commenced? With what Nations?
21	The Japanese (who have long experience of earthquakes and are the world's biggest LNG importers) bury their LNG storage tanks so spills or ruptures can't go far. In a seismic zone as prone to liquefaction as Richmond/Delta, why are FortisBC's storage tanks over ground?
22	Turning LNG tankers (which can only be filled on one side of the vessel) and barges in a busy, narrow river channel will be problematic. SIGTTO recommends a turning circle of at least 5 times the ship's length (about 1,500m. for a full-sized LNG tanker). How will that be possible in the narrow, busy Fraser navigation channel?
23	FortisBC is a regulated utility whose charges to Customers are based on recovering its expenses for service. Building a 5 megatonne LNG plant will cost in excess of $5 Billion. Won't financing for this come out of our (i.e. customers') pockets and raise our heating and food preparation costs through the roof (as happened with Australian LNG developments, which tripled gas bills for locals)?
24	Describe the public liability insurance arrangements for the LNG carriers /barges which will pass close by heavily-populated areas of Richmond and Delta? (we appreciate that most vessels carry cargo and hull insurance – this is about the public liability coverages, where there is no in-force international insurance agreement for LNG such as exists for oil spills).
25	Your Phase 1 expansion was built by Bechtel, a U.S. firm. Do you plan to use local suppliers for the

	site prep., Liquefaction/compression build stages?
26	The Fraser is a flyway for migrating birds. Several years ago, Canada's only LNG import facility (Canaport in N.B., then owned by Irving Oil), fried several thousand songbirds when they flew into the plant's flare in a fog. How will your flare avoid this?
27	FortisBC does not have a CER Export license (WesPAc Midstream does). So - who would sell the gas to foreign buyers, and who would collect any offset credits (if and when the Canadian and Asian Governments approve and agree such trading)?
28	Who is represented on the Community Advisory Committee for this project?
29	GHGs, other air pollutants: What air and water emissions will the plant produce (quantity, frequency, toxicity)?
30	Why has the BC EAO allowed the proponents to assess the Jetty and the associated impacts of marine shipping separate from the rest of this project?
31	For safety reasons, LNG plants need redundant power inputs. Will BC Hydro need to build more power pylons across Delta farmland to the plant?
32	Burning 5 million tonnes of LNG will produce at least 14 million tonnes of GHGs. That is more than 100% of BC's legislated 2050 Clean BC target for the whole province. How can this be aligned with the objectives of "CleanBC"?
33	There are considerable health effects to the increased use of LNG (health impacts of climate change etc.) Will these be considered?
34	Why is there no linkage of this Project to the Tilbury LNG Marine Terminal Project currently undergoing an Environmental Assessment? This Project, when combined with the marine terminal will have a far greater impact than presented.
35	What are the mitigation plans for the impacts on riparian, water, systems?
36	You say don't mention export as an objective of your project but your partner Wespac has an export permit for the full 3.5 million tonnes per annum. Why are you down playing the role the LNG export plays in this project?
37	You are counting LNG exports in the 30by30 plan. But - agreement on international trading of carbon offsets (Article 6 of COP21 in Paris) has not been agreed or ratified by any country. Since when has FortisBC had the authority to conclude what Canada has not?
38	Currently, the spot price of LNG in a glutted Asian market is around US $2.10 (averaging less than $6 over the past 5 years), while, according to the Canadian Energy Research Institute (CERI), the full cost of BC-produced LNG is over US $8 (both per million British Thermal Units (mmBTU)). How does Fortis plan to profit from this dismal scene?
39	What parameters does IAAC use in evaluating whether / not to allow a substitution?
40	Flare(s): All LNG plants have tall flares to burn boil-off gases and the impurities in the feed gas. What will/would Tilbury have and how tall would the flare stack, the flame be

Attachment 63.1

PATHWAYS FOR BRITISH COLUMBIA TO ACHIEVE ITS GHG REDUCTION GOALS

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NAVIGANT
A Guidehouse Company

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FORTIS BC™
Energy at work

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FOREWORD

In 2018, FortisBC Energy Inc. (FortisBC) developed its Clean Growth Pathway to 2050, which outlined actions the company would take to help British Columbia (BC) achieve its greenhouse gas (GHG) emissions targets. The Clean Growth Pathway takes a diversified approach to GHG reduction by using BC's electricity and gas infrastructure. As owners and operators of reliable gas, electric, and thermal energy infrastructure, FortisBC will have a key role in leading the transition to lower carbon energy. As a regulated utility, FortisBC is accountable to the BC Utilities Commission and obligated to serve the interests of over 1 million homes and businesses across BC.

The provincial government's CleanBC plan aims to significantly reduce provincial GHG emissions and strengthen BC's economy. FortisBC delivers more energy to consumers than any other entity in the province and will be critical to ensuring BC can efficiently, reliably, and affordably achieve its plan. To help do so, FortisBC commissioned Guidehouse to chart a viable path for BC to achieve its 2050 targets while identifying solutions that are in the best interest of its customers.

FortisBC and Guidehouse worked with the BC Ministry of Energy, Mines and Petroleum Resources and the Climate Action Secretariat to ensure that CleanBC, provincial data, and projects are included in the analysis as much possible.

The goal of this report is to generate dialogue and solutions-focused thinking on how BC can achieve the transition to a lower carbon energy system while building understanding on factors such as maintaining a flexible, reliable, and resilient provincewide energy system. The report's analysis presents two pathways to achieving GHG emission reductions; neither reflect what is an expected future outcome by either Guidehouse or FortisBC. FortisBC welcomes an ongoing discussion on the merits and key challenges of the various pathways available. FortisBC has a long-standing role in serving British Columbians and, by engaging with the communities it serves, the company aims to continue providing low carbon, affordable, and reliable energy in the decades to come.

Guidehouse is a leading global provider of consulting services to the public and commercial markets with broad capabilities in management, technology, and risk consulting. We help clients address their toughest challenges with a focus on markets and clients facing transformational change, technology-driven innovation, and significant regulatory pressure. Across a range of advisory, consulting, outsourcing, and technology/analytics services, our teams help clients create scalable, innovative solutions that prepare them for future growth and success. Headquartered in Washington, DC, the company has more than 7,000 professionals in more than 50 locations. Guidehouse recently completed the Gas Decarbonisation Pathway 2020-2050 study for the Gas for Climate consortium; the study analyzes the transition toward the lowest cost climate-neutral system in Europe by 2050.

1. EXECUTIVE SUMMARY

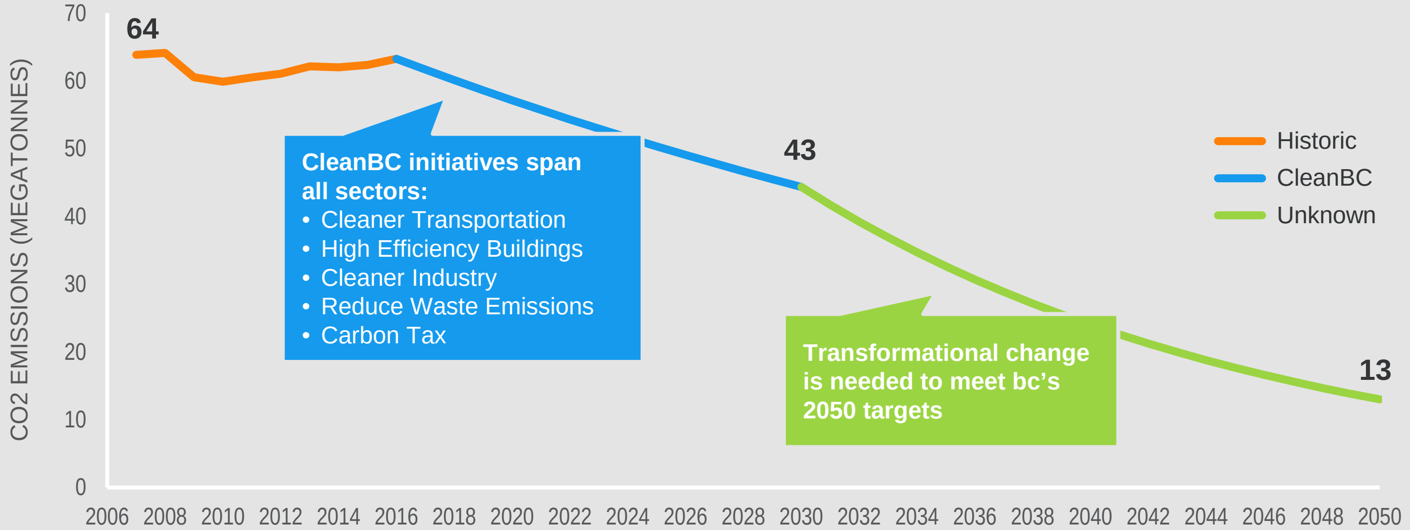
As part of its Climate Change Accountability Act, British Columbia (BC) has committed to reducing greenhouse gas (GHG) emissions to 80% below 2007 levels by 2050. The CleanBC plan puts the province on a path toward this goal, but only sets in action initiatives designed to meet a 2030 target (30% reduction below 2007 levels).[1] The pathway to meeting the 2050 goal is definable but a challenge. (Figure 1).

FortisBC commissioned Guidehouse to explore the role of the company's energy delivery system and the advantages that system could provide under ambitious decarbonization in the province. Over the past several years, Guidehouse has conducted detailed analyses of the role of utilities in decarbonization in Europe and North America.

Guidehouse experts have consistently found that a moderate, targeted approach to electrification tied with deployment of renewable gases while fuel switching away from petroleum is the most cost-effective and resilient method to achieve a lower carbon energy future.

To estimate the gas system's societal value, Guidehouse developed two energy pathways: an Electrification Pathway that focuses on deep electrification of all sectors, and a Diversified Pathway that includes a mix of expanded electrification and advances in low carbon gases and gas delivery infrastructure. The Diversified Pathway reflects the climate initiatives included in FortisBC's Clean Growth Pathway to 2050.

FIGURE 1. BC GHG EMISSIONS AND TARGETS



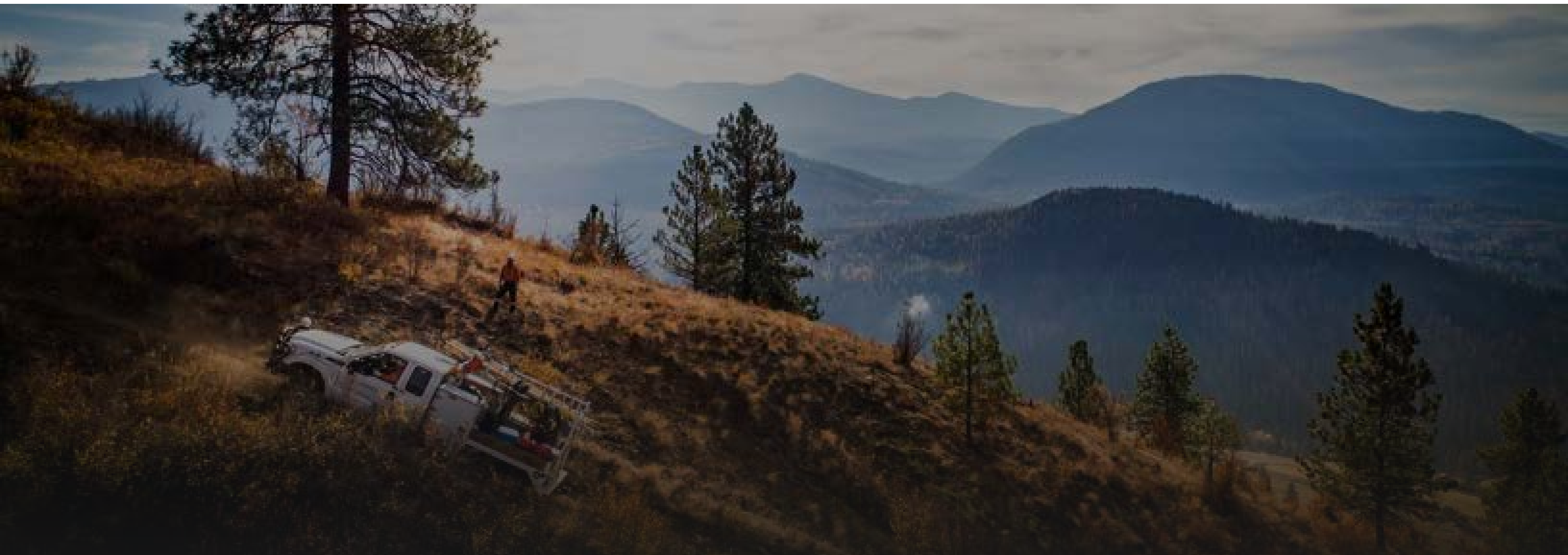
Source: Government of Canada – Canada's Greenhouse Gas Inventory; Government of British Columbia – CleanBC; Guidehouse Analysis

[1] The 30% reduction represents an adjustment of the interim 40% reduction by 2030 target, originally set in the Climate Change Accountability Act. The adjustment aligns with the provincial government's CleanBC plan, while the 80% reduction by 2050 target set in the Climate Change Accountability Act still stands.

The study's core conclusions are as follows:

- The Electrification and Diversified Pathways both achieve significant domestic GHG reductions in-line with the provincial government's 2050 targets.[2]
- The Diversified Pathway uses gas infrastructure and saves in excess of $100 billion by 2050.
- Both scenarios face challenges, including massive energy infrastructure deployment, and require significant technological improvement.
- Peak demand is an important factor that needs to be considered.
  - The Diversified Pathway will more efficiently meet customers' peak energy use.
- Peak demand in the Electrification Pathway would require thousands of megawatts of firm renewable electricity generation and energy storage to be built, which is made more difficult by the challenges of developing new large-scale hydroelectric power stations.

- Policy decisions made today will have long-term implications beyond the 2030 time horizon of CleanBC. Consequently, BC's approach to climate policy should consider how factors like peak demand will be met well beyond 2030 and what the long-term implications will be for costs.
- Hydrogen can be a key low or no carbon fuel that can be injected into the existing gas system. Hydrogen produced from renewable electricity can be stored in the gas system for use in peak times, which helps increase the value of renewable electricity in decarbonization pathways.
- The gas system provides valuable reliability and resiliency to the province's energy system. As decarbonization progresses, this resiliency increases in importance. As the gas system grows into serving new markets where decarbonization is more difficult, the system will be relied on as a fundamental tool. For example, liquefied natural gas (LNG) for international marine vessels is one of the primary near-term options to make meaningful GHG reductions.

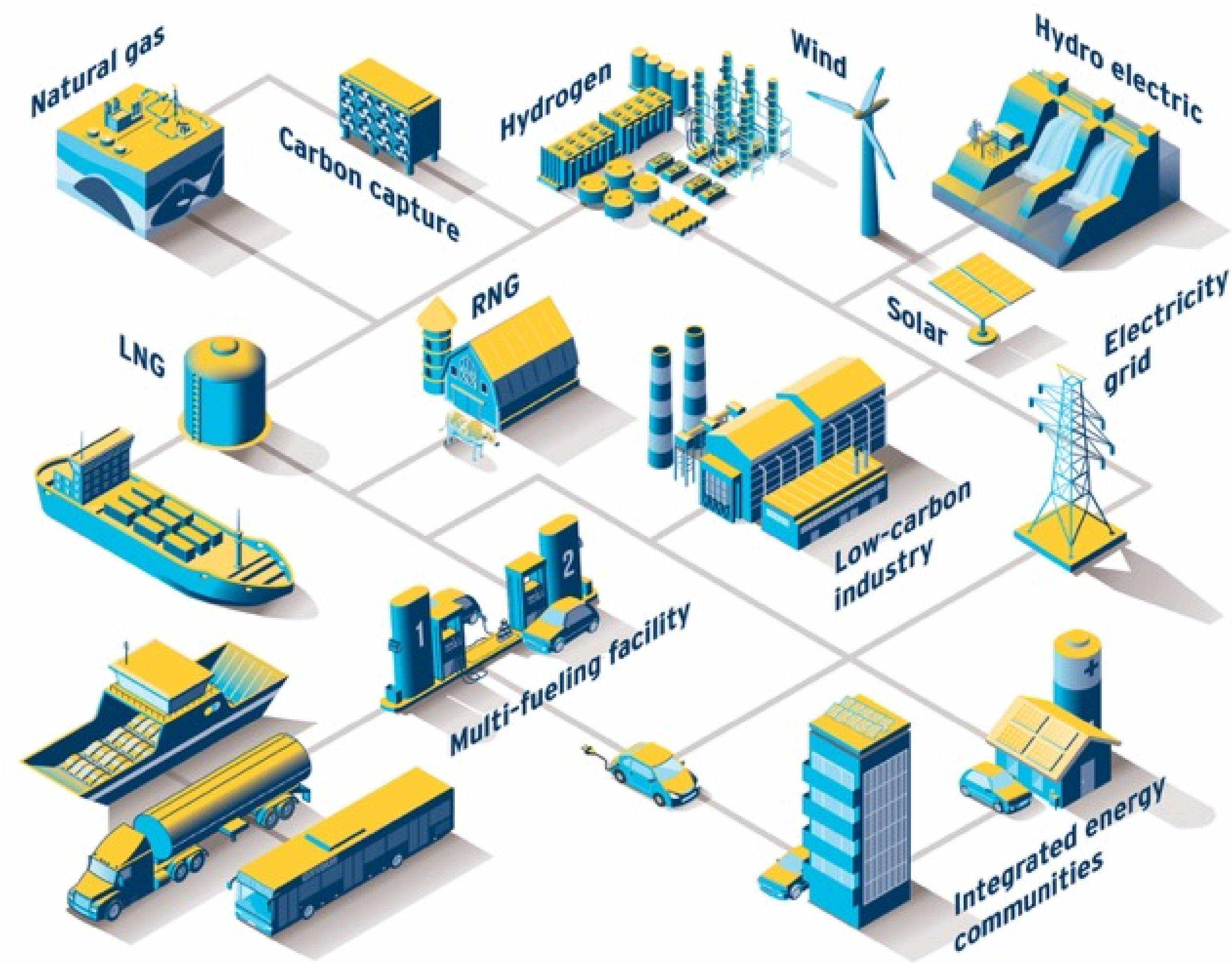


[2] Both pathways developed in this study achieve 95% of the domestic reductions required by 2050.

FortisBC's Clean Growth Pathway to 2050 is a diversified and flexible approach that supports BC's energy needs and GHG reduction targets. In 2050, gas infrastructure transports renewable natural gas (RNG), low carbon hydrogen (largely made from renewable electricity), and synthetic methane developed from captured carbon and hydrogen as well as natural gas. The system delivers this low carbon energy for specific end uses with high energy needs: space and water heating, medium and heavy duty (MHD) road vehicles, marine transportation, and industrial processes (Figure 2).

The Clean Growth Pathway also supports targeted electrification. Excess renewable power that would otherwise be curtailed or stored using expensive applications such as batteries or mechanical storage could instead produce hydrogen for use in the gas system.[3] In addition to providing flexible peak capacity, gas systems are key in stabilizing and securing the power grid, underpinning firm dispatchable electricity capacity and providing longer duration and affordable energy storage. Furthermore, Guidehouse's Gas for Climate study[4] demonstrates that deploying gas-fired dispatchable power (hydrogen and biomethane) as compared to more expensive solid biomass-fired dispatchable power can lead to annual cost savings of €54 billion across Europe.

FIGURE 2. FORTISBC'S CLEAN GROWTH NETWORK TO 2050



[3] It is unlikely that battery storage alone will be sufficient to meet the energy storage needs of the Electrification Pathway.

[4] Guidehouse, *Gas Decarbonisation Pathways 2020–2050*, April 2020, https://gasforclimate2050.eu/?smd_process_download=1&download_id=339.

POLICY IMPLICATIONS

To moderate costs, reduce risks, enhance GHG reduction options, and maintain a reliable provincial energy system while achieving the 2050 goal, a number of outcomes need to be pursued:

- **Policy should be focused on fostering an integrated low carbon energy system.** It is critical to acknowledge that electricity and gas complement each other—both are needed and can reinforce each other. Taking a systemwide view of energy infrastructure that recognizes the value and coordinates the gas and electric systems to manage decarbonization affordability and resiliency provides the greatest overall benefits for BC.
- **Focus electrification efforts where they are most effective** to maximize limited ability to expand clean and firm generation resources. For example, in the passenger transport sector.
- **Prioritize the expansion and supply of renewable gas through a coordinated strategy** that invests in research and development (R&D), addresses policy barriers, and offers incentives for renewable gas development.
- **Support new technologies** that leverage the GHG reduction potential of the gas system including gas heat pumps, compressed natural gas (CNG)- and LNG-powered commercial vehicles, and carbon capture and storage.
- **Maintain the operational and financial health of the gas system** to allow for continued investment in infrastructure and programs that align with the 2050 target.
- **Leverage the potential of the gas sector to reduce GHG emissions internationally** through LNG marine refuelling (referred to as bunkering) and LNG exports.
- **Consider the cost and source of energy post-2030** in current and ongoing policy decisions.

2. INTRODUCTION

This report discusses potential pathways for BC to achieve its 2050 GHG reduction target, focusing on the roles of the gas and electric systems in the province. The report takes a BC-specific view of decarbonization considering the province's unique energy systems and resources. The objective is to discuss the tradeoffs of different approaches and to emphasize important points to consider when embarking on a long-term decarbonization pathway. The report is organized into the following sections:

- **BC's Energy Systems:** Focuses on the roles of energy delivery infrastructure and key operational and practical considerations.
- **Study Approach:** Describes the methodology used to analyze decarbonization pathways for BC. This section also outlines the main differences between the pathways and the key inputs and assumptions that went into the analysis.
- **Study Results – Side-by-Side Comparison of Pathways:** Compares the outcomes of the analysis, pathways, and key considerations.
- **Other Benefits of Using the Gas System for Decarbonization:** Discusses other benefits, in addition to results from the analysis of decarbonization pathways, that emphasize the importance of the gas delivery system.
- **Conclusions:** Provides general conclusions of the study.

3. BC'S ENERGY SYSTEMS

BC has an expansive energy system that includes the following:

- A large electrical grid primarily administered by BC Hydro and FortisBC electric
- A gas system operated primarily by FortisBC gas and Pacific Northern Gas
- Vast amounts of renewable electric and natural gas resources

BC has a large supply of biomass that could be used to sustainably produce renewable energy such as RNG. BC is connected to the US and other Canadian provinces and territories through electric interties and natural gas pipelines.

BC'S NATURAL GAS AND ELECTRIC SYSTEMS TODAY

FortisBC operates approximately 49,000 km of natural gas transmission and distribution pipelines in BC.

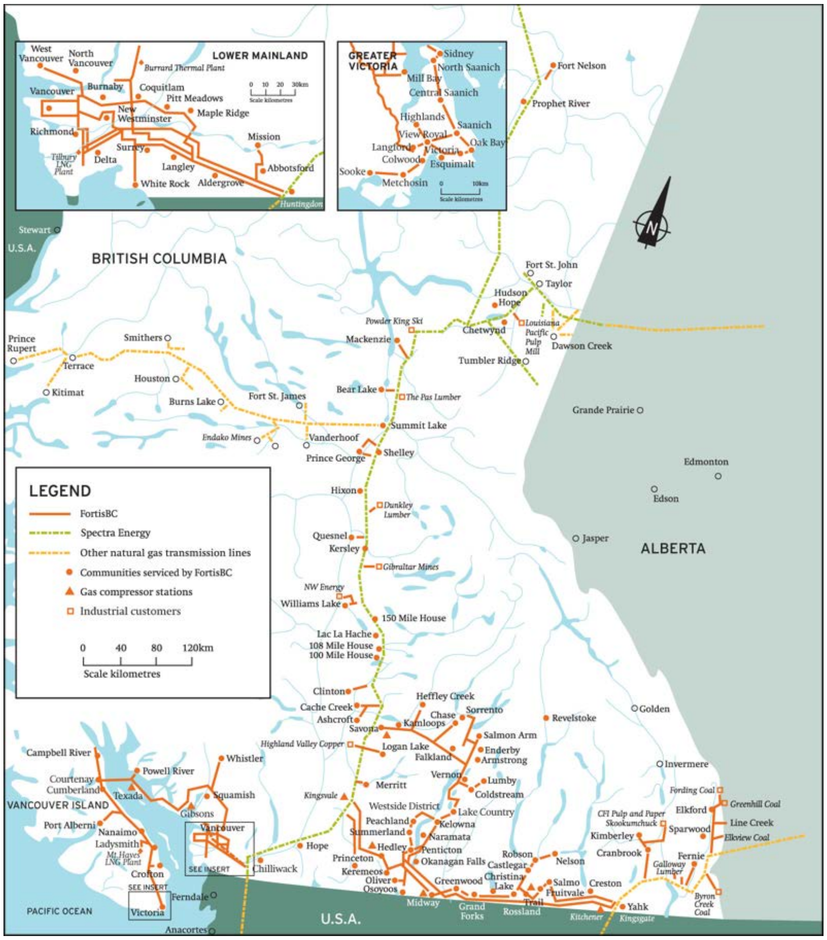
This infrastructure, along with the natural gas pipelines owned by Pacific Northern Gas, TC Energy, Enbridge, and other organizations, spans across the province. The system has multiple import/export points on the borders between Alberta, Yukon, and the US, as well as LNG on the west coast. All of this infrastructure is part of an integrated provincial system that represents billions of dollars of investment to supply natural gas to domestic markets and for export.

BC depends on energy delivered by the natural gas system (Figure 4). Over 30% of BC's total energy consumption[5] is transported through gas infrastructure.[6] Natural gas represents approximately 50% of residential and commercial end-use demand and almost 40% of industrial end-use demand in BC. The extensive coverage and interconnectivity of the gas network makes the system a critical vehicle to deliver low carbon energy to British Columbians.

BC also has an expansive electric system primarily administered by BC Hydro and FortisBC.

[5] Includes upstream energy consumption
[6] Canada Energy Regulator, "Canada's Energy Future 2019: Energy Supply and Demand Projections to 2040, Macro Indicators," accessed March 2, 2020.

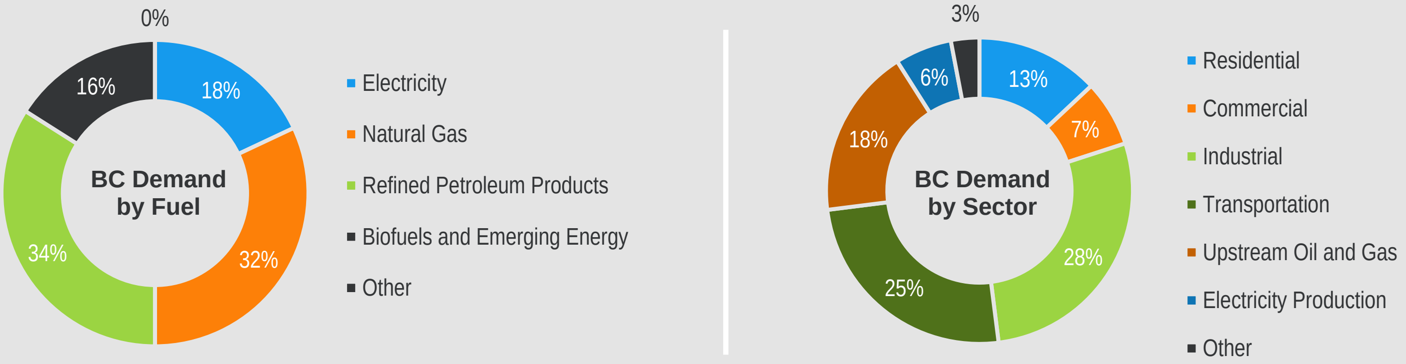
FIGURE 3. NATURAL GAS INFRASTRUCTURE SERVING BC



Combined, the two utilities serve over 2.16 million electricity customers through over 86,000 km of electric transmission and distribution lines. BC's electricity system is part of the Northwest Power Pool and is connected to Alberta and the US. Approximately 90% of BC's electric capacity is made up of hydro, with the remainder from wind, other renewables, and natural gas for peak electricity supply.

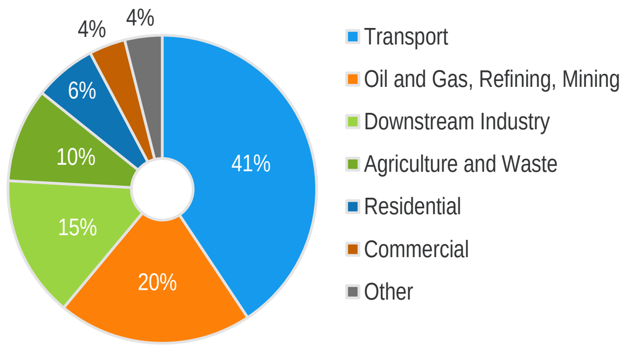
BC has large domestic resources of natural gas and electricity. In 2018, net electricity imports made up 2% of domestic generation. Over 90% of the natural gas consumed in BC is produced in BC (remaining supply is imported from Alberta). However, BC's total natural gas production is greater than its domestic demand and is exported to Alberta or the US. BC relies on deliveries from other provinces and from imports from the US for refined petroleum products like gasoline and diesel. BC imports almost double the volume of gasoline and diesel from Alberta and the US then it refines in domestic refineries.

FIGURE 4. BC 2019 ENERGY DEMAND



Source: Canada Energy Regulator – Canada's Energy Future 2019 and CanESS (CANSIM)

FIGURE 5. BC EMISSIONS BY SECTOR



Source: BC GHG Inventory

The transport sector has the largest emissions footprint in BC, consisting of 41% of all GHG emissions (Figure 5). Industry, including oil & gas extraction and downstream manufacturing, makes up 35% of provincial GHG emissions. Residential and commercial buildings make up a comparatively smaller 10% of provincial GHG emissions.

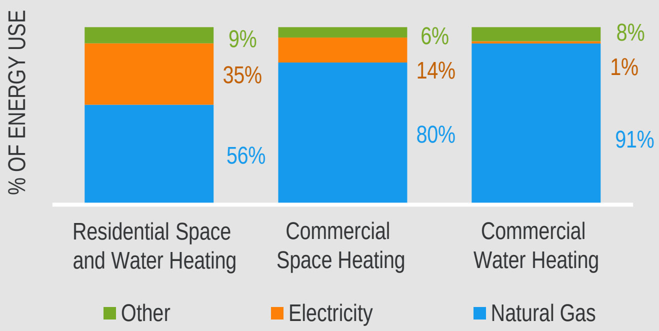
A focus on reduction of emissions across all sectors will be required to achieve the reductions targeted by 2050. Given the significant emissions associated with the transportation and industrial sectors, substantial efforts will be required in these sectors.

GAS SYSTEM IN BC ALLOWS FOR FLEXIBLE SUPPLY, SECURITY, AND STORAGE

Natural gas is one of the most flexible forms of energy because it can be stored relatively inexpensively for long periods of time. This flexibility allows the gas system to deal with large fluctuations in demand and volume, which is common in BC due to the seasonal nature of space and process heating loads in the province.

Most residential and commercial energy customers in BC depend on natural gas for space and water heating as well as cooking (Figure 6). Natural gas is also well-suited for combustion for heat. Many industries rely on natural gas because they can handle the high temperatures used in industrial applications. As well, natural gas use as a transport fuel for commercial vehicles and marine vessels is growing.

FIGURE 6. BC SPACE AND WATER HEATING BY SOURCE, 2016



Natural gas demand peaks in the winter and declines in the summer. Demand can be handled by the existing gas system seasonally. Figure 7 highlights the gas system's role in meeting peaks—i.e., the coldest days of the year.[7] On a summer day, throughput is approximately 3,000 MW, representing mostly water heating and industrial energy consumption. On an average winter day when most homes are using their gas heating systems, throughput on the system can increase by over three times and approaches the equivalent of 10,000 MW in electrical terms.

The gas system is designed to deliver significant volumes of energy to meet demand on very cold days. For example, on the coldest day in 2019, the volume of gas delivered was 40% higher than an average winter day and over three times the energy delivered on a summer day.

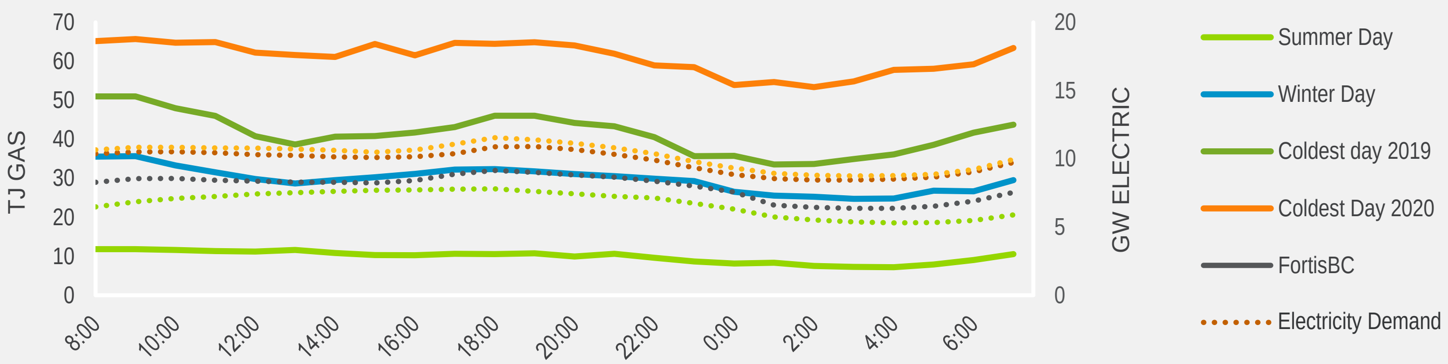
On a very cold day, such as January 14, 2020 when temperatures in the Lower Mainland approached -10°C, the energy delivered by the gas system can be double an average winter day and 50% higher than the coldest day in 2019.

The gas system provides critical versatility to meet peak energy demand. The electricity system needs to generate enough electrical energy at any one time to match the amount of consumption, whereas the gas system can store the energy and regulate flow on the system to meet demand. This means that electric systems need to have enough generating capacity to meet peaks while the gas system needs enough storage and pipeline throughput.

On January 14, 2020, the peak volume of gas delivered between 7:00 a.m. and 8:00 a.m. was equivalent to over 18,000 MW of electrical generating capacity, approximately 60% greater than the peak on the electric system during the same day and 50% larger than the entire hydroelectric generating capacity owned by BC Hydro (11,900 MW). While January 14, 2020 was one of the highest demand days on the gas system, some capacity remained to be distributed if demand continued to increase.

One of the gas system's main strengths is its ability to meet extreme peaks. It can store, ramp up, and deliver high volumes of energy on short notice and can handle large changes in volumes over time without operational, reliability, or financial strain. The electricity system would require significant investment to meet the province's space and water heating needs seasonally and daily in the electrification scenario.

FIGURE 7. HOURLY GAS AND ELECTRICITY DEMAND IN BC



Source: FortisBC

[7] Figure 7 represents actual natural gas flows in FortisBC's service territory. Electricity demand is gross telemetered load on BC's electricity transmission system.

The ability of natural gas to be stored adds to its value as a reliable energy source. FortisBC's affiliate, Aitken Creek Gas Storage, owns a large underground natural gas storage facility, which has over 90 PJ of gas storage to provide seasonal storage.[8] Gas storage is low cost—on average, the cost of storage at Aitken Creek is approximately $1 per GJ or 0.3 cents ($0.003) per kilowatt-hour in electricity storage equivalent.

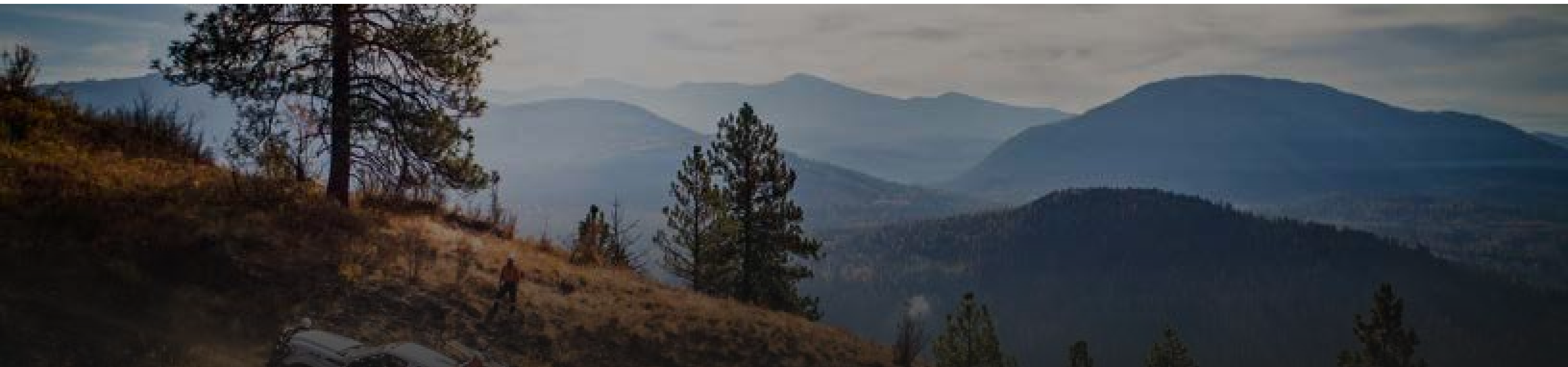
Although electric storage costs are falling significantly, they are still much more costly between $50 and $90 per GJ equivalent comparatively.[9] In addition to Aitken Creek, several smaller natural gas storage facilities exist throughout BC. Natural gas is injected into seasonal storage in summer months when demand is low and is withdrawn in the winter when demand for natural gas is higher. Low cost gas storage allows for year-round gas production and for production to deviate from gas consumption. Storage more effectively manages the costs of gas production and disruptions in production when they occur.

Gas can also be stored in the transmission pipelines themselves—typically referred to as line pack. Transmission pipelines operate within a minimum and maximum pressure as determined by the volume of gas in the line. Line pack can allow segments of the gas line, for short periods in a day, to deliver more gas per hour to consumers than is being delivered per hour by suppliers.

Line pack poses small incremental costs and can be cycled, meaning it can be maintained or used with relative ease. The estimated seasonal variation in line pack of FortisBC's transmission pipelines between a period of high demand and low demand can be as high as 0.15 PJ. In electrical terms, this would be equivalent to 40 GWh—over 30 times larger than the entire electrical energy storage capacity of utility-scale batteries in the US in 2018.[10]

Natural gas and the gas delivery system can serve a critical role in extreme conditions. Global climate change has resulted in the increased prevalence of wildfires, which can severely impact electricity systems. California has experienced severe wildfires in recent years, including a 2019 wildfire that resulted in mass evacuations and blackouts, leaving millions of people without electricity.[11] A study by the California gas and electric utilities indicated that Southern California Gas' natural gas storage assets has played a vital role in addressing emergency situations like extreme weather and wildfires.[12]

Over the past 20 years, the average number of hours a customer is without electric power in a year has increased. With the large expected growth in electricity demand, this trend is expected to continue, highlighting the importance of natural gas use as a heating source; its use is especially important during the cold winters experienced in many parts of BC.



[8] Canada Energy Regulator, "Market Snapshot: Where does Canada store natural gas," May 23, 2018, https://www.cer-rec.gc.ca/nrg/ntgrtd/mrkt/snpsht/2018/05-03whrdscncstrngrlgs-eng.html.

[9] Lazard, *Lazard's Levelized Cost of Storage Analysis—Version 5.0*, November 2019, https://www.lazard.com/media/451087/lazards-levelized-cost-of-storage-version-50-vf.pdf.

[10] U.S. Energy Information Administration, "Most utility-scale batteries in the United States are made of lithium-ion," Today in Energy, October 30, 2019, https://www.eia.gov/todayinenergy/detail.php?id=41813.

[11] Newburger, Emma, "More than 2 million people expected to lose power in PG&E blackout as California wildfires rage," CNBC, October 26, 2019, https://www.cnbc.com/2019/10/26/pge-will-shut-off-power-to-940000-customers-in-northern-california-to-reduce-wildfire-risk.html.

[12] California Gas and Electric Utilities, *2018 California Gas Report*, 2018, https://www.socalgas.com/regulatory/documents/cgr/2018_California_Gas_Report.pdf

4. STUDY APPROACH

The Electrification and Diversified Pathways developed in this study achieve 95% of the domestic reductions required by 2050.[13] The remaining emissions are assumed to be addressed with continued advances in technology and changing consumer behaviors, as well as emissions reductions related to non BC-specific initiatives (e.g., commercial airline emissions reductions). The pathways differ in the extent to which renewable electricity and low carbon gas play a role in the scenarios. The Electrification Pathway aims to increase the use of electricity for all applicable end uses, so renewable and low carbon natural gas use is limited to those sectors where no alternatives are available. In the Diversified Pathway, renewable and low carbon natural gas is used to its full potential.

Guidehouse worked closely with FortisBC to characterize initiatives under each pathway that could contribute to reducing GHG emissions. The goal of the characterization was to identify, understand, and define GHG mitigation options relevant for BC and to develop a common understanding of initiatives to implement in the model and analyze deeply. Guidehouse leveraged other studies it conducted on the role of the gas system in decarbonization, as well as FortisBC's internal research group and BC-specific research, to build a set of technologies and initiatives that were characterized and input into the Canadian Energy Systems Simulator (CanESS), an economy-wide model. Guidehouse also used data from the BC Climate Action Secretariat to align modelling assumptions with those used in the CleanBC climate plan. Figure 8 highlights how initiatives were developed across four major sectors and modelled into the two pathways, which were compared to a business-as-usual (BAU) scenario.

FIGURE 8. PATHWAY DEVELOPMENT AND MODELLING

1. GHG MITIGATION INITIATIVES

BUILDING EFFICIENCY
- Improved building envelopes
- Building automation and controls

TRANSPORTATION
- # light duty EVs
- # heavy duty EVs and CNG vehicles
- # trips on E-public transit
- # of CNG buses

2. PATHWAY MODELING

FUEL SWITCHING
- Building heating and cooling
- Floor space serviced by heat pump
- Water heated with heat pump
- Floor space serviced by alternative fuels

RENEWABLE GAS
- Volume of RNG supply
- # of vehicle KMs fueled by RNG
- Litres of ethanol blends

BUSINESS AS USUAL SCENARIO
- Baseline energy demand and economic activity
- LTGRP
- Consensus alterations

COMBINED INITIATIVES SCENARIO SCENARIO
- Baseline energy demand and economic activity
- LTGRP
- Consensus alterations
- Electrification initiatives
- Low Carbon Fuels initiatives

ELECTRIFICATION INITIATIVES SCENARIO
- Baseline energy demand and economic activity
- LTGRP
- Consensus alterations
- Electrification initiatives

Note: LTGRP refers to FortisBC's Long-Term Gas Resource Plan. Source: Guidehouse

[13] This study develops two future scenarios to achieve BC's GHG reduction targets and analyzes the required changes to the energy system and incremental societal cost to the province. The intent of the study was to determine the extent of change required in BC to meet climate reduction targets. The economy-wide energy models used in this exercise are key tools to outline the magnitude of changes required over the coming decades. These models are built from historical data and are extrapolated into the future based on announced policy initiatives, observed historical trends, and other assumptions. As such, the results of this energy modelling engagement are intended to be indicative of possible future scenarios, but they are not intended to be taken as definitive results. Various opportunities for emissions reductions were not included in this analysis, including emissions trading, initiatives targeted at international sectors (e.g., airlines and shipping), etc.

Technologies and initiatives were selected with consideration for how practical and defensible they are. The total societal cost for each pathway was assessed by considering the consumer commodity costs, utility system costs, incremental infrastructure costs, consumer equipment costs, retrofit costs, and government subsidies (Figure 9). The costs of an underutilized gas system were also estimated to reflect additional costs to customers should gas system utilization be meaningfully reduced.

FIGURE 9. PATHWAY TOTAL SOCIETAL COST IMPACTS

ELEMENTS OF TOTAL RATES BUILDUP

Consumer Commodity Costs
- Forecasted global and local commodity prices
- Unit cost ($GJ)
- Total energy consumed by commodity (PJ)

Utility System Costs
- Electric Utility Revenue Requirement
- Gas Utility Revenue Requirement
- Subsidies/ Deferral Accounts
- Normalized by (GJ)

Incremental Infrastructure Costs
- Electric Supply and Capacity Costs
- Electric System Costs
- Natural Gas System Costs
- Transportation Fuel Supply Chain

Utility System Planning Cost Estimates
- IRP System Cost Factors

System Cost Modelling
- Capacity Expansion Modelling
- Powerflow Modelling

System Cost Estimates
- Capacity/ System Needs Analysis
- Assumptions-Based

Based on macro analysis, build up consumer rates with:
- Total wholesale energy and commodity costs
- Utility revenue requirements (inclusive of subsidies and deferrals)
- Estimates of incremental system costs

+

CONSUMER EQUIPMENT INVESTMENT

RETROFIT COSTS

UNDERUTILIZED CAPACITY COSTS

Source: Guidehouse

PATHWAYS

Table 1 shows how Guidehouse modelled the five major initiative categories differently across the two pathways. In general, the Electrification Pathway focused on energy efficiency, fuel switching to electricity for space/water heating, industrial processes, and transportation. The Diversified Pathway focused on energy efficiency, implementation of efficient gas end uses, and the deployment of renewable gas. **The analysis described in this section presents two pathways to achieving GHG emissions reductions. While both are theoretically potential pathways, they are not forecasts of the future.** Guidehouse welcomes an ongoing discussion on the merits and key challenges of various pathways available.

TABLE 1. INITIATIVES BY PATHWAY

Initiative	Electrification Pathway	Diversified Pathway
Electric Peak Demand	Peak demand increases to 21,600 MW in 2050, requiring 8,800 MW of new peak capacity versus the BAU case.	Peak demand increases to 17,700 MW in 2050, requiring 4,900 MW of new peak capacity versus the BAU case.
Renewable Gas	Of end-use natural gas demand, 35% (26 PJ) is served by renewable gas in 2050 (mix of hydrogen and renewable natural gas). Incremental 1.8 MT of carbon sequestered per year through carbon capture by 2050.	Of end-use natural gas demand, 73% (136 PJ) is served by renewable gas in 2050 (mix of hydrogen, renewable natural gas, and synthetic methane). Incremental 1.8 MT of carbon sequestered per year through carbon capture by 2050.
Transportation	Transition to 100% zero-emissions light duty vehicles. Significant role for MHD electric vehicles (EVs) (60% EV, 40% CNG/LNG and internal combustion).	Transition to 100% zero-emissions light duty vehicles. Significant role for gases in MHD vehicles (75% CNG, 20% EV, 5% fuel cell vehicles).
Fuel Switching	Transition 100% of residential and commercial space and water heating to electricity with electric heat pumps and other appliances, 20% of industrial fuel switching.	Transition up to 25% of residential and commercial space and water heating to electricity, 10% of industrial fuel switching.
Energy Efficiency	Improve envelope of 1.6 million homes and 436 million m^2 of commercial floor space.	Improve envelope of 1.7 million homes and 328 million m^2 of commercial floor space. Deploy gas heat pumps in ~70% of buildings.

Table 2 includes select modelling inputs that have a major impact on the results. These inputs have been informed by:

- Past engagements carried out by Guidehouse
- Pilot programs and research assessments carried out by FortisBC
- Discussions with key BC stakeholders
- Various public sources

The assumptions in the table represent theoretically possible future scenarios—they are not forecasts of the expected future by either Guidehouse or FortisBC.

TABLE 2. SELECT MODELLING INPUTS

Input	Assumption/Description
Cost of New Electricity Generation	$126/MWh was assumed in both pathways. This value represents an estimate of the expected cost of Site C[14] and is considered a conservative estimate of new renewable power costs. It is conservative because solar, wind, and energy storage costs are significantly higher and do not provide the same level of inter-seasonal storage. These higher priced renewable assets may need to be deployed due to the difficulty of developing large hydro in Canada. It is assumed that hydro resources will be available at the levels modelled in the pathways, which further assumes the deployment of multiple large hydro facilities (similar in size to Site C) in both pathways.
Renewable Gas Costs	RNG production costs were derived from Hallbar Consulting's report on RNG potential in BC and range from $14 to $28 per GJ.[15] It is assumed that progress will be made in wood-to-RNG technology to achieve the levels of RNG modelled in the two pathways. Green hydrogen (i.e., hydrogen produced with renewable electricity) and synthetic methane costs were developed from current production cost estimates (roughly $40/GJ for hydrogen, ~$10/GJ extra to create synthetic methane based off FortisBC pilot projects). These costs were extrapolated for the forecast, taking into consideration cost declines due to technology improvements. Guidehouse also aligned hydrogen production costs with the cost of renewable electricity because that is the primary input for producing green hydrogen. The weighted average cost across all renewable gases for each pathway in 2050 are: • Electrification Pathway: $19/GJ ($0.068/kWh equivalent) • Diversified Pathway: $23/GJ ($0.083/kWh equivalent) The Diversified Pathway renewable gas cost is higher because it requires more RNG at higher prices and includes a small amount of synthetic methane, which is the most expensive renewable gas.
Peak Demand Impacts	Annual hourly load shapes were selected or developed using public sources for each of the initiatives described in Table 1. These load shapes were applied to the energy consumption of each initiative to determine peak demand impact.
Electric Heat Pump Characteristics	Electric heat pump costs were modelled to align with the BC Conservation Potential Review, which included a specific assessment of the achievable potential of electric heat pumps in BC. The incremental cost for electric heat pumps was modelled as approximately $376 per residential household and $16,500 per 1,000 m^2 of commercial floor space. Electric heat pumps were modelled with 190% efficiency for both residential and commercial applications.[16] This efficiency depends on climate and likely will vary by region within BC.

[14] Guidehouse calculated a levelized cost of energy (LCOE) for Site C based off capital cost estimates from the BCUC Site C inquiry, historical financials from BC Hydro, and internal estimates. The results were benchmarked against Lazard's published LCOEs.

[15] Hallbar Consulting, *Resource Supply Potential for Renewable Natural Gas in B.C.*, March 2017, https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/resource_supply_potential_for_renewable_natural_gas_in_bc_public_version.pdf.

[16] The 190% value is a conservative estimate for heat pump efficiency, which aligns with a baseline assumed efficiency for air-source heat pumps in Guidehouse's 2019 BC Conservation Potential Review. This conservative assumption was used to attempt to represent provincial efficiency as a whole because heat pump efficiency is assumed to vary significantly by climate zone.

Input	Assumption/Description
Gas heat Pump Characteristics	Gas heat pump costs were derived from a heat pump feasibility study provided by FortisBC and interviews with developers.[17] Initial costs were set at roughly $6,800 and $45,000 for a residential home and commercial building, respectively. Both residential and commercial gas heat pumps were modelled with a 140% gas utilization efficiency. This efficiency depends on climate and likely will vary by region within BC.
Natural Gas System Utilization	The utilization of the gas system differs significantly between the two pathways. In the Electrification Pathway, the 2050 throughput drops to roughly 40% of the 2019 throughput. Conversely, the 2050 throughput of the Diversified Pathway is not significantly less than the 2019 throughput.[18] Electrification Pathway: • 2019 throughput = 200 PJ • 2050 throughput = 75 PJ Diversified Pathway: • 2019 throughput = 200 PJ • 2050 throughput = 186 PJ

CanESS, which Guidehouse used to complete the pathway modelling, is an integrated, multifuel, multisector, provincially disaggregated energy systems model for Canada. CanESS enables bottom-up accounting for energy supply and demand, including energy feedstocks (e.g., coal, oil, natural gas), energy-consuming stocks (e.g., vehicles, appliances, dwellings), and all intermediate energy flows (e.g., electricity), including interprovincial imports and exports that may offer incremental opportunities to contribute to achieving regional GHG reduction targets.

Note: CanESS projections were based on extended trends observed in historical data (key data sources include CANSIM, Natural Resources Canada, and Environment Canada) and projections obtained from the Canada Energy Regulator (CER, Energy Future 2017). In addition, CanESS projections account for the expected effects of all approved legislation and regulation (including the CleanBC plan) and was driven by the best publicly available data from government sources. (Canada Energy Regulator (CER), Canada's Energy Future 2017, https://www.cer-rec.gc.ca/nrg/ntgrtd/ftr/2017/index-eng.html)

[17] Posterity Group, Prefeasibility Study on Natural Gas Heat Pumps, May 2017.

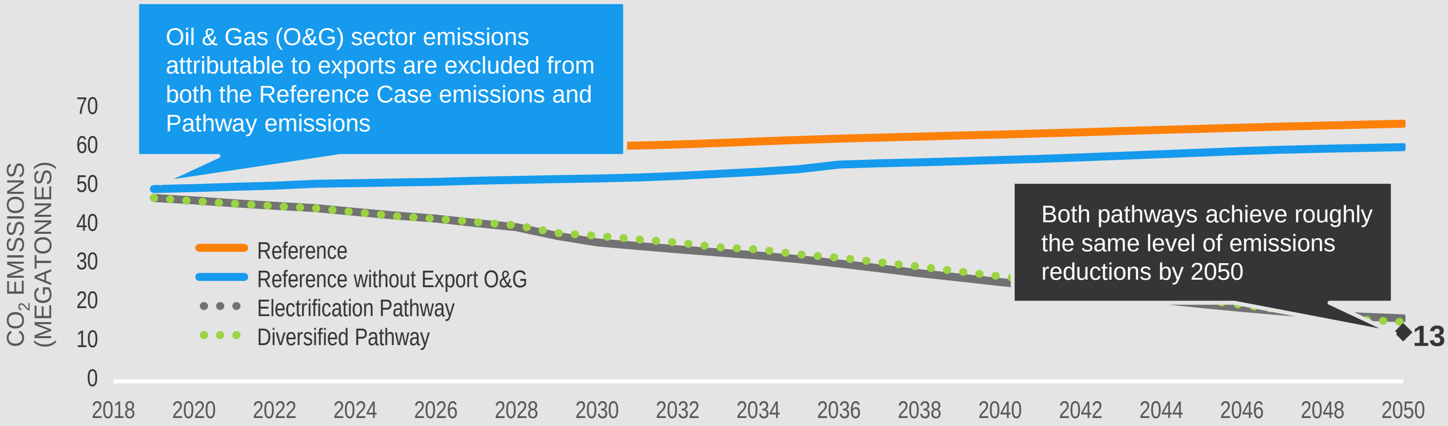
[18] Gas system utilization includes only gas consumed by the buildings, industry, and transport domestic end-use sectors. Natural gas throughput for LNG for marine vessels and for international export are excluded.

5.1 EMISSIONS REDUCTIONS

Each pathway meets 95% of the reductions required by 2050, representing greater than 32 million tonnes of CO_2e emissions avoided from BC annually in 2050 from a BAU scenario. The pathways use initiatives to different extents, but both pathways require transformative changes in every sector. The remaining 5% of emissions reductions must be achieved through initiatives that target sectors that cannot be modelled for BC in isolation—e.g., aviation fuel. These sectors are beyond the scope of this study.

The scope of this report is focused on BC's domestic GHG emissions. The pathways reduce domestic emissions by 80%. Emissions associated with energy exports, notably for LNG and other oil & gas for export, are separated out and are assumed to be addressed through a combination of nature-based carbon offsets, internationally transferred mitigation outcomes,[19] and technology improvements.

FIGURE 10. BRITISH COLUMBIA EMISSIONS REDUCTIONS UNDER ENERGY VISION PATHWAYS



Source: Guidehouse Analysis

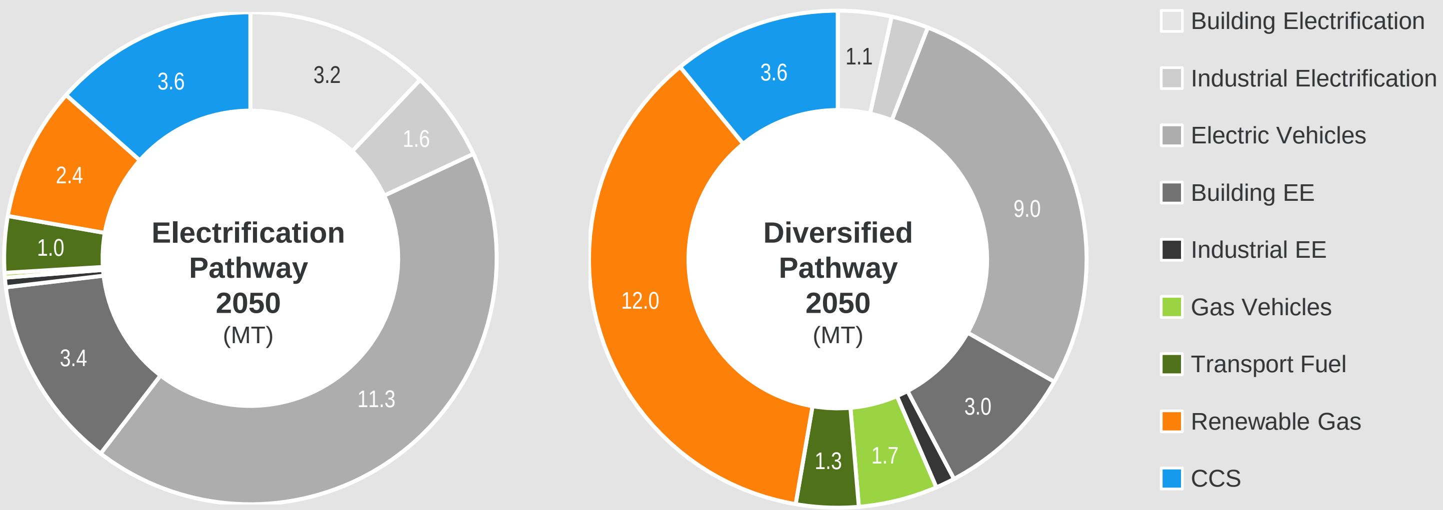
As Figure 11 shows, light duty EVs have a large role to reduce GHG emissions in both pathways, as both pathways were modelled to include the Zero-Emission Vehicles [20] Act; the Zero-Emission Vehicles Act requires 100% of light duty vehicles sold in 2040 to be zero-emissions vehicles.[21] MHD vehicles is the second-most impactful initiative in the Electrification Pathway, which has been modelled such that 60% of MHD vehicles on the road in BC are electric by 2050. The most impactful initiative to reduce BC's domestic GHG emissions in the Diversified Pathway is renewable gas, which results in over 5 million tonnes of emissions reductions in 2050 by transforming the natural gas fuel mix to be mostly made up of RNG and hydrogen. Energy efficiency in buildings is also a critical initiative in both pathways. This initiative results in over 3 million tonnes of reductions by 2050 through the implementation of improved building envelopes, high efficiency heat pumps, and commercial automated building controls.

[19] Internationally transferred mitigation outcomes are identified in the Paris Agreement to facilitate compliance with national GHG reduction goals through the trade of emissions reductions between nations.

[20] ZEVs are modelled in this study as EVs and fuel cell vehicles.

[21] Province of British Columbia, Zero-Emission Vehicles Act, May 2019, https://www2.gov.bc.ca/gov/content/industry/electricity-alternative-energy/transportation-energies/clean-transportation-policies-programs/zero-emission-vehicles-act.

FIGURE 11. GHG REDUCTIONS BY INITIATIVE: 2050



* Note that summing up all the initiatives will not exactly match total emission reductions values in earlier slides. Source: Guidehouse Analysis

5.2 GAS SYSTEM ENABLES GHG EMISSIONS REDUCTIONS OUTSIDE BC

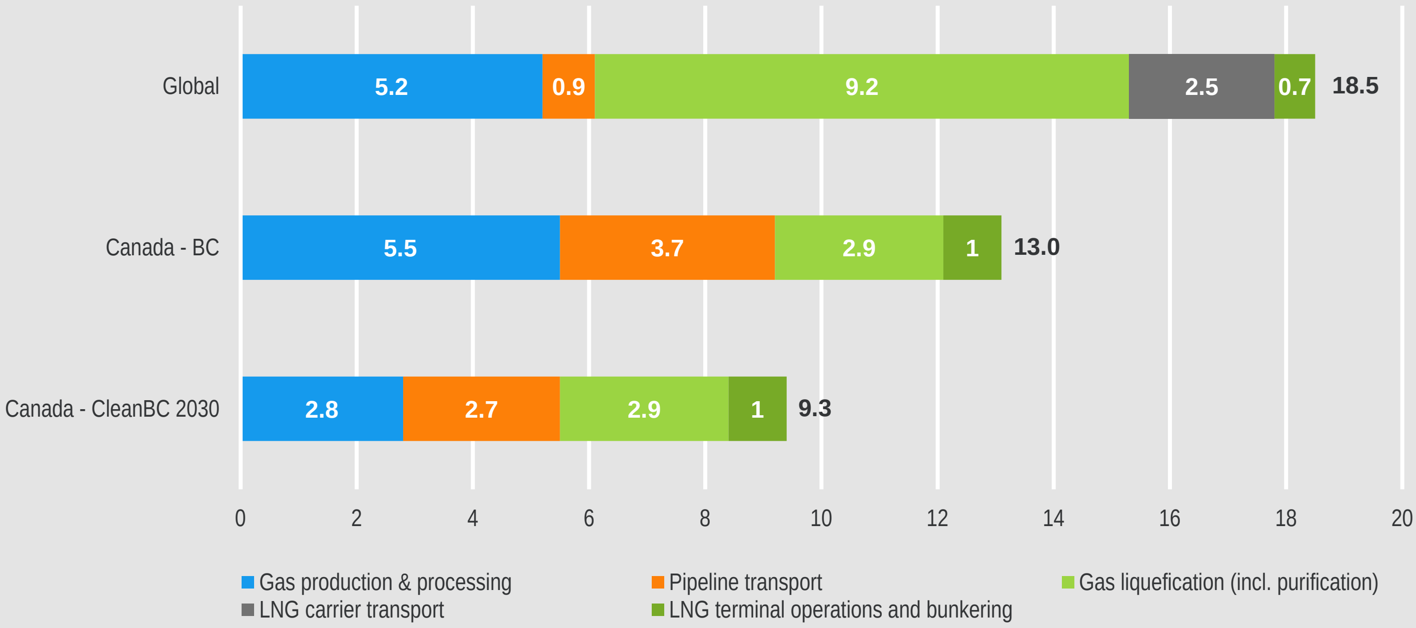
The gas system can also lead to GHG emissions reductions outside of BC. Although these reductions were not evaluated in this analysis, FortisBC has conducted separate evaluations on the role of the gas system to supply LNG to marine vessels and to displace carbon-intensive energy consumption in China with LNG exports. Both of these activities could have significant near-term emissions reductions.

For marine vessels, LNG from FortisBC's Tilbury facility has a 27% lower carbon intensity than the global average for LNG.

This means that LNG from FortisBC used in marine vessels would reduce life cycle emissions by between 20% and 27%. As the measures in CleanBC take hold, reducing methane emissions and extending electrification in natural gas production, LNG from BC could reduce GHG emissions by up to 30% and would make the carbon intensity of LNG from Tilbury half that of the global average. Because the GHG emissions associated with international marine vessels in their journeys to and from ports in BC are higher than BC's total annual GHG emissions, this would make an important contribution to global GHG reduction efforts.[22]

[22] thinkstep, *Life Cycle GHG Emissions of the LNG Supply at the Port of Vancouver: 2nd Project Phase*, 2020, https://www.thinkstep.com/content/life-cycle-ghg-emission-study-use-lng-marine-fuel-1 .

FIGURE 12. WELL TO TANK LNG CARBON INTENSITIES (g CO_2e/MJ)



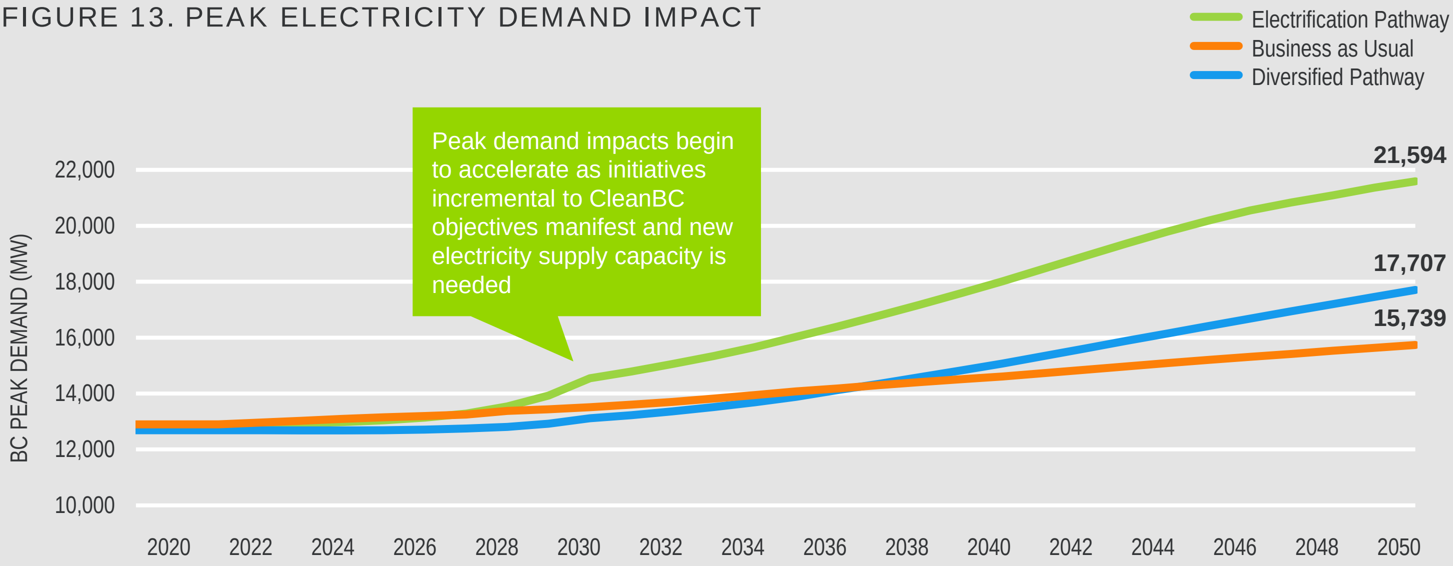
Source: Thinkstep, Life Cycle GHG Emissions of the LNG Supply at the Port of Vancouver: 2nd Project Phase, 2020

5.3 GROWTH IN LOW CARBON ENERGY SUPPLY

The 2050 peak demand of the Electrification Pathway is estimated to be 68% higher than the peak electricity demand of 2018. This will require the deployment of over 8,700 MW of peak capacity in the Electrification Pathway, which is double the requirement for the Diversified Pathway and triple the BAU requirement. The peak demand in both pathways increases from 2018 levels because of the significant deployment of EVs, electric heating, and fuel switching. However, the net increase in peak demand is significantly higher in the Electrification Pathway.[23] To achieve the 2050 GHG reduction targets, peak demand must be met with low or no carbon firm generating capacity. In this study, Guidehouse used the lowest cost supply option for peak capacity—hydroelectric generation. There are practical limitations to developing new hydroelectric generation in BC, however. This report does not assess those limitations but acknowledges other sources of peak capacity may be preferred.

[23] Peak demand impacts are based on conservative assumptions in both pathways (e.g., majority of MHD vehicle charging occurs in non-peak times).

FIGURE 13. PEAK ELECTRICITY DEMAND IMPACT

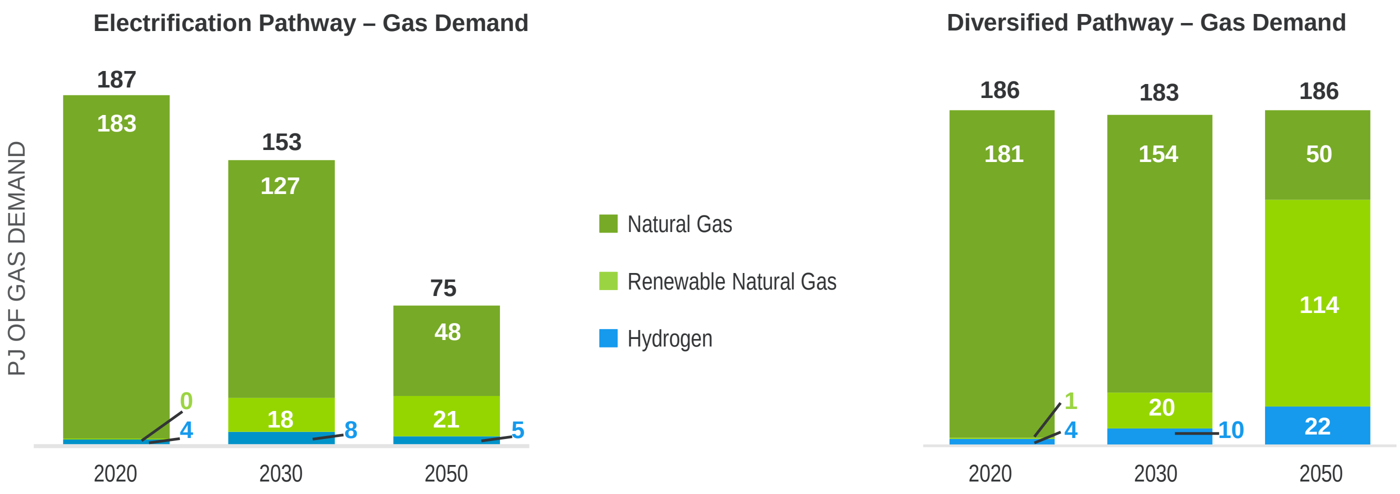


*Peak demand impacts are based on conservative assumptions in both pathways (e.g., majority of MHD vehicle charging occurs in non-peak times)
Source: Guidehouse Analysis

Natural and renewable gases are critical in the Diversified Pathway and support a more robust energy system in the province. Figure 14 shows that renewable gases will make up 35% of natural gas demand in the Electrification Pathway by 2050, aligning with current BC targets. Renewable gases make up 73% of natural gas demand in the Diversified Pathway.

In the Electrification Pathway, total gas demand declines by almost 60% between 2020 and 2050, while total gas demand (natural gas and RNG) remains flat during the same period in the Diversified Pathway.

FIGURE 14. END-USE GAS DEMAND IN EACH PATHWAY



Note: End-use natural gas demand includes consumption in residential and commercial buildings, industry, and transport but excludes gas consumption in upstream gas extraction, processing, and transmission.

Source: Guidehouse Analysis

TABLE 3. RENEWABLE GAS DESCRIPTIONS

Renewable Gas	Assumption/Description
Renewable Natural Gas (RNG)	RNG is natural gas created from renewable energy sources such as organic waste (i.e., from landfills) and agricultural waste. Guidehouse used a report by Hallbar Consulting commissioned by the Province of British Columbia, FortisBC, and Pacific Northern Gas to determine the level of RNG potential in BC and its associated production costs. The RNG amounts modelled in 2050 align with the long-term technical potential in the Hallbar Consulting report, which assumes improvements will be made in wood-to-RNG technology. It is assumed RNG can be injected directly into existing natural gas infrastructure without any associated complications, and all associated costs are covered in the production costs.
Hydrogen	Two types of hydrogen were considered in this report: green hydrogen, which is produced from an electrolysis reaction of renewable electric power with water, and blue hydrogen, which is produced from fossil fuel natural gas and cleaned up using carbon capture and storage. Blue hydrogen is cheaper than green, and its cost is not forecast to decline significantly in the forecast period. Guidehouse modelled the hydrogen mix to increasingly be composed of green hydrogen under the assumption that costs are likely to decline. Green hydrogen costs were based off production cost assessments from the *British Columbia Hydrogen Study*[24] and are forecast to decrease due to technology improvements. Guidehouse benchmarked these costs with production costs observed in other regions (e.g., Europe).[25] Green hydrogen costs are highly dependent on the price of electricity, so Guidehouse aligned the forecast to the cost of new renewable power in the future. Hydrogen was modelled to make up a maximum of 15% (by volume) of BC's natural gas mix to represent the estimated operational limitations of the gas system to incorporate higher volumes.[26]
Synthetic Methane	Synthetic methane is hydrogen that has been upgraded with CO_2 to create methane (CH_4) and that can be safely injected into the natural gas mix at any level. Synthetic methane is modelled as the most expensive renewable gas because its price includes the cost of hydrogen plus an incremental cost related to carbon capture and storage to provide the required CO_2. Guidehouse only modelled the production of synthetic methane when the requirement for renewable gas exceeded both the technical potential of RNG and the physical limit of hydrogen (i.e., 5% of the fuel mix).

Electricity's share of the energy supply increases significantly in both pathways. Refined petroleum, which makes up over 33% of total end-use energy demand in BC, will decline to less than 15% of end-use demand by 2050 in both pathways. This decline is due to the widespread adoption of vehicles that use alternative fuels to diesel and gasoline in both pathways—i.e., electric, fuel cell, CNG, and LNG. This analysis highlights the importance, costs and scarcity of low-carbon energy whether in the form of renewable gas molecules for the gas system or electrons through the electric grid.

Maximizing the potential of clean electrons or clean gas molecules should be pursued to harness the differences between these energy carriers. Because of the high cost of building new clean reliable electricity generation and transmission, electrification initiatives should be matched to their most effective and valued uses to reduce GHG emissions, while natural gas and renewable gas molecules should be delivered to end-uses where there are high-costs of electrifying and/or the GHG reduction potential is lower. This integrated approach to system-wide decarbonization should be pursued rather than a compartmentalized sector by sector approach.

[24] Zen and the Art of Clean Energy Solutions, British Columbia Hydrogen Study, June 2019, https://www2.gov.bc.ca/assets/gov/government/ministries-organizations/zen-bcbn-hydrogen-study-final-v6.pdf.

[25] Guidehouse, Gas Decarbonisation Pathways 2020–2050, April 2020, https://gasforclimate2050.eu/?smd_process_download=1&download_id=339.

[26] A maximum hydrogen blend concentration by volume in FortisBC's gas system is being analyzed and depends on several factors. FortisBC is conducting feasibility studies to outline the minimum safe blending volume with the current system. The gas system can also adapt over the coming decades as scheduled maintenance, asset integrity, and operational management advancements and infrastructure upgrades offer opportunities to increase the system's compatibility with hydrogen.

Renewable gases have been an area of growing interest around the world. Large utilities in North America are moving to expand the supply of RNG into their portfolios. In Quebec, the provincial government has set a 5% RNG blend target by 2025 and has devoted $70 million to increase the production of RNG. Southern California Gas has set a corporate target to expand RNG supply to 20% of its throughput in 2030. In some European countries, promotion of biogas and RNG has been an ongoing policy objective. Denmark is producing over 15 PJ of biogas, with approximately 10% of the throughput through its gas grid being RNG. In France, the government has set an objective to inject 10% RNG into the country's pipelines by 2030.

Hydrogen is also taking on a larger role in meeting global energy needs. Natural gas utilities in France recently recommended the government set a hydrogen target of 10% of the natural gas mix in 2030, increasing up to 20% thereafter.[27] The Guidehouse Gas for Climate work in the EU demonstrates support in the EU for setting a binding mandate for 10% gas from renewable sources (i.e., RNG and green hydrogen) by 2030. [28] Hydrogen is being considered as a replacement fuel for coal in electricity production. The largest municipal utility in the US, Los Angeles Department of Water and Power (LADWP), announced it would transform a coal-fired plant to run on green hydrogen. LADWP plans to run the coal plant on a blend of 30% hydrogen, 70% natural gas by 2025. By 2045, the plant is expected to be run completely on hydrogen.[29]

5.4 COST COMPARISONS

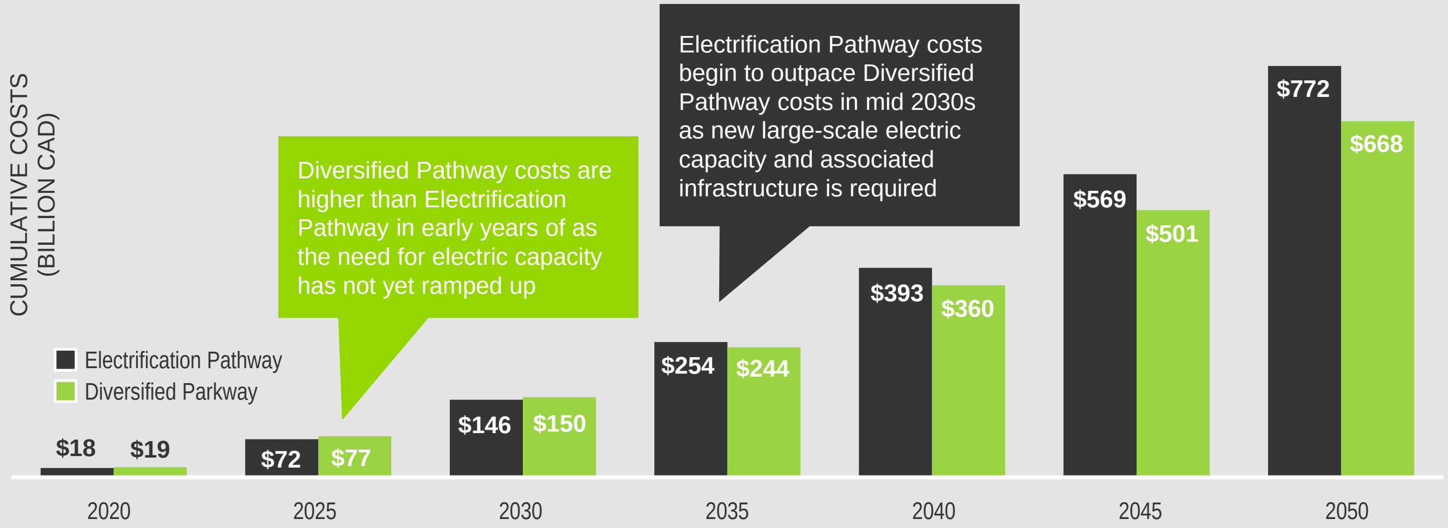
By 2050, the societal value of the Diversified Pathway is expected to be at least $100 billion higher than the Electrification Pathway. The cost of each pathway is roughly the same until the mid-2030s, when the costs of the Electrification Pathway rises much higher than the Diversified Pathway. This finding emphasizes the need to prioritize pathways over a longer time horizon because pathway costs represent incremental costs borne by society relative to the BAU case. These costs include commodity (the electricity and natural gas itself), infrastructure (the poles, wires, and pipelines needed to deliver energy), and initiative costs (the cost of efficient alternatives to existing equipment and fuel).

[27] Hydrocarbon Processing, "France plans hydrogen blending with natgas to tackle carbon emissions," November 15, 2019, https://www.hydrocarbonprocessing.com/news/2019/11/france-plans-hydrogen-blending-with-natgas-to-tackle-carbon-emissions.

[28] Guidehouse, *Gas Decarbonisation Pathways 2020–2050*, April 2020, https://gasforclimate2050.eu/?smd_process_download=1&download_id=339.

[29] Smith, Carl, "America's Largest Municipal Utility Invests in Move from Coal to Hydrogen Power," *Governing: The Future of States and Localities*, April 15, 2020, https://www.governing.com/next/Americas-Largest-Municipal-Utility-Invests-from-Coal-to-Hydrogen-Power.html.

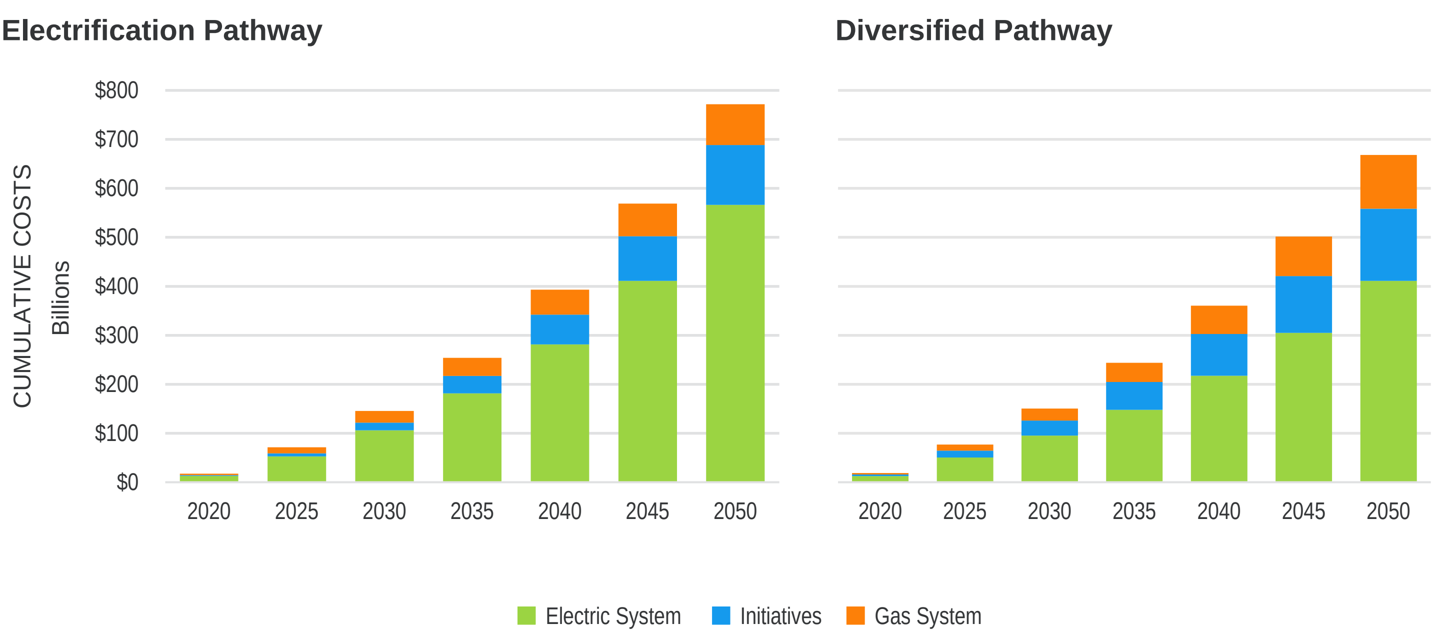
FIGURE 15. PATHWAY COSTS



Source: Guidehouse Analysis

The Diversified Pathway has higher initiative and gas system costs but significantly lower electricity system costs than the Electrification Pathway. Figure 16 compares the Diversified Pathway costs relative to the Electrification Pathway costs; the text following the figure describes the costs by component.

FIGURE 16. PATHWAY COSTS BY COMPONENT



Source: Guidehouse Analysis

- **$155 billion less spent on the electricity system:** Electricity system costs represent the incremental infrastructure needed to meet peak demand in both pathways. These costs include generation asset buildout, currently modelled to be the implementation of several large hydro generating stations in each pathway. These costs also include transmission and distribution infrastructure—this is money spent on the delivery system itself as opposed to the energy that passes through it. The Electrification Pathway has significantly higher electricity system costs due to the comparatively higher peak demand requirements.

- **$25 billion more spent on initiatives:** These initiatives are summarized in Table 1 and include vehicles, building envelope improvements, space and water heating, industrial process improvements, and renewable gases. The Diversified Pathway has higher initiative costs than the Electrification Pathway due to the large amount of renewable gas needed to decrease emissions. Further, the Diversified Pathway implements higher priced energy efficiency initiatives (e.g., gas heat pumps are more expensive than electric heat pumps).

- **$26 billion more spent on the gas system:** Gas system costs represent the expenses associated with the maintenance and operation of gas infrastructure. The Diversified Pathway has higher gas system costs because there is higher throughput during the forecast period.

The costs for both electric and natural gas ratepayers is higher in the Electrification Pathway as compared to the Diversified Pathway. Costs for electricity customers are higher because of the higher system costs in the Electrification Pathway, which are passed on to customers through electricity rates. Costs for natural gas customers are higher because significant reductions in gas consumption will not be enough to offset the cost of operating the system for a smaller number of remaining customers.

A cost sensitivity analysis was completed to determine the impact of a number of variables and found that cost drivers could increase the cost differential between the two pathways by $5 billion to $7 billion, or could narrow the gap by $5 billion to $12 billion. If conservative assumptions about key factors including the capital cost, the capital structure, or the cost of RNG or hydrogen are lower than expected, the cost differential between the two pathways will be greater. If these costs are higher, the Diversified Pathway will still be less expensive than the Electrification Pathway.

6. OTHER BENEFITS OF USING THE GAS SYSTEM FOR DECARBONIZATION

FortisBC asked Guidehouse to look at the total benefits of the gas system in BC. From a modelling perspective, the Diversified Pathway can achieve the same level of emissions reductions as the Electrification Pathway at a significantly lower cost in BC. In addition, the gas system can deliver other benefits related to security, stability, and flexibility that can advance BC's work toward a low carbon future.

GAS SYSTEM ALLOWS FOR A BROADER SET OF SOLUTIONS TO REDUCE EMISSIONS

Using the gas system to achieve GHG reductions diversifies the approach across multiple energy systems. A pathway that focuses on electrification could have higher risks should key barriers like developing new peak demand emerge. A broader approach to GHG reductions further into the scenario period could lower the risk of missing BC's 2050 target.

A significant amount of R&D has gone into various electrification and renewable technologies, resulting in widespread acceptance and economies of scale. For example, the cost on a dollars-per-watt basis of distributed solar PV has dropped over 55% between 2011 and 2018 (-11% compound annual growth rate). However, the opportunities for advancement in electrification may be reaching saturation and the development and improvement of some of these technologies is declining (e.g., the rate of solar PV cost declines is expected to slow down in the coming decade).[30]

There is more opportunity for R&D and efficiency improvements in the gas supply and corresponding end-use equipment that can be investigated alongside electrification initiatives. This opportunity could result in more economic development and societal benefit than if only electrification measures were prioritized.

Renewable gases are a major target for innovation and can play a vital role in the future of the natural gas industry. RNG, hydrogen, and synthetic methane all have great potential for the province. BC has the potential to be a major producer of RNG given its large forestry industry, which produces a large amount of woody biomass. Technical advancements are needed to more efficiently convert wood biomass waste to RNG, and researchers and organizations are identifying recommendations for technological improvement.[31] Assuming this technology meets its potential in the coming years, BC's RNG production potential could be 90 PJ per year, representing almost half of the natural gas currently delivered by FortisBC.[32] This estimate assumes only wood waste within a 50 km-75 km of natural gas compressor stations is used. If this radius can be expanded, BC's RNG potential would increase further.

[30] Navigant Research (now Guidehouse Insights), *Market Data: Solar PV Global Forecasts*, 3Q 2018, https://guidehouseinsights.com/reports/market-data-solar-pv-global-forecasts.

[31] Gas Technology Institute, *Low-Carbon Renewable Natural Gas (RNG) from Wood Wastes*, February 2019, https://www.gti.energy/wp-content/uploads/2019/02/Low-Carbon-Renewable-Natural-Gas-RNG-from-Wood-Wastes-Final-Report-Feb2019.pdf.

[32] Hallbar Consulting, *Resource Supply Potential for Renewable Natural Gas in B.C.*, March 2017, https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/transportation/renewable-low-carbon-fuels/resource_supply_potential_for_renewable_natural_gas_in_bc_public_version.pdf.

Hydrogen and synthetic methane also represent key initiatives to lower emissions in BC. Hydrogen and synthetic methane production technologies have not reached the limit of technical ability and offer a great opportunity for improvement through R&D and pilot projects.

Natural gas heat pumps are a gas-consuming technology that represent an opportunity for R&D and innovation. Gas heat pumps are more efficient than conventional gas space heating systems, but they have not yet reached their full market potential in Canada due to cost, availability, and other factors. However, there is strong federal support for gas heat pumps because they are expected to be instrumental in helping Canada meet its 2030 and 2050 emissions reductions targets.[33]

DROP-IN FUELS CAN BE MORE FEASIBLE AND COST-EFFECTIVE THAN FUEL SWITCHING

For many residences and businesses, switching to different heating systems may be difficult or undesirable. For policymakers focused on reducing GHG emissions, relying on broad-based fuel switching to different heating systems will involve mobilizing millions of building owners to switch. The policies and strategies to make this happen are not well understood or are infeasible.

Deploying low carbon drop-in fuels like renewable gas would leverage existing policy and regulatory frameworks and involve fewer players.[34] While it would be a challenge to develop the volume of low carbon fuels needed by 2050, governments and industry have experience in promoting low carbon energy in other sectors—notably in the electricity sector, where policy and financial incentives have led to a massive increase in renewable power investment. This model could be emulated for renewable gases.

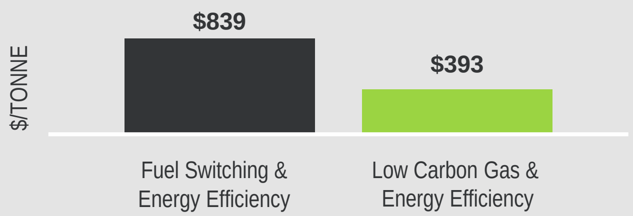
The findings in this analysis suggest drop-in fuels would be more cost-effective than fuel switching to electricity. The cost per tonne of reducing emissions in difficult-to-address sectors like buildings with renewable gases is approximately half that of fuel switching when accounting for the full system cost impacts. Figure 17 shows that the cost per tonne to reduce residential building emissions by fuel switching is higher than reducing residential building emissions using low carbon fuels in both pathways. The components of each option are summarized below:

- Fuel switching includes residential electric heat pump costs, electric system impact costs (i.e., system buildout to meet peak demand), and energy costs to switch from electricity to gas. Both electric system impact costs and energy costs are net of energy efficiency improvements.
- Low carbon gas includes the deployment of RNG/hydrogen and the implementation of gas heat pumps, building envelope improvements, and other efficiency measures.

[33] Energy and Mines Ministers' Conference, *Paving the Road to 2030 and Beyond: Market transformation road map for energy efficient equipment in the building sector*, August 2018, https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/emmc/pdf/2018/en/18-00072-nrcan-road-map-eng.pdf.

[34] Drop-in fuel refers to a fuel that can be added to an existing energy system without significant reconfiguration.

FIGURE 17. COST PER TONNE OF FUEL SWITCHING VS. LOW CARBON GAS AND ENERGY EFFICIENCY



Source: Guidehouse Analysis

SOCIO-ECONOMIC IMPACT OF AN OPTIMIZED GAS SYSTEM

The Electrification Pathway would eliminate portions of BC's natural gas industry. This elimination may result in the loss of thousands of jobs and billions of dollars of unused gas pipelines that the province has committed to financially. As a result, the province will have an under-utilized gas system, which does not provide a significant benefit. The cost to maintain and oversee this infrastructure will adversely impact British Columbians. In contrast, the Diversified Pathway optimizes the gas system to continue to deliver low carbon solutions, resulting in higher societal value.

GAS SYSTEM CAN BE USED TO REDUCE GLOBAL CARBON EMISSIONS

BC has significant natural gas resources, with remaining raw reserves of approximately 1,165 billion cubic metres. Over 60 billion cubic metres of natural gas was produced in 2018.[35] However, domestic use will likely decrease over time to reach BC's 2050 target. BC's natural gas can be exported as LNG to Asia to displace higher carbon fuels like coal, which could result in a net reduction of global GHG emissions. BC's LNG can also power large ocean vessels, which would displace higher emissions fuels like diesel and heavy oil. An analysis conducted by thinkstep concluded that LNG from BC used in marine shipping could reduce GHG emissions by up to 27%.[36]

As the policies in CleanBC are implemented (e.g., electrifying upstream gas production and implementing regulations to reduce methane emissions), the carbon intensity of the LNG supply chain in BC in 2030 would be half that of the current global average.

MAINTAINING THE GAS SYSTEM WILL SPEED INNOVATION AND ALLOW FOR FLEXIBILITY IN FUTURE TECHNOLOGY SOLUTIONS

We have modeled two pathways that both nearly achieve the required GHG emission reductions in 2050. Each pathway has been modelled by relying primarily on existing proven technologies and solutions. Continued innovation is expected to accelerate decarbonization, particularly in years after 2030. Maintaining both the gas and electric infrastructure as part of the future energy system will provide more flexibility in which innovative solutions can be easily developed and deployed. This will allow BC to achieve accelerated deployment of innovations in clean technologies and even faster decarbonization.

ROLE OF THE GAS SYSTEM IN OTHER JURISDICTIONS

Guidehouse carried out an analysis similar to this one for Gas for Climate, a group of European natural gas companies. The group commissioned a study to assess the possible role and value for gas used in existing gas infrastructure in a net-zero emissions EU energy system compared to a situation in which a minimal quantity of gas would be used.

[35] BC Oil and Gas Commission, *British Columbia's Oil and Gas Reserves and Production Report*, 2018, https://www.bcogc.ca/node/15819/download.

[36] thinkstep, *Life Cycle GHG Emissions of the LNG Supply at the Port of Vancouver: 2nd Project Phase*, 2020.

The Gas for Climate analysis[37] involved developing two scenarios to meet the EU's decarbonization requirements by 2050:

- **Minimal gas scenario:** Almost full electrification of buildings, industry, and transportation sectors.
- **Optimized gas scenario:** Moderate electrification of the abovementioned sectors, as well as large deployment of renewable and low carbon gases in select applications (heavy road transport, building heating in peak demand times, and some electricity production).

Guidehouse found the following conclusions from the Gas for Climate analysis:

- Both scenarios meet EU decarbonization requirements by 2050.
- Both scenarios need substantial quantities of renewable electricity.
- Green/blue hydrogen and RNG can help meet heating and industrial needs at low/no carbon.
- Significant benefits exist in the optimized gas scenario related to energy flexibility (i.e., gas and electric systems are used).
- Higher societal value of optimized gas pathway (over €200 billion annually across the energy system by 2050).
- The cost to decommission the gas infrastructure (in minimal gas pathway) is high.

The results of this analysis mirror that of the FortisBC study and support to the concept that gas networks have a clear role in a decarbonized future.

[37] Guidehouse, *Gas Decarbonisation Pathways 2020–2050*, April 2020, https://gasforclimate2050.eu/?smd_process_download=1&download_id=339.

7. CONCLUSIONS

This analysis indicates that the Diversified Pathway can achieve the same level of provincial GHG emissions reductions as the Electrified Pathway at a significantly lower cost to British Columbians. Although initiatives are used to different extents, both pathways defined in this study would require transformative changes in every sector of BC's economy. By 2050, the societal value of achieving the Diversified Pathway is expected to be in excess of $100 billion higher than the Electrification Pathway.

Other benefits of maintaining a robust natural gas system are preserved by adopting a strategically diversified approach. The existing gas infrastructure represents a vital component to servicing current energy demand and can continue to benefit BC by providing security, flexibility, and storage to the overall energy system. The gas system delivers cost-effective energy services, energy reliability, and significant economic benefits to the province. The gas system also provides an opportunity for a broader set of technologies and initiatives to help achieve BC's 2050 GHG reduction goal.