Sarah Walsh
Director, Regulatory Affairs

Gas Regulatory Affairs Correspondence
Email: gas.regulatory.affairs@fortisbc.com

Electric Regulatory Affairs Correspondence
Email: electricity.regulatory.affairs@fortisbc.com

FortisBC
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (778) 578-3861
Cell: (604) 230-7874
Fax: (604) 576-7074
www.fortisbc.com

March 20, 2025

My Sea to Sky
P.O. Box 2668
Squamish, BC
V8B 0B8

Attention: Mr. Eoin Finn, Research Director

Dear Mr. Finn:

Re: FortisBC Energy Inc. (FEI)

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

Response to My Sea to Sky (MS2S) Information Request (IR) No. 5

On December 20, 2025, FEI filed the Application referenced above and on October 24, 2024, FEI filed its Supplemental Evidence to the Application. In accordance with the regulatory timetable established in British Columbia Utilities Commission Order G-324-24 for the review of the Application, FEI respectfully submits the attached response to MS2S IR No. 5.

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

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Commission Secretary
Registered Interveners

Issue 1.0: Use of Economic Loss as a proxy for TLSE benefit

Reference: TLSE Exhibit B-60 – Application for a Certificate of Public Convenience and Necessity (CPCN) for the Tilbury Liquefied Natural Gas (LNG) Storage Expansion Project (Application): Supplemental Evidence, at **pages 5, 8-10, 53, 123-124.**

FEI commissioned PricewaterhouseCoopers (PwC) to prepare an estimate of the likely **economic loss** to BC resulting from a significant rupture of the T-South pipeline(s) (comprised of Assessed Vulnerabilities ("AVs") 1, 2, 3, & 54). The results of this study and its underlying assumptions are reproduced in **Sections 1.3 and 3** of TLSE Exhibit B-60. MS2S has not seen the redacted portions of TLSE Exhibit B-60 or the redacted portions of the PwC or Exponent reports referenced therein.

On page 5 of TLSE Exhibit B-60, FEI states that:

> "**The risk assessment has reconfirmed that a total loss of T-South supply during winter is, and (unless mitigated) will remain by far FEI's single greatest risk of a widespread and prolonged service disruption"**

Table 1-1 (page 8) of TLSE Exhibit B-60 (reproduced below) shows that, for an average winter- time temperature in Southwestern British Columbia/the Lower Mainland, current infrastructure would supply about 7 hours of normal demand without causing "hydraulic collapse". The accompanying discussion notes assumptions including the implementation of Advanced Metering Infrastructure and the taking offline of "all interruptible customers… within 4 hours of the no-flow event." ".

Table 1-1: Time to Failure Following T-South Winter No-flow Event – Status Quo (150 MMcf/d, Regardless of LNG Volumes Available)

Temperature Condition	Approximate Time Until Customers in the Lower Mainland Begin Losing Service[25]
-10.0°C (very cold Lower Mainland winter day)[26]	2 hours
-1.4°C (warmest Lower Mainland winter in 10 years)[27]	5 hours
+4.0°C (average Lower Mainland winter)[28]	7 hours

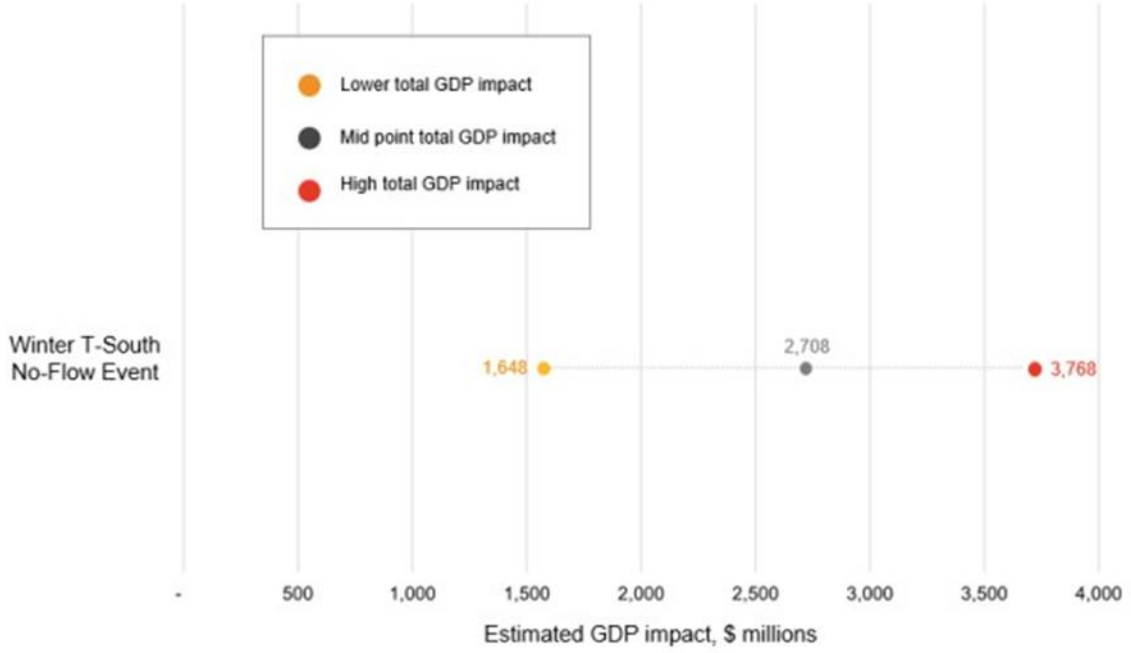
Table 1-2 (page 9) of TLSE Exhibit B-60 (reproduced below), shows that depending on the AV involved (the location of the incident), a no-flow event would result in a 63- to 72-day "Total Outage Duration" for between 600,400-640,400 FEI customers.

Table 1-2: Quantitative Metrics Related to Severity of a T-South No-Flow Event at Average Winter Temperatures by Incident Location

Type of Impact	Quantitative Metric	AV-1 Value	AV-2 Value	AV-3 Value	AV-54 Value
Direct customer service impact	Number of firm customers losing service on Day 1	640,100	600,400	640,400	600,400
Direct customer service impact	Total Outage Duration[31]	63.3 days	60.2 days	71.9 days	66.3 days
Direct customer service impact	Total firm customer-outage-days	24 million	21 million	32 million	28 million
Direct customer service impact	Firm customers losing service on Day 1 as a percentage of total FEI customers	60%	56%	60%	56%

Figure 1-2 (page 10) of TLSE Exhibit B-60 (reproduced below) shows a mid-point economic (GDP) loss of $2.71 Billion, with lower and higher bounds of $1.648 Billion and $3.768 Billion, respectively.

Figure 1-2: PwC Economic Harm Calculation for Winter T-South No-Flow Event (Low, Median, High)[33]



At **pages 9 and 53** of TLSE Exhibit B-60, FEI states that a wintertime no-flow event on the T- South pipeline(s) would cause “catastrophic economic harm well in excess of the cost of the Preferred Alternative” (referring to the proposed TLSE project).

At **pages 123-124** of TLSE Exhibit B-60, FEI states that the addition of the TLSE storage tank (referred to as "Alternative 9") if approved could supply at most 4.54 days (and as little as 2.71 days) of demand in a wintertime no-flow event.

Questions:

1.1 Given FEI's estimate that the proposed TLSE storage tank could supply at most 4.54 days (and as little as 2.71 days) of demand in a wintertime no-flow event, should the avoided economic losses not be based on 2.71-4.54 days of avoided outages rather than the avoidance of the full 60-72 days resulting from a no-flow incident under the status- quo?

Response:

The following response has been provided by Exponent:

If a T-South no-flow event occurs, and the TLSE storage tank is depleted prior to completion of repairs, there will be a shutdown resulting in customer outages. Restoring services following a shutdown requires completing repairs, purging the system, and relighting customers. The outage duration therefore extends beyond the period in which the TLSE storage tank provides supply. Similarly, without any resilience capacity from the TLSE storage tank, an outage occurs immediately, and repairs must be completed, followed by regasifying the system and relighting customers. Repairs, regasifying, and relighting require an extended period of time, e.g., the referenced 60-72 days (this duration is carried forward in this discussion for illustrative purposes, but in reality it varies by outage reason, etc.).

When considering the TLSE storage tank with 4.54 days of supply, if there is a no-flow event and repairs are completed within this period or if the regulatory shutdown period (for parallel pipes where only one fails) is less than 4.54 days, then losses are zero. If repairs are not completed or if the regulatory shutdown period extends beyond 4.54 days, there will be an outage requiring completing repairs, purging, and relighting customers. The losses will therefore be either a. zero or b. based on a much longer shutdown (e.g., 60-72 days).

Without the TLSE, there will be an outage immediately, requiring repair, purging, and relighting. Thus, the losses will be based on the full outage duration, e.g., 60-72 days.

The avoided economic losses can therefore be based on:

1. 4.54 days in cases where the asset is not repaired at the time the TLSE storage tank is depleted.

2. 60-72 days in cases where the asset is repaired prior to depletion of the TLSE storage tank.

Exponent's analysis accounts for the probability of both of these scenarios.

1.2 In 2018, the T-South pipelines suffered an explosion and subsequent no-flow event. The regulator (NEB) imposed a three-day shutdown of both T-South pipelines, and reduced pressure limits for months afterwards as a safety measure. As three days is beyond FEI's suggested limit whereby air would be induced into its local transmission and distribution pipelines, does that mean a "hydraulic collapse" is inevitable if a three-day no-flow event occurs in winter-time?

Response:

FEI clarifies that the 2018 T-South Incident resulted in a 2-day no-flow event, not a 3-day no-flow event as stated in the question. Further, FEI is uncertain of the meaning of the statement "As three days is beyond FEI's suggested limit whereby air would be induced into its local transmission and distribution pipelines,…".

However, in order to be responsive, FEI provides a discussion on how a hydraulic collapse can be prevented.

A hydraulic collapse (i.e., an uncontrolled shutdown) is not inevitable if a three-day no-flow event occurs during the winter.

An uncontrolled shutdown occurs when there is an unmitigated supply and demand imbalance that results in the collapse of FEI's system pressure. That is, when supply ceases (e.g., due to a T-South no-flow event), but customers continue to consume the remaining gas in the system, FEI's system pressure will drop to atmospheric pressure, resulting in an uncontrolled shutdown. An uncontrolled shutdown can be prevented by mitigating the supply and demand imbalance in one of two ways:

1. **Supply:** Avoiding the shutdown altogether, controlled or uncontrolled, by bridging the T-South no-flow duration via another supply source, such as the TLSE Project.

2. **Demand:** Executing a controlled shutdown by ceasing demand (i.e., shutting in FEI's customers) before FEI's system pressure collapses, such that pressure is maintained in FEI's system.

As discussed in the Supplemental Evidence, a controlled shutdown takes time to implement.[1] With respect to the time required for FEI to implement a controlled shutdown, FEI stated the following in the 2024 Resiliency Plan:[2]

[1] Exhibit B-60, Supplemental Evidence, Section 4.7.3.1.
[2] Exhibit B-61, 2024 Resiliency Plan, Section 3.4.1.2.2.

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

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

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

Under FEI's existing capabilities (i.e., without the TLSE Project), in the event of a 3-day T-South no-flow event occurring under average winter conditions in the Lower Mainland, FEI would be unable to mitigate the supply and demand imbalance and thus an uncontrolled shutdown would occur. The supply-side mitigation technique is ineffective since FEI's existing Tilbury Base Plant, assuming it is full at the time of the incident, only provides 7 hours of support, which is too short to bridge the 3-day no-flow event. The demand-side mitigation technique is also ineffective as the Base Plant would not provide enough time for FEI to execute a controlled shutdown. This is again due to the Base Plant only providing 7 hours of support duration, which is not enough time to execute a controlled shutdown.

In contrast, with the TLSE Project, both the supply-side and demand-side techniques will be effective at preventing an uncontrolled shutdown. In this scenario, the supply-side technique is effective since, under average winter conditions, the TLSE Project will provide 4 days and 13 hours of support and can therefore bridge the 3-day no-flow duration, thus preventing the outage altogether.

Even if the TLSE Project could not bridge the no-flow period (i.e., the no-flow duration exceeded 4 days and 13 hours), an uncontrolled shutdown would still be avoided. This is because the TLSE Project will provide enough time for FEI to execute a controlled shutdown.

As demonstrated above, with the TLSE Project in place, a hydraulic collapse could be avoided if a 3-day no-flow event occurs during the winter.

The supply duration provided by the TLSE Project will be a function of the system demand at the time of the no-flow event. In FEI's analysis, three temperature conditions were evaluated as shown in Table 4-8 of the Supplemental Evidence. At the -10 degrees Celsius condition, the evaluated supply duration with Supplemental Alternative 9 was 2.71 days, which is less than the 3 days associated with a regulatory shutdown. This time, however, would likely allow FEI to prepare for and execute (if necessary) a controlled system shutdown, preventing an "hydraulic collapse". Further, FEI could use the support duration time provided by the TLSE Project's resiliency reserve to shed portions of the remaining firm load, thus extending the time before a complete system shutdown would be required, if at all.

1.3 As the economic losses estimated are those that would be avoidable with the approval and construction of the TLSE project, should the midpoint be closer to $191.5 million in avoidable potential loss (PwC's $2.708 billion estimate pro-rated based on the amount of time the TLSE project could satisfy demand in the event of a no-flow incident)?[3]

1.3.1 As $191.5 million is significantly less than the proposed cost of the TLSE storage tank (estimated at over $873 Million[4]), can FEI clarify its statement at **pages 9 and 53** of TLSE Exhibit B-60 (that a no-flow event would cause "catastrophic economic harm well in excess of the cost of the Preferred Alternative")?

Response:

The following response has been provided by Exponent:

Please refer to the response to MS2S IR5 1.1. The avoided potential loss would be prorated based on the amount of time the TLSE Project satisfies demand in the event of a no-flow incident only in cases where repairs are not completed prior to depleting the resilience supply. In cases where repairs are completed prior to exhausting the resilience supply (or a regulatory shutdown period ends, for parallel pipes where only one fails), the avoided losses should not be prorated, as the TLSE Project prevents long duration outages that would otherwise occur without the TLSE. Exponent's analysis accounts for the probability out the TLSE depleting its resilience supply prior to completion of repairs or the end of a regulatory shutdown period.

FEI's statement referenced in MS2S IR5 1.3.1 does not need to be clarified as the Question is based on an incorrect premise.

[3] The table below outlines the low, middle, and high-point GDP Loss estimates by PwC depicted in **Figure 1-2 (page 10)** of TLSE Exhibit B-60, along with estimates pro-rated based on the avoided outage period of only 4.54 days, rather than the 63-day outage period forming the basis of PwC's estimate.

	Avoided Economic Loss from a 63-day outage ($ millions)	Avoided Economic Loss from a 4.54-day outage ($ millions)
Lower	$1,648	$118.8
Mid-Point	$2,708	$191.5
High	$3,768	$271.5

[4] Exhibit B-60, P. 208.

1.4 Can FEI provide more details regarding the number of additional customers (if any) who would lose service in the days after the initial no-flow event (beyond day 1), and how the shorter outage times for these customers is considered in estimating potential economic losses?

Response:

The following response has been provided by Exponent:

In most cases, additional customers do not lose service after the initial no-flow event. The exception is where there are existing resilience gas supplies, such as that provided by the Mt. Hayes facility to Vancouver Island (see Exhibit B-61, PDF p. 537). In those instances, customers in only the Lower Mainland may experience an outage immediately (with no Tilbury facility), and additional customers will lose service after the initial no-flow event only if service is not restored prior to depletion of the resilience gas supply. The shorter outage duration for customers supplied by existing resilience gas supplies is accounted for in Exponent's analysis.

1.5 In such a no-flow event as is contemplated here, who bears the risk for the economic losses arising from the event? Is it the utility's shareholders (as in the Stores Block decision, which recognized the principle that, just as utility shareholders enjoy the rewards of asset ownership, they also must bear some risk from asset ownership)? Or the utility's ratepayers (as in the recent UAD- Utility Asset Disposition decision re Atco in Alberta. In *ATCO Electric Ltd v Alberta Utilities Commission*, the court[5] rejected the Commission's application of the UAD policy, opening the door to the possible recovery of such losses from ratepayers).

Response:

The cost of operating a resilient system, and the cost of restoring service in an emergency, are legitimate costs of providing service to customers. They are recoverable in rates. The question is misapplying the ATCO case, as there is no apparent stranded asset in the context of a gas supply emergency.

[5] https://www.nortonrosefulbright.com/en-ca/knowledge/publications/05f04c28/who-bears-the-risk-associated-with- extraordinary-utility-asset-retirements.

Issue 2.0: Economic Loss- definition of Total Outage Duration (re AVs 1,2,3, 54)

Reference: TLSE Exhibit B-60 – Application for a Certificate of Public Convenience and Necessity (CPCN) for the Tilbury Liquefied Natural Gas (LNG) Storage Expansion Project (Application): Supplemental Evidence, at **pages 9, 51.**

At **page 9** of TLSE Exhibit B-60, FEI defines the "Total Outage Duration" as:

> "the estimated period (in days) starting on Day 1 of the customer outage to the day when service is finally restored to the last customer (emphasis added). Reported as the mean from Exponent's Monte Carlo analysis".

At **page 51** of TLSE Exhibit B-60, FEI states that PwC's risk analysis "assumes that 25 percent of customers relight their own appliances."

Questions:

2.1 Do customers relighting their own appliances in advance of a vent/relight team visit not run the risk of triggering in-pipe explosions?

Response:

FEI has assumed that the reference to "in-pipeline explosion" refers to an explosion that occurs within FEI's system, as opposed to in a premises downstream of the gas riser (meter set).

The risk of a customer triggering an in-pipeline explosion by relighting their own appliances is extremely remote given the steps to ensure the system is safe prior to the reconnection of service. Please refer to the Application[6] and the Workshop Transcript from March 11, 2021[7].

Further, in its Rebuttal Evidence to RCIA (Exhibit B-46-1), FEI identified the following considerations that would mitigate the risk of an explosion occurring within FEI's system:

- First, FEI's experience and data supports that the vast majority of customers require assistance relighting appliances when FEI restores service to a premises after outages, either because they would be unable to perform the work or would be very hesitant to undertake this work. Even if they were to attempt a self-relight, FEI expects that customers in the earlier areas being re-gasified would save little time by performing their own relights (Rebuttal Evidence, A35).
- Second, the safety "lock out" features in electronic ignition appliances would likely prevent or dissuade customers from relighting their own appliances (Rebuttal Evidence, A37).
- Third, FEI's obligations under section 53 of the *BC Gas Safety Regulation* 208/2019 require it to notify customers before turning the gas supply back on and ensure that no gas flows through to appliances or outlets in premises unless they are checked to ascertain that they are relighted or turned off. After the Advanced Metering Infrastructure

[6] Exhibit B-1-4, Application, Section 3.2.1.3, pp. 23-24.
[7] Transcript Volume 1, pp. 86-88 and 95-96.

(AMI) project is in place, FEI will be able to use the automated meters to perform this "careful check" remotely for the majority of customers, thus mitigating a potential safety risk (Rebuttal Evidence, A19 and A20).

FEI has also established standard procedures for purging gas lines during a supply outage to ensure the safe and reliable delivery of natural gas to customers. For example, personnel are trained and equipped with commercial-grade combustible gas indicators (CGIs) to detect the presence of natural gas. These CGIs are regularly tested with known gas values to ensure their accuracy.

2.2 Does this definition of "Total Outage duration" not significantly exaggerate the severity of the economic loss? By the mid-point of the 63 (or so – from Table 1-2) days of the loss of service/vent/relight outage, should we not expect that about half the customers would be restored to normal service? We note the re-definition of the term "Total Firm Customer Outage Days" in the 2024 Gas System Resiliency Plan (P. 42)[8] and wish to confirm that the latter is indeed the basis for the calculation.

Response:

The following response has been provided by Exponent:

The definition of "Total Outage duration" does not exaggerate the severity of the economic loss. Exponent's analysis calculates the daily losses on a given AV when all customers are experiencing the outage, and then scales them down during the relight period. This is seen, for example, in the equation to calculate the GDP loss associated with an outage (Exhibit B-61, PDF p. 530, para. 40):

$$L^i_{GDP} = l^i_{GDP} \times \left(MTTR^i + d_{regulatory} + d_{regasify} + \frac{d_{relight}}{2} \right)$$

In the above equation, the total loss for the outage is calculated as the product of the daily loss (with all customers out) and the sum of: the repair time, regulatory/planning time, regas time, and half of the relight time. Half of the relight time is used to account for the progressive relighting of customers.

[8] *"A measure of the number of firm customers losing service multiplied by components of the Total Outage Duration. The calculation accounts for: (a) 100 percent of the customers being without service for the time before relighting activity begins; and (b) half of the customers thereafter, so as to account for a linear relighting trajectory".*

2.3 Can FEI clarify its strategy for restoring service, including whether it would prioritize venting/re-lighting for its largest and most critical customers? Please provide justification and indicate how this would affect the estimate of economic loss resulting from an outage.

Response:

FEI's approach to restoring service will follow its approved System Preservation and Restoration Plan (SP&R Plan), which was found by the BCUC to be in the public interest and not unduly discriminatory as it is in accordance with FEI's approved tariff[9]. FEI has confidentially filed the SP&R Plan in this proceeding (Exhibit B-48-1, Confidential Attachment 14.2).

The SP&R Plan is confidential but, broadly speaking, the approach in the plan is to minimize overall harm, including physical harm associated with loss of heat, by prioritizing areas of the system which were shut-in first. FEI's approach reduces the overall restoration time by contemplating, for instance, efficient crew allocation to reduce standby time and unnecessary travel.

Please refer to the response to MS2S IR5 2.2 for a discussion on how the gradual nature of customer relights is accounted for in the GDP loss calculation.

2.4 How do the vent-relight teams know when it is safe to relight customer appliances at a site? What on-premises "sniffer" technology(ies) do they employ to determine a safe (i.e. not explosive) level of air entrained in the gas supply?

Response:

Please refer to the response to MS2S IR5 2.1.

2.5 Since the 1970's, manufacturers of gas appliances (especially gas boilers & furnaces), have featured electric auto-ignition technology in these appliances – eliminating manual pilot-lighting (called "standing pilot ignition") from their product offerings. Over 95% of new gas furnaces sold today use electronic ignition. (i) Does

[9] Letter L-32-18 dated December 7, 2018.

FEI know how many of these appliances are in use in its service territory? (ii) Can FEI confirm whether its estimate that "25 percent of customers relight their own appliances" (TLSE Exhibit B-60 at **page 51**) and its estimates of vent/re-light requirements (timing, resources, & processes) consider the impact of electric auto-ignition technology in gas appliances?

Response:

Please refer to Answer 37 of FEI's Rebuttal Evidence to RCIA[10] for a discussion regarding the impacts of auto-ignition technology on FEI's relight estimates. FEI does not have information regarding the ignition technology used by its customers. Please also refer to the response to BCUC IR3 112.1[11] for the basis of FEI's 25 percent assumption.

2.6 How will the approximately 25% (or other proportion as clarified in the answer to Q.2.5) of customers relighting their own appliances know when it is safe to do so? Please provide detail on what measures FEI will take to provide relevant and timely information about system conditions to those customers.

Response:

Please refer to the response to BCUC IR3 109.4 for a list of the activities that FEI would undertake to communicate with customers in anticipation of repressurizing nearby gas system infrastructure.

Under FEI's current approach, restoring service in an area (i.e., repressurizing the distribution piping directly upstream of the customer premises), involves technicians going door to door to inform customers that gas service is ready to be restored and offering to relight appliances. If there is no answer, the technicians leave a tag informing the customer that service is ready to be restored and asking them to contact FEI to book an appointment for a relight. At this point, some customers may elect to relight their own appliances without contacting FEI to book an appointment.

[10] Exhibit B-46-1.
[11] Exhibit B-52.

Issue 3.0: Controlled load shedding from the gas system

Reference: TLSE Exhibit B-60 – Application for a Certificate of Public Convenience and Necessity (CPCN) for the Tilbury Liquefied Natural Gas (LNG) Storage Expansion Project (Application): Supplemental Evidence, at **pages 41, 50-51.**

At **pages 8, 41, 50-51**, of TLSE Exhibit B-60, FEI notes that PwC's risk analysis assumes that Advanced Metering Infrastructure (AMI) would be fully implemented, and that "all interruptible customers are offline within 4 hours" of a no-flow event.

At **pages 50-51** of TLSE Exhibit B-60, FEI estimates that "approximately 50,000" customers would require manual shut-off, taking 3-4 days to accomplish.

Questions:

3.1 How many FEI customers does FEI expect will (i) be interruptible or uninterruptible and (ii) have AMI installed by the time TLSE is operational? Please provide the number of customers and proportion of FEI's total customer base. (subquestion: Is this proportion different for customers served by the Coastal Transmission System (CTS)?)

Response:

FEI does not forecast additions of interruptible customers.

FEI expects the AMI project to be completed in 2028, with the TLSE Project expected to be completed at the end of 2030.

Upon the completion of the AMI project in 2028, there will be approximately 1 million gas meters with remote disconnect capability across FEI's service territory. This is approximately 93 percent of FEI's total customer base. The proportion is slightly higher for customers within the CTS, with approximately 95 percent of those customers receiving the remote disconnect capability.

3.2 Why would up to 50,000 customers require manual shut-off after the implementation of AMI?

Response:

The implementation of AMI does not provide the capability to remotely disconnect customers with large commercial/industrial meters or non-communicating small commercial/residential meters. As a result, these customers would need to be manually shut-off.

3.3 How would AMI affect FEI's ability to shut off customer demand in a T-South no-flow/rupture event? Please provide estimates of the extent to which interruptible and uninterruptible customers would be taken offline, details on the segment of customers requiring manual shut-off, and the timeframe required.

Response:

As noted in Section 1.3.2.1 of the Supplemental Evidence (page 8, footnote 23):

> As the BCUC has approved the AMI Project, the entirety of the analysis in this Supplementary Evidence and the 2024 Resiliency Plan assumes that residential and small commercial AMI is in place. The extent of the mitigation provided by AMI, in terms of reducing the extent and duration of an outage, was discussed in FEI's Rebuttal Evidence.

In the event of a supply disruption, all interruptible customers would be taken offline. FEI would then determine which additional firm customers require curtailment, if any, to minimize the impact across the system based on information available at the time, including how long Enbridge expects it to take to recover service, quantities of gas available to FEI, and demand on the system. More information regarding the timeframe required for the restoration of service with AMI can be found in Answer 17 of FEI's Rebuttal Evidence to RCIA (Exhibit B-46-1).

Please also refer to the response to BCUC IR1 16.1 regarding the benefits of AMI.

Issue 4.0: Venting, Flaring, GHG Emissions from TLSE

Reference:
https://www.projects.eao.gov.bc.ca/api/public/document/674ab1f718e13c0022214d30/download/TIL2_Volume1_Assessment_Summary_English_20241129.pdf, Fig. ES-3, P. S-7

We see a flare stack[12] in the images posted on BC EAO's Epic database for the full Tilbury LNG Phase 2 expansion. However, we do not see it on the TLSE images[13], even though the proposed expansion tank will certainly experience boil-off of the stored LNG . What we do see is a pipe connecting the TLSE tank and the Tilbury Jetty. We have the following questions in regard to the role of flaring in the TLSE project:

Questions:

4.1 Please describe how boil off gases (BOG) from the TLSE Project LNG tanks are handled during normal operation. Are they returned to the Base unit for re-liquefaction, or are they vented or flared?

Response:

Please refer to the response to BCUC IR5 133.1.

4.2 Please describe how boil off gases from the TLSE Project LNG tank are handled during upset conditions or periods of maintenance.

Response:

Please refer to the response to BCUC IR5 133.2.

4.3 Please explain the frequency, duration and volumetric extent of the flare-offs from (i) the Plant and (ii) the vessels filling at the jetty. What can residents of the area expect?

4.4 Please estimate the GHGs (as TCO2e per annum) these flares will emit - allowing for normal levels of "incidents" requiring flaring, and the methane slip such flaring

[12] https://www.projects.eao.gov.bc.ca/api/public/document/674ab1f718e13c0022214d30/download/TIL2_Volume1_Assessment_Summary_English_20241129.pdf, Fig. ES-3, P. S-7.

[13] https://docs.bcuc.com/documents/proceedings/2021/doc_60434_b-1-fei-tilbury-lng-cpcn-application-redacted.pdf. Fig. 7-1, P. 177.

will entail? How will these emissions be handled (i.e. offset?) in FEI's plan for the provincial requirement for "Net Zero by 2030" compliance.

Response:

A dedicated flare system is not within the proposed TLSE Project scope. Please also refer to the responses to BCUC IR5 133.4 and 133.5.

4.5 Please explain the proposed boil-off gas (BOG) compressor(s) redundancy and proposed utilization of compressed BOG within the Tilbury site.

Response:

Please refer to the responses to BCUC IR5 133.1 and 133.2.

4.6 In the event that the BOG compressor(s) is/are not part of TLSE, please explain whether FEI proposes to vent BOG to atmosphere or to a flare system.

Response:

Please refer to the responses to BCUC IR5 133.1 and 133.2.

4.7 Please confirm, or explain otherwise, that a flare system is /is not within the scope of FEI's proposed TLSE Project.

Response:

Please refer to the response to BCUC IR5 133.4.

4.8 How many flares are planned for the expanded Tilbury LNG site? Please give details of the number of ground and aerial flares.

Response:

The current design of the Tilbury Phase 2 LNG Expansion Project includes a single totally enclosed ground flare, which is associated within the liquefaction plant, not the TLSE Project facilities. Please also refer to the response to BCUC IR5 133.5.

4.9 If confirmed, please clarify whether FEI proposes to utilize the Tilbury Phase 2 Expansion Project flare system in the event that the TLSE Project BOG compressor(s) are not available.

Response:

Please refer to the response to MS2S IR5 4.8.

4.10 Please confirm, or explain otherwise, that the scope of the Tilbury Phase 2 Expansion Project includes BOG compressors for use during delivery of LNG from TLSE to the Tilbury Marine Jetty (i.e. LNG delivered from TLSE to marine transportation fuel customers).

Response:

Please refer to the responses to the BCUC IR5 133 series.

Issue 5.0: Base Plant obsolescence

Reference: TLSE Exhibit B-60 – Application for a Certificate of Public Convenience and Necessity (CPCN) for the Tilbury Liquefied Natural Gas (LNG) Storage Expansion Project (Application): Supplemental Evidence, at **pages 68-98**

In **Section 3.3 (pages 68-98)** of TLSE Exhibit B-60, FEI makes the case that the Base Plant is reaching obsolescence, citing aging compressors, pumps, and vaporizers.

At **page 76** of TLSE Exhibit B-60, FEI describes a 2023 study by CB&I that "confirmed that operating the tank above 16 metres could cause the tank's ring wall to unload under the CSA Z276-2015 geotechnical and seismic standards," referring to the existing Base Plant tank.

Questions:

5.1 Can FEI outline the frequency and duration of the Base Plant's peak-shaving (i.e. re- gasification) function over the past five years (2019-present)?

Response:

Please refer to the responses to BCUC IR5 127.5 and 139.1.

5.2 Given the limitations of the Base Plant tank, how much of that tank's operational peak shaving role, not including standby service, has been carried by the Phase 1A tank over the past five years (2019-present)?

Response:

Please refer to the responses to BCUC IR5 127.5 and 139.1.

5.3 Can FEI provide the timing, frequency and duration of Base plant malfunctions during peak-shaving/re-gasification service over the past five years?

Response:

Please refer to the response to RCIA IR5 63.1.

5.4 Can new pumps & vaporizers - if ordered for a Base Plant refurbishment - be adapted to function (i.e. be re-used) with the TLSE tank? If not, why not?

Response:

FEI interprets this question to be asking whether it could install new pumps and vaporizers, connect them to the existing Tilbury Base Plant tank in the short-term and subsequently connect them to a new TLSE tank at some point in the future.

The primary difficulty in installing regasification now and reutilizing it with a new tank in the future is the difference in technologies between the Tilbury Base Plant tank and the new systems. The Base Plant tank currently has the sendout pumps installed outside of the tank itself, whereas the new technology proposed for the TLSE Project will install the pumps internally to the tank. This means that the high-pressure sendout pumps would not be compatible with the future tank.

The vaporizers required today are also significantly larger than the equipment currently connected to the Base Plant tank. While these could technically be connected to the existing Base Plant, there would be insufficient storage capacity to make the installation useful in a supply disruption (i.e., no improvement over today's condition with the exception of improved reliability).

Further, a retrofit of the Base Plant tank to accommodate new regasification equipment would require a prolonged outage that would take the system out of service during sendout season, and would involve significant modifications and engineering challenges to integrate new equipment.

Issue 6.0: TLSE fire-suppressant system

Reference: TLSE Exhibit B-60 – Application for a Certificate of Public Convenience and Necessity (CPCN) for the Tilbury Liquefied Natural Gas (LNG) Storage Expansion Project (Application): Supplemental Evidence, at **pages 75-79**

In **Section 3.3.2.1 (page 76)** of TLSE Exhibit B-60, FEI includes the following description in its outline of the inadequacies of the Base Plant:

> "2018: FEI operated the tank at the reduced 95 percent level until 2018 when further studies were initiated to check the tank performance against the 2015 version of the CSA 5 Z276 standard and to review the performance of the tank related to any potential breach 6 (in particular the fire suppression system). Those reviews identified the following (emphasis added): The firewater foam system was inadequate to combat a fire within the containment walls from a full breach of the tank".

Questions:

6.1 Given the highly flammable nature of methane (in gas-to-air mixtures from 5%-15%), and the low temperature of LNG, water-based fire suppression systems[14].[15] can often worsen matters when applied to LNG fires. While details of the fire-suppressant system for TLSE are (presumably) contained in the redacted appendices accompanying TLSE Exhibit B-60, FEI has noted that reviews found the firewater foam system to be "inadequate to combat a fire within the containment walls from a full breach of the tank." Given this, please describe in detail the fire suppression system that is proposed for the TLSE storage tank

Response:

For clarity, it is only the vapour (i.e., methane) that is flammable and not the liquefied natural gas itself.

The proposed TLSE tank is classified as a full containment tank, comprising an inner tank and an outer tank. The inner tank, constructed from cryogenic steel (9 percent nickel steel), is designed to hold the LNG. The outer tank, made of pre-stressed concrete, is engineered to contain both liquid and vapour in the event of an inner tank failure.

Fire protection measures for the TLSE storage tank are focused on two potential fire sources:

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[14] From ChatGPT: Water-based firefighting is generally less effective on LNG (liquefied natural gas) fires due to the nature of the fuel and the fire behavior. LNG fires burn at extremely high temperatures and can vaporize water quickly, reducing its effectiveness. Additionally, the spread of LNG fires can be rapid, making it challenging to control with water alone. Specialized firefighting agents or techniques, such as foam, are often preferred for LNG fires to effectively suppress the flames and prevent re-ignition.

[15] http://www.liquefiedgascarrier.com/tackling-fire-LNG-ships.html#:~:text=Tackling%20the%20fire%20requires%20the,cool%20surfaces%20exposed%20to%20heat.

- First, external piping and systems that are associated with the TLSE storage tank are effectively identical to those of the existing storage tanks at the Tilbury LNG site. Fire protection is achieved with emergency shutdowns (ESDs) to stop the flow of flammable materials and reduce the duration of the fire. Moreover, externally-applied fire water is available for exposure protection.
- Second, the pressure relief valves (PRVs) on the TLSE storage tank are being designed with a dry chemical system. The PRVs and the dry chemical system are located at the top of the LNG storage tank, approximately 50 meters above grade level. If the PRVs happen to discharge, and the released vapours are ignited, fire detection devices will activate the dry chemical system and extinguish the fire to minimize any adverse impacts to the tank's top or associated appurtenances.

6.2 Will the existing "firewater foam system" be improved to match the larger size of the proposed TLSE storage tank? If so, please explain: (a) how the existing system will be improved; and (b) if these improvements have been included in and how they affect the plan and budget for the TLSE project. If not, please explain why not.

Response:

As explained in the response to MS2S IR5 6.1, the existing foam system was designed specifically for the Tilbury Base Plant's external containment system (i.e., a concrete wall surrounding the tank). This foam system is located at the Base Plant tank and does not provide fire fighting protection outside of the external containment.

As there is no open containment space where a fire may occur in the full containment design of the TLSE tank, an external containment system and firewater foam system are not required.

6.3 Does the City of Delta's Fire Department ("Delta FD") have foam-retardant on hand to assist putting out an LNG tank fire at Tilbury/TLSE? If so, how much does the Delta FD have, and is that amount adequate to address the risk of an LNG tank fire at Tilbury/TLSE? Does the City of Delta provide for the purchase of foam retardant for use at Tilbury/TLSE in its annual budget?

Response:

The fire assessment for Tilbury does not rely on the Delta Fire Department to have foam-retardant to respond to an LNG fire. The Tilbury Base Plant contains 2 fire pumps (1 electric primary and 1 diesel backup), that supply water and foam concentrate to foam generators mounted on the wall

surrounding the secondary containment dyke. In contrast, the TLSE and T1A tank designs include a fully enclosed concrete wall with a secondary containment, which does not require an additional containment dyke open to atmosphere; therefore, a foam system is not required.

Foam systems for LNG facilities use high-expansion foam which is different than the Class A (used for wood/cardboard/paper fires) and Class B (used for hydrocarbon fires, excluding LNG) foams carried by municipal fire departments.

Issue 7. TLSE – risk of becoming a stranded asset

In a decarbonizing province which is increasingly taxed to meet its legislated climate targets, TLSE bears a risk of becoming a stranded asset if demand should decline as quickly as

BCUC's Adjournment Decision, p. 52, states that (emphasis added): *"Further, if the throughput of natural gas is reduced due to a decrease in demand, the size of a tank and the amount of regasification required would likely be reduced."* And on p. 22: "*The larger tank provides flexibility to accommodate future load growth that may occur. However, given the current emphasis on electrification and decarbonization in BC, it is unclear whether FEI will experience significant, or even any, future natural gas load growth. The larger tank means greater risk of a stranded, or partially stranded, asset in the event that FEI's increased load does not emerge or decreases beyond the current load."*

Recently, some three dozen of BC's larger municipalities and regional districts have passed zoning by-laws adopting higher levels (EL-3 and EL-4) of the Zero Carbon Step Code for new Part 3 and Part 9 buildings – before being made mandatory by the Province. Together these districts represent over 42% of BC's population[16]. Although the ZCSC standards do allow minor gas uses such as barbeques and fireplaces, the ZCSC standards largely dissuade developers[17] from providing gas services to new buildings.

Questions:

7.1 What does FEI expect will be the effect of the spread of the Energy Efficiency Step Code and ZCSC on demand for gas service, especially in the urban areas of the province?

Response:

Please refer to Section 4.5.5 of the Supplemental Evidence and the response to BCUC IR5 129.1 for a discussion of how FEI has analyzed the effects of declining load due to the Energy Step Code and Zero Carbon Step Code on the TLSE Project.

[16] From a database of municipal and regional ZCSC decisions maintained by Stand.earth, Vancouver. Public link is at https://www.safecities.earth/zero-carbon-step-code-provides-b-c-communities-a-pathway-toward-ambitious- electrification-goals-for-new-buildings/.

[17] As an example, the City of Victoria BC (CoV), has required ZCSC EL-4 since November 2023, but the ZCSC requirement only just came into place for all buildings in November 2024. Data for CoV from August 2024 reported to the B2E Group showed 34 permits (139 units) since November 2023, but only 3 of those buildings (all Single Family Dwellings) have reported NG (Natural Gas) connections. Victoria requires EL4 for these buildings, which is most likely driving this trend. The vast majority are choosing not to connect to gas. Before implementing the ZCSC Victoria would have expected almost every one of those units to have on-demand gas hot water. (Building to Electrification Coalition B2E).

7.2 Considering the answer to Q7.1, what effect will this have on the size and need for the TLSE tank and associated regasification infrastructure?

Response:

Please refer to the response to MS2S IR5 7.1.

Issue 8. T-South capacity, Sunrise Expansion Project

In Section 3.2.1.1 (Supplemental evidence P.90), FEI outlines the impact of Woodfibre LNG's 15% demand on T-South's capacity / its ability to support existing demand without additions to its capacity- viz. the T-South Sunrise Expansion project. FEI states that (emphasis added):

"Woodfibre LNG Completion Will Remove 15 Percent of T-South Capacity.

In addition to increased daily demand from the natural gas-fired generators since FEI filed the Application, development of the Woodfibre LNG facility has progressed and will significantly impact the regional market when it comes online. In November 2021, Woodfibre LNG Ltd. (Woodfibre) signaled its intent to construct an LNG export terminal, with a capacity of 2.1 MTPA (approximately 275 MMcf/d) located near Squamish. Woodfibre has since commenced construction on its facilities and FEI is constructing the infrastructure to bring gas to Woodfibre.

Woodfibre has already contracted approximately 15 percent of the existing T-South capacity to supply its facilities, and for the moment is reselling it. However, when the Woodfibre LNG facility commences operations, the capacity will no longer be available to the market. This will represent a very significant tightening of the market. The expected loss of Woodfibre capacity has led to proposals for pipeline expansions to help solve existing market dynamics. In particular, Enbridge Inc. (Enbridge) conducted an "open season" in Q2 2022 to develop an expansion of T-South, specifically to replace the capacity that will no longer be available to the market when Woodfibre enters service.

In November 2022, after this open season was over-subscribed, Enbridge announced that it is moving ahead with plans to expand T-South with up to 300 MMcf/d of additional capacity (i.e., T- South Sunrise Expansion). Since the open season, Enbridge has provided two updates regarding Sunrise's capital cost. The first update occurred during the open season process, with the capital cost estimated at $3.6 billion. Subsequently, the capital cost estimate was revised to $4 billion. These cost increases reflect a refinement of the scope of the project and a more detailed build- up of project requirements. The T-South Sunrise Expansion does not add capacity beyond what will be lost to Woodfibre LNG, and it could thus not serve as a replacement for peaking supply from Tilbury".

8.1 Would the fact that 15% of T-South capacity would be attached to a single customer (Woodfibre LNG) affect FEI's ability to curtail demand in a T-South no-flow event, and was this accounted for in the 2- to 7-hour estimate of system resiliency under current infrastructure?

Response:

FEI does not expect Woodfibre's 15 percent proportion of T-South capacity to impact its ability to curtail demand during a winter T-South no-flow event.

As Woodfibre LNG sources their supply from the T-South system, they would be subject to a T-South curtailment along with all other customers affected by a no-flow event. Further, FEI's transient analysis assumed that flow to the Vancouver Island Transmission System (VITS), from which Woodfibre LNG takes service, is physically reduced to zero soon after identifying a loss of supply from T-South to preserve supply for the CTS customers. With or without Woodfibre LNG demand present on the system, FEI's gas control can remotely enact this flow reduction to the VITS by shutting down the V1 compressor station. Therefore, FEI's 2- to 7-hour estimates of the CTS resiliency are not affected by Woodfibre LNG demand.

While the VITS core customer load can be supported with Mt. Hayes LNG, there is inadequate sendout capacity to sustain deliveries to Woodfibre LNG which would have to be curtailed immediately following isolation of the VITS. If necessary, this can be achieved by using a remotely operated flow control device.