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November 10, 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. 2

On December 29, 2021, FEI filed the Application referenced above. In accordance with the regulatory timetable established in Order G-185-21 for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 2.

Treatment of Confidential Material

Due to the sensitive and confidential nature of some of the information in the Application, FEI is filing some responses 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 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

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A. PROJECT NEED

66.0 Reference: PROJECT NEED

Exhibit B-15, BCUC IR 1.1, 1.3

Incidents Affecting Both T-South Pipelines

In response to British Columbia Utilities Commission (BCUC) Information Request (IR) 1.3, FortisBC Energy Inc. (FEI) stated:

> 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 [Westcoast Energy's 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;
- 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.

In response to BCUC IR 1.1, FEI stated: "At compressor stations, Westcoast would have some excess and/or redundant compression capacity to accommodate the failures of individual compressor units."

66.1 To the extent FEI is able to, please rank the examples outlined in response to BCUC IR 1.3 from most likely to occur to least likely.

Response:

In order to rank the examples provided in the response to BCUC IR1 1.3, FEI would need to undertake a detailed site-specific risk analysis of the Westcoast system. The information to support such an assessment is not available to FEI.

Please refer to the response to BCUC IR1 1.5 for system-level estimates of the cumulative probability of a rupture event and cumulative probability of an ignited rupture over the 67-year analysis period for the TLSE Project prepared by JANA.

66.2 Please confirm, or explain otherwise, that aerial crossings constitute a minor proportion of the total length of the T-South system.

Response:

Confirmed.

66.2.1 Please further explain why aerial crossings present a risk of both pipelines rupturing.

Response:

Aerial crossings present a risk of both pipelines rupturing for the following reasons:

- In the event that one pipeline ruptures, pipe material (steel pipe fragments or sections) may be expelled at a high velocity causing physical damage to the adjacent pipeline. As adjacent pipelines are not protected by surrounding soil at an aerial crossing, they are more susceptible to concomitant damage.
- In the event that one pipeline ruptures, pipe material (steel pipe fragments or sections) may be expelled at a high velocity causing physical damage to the structural supports of the adjacent pipeline. Loss of support could result in the collapse and subsequent rupture of the adjacent pipeline.
- In the event of an ignited rupture of one pipeline, it is possible that heat damage could weaken the steel of an adjacent pipeline or structural support thereby increasing the risk of the second pipeline rupturing.

66.3 Please clarify whether the occurrence of damage to an adjacent pipeline (because of integrity issues on an adjacent pipeline) would require the presence of undetected integrity issues in parallel sections of both pipelines.

66.3.1 Please discuss whether FEI considers this is a likely or plausible scenario.

Response:

Confirmed, the specific example given in the second bullet in the preamble was referring to this scenario. However, the other line does not need to have a pre-existing undetected integrity issue for the rupture to cause the other line to fail.

Failure modes considered in analyses of parallel pipelines typically include:

1. Failure due to exposure from a blast crater that may be formed by the failed adjacent pipeline; and
2. Failure due to exposure to an ignited rupture (i.e., potential weakening of the steel due to exposure to high temperatures).

These scenarios are sufficiently plausible as to have warranted a regulatory requirement via the CSA Z662 standard such that pipeline operators/designers must consider failure of an adjacent pipeline when specifying the minimum clearance distance in any direction between an existing buried pipeline, regardless of the presence of integrity issues, and a newly constructed pipeline. This requirement has existed since the 2003 edition of the standard; however, the construction of both T-South pipelines predate this edition of the standard by many years.

The regulatory requirement was further bolstered in 2015 through additions to the CSA Z662 standard. Pipeline designers are now also required to consider the impacts of a potential failure of the new pipeline on all existing buried facilities.

FEI considers that the occurrence of damage to an adjacent pipeline (because of integrity issues on an adjacent pipeline) is a plausible scenario that must be considered by operators.

66.4 Please confirm, or explain otherwise, that a precautionary shut-down of an adjacent pipeline does not necessarily mean a no-flow event lasting longer than two days.

Response:

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

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

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

66.5 Please further explain why facility or equipment failure at a compressor station would result in a no-flow event if there is excess/ redundant capacity at compressor stations.

Response:

In spite of the inherent redundancy at compressor stations, there are still plausible scenarios leading to a complete loss or decreased function of a Westcoast compressor station that could result in either no-flow or reduced-flow events, which would impact FEI's gas supply capabilities.

The following examples illustrate how such events could occur:

- A failure of section of pipe (e.g., cross-over) that joins together two transmission pipelines within a compressor station compound could reduce the delivery capability of both transmission pipelines;
- A complete loss of or damage to power supply for some or all compressors; and
- A major fire, flood, landslide, or explosion that decreases or interrupts some or all functions of a compressor station.

67.0 Reference: PROJECT NEED

Exhibit B-15, BCUC IR 1.3.1, 1.4, 1.6.1, 1.9

Integrity Management

In response to BCUC IR 1.3.1, FEI stated:

> 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.

In response to BCUC IR 1.4, FEI stated:

> 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.

67.1 Does FEI consider that Westcoast's integrity management reduces the likelihood of the greatest risk of a no-flow event on the T-South system?

Response:

As a general objective of integrity management is failure prevention, FEI considers that Westcoast's integrity management practices reduce the likelihood of a failure and thus of a potential no-flow event on the T-South system.

Integrity-related failures can nonetheless occur (as JANA's analysis of industry rupture events illustrates) and some intentional and external causes of no-flow events (e.g., sabotage or cyber-attacks) are not directly mitigated through integrity management. Irrespective of mitigation through integrity management programs, a disruption on the T-South system is the greatest supply risk facing FEI at present because of residual risk and the magnitude of the consequences.

67.2 Please discuss in what circumstances FEI considers it is prudent or possible to attempt to mitigate all non-zero risks respecting its supply, and in which circumstances FEI does not.

Response:

FEI agrees that eliminating all risk is not achievable; however, as a prudent operator, FEI attempts to prevent and/or mitigate non-zero risks where the outcome is considered unacceptable.

The scenarios addressed by the TLSE Project (i.e., low-probability but high-consequence events) create a unique set of challenges, as compared to responding to more frequent, but lower-consequence events. When an outcome is unacceptable, such as the societal and economic consequences associated with a widespread outage on FEI's system, the risk must be addressed. For example, FEI's Integrity Management Program for Pipelines (IMP-P) identifies three types of significant consequences that are unacceptable. This includes pipeline incidents resulting in:

- Serious injury or worse to any person;
- Irreversible or long-term harm to the ambient environment; or
- Outages to large numbers of customers.

FEI strives for zero incidents resulting in significant consequences and undertakes numerous activities through its IMP-P to mitigate both the likelihood and consequences of incidents. In contrast, higher-probability, but lower-consequence events are typically addressed through FEI's ongoing sustainment capital and operations and maintenance activities. Given the lower consequences associated with many of these types of events, prevention of all incidents is not necessarily possible, warranted, or cost-effective.

However, similar to the pipeline rupture risk that is addressed through its IMP-P, FEI considers the potential for sudden, widespread, and prolonged outages to several hundred thousand customers in the Lower Mainland to be an unacceptable risk, and on this basis FEI has proposed the TLSE Project to mitigate the occurrence of this risk.

Please also refer to the response to BCUC IR2 68.11.

In response to BCUC IR 1.6.1, FEI stated:

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

In response to BCUC IR 1.9, FEI stated:

> FEI would expect that the threats that could potentially cause a supply disruption of Westcoast's T-South system are similar to those managed by FEI. This would include cyber-attacks, as well as disruption of physical infrastructure.
>
> …

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

67.3 Please discuss whether FEI considers information from Westcoast to better understand the extent to which threats of supply disruptions are mitigated by Westcoast's integrity management processes would be relevant in assessing the need for the TLSE Project.

67.3.1 If yes, please discuss whether FEI is able to seek further information from Westcoast to better understand the extent to which threats of supply disruptions are mitigated by Westcoast's integrity management processes.

67.3.2 If not, please explain why not.

Response:

FEI considers the information available to it from Westcoast and Westcoast's safety regulator on its integrity management practices. However, information regarding the estimated extent to which threats of supply disruptions are mitigated by Westcoast's integrity management processes would not change FEI's assessment of the need for the TLSE Project. While integrity management processes are an essential component of the overall safety and reliability of a gas transmission system, the residual risk of a no-flow event occurring cannot be eliminated. FEI's reliance on the T-South system gives rise to the potential for a supply disruption that has very significant consequences (i.e., sudden, widespread, and prolonged outages to hundreds of thousands of customers in the Lower Mainland) that must be mitigated through added system resiliency, which the TLSE Project will provide.

68.0 Reference: PROJECT NEED

Exhibit B-15, BCUC IR 1.5.2, 9.1, 10.5.2, Attachment 1.5c, pp. 4-5

Exhibit B-22, RCIA IR 5.1

Probability of Rupture Event

In response to BCUC IR 1.5, JANA Corporation (JANA) 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.

In response to BCUC IR 9.1, FEI stated:

> 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.

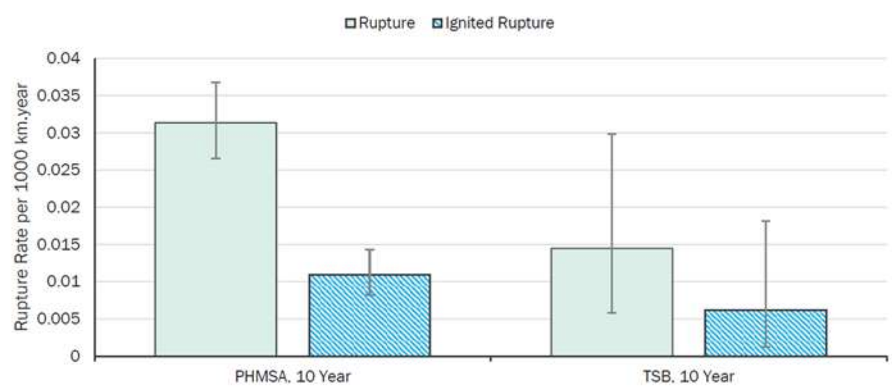
On page 4 of Attachment 1.5c, JANA stated:

> 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.
>
> …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.

On page 5, JANA provided the following figures:

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

68.1 Please explain why JANA used a 10 year dataset.

68.1.1 Please discuss whether longer datasets would result in narrower confidence intervals.

Response:

The following response was provided by JANA:

It is correct that higher levels of data would typically be expected to result in narrower confidence limits (this is generally true in any analysis). The specific outcome would depend on the specific nature of the data. Ten years was used as the basis for the analysis to represent a balance between the amount of data and the data representing current industry practices and reporting criteria.

68.2 Please discuss whether the PHMSA or TSB data provides any information regarding severity or duration of a rupture incident.

68.2.1 If so, please discuss whether there are further insights that can be derived from such data to estimate the probability of different outage lengths.

Response:

The following response was provided by JANA:

Outage duration is reported for some of the PHMSA and TSB reported rupture events. Any rupture of a 30" or 36" NPS transmission pipeline would be expected to result in an outage of at least two days duration and most likely three days or greater. Ignition events do tend to result in slightly longer outages. For PHMSA reported ruptures for pipelines 30" NPS or greater with reported outage durations, 100% had an outage duration ≥ 2 days (26 of 26) and 96% ≥ 3 days (25 of 26). For ignited ruptures, 100% of reported incidents had outage durations ≥ 3 days (20 of 20). Of the 4 TSB reported ruptures with outage durations for pipelines 30" and greater, 3 of 4 were ≥ 2 days and 2 of 4 were ≥ 3 days. For ignited ruptures, 100% of reported incidents had outage durations ≥ 2 days and 2 of 3 ≥ 3 days.

68.3 Please provide a detailed discussion of any possible reasons for the lower rupture rates in the TSB dataset, besides the difference in the size of the PHMSA and TSB datasets.

68.3.1 Given that Westcoast's T-South system is regulated by the Canadian Energy Regulator, please discuss whether the TSB dataset represents a more appropriate comparator for predicted rupture rates.

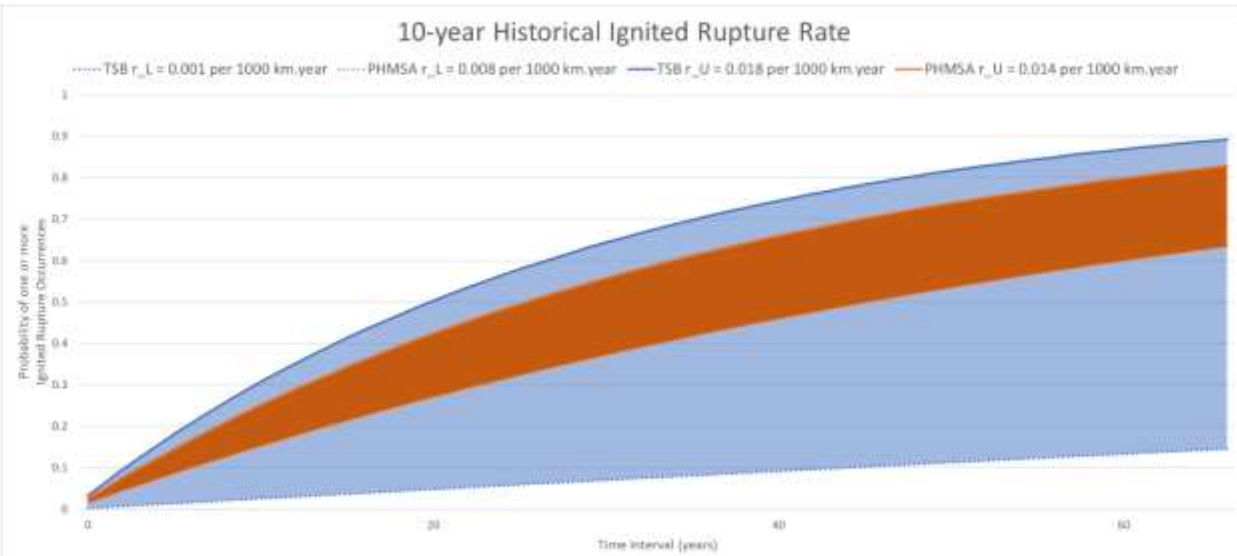
Response:

The following response was provided by JANA:

There is extremely limited data in the 10-year TSB data sets (7 ruptures and 3 ignited ruptures) versus 149 ruptures and 52 ignited ruptures for the PHMSA data. This is believed to be the primary driver of the difference between the means. For example, one additional ignited rupture in the TSB dataset would increase the TSB mean ignited rupture rate by approximately 40 percent.

The PHMSA data set was used as the basis for the analysis as it contained roughly 20 times the data of the TSB data sets, had narrower confidence limits and the 95 percent confidence limits for the datasets overlapped.

The broad confidence limits in the TSB data that result from the limited data do not, in JANA's opinion, provide for a meaningful assessment (see comparison of results for PHMSA (orange) and TSB (blue) for ignited ruptures below).



68.4 Please discuss whether the data respecting rupture rates would also be applicable to predicting rupture rates on FEI's transmission pipelines.

Response:

The following response was provided by JANA:

The rupture rates represent the average performance of North American pipelines and could be used to provide high level directional information on any pipeline system.

68.5 Please clarify whether data respecting "ruptures" as outlined in the JANA report represents the sum of ignited ruptures and non-ignited ruptures.

Response:

The following response was provided by JANA:

Confirmed.

68.6 Please confirm, or explain otherwise, that the 2018 T-South Incident would be classified as an ignited rupture.

Response:

The following response was provided by JANA:

Confirmed.

68.7 Please discuss the main factors that determine whether a pipeline rupture ignites.

Response:

The following response was provided by JANA:

The primary factors determining if a pipeline rupture ignites are the pipeline diameter (rupture probability increases with increasing diameter), operating pressure (rupture probability increases with increasing pressure), the cause of the rupture (e.g. third-party damage provides a possible ignition source) and the local environment at the time of the rupture (e.g. rocky soil, local environmental conditions, other potential ignition sources, etc.).

68.8 Please discuss if FEI considers ignited ruptures to be a more likely cause of a no-flow event affecting both T-South pipelines than non-igniting ruptures

68.8.1 Please explain under what circumstances (if any) FEI considers non-igniting ruptures on a single pipeline on T-South may result in a shutdown of both pipelines for a period of 3 days or more.

Response:

The following response was provided by JANA:

Any rupture of a 30" or 36" NPS transmission pipeline would be expected to result in an outage of at least two days duration and most likely three days or greater followed by some period of reduced capacity on the lines, whether the rupture ignites or not. For PHMSA reported ruptures for pipelines 30" NPS or greater with reported outage durations, 100% had an outage duration ≥ 2 days (26 of 26) and 96% ≥ 3 days (25 of 26). For ignited ruptures, 100% of reported incidents had outage durations ≥ 3 days (20 of 20). Of the 4 TSB reported ruptures with outage durations for pipelines 30" and greater, 3 of 4 were ≥ 2 days and 2 of 4 were ≥ 3 days. For ignited ruptures, 100% of reported incidents had outage durations ≥ 2 days and 2 of 3 ≥ 3 days.

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

The following response is provided by FEI:

As explained in the response to BCUC IR1 1.3, ruptures (whether ignited or non-ignited) are just one potential cause of a no-flow event on the T-South system. Using industry pipeline performance data, JANA has provided quantitative probabilities of pipeline failures due to ruptures only.[1] As JANA notes (in Attachment 1.5C to BCUC IR1 1.5, p. 4), a loss of supply event could arise "[…] due to many potential causes (loss of compressor stations, pipeline failure, etc.)."

Additional failure causes (which are not included in JANA's probability analysis) include physical sabotage, cyber-attacks, geotechnical / hydrotechnical / seismic hazards, and third-party damage. FEI is unable to determine quantitative probabilities for these types of events, and hence is unable to comment on whether they are more or less likely to occur than pipeline ruptures. Regardless, they are plausible causes of pipeline failures, and have occurred in other pipeline operators' systems. As such, they must also be considered when determining the total failure likelihood of a no-flow event impacting the T-South system.

[1] JANA defines rupture as follows: "Ruptures are through wall failures of the pipeline where the stress within the pipeline extends 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." (Attachment 1.5C, p. 2).

68.9 Please discuss, in the view of FEI and/or JANA, whether directionally the factors that affect the number of pipeline ruptures over time (as identified in the preamble) are more likely to result in an increase or decrease to the rate of pipeline ruptures.

Response:

The following response was provided by JANA:

There are multiple factors involved that, over the 67-year timeframe of the analysis, are difficult to speculate on. The factors that drive increasing rates of failure would be pipeline aging (time dependent threats), increased activity around the pipeline (third-party damage), increasing severity and frequency of extreme weather events, etc. The primary factors that would drive decreasing failure rates would be enhanced mitigation technologies, increased mitigation activities, pipeline replacements, etc. The uncertainty in speculating how these forces will act in concert over a 67-year timeframe is why the 10-year historical average industry performance was used for the analysis.

68.10 Please confirm, or explain otherwise, that the cumulative probability of (i) a rupture or (ii) an ignited rupture occurring on the T-South system does not equate to the cumulative probability of the occurrence of:

a. a no-flow event of any duration, and

b. a no-flow event lasting 3 days.

68.10.1 Please confirm, or explain otherwise, that there are other factors besides the occurrence of a rupture (including as but not limited to: the location of the rupture, time of year, availability of other supply resources) that would determine the extent to which the TLSE Project is needed for resiliency purposes, or whether the TLSE Project is needed at all, in the event that a rupture occurs.

68.10.1.1 Considering the responses for the previous IRs, please provide further support for the statement that there is a “high likelihood that the TLSE Project will be needed and used at least once over the 67-year analysis period for resiliency purposes.”

Response:

The following response was provided by JANA:

It is confirmed that the cumulative probabilities of (i) a rupture or (ii) an ignited rupture occurring on the T-South system does not directly equate to the cumulative probability of the occurrence of:

a. A no-flow event of any duration, and

b. A no-flow event lasting 3 days.

Any rupture of a 30" or 36" NPS transmission pipeline would, however, be expected to result in an outage of at least two days duration and most likely three days or greater followed by some period of reduced capacity on the lines. This is based on:

- 100% of PHMSA reported ruptures for pipelines 30" NPS or greater with reported outage durations had an outage duration ≥ 2 days (26 of 26) and 96% ≥ 3 days (25 of 26). For ignited ruptures, 100% of reported incidents had outage durations ≥ 3 days (20 of 20). Of the 4 TSB reported ruptures with outage durations for pipelines 30" and greater, 3 of 4 were ≥ 2 days and 2 of 4 were ≥ 3 days. For ignited ruptures, 100% of reported incidents had outage durations ≥ 2 days and 2 of 3 ≥ 3 days.
- After a rupture of one pipeline in a shared ROW, a likely outcome is that the second pipeline would be shut down to ensure integrity of the pipeline (as was done following the T-South pipeline rupture), therefore resulting in an outage on both lines. This outage would also be expected to be on the order of two to three days based on the sequence of steps involved: get to site, conduct investigation of site, assess potential impact on adjacent line, determine if and additional integrity confirmations required, approve putting line back into service, etc. (it was two days for the T-South system).
- Upon resumption of flow it is common industry practice to operate at 80% of pre-rupture pressures until additional investigations and confirmation of integrity can be conducted (both the 30" and 36" T-South lines were returned to service at 80% operating pressure). This could require supplemental gas supply through this extended period.

An outage duration of three days, therefore, for any rupture on the system seems to be a reasonable minimum duration.

The following response is provided by FEI:

Since the response to BCUC IR1 9.1 that is quoted in the final question above was prepared by FEI and was not provided by JANA, FEI responds to the final question below.

In its response to BCUC IR1 9.1, FEI addressed whether there was a potential for the TLSE Project to be "underutilized" for the duration of its expected useful life. As described by JANA in the responses to BCUC IR1 1.5, BCUC IR2 68.9, and further clarified above, FEI considers the cumulative probability of pipeline rupture on the T-South system is a significant contributor to the likelihood of a no-flow event on the T-South system. FEI reiterates that, as explained in the responses to BCUC IR2 68.8 and 68.9, other potential causes of no-flow events must be added to this cumulative probability. Given all of these potential failure causes that may occur over the long life-span of the TLSE Project, FEI has determined that there is a high likelihood that the

TLSE Project will be needed and used for resiliency purposes at least once over the 67-year analysis period.

In response to Residential Consumer Intervenor Association (RCIA) IR 5.1, FEI stated:

> Given that a no-flow incident on the T-South system is the most impactful supply disruption to the Lower Mainland, FEI commissioned an analysis to explore the probability of a T-South failure, as discussed in the response to BCUC IR1 1.5. With respect to the consequences of a T-South failure or other supply-related no-flow event, this information is quantified in Section 3.4.3 of the Confidential Application. Since risk is mathematically quantified as the probability of an undesirable event occurring, multiplied by the consequences of that event if it occurs, together these analyses represent FEI's quantified risk assessment associated with the T-South system.

68.11 Please confirm, or explain otherwise, that the occurrence of a T-South failure (for which the probability is discussed in the response to BCUC IR 1.5) will not necessarily result in the consequences outlined in Section 3.4.3 of the Confidential Application.

68.11.1 If confirmed, please explain how the combination of these analyses represents a quantified risk assessment.

Response:

FEI agrees that a quantified risk assessment typically equals the cumulative probability of the possible consequences of undesirable events, multiplied by the consequences of each outcome if they occur. Mathematically, this can be expressed as:

$$R_{total} = \sum_{n} C_n p(C_n)$$

where, R_{total} equals the total risk over the sum of n individual consequences C_n, and their probabilities $p(C_n)$.

However, this methodology is not appropriate for managing the risk associated with low-probability but high-consequence incidents. For these events, applying this methodology will typically result in a bias towards ignoring the undesirable outcomes of plausible events based solely on their low probability of occurrence. This increases the vulnerability to events that, while they may be considered unlikely, have unacceptable outcomes.

FEI does not consider a probability analysis to be necessary to support the need for the TLSE Project, because when incidents can result in consequences that are unacceptable (i.e., an extended outage to hundreds of thousands of Lower Mainland customers with attendant social and economic impacts described by PwC), a probabilistic approach is not necessary to confirm the need for mitigating actions. This principle is further explained by JANA in their paper *Managing Low Probability – High Consequence Pipeline Risk*:[2]

> When we land in Quadrant IV, what we must do is: 1.) Accept that we cannot predict what will happen, or when; 2.) Reject all narratives and projections that try to tell us what will happen and when; and 3) Work towards mitigating the consequence of such an occurrence.
>
> The fourth quadrant, then, as defined by Taleb, is about the areas in our domain (in our case, pipelines) where our knowledge is limited AND that limitation has the capability to result in an event of high consequence. Also, while we may know the probability of an event occurring, due to the complexity of the system, we will not be able to predict it in terms of where and when. This need not imply that we need to be a victim of the situation. We can take action to change our risk position.

The JANA analysis determined the cumulative probability of a rupture event on the T-South system is forecast to be between 83.1 and 97.9 percent, and the cumulative probability of an ignited rupture between 53.4 and 73.9 percent over the 67-year analysis period of the TLSE Project. Given that these incidents can lead to unacceptable outcomes (a sudden, widespread, and prolonged outage to FEI's Lower Mainland customers), FEI has prudently proposed the TLSE Project to mitigate the occurrence of this risk.

Please also refer to the response to BCOAPO IR2 2.1.

In response to BCUC IR 10.5.2, FEI stated: "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."

68.12 Please discuss whether FEI considers that the TLSE Project is being designed for an event that has a return period which is less frequent than 1 in 20 years.

68.12.1 If so, please explain.

<u>Response:</u>

The TLSE Project does not have the same drivers as FEI's capacity projects or gas supply contracts (both of which are typically driven by expected weather variability), and hence is not being designed for the 1 in 20 year return period cited in the preamble. As FEI's peak demands are driven by extreme low temperature conditions, for capacity planning purposes, FEI uses an established methodology for determining system peaks using a 1 in 20 year return period for cold weather conditions.

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[2] http://www.janacorporation.com/s/Managing-Low-Probability-High-Consequence-Pipeline-Risk-c.pdf.

In contrast, the driver for the TLSE Project is the need to increase the resiliency of FEI's Lower Mainland system in order to meet the MRPO (i.e., 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). To support this need, FEI has described all possible causes of no-flow events which include pipeline ruptures, cyber-attacks, sabotage, and other external causes outside of FEI's control. As described in the response to BCUC IR2 68.9, the cumulative probability of pipeline rupture on the T-South system is a significant contributor to the likelihood of a no-flow event on the T-South system. To this cumulative probability must be added the probability of no-flow events due to the other listed causes, which although they are not easily defined, are non-zero.

As discussed in the response to RCIA IR2 31.1, relative to probability, consequence is of greater importance in the case of a material disruption to the T-South pipeline specifically because of the unacceptable outcome that can result. As such, while there is no established method for determining a "return period" for no-flow events on the T-South system, such a determination is not necessary for confirming the need for the TLSE Project.

69.0 Reference: PROJECT NEED

Exhibit B-15, BCUC IR 5.1, 16.1

Pressure Collapse

In response to BCUC IR 5.1, FEI stated:

> 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.

In response to BCUC IR 16.1, FEI stated: "AMI [Advanced Metering Infrastructure] 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."

69.1 Please provide a detailed description of the scenarios where AMI may not be able to stop a pressure collapse occurring.

69.1.1 Please provide comments on the relative likelihood of such scenarios occurring.

Response:

FEI's proposed AMI technology will not be capable of remotely disconnecting a small group of meters within the meter fleet at this time, including a portion of the commercial meters and the industrial meters. Consequently, AMI on its own will not stop a pressure collapse from occurring in circumstances where immediate disconnection of all commercial and industrial customers from the vulnerable portion of the system is necessary to maintain sufficient pressure to avoid a collapse.

Another scenario in which AMI on its own may not be able to stop a pressure collapse occurring is if the gas supply emergency is sufficiently serious that a pressure collapse will occur before AMI is able to remotely disconnect all the Lower Mainland advanced meters within one hour (i.e., if the AMI response time is insufficient due to the system demand and the location of the interruption).

FEI is unable to comment on the relative likelihood of these scenarios due to the unknown variables that influence their occurrence. Please also refer to the response to RCIA IR2 36.1.1 for further details on how long FEI expects it will take to disconnect all Lower Mainland customers with AMI installed.

Ultimately, AMI is not a replacement for the TLSE Project; rather, the two projects are complementary resiliency solutions. Combining these solutions provides FEI with the ability to obtain near real-time system demand and supply information which will allow FEI to take a measured approach and avert a pressure collapse in almost all situations.

69.2 Please discuss whether FEI considers there are scenarios that a pressure collapse could occur following the construction of the TLSE Project.

Response:

The following response is being filed on a confidential basis as it contains security sensitive information, pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-15-19 and consistent with Order G-161-21 regarding treatment of security-sensitive information.

[redacted]

69.3 Please discuss whether all gas appliances need to be relighted following a pressure collapse.

Response:

As part of the response to the T-South Incident in 2018, 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 safely restoring gas service to as many customers and areas as quickly as possible under evolving conditions. This includes reconnect and relight strategies, divided by customer groups and geographic regions. Following a pressure collapse, all appliances will have to be relit; however, the P&R Plan recognizes essential appliances (e.g., furnaces and domestic hot water heaters) may need to be prioritized for relighting, while relighting of non-essential appliances (e.g., decorative fireplaces) may be delayed if field resources are constrained.

The P&R Plan was designed to evolve as circumstances change, including new potential technical solutions provided by AMI which provides potential new gas supply restoration options.

70.0 Reference: PROJECT NEED

Exhibit B-15, BCUC IR 6.1, 6.2, 18.2

Controlled Shutdowns

In response to BCUC IR 6.1, FEI explained the process and time required by FEI to implement a controlled shutdown. FEI stated:

> 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… 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.

In response to BCUC IR 6.2, FEI explained the process to restore service to customers following a controlled shutdown. The final stage is described by FEI as follows:

> 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.

In response to BCUC IR 18.2, FEI stated:

> 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.

70.1 Given the potential time required to initiate and restore service following a controlled shutdown described by FEI above, please explain the key differences in the potential impacts to customers following larger scale controlled shutdowns, compared to larger scale uncontrolled shutdowns.

<u>Response:</u>

FEI considers any shutdown of a system or portion of a system as "controlled" when the utility operator has the opportunity to proactively take actions to minimize both customer and system impacts. Conversely, an uncontrolled shutdown of a system occurs rapidly or under circumstances where the utility operator is forced to respond reactively, and is therefore unable to take any mitigating action(s) in advance.

While both scenarios are highly disruptive and undesirable for customers, the benefits of large-scale controlled shutdowns are that they would be less impactful than uncontrolled outages. This fact underlies FEI's P&R Plan, which was reviewed by the BCUC and determined to be in the public interest.

FEI would adjust its controlled shutdown strategy to reflect the available time and resources, balancing the need for timely action with the objective of shedding load more precisely to address supply constraints. This approach is less impactful than an uncontrolled shutdown because FEI would be able to minimize the number of impacted customers, and overall be more efficient in managing the shutdown and restoration of service. AMI will enable more precise and timely shutdowns (if and when necessary). In particular, the implementation of AMI will provide FEI more operational knowledge and control of the system to minimize customer impacts and enable a return to service sooner.

70.2 Given that FEI states the isolation phase of a controlled shutdown could take "up to several days", please discuss whether the TLSE Project buys FEI sufficient time to execute a larger-scale controlled shutdown, assuming the TLSE Project can provide 3 days of supply.

Response:

Confirmed. The TLSE Project will provide a three-day supply under peak conditions, and more time in more favourable weather conditions, providing FEI reasonable time to understand the incident, formulate a response, and then execute a controlled load-shedding strategy (if and when necessary), consistent with the factors described in the response to BCUC IR2 70.1. If system conditions necessitate that FEI complete a controlled shutdown in under three days, FEI can accelerate its shutdown plans by shutting in larger sections of the system at a time in order to meet the required timeline. Alternatively, if system conditions allow more time for FEI to complete a controlled shutdown, FEI can take the opportunity to adjust its shutdown plans accordingly and better optimize the impact on the pipeline system. For clarity, FEI considers either situation to be a controlled shutdown, given that it has had an opportunity to mitigate the impact of the outage. Having the TLSE Project in place will afford FEI greater time to tailor and optimize its response to any gas supply shortfall on the T-South system.

70.2.1 In a scenario where reduced flow followed a no-flow event, would FEI still need to initiate a controlled shutdown if the proposed 3Bcf tank had been depleted during the no-flow event, and Lower Mainland (LML) demand was greater than the reduced supply?

Response:

Even with the TLSE Project in place, there is still some possibility that a sustained no-flow event followed by a partial restoration of service from the Westcoast T-South system at reduced flow could result in the need for some controlled curtailment (shutdown) to minimize the overall impact to FEI's customers. During a partial restoration of service, FEI anticipates that some volume of gas supply would resume flowing on the T-South pipeline, providing FEI with additional flexibility to restore the supply and demand balance. The TLSE Project will provide FEI sufficient time to assess which tools could be available during this phase of the incident. As discussed in Section 3.3.3.2.1 of the Application, these tools may include:

- Curtailing firm customer load;
- Communicating conservation messaging to customers;
- Using any available on-system storage resources (e.g., Mt. Hayes, depending on the time of year);
- Accessing off-system storage resources, assuming it is both commercially and physically available;
- Purchasing incremental supply, assuming it is both commercially and physically available; and
- Enlisting mutual aid arrangements, assuming supply is not required by other parties to the mutual aid agreements and supply is physically available.

However, FEI's ability to access the above alternate supply resources can be limited or precluded depending on the time of year; in winter, for instance, physical flows in the regional supply system and competing demands from the Pacific Northwest present impediments to accessing alternative supply even after flows on T-South resume. This type of scenario thus underscores the need for both the TLSE Project as well as new pipeline expansion in the region, since each provides critical and interrelated resiliency benefits. Together, both projects would address short- and long-duration supply issues. The potential Regional Gas Supply Pipeline Diversity solution would be optimally sized having regard to managing long-duration supply disruptions such as gas supply reductions following a no-flow event (i.e., Phases 2 and 3 of the T-South Incident).[3]

[3] The T-South phases are described in Sections 3.4.2.2.1, 3.4.2.2.2, and 3.4.2.2.3 of the Application.

71.0 Reference: PROJECT NEED

Exhibit B-15, BCUC IR 7.1, 7.5

Customer Survey

In response to BCUC IR 7.1, FEI stated:

> … members of the FortisBC MyVoice community panel 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.

In response to BCUC IR 7.5, FEI stated:

> 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)…
>
> 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.

71.1 Please discuss whether FEI considers the MyVoice survey provides meaningful insights into the relative importance of resiliency to customers, given FEI's comments around customer understanding of resiliency investments.

<u>Response:</u>

Yes, FEI considers the feedback from the MyVoice survey to provide meaningful insights into the relative importance of resiliency to customers. The research investigated and confirmed that customers value initiatives undertaken to help safeguard energy infrastructure from unusual or extreme events.

71.2 Please discuss whether defining resiliency as withstanding and recovering from extreme disruption events as "severe weather-related disasters, deliberate systems damage or cyber-attacks" provides appropriate context for the primary resiliency risks underpinning the need for the TLSE Project.

Response:

FEI referred to "severe weather-related disasters, deliberate systems damage or cyber-attack" as a concise way to help respondents differentiate between typical service disruptions and less frequent but more impactful emergencies. FEI believes the approach used in the survey provided an appropriate and reasonable context for customers to evaluate different types of investments to further inform this proceeding.

Moreover, a disruption of supply from the T-South system could occur for any of the identified examples. The Colonial Pipeline disruption that occurred recently was a result of a cyber-attack. The recent outage in Colorado was due to sabotage. Fires and other natural events can also disrupt service on energy infrastructure. Please also refer to the responses to BCUC Confidential IR1 15.3 and RCIA IR1 9.1 for a description of the disruption caused by the 2016 wildfire event in Fort McMurray.

71.3 Please discuss whether FEI has considered ways of better educating its customers around the concept of resiliency and the associated costs and benefits. If not, why not?

Response:

FEI has engaged with customers and the public extensively to educate them on the Project costs and benefits in accordance with its Communications and Engagement plan. This communication includes education regarding the resiliency benefits of the Project through various channels including public information sessions, bill inserts, talkingenergy.ca posts, and direct communication. In addition, the regulatory processes provides an important venue for exploring the need for resiliency investments.

72.0 Reference: PROJECT NEED

Exhibit B-15, BCUC IR 1.3.1, 8.1, 8.2, 8.3

Exhibit B-21, MS2S IR 4i

Duration of No-Flow Event

In response to BCUC IR 1.3.1, FEI stated:

> 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.

In response to BCUC IR 8.1, FEI stated (in part):

> 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…
>
> 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.

72.1 Please discuss which types of incident require assessment by the Canada Energy Regulator, and the nature and duration of such assessments.

Response:

Companies regulated by the Canada Energy Regulator (CER) must comply with the CER's reporting requirements.[4] When an incident (as defined in the CER Event Reporting Guidelines) occurs, it must be reported to the CER immediately. Detailed supporting information is generally provided within 12 weeks from the date the incident was reported. Companies must also provide the CER with an explanation of the incident's root cause and any corrective action(s) taken to prevent future occurrences.

The CER reviews all reported incidents in order to assess whether companies that it regulates have taken appropriate corrective and preventative action(s). The nature and duration of these assessments are ultimately determined by the CER and reflect the specific circumstances of an incident. If a non-compliance is identified during the course of its review of an incident, the CER has the power to undertake enforcement action. The CER may also open a formal investigation of an incident on its own or working with other government bodies.

In the case of more serious incidents, such as a pipeline failure, the CER will not allow the pipeline to return to service until it is satisfied that it is safe for operation. The CER can order operators to take actions that may extend the duration of a service disruption. As demonstrated by the CER's response to the Westcoast T-South rupture in 2018, the CER can impose a precautionary operating pressure restriction until such time that mitigating actions are completed and that it is satisfied that the pipeline can again be operated safely at its maximum operating pressure. The mitigation actions undertaken by Westcoast to comply with the CER's requirements required over one year to complete before the CER's concerns were addressed and allowed for full operation to be re-established.

72.2 Please clarify whether "pipeline operator" as referenced in the response to BCUC IR 8.1 refers to FEI, Westcoast, or both.

Response:

The reference to "pipeline operator" in the response to BCUC IR1 8.1 refers to both Westcoast (as the upstream gas supplier) and FEI (as the downstream distributor of gas to end-use customers).

4 https://www.cer-rec.gc.ca/en/about/acts-regulations/cer-act-regulations-guidance-notes-related-documents/canada-energy-regulator-event-reporting-guidelines/index.html.

72.3 Please provide further support for the statement "three days was a reasonable minimum amount of time for a pipeline operator to make an informed decision on next steps" [Emphasis added], given that the T-South incident lasted two days.

72.3.1 Please explain why a pipeline operator cannot make informed decisions on next steps in fewer than three days.

Response:

FEI agrees that the amount of time to make an informed decision will vary depending on a number of factors, and that three days may not be required in all instances to make an informed decision, including whether to take actions that are irreversible in the short-term (such as shutting off supply to portions of the Lower Mainland to balance available supply and demand). With the above quoted statement, FEI was intending to make the point that, in the current context where there is insufficient regasification capacity and storage in the Lower Mainland for FEI to outlast a no-flow event of any material duration, FEI is forced into making decisions and taking actions that are irreversible in the short-term almost immediately and in the absence of reliable information will not have the luxury of being able to take a measured approach to shut-down its system. Extending this decision-making interval to three days maximizes the ability for FEI to collect information, assess and evaluate the situation, consider the timeliness of repairs, curtail demand in a tailored way that minimizes overall harm, arrange alternate supply if available and determine the appropriate next steps.

Based on the actual two-day no-flow duration of the T-South Incident (and that it is plausible that this duration could have been extended if challenges in accessing the rupture site had occurred), three days is a reasonable amount of time to allow FEI to make an informed determination of the utility's next steps so as to minimize the extent of a controlled shut-down. Given the size of the T-South system and potential challenges in accessing failure sites, it is reasonable to expect that communicating the situation status of the incident could take several days.

In BCUC IR No. 1, BCUC asked the following questions:

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.

In its response, FEI referred to its responses to BCUC IR 8.1.

72.4 BCUC notes that FEI does not appear to have not directly addressed the BCUC IR 8.3 series. Please address each of the above noted questions in turn. For further clarity, BCUC emphasize that IR 8.3 seeks further support for FEI’s view on why the most probable duration of a no-flow event is at least three days, compared to some other duration, with supporting analysis.

Response:

The series of questions was premised on a misunderstanding of FEI’s position. For clarity, it is not FEI’s view that a 3-day no-flow event duration is the “most probable” outcome, but rather that it is a *plausible* no-flow duration that FEI’s system must be able to withstand. A fundamental underpinning of the need for the TLSE Project is the need to increase the resiliency of FEI’s Lower Mainland system. By definition, projects to increase resilience should not be designed to accommodate the “most probable” scenario outcomes. Instead, they must consider outcomes that—while they may be less likely—are still possible. This is further explained in Section 1.1 of Appendix A, where Guidehouse defines resiliency as “[…] the ability to prevent, withstand and recover from system failures or unforeseen events such as damage and/or operational disruption that impact the operations of the system.” [emphasis added]

Please also refer to the responses to BCUC IR2 68.11, 72.3, and 72.5 which further explain why a probabilistic approach based on mostly likely outcomes is not appropriate when confirming the need for mitigating actions to address incidents that can result in unacceptable consequences.

FEI believes that there is ample evidence to support a three-day no-flow event being a plausible scenario that should be addressed. First, in the case of the October 2018 Westcoast T-South Incident, the no-flow portion of the event lasted approximately 2 days. As discussed in Section 3.4.4.1 of the Application, this incident occurred during favourable conditions that allowed Westcoast to access and assess the site, which allowed for relatively timely restoration of service (albeit, with greatly reduced capacity for the subsequent three week period). There is no certainty that the time of occurrence or location of a future pipeline failure would support a similar response time. In Section 3.4.4.1, FEI noted that the very real potential exists under somewhat less favourable conditions for a no-flow supply emergency to last three days, or conceivably longer.

This 3 day duration is further supported by JANA’s evidence in the response to BCUC IR2 68.10 where it notes that:

> 100% of PHMSA reported ruptures for pipelines 30” NPS or greater with reported outage durations had an outage duration ≥ 2 days (26 of 26) and 96% ≥ 3 days (25 of 26). For ignited ruptures, 100% of reported incidents had outage durations ≥ 3 days (20 of 20).

JANA also expressed the view in its responses to BCUC IR2 68.8 and 69.10 that a rupture of one of the T-South pipelines would likely result in the shut-down of the adjacent pipe for two days or longer to assess the integrity of the adjacent line.

FEI's responses to the BCUC IR1 8.3 series remain accurate.

In response to BCUC IR 8.2, FEI stated:

> 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 T28 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…
>
> 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.

72.5 Please discuss whether the MRPO requires that a no-flow event is coincidentally severe in nature, occurs in unfavourable conditions for Westcoast to respond, occurs in during a period of significant demand for FEI's customers in the LML, and assumes no other supply resources are available to FEI.

Response:

FEI does not agree with the premise that the MRPO reflects the combination of coincidental events. All of these conditions are associated with winter months. As discussed in the response to BCUC IR2 78.1, had the 2018 T-South Incident simply occurred in winter rather than October, there would have been widespread and prolonged outages in the Lower Mainland on the *first* day of the no-flow event. FEI knows from its own experience that snow would have unquestionably slowed Westcoast's response time to repair the pipeline.

In any event, as discussed in the response to BCUC IR2 72.4, resiliency projects are intended to prevent, withstand and recover from system failures or unforeseen events such as damage and/or disruptions that have unacceptable impacts on the operation of the system. As such, these events must go beyond a consideration of the *most probable* outcomes and must consider the *possible* outcomes. Given that there is an extended period during the winter months for which the Lower Mainland system currently could not withstand a single day without supply from the T-South system without widespread prolonged outages, and the evidence that a 3-day no-flow period is a plausible outage duration, the MRPO is a prudently determined statement that articulates an appropriate level of resiliency for FEI's Lower Mainland customers. Please also refer to the response to BCUC IR2 68.11.

72.6 Please discuss whether FEI had identified the risk of dependency on T-South prior to the 2018 Incident.

72.6.1 If so, please explain whether FEI had contemplated establishing a minimum resiliency planning objective prior to the 2018 Incident.

Response:

Given that all of the gas supply to the Lower Mainland originates from a single point (the Huntingdon Station near Abbotsford) which is primarily supplied by the T-South system, FEI has long been aware of its exposure to upstream supply disruptions which could affect its ability to take gas from this delivery point.

FEI placed some reliance on the apparent redundancy inherent in the T-South system, which consists of two pipelines (though both are located in a single right of way), and as such did not identify a minimum resiliency planning objective prior to the 2018 Incident. However, during the T-South rupture in October 2018, both pipelines were shut-in: one due to the rupture, and the other as a precautionary measure by Westcoast due to its proximity to the rupture and unknown condition. As such, the T-South Incident in October 2018 underscored that FEI's current reliance on a single pipeline system for most of its supply creates a challenge for FEI's system resiliency.

In response to My Sea to Sky (MS2S) IR 4i, FEI develops a timeline to illustrate how a no-flow event could last three (or more) days. The timeline includes the following assumptions:

- The rupture occurs early on a winter morning;
- The rupture occurs in steep mountainous terrain without helicopter landing sites;
- There is early winter snow and unplowed service roads;

- A snowstorm occurs after the mobilization of construction and emergency response personnel, bringing heavy snowfall, limited visibility and temperatures of minus 20°C to the emergency response area;
- Construction equipment and emergency response personnel must be winched down a steep slope to the actual site of the failure.

72.7 Please discuss the extent to which the illustrative timeline described above represents the convergence of several worst cast factors.

72.7.1 Please explain how this scenario provides support for FEI's assumption that the most probable duration of a no-flow event is at least three days.

Response:

For clarity, FEI was not suggesting the illustrative timeline described in the response to MS2S IR1 4i was the most likely scenario culminating in a no-flow event, nor does it represent a "convergence of several worst case factors". Low pressure weather systems resulting in the conditions noted above (i.e., low temperatures and high snowfall) occur multiple times each winter in BC. Arctic outflow conditions that bring extreme cold to much of BC occur at least once or twice each winter on average.[5] Since FEI's customer load is highly correlated with cold temperatures, system peak demands and lack of access to mutual aid and off-system storage would be expected to occur coincident with the same conditions that would hinder access to the location of a pipeline failure. Finally, the Westcoast T-South system traverses over 900 km through remote and unpopulated areas, many of which are mountainous or otherwise difficult to access and that experience significant snowfall in winter. As such, the illustrative timeline does not represent a worst-case scenario, and is but one plausible outcome of many that could occur and that drive the need for the TLSE Project.

[5] The Weather of British Columbia, NAV Canada (2001), p. 67. https://www.navcanada.ca/en/lawm-bc-en.pdf.

73.0 Reference: PROJECT NEED

Exhibit B-15, BCUC IR 9.2

Cost-reasonableness

In response to BCUC IR 9.2, FEI stated:

> 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)…

73.1 Please discuss whether "ample storage" suggests building more storage than FEI expects to require.

<u>Response:</u>

FEI considers "ample storage" in this instance to be synonymous with an "appropriate and reasonable amount of storage that addresses FEI's gas supply and resiliency needs, provides opportunities to mitigate costs through commercial arrangements, and also leverages economies of scale." It is not intended to suggest that FEI would build more storage than expected to be required.

74.0 Reference: PROJECT NEED

Exhibit B-1-4 (Updated Application), p. 74

Exhibit B-15, BCUC IR 4.2, Attachment 4.2 p. 3

Mutual Aid

On page 74 of the Updated Application, FEI states:

> Participation in this organization is a key aspect of emergency planning for potential issues on the gas supply system in the Pacific Northwest; however, similar to other points made above, it does not provide FEI with certainty in the event of a supply disruption.

In response to BCUC IR 4.2, FEI stated:

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

Page 3 of Attachment 4.2 states:

> In the event of a major natural gas regional emergency, <u>it is expected that many or all of the Members could be directly involved in providing assistance</u>. 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. [Emphasis added]

74.1 Please discuss whether the language in Attachment 4.2 should be interpreted to mean that under most circumstances, mutual aid is expected be available in a major natural gas regional emergency.

<u>Response:</u>

The language in the NWMAA (Attachment 4.2) should not be interpreted to mean that mutual aid is expected to be available under most circumstances in a major natural gas regional emergency.

First, participation in the NWMAA is voluntary, and there is no obligation on the part of signatories to mutual aid agreements guaranteeing any support in the event of an emergency. The level of assistance will vary as between emergencies, and in practice, member organizations must first assess the impacts of an emergency on their own resources, service territories and customers. The location, severity, time of year and duration of the event, among other factors, will determine what level of response and assistance (if any) a member organization will be able to provide.

Second, the most significant potential source of mutual aid assistance is from entities in the US Pacific Northwest, and there are hydraulic limitations on FEI's ability to access physical gas molecules from the US during certain times of the year. As discussed in Section 3.5.6 of the

Application, mutual aid support was only physically possible in 2018 because of when the T-South Incident occurred (October). In the Winter period, the high demand in the US Pacific Northwest means that gas can only physically flow north-south across the border.

75.0 Reference: PROJECT NEED

Exhibit B-15, BCUC IR 11.10

Southern Crossing Pipeline (SCP)

In response to BCUC IR 11.10, FEI stated:

> 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.

75.1 Please outline the length of the T-South pipeline that is north of Kingsvale, in km and as a percentage of the total length of the pipeline.

Response:

The T-South pipeline that is north of Kingsvale (i.e., between Station 2 and Kingsvale) is approximately 744 km, which is 81 percent of the total length of the T-South pipeline. The distance between Kingsvale south to Huntingdon is approximately 172 km.

75.1.1 Please discuss whether FEI could rely upon 105 MMcf/day from SCP to serve LML demand at all times of the year, in a scenario where the cause of a no-flow event on the T-South system occurred north of Kingsvale.

Response:

It would be possible to access 105 MMcf/day from SCP in most, but not all, circumstances. FEI conducts integrity work on the Southern Crossing Pipeline (SCP), maintenance and upgrades on compressor units and stations that provide compression to move the gas on SCP, and capital project work in the Interior System. When these activities are in progress, the capacity of the Southern Crossing Pipeline may be reduced, and therefore, the design capacity of 105 MMcf/day may not be available during a no-flow event on the T-South system.

76.0 Reference: PROJECT NEED

Exhibit B-15, BCUC IR 11.9, 11.9.2

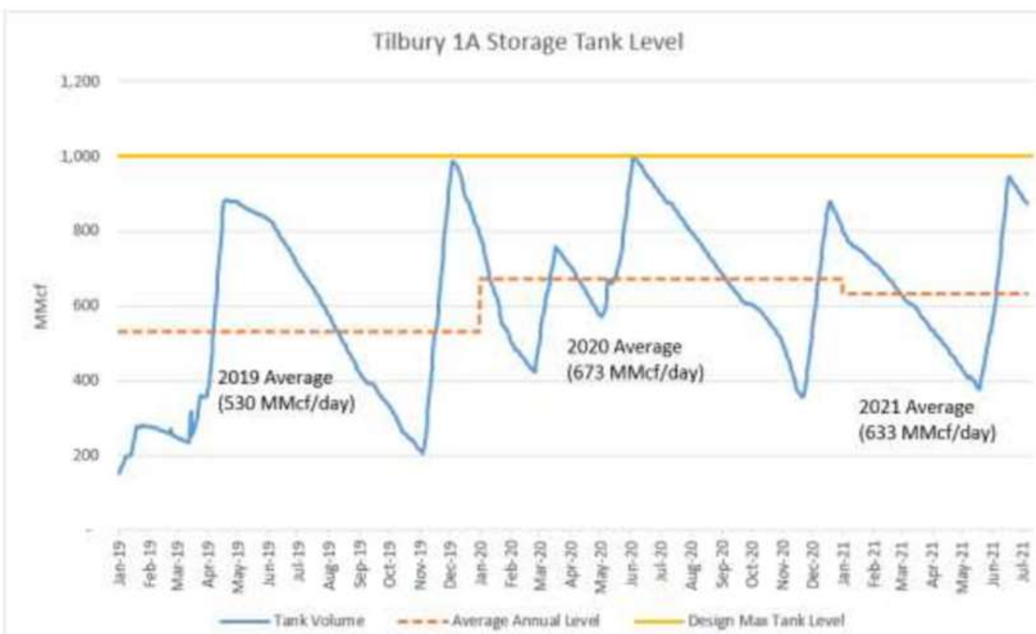
Resiliency of Tilbury T1A Tank

In response to BCUC IR 11.9, FEI stated:

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

In response to BCUC IR 11.9.2, FEI stated: "The average storage volume increased to 673 MMcf/day for 2020."

In response to BCUC IR 11.9.2, FEI provides the following graph of the Tilbury T1A tank storage level since operation began in January 2019:



76.1 Please explain whether FEI could manage the volume in the Tilbury T1A tank to better support resiliency, while still meeting its obligations to liquefied natural gas (LNG) sales customers. For example, by ensuring there are higher storage volumes during winter.

Response:

As an initial point, it should be understood that no matter how much volume is available in the Tilbury T1A tank at the time of a no-flow event, FEI's current ability to use it to withstand the no-flow event is constrained by the existing regasification capacity at Tilbury (150 MMcf/day). In other words, FEI cannot regasify the stored volume of LNG fast enough to support the Lower Mainland system load. As explained in the response to BCUC IR2 78.1, the regasification constraint means that the Lower Mainland would currently experience widespread and prolonged outages on the first day of a no-flow event occurring any time during the winter months. This outcome would occur irrespective of the volumes in the Tilbury T1A tank at the time.

Removing that regasification constraint on its own without replacing the entire Base Plant is impractical (as discussed in the response to BCUC IR2 78.1), such that in reality, LNG in the Tilbury T1A tank would only become useful as a potential additional resource to help FEI withstand a no-flow event once the TLSE Project is built and regasification capacity at Tilbury is significantly expanded. At that point, FEI could, in theory, improve the resiliency value of Tilbury T1A by ensuring the Tilbury T1A tank is full at the start of the winter heating season, and when possible, maintaining higher LNG volumes during the winter heating season. However, the LNG storage volume that FEI would be able to maintain during the winter months is a function of the volume of sales that are committed during that winter.

As discussed in the response to BCUC IR1 11.9.4, the purpose of the Tilbury T1A facilities is to serve customers under the BCUC-approved Rate Schedule 46 (RS 46). Direction No. 5 to the BCUC constrains the BCUC's ability to require volumes in the Tilbury T1A tank to be set aside for resiliency purposes such that they would be unavailable for LNG sales. Some RS 46 customers are using LNG to displace higher carbon intensity fuels for power generation and industrial uses that have seasonal variations, and as such, the LNG volumes stored in the tank will be drawn down during the winter months.

76.2 Please explain why FEI does not maximize storage levels year-round.

Response:

When considering the optimum storage levels for the Tilbury T1A tank, FEI must consider the cost of LNG production. The Tilbury T1A liquefaction facility produces up to 1500 cubic metres of LNG per day, which would fill the T1A storage tank from empty in approximately 30 days. The draw-down of LNG from the tank depends on the volume of LNG sales. From 2019 to present, LNG sales have not been equal to the LNG production capacity. As a result, the liquefaction plant must shut down to allow the LNG storage levels in the tank to drop sufficiently to restart liquefaction.

Each startup of the liquefaction facility requires additional effort, including pre-start checks and activities, and there is increased stress on rotating equipment during starts and shutdowns. For these reasons it is desirable to minimize the number of startups throughout the year. While FEI could run the plant at lower rates to fill the tank more slowly, the energy efficiency of the plant is impacted at lower production rates, meaning there would be a higher cost to produce LNG.

Based on the above considerations, FEI balances the overall cost and equipment impacts by optimizing production runs to reduce operator effort during startups, preserve energy efficiency (i.e., run at design rates), and minimize the number of stops and starts during the year.

Tilbury T1A has only been in operation for two years (including operating through the COVID-19 pandemic, which has impacted LNG sales). As a result, the storage levels reported in the above graph may not be indicative of future storage levels. Further, as explained in the response to BCUC IR1 11.9.2, tank levels will be managed considering both LNG sales and maintenance activities. From an operational perspective, it is preferable to keep LNG storage levels high to provide inventory in the event of an unplanned liquefaction outage; however, the ability to keep tank levels high will continue to be impacted by the considerations described above.

As FEI noted in the response to BCUC IR2 76.1, regardless of the volumes in the Tilbury T1A tank at the time of a no-flow event, FEI could not make effective use of it to prevent a collapse of the Lower Mainland system in winter without expanding the current regasification capacity (MMcf/day) at Tilbury as contemplated in the TLSE Project.

77.0 Reference: PROJECT NEED

Exhibit B-15, BCUC IR 7.3, 11.9.1

Curtailment of LNG Customers

In response to BCUC IR 7.3 FEI confirmed it has the right to restrict service to its customers under FEI's General Terms and Conditions and that in certain circumstances a no-flow event on T-South could constitute an emergency.

In response to BCUC IR 11.9.1, FEI stated:

> 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.

FEI's LNG sales and transportation customers take service under Rate Schedule 46 (RS46).

77.1 Please explain how FEI would determine the priority of services to its RS 46 LNG customers compared to other firm service customers during a no-flow event on the T-South system.

Response:

FEI's approach to prioritizing customer curtailments in circumstances where there is a supply emergency is determined by FEI's confidential System Preservation and Restoration (P&R) Plan which, pursuant to Letter L-32-18, the BCUC found to be in the public interest.

The details of the P&R Plan are security sensitive, but at a high level the P&R Plan contemplates firm LNG customers initially being served from the remaining Tilbury 1A volumes under the RS 46 curtailment priority, and thereafter being included in curtailment groupings along with other natural gas customers. As explained in the P&R Plan (pp. 6-7), this approach is informed by the current regasification constraint at Tilbury which physically limits the amount of supply injected into the system to 150 MMcf/day, regardless of the volume available in Tilbury 1A (see FEI's responses to BCUC IR2 76.1 and IR2 78.1 for further discussion of the implications of this regasification constraint). The groupings are informed by considerations relevant to minimizing the extent of an outage and the overall harm.

77.2 Please discuss whether FEI would prioritize the restriction of service to LNG sales during a no-flow event on T-South in order to maintain service to other firm customers in the Lower Mainland.

Response:

Please refer to the response to BCUC IR2 77.1.

78.0 Reference: PROJECT NEED

Exhibit B-1-4, Section 3.5, pp. 57-74

Exhibit B-15, BCUC IR 7 series, 11.2, 11.8. 11.9.2

Exhibit B-24, Sentinel IR 29a

Resiliency of Tilbury T1A Tank

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; and
- Mutual aid agreements.

In BCUC IR 11.2, the BCUC asked: "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."

In response, FEI stated: "If purchases are excluded, the only remaining tool available to support the LML load is the Tilbury Base Plant." FEI further explains that the capability of the base plant is limited to its vapourization capability of 150MMcf/day, which would be able to supply the Lower Mainland load on 95 days of the year.

In response to BCUC IR 11.9.2, referring to the volume of LNG in the Tilbury T1A tank, FEI stated: "The average storage volume increased to 673 MMcf/day for 2020."

In response to Sentinel Energy Management Inc. (Sentinel) IR 29a, FEI stated: "Linepack provides 3.6 hours of supply under no-flow."

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."

In response to BCUC IR 7 series FEI confirms it has the right to restrict service to its customers under FEI's General Terms and Conditions.

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.

In response to BCUC IR 11.8, FEI stated:

> 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.

78.1 Please explain, if a three-day no-flow scenario were to materialize in 2021/2022, which days or periods of the year FEI could avoid a pressure collapse in the Lower Mainland based upon the following assumptions:

-Tilbury base plant tank is full at 0.6Bcf;

-Tilbury T1A tank is at its annual average level of 673MMcf;

-Linepack as stated in the preamble is present and used-interruptible load is shed equivalent to 10 percent of FEI's load using AMI meters;

-Mount Hayes LNG can backfeed the Lower Mainland 60MMcf/day during warmer periods; and

-customers conserve an average of 39MMcf/day during the no-flow event.

<u>Response:</u>

In order to be responsive, FEI has provided an answer to this hypothetical scenario, but it was necessary to adjust certain supply assumptions that physically cannot occur.

In summary, the analysis shows that, even with all available supply sources and the demand assumptions provided, FEI would not be able to withstand a winter disruption on the T-South system for the following reasons:

- For approximately 200 days of the year, FEI would not be able to supply the single-day load requirements of the Lower Mainland. Large portions of the Lower Mainland system, equivalent to entire municipalities, would have to be shut down within hours of a no-flow event on the T-South system occurring in a normal winter. This is due to the fact that, no matter how much storage is assumed to be available at Tilbury (including the Tilbury T1A tank), the limited regasification capacity at Tilbury (150 MMcf/day) constrains FEI's ability to regasify and send-out stored volumes of LNG at Tilbury into FEI's Lower Mainland system.

- Resolving this regasification capacity limitation, in practice, means constructing a new facility at Tilbury that incorporates both storage and regasification.
  - Attempting to attach new regasification units to the existing 50-year old Base Plant storage facility to increase its regasification capacity (measured in MMcf/day) would be technically challenging and costly to the point where FEI would not consider it to be a prudent investment. Most of the existing Base Plant infrastructure is not adequately sized for the volume of regasification required. It would still leave unresolved the fact that the tank itself is already 50 years old.
  - Moreover, even if for the purposes of this hypothetical scenario the Base Plant regasification constraint at Tilbury is ignored and one were to assume that FEI would choose to imprudently add regasification to the undersized 50-year old Base Plant facility, the dependable storage volume available at Tilbury would have to be much larger than it is now to outlast a significant no-flow event. Under the assumed conditions, FEI would likely have to begin a controlled shutdown of large parts of the Lower Mainland system within two days of the no-flow event to avoid running out of supply on the third day of a no-flow event occurring in winter. This is because expanding the regasification capacity would quickly exhaust the existing storage (measured in Bcf) volumes.

These scenarios reinforce why FEI needs both additional regasification capacity and storage at Tilbury for resiliency purposes (i.e., a minimum of 2 Bcf of storage and 800 MMcf/day of regasification).

Explanation of Scenario Assumptions

FEI's assumptions for this analysis are provided below, along with further discussion about why certain assumptions had to be modified:

1. The analysis performed below assumes that 0.6 Bcf is available from the Base Plant. Although the design capacity of the Base Plant tank is 0.6 Bcf, FEI is currently operating the tank at a reduced capacity while it assesses the future operability of the tank. This was explained in Section 3.5.4.1.2 of the Application. The assumption that the entire 0.6 Bcf is available for resiliency purposes also departs from the way that the Tilbury Base Plant currently operates, which is to use the stored LNG to serve peak demand and/or other operational related purposes.
2. The analysis performed below assumes that 0.67 Bcf is available from the T1A tank. However, taking the annual average level of the T1A tank of 673 MMcf (0.67 Bcf) assumes FEI will have access to stored LNG in the T1A tank for resiliency purposes. The tank was built to support LNG sales pursuant to *Direction 5 to the British Columbia Utilities*

Commission and Direction 5 constrains dedicating its use for other purposes.[6] As discussed in the response to BCUC IR1 11.9.1, many LNG sales customers are firm customers with similar expectations as natural gas customers for firm service. Therefore, FEI cannot plan to use the Tilbury T1A tank inventory as this scenario suggests.

3. The line pack discussed in the preamble above was based on a hypothetical scenario posed in round one of the IRs and cannot occur in practice. Specifically, the question asked about the time until a complete system collapse of FEI's Coastal Transmission System. As discussed in the response to MS2S IR1 6i, it is not possible operationally to expend the line pack to complete system collapse and then continue operating the system. Instead, FEI would only be able to expend a small fraction of the line pack in each daily peak period, and would have to rebuild it during subsequent daily off-peak periods from any available supplies in order for the system to continue to function. Therefore, FEI has not included any line pack volume in this scenario.

4. As discussed in the TLSE Workshop[7] and further detailed in the responses to BCUC IR1 19.1 and 19.6, the analysis included in the Application was based on the assumption that FEI has already shed all interruptible customer demand. Therefore, FEI does not need to revise the demand curve for the scenario in this IR to reflect shedding of interruptible load.

5. FEI has taken into account 39 MMcf/day of customer conservation during a no-flow event as requested, which reflects the average amount conserved during the T-South Incident. However, as discussed in the response to BCUC IR1 13.1, in the absence of AMI this should not be considered a reliable demand side resource, as the public's response and conservation of their demand cannot be relied upon, particularly during cold winter weather. Further, similar to FEI's concern with load-shedding using AMI, customer conservation does not address the lack of gas supply issue during a no-flow event and its impact on customers.

6. The calculations assume an operating regime where the Mt. Hayes LNG facility is able to backfeed the Lower Mainland 60MMcf/day during the summer period only (i.e., April to October). As noted in the preamble, this is close to the maximum reverse flow capability from Mt. Hayes. This reverse flow may also be delayed by several hours, given that there are certain months in the summer during which the Mt. Hayes facility undergoes maintenance.

Finally, the following analysis is also based on the 2019/20 design load forecast and not the 2021/22 gas year, to remain consistent with the analysis that was conducted in the Application and the first round of IRs. However, FEI confirms there is no material difference between the two load forecasts.

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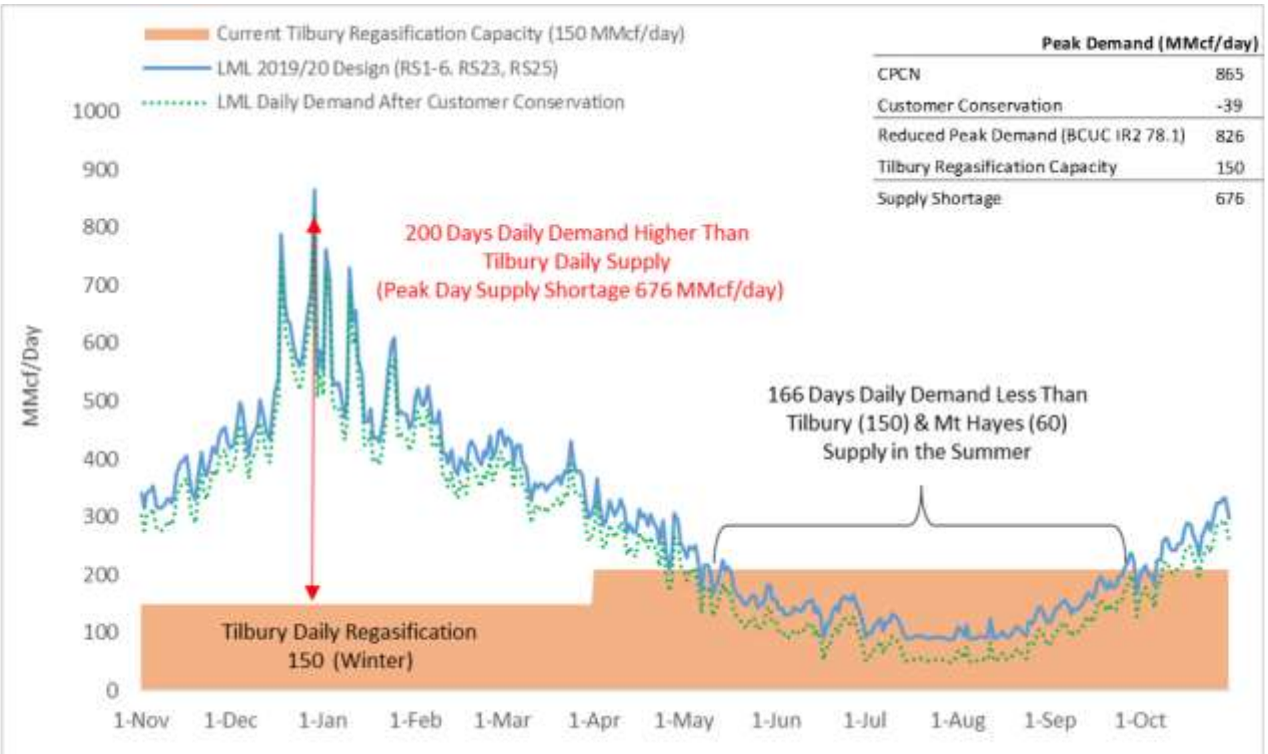
[6] Section 5(4) of Direction No.5 to the BCUC states: "The commission must not exercise a power under the Act in a way that would directly or indirectly prevent FortisBC Energy Inc. from providing LNG dispensing service under the LNG rate schedule."

[7] Transcript Volume 1, pp. 176.

The Impact of the Limited Regasification Capacity at Tilbury

This hypothetical scenario is limited to the 150 MMcf/day of regasification capacity available at Tilbury. As Figure 1 below shows, the current regasification capacity is inadequate to meet the single-day load requirements of the Lower Mainland for 200 days of the year.

Figure 1: Single Day Capacity View – 200 Days of Supply Shortfall During Winter due to Regasification Capacity Constraints



Eliminating the Regasification Constraint Is Impractical and Insufficient in Any Event

As described below, it is unrealistic to contemplate addressing the regasification constraint without replacing the Base Plant in its entirety. Even if, hypothetically, new regasification equipment could be appended to the Base Plant tank to increase the Tilbury send-out capability to 800 MMcf/day for the above assumptions, the tank would still be undersized and incapable of bridging a three-day no-flow event.

<u>Significant Work Would Be Necessary to Upgrade the Existing Facilities (Base Plant and T1A Tank) to Eliminate Regasification Constraint</u>

It would be impractical and costly to redesign the existing Base Tank and T1A facilities to support the required 800 MMcf/day of regasification capacity. The existing regasification equipment at the Base Plant is significantly undersized compared to the MRPO requirements. New regasification trains (similar to those proposed in the current Application) would be required to meet FEI's resiliency needs. The existing ancillary equipment would be undersized to support the higher send out rate. Thus, at a minimum this scenario would involve:

- New high pressure pumps (200 MMcf/day each) with a new pump house and changes to the existing Base Plant tank piping;
- New ancillary piping and pipe racks including an 18 inch line connecting the Base Plant tank to the T1A tank; and
- New vapourizers sized to meet the required capacity and response times.

An AACE Class 5 cost estimate for the above infrastructure alone is approximately $215 million. However, this new equipment would still be connected to two assets (one of them, the Base Plant tank, is 50 years old) which were not designed to operate in the new configuration. As such, additional engineering and investments would be required to ensure the system could operate reliably for the design life of the new equipment under significantly different operating parameters (i.e., increasing regasification output five-fold). Other considerations which have not been included in this already significant cost estimate include:

1. Redesign of the Base Plant tank and T1A tank safety and control systems. The safety features and control systems would require upgrading to meet current codes and regulations for the new operating scenario in order to process a significantly larger volume of LNG.
2. New vacuum relief valves and vacuum breaker system. Due to the increased LNG outflow rate from the tank, the vacuum pressure protection systems would also require upgrading. Further, the new mode of operation would necessitate new pressure relief valves and additional nozzles for the new operating scenario. Significant modifications to the Base Plant tank top and roof structure would be required. It is unknown at this stage whether the tank would be able to withstand the addition of new nozzles or the full scope of modifications required to accommodate this change.
3. In order to provide the necessary reliability, new boil off gas compressors would be required sized to match the new operating scenario.

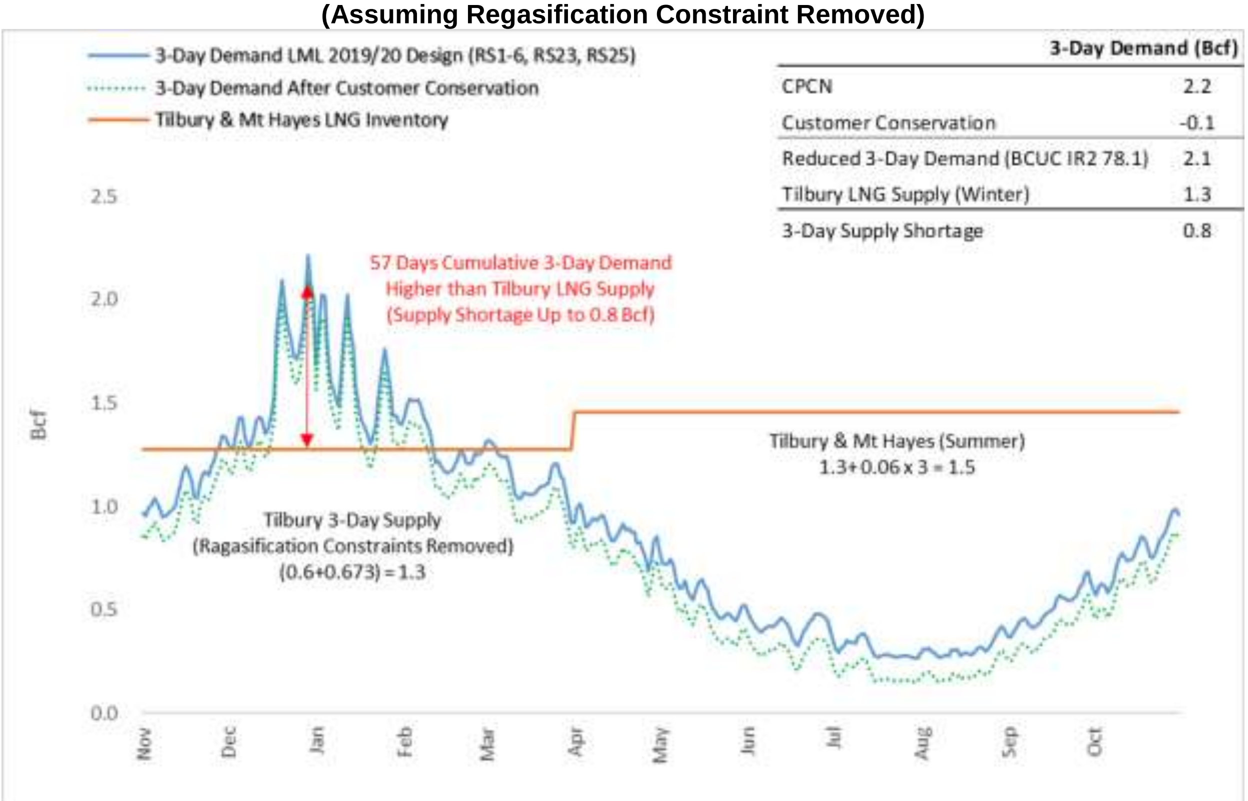
Finally, the Base Plant tank is currently operating at a reduced capacity. There would be no point in initiating the above significant retrofits without ensuring that the Base Plant tank could hold the full 0.6 Bcf design inventory. This could require draining the tank and conducting an internal inspection as well as completing structural reinforcements to ensure the ability of the tank to meet current seismic requirements.

All of the Above Work Would Still Leave FEI Short on Storage Volume

Even if the existing regasification constraint is removed for the sake of argument and the Base Plant tank was capable of holding the full 0.6 Bcf design capacity, the hypothetical scenario suggests that FEI would have only approximately 1.27 Bcf of Tilbury supply to handle a 3-day no-flow event (i.e., Assumptions #1 and #2 as listed above). Even if FEI reduces customer demand through conservation (Assumption #5), the cumulative three-day demand in the Lower Mainland would be 2.1 Bcf, compared to 2.2 Bcf as set out in the CPCN. Setting aside the fact that the existing Tilbury facilities are not designed for resiliency purposes, Figure 2 below shows that there still would not be sufficient supply to bridge a three-day no-flow period occurring any time during the winter period.

Although the two-day rolling demand based on no regasification constraint is not shown in the figure below, FEI confirms that there were five days in the 2019/20 Design Year where FEI would have exhausted its supply in less than two days. Such periods could occur at any time during the heating season. The shorter duration leaves even less time for FEI before it would have to conduct a controlled shutdown (which is irreversible in the short-term), and it would likely have to start the shut-down process on the first day of the no-flow event.

Figure 2: Cumulative 3-Day Demand and Supply to Determine Storage Size (Assuming Regasification Constraint Removed)



This analysis validates FEI's primary concern, which is that the load requirements for Lower Mainland customers are so significant that FEI currently has no resource available that can help FEI avoid a pressure collapse if a no-flow event occurs during the winter season.

78.1.1 Please explain why this level of resiliency/insurance does not represents a reasonable of level resiliency.

Response:

The resources discussed in the preamble do not provide a reasonable level of resiliency because, even if they could be relied upon and were available together (which is not realistic), they would not be sufficient to avoid exposing large numbers of Lower Mainland customers to sudden, prolonged, and widespread gas supply outages resulting from no-flow events on the T-South system. This is demonstrated in the response to BCUC IR2 78.1.

79.0 Reference: PROJECT NEED

Exhibit B-22, RCIA IR 18.1, 18.3

Lifespan of Existing Base Plant Tank

In response to RCIA IR 18.1, FEI stated:

> … the average service life of the Base Plant tank is 40 years and thus the asset has already exceeded its financial life by 10 years (the tank was placed into service in 1971). The operational life of the tank has been extended due to the maintenance activities over the years that have involved replacing and repairing major components of the tank. While FEI could continue to perform sustaining capital maintenance on the Base Plant tank, this maintenance would be an added cost to customers and the additional operational life that might be achieved through such sustaining capital activities is uncertain given that the tank is already 50 years old.

In response to RCIA IR 18.3, FEI stated:

> In order to properly assess the expected remaining operational life of the Base Plant tank FEI would need to conduct an internal inspection of the tank. This would require the tank to be drained to allow safe entry and assessment. FEI has not completed this internal inspection given the difficulty and cost associated with this work.

79.1 Please describe the costs involved in completing the draining and inspection of the base plant tank and when FEI last completed a similar inspection.

Response:

An internal inspection and repairs were done on the Base Plant tank in 2002 and took one year to complete. The following repairs were carried out during the inspection:

- Addition of an internal flapper valve over the bottom withdrawal sump;
- Replacement of the liquid level gauge;
- Replenishment of the perlite insulating material between the inner and outer shells of the tank; and
- Repairs to the outer tank bottom to address a warm-gas leak.

This project required draining the LNG tank and regasification of the LNG (to make the tank safe for entry) and refilling with LNG following completion of the work. These steps took approximately 6.5 months of the year-long outage, with the remaining 5.5 months spent on the inspection and repairs. The cost for this project was approximately $5.5 million (in 2002 dollars).

79.1.1 Please discuss if such costs represent a reasonable approximation of costs of a future inspection.

Response:

As discussed in the response to BCUC IR2 79.1, the cost of the last inspection was $5.5 million, in 2002 dollars. Based on inflation alone over the subsequent 19-year period, FEI would expect a current-day cost to be approximately $8 million in 2021 dollars. However, $8 million likely represents a low-end range for a Class 5 estimate due to the tank's increased age, with the mid-range being $10.5 million and the high end of the range being approximately $16 million. FEI has assumed that, consistent with the 2002 project timeline, an inspection would take approximately 7 to 8 months, including up to 6 months for emptying and preparing the tank for entry and refilling the tank. Should the inspection reveal any major issues that require repairs, the tank outage would be extended to necessitate the repairs if deemed technically feasible and financially prudent.

The delay resulting from an inspection would require FEI to find a replacement in the open market for what the Base Plant currently provides to FEI's existing gas supply resource stack and this would be addressed in FEI's Annual Contracting Plan. As discussed in the response to BCUC IR1 46.2, FEI estimated the cost for this replacement would be approximately $30 million per year.

79.1.2 Please explain the period between inspection activities and why the chosen inspection schedule is appropriate.

Response:

Please refer to the response to BCUC IR2 79.2.

79.2 Please explain why FEI has chosen not to inspect the existing tank, and whether an inspection would provide some assurance regarding the resiliency risk FEI is currently subject to.

Response:

There are three main reasons FEI has chosen not to conduct an internal inspection of the existing tank:

1. The specific nature of cryogenic service requires special consideration with regard to internal inspections of an LNG storage tank. Damage can potentially be done to the tank by warming the tank to the ambient temperature and then cycling it back down to minus 160 degrees Celsius.
2. The time associated with the internal inspection is lengthy. The 2002 internal tank inspection confirmed repairs were required to address a leak, taking the tank out of service for one year while the inspection was completed and the leak repaired.
3. FEI undertakes an ongoing external monitoring and inspection program. In 2002, FEI's external monitoring program identified a potential leak which was subsequently confirmed by the internal inspection. Ongoing external monitoring and inspection includes:
    a. Continuous monitoring of internal tank pressure and temperature profile (top to bottom of inner tank wall, insulating space between inner and outer tank, and vapor space);
    b. Continuous monitoring of LNG density profile for rollover protection;
    c. Continuous monitoring of tank foundation temperature for frost heaves;
    d. Continuous seismic monitoring as a part of the seismic monitoring and response program;
    e. Continuous gas monitoring and detection;
    f. Periodic infrared thermal scans of the outer tank and roof surface for cold spots; and
    g. Periodic quadrant and area elevation surveying for differential and general ground/tank foundation settlement.

The results of ongoing external monitoring and inspections have not identified any concerns with the Base Plant tank to date that would suggest an internal inspection is required. As such, it is not expected that an internal inspection would materially change the outcome of the assessment that the tank should be replaced by the proposed 3 Bcf TLSE tank. As discussed in Section 4.3.5.6 of the Application, the Base Plant tank would need to remain in service for another 44 years with no further sustaining capital investments in order to make economic sense to retain it in service, and it is not expected that an internal inspection would change that assessment.

79.3 Please provide an estimate of the remaining life of the base plant tank, including all assumptions and data used to develop this estimate.

Response:

It is extremely difficult to estimate the remaining life of a 50-year-old piece of equipment without a detailed engineering assessment which would be necessarily imprecise unless accompanied by a thorough and costly tank inspection requiring the tank to be drained, as noted in the responses to RCIA IR1 18.3, and BCUC IR2 79.1.1 and 79.2.

However, as discussed in Section 4.3.5.6 of the Application and in the responses to BCUC IR1 16.21 and 16.21.1, the Base Plant would have to remain in service without any future sustainment/maintenance capital until it is at least 94 years old (i.e., 44 more years) to be more financially beneficial than replacing it with a new tank and regasification capacity now.

From a technical perspective, FEI consulted globally recognized tank experts, CB&I[8] regarding the remaining life of the Base Plant tank. CB&I confirmed that it is unlikely, as well as unreasonable, to assume the Base Plant can operate for 94 years or longer, regardless of the future sustainment/maintenance capital performed on the Base Plant. In other words, it is financially beneficial to FEI's customers to replace the Base Plant tank with a new larger storage tank at this time as part of the TLSE Project, even if the Base Plant tank has any remaining life.

[8] As discussed in Section 5.4, CB&I also was retained to provide the engineering and cost estimate of the 3 Bcf LNG storage tank. CB&I's credentials were included as part of Appendix D to the Application.

80.0 Reference: PROJECT NEED

Exhibit B-15, BCUC IR 10.6, 16.9

Regional Gas Supply Diversity Project

In response to BCUC IR 10.6, FEI stated:

> FEI is completing the initial scoping and planning for a Regional Gas Supply Diversity (RGSD) solution which would entail building a new pipeline route to the Lower Mainland connecting 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 response to BCUC IR 16.9, FEI stated:

> 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.

80.1 Please further explain the need for the RGSD Project.

<u>Response:</u>

The need for the RGSD project was described in the Letter L-31-20 Compliance Filing to the 2020/21 Annual Contracting Plan on August 31, 2020 (ACP Compliance Filing) which was provided as Appendix C to the Application. Please refer to Section 3.2.2 and Section 5 of the ACP Compliance Filing for details.

80.1.1 Please describe the source of load growth in the region as stated in the preamble.

Response:

New loads in the region could result from a variety of sources, including:

- Gas-fired electricity generation due to coal plant retirements in the US Pacific Northwest;
- Woodfibre LNG project in Squamish, BC;
- Demand for renewable gases in residential and commercial sectors;
- Higher than expected population growth in the Lower Mainland and Vancouver Island;
- Marine fueling load on FEI's system; and
- Industrial demand growth in the region, including LNG exports from Tilbury.

All or even a few of these initiatives would require increased capacity since existing pipeline infrastructure is already constrained.

80.1.2 Please discuss how the RGSD Project will assist the transition to low carbon energy future.

Response:

FEI's framework to transition to a low carbon energy future is the Clean Growth Pathway to 2050. The Clean Growth Pathway is a diversified approach that is technology agnostic. At this point in the energy transition it is important to maximize the number of de-carbonization pathways available and explore business models that meet energy demands without risking stranded assets and the costs that come with the complete re-engineering of the energy sectors.

The RGSD project will form a critical link in FEI's decarbonization strategy, and will be an important contributor to reducing GHG emissions in British Columbia. There are two gases that are likely to make up the decarbonized gas molecules: renewable natural gas (RNG) and hydrogen. The RGSD project will enable greater development and capture of RNG and hydrogen projects and will be capable of transporting hydrogen as the energy transition progresses. The RGSD project will provide a physical connection to low-cost hydrogen sources from Alberta. Since the project will be built to be "hydrogen ready", it will enable greater capture of hydrogen and access to cost-effective supply, enhancing the potential for GHG emission reductions in the long-term, compared to mature pipeline systems.

Importantly, the RGSD project provides the ability for hydrogen supply projects to be developed on-system within FEI's operating territory in the Southern Interior of British Columbia. The availability of in-place pipeline infrastructure will provide greater certainty for developers of hydrogen projects, and thus enable more regional projects that will facilitate FEI's long-term decarbonization initiatives. FEI is in early discussions with developers and Indigenous groups along the route regarding such opportunities.

80.2 Please explain FEI's ability to withstand a three-day no-flow event in a scenario where both the AMI Project and the RGSD Project are built, but the Tilbury LNG facilities remain as they are today, with the same assumptions in BCUC IR 78.1 above.

80.2.1 Please further explain why the TLSE Project is required to support resiliency if both the AMI Project and RGSD Projects are completed.

Response:

A portion of this response is being filed on a confidential basis as it contains commercially sensitive information, pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents as set out in Order G-15-19 and consistent with Order G-161-21 regarding treatment of commercially-sensitive information.

In the response to BCUC IR2 78.1 FEI has identified several assumptions and adjustments that must be considered when assessing this hypothetical scenario.

The further assumptions suggested in this IR include the completion of the RGSD project in addition to the AMI project. In the resulting scenario, FEI would still experience widespread load loss following a significant no-flow event on the T-South system. Only on-system storage can provide the necessary system support in the initial period following a no-flow event, and the current on-system resources (both regasification capacity and storage volume) are insufficient as described in the response to BCUC IR2 78.1.

There are two reasons why the addition of AMI and RGSD would not prevent widespread load loss following a no-flow event on the T-South system during the winter season:

1. AMI does not add supply or storage in the Lower Mainland region, but simply improves FEI's ability to disconnect customers to allow for a controlled shutdown.
2. The RGSD project is critical to enhancing system resiliency for Lower Mainland customers by providing supply when needed during longer periods of supply disruption; however, in order to have the capacity available immediately after the no-flow event as contemplated in the hypothetical scenario, FEI would have to over-contract (i.e., contract a higher than necessary amount) pipeline capacity on the RGSD, thus leaving a significant portion on

standby until a no-flow event occurs. However, as explained in Section 4.3.4.5.2 of the Application, during the TLSE Workshop, and in the response to BCUC IR1 16.3, this would not be a cost-effective approach for customers.

Ultimately, the TLSE Project and the RGSD project need to be viewed as complementary assets from a resiliency standpoint, as each separately addresses short duration (i.e., the TLSE Project) and long duration (i.e., the RGSD project) supply disruptions.

Response to the Scenario Posed

In this section, FEI provides the analysis for the question posed, which makes the assumption that the RGSD project is available. The RGSD project is still in early development and the total amount of pipeline capacity it would provide has yet to be determined.

In assessing this hypothetical scenario FEI has used the following assumptions from Section 4.3.4.5.1 of the Application:

[redacted]

[redacted]

The Impact of the Limited Regasification Capacity at Tilbury

Consistent with the response to BCUC IR2 78.1, this hypothetical scenario is still subject to the 150 MMcf/day regasification capacity limitation at the existing Tilbury facilities. As shown in Figure 2 below, the current regasification capacity plus the availability of resources from RGSD and assumed customer conservation is inadequate to meet the single-day load requirements of the Lower Mainland during the winter season. As such, the Lower Mainland would still experience widespread loss of load on the first day of a winter no-flow event.

[redacted]

Eliminating the Regasification Constraint Is Not Enough: More Volume Would Also Be Required to Last Three Days in Winter

Please refer to the response to BCUC IR2 78.1 for why it is impractical to increase the regasification capacity at the Base Plant while leaving the rest of the Base Plant in place. In any event, if it were assumed for the purposes of this response that the regasification constraint is removed without increasing the size of the Base Plant tank, the volumes available from on-system storage at Tilbury and the assumed volumes from RGSD would be insufficient to outlast a three-day no-flow event.

The hypothetical scenario would provide FEI with approximately [redacted] of total cumulative supply and storage for the Lower Mainland, as shown in the table below:

[redacted]

9 As explained in the bulleted excerpts above from Section 4.3.4.5.1 of the Application.

[redacted]

Even if FEI were able to reduce peak demand through customer conservation,[10] the cumulative 3-day demand in the Lower Mainland would still be 2.1 Bcf (compared to 2.2 Bcf as set out in the Application). This leaves a material shortfall over three days. Therefore, this hypothetical scenario (even incorporating the above-noted assumption) would not provide sufficient supply to bridge a three-day no-flow period.

As the figure below shows, there are six days in the 2019/20 design year where FEI would exhaust its storage in less than three days, requiring a more rapid initiation of a controlled shut-down. These periods of higher demand can occur at any time during the heating season.

[redacted]

In summary, while this hypothetical scenario was developed to be responsive, given that several of the assumptions made to the existing Tilbury facilities are not practical, the TLSE Project is still required. As previously discussed, the TLSE Project and RGSD project both provide critical and interrelated resiliency benefits, but the only cost-effective solution to address the risk of a no-flow event is the TLSE Project.

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10 Assumption #5 as listed in the response to BCUC IR2 78.1.

B. DESCRIPTION AND EVALUATION OF ALTERNATIVES

81.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-15, BCUC IR 8.5, 19.3, 19.5

Exhibit B-21, MS2S IR 9i

Project Sizing

In response to BCUC IR 8.5, FEI stated:

> 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.

In response to MS2S IR 9i, FEI stated:

> The need for and the sizing associated with the TLSE Project is driven by existing gas demand from customers in the Lower Mainland. The current Tilbury LNG storage capacity is only able to provide 17 hours of gas supply during peak demand periods. As such, FEI is unable to withstand the type of disruption reflected in its Minimum Resiliency Planning Objective based on existing customer load. Future load changes, whether due to core demand or LNG sales, do not affect the resiliency need for the TLSE Project today.

81.1 Please discuss how FEI anticipates peak demand for residential, commercial and industrial customers may change in the Lower Mainland during the lifetime of the TLSE Project, for example but not limited to changes influenced by economic growth, CleanBC, Metro Vancouver emissions limits, City of Vancouver policies.

81.1.1 Please explain, with rationale, whether the sizing of the TLSE Project (in terms of minimum tank size and regasification) has accounted for these potential changes in peak demand in the LML.

81.1.2 If no, please discuss whether FEI considers there are risks associated with sizing the TLSE Project based upon current demand.

<u>Response:</u>

There are several developments affecting the Lower Mainland region that could change natural gas use over time; however, those changes also increase the use of renewable and low carbon energy, such as RNG, which FEI expects to be an integral part of BC's clean energy future.

Policies such as the Province’s plan to cap greenhouse gas emissions from gas utility customers, or the transition of new buildings to zero emissions by 2030, are expected to result in less conventional natural gas use in the residential, commercial, and industrial sectors. However, FEI expects the continued development and expansion of renewable gas supply, such as RNG and hydrogen, will offset this impact. Similarly, FEI expects increased gas use in the transportation sector, which can also offset reduced use of the gas system and will be critical to achieving BC's climate goals. These offsetting drivers mean that a decline in overall peak demand for all gases is not a given, and may increase in some scenarios. In addition, given the gas system's unique ability to store and deliver large volumes of energy during peak periods, FEI expects it will continue to play a key role in providing peaking energy in BC.

FEI has considered the role of the gas system to achieve BC's climate targets within its Pathways Report.[11] This report concludes that following a diversified pathway relying on both gas and electric systems results in overall load of 186 PJ on the gas system by 2050[12], of which, approximately 75 percent is renewable and low carbon gases. In addition, higher growth scenarios (i.e., population growth in the Lower Mainland) could trigger additional demand for renewable gases, which FEI would need to consider when planning its infrastructure.

FEI's infrastructure planning is based on peak demand and takes into account factors that both increase and decrease the use of gas because using only a limited set of assumptions could have significant consequences to FEI's customers and the province of BC generally. FEI does not consider this to be a prudent approach to energy planning. To avoid the future uncertainties that will affect future peak demand, FEI believes sizing the TLSE Project based on the 2019/20 design load forecast remains appropriate.

Finally, the risk associated with the peak demand declining over time can be mitigated through the flexibility of FEI's contracted assets (i.e., off system storage at JPS or Mist). In particular, FEI's storage profile typically has contracts expiring once every three years. If the load duration curve changes over time (such that less supply is needed from the TLSE assets), FEI has the ability to de-contract a portion of its off-system storage resources.

[11] https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/guidehouse-report.pdf.

[12] This figure excludes LNG for export. Projects like Woodfibre LNG will place upwards pressure on throughput and peak demand on FEI's system.

82.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-15, BCUC IR 16.23

1.5 Bcf Tank

In response to BCUC IR 16.23, FEI stated:

> 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.

82.1 Please calculate the PV of the incremental revenue requirement and the levelized delivery rate over a 67-year analysis period if FEI were to pursue a 1.5 Bcf tank.

<u>Response:</u>

Please refer to the response to BCUC IR1 16.27 which provided the capital costs, PV of incremental revenue requirement, levelized delivery rate impact over a 67-year analysis period and the average annual residential bill impact for a 1 Bcf, 1.5 Bcf, 2 Bcf, 3 Bcf and 3.5 Bcf storage tank. Specifically with regard to a 1.5 Bcf tank, the PV of incremental revenue requirement and the levelized delivery rate impact over a 67-year analysis period is $918 million and 5.88 percent, respectively.

83.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-15, BCUC IR 21.1

Government of Canada Hydrogen Strategy for Canada[13], p. 41

Hydrogen

In response to BCUC IR 21.1, FEI stated:

> FEI does not anticipate impacts on the TLSE Project, nor on its liquefaction process, as a result of increasing hydrogen content in the gas stream as hydrogen can be separated if introduced upstream of the Tilbury facility…
>
> There are two potential options available to mitigate the impact on LNG operations from increasing hydrogen content in the gas system…
>
> 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.

Page 41 of the Government of Canada's Hydrogen Strategy for Canada document states:

> Hydrogen can be blended into NG pipelines, typically at pressures less than 100 bar, taking advantage of the inherent storage capacity in the network. Once blended into the NG pipeline, the hydrogen-NG mixture can be used in many applications in place of pure NG. Blend ratios of up to 20% hydrogen are being trialed around the world, with limited impact on infrastructure and end-use appliances. <u>While there is a significant technology development focused on separation technologies, it is currently difficult to separate the hydrogen from the NG once blended</u>. This may become viable in the mid term and would allow the separated hydrogen to be used in fuel cell applications. [Emphasis added]

83.1 Please explain the extent to which FEI has investigated the separation of hydrogen from natural gas. Please include in the response discussion of specific separation technologies FEI has investigated, the natural gas-hydrogen blend ratios the separation technologies can process and the commercial availability and cost of the separation technologies.

<u>Response:</u>

FEI and the University of British Columbia (Okanagan Campus) have completed a desktop study on the use of commercial membrane technology for the separation of mixed natural gas and hydrogen steams. The study suggests that the separation process is technically feasible.

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13 https://www.nrcan.gc.ca/sites/www.nrcan.gc.ca/files/environment/hydrogen/NRCan_Hydrogen-Strategy-Canada-na-en-v3.pdf

In particular, the study found several membranes that are available in the market to accomplish the separation of hydrogen from methane. These are outlined in Table 1 below. It is mainly the process conditions (e.g., inlet feed composition, feed pressure, etc.) that make certain membranes more suitable than the others. The tolerance to feed contaminants such as aromatics and the ability to handle high feed pressures are examples of these conditions. Most of the hydrogen separation membranes offered in the market are of the hollow-fiber module type, which are distinguishable by their high separation area per module's volume compared to the other membrane modules.

The study also considered natural gas/hydrogen blend ratios from 0.5 percent hydrogen blend concentration to 50 percent hydrogen blend concentration by volume. The cost to purchase these separation technologies did not form part of the study.

Table 1: Commercial Membranes for H2 / CH4 Separation

Supplier	Origin	Product Name	Module	Membrane Properties
AIR LIQUIDE	US	ALaS	Hollow-fiber	H_2 Selectivity: 70 – 100
EVONIK	Germany	SEPURAN® Noble	Hollow-fiber	
UBE	Japan	A, B-L, B-H	Hollow-fiber	
UOP	US	Polysep™	Hollow-fiber	H_2 Permeance: 100 – 200 GPU
Air Product	US	PRISM®	Hollow-fiber	

83.2 Please discuss FEI's plans for blending of hydrogen into its natural gas transmission and distribution infrastructure, including anticipated levels of hydrogen blending in the near, medium and long-term (e.g. 2030, 2040, 2050).

Response:

Currently, ongoing research and development, and pilot projects in BC, across Canada, and internationally indicate that hydrogen can be blended with natural gas for distribution in the low-pressure gas system at low to medium blend concentrations of 2 to 20 percent by volume. Furthermore, large-volume gas customers could be converted to using higher percent blends of hydrogen up to 100 percent by delivering hydrogen from local hydrogen production facilities in new or repurposed, but dedicated, hydrogen infrastructure.

In the short term (over the next five years), FEI considers that the approaches described above for hydrogen deployment will be necessary to establish hydrogen demand in BC and inform new market segments as to the versatility and safety of hydrogen as a mass-market consumer fuel. To support this goal, FEI is enabled under the amended GGRR to acquire hydrogen to meet near-term objectives including:

- Blending hydrogen in the gas distribution system to displace conventional natural gas (similar to RNG), including either hydrogen produced by FEI or by paying a third party to produce it; and/or
- Purchasing hydrogen that could be distributed through dedicated infrastructure (new or repurposed) to gas customers to displace conventional natural gas usage.

In the medium term (assumed to be by 2030), blending of hydrogen would expand across the low-pressure gas distribution system with the potential for segments of that system to be converted to 100 percent hydrogen near hydrogen hubs.

Over the longer term (assumed between 2030 and 2050), as demand for hydrogen grows, the existing gas system high pressure transmission pipeline corridors would be retrofitted, upgraded, and expanded to transport an increasing share of hydrogen and (bio)methane in a progressively decarbonized gas system.

83.3 Please discuss the capital and operating costs of technologies to separate hydrogen from natural gas.

Response:

FEI has not yet investigated the capital and operating costs required to accommodate hydrogen separation equipment on the gas system.

As FEI explained in the response to BCUC IR1 21.1, there are no increased capital costs included in the TLSE Project associated with the future use of hydrogen. FEI is currently investigating hydrogen's potential as a low-carbon fuel to displace natural gas thorough feasibility work, research and development, and planned pilot demonstration projects. These activities will inform FEI's ultimate hydrogen deployment strategy and rollout plan. Whatever costs may arise as hydrogen is deployed in the gas system would not be as a result of the TLSE Project, and would occur regardless of it.

83.4 Please discuss any space limitations at the Tilbury Site to accommodate natural gas-hydrogen separation equipment.

Response:

FEI has not yet investigated hydrogen separation technology for implementation at the Tilbury site. If required in the future, FEI would consider multiple locations across the system to optimize siting for gas-hydrogen separation equipment, including at the Tilbury site where adequate space exists if selected as the optimal location.

83.5 Please discuss whether FEI will require natural gas-hydrogen separation equipment at all of its existing LNG storage facilities.

Response:

FEI will likely require natural gas-hydrogen separation at existing LNG storage facilities if hydrogen is present in the feedstock gas supply to the LNG facility. However, FEI has not yet confirmed how hydrogen will be deployed in the gas system and, as such, cannot currently confirm the future requirements for hydrogen separation at its LNG facilities, including the Tilbury site.

84.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-15, BCUC IR 21.3.2; May 25, 2021 amendment to the *Greenhouse Gas Reduction (Clean Energy) Regulation*, Section 7(2)

Renewable Natural Gas

In response to BCUC IR 21.3.2, FEI stated:

> 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…
> - 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.

84.1 Please confirm the maximum concentration of nitrogen within natural gas that the Tilbury site and its processes could safely accommodate.

Response:

The Tilbury site can safely accommodate up to 1 mol percent of nitrogen in the feed gas.

84.2 Please discuss whether FEI has considered the need for nitrogen separation equipment upstream or downstream of the liquefaction process at the Tilbury Site.

Response:

As explained in the response to BCUC IR1 21.3.2, FEI does not consider that nitrogen separation technology will be necessary and has therefore not investigated nitrogen separation equipment upstream or downstream of the liquefaction process at the Tilbury site.

84.3 Please discuss any space limitations at the Tilbury Site to accommodate natural gas-nitrogen separation equipment.

Response:

Please refer to the response to BCUC IR2 84.2.

84.4 Please provide a copy of FEI's biomethane (RNG) specification.

Response:

Please refer to Attachment 84.4 for FEI's Biomethane (RNG) specification.

Section 7(2) of the May 25, 2021 amendment to the *Greenhouse Gas Reduction (Clean Energy) Regulation*[14] states:

> A public utility's undertaking that is in a class defined as follows is a prescribed undertaking for the purposes of section 18 of the Act:
>
> (a) the public utility purchases and distributes synthesis gas that is
>
> (i) derived from biomass,
>
> (ii) to be used by a customer to replace, at least in part, natural gas derived primarily from fossil fuels, and
>
> (iii) to be used at the site at which it is produced;

84.5 Please confirm, or explain otherwise, that FEI does not plan to inject synthesis gas into its transmission system.

84.5.1 If not confirmed, please explain any implications for LNG storage.

[14] https://www.bclaws.gov.bc.ca/civix/document/id/lc/bcgaz2/v64n11_134-2021

Response:

FEI confirms that it does not plan to inject synthesis gas directly into its gas transmission system.

85.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-15, BCUC IR 24.1.1

Regasification Capacity

In response to BCUC IR 24.1.1, FEI stated:

> 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.

85.1 Please provide the anticipated timing of the pipeline upgrade between the Tilbury Plant and the Tilbury Gate Station, the length of time to complete the pipeline upgrade and its estimated capital cost.

Response:

Based on the current status of the pipeline upgrade project, FEI anticipates moving into the Class 4 estimate phase in early 2022, with an in-service date of end of 2025.

The Class 5 estimated costs are provided in the table below.

Description	Class 5 Cost Range Low ($millions)	Class 5 Cost Range High ($millions)
Metering Station	11.0	26.0
Route Alternative A	11.0	24.0
Route Alternative B	25.0	54.0

C. PROJECT DESCRIPTION

86.0 Reference: PROJECT DESCRIPTION

Exhibit B-15, BCUC IR 23.1, 23.2

Tilbury Phase 2 Expansion Project

In response to BCUC IR 23.1, FEI stated:

> The Tilbury Phase 2 Expansion Project has two components: (i) the 3 Bcf storage tank, and (ii) a liquefaction facility… it would be incorrect to characterize the TLSE Project as being required to support the Liquefaction Facility. <u>The Liquefaction Facility may or may not require storage</u>, 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… [Emphasis added]
>
> 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.

86.1 With reference to the underlined statement above, please explain how the Liquefaction Facility, as proposed in the Environmental Assessment (EA) process, would operate with no storage capacity.

<u>Response:</u>

If the Liquefaction Facility is constructed, it would require storage to operate. FEI had intended to convey that the Liquefaction Facility may not necessarily need <u>new</u> storage. If a smaller Liquefaction Facility were built to further support sales under Rate Schedule 46 (i.e., LNG as a low carbon transportation fuel), then it may be possible to leverage the existing Tilbury 1A storage capacity.

However, if the Liquefaction Facility were constructed to support larger volume LNG shipments, it would require additional storage capacity. If the TLSE Project is approved and constructed, the party developing the Liquefaction Facility could seek to obtain that storage contractually from FEI, including the remaining 1 Bcf of storage discussed in the preamble, subject to ensuring FEI's resiliency and/or supply and operational requirements are maintained. Any such contract would be subject to further BCUC oversight.

In response to BCUC IR 23.2, FEI stated:

> 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…
>
> <u>The purpose of the TLSE Project is to address the resiliency needs of FEI customers</u>…
>
> <u>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</u>. This may ultimately require some form of LNG storage, which may be provided by the TLSE tank if approved. [Emphasis added]

86.2 Please confirm, or explain otherwise, that the maximum LNG storage required for the Liquefaction Facility, as currently proposed in the EA, is up to 1 Bcf.

<u>Response:</u>

Not confirmed. There is no maximum LNG storage "requirement" for the Liquefaction Facility. Rather, the maximum available storage that could be used from the proposed 3 Bcf TLSE tank for the Liquefaction Facility is 1 Bcf.

The Liquefaction Facility design capacity has not yet been set. If a commercial opportunity emerges, the storage available for liquefaction purposes will inform the design capacity, as will shipping considerations, market characteristics, etc. The capacity built will not exceed that which can be practically used given the storage available.

In the TLSE CPCN Application, FEI is proposing to construct and operate a 3 Bcf storage facility. As proposed, 2 Bcf of that capacity would be reserved <u>exclusively</u> for resiliency based on current load. That would leave 1 Bcf of capacity which could then be used flexibly, such as to provide an additional resiliency margin, maintain the current supply and ancillary benefits provided by the existing Base Plant tank, and/or to support the Liquefaction Facility. Any potential future use of a portion of the TLSE Project tank to support additional liquefaction would be subject to BCUC oversight.

86.3 Please provide the approximate costs to construct a 1 Bcf LNG storage tank.

Response:

Please refer to the response to BCUC IR1 16.27 which provided the capital costs, PV of incremental revenue requirement, levelized delivery rate impact over a 67-year analysis period and the average annual residential bill impact for a 1 Bcf, 1.5 Bcf, 2 Bcf, 3 Bcf and 3.5 Bcf storage tank. Specifically with regard to a 1 Bcf tank, the estimated total project capital costs are $492 million in 2020 dollars.

86.4 Please explain the rationale for including both the 3 Bcf storage tank and the Liquefaction Facility in the same EA process if the purpose of each component is different, the timing of each component is different and neither component requires the other to proceed.

Response:

For the purpose of the provincial and federal assessments, the scope of the Tilbury Phase 2 Expansion Project is determined under the provincial *Environmental Assessment Act* and the federal *Impact Assessment Act* in processes administered by the Environmental Assessment Office and the Impact Assessment Agency of Canada. The scope of project in those assessments is not a question that the BCUC can or will determine in this proceeding.

87.0 Reference: PROJECT DESCRIPTION

Exhibit B-15, BCUC IR 26.2, 26.2.2

CSA Z276-18, Clause 5.3.2.2.4

BC OGC Liquefied Natural Gas Facility Permit Application and Operations Manual, Section 2.1.7

Site Spacing

In response to BCUC IR 26.2, FEI stated: "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."

Further, in response to BCUC IR 26.2.2, FEI stated:

> 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.

Clause 5.3.2.2.4 of CSA Z276-18 states:

> The separation distance shall not be less than half the diameter of the largest container.

87.1 Please explain whether the separation distance required by Clause 5.3.2.2.4 of CSA Z276-18 applies to the TLSE Project.

87.1.1 If so, please confirm that the current tank separation distance complies with Clause 5.3.2.2.4 and, if not, any anticipated changes to site layout in order to comply.

<u>Response:</u>

FEI's interpretation of Clause 5.3.2.2.4 of CSA Z276-18 is that it does not apply to the separation distance of full containment tanks of water capacity greater than 265 m^3. Clause 5.3.2.2.1 states that the separation distance related to full containment tank water capacity more than 265 m^3 should follow Table 3 of CSA Z276-18, which is reproduced below.

> **5.3.2.2.1**
>
> The minimum spacing of double containment, full containment, and membrane containment tank systems of greater than 265 m^3 (70 000 US gal) water capacity to each other, to tanks containing flammable liquids, and to property lines shall be in accordance with Table 3.

Table 3
Distances from containers
(See Clauses 5.3.1.1, 5.3.2.1, 5.3.2.2.1, 5.3.3.2, D.4.3.2, and D.16.4.7.)

Container water capacity, m³ (US gal)	Minimum distance from inner edge of impounding area or container drainage system to property lines that can be built upon, m (ft)	Minimum distance between storage containers, m (ft)
< 0.5 (< 125)	0 (0)	0 (0)
0.5 – < 1.9 (125 – < 500)	3 (10)	1 (3)
1.9 – < 7.6 (500 – < 2 000)	4.6 (15)	1.5 (5)
7.6 – < 68 (2 000 – < 18 000)	7.6 (25)	1.5 (5)
68 – < 114 (18 000 – < 30 000)	15 (50)	1.5 (5)
114 – 265 (30 000 – 70 000)	23 (75)	1/4 of the sum of the diameters of adjacent containers (1.5 m [5 ft] minimum)
> 265 (> 70 000)	0.7 × the container diameter, but not less than 30 m (100 ft)	1/4 of the sum of the diameters of adjacent containers (1.5 m [5 ft] minimum)

In response to BCUC IR 26.2.2, FEI stated:

> 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.

CSA Z276-18 Table 7 includes the following footnote for full containment tank system with reinforced concrete roof:

> c) Roof collapse and subsequent fire scenario is not considered for these tank types except when required by the risk assessment or by the authority having jurisdiction.

87.2 Please clarify whether FEI’s engineering consultant responsible for the tank design – Horton CB&I, Limited – has confirmed that an engineering analysis to assess the radiant heat flux in the vicinity of the proposed 3 BCF tank is not required.

Response:

The following response was provided by CB&I:

A general industry consensus is that an in-tank fire for a full containment concrete tank with a concrete roof is not a credible design event. This is reflected in CSA Z276-18 Table 7 as well as in other LNG facility standards such as NFPA 59A-19 and EN 1473-2021. These standards recognize that the probability of a full containment tank concrete roof failure allowing significant ingress of oxygen inside the tank to support product combustion is extremely low, which makes this event non-credible. NFPA 59A specifically limits the adjacent tank fire condition only to single and double containment tanks. CB&I therefore does not typically consider an adjacent tank fire condition for a tank where the adjacent tank is of the full containment concrete type with a concrete roof unless specifically required by the tank owner or issuing authority.

The BC Oil and Gas Commission (BC OGC) Liquefied Natural Gas Facility Permit Application and Operations Manual[15] Section 2.1.7 states:

> Facility siting is the process of managing risk to people, the environment and property from explosions, fires, and hazardous material releases through equipment and occupied building location and layout. The Commission [BC OGC] expects the applicants to have completed comprehensive design and safety studies when determining siting for the facility…
>
> CSA Z276 prescribes siting requirements for facility components and spill scenarios that are expected to pose significant risk to people, the environment and property…
>
> The facility siting study should consider, but is not limited to, risks associated with…dispersion of vapours; jet fires; flash fires; explosions; fireballs; pool fires; boiling liquid expanding vapour explosion (BLEVE); liquid/water interaction effects; radiant heat; overpressure; and, toxic spills.

87.3 Please confirm, or explain otherwise, that the BC OGC is the authority having jurisdiction referred to in Table 7 of CSA Z276-18.

Response:

Confirmed.

[15] https://www.bcogc.ca/files/application-manuals/LNG-Application-and-Operations/lng-facility-permit-application-and-operations-manual-august-release-v16-2018.pdf.

87.4 Please explain, with rationale, whether FEI has confirmed which risk assessments the BC OGC requires to be included within a facility siting study.

Response:

The TLSE Project has not yet been referred to the BCOGC as FEI has not received approval for the Project; however, upon referral, FEI and the BCOGC will be referring to the same clauses of CSA Z276-18 for the purposes of determining the required risk assessment studies.

87.4.1 Please explain whether the BC OGC considers a roof collapse and subsequent fire to be a credible scenario applicable to this Project as proposed.

Response:

The BCOGC typically provides their feedback for a specific project based on the requirements of CSA Z276. As discussed in the response to BCUC IR2 87.4, the Project has not yet been referred to BCOGC. As such, FEI is unable to predict the BCOGC’s potential feedback at this phase of the Project development. Based on FEI’s experience with other projects, it is expected that the BCOGC is likely to enforce the standards laid out in CSA Z276.

88.0 Reference: PROJECT DESCRIPTION

Exhibit B-15, BCUC IR 30.1, 30.2, 30.3.1

Filling Methodology

In response to BCUC IR 30.1, FEI stated:

> 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.

In response to BCUC IR 30.2, FEI stated:

> 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.

88.1 Please clarify how long, in days, FEI anticipates it will take to fill the 3 BCF tank following a three day no flow event.

<u>Response:</u>

As noted in the responses to BCUC IR1 30.1 and 30.2, the time to refill the new 3 Bcf tank is dependent on the available liquefaction capacity following a no-flow event. The maximum time to fill the tank would only occur if FEI was limited to the 5 MMcf/day of Tilbury T1A liquefaction reserve capacity.

If a three-day no-flow event occurred during the winter heating season, the Minimum Resiliency Planning Objective currently requires 2 Bcf of supply. Utilizing the 5 MMcf/day reserve capacity, it would take up to 400 days to replenish following a no-flow event. However, if only 2 Bcf were utilized this would potentially leave up to 1 Bcf of LNG remaining in the tank. In order to ensure a minimum of 2 Bcf for resiliency purposes in the next winter heating season it would take up to 200 days to refill the tank to the 2 Bcf level if that third Bcf of LNG was available.

However, if the supply disruption occurred during the summer period, the average summer design load (April to October) is approximately 180 MMcf/day. Over the three-day no-flow event this would result in a requirement to supply 0.54 Bcf. At worst, utilizing the 5 MMcf/day reserve capacity, this would take approximately 108 days to replenish. Depending on the time of the no-flow event it is possible that the tank could be fully replenished prior to the winter heating season. If the no-flow event occurs closer to the end of the summer, it is also possible that a combination of refilling along with the third Bcf could be used to ensure a minimum of 2 Bcf during the winter heating season.

88.1.1 Please discuss FEI's assessment of the likelihood of multiple no-flow events occurring within days and/or months of each other.

Response:

As discussed in the response to BCUC IR1 7.2, FEI is unaware of any outage frequency tables or figures that directly compare the frequency and probability of outages, including no-flow events, on the gas system. As explained in the response to BCUC IR1 1.3, there are a number of potential sources of supply interruptions including:

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).

There is residual risk in the scenario of two no-flow events in rapid succession. The mitigation that the TLSE Project would provide in that circumstance would be the ability to access any remaining volumes in the tank after the first no-flow event and having additional time to execute a controlled shut-down. Access to additional supply from another pipeline such as that contemplated in the RGSD project would help prolong the supply held in the TLSE tank and thus mitigate the residual risk.

88.1.2 In the scenario of multiple no-flow events occurring within days and/or months of each other, please discuss the effectiveness of the 3 BCF storage tank as a resiliency resource.

Response:

In the event of multiple no-flow events occurring within days or months of each other, the effectiveness of the 3 Bcf storage tank would depend on several factors, including the time of year and the duration of the no-flow events.

If the events occurred during the summer, the TLSE Project would be able to handle the lower demand requirements for a period of time beyond three days. Further, there may be opportunities to replenish the storage between no-flow events.

In the scenario where multiple no-flow events occur in the winter, the effectiveness of the 3 Bcf tank as a resiliency resource would likely be limited by the storage tank size. As discussed in the response to BCUC IR1 4.5, the 2 Bcf of LNG storage can help meet three days of no-flow, and the incremental 1 Bcf of LNG may be able to handle additional days of supply disruption. If multiple no-flow events exceed the 3 Bcf capacity of the storage tank, FEI would use the additional time provided by the storage to shut down the system in a controlled manner. Access to additional supply from another pipeline such as that contemplated in the RGSD project would help prolong the supply held in the TLSE tank and thus mitigate the residual risk.

In response to BCUC IR 30.3.1, FEI stated:

> 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.

88.2 If the 3 Bcf tank is approved as proposed, please discuss whether FEI would use the incremental 1 Bcf storage capacity to reduce its reliance on off-system storage and/or reduce FEI's contracted delivery capacity from upstream pipelines.

Response:

FEI's Annual Contracting Plan evaluates the short- to long-term contracting strategies for storage and pipeline transportation resources to meet the peak day, seasonal, and annual load requirements for future gas years. At this time, FEI's current load forecasts would not provide FEI the flexibility to reduce its reliance on off-system storage by using the incremental 1 Bcf of storage from the proposed TLSE Project. FEI will continue to evaluate this potential over time in order to reflect changes to its load forecast. Further, any reduction in FEI's reliance on off-system storage will need to take into account that the incremental 1 Bcf of storage in the proposed tank may also be used for operational requirements.

The incremental 1 Bcf of the 3 Bcf TLSE tank can be used to provide peaking supply in the way the Tilbury Base Plant does today. With a smaller 2 Bcf tank, it would not be possible to reserve 2 Bcf exclusively for resiliency without foregoing the gas supply and operational function that the current Base Plant has served since 1971, and which remains important to serving customers. FEI would need to contract 150 MMcf/day of supply as part of the existing gas supply resource stack to replace it, as discussed in the response to BCUC IR1 22.7. As discussed in the response to BCUC IR1 46.2, FEI estimated the cost for procuring supply in the market for peak demand purposes would be approximately $30 million per year.

89.0 Reference: PROJECT DESCRIPTION

Exhibit B-15, BCUC IR 33.2

Height of Foundation

In response to BCUC IR 33.2, FEI stated:

> 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.

89.1 Please discuss the likelihood that the outcomes from the Provincial Environmental Assessment or the Federal Impact Assessment will result in a need to raise the grade elevation of the TLSE Project site above 3.5 metres.

Response:

For the reasons described in the preamble, it is highly unlikely that any regulatory authority would require the final site grade of the TLSE Project to be above 3.5 metres.

89.1.1 Please provide an approximate cost estimate to raise the grade elevation of the TLSE Project site above 3.5 metres.

Response:

FEI is unable to provide an approximate cost estimate to raise the grade elevation for the following reasons:

- As noted in the response to BCUC IR2 89.1, FEI does not believe there will be any requirement to raise the grade above 3.5 meters; and
- The cost to raise the grade would be impacted by numerous factors including the additional height, type of fill, and whether it would be uniform or different elevation depending on the asset (i.e., tanks versus processing equipment), all of which would materially impact the requested hypothetical cost estimate.

89.2 Please elaborate on any feedback FEI has received from the City of Delta regarding the site stripping and grading plan, or any other flood mitigation measures required of the City's development permit process.

Response:

FEI has not received any feedback from the City of Delta regarding the site stripping and grading plan or any other flood mitigation measures at this stage of the Project development. FEI and FortisBC Holdings Inc., which are collectively engaging regarding the Tilbury Phase 2 LNG Expansion Project, expect to receive any feedback related to these items as they work through the permitting process. Given the recent engagement with the City of Delta during the Tilbury T1A Project regarding this topic, FEI does not anticipate that there will be any material deviation from previous direction provided by the City.

90.0 Reference: PROJECT DESCRIPTION

Exhibit B-15, BCUC IR 36.1

Provincial and Federal Environmental Assessment Processes

In response to BCUC IR 36.1, FEI stated:

> 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.

90.1 Please provide an update on the status of the British Columbia Environmental Assessment Office (BC EAO) and IAAC process.

Response:

The Federal assessment is in the Planning Phase.

In the Provincial assessment, with the filing of the Detailed Project Description on September 8, 2021, the Tilbury Phase 2 LNG Expansion Project completed the Early Engagement Phase and proceeded to the EA Readiness Phase which is led by the BC EAO.

At the conclusion of the concurrent EA Readiness Phase (provincial) and the Planning Phase (federal), both the BC EAO and IAAC will make a decision on whether or not the project can proceed to the next step of the provincial EA or federal IA process. Following these decisions, the federal Minister of Environment and Climate Change is expected to make the substitution decision on the federal IA process. These decisions are expected as early as December 2021.

90.2 Please provide any updates regarding the decision to have the federal impact assessment process be substituted to the province.

Response:

Please refer to the response to BCUC IR2 90.1.

D. FINANCIAL ANALYSIS

91.0 Reference: FINANCIAL ANALYSIS

Exhibit B-15, BCUC IR 16. 24, 40.1, 40.2, 63.1

LNG Tank Depreciation

In response to BCUC IR 40.1, FEI stated:

> 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.
>
> […]
>
> 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. 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 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.

In response to BCUC IR 40.2, FEI provided the following table comparing the present value (PV) of the incremental revenue requirement and levelized delivery rate impact over the 67-year analysis period between the proposed depreciation and salvage rates based on Account Class 44305 and the depreciation and salvage rates for Account Class 44300:

	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

91.1 Please discuss which asset class, Account Class 44300 (containing the existing Tilbury Base Plant) or Account Class 44305 (containing the Mt. Hayes storage tank), the proposed 3 Bcf LNG tank will be recorded under. As part of the response, please explain why.

Response:

FEI is not proposing to record the new 3 Bcf LNG tank under either account 44300 or 44305. FEI will record the new 3 Bcf tank under a new account with the proposed new depreciation rate of 1.67 percent and net salvage rate of 0.67 percent as discussed in Section 6.4.1. To further clarify, the account number is simply a specific number in FEI's accounting system to distinguish this new asset from the other LNG tank assets (and any other capital assets) in order to ensure that the new 3 Bcf LNG tank is depreciated based on its specific depreciation and net salvage rates.

91.2 Please expand the table above to provide the PV of the incremental revenue requirement and the levelized delivery rate over a 67-year analysis period if the depreciation rate and salvage rate were based on the existing Base Plant when the accumulated gains or losses are excluded (i.e. – an average service life of 40 years and salvage rate of 0.5 percent).

Response:

Please refer to the expanded table below which includes the scenario of using a depreciation rate of 2.5 percent (i.e., 1/40 years) and a net salvage rate of 0.5 percent. As shown in the table, the PV of incremental revenue requirement and the levelized delivery rate impact over the 67-year analysis period is increased slightly primarily due to the increased depreciation expense resulting from the higher depreciation rate.

	Proposed Depreciation Rate of 1.67% and Salvage Rate of 0.67%	Current Depreciation Rate of 1.23% and Salvage Rate of 1.12%	Depreciation Rate of 2.5% and Salvage Rate of 0.5% (Excl. Accumlated Gains and Losses)
PV of Incremental Revenue Requirement 67 years ($ millions)	1,041.925	1,041.963	1,046.918
Levelized Delivery Rate Impact 67 years (%)	6.67%	6.67%	6.70%
Levelized Delivery Rate Impact 67 years ($/GJ)	0.301	0.301	0.302

In response to BCUC IR 63.1, FEI stated: "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."

In response to BCUC IR 16.24, FEI stated:

> the objective of the TLSE Project is to have 2 Bcf reserved for resiliency purposes at all times

91.3 Please discuss whether FEI intends to change the amount of the tank reserved for resiliency purposes if peak demand in the LML decreases or increases in future.

91.3.1 If so, please discuss how FEI intends to use the full remaining capacity of the proposed tank if peak demand changes in future.

Response:

FEI's intention is to meet the MRPO. Based on the present load in the Lower Mainland, this requires a minimum of 2 Bcf, and as such FEI would set aside 2 Bcf in the 3 Bcf tank exclusively for resiliency purposes. FEI understands that, if the Lower Mainland load changes materially, meeting the MRPO could require a different allocation of the tank capacity.

If the peak demand in the LML changes in the future, FEI will evaluate the supply allocation of the TLSE tank and present any plans to the BCUC (likely as part of its resource plan filings and/or annual contracting plans). This is consistent with how FEI evaluates all of its existing gas supply resources and system requirements over time. However, at this time FEI has no reason to expect peak demand to change materially enough for the 2 Bcf to be allocated differently in the foreseeable future.

FEI notes that it would not be possible to set aside 2 Bcf exclusively for resiliency purposes with only a 2 Bcf tank without foregoing the gas supply and operational function that the current Base Plant has served since 1971, and which remains important to serving customers.

91.4 Please provide the PV of the incremental revenue requirement and the levelized delivery rate impact over a 67-year analysis period if the useful life of the proposed 3 Bcf LNG tank were to end in 2050.

Response:

Please refer to the table below which shows the PV of incremental revenue requirement and the levelized delivery rate impact over a 67-year analysis period if the useful life of the proposed 3 Bcf LNG tank were to end in 2050 (i.e., in 24 years[16]), as compared to the proposed depreciation of 60 years. For the purposes of this analysis, FEI assumed the proposed 3 Bcf LNG facility (i.e., tank, regasification, auxiliary systems, etc.) would be retired from FEI's plant-in-service in 2050[17] and that O&M as well as sustainment capital related to the proposed 3 Bcf LNG facility would stop in 2050.

[16] Estimated in-service year is 2026, therefore 24 years to 2050.
[17] Retirement from plant-in-service resulting in elimination of depreciation and reduction in earned return as well as income tax expense.

	Useful Life of 24 years (to 2050) for the proposed 3 Bcf LNG Tank	Useful life of 60 years for the proposed 3 Bcf Tank as per Application
PV of Incremental Revenue Requirement 67 years ($ millions)	880.800	1,041.925
Delivery Rate Impact in 2027 (%)	11.90%	9.07%
Levelized Delivery Rate Impact 67 years (%)	5.64%	6.67%
Levelized Delivery Rate Impact 67 years ($/GJ)	0.254	0.301

As shown in the above table, the delivery rate impact in 2027 when all assets enter FEI's rate base would increase from 9.07 percent to 11.90 percent due to the higher annual depreciation; however, the levelized delivery rate impact over the 67-year analysis period would reduce from 6.67 percent to 5.64 percent. This is primarily due to the reduced O&M, sustainment capital, and earned return after 2050.

92.0 Reference: FINANCIAL ANALYSIS

Exhibit B-15, BCUC IR 43.1

Operation and Maintenance (O&M)

In response to BCUC IR 43.1, FEI stated:

> 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.
>
> […]
>
> [T]he actual O&M expenses from 2008 to 2019 […] on average, result in an annual O&M expense of $2.263 million.

FEI also provided a figure showing the actual O&M expenses from 2008 to 2019 as part of the IR response.

92.1 Please explain how FEI determines that there is “no particular trend” shown in the historical O&M expenses.

92.1.1 Please expand the figure provided in response to BCUC IR 43.1 to show the actual O&M expenses from 1998 to 2019 and the average from 1998 to 2019. Please also provide the levelized delivery rate impact over a 67-year analysis period based on the O&M expense using the average from 1998 to 2019.

Response:

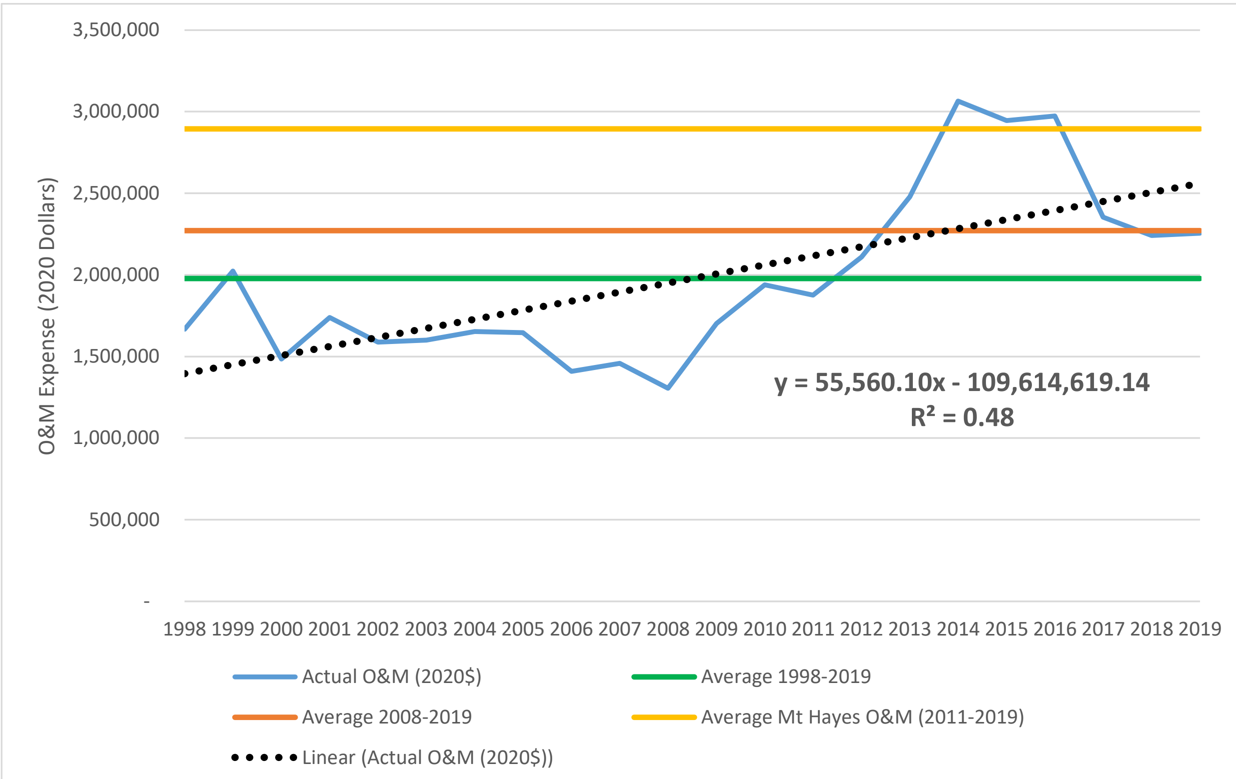
While responding to this IR, FEI discovered that the actual O&M expenses for the Tilbury Base Plant provided in the response to BCUC IR1 43.1 were incorrect for 2008, 2009 and 2010. The O&M expenses for these three years inadvertently included other O&M costs that were not related to the operation of the Tilbury Base Plant. The incorrect O&M for 2008, 2009 and 2010 also resulted in the incorrect assessment that there was “no particular trend” in O&M between 2008 and 2019. As demonstrated below, the correction of the O&M for 2008, 2009 and 2010 does not result in a change to the levelized delivery rate impact of 6.67 percent or 0.301 per GJ over the 67-year analysis period.

Please refer to the figure below which shows the actual O&M expenses from 1998 to 2019 with the years 2008, 2009 and 2010 corrected (blue line). The amounts shown are in 2020 dollars based on actual BC CPI between 1998 and 2019[18] as FEI does not consider it reasonable to use O&M expenses from more than 20 years ago without accounting for inflation over the years.

Using these corrected and inflated figures, the figure also shows the average O&M for the Tilbury Base Plant from 1998 to 2019 (green line), the average O&M for the Tilbury Base Plant from 2008

[18] https://www2.gov.bc.ca/assets/gov/data/statistics/economy/cpi/cpi_annual_averages.pdf.

to 2019 (orange line), and a linear regression of O&M for the Tilbury Base Plant from 1998 to 2019 (black dotted line). The figure also includes the average O&M for the Mt. Hayes LNG facility from 2011[19] to 2019 (yellow line), provided to respond to BCUC IR2 92.3.



Please refer to the table below which shows the PV of incremental revenue requirement and the levelized delivery rate impact over the 67-year analysis period for the following scenarios:

- Average O&M (2020 dollars) from 2008 to 2019 as filed (including the incorrect O&M costs from 2008, 2009, and 2010 as discussed above);
- Corrected average O&M (in 2020 dollars) from 2008 to 2019;
- Average O&M (in 2020 dollars) from 1998 to 2019 (with correct 2008, 2009, and 2010 O&M costs);
- O&M (in 2020 dollars) based on a linear regression from 1998 to 2019 (with correct 2008, 2009, and 2010 O&M costs); and
- Average Mt. Hayes O&M (in 2020 dollars) from 2011 to 2019.

As the table below shows, the difference in PV of incremental revenue requirement and levelized delivery rate impact over the 67-year analysis period is minor among all of the scenarios.

[19] The Mt Hayes LNG facility was first in-use in 2009 with ramp-up/commissioning from 2009 to 2010. Steady-state operation began in 2011.

	Average 2008-2019 as Filed	Correct 2008-2019 O&M	Average 1998-2019 O&M	Linear Regression 1998-2019 O&M	Mt Hayes Average 2011-2019 O&M
Tilbury Base Plant O&M (2020$)	2,262,864	2,270,344	1,977,851	2,616,783	2,895,193
PV of Incremental Revenue Requirement 67 years ($000s)	1,041.925	1,042.032	1,048.799	1,038.329	1,028.388
Levelized Delivery Rate Impact 67 years (%)	6.67%	6.67%	6.71%	6.65%	6.58%
Levelized Delivery Rate Impact 67 years ($/GJ)	0.301	0.301	0.303	0.300	0.297

92.2 Please provide the O&M historical costs of the Mt. Hayes LNG storage tank since entering service, and the average of actual O&M expenses for that period.

<u>Response:</u>

The Mt. Hayes LNG facility is very different in size, service, and operating characteristics to Tilbury. Therefore, FEI does not consider the Mt. Hayes O&M expenses to be relevant or predictive of Tilbury's experience. However, as shown in the response to BCUC IR2 92.1, the difference between the levelized delivery rate impact of the TLSE Project between using the average historical Mt. Hayes O&M and the average historical Tilbury Base Plant O&M is small.

92.3 Please provide the levelized delivery rate impact over a 67-year analysis period if the historical costs of the Mt. Hayes LNG storage tank were used to estimate the annual O&M expenses in 2020 for the Tilbury Base Plant.

<u>Response:</u>

Please refer to the response to BCUC IR2 92.1.

93.0 Reference: FINANCIAL ANALYSIS

Exhibit B-15, BCUC IR 45.1

TLSE Foreign Exchange (Fx) Mark to Market Valuation Deferral Account

In response to BCUC IR 45.1, FEI provided a table showing the capital cost and USD/CAD exchange rates used by consultants that developed the individual components of the cost estimates, which has been reproduced below:

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%**		

93.1 Please confirm, or explain otherwise, that the "Portion USD" column of the above table are for labour, material, or services that are sourced/produced outside of Canada.

93.1.1 If not confirmed, please identify the costs in the "Portion USD" column of the above table that are for labour, material, or services that are sourced/produced in Canada.

93.1.2 For any costs identified in response to the preceding IR, please explain why FEI will be paying for these expenditures in USD dollars instead of Canadian dollars.

<u>Response:</u>

FEI confirms the "Portion USD" column includes all labour, materials, and services required for the components expected to be denominated in USD. To clarify, until final contracts with contractors are executed, FEI is unable to confirm whether the expenditures referenced in the table in response to BCUC IR1 45.1 will be invoiced in USD or CAD. In the response to BCUC IR1 45.1, FEI indicated that the "Total As-spent" dollars is expected to include USD payments; however, that could include amounts invoiced directly to FEI in USD or amounts incurred in USD by the contractor, converted to CAD, and invoiced to FEI in CAD. In either case, there is some exposure to foreign exchange in the "Total As-spent" forecast.

FEI notes that, as discussed in the responses to CEC IR1 61.3 and 61.5, FEI endeavors to use local and Canadian companies where possible. However, there will be aspects of the Project that cannot be practicably sourced within Canada due to unavailability of materials or expertise, and also due to the fact that most commodity prices for materials that will be used in the Project are benchmarked to USD. As such, there will be some expenditures for materials or expertise that would be unavoidably in US dollars instead of Canadian dollars.

94.0 Reference: FINANCIAL ANALYSIS

Exhibit B-15, BCUC IR 46.1, 46.2

Rate Impact

In response to BCUC IR 46.1, FEI stated it "is aware of only a few counterparties that would be willing to structure a peaking arrangement deal."

94.1 Please identify the counterparties FEI would structure a peaking arrangement deal with under a non-no-flow event scenario. As part of the response, please provide a brief description of prior arrangement deals with the respective counterparties.

94.1.1 Please discuss whether the counterparties identified in the response to the preceding IR would be willing to structure a peaking arrangement deal in the event of a no-flow scenario. If not, please explain why not and identify the counterparties who would be willing to structure a peaking arrangement deal in the event of a no-flow scenario.

Response:

In all scenarios, FEI would structure peaking arrangement deals with counterparties that have either contracted firm transportation capacity on Westcoast's T-South pipeline and/or have storage capacity at Jackson Prairie and Mist assigned to them. As an example, FEI would review the names of the counterparties that are on the Pipeline Contracted Firm Service Report that Westcoast releases on a monthly basis.[20]

FEI considers it unnecessary to identify the counterparties by name, as their commitment to this infrastructure may change in the short-term and their willingness to negotiate this type of deal may vary from year-to-year depending on their own portfolio requirements. An arrangement with these counterparties would be similar to how FEI currently transacts peaking arrangement deals at the East Kootenay Exchange (EKE). Since the 2020/21 gas year, FEI has been paying a demand charge to a counterparty for the entire term to ensure that supply will be available at the EKE when FEI requires it (i.e., a call option). FEI pays the daily settled commodity price at the market hub only on the days that the supply is called upon. While this type of deal could also be structured at Huntingdon, it would be more challenging to transact and would have a much higher demand charge.

FEI could have a peaking arrangement deal in place when a no-flow scenario occurs; however, there is no way to assure that the gas would be physically delivered during an emergency event. This was exemplified during the T-South Incident, as Westcoast declared *force majeure* and commercial arrangements in the marketplace were suspended during the first 48 hours of the incident.

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[20] Westcoast Energy Inc.'s Informational Postings "Pipeline Contracted Firm Service – T-South." https://noms.wei-pipeline.com/info/.

FEI does not believe that structuring a peaking deal at Huntingdon could replace the Tilbury Base Plant in FEI's gas supply portfolio. FEI would not be able to find enough deals to replace the 150 MMcf/day of the Tilbury Base Plant's existing deliverability, because that is a large supply resource in the regional context. As discussed in the response to BCUC IR1 46.1, the Tilbury deliverability is about 9 percent of the Westcoast T-South Capacity to Huntington, which is 1.7 Bcf/day. Further, FEI has experienced a contract breach in the past with regards to a peaking arrangement deal at Huntingdon. FEI was able to manage this situation with supply from the Tilbury Base Plant by effectively replacing the supply that FEI required from the peaking deal.

In response to BCUC IR 46.2, FEI provided the following table showing the financial comparison between 3 Bcf of Storage and 2 Bcf of Storage with 150 MMcf/d of Contracted Supply:

	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%)**

94.2 Please confirm, or explain otherwise, that the minimum tank size of 2 Bcf and regasification capacity for the TLSE Project is sized to meet demand for the highest cumulative 3-day demand in the design year.

94.2.1 If confirmed, please explain why FEI also requires the contracting of 150 MMcf/d peaking supply. Please further explain how FEI determined a 150 MMcf/d of contracted supply would be necessary if a 2 Bcf tank was used.

94.2.2 Please discuss the impact to the PV of the incremental revenue requirement and the levelized delivery rate impact over the 67-year analysis period if the contracted supply required for peaking were less than 150 MMcf/d (e.g. 100 MMcf/d).

94.2.3 Please calculate at what peak capacity (e.g. between 0 MMcf/d and 150 MMcf/d) of contracted supply would the $91 million of PV of cost savings under the 2 Bcf plus T-South contract scenario be reduced to zero.

Response:

Not confirmed. As discussed in Section 4.4.2.2.1 of the Application and further detailed in the response to BCUC IR1 19.6, the 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. FEI believes regasification capacity at this level is reasonable and in the event the no-flow event occurred simultaneously with the design peak day FEI would need to address the residual risk through load shedding.

FEI confirms 3 Bcf will meet demand for the highest cumulative 3-day demand in the design year. However, 2 Bcf would not meet this demand. As noted in Section 4.3.5.3.1 of the Application:

> The maximum calculated cumulative design load over a 3-day period (extrapolated from FEI 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 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 Bcf in order to meet FEI's 3-day Minimum Resiliency Planning Objective.

With a smaller 2 Bcf tank, it would not be possible to reserve 2 Bcf exclusively for resiliency without foregoing the gas supply and operational function that the current Base Plant has served since 1971, and which remains important to serving customers. FEI would need to contract 150 MMcf/day of supply as part of the existing gas supply resource stack to replace it, as discussed in the response to BCUC IR1 22.7. As discussed in the response to BCUC IR1 46.2, FEI estimated the cost for procuring supply in the market for peak demand purposes would be approximately $30 million per year.

FEI nevertheless provides the requested information in order to be responsive. Tables 1 and 2 below show the impact to the PV of incremental revenue requirement and the levelized delivery rate impact over the 67-year analysis period if the contracted supply required for peaking were at 100 MMcf/day and 33.6 MMcf/day, respectively.[21] A contracted supply of 33.6 MMcf/day for peaking is the breakeven point where there is no difference in total PV of incremental revenue requirement over the 67-year analysis period when comparing the preferred 3 Bcf LNG tank and the alternative of a 2 Bcf tank plus T-South contracted supply.

However, as noted above, the Tilbury Base Plant currently provides 150 MMcf/day for peak demand requirements as part of FEI's existing gas supply portfolio. Based on the current design load forecast, FEI would not have enough supply to meet its peak day demand requirements if contracted supply was reduced to either 100 MMcf/day or 33.6 MMcf/day.

[21] FEI assumed the annual costs for the supply contract would be approximately $20 million per year without escalation or inflation for 100 MMcf/day, and approximately $6.7 million per year without escalation or inflation for 33.6 MMcf/day.

Table 1: Financial Comparison between 3 Bcf of Storage and 2 Bcf of Storage with 100 MMcf/day of Contracted Supply

	3 BCF (Preferred Alternative)	2 BCF & plus T-South 100 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; $20 million (2021 $) per year ($ millions)	-	270	(270)
Total PV of Incremental Revenue Requirement 67 years ($ millions)	**1,042**	**1,220**	**(179)**
Levelized Delivery Rate Impact 67 years (%)	**6.67%**	**7.81%**	**(1.14%)**
Levelized Delivery Rate Impact 67 years ($/GJ)	0.301	0.352	(0.052)
Cumulative Delivery Rate Impact (2022 to 2027)	**9.07%**	**10.61%**	**(1.54%)**

Table 2: Financial Comparison between 3 Bcf of Storage and 2 Bcf of Storage with 33.6 MMcf/day of Contracted Supply

	3 BCF (Preferred Alternative)	2 BCF & plus T-South 33.6 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; $6.7 million (2021 $) per year ($ millions)	-	91	(91)
Total PV of Incremental Revenue Requirement 67 years ($ millions)	**1,042**	**1,042**	**0**
Levelized Delivery Rate Impact 67 years (%)	**6.67%**	**6.67%**	**0.00%**
Levelized Delivery Rate Impact 67 years ($/GJ)	0.301	0.301	0.000
Cumulative Delivery Rate Impact (2022 to 2027)	**9.07%**	**9.07%**	**(0.00%)**

95.0 Reference: FINANCIAL ANALYSIS

Exhibit B-15, BCUC IR 23.2.2, 23.3, 23.6, 46.3

Exhibit B-1-4, Section 1.2.2, pp. 9-10; Section 3.5.4, p. 63; Section 4.4.1, p. 115; Section 6.3, p. 161; Appendix P, the Archaeological Overview Assessment Report, p. 1

Rate Impact

In response to BCUC IR 23.3, FEI stated:

> 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.

In response to BCUC IR 46.3, FEI stated:

> 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.

95.1 Please identify potential customers that would contract space in the tank.

95.1.1 Please discuss whether FEI has formally or informally engaged any potential customers.

Response:

At this time, FEI's expectation is that, if the opportunity arises, a FortisBC affiliate would likely be the entity contracting directly with FEI for storage in the TLSE Project tank (FortisBC Holdings Inc. is the other proponent of the Phase 2 Expansion Project). The affiliate's interest in such an opportunity would be market dependent, and FEI's ability to provide space would be dependent on FEI's own needs to serve its customers and BCUC oversight. FEI's rationale for the TLSE

Project is not dependent on such an opportunity arising. As such, discussions have been high-level and conceptual as presented in the Application (i.e., that the opportunity exists).

95.2 Please discuss whether there are entities that currently contract for LNG storage space in North America. If so, please identify.

Response:

FEI understands that there are entities that currently contract for LNG storage space in North America; however, without a detailed review of integrated resource plans and regulatory filings, FEI cannot identify the specific entities. One example of an entity that offers third party storage services to its customers is Plymouth LNG. LNG storage contracting can be done on a similar basis to conventional gas storage operations when combined with liquefaction and regasification. Conventional gas storage operations in the region, such as Aitken Creek Gas Storage, Jackson Prairie (JPS), and Mist also offer storage contracts to third parties. The entities that contract for these storage services include load serving entities, energy trading companies, or any other participant that is active in the buying and selling of gas in the region.

95.3 Please confirm, or explain otherwise, that in a scenario where an entity contracts X percent of the storage capacity, there would be an equivalent X percent reduction in the levelized delivery rate impact over the 67-year analysis period for ratepayers.

Response:

Confirmed. As per the example demonstrated in the response to BCUC IR1 46.3, if an entity contracts for 20 percent (or X percent) of the storage, then 20 percent (or X percent) of the fully allocated cost of service would be recovered from that entity, thereby reducing the levelized delivery rate impact of the TLSE Project over the 67-year analysis period by 20 percent (or X percent). A 20 percent reduction to the forecast levelized delivery rate impact of 6.67 percent results in an impact of 5.33 percent (i.e., 5.33 percent = 6.67 percent x (1 - 20 percent)).

FEI notes that using the storage capacity is only one of the possible allocation methods between FEI and the third party entity. FEI's ability to provide space would also be dependent on FEI's own needs to serve its customers and BCUC oversight.

On page 63 of the Updated Application, FEI states: "the design capacity of the Base Plant tank is 0.6 Bcf."

95.4 Please discuss whether FEI intends to lease out 20 percent of the storage capacity, which equates to 0.6 Bcf of the proposed 3 Bcf tank and is equivalent to the existing capacity of the Base tank. [22]

95.4.1 If not confirmed, please discuss what percentage of the storage capacity FEI anticipates leasing out for ancillary revenue.

Response:

The 20 percent example provided in the response to BCUC IR1 46.3 was illustrative only, and the potential to offer storage space in the TLSE Project tank remains conceptual (i.e., FEI does not have a forecast of the percentage of storage capacity). The potential to offer storage space is just one of several opportunities to utilize the value of the "third Bcf" of the TLSE tank for FEI customers by generating ancillary revenue.

As described in the response to BCUC IR2 95.1, any contracting of the TLSE tank storage space will be dependent on FEI's requirements to serve its own customers, and will be subject to BCUC oversight.

On page 115 of the Updated Application, FEI states that "[d]iscussions have been ongoing over the past number of years with several overseas customers who have interest in exporting LNG from Tilbury to destinations in Asia."

On page 1 of the Archaeological Overview Assessment Report in Appendix P, the report states "[t]he proposed Tilbury Tank 2, with the Tilbury Phase 1A tank or Tilbury Tank 1, is intended 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 with capacity to meet the future demands of the LNG export market."

95.5 Please discuss the expected capacity usage of the proposed 3 Bcf tank to meet the future demands of the LNG export market compared to the usage to provide security and resiliency. As part of the response, please calculate the levelized delivery rate impact over the 67-year analysis period based on this division of usage and the rationale of how that split was determined.

Response:

[22] "20 percent of the storage capacity" x proposed 3 Bcf tank = 0.6 Bcf.

As discussed in the response to BCUC IR1 23.1, 2 Bcf is currently required to address the risk reflected in the Minimum Resiliency Planning Objective (MRPO); therefore, from a planning perspective based on current load, FEI will reserve 2 Bcf in the tank solely for resiliency purposes. It is the "third Bcf" that would permit FEI to capture other ancillary benefits as discussed in Section 4.4.1.5 of the Application, including continuing to use Tilbury to play the role the Base Plant has played since 1971, with the potential of reducing customer rates through storage contracting and/or LNG export being only one of the ancillary benefits listed. Further, as explained in Section 4.4.1.5.5, the timing of the LNG export opportunity materializing is contingent on the market. Regardless, FEI must consider the needs of its own customers and any value that FEI would obtain from retaining use of some or all of the "third Bcf" (e.g., the value of using a portion of the "third Bcf" to replace the role currently served by the Base Plant, versus looking to the market). Therefore, FEI is unable to determine an expected capacity usage of the "third Bcf" that would be for the future demand of LNG export.

However, as an illustration only, FEI provides the following calculation based on contracting out 0.4 Bcf (i.e., approximately 13.3 percent of the total 3 Bcf storage capacity). FEI selected 0.4 Bcf for this illustration as it represents the difference between the "third Bcf" and the 0.6 Bcf design capacity of the Tilbury Base Plant (the Base Plant is actually currently being operated at 0.3 Bcf while it is being assessed). In this scenario of contracting 0.4 Bcf, FEI would continue to be able to realize the benefits currently provided by the Base Plant. By contrast, if one assumes that the full "third Bcf" was contracted out, when valuing that opportunity from the perspective of FEI ratepayers it would be necessary to consider the costs for securing the equivalent gas supply capacity of the 150 MMcf/day currently provided by the Base Plant through commercial arrangements.

	TLSE Project (As Filed)	0.4 Bcf for LNG Export (i.e. 13.3% of Cost of Service is allocated to LNG Export)
PV of Incremental Revenue Requirement 67 years ($ millions)	1,042	903
Levelized Delivery Rate Impact 67 years (%)	6.67%	5.78%
Levelized Delivery Rate Impact 67 years ($/GJ)	0.301	0.261

95.6 Please discuss whether FEI would have potential opportunities to contract storage capacity if the 2 Bcf tank was built.

Response:

FEI would not have potential opportunities to contract TLSE storage capacity if the 2 Bcf tank was built based on current Lower Mainland load.

As explained in FEI's responses to IR1, including the response to BCUC IR1 23.1, 2 Bcf is required to address the risk reflected in the Minimum Resiliency Planning Objective (MRPO) based on current Lower Mainland load. Accordingly, from a planning perspective, FEI will reserve 2 Bcf in the 3 Bcf tank <u>solely</u> for resiliency purposes. It is the “third Bcf”, that would permit FEI to capture the other ancillary benefits discussed in the Application, which would also include supply and ancillary benefits that are, in part, currently associated with having the Tilbury Base Plant as a peaking facility. (As discussed in the response to BCUC IR2 88.2, with a smaller 2 Bcf tank, it would not be possible to reserve 2 Bcf exclusively for resiliency without foregoing the gas supply and operational function that the current Base Plant has served since 1971, and which remains important to serving customers.)

On page 161 of Updated the Application, FEI provides the following table:

Table 6-3: Financial Analysis of the Project

Line	Particular	TOTAL	Reference (Confidential Appendix M1, Financial Schedule)
1	Total Charged to Gas Plant in Service ($ millions)	752.250	Schedule 6; Line 37
2	Base Plant Demolition Costs ($ millions)	17.129	Schedule 6; Sum of Line 34 (2020 to 2025)
3	Total Project Deferral Cost, Net of Tax ($ millions)	(0.381)	Schedule 9; Line 6 + Line 15
4	***Total Project Cost ($ millions)***	**768.998**	**Sum of Line 1 to Line 3**
5			
6	Incremental Rate Base in 2027 ($ millions)	814.400	Schedule 5; Line 19 (2027)
7	Incremental Revenue Requirement in 2027 ($ millions)	79.799	Schedule 1; Line 11 (2027)
8	***PV of Incremental Revenue Requirement 67 years ($ million)***	**1,041.925**	**Schedule 10; Line 20**
9	Net Cash Flow NPV 67 years ($ million)	66.177	Schedule 11; Line 17
10			
11	Delivery Rate Impact in 2027 (%)	9.07%	Schedule 10; Line 23 (2027)
12	***Levelized Delivery Rate Impact 67 years (%)***	**6.67%**	**Schedule 10; Line 27**
13	Levelized Delivery Rate Impact 67 years ($/GJ)	0.301	Schedule 10; Line 33

95.7 Please confirm, or explain otherwise, that revenues associated with the contracting of storage capacity have not been included in the financial analysis provided in Table 6-3. If revenues associated with the contracting of storage capacity are included, please remove, and provide an updated Table 6-3.

<u>Response:</u>

Confirmed. The financial analysis provided in Table 6-3 of the Application does not include any potential revenue from contracting the storage capacity.

On page 9 of the Updated Application, in discussing the 2 Bcf and 3 Bcf tank size alternatives, FEI states that “[b]oth tank sizes are able to meet the Minimum Resiliency Planning Objective.”

On page 10 of the Updated Application, FEI states the “3 Bcf tank provides economies of scale. The total capital cost of the Project with a 3 Bcf tank is $50 million greater in 2020 dollars (approximately 8.4 percent) than one with a 2 Bcf tank, but provides 50 percent more storage. The 3 Bcf tank yields a much lower cost/Bcf.”

95.8 Please calculate the PV of the incremental revenue requirement and levelized delivery rate impact over the 67-year analysis period under each of the following hypothetical scenarios:

i) Project cost were two thirds of the current project cost of a 3 Bcf tank;

ii) Project cost were one half of the cost to build a 2 Bcf tank plus $50 million.

Response:

Please refer to the table below for the PV of incremental revenue requirement and the levelized delivery rate impact over the 67-year analysis period for the two requested scenarios. FEI has also provided the same information for the proposed Project (i.e., 3 Bcf tank) and the 2 Bcf tank as filed in the Application, as FEI interprets the purpose of the two hypothetical scenarios to be that the BCUC is trying to assess the economies of scale between different tank sizes. However, FEI notes the project costs of different tank sizes are not developed based on scaling between the project costs of each tank size; therefore, the hypothetical scenarios presented in this IR do not provide a meaningful comparison. Please refer to the response to BCUC IR1 16.27 which showed the estimated project costs and the $ per Bcf from a 1 Bcf to a 3.5 Bcf storage tank. As that IR response showed, the $ per Bcf reduces as the tank size increases, showing the strong economies of scale.

Line	Particular	3 BCF (As-Filed)	2 BCF (As-Filed)	Scenario 1: 3 BCF (Project Costs equal to 2/3 of current project costs of a 3 Bcf tank)	Scenario 2: 2 BCF (Project cost were 1/2 of the cost to build a 2 Bcf tank plus $50 million)
1	Total Project Capital Costs, 2020 dollars ($ millions)	637	588	425	344
2					
3	PV of Incremental Revenue Requirement 67 years ($ millions)	1,042	951	831	695
4	Levelized Delivery Rate Impact 67 years (%)	6.67%	6.09%	5.32%	4.45%
5	Levelized Delivery Rate Impact 67 years ($/GJ)	0.301	0.275	0.240	0.201

In response to BCUC IR 23.2.2, FEI stated:

> FEI notes that for export sales of LNG using ISO 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 Code of Conduct (COC) and Transfer Pricing Policy (TPP).

In response to BCUC IR 23.3, FEI stated that "[a]ny activity undertaken by FEI in relation to the TLSE Project would be regulated."

In response to BCUC IR 23.6, FEI stated:

> 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.

95.9 Please confirm, or explain otherwise, that all ancillary services (such as export activities and storage contracting opportunities) using the proposed 3 Bcf tank would be considered part of FEI's regulated services and included in FEI's revenue requirements.

95.9.1 If confirmed, please clarify why there would be costs related to the TLSE project that would not be included in FEI's revenue requirements.

Response:

FEI clarifies that the statement in the response to BCUC IR1 23.6, as cited in the preamble, was meant to indicate that if the minor design components associated with the auxiliary system are used by the future Liquefaction Facility for serving the LNG sales market, offsetting revenues[23] will be recovered from the contracting parties for the cost of service related to these components. In other words, the offsetting revenue ensures that the cost of service related to these components is essentially excluded from FEI's delivery rates for non-bypass customers.

FEI notes that, as identified in response to BCUC Confidential IR1 8.2, the costs related to these minor design components/assets are small in comparison to the overall Project cost at approximately $5.2 million. As explained further in BCUC IR1 23.6 and BCUC Confidential IR1 8.2, the reason that the costs of these components/assets are included as part of the TLSE Project costs (and therefore included in the financial analysis shown in Table 6-3 of the Application) is because it is not possible to add or retrofit these assets once the TLSE Project is constructed and in-service. Please refer to the table below which shows the minor impact due to these design components being included in the financial analysis. The inclusion of these costs has an impact of 0.05 percent to the delivery rate in 2027 when all assets enter rate base or a 0.03 percent impact (equivalent to $0.001 per GJ) in the levelized delivery rate over the 67-year analysis period.

[23] Depending on the use of the future liquefaction, offsetting revenue could potentially be received from LNG sales by FEI under RS 46 or from LNG export through a non-regulated entity. In the case of the latter, the recovery of the allocated costs would be subject to BCUC review at that time.

Line	Particular	TLSE Project (As Filed)	TLSE Project (excl. $5.2 million of Minor Design Component)	Difference
1	Total Project Cost in 2020 dollars ($ millions)	639.449	634.249	5.200
2	Total Project Cost in As-Spent dollars ($ millions)	768.998	763.187	5.811
3				
4	PV of Incremental Revenue Requirement 67 years ($ millions)	1,041.925	1,037.220	4.705
5				
6	Delivery Rate Impact in 2027 (%)	9.07%	9.02%	0.05%
7	Levelized Delivery Rate Impact 67 years (%)	6.67%	6.64%	0.03%
8	Levelized Delivery Rate Impact 67 years ($/GJ)	0.301	0.299	0.001

95.10 Please identify the costs related to the TLSE Project that would not be included in FEI's revenue requirements.

95.10.1 Please confirm, or explain otherwise, that costs identified in the preceding IR have not been included in the financial analysis in Table 6-3 of the Updated Application. If not confirmed, please remove the costs, and provide an updated Table 6-3.

Response:

Please refer to the response to BCUC IR2 95.9.

96.0 Reference: FINANCIAL ANALYSIS

Exhibit B-15, BCUC IR 47.2

Cost Allocation

In response to BCUC IR 47.2, FEI stated:

> 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.

96.1 Please discuss whether there is a risk of using only one EPC contractor. Why or why not?

<u>Response:</u>

The primary risks of using one EPC contractor versus several include:

- Risk of Default: where the chosen single EPC contractor defaults on its commitments before completion, perhaps due to financial insolvency, and all progress is halted rather than a portion of the scopes.
- Risk of Litigation: In the event FEI and the single EPC contractor have a legal dispute of sufficient gravity that all work stops on the site before the dispute's resolution (rather than only affecting a portion of the project scope or one of several contracts).

The likelihood of these circumstances coming to pass is remote, as FEI will screen proponents for financial strength, organizational capability to execute the work as part of the evaluation process, and contractual terms will be agreed to before award. Provisions will be included such that if any legal disputes arise during Project execution, they would not stop the work, and would be handled through a separate dispute resolution process. This is typical for large EPC contracts.

In practice, a "single EPC contractor" could be a consortium of separate firms that group together under a single legal entity to execute a project within a single scope of work, and will be jointly obliged to each other to progress the work successfully.

The risks of using several EPC entities are both more likely to occur and greater in impact. If the work were split into several scopes of work, FEI would assume responsibility for coordinating the work on site and the liability for inefficiencies caused by competing concurrent operations. This would require FEI to dramatically increase the size of its execution team to properly mitigate these risks, with a corresponding increase to the TLSE Project's capital costs.

96.2 Please discuss how FEI intends to ensure expertise across a range of complex projects with different needs given the intended use of only one contractor.

Response:

FEI intends to employ a competitive process with proponents who have demonstrated their ability to complete projects of a similar nature and scope.

As explained in the response to BCUC IR2 96.1, it is possible that a “single EPC contractor” will be a consortium of formally separate firms, with separate but complementary specialties, that group together under a single legal entity to execute the scopes.

FEI will evaluate each proponent’s proposal(s) using a comprehensive set of criteria, including:

- A demonstrated ability to execute work of this type and at this scale;
- A demonstrated capacity to execute this work at the present moment in time with personnel, expertise, and other resources acceptable to FEI; and
- A credible execution plan.

These criteria will be among the key considerations of the evaluation process.

E. ENVIRONMENT AND ARCHEOLOGY

97.0 Reference: ENVIRONMENT AND ARCHEOLOGY

Exhibit B-1-4, Appendix O, p. 6-3

Exhibit B-15, BCUC IR 50.1

Contaminated Soils and Groundwater Impacts - APECs

Table 6-1 in Appendix O shows the risk rating for contaminated soils and groundwater receptors is Medium to High. Mitigation/follow-up activities noted in Table 6-1 includes the completion of Stage 2 Preliminary Site Investigation (PSI) work on all areas of potential environmental concern (APEC) for soil and groundwater to determine if contamination exists and to provide additional information for quantifying expected volumes of contaminated soils and/or groundwater.

In response to BCUC 50.1, FEI stated that 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.

97.1 Please provide the updated risk ratings for all APECs, following the Stage 2 PSI, including the adjusted risk ratings for contaminated soil and groundwater receptors.

Response:

The Stage 2 PSI results are currently in draft form and will likely be finalized in Q1 2022. Once the Stage 2 PSI is finalized, the risk ratings presented in Appendix O will be adjusted based on the findings of the final Stage 2 PSI report.

F. CONSULTATION

98.0 Reference: CONSULTATION

Exhibit B-15 BCUC IR 54.1

Further Comments Received

In response to BCUC 54.1 FEI provided three comments that had been received that were specific to the TLSE Project. In the first one titled "project purpose", the unnamed Indigenous Group "is in (sic) 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."

FEI also provided a summary list of additional comments, which FEI describes as "while not specific to the TLSE Project, are relevant to the project."

98.1 Please clarify if FEI has responded to the comment from the unnamed Indigenous Group. If not, when does FEI expect to respond to the question. If yes, please provide a copy of FEI's response.

Response:

FEI has responded to the comment from the Indigenous group referenced in the preamble. As part of the engagement on the Phase 2 LNG Expansion project (the proponents of which are FEI and FortisBC Holdings Inc.), the Environmental Assessment technical advisors and participating Indigenous groups were provided with the draft Detailed Project Description (DPD) in two parts. The "project purpose" was directly addressed in part 2 of the draft DPD. As a result, FortisBC provided the following initial response:

> Tilbury is already producing LNG for marine customers such as BC Ferries and Seaspan Ferries and storing LNG to meet the energy needs of our customers. The Project rationale is being further clarified and an update will be provided in Part 2 of the DPD for [the Indigenous group] review.

The Tilbury Phase 2 LNG Expansion project need and purpose is provided in Section 2.2 of the final detailed project description, found on the BC EAO's website.[24]

[24] https://www.projects.eao.gov.bc.ca/api/public/document/6138dcca17ba3b0022913ab0/download/FortisBC_Tilbury_DPD_Package.pdf.

98.2 Please provide copies of the original comments received, along with responses provided by FEI.

Response:

The table below sets out the original comments received, along with the responses provided by FortisBC (FEI and FortisBC Holdings Inc., the proponents of the Phase 2 Expansion Project EA).

Topic	Comment	FortisBC response
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.	Tilbury is already producing LNG for marine customers such as BC Ferries and Seaspan Ferries and storing LNG to meet the energy needs of our customers. The Project rationale is being further clarified and an update will be provided in Part 2 of the DPD for [Indigenous group] review.
Accidents and malfunctions	Consider specific malfunctions and accidents associated with facility commissioning and LNG tank cool down	Thank you for the comment. FortisBC will take this into consideration in proposed Project planning and development.
Decommissioning	[The Indigenous group] would like more details about the process for decommissioning and demolition of the old plant.	Removal of the old plant will involve an application to the OGC and is not part of the Phase 2 expansion scope. The OGC process includes consultation opportunities with Indigenous groups. Details to be finalized at later date with application to the OGC.

99.0 Reference: CONSULTATION

Exhibit B-15, BCUC IR 56.1, BCUC Attachment 56.1b, p. 369; 56.1c, p. 373

May 4, 2021 and June 16, 2021 Meetings

In response to BCUC IR 56.1, FEI referred to two meetings held with various stakeholders at the request of the BC EAO. Participants included Indigenous Nations and their representatives; Municipal & Regional governments; Provincial Agencies; Federal Government; and Fortis BC

The May 4, 2021 meeting was in response to a BC EAO request 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.

The June 16, 2021 occurred as part of the Early Engagement process. The BC EAO requested FortisBC provide a presentation of the draft Detailed Project Description to Indigenous groups and government agencies, providing them with another opportunity to ask questions and provide feedback.

Questions submitted by stakeholders included the following related to resiliency:

In Attachment 56.1b (page 369 of Exhibit B-15) states: “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)”

In Attachment 56.1c (page 373 of Exhibit B-15) states: “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.”

99.1 Please supply the answers provided by FEI and/or Fortis BC in response to these questions. If a response has not been provided yet, please confirm when FEI intends to do so.

Response:

Please refer to the responses provided by FEI and FortisBC Holding Inc. (collectively referred to as FortisBC) to the questions identified in the preamble for each below:

Topic	Question	FortisBC Response
Resiliency	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)	FortisBC based its estimates on current gas demand forecasts. These forecasts take into account a myriad of factors including scenarios that put downward pressure on gas usage and scenarios that would increase usage. These scenarios support the need to strengthen system resiliency by building a larger storage tank to provide a source of backup energy supply in the region.
Resiliency	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.	FortisBC provides up to 50% of the province's energy needs on the coldest days of the year and small-scale renewables are not a viable alternative to meet this demand. FortisBC is a key partner in meeting the province's climate action goals. In the future, the company's energy supply will be increasingly renewable to meet provincial targets. FortisBC has set a target that by 2030 its gas supply would be 15% renewable. Increasing the supply of renewable gas in B.C. is one of the key actions FortisBC is taking as part of its 30BY30 target to reduce customers' greenhouse gas emissions 30% by 2030.

100.0 Reference: CONSULTATION

Exhibit B-15, BCUC IR 62.1 Attachment 62.1

Questions from Open House June 18, 2020 and June 23, 2020

In response to BCUC IR 62.1, FEI provided a complete version of Appendix Q-7, which contains questions and comments submitted during Virtual Open Houses held on June 18 and 23, 2020.

Questions submitted at the June 18, 2020 virtual open house included the following:

- 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?
- 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?
- 26: Will upgrades be required to the current infrastructure leading to Tilbury?

Questions submitted at the June 18, 2020 meeting included the following:

- 9: The site is only ~ 1 metre above current sea-level. Won't flooding due to sea-level rise be an issue?
- 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?
- 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?

- 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)?
- 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?

100.1 Please supply the answers provided by FEI and/or Fortis BC in response to these questions. If a response has not been provided yet, please confirm when Fortis intends to do so.

Response:

FEI and FortisBC Holdings Inc. (together, FortisBC) provided verbal responses during the virtual open houses, which were not recorded. The responses provided in the table below are a summary of the information provided at the virtual open houses.

Questions June 18, 2020 Virtual Open House	Responses
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?	• Existing gas lines and rights-of-way already supply natural gas to the Tilbury LNG facility, however a full scale build out of the facility may require additional pipe capacity for gas access. • The ultimate capacity of the Tilbury facility would be driven by market demand while upstream pipe capacity is driven by growth on the gas system in general, including other projects (e.g. Woodfibre) that may or may not proceed. • Project-related gas requirements are being provided to FortisBC's gas system planning group as well as other transmission operators that provide natural gas to FortisBC to inform their system planning. Any such expansions would be subject to their own regulatory reviews.

Questions June 18, 2020 Virtual Open House	Responses
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?	• FortisBC's LNG facilities are built to industry standards including secondary containment to ensure safe operation. It's worth noting that Japan does not require that tanks are built below-ground. Tanks are built below-ground to allow them to be built closer together to maximize available limited land and is not driven primarily by safety. • The existing Tilbury LNG facility has been in operation since 1971 and has continued to operate safely through a number of seismic events. As part of the expansion completed in 2018, extensive stone columns were installed below the ground to help reduce the risk to the facility during a seismic event. Similar ground improvements are being proposed for the Tilbury Phase 2 Expansion Project.
26: Will upgrades be required to the current infrastructure leading to Tilbury?	• FortisBC is considering a new six kilometre power line as part of the Phase 1 development plan to continue powering our facility with hydroelectricity. If approved, the Phase 2 project would also be powered by the new power line. • FortisBC is planning a 1-3 kilometre gas line upgrade adjacent to the facility and is exploring the possibility of additional gas line capacity to maintain gas supply to our customers.

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Questions: June 23, 2020 Virtual Open House	Responses
9: The site is only ~ 1 metre above current sea-level. Won't flooding due to sea-level rise be an issue?	• Flood protection was considered as part of the site design of the Tilbury expansion completed in 2018. FortisBC constructed a dike along the Fraser and built the facility at a higher elevation. Future expansions will also be built on elevated ground. • This flood protection infrastructure was designed to meet and exceed the seismic provisions of the BC Building Code, to ensure this public safety infrastructure is better suited to withstand an earthquake.

Questions: June 23, 2020 Virtual Open House	Responses
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?	• The Tilbury LNG facility already has procedures and safety measures in place to prevent and manage emergencies. • This includes complete on-site fire control and response systems independent of the fire department. The facility is monitored 24/7 year-round by highly-trained site personnel. • FortisBC provides training to local first responders and conducts regular emergency exercises with first responders to coordinate our response in the unlikely event of an emergency.
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?	• The lower Fraser River is a safe and suitable location for a liquefied natural gas facility. • The existing Tilbury LNG facility has been operating safely since 1971 in an industrial area in Delta and plays an important role in ensuring British Columbians have the energy they need. • The Vancouver Fraser Port Authority has developed rules and procedures specifically for the safe navigation of all LNG carriers on the Fraser River. • For marine customers interested in cleaner marine fuel, the Tilbury site has access to an existing deep-sea navigation channel on the Fraser River, which is already being safely used as an international shipping route.
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?	• Japan does not require tanks to be built below-ground. Tanks are built below-ground to allow them to be built closer together to maximize available limited land which is not driven by safety.
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)?	• Any FEI costs and rate impacts will be included in an application we are preparing to submit to the BC Utilities Commission later this year.

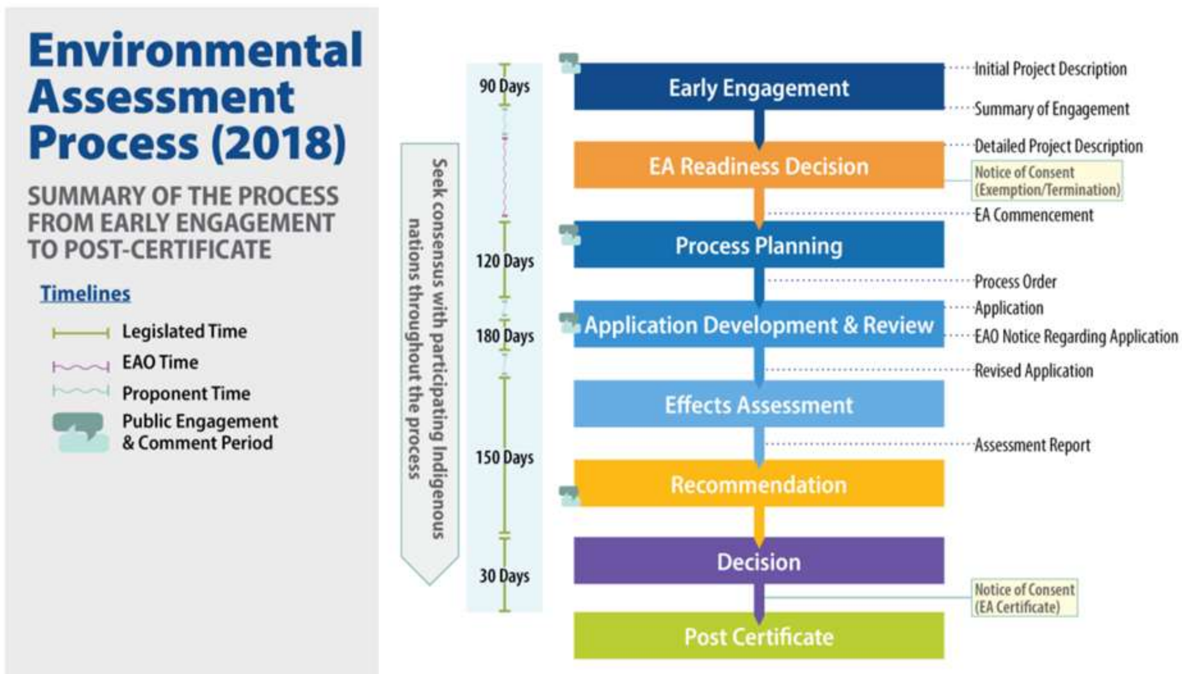
Questions: June 23, 2020 Virtual Open House	Responses
38: Currently, the spot price of LNG in a glutted Asian market is around US $2.10 (averaging less than $6 over the past 5 years), while, according to the Canadian Energy Research Institute (CERI), the full cost of BC-produced LNG is over US $8 (both per million British Thermal Units (mmBTU)). How does Fortis plan to profit from this dismal scene?	• International targets to reduce emissions from global shipping are creating increased demand for lower-carbon fuels, like LNG. • FortisBC believes that LNG can be a major step forward in reducing greenhouse gas emissions from ships compared with traditional heavy marine fuels. • The Tilbury facility is well-positioned to help meet this growing demand for overseas customers looking to replace coal or heavy fuels. • There are several overseas customers interested in purchasing LNG from Tilbury.

101.0 Reference: CONSULTATION

Exhibit B-15, BCUC IR 55.1, 58.2, 61.1, 61.2, 61.3, 61.3.1

Phases of Consultation and Capacity Funding Agreements

Footnote 58 of BCUC IR 61.3.1 provided the link to the following diagram of the Environmental Assessment (EA) Process (note that the timing is generic and does not reflect the timing for the Phase 2 Tilbury EA process): [25]



In response to BCUC IR 61.3, FEI stated that the Early Engagement phase concluded in September 2021. The next phases include the regulator-led Readiness Decision and Process Planning phases, which are conducted by the BC EAO.

In response to BCUC IR 55.1, FEI stated that 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.

101.1 Please clarify when FEI expects the Readiness Decision to be available.

[25] Footnote 58 reference: https://www2.gov.bc.ca/gov/content/environment/natural-resource-stewardship/environmental-assessments/theenvironmental-assessment-process/2018-act-environmental-assessment-process.

Response:

Although there is no established timeline for the Readiness Decision phase, FEI expects this phase to conclude in December 2021.

FEI states in BCUC IR 61.3.1 that it expects capacity funding for Indigenous groups will be required for the Early Engagement Phase and the Application Development and Review. More detail about the assessment process and engagement needs will become available following Process Planning. 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.

BCUC IR 61.2 requesting an update on the status of any capacity funding agreements which are being negotiated. FEI in its response referred to the response to BCUC IR 61.1, and stated that a capacity funding agreement has been executed with Chawathil First Nation.

In response to BCUC IR 61.1, FEI stated that it signed capacity funding agreements with Musqueum First Nation and Cowichan Tribes prior to entering the Early Engagement phase of the EA.

In response to BCUC 58.2, FEI stated:

> 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.

101.2 Please confirm if the response to BCUC IR 61.1 is complete. If not, please provide an update on capacity agreements which are being negotiated, including the communities that FEI is negotiating with.

Response:

Not confirmed. FEI has offered capacity funding agreements to Indigenous groups that are participating in the Tilbury Phase 2 Expansion Project engagement process, including: Chawathil First Nation, Cheam First Nation, Cowichan Tribes, Penelakut Tribe, Stz'uminus First Nation, Halalt First Nation, Lyackson First Nation, Kwantlen First Nation, Musqueam Indian Band, S'ólh Téméxw Stewardship Alliance, Tsleil-Waututh Nation, Tsawwassen First Nation, and Ts'uubaa-asatx Nation.

Of these offers, and in addition to those groups identified in response to BCUC IR1 61.1 and 61.2, FEI has signed Capacity funding agreement with Lyackson First Nation.

101.3 Please clarify if the negotiation of capacity funding agreements for subsequent phases is currently on hold, pending the outcome of the Readiness Decision, or explain otherwise.

Response:

Capacity funding agreements that have been signed or are under negotiation are intended to support engagement with Indigenous groups from the Early Engagement phase through to, and including, the Process Planning phase as part of the parallel federal IA and provincial EA processes. FEI will update existing capacity funding agreements to capture subsequent phases after receiving the outcome of the Readiness Decision. FEI will also continue to work towards capacity funding agreements with other Indigenous groups. The agreements are subject to the continuance of the associated regulatory processes and may be terminated with notice, by either party.

102.0 Reference: CONSULTATION

Exhibit B-1-4, pp. 185, 197-198

Exhibit B-15, BCUC IR 55.1, 58.1, 62.1 Attachment 62.1

Level of Engagement

FEI states on page 185 of the Updated Public Application that 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.

Table 8-4 on page 197 of the Updated Application lists the Indigenous Groups identified by FEI as being affected by the Project:

Table 8-4: Indigenous Groups Affected by Project

Indigenous Groups		
Cowichan Tribes	Musqueam Indian Band	Squamish First Nation
Halalt First Nation	Penelakut Tribe	Stó:lō Nation
Katzie First Nation	Seabird Island Band	Stó:lō Tribal Council
Kwantlen First Nation	Semiahmoo First Nation	Stz'uminus First Nation
Lake Cowichan First Nation	Shxw'ōwhámél First Nation	Tsawwassen First Nation
Lyackson First Nation	Skawahlook First Nation	Tsleil-Waututh Nation
Métis Nation British Columbia	Soowahlie First Nation	

On pages 197 and 198 of the Updated Application FEI provides a list of 10 communities that engaged in two-way communication with FEI during the preliminary engagement activities from July 2019 to July 2020, including (in alphabetical order): Cowichan Tribes; Halalt First Nation; Katzie First Nation; Kwantlen First Nation; Musqueam Indian Band; Penelakut Tribe; Seabird Island Band; Stz'uminus First Nation; Tsawwassen First Nation; Tsleil-Waututh Nation.

In response to BCUC 55.1, FEI stated that 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.

In response to BCUC IR 58.1, FEI identified a list of 12 Indigenous groups requesting to meet on the Project and discuss next steps, as of August 2020.

102.1 Please provide an updated list of Indigenous groups that FEI has actively engaged with on the Project to date, if applicable.

<u>Response:</u>

As of the date of writing, FEI has actively engaged in two-way communication with the following Indigenous groups:

1. Cheam Indian Band
2. Chawathil First Nation

3. Cowichan Tribes
4. Halalt First Nation
5. Katzie First Nation
6. Kwantlen First Nation
7. Kwikwetlem First Nation
8. Musqueam Indian Band
9. Penelakut Tribe
10. Seabird Island Band
11. S'ólh Téméxw Stewardship Alliance
12. Stz'uminus First Nation
13. Tsawwassen First Nation
14. Tsleil-Waututh Nation
15. Ts'uubaa-asatx Nation

102.2 Please clarify if the required level of engagement for each of the affected Indigenous Communities has been established, or if this will only be determined during the Process Planning phase.

102.2.1 If the appropriate level of engagement has already been established, please provide an updated version of Table 8-4, clarifying the level of engagement for each Indigenous group.

Response:

The role of Indigenous groups as part of the EA process will be further defined during the Process Planning Phase. The outcome of the Process Planning Phase will be formalized in the Process Order issued by the EAO.

103.0 Reference: CONSULTATION

Exhibit B-15, BCUC 54.1

Further Comments Received

In response to BCUC IR 54.1, FEI provided further comments that had been received specific to the TLSE Project since the filing of the Application, in the table copied 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.

FEI also provided a list of topics, reflecting a number of additional comments that have been received that "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.

103.1 Please provide a copy of any responses FEI has provided responses to the questions listed in the table above.

Response:

The responses of FEI and FortisBC Holding Inc. (collectively referred to as FortisBC) to the questions listed in the table in the preamble are included below:

Topic	Question	FortisBC Response
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'. TWN 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.	Tilbury is already producing LNG for marine customers such as BC Ferries and Seaspan Ferries and storing LNG to meet the energy needs of our customers. The Project rationale is being further clarified and an update will be provided in Part 2 of the DPD for [Indigenous group] review.
Accidents and malfunctions	Consider specific malfunctions and accidents associated with facility commissioning and LNG tank cool down	Thank you for the comment. FortisBC will take this into consideration in proposed Project planning and development.
Decommissioning	[The Indigenous group] would like more details about the process for decommissioning and demolition of the old plant.	Removal of the old plant will involve an application to the OGC and is not part of the Phase 2 expansion scope. The OGC process includes consultation opportunities with Indigenous groups. Details to be finalized at later date with application to the OGC.

103.2 Please discuss the approach used by FEI to determine which comments are relevant to the TLSE Project only.

Response:

FEI's approach was to classify any comments that reference the proposed storage tank as specific to the TLSE Project. Any comments that could apply to both the proposed storage tank and the liquefaction component of the Tilbury Phase 2 LNG Expansion were classified as relevant to the TLSE Project, but not specific to it.

104.0 Reference: CONSULTATION

Exhibit B-15, BCUC IR 56.1

Exhibit B-1-4, p. 195; Appendix Q-2, p. 22; City of Vancouver, Minutes of the Standing Committee of Council on Policy and Strategic Priorities September 22, 2021

Municipal Consultation

In response to BCUC 56.1, FEI provided an updated version of the Provincial and Local Government Communications Log provided in Table 8-2 of the Application. The update covers the period November 2020 to June 2021.

FEI's Engagement Plan submitted as Appendix Q-2 identifies the City of Delta, City of Richmond and Metro Vancouver for engagement.

On page 195 of the Updated Application, FEI states that the Company will continue to work with the local municipalities, primarily with Delta and Richmond, and other stakeholders to maintain transparency, and will address feedback throughout the process.

On Wednesday, September 22, 2021, the City of Vancouver passed a motion to oppose the expansion of the Tilbury LNG facility in Delta.[26] The motion states that the "Richmond City Council and Port Moody City Council both voted to oppose Tilbury LNG in 2020. Delta has provided some comments about fire safety and continues to engage with the review but has not yet taken a position on the proposal."[27][28]

104.1 Please confirm if FEI has received notification of any official opposition from municipalities, or other government agencies, with respect to the Phase 2 Tilbury Expansion project.

Response:

FEI and FortisBC Holdings Inc. have not received any formal notification of official opposition from municipalities or other government agencies with respect to the Tilbury Phase 2 LNG Expansion Project, but is aware that the cities of Richmond, Port Moody, Vancouver and New Westminster have passed motions to oppose the Project. In addition, the City of Burnaby passed a motion to support Richmond's resolution opposing the Project.

104.1.1 Should the Phase 2 Tilbury Expansion project not be approved by the BC EAO, please discuss the implications for the TLSE Project.

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26 https://council.vancouver.ca/20210922/StandingCommitteeonPolicyandStrategicPriorities-September222021.htm.

27 Motion - Acting on the Climate Emergency by Opposing the Tilbury LNG Phase Two Expansion Project (Member's Motion B.3) - September 22, 2021 (vancouver.ca).

28 https://www.richmond.ca/__shared/assets/_3_-_TilburyPhase2LNGExpansion_GP_07062056545.pdf.

Response:

Please refer to the response to BCUC IR1 37.2.

104.2 Please confirm if FEI has received any negative feedback from Municipalities or other government agencies with respect to the TLSE Project.

Response:

To date, only the City of Richmond has provided feedback through the EA process that may be interpreted as "negative." The City's feedback is preliminary as part of a long-term engagement process, and FEI and FortisBC Holdings Inc. (collectively, FortisBC) continue to engage and respond to the City's feedback. FortisBC considers all comments and feedback received from municipalities and other government agencies as constructive and a fundamental part of both the environmental assessment (EA) and CPCN processes.

The table below provides the comments received from the City to date, and FortisBC's response.

Topic	City of Richmond Comments	FortisBC Responses
Accidents and malfunctions	**Initial Comment:** The City is concerned with the proposed volumes of LNG that will be stored at the facility should the Project be approved. The volatile material poses a risk to the community and Fraser River in terms of spills, accidents, malfunctions and potential security breaches. **Further Comment:** CoR notes the inclusion of spills and additional specific accident and malfunction types within table 10-20 List of Potential Accident and Malfunction Scenarios though reiterates that the inclusion of intentional terroristic style attack be considered. Please clarify if the fire systems are inclusive of automatic fire suppression solutions as well as automatic detection and shut down.	The Detailed Project Description (DPD) has been updated to include more information on safety systems at the site and the risk of security breaches. As described in the DPD the risk of terrorism has been determined to be negligible (See section 10.7 of the DPD for additional information). Project safety systems will meet the legislated requirements for fire detection and suppression appropriate for an operating LNG facility.

Topic	City of Richmond Comments	FortisBC Responses
Cumulative effects	**Initial Comment:** The Project represents another industrial upgrade that is further contributing to the industrialization of the Fraser River estuary and its sensitive ecosystems. There are currently a number of major projects (proposed and/or approved), at or near the Fraser River estuary including the Robert's Bank Terminal 2 Project, the Delta Grinding Facility Project, the Vancouver Airport Fuel Delivery Project and the George Massey Tunnel Replacement Project (Attachment 3). The City relies on the ecosystem functions of the Fraser River estuary to reduce the impacts of flooding and improve the community's quality of life. Recent updates under BC's Environmental Assessment Act and federal Impact Assessment Act have not been tested and have the potential to not adequately mitigate the long-term cumulative effects of climate change caused by the Project and others. **Further Comment:** CoR notes that Cumulative Effects are addressed within comments 22 – 26. Specifically, within ID 26 the proponent states: "The Application will include a Cumulative Effects Assessment that will identify potential cumulative effects to each VC comparing the current and future conditions."	The projects to be included in the cumulative effects assessment will be developed following the method described in Section 10.6 – Anticipated Cumulative Effects of the DPD and Section 6.7 - Cumulative Effects Assessment of the dAIR.
Human health and well-being	**Initial Comment:** The Project does not align with Metro Vancouver's regional air quality objectives. Richmond is concerned that the Project will impact the region's air quality during construction and operation as volumes of contaminates (nitrogen oxides, carbon dioxide, sulfur dioxide, hydrocarbons, and particulate matter) are expected to be released from the Project's related infrastructure. **Further Comment:** CoR is satisfied with the responses that confirms that air quality and its effects will be address under the Human Health VC and that the project "will need to be aligned with Metro Vancouver Ambient Air Quality Objective (AAQOs), Canadian Ambient Air Quality Standards, and BC Provincial AAQOs."	Noted.

Topic	City of Richmond Comments	FortisBC Responses
Human Health and Well-Being Species at Risk, Terrestrial Wildlife and their Habitat Visual Environment	**Initial Comment:** Fortis is proposing to increase LNG production and storage capacity, and is preparing their operations to include marine shipping to offshore markets. Staff have concerns with the potential impacts that increased noise, light and atmospheric pollution will have on local wildlife and the community. **Further comment:** CoR notes that per comment 41 & 83: Health Canada's (HC) Guidance for Evaluating Human Health Impacts in Environmental Assessment: Noise (HC 2017) along with a Visual Impact Assessment will be included in the application & assessment.	Noted.
Alternative Means of Carrying Out the Project	**Initial Comment:** This project does not align with local, provincial national strategies to reduce greenhouse gas emissions and reduce BC's economic reliance on fossil fuels. Fortis should be directed to develop alternative and renewable fuel sources that have less socio-economic and environmental impacts than drilling, processing and transporting LNG. **Further Comment:** CoR notes the proponent's addition of section 2.7 & 2.8 that details alternatives to technologies and project components presented in the Initial Project Description. This does not however present alternatives to LNG itself as a fuel. CoR requests a practical assessment of pragmatic alternatives to LNG to be included within the assessment.	LNG remains an important fuel for hard to decarbonize sectors of the economy, including heavy duty transport and marine shipping. Additionally, LNG remains an effective means of storing energy to meet peak energy demands and to mitigate against supply disruptions. The Project addresses both of those needs and is equally capable of liquefying and storing renewable and conventional gases. There is no obligation to assess alternatives to the underlying need or purpose of any project. Doing so lies outside the scope of assessment under BCEAA and the IAA and could not be done in any objectively defensible manner.

104.2.1 Please discuss whether FEI is planning to engage further with municipalities or other government that have provided negative feedback or formal oppose to the TLSE Project.

Response:

FEI plans to in engage with any municipalities that are interested in the TLSE Project, including those that may provide 'negative' feedback. As explained in BCUC IR2 104.2, FEI considers feedback received from other municipalities and government agencies to be constructive. At present, FEI and FortisBC Holdings Inc. are actively engaged with the City of Delta and City of Richmond through the Tilbury Phase 2 Expansion Project environmental assessment processes.

FEI is engaging with local governments across the Province to understand their energy needs as it works toward its 30BY30 target of reducing customer emissions 30 percent by 2030. FEI is also supporting municipalities with emissions reductions through renewable natural gas and improving energy efficiency. As part of those engagement activities, FEI will also provide information about the TLSE Project.

G. APPENDIX B – PRICEWATERHOUSE COOPERS ECONOMIC ASSESSMENT

105.0 Reference: PRICEWATERHOUSE COOPERS ECONOMIC ASSESSMENT

Exhibit B-1-4, Appendix B, pp. 2;5; Exhibit B-15, BCUC IR 65.2

Scenario Definition: Geographical Coverage

PricewaterhouseCooper's (PWC)scenario definition is based on 4 dimensions: duration (how long is the imbalance in place for), temperature, area (how broadly is the affected), and magnitude (how severe was the supply/demand imbalance)

The area dimension uses a lower impact notable of a community outage (little to no industrial customers) to a higher impact of a regional outage (outage impacts the entire energy FortisBC operating region). An upper bound of "system outage" has been specified.

PWC stated in response to BCUC IR 65.2 that 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.

As shown in the Figure on page 2 of Appendix B to the Updated Application, FEI's natural gas system consists of four areas: Vancouver Island; Lower mainland; Inland; and Columbia.

105.1 Please discuss under what circumstances all four regions would be affected to the same degree.

<u>Response:</u>

The following response was provided by PwC:

[redacted]

[29] City of Vancouver, Economic Structure of Vancouver: GDP of Metro Vancouver. https://vancouver.ca/files/cov/1-5-economic-structure-gdp-of-metro-vancouver.pdf

[redacted]

[redacted]

[redacted]

[redacted]

FEI believes that, while the actual outage associated with a no-flow event on T-South may differ from the PwC assumed scenarios, the scenarios provide ample basis to conclude that the socio-economic impacts would be significant.

105.2 Please explain whether the TLSE Project will benefit customers in all regions, in terms of avoiding the impacts quantified in the three scenarios.

Response:

The following response was provided by PwC:

PwC was not engaged in FEI's resiliency planning or to determine if or how the TLSE Project would benefit customers.

Additional commentary:

- Please refer to our response to question 105.1 above with reference to indirect "knock-on" effects.

The following additional response is provided by FEI:

The TLSE Project benefits customers in all regions as it will mitigate the risk of sudden, widespread, and prolonged negative impacts from gas supply shortages in the Lower Mainland region, and the resulting severe economic impacts that would be felt province-wide.

106.0 Reference: PRICEWATERHOUSE COOPERS ECONOMIC ASSESSMENT

Exhibit B-15, BCUC IR 65.1; 1.5

Probability of Scenarios

PWC confirmed in response to BCUC IR 65.1 that the probability of the 3 scenarios occurring was not assessed, and states that “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”

In response to BCUC IR 1.5, FEI retained JANA to conduct an independent, expert probabilistic analysis of a pipeline incident occurring on the Westcoast T-South system.

JANA stated that:

> 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.

106.1 Please confirm if it FEI’s view that that while a cumulative probability of rupture may be high, the risk of an individual rupture, at a particular point in the network leading to a system wide outage, is a rare, black-swan event. If not, please explain.

Response:

FEI agrees that the annual likelihood of a rupture is low (on the order of 1 to 3 percent per year per 1,000 km of pipeline); however, the long-term cumulative probability of an incident on the T-South system represents an unacceptable level of exposure for FEI’s customers because of the magnitude of the harm that would result (a no-flow incident resulting in a sudden, wide-scale, and prolonged outage to the Lower Mainland Region). A pipeline rupture is just one possible cause of a no-flow event. As described in the response to BCUC IR1 1.3, there are numerous other possible causes that could result in a gas supply disruption to the Lower Mainland. While FEI is unable to quantitatively determine the annual likelihood for these other causes, they further increase the probability of a no-flow event occurring at any given point in time. As such, dismissing the individual causes of T-South no-flow incidents as “rare, black-swan events” appears to understate the potential for a no-flow event on the T-South system. Regardless of the characterization or the specific probabilities, a no-flow event has already occurred and had it occurred in winter instead of October the outcome would have been severe and unacceptable.

FEI believes it is appropriate to mitigate the potential for the unacceptable consequences associated with hundreds of thousands of FEI customers experiencing a prolonged outage.

107.0 Reference: PRICEWATERHOUSE COOPERS ECONOMIC ASSESSMENT

Exhibit B-15, BCUC IR 65.3, 65.5

Calculation of Impact

PWC confirmed in response to BCUC IR 65.3 that it was not engaged in FEI's minimum resiliency planning, and the 3 scenarios were not defined based on, or in relation to, FEI's minimum resilience planning objective. 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.

In response to BCUC IR 65.5 PWC stated that 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.

107.1 Please discuss whether PWC excluded the potential impact of a 3 day outage from the impact calculations, in cases where stakeholders such as hospitals are mandated to have back up heating sources, or where industrial customers have contingency plans in place to continue for a short term.

<u>Response:</u>

The following response was provided by PwC:

[redacted]

[redacted]

107.2 Given the lack of connection to FEI's MRPO, how does FEI propose the BCUC should use the results provided by PWC?

Response:

FEI considers the PwC assessment to be relevant to the TLSE Project. As discussed in the response to BCUC IR2 105.1, [redacted]

108.0 Reference: PRICEWATERHOUSE COOPERS ECONOMIC ASSESSMENT

Exhibit B-15, BCUC IR 4.5, 65.6

Impact of the TLSE Project on the Imbalances Assumed in the 3 Scenarios

In response to BCUC IR 65.6, FEI confirmed that 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.

FEI stated in response to BCUC IR 4.5 that FEI's MRPO is a short-duration objective.

108.1 Please confirm which of the three scenarios would be mitigated or avoided by the TLSE Project, given the MRPO contemplates a three day no flow event.

Response:

As discussed in the response to BCUC IR1 65.3, FEI considers that the three PwC scenarios illustrate the consequences that could result from a supply disruption to customers ranging from relatively small-scale to large scale. The three scenarios were hypothetical and did not provide details in terms of the location or amount of the supply constraint during the no-flow event, partial outage, or the ramp-up to normal supply. As discussed in the response to BCUC IR2 105.1, while not in perfect alignment, the closest of the three PwC scenarios to what would occur with a Lower Mainland disruption in winter is PwC Scenario 2.

However, the TLSE Project will help mitigate the risks in all three scenarios as it significantly improves FEI's ability to maintain continuity of service for the Lower Mainland service area, either by withstanding the supply disruption entirely or by "buying time" to shut down the system in a controlled manner (as explained in the response to BCUC IR1 4.4).

Attachment 84.4

Biomethane Specifications

DOCUMENT NUMBER: 1638
DOCUMENT TYPE: SPECIFICATION
Owner: Gramm, Scott
SML: Wilcock, Chris
CATEGORY: ENGINEERING - ENGINEERING - GENERAL

Utility: Gas
Approved Date: August 06, 2019
Effective Date: August 06, 2019
Next Review Date: August 06, 2024

Document History: This document replaces 1638 Biomethane Specifications dated 06 January 2016.

Summary of Changes

Changed recommended measurement frequency in Table 1 for Inert gasses from Nitrogen periodically to Nitrogen Continuous.

Overview

This is a specification for the composition of Fortis BC biomethane supply. "Biomethane" is defined as pipeline quality "biogas". "Biogas" is defined as natural gas sourced from non-fossil resources, such as agricultural waste, landfill gas, sewage treatment plant bi-product, etc. These specifications ensure that biomethane supplied to Fortis BC is within the expected operating parameters of Fortis BC infrastructure. These specifications are also used as a basis for negotiating and contracting for new renewable natural gas supply.

Audience

The specification is intended for suppliers of biogas or biomethane, engineers, designers, and planners who are involved with developing biomethane supply either through the development of a biogas plant or a biomethane-specific interconnect. The specification is also intended for managers and business leaders who are negotiating new contract agreements for biogas and/or biomethane suppliers. The specification is not intended for suppliers of conventional natural gas, such as Enbridge, TransCanada, or similar suppliers.

Contents

Biomethane Specifications

Section 1

1. The Biomethane must meet the specifications herein, as may be amended, replaced or superseded from time to time.

   The biomethane must:

   a. not contain sand, dust, gums, oils and other impurities or other objectionable substances in such quantities as may be injurious to pipelines or may interfere with the transmission or commercial utilization of the gas;
   b. not contain more than six milligrams per cubic meter of hydrogen sulphide;
   a. not contain water in the liquid phase and not contain more than 65 milligrams per cubic meter of water vapour;
   b. be free of hydrocarbons in liquid form and not have a hydrocarbon dewpoint in excess of minus 9°C at the delivery pressure;
   c. not contain more than 23 milligrams per cubic meter of total sulphur;
   d. not contain more than two percent by volume of carbon dioxide;
   e. be as free of oxygen as supplier can keep it through the exercise of all reasonable precautions and shall not in any event contain more than 0.4 percent by volume of oxygen;
   f. have a temperature not exceeding 54°C;
   g. have a total heating value of not less than 36.00 megajoules per cubic meter;
   h. not contain more than 1 milligram per cubic meter of total siloxanes;
   i. not contain more than 2.0 percent by volume of carbon monoxide;
   j. not contain more than 4.0 percent by volume of inert gases;
   k. not contain more than 3 milligrams per cubic meter of ammonia; and
   l. be free of bacteria and pathogens.

2. In addition, the biomethane shall be supplied at a pressure not less than 420 kilopascals.

3. For convenience, FEI has provided the specification parameters in a tabular format below (Table 1). If there is a conflict between Table 1 and Section 1, Section 1 shall be used.

Table 1: Recommended Specifications for Biomethane

Contaminant Property	Specification	Recommended Measurement Frequency
Sand, dust, gums, oils and other impurities	*Free from any impurities*	
Hydrogen Sulphide (H_2S)	Less than 6 mg/m^3	Continuous
Water	Less than 65 mg/m^3 of water vapour and no liquid water	Continuous
Hydrocarbon dew point	Be free of hydrocarbons in liquid form and not have a hydrocarbon dewpoint in excess of minus 9°C at the delivery pressure	Periodic
Total Sulphur	Less than 23 mg/m^3	Periodic
Carbon Dioxide (CO_2)	Less than 2% by volume	Continuous

Oxygen (O_2)	Less than 0.4% by volume	Continuous
Temperature	54°C maximum	Continuously
Calorific power	36.00 MJ/m^3 minimum (15°C, 101.3kPa)	Calculated based on data collected continuously
Siloxanes	Less than 1 mg/m^3	Periodic
Carbon monoxide (CO)	Less than 2% by volume	Periodic
Inert gasses	Less than 4% volume	Nitrogen Continuous
Ammonia (NH_3)	3mg/m^3	Periodic – semi-annually
Bacteria and pathogens	Impurity filter (0.3 to 5 microns)	Semi-annually

Communication and Enforcement

Follow as per Specification above.

Related Information

Other References:

- GEN 06-02 Approval record