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September 13, 2021

Citizens for My Sea to Sky
PO Box 2668
Squamish BC,
V8B 0B8

Attention: Mr. Eoin Finn

Dear Mr. Finn:

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 Citizens for My Sea to Sky Society (MS2S) Information Request (IR) No. 1

FEI respectfully submits the attached response to MS2S No. 1 in the Application referenced above.

FEI notes that MS2S has provided lengthy preambles to its information requests, which contain a significant amount of content that FEI takes issue with. In many instances, the manner in which MS2S has framed its information requests appears to attempt to provide intervener evidence. However, this is procedurally improper. A preamble to an information request is not evidence; its only purpose is to provide context for why the intervener is asking the question.

FEI has provided its responses to the information requests by focusing on the questions themselves, rather than parsing and rebutting each preamble. However, FEI wishes to be clear that the preambles contain inaccuracies and characterizations that FEI does not accept. As such, FEI's silence regarding the content of a preamble should not be interpreted as agreement.

FEI will object to any attempt by MS2S to rely in final argument on the content of preambles to its information requests.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

Issue 1: Event probability.

A key issue in this application is the reliability record of the T-South pipeline. Four event references to gas pipeline outages in BC are provided in the PWC report (Appendix B of the revised redacted submission of March 25th, 2021- document B-1-3), three of which have no relationship to T-South or gas supply to Lower Mainland (LM) ratepayers. These are detailed in the table below.

Event	Details	Relationship to T-South, effect on Lower Mainland gas supply
Alaska Highway pipeline rupture 2009	In February, 2009, Spectra reported a gas leak in its 18-inch Alaska Highway pipeline. Two workers were conducting routine maintenance at the site when the leak occurred. Both were taken to hospital with non-life threatening injuries.	None, none
Enbridge Valve Enclosure Fire 2012	On June 23, 2012, an ignition and fire occurred in a valve-enclosure structure at Spectra Energy Transmission Compressor Station N4, located approximately 160 km northwest of Fort St. John, British Columbia. Two maintenance employees sustained burn injuries when sweet natural gas that had been leaking from a station valve ignited. The 2 employees were performing annual inspection work on motor-operated valves. The injured employees were air-lifted to the Fort St. John Hospital.	None, none
Enbridge Nig Creek pipeline rupture 2012	On June 28, 2012, a pipeline rupture and ignition occurred on Westcoast Energy Inc.'s 406.4 mm (16-inch) Nig Creek pipeline, located about 40 km northwest of Buick, British Columbia. Approximately 25 minutes later, a pipeline rupture and ignition occurred on Bonavista Energy Corporation's 168.3 mm (6.625-inch) pipeline installed nearby in the same right-of-way. At the time of the ruptures, both pipelines had been shut down and contained pressurized sour gas. The fire spread to adjacent forested areas. A large crater was created, and one piece of the Nig Creek pipe was ejected along with other debris to approximately 20 m from the rupture site. There were no injuries and no evacuation were required.	None, none
Enbridge T-South rupture, October 2018	On October 9th, 2018, the Enbridge T-south pipeline ruptured near Prince George, BC.	Affected 1 (of 2) T-South pipelines. 700,000 LM BC gas customers were asked to reduce their usage by turning down thermostats, minimizing the use of hot water, or using alternative energy sources. Fortunately, a second, looped, pipeline in the same right of way was not damaged, and a major shutdown was avoided.

Anecdotally, I have been a Lower Mainland FortisBC gas customer since 1981, and have not experienced a single service outage in those 40 years.

However, the application does include several references which are helpful in bridging this gap. One of these (P. 26 footnote) compares the unplanned outages of the (mostly over ground) electrical energy supply with that of the (mostly underground) gas supply – Figure 14 of the reference (GTI's Assessment of Natural Gas and Electric Distribution Service Reliability[1] - is reproduced opposite. The key gas statistic – 0.00234 probability – equivalent to one outage every 427 years – suggests that the T- South event was quite a rarity. Further, in this project's worst-case scenario – an unplanned total outage of T-South spanning three of SW BC's coldest Winter-time days – the probability of such a coincidence is about once every 3,800 years[2].

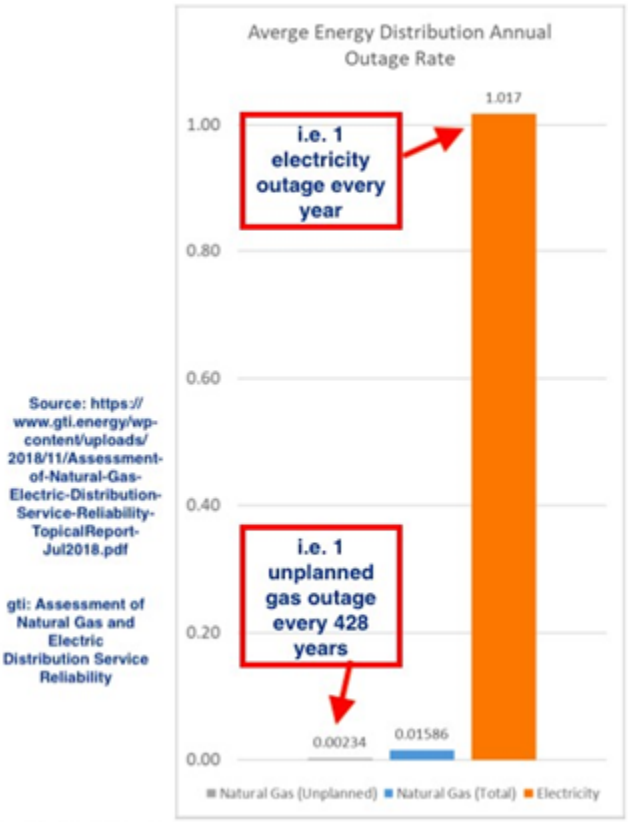


Figure 14: Comparison of Natural Gas and Electric Annual Outage Rates

By comparison, an outage which would severely disrupt Tilbury and the local gas distribution system – a severe earthquake affecting SW BC - is statistically far more likely (30% probability in the next 50 years, according to Natural Resources Canada). So too is the forced evacuation of Tilbury Industrial Park , which (due to the nearby Burns Bog catching fire and threatening to spread to Tilbury Island) has occurred eight times in the past 43 years – the latest in in 2007 and 2016). On July 3, 2016. Tilbury Industrial Park was evacuated – see https://www.delta-optimist.com/local-news/burns-bog-fire-threatens-tilbury-3035252, leaving the Tilbury peak-

[1] https://www.gti.energy/wp-content/uploads/2018/11/Assessment-of-Natural-Gas-Electric-Distribution-Service-Reliability-TopicalReport- Jul2018.pdf

[2] Environment Canada records show the window for Vancouver's coldest days stretching ~ 40 days from early January until mid-February.

shaving plant unattended. Dry peat can catch and spread fire rapidly. Thus, fires in Burns Bog can burn underground for months in methane-rich peat. Large fires occurred in Burns Bog in 1977, twice in 1990, in 1994, 1996, 2005, 2007, and 2016. These far-more-likely events would each cause significant damage to FEI's Lower Mainland delivery infrastructure, and render useless - even dangerous - a large store of liquefied gas in this proposed tank at Tilbury.

FEI's own data corroborates the infrequency argument. In its submission (P. 26) FEI states: "*The rates of reliability would suggest that, on average, a typical natural gas customer would expect 69 seconds of service outage per year compared to almost four hours per year for a typical electric customer in BC (even with the high standards of redundancy on the electric system). In practice, the vast majority of FEI's customers have never experienced a single natural gas outage, other than for planned reasons such as a meter exchange*". Doing the math: 69 seconds/year= 2 days in 2*69*1440* years = > 100% chance of a 2 days of service outage event(s) once every 3,312 years.

Questions:

1.i In the absence of any data to the contrary, may we assume that the reliability of the T-South pipe is in line with this 1 in 428 year North American gas pipeline average? and;

1.ii Is the application's worst-case scenario - the coincidence of a severe cold snap in Southwest BC coinciding with a total outage of T-South - not an extremely unlikely event ? and;

Response:

FEI disagrees with the assumptions and calculations that underlie the above questions. The following response answers the above questions, while also addressing notable incorrect assumptions and flawed calculations in turn:

1. "*A key issue in this application is the reliability record of the T-South pipeline."*

   It is statistically invalid to use the current performance record of a single event (one no-flow incident in 60 years of operation) to infer an ongoing no-flow failure rate probability for T-South of 1 in 60 years. Similarly, if FEI had proposed the TLSE Project in early 2018 (prior to the T-South rupture) it would have been improper to cite the perfect pipeline performance record at that time (zero no-flow events in 60 years of operation) and extrapolate to an ongoing probability of failure of zero incidents forever.

   Please refer to the response to BCUC IR1 1.5 that provides a statistical failure rate analysis based on Canadian and US pipeline performance data and which is applicable to the T-South system.

2. *"Four event references to gas pipeline outages in BC are provided in the PWC report […], three of which have no relationship to T-South or gas supply to Lower Mainland (LM) ratepayers*."

As PwC has explained in its response to BCUC IR1 3.3, the events referenced in the PwC report were not included to suggest that they were directly associated with T-South or gas supply to the Lower Mainland. Rather, they were intended to illustrate that pipeline failures have occurred and have resulted in incidents of significant consequences in other systems.

3. "*The key gas statistic – 0.00234 probability – equivalent to one outage every 427 years – suggests that the T-South event was quite a rarity*." and "*In the absence of any data to the contrary, may we assume that the reliability of the T-South pipe is in line with this 1 in 428 year North American gas pipeline average*."

This probability calculation (either 1 in 427 or 1 in 428 years) for T-South is invalid because it incorrectly applies the GTI reliability statistics—which are based on the average reliability levels experienced by individual customers—to a single pipeline system component. The reliability experienced by individual customers is not correlated with that of the individual components that make up a gas transmission and distribution system. This is because most transmission systems incorporate redundancy, including multiple supply sources, looped transmission pipelines, and storage (either underground or LNG). Similarly, gas distribution systems are commonly looped to provide operational flexibility. Together, the redundancy of the multitude of system elements results in very high average service availability for individual gas customers. In other words, even though the reliability of individual system components (such as T-South) may be far lower, the gas supply reliability at the customer location is very high. Attributing the same average reliability levels experienced at the customer location to the performance of individual system components is incorrect.

Please also refer to the response to BCUC IR1 1.5, which provides a statistical failure rate analysis based on Canadian and US pipeline performance data and that is applicable to the T-South system. The cumulative probability analysis included in that response demonstrates the high likelihood that the TLSE Project will be needed and used at least once over the 67-year analysis period of the Project for resiliency purposes.

4. "*Further, in this project's worst-case scenario – an unplanned total outage of T-South spanning three of SW BC's coldest Winter-time days – the probability of such a coincidence is about once every 3,800 years*" and "*Doing the math: 69 seconds/year= 2 days in 2*69*1440* years = > 100% chance of a 2 days of service outage event(s) once every 3,312 years*."

The calculated probabilities of once every 3,800 years or once every 3,312 years are incorrect because the input assumptions and calculations are flawed. As discussed in item 3 above, the probability of a no-flow event on the T-South system is not 69 seconds per year or once in 428 years.

In addition, the calculation in the preamble assumes that the no-flow event must occur coincident with "SW BC's coldest Winter-time days". This is also an incorrect assumption. As discussed in Section 3.5.4.1.6 of the Application, without the TLSE Project, there is an approximate 151-day winter period when the current 0.6 Bcf tank at Tilbury could not bridge a 3-day no-flow supply emergency.[3] Further, if this event occurs, the ensuing outages and system restoration could take weeks to months. As such, the T-South no-flow incident and

[3] This analysis also assumes that the existing regasification constraint has been removed.

cold winter temperatures do not have to align temporally. Even if the no-flow event occurred in early winter when temperatures were cold (but not unusually so), the ensuing customer outages could last for weeks and coincide at some later date with very cold temperatures.

1.iii Are there no other more likely worst-case scenarios affecting customer gas service in BC that were not addressed in this assessment of resiliency need (such as seismic, fire, cyber-attack, terrorist attack etc.)?

Response:

The worst-cast scenario that can impact customers' gas service in BC is a no-flow event on the T-South system. As discussed in Section 1.2.1.2 of the Application, a major disruption on the T-South system leaves FEI with insufficient supply to meet the daily Lower Mainland load at most times of the year. Without additional investment in resiliency, future supply disruptions that may occur could have significant consequences in terms of cost to customers and socio-economic impacts to society generally.

The T-South Incident that occurred in October 2018 underscored the risk of a no-flow event resulting from a rupture due to an integrity issue with the pipeline. However, this is not the only potential cause of a no-flow scenario. Other initiating events could include earthquakes, landslides, washouts, or sabotage. Please also refer to the response to BCUC IR1 1.3.

Cyber-attacks could also disrupt 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.[4]

Regardless of the initiating cause, the TLSE Project will provide FEI with enhanced capability 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.

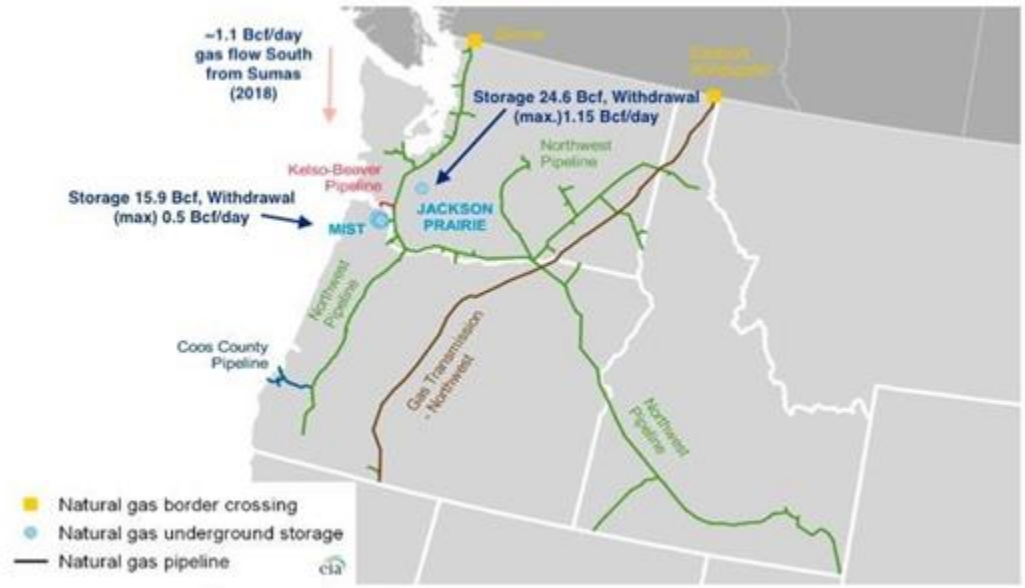
[4] https://www.reuters.com/business/energy/us-govt-top-fuel-supplier-work-secure-pipelines-closure-enters-4th-day-2021-05-10/.

Issue 2: Need for, and lack of, mutual assistance arrangements with other gas companies.

FEI's worst-case scenario contemplates (P. 63 of its March 25th submission) needing some 871 MMcf/day (0.87 Bcf/day) to maintain customer service without curtailments or interruptions.

Underground natural gas storage is an integral component of the natural gas supply chain, with a function different than the other components of that supply chain. Storage serves to augment natural gas production, and the location of a storage facility can also provide operational flexibility for the natural gas delivery infrastructure. There are 385 underground storage facilities in the lower-48 U.S. states with a total of 4,688 Bcf of working gas design capacity. The closest underground supplies to SW BC are the Jackson Prairie and Mist facilities in Washington/Oregon, with a combined sendout of 1.65 bcf/day – twice the worst-case requirement to keep BC ratepayers whole. These are shown in the diagram opposite, as are the connections to the Williams Northwest pipeline system.

Selected U.S. Pacific Northwest natural gas infrastructure



Source: U.S. Energy Information Administration

SoCalGas's website declares: https://www.socalgas.com/1443742022576/SoCalGas-Case-Studies.pdf: "*Mutual assistance agreements between utilities are critical to disaster response and could be further strengthened. In times of emergency, mutual assistance agreements were effective complements to the limited standby utility resources (e.g., backup generators) and staff (e.g., qualified technicians) utilities can maintain. Mutual assistance agreements and coordination through bodies such as the CUEA allow for pooling resources when necessary and swelling the labor force in specific areas in need. Mutual assistance agreements could be further strengthened to increase responsiveness, proactively address challenges (e.g., transportation and telecommunication service disruptions), and provide a larger array of assets during emergency events*"

Below is a table we have compiled showing the potential sources of emergency supply for FEI's customers. It would appear that FEI has several options for garnering emergency supply to cope with a T-South service interruption.

Source	MMcf/day	Comment
Williams Northwest pipeline assist (via Sumas, Kingsvale)	?	Not negotiated?
Tilbury (existing regas.)	155	Per Guidehouse report (P. 37)
Mt. Hayes (existing regas.)	153	Per Guidehouse report (P. 37). 10 days storage
Southern Crossing supply	100	This source helped replace supply in the Oct. 10, 2018 rupture
Mist, JP underground supply (max.)	1,650	Per Guidehouse report (P. 37). As currently contracted, requires one or both of the two T-south pipes to be operational. Depletes over time , but total storage of 40bcf is capable of delivering BC's 800MMcf/d demand max. for at least 2 weeks. Not
Linepack in Fortis, Spectra pipes (max.)	800	For 24 hours or 400mmcf/day over 2-day outage. Up to 1000km of 30" pipe at 1,000psi
Total without/with Mist & JP backup supply	1,208 / 2,858	
FEI's worst-case load requirement	871	

The examples given by FEI (P. 64) of resiliency measures taken by other gas utilities seem unconvincing.

- **New Jersey Natural Gas's** actions included 7 reliability measures, none of which involved increasing LNG storage or regasification capacity. Rather, its main resiliency actions, in the wake of service interruptions caused by Hurricane Sandy, included several pipeline loops and a short connector pipeline to a gas supply in a neighbouring state.
- **Dominion Energy Utah's** actions: In its website, DEU states "*With the need for continued reliability in one of the fastest-growing states in the country, Dominion Energy Utah analyzed options the company could pursue to ensure supply dependability and avoid disruptions. We concluded that the best available long-term solution would be construction of an LNG facility. Dominion Energy is working with regulators to obtain approval for this option*". Though DEU and FEI have about the same (1Million -plus) customer base, DEU's proposed "Magna LNG" facility, as yet unbuilt, will liquefy gas at a rate of 8.2 MMscfd (378,000 litres = 160 tonnes per day), store it in a 56-million-litre (~24,000 tonne) storage tank and, when needed, vaporize the LNG at a rate of 150 MMscfd. By contrast, FEI is proposing a facility for its maybe 700,000 Lower Mainland customers of 10,460 tonnes LNG production per day, 96,000 tonnes LNG storage and a regasification capacity of 870 MMscfd. That is several times the capacity of DEU's plant. In other states, Dominion Energy's resilience efforts are focused on pipeline replacements and looping - not on the liquefaction and regasification alternative.

Questions:

2.i Has Guidehouse /FEI sufficiently explored the mutual benefits of cooperative agreements with gas companies with interconnections to T-South (Puget, Williams, Enbridge…)?

Response:

As discussed in the responses to BCUC IR1 4.2 and CEC IR1 14.1, FEI is a member of the Northwest Mutual Assistance Agreement (NWMAA). However, the types of mutual aid agreements suggested in the question above do not provide any supply certainty to FEI in the event of a supply disruption.

2.ii Has FEI done any comparative studies of the costs and benefits of such cooperative arrangements relative to the $770 Million cost of the proposed expansion?

Response:

Please refer to the response to MS2S IR1 2.i.

2.iii FEI includes a force majeure clause in all of its industrial and commercial contracts, including those for gas delivery to U.S. customers. Is this credited as a liability limitation in evaluating the financial consequences to FEI of a prolonged service interruption beyond its reasonable control?

Response:

In general, *force majeure* clauses are contractual terms that excuse performance under a contract in light of specific circumstances beyond the control of a party. FEI has *force majeure* clauses in various rate schedules, which can be found on the following web page: https://www.fortisbc.com/about-us/corporate-information/regulatory-affairs/our-gas-utility/FortisBC-Energy-Inc.-Mainland-Vancouver-Island-and-Whistler-service-areas.

While a *force majeure* clause can mitigate FEI's corporate liability exposure in qualifying circumstances, it does not prevent the adverse outcome from occurring. In contrast, the TLSE Project is intended to mitigate the risk of the adverse outcome by mitigating the risk of customer outages. Given the potential for supply to be disrupted (as evidenced, for instance, by the T-South Incident) and the potential magnitude of the harm to customers and society generally in the event of a disruption, the TLSE Project is a reasonable and prudent investment to mitigate this resiliency risk.

2.iv Please explain the discrepancy between Dominion Energy Utah's and FEI's resiliency preparations – especially focusing on the volume differences in storage and regasification capabilities despite having roughly equivalent customer bases.

Response:

The following response has been provided by Guidehouse:

Guidehouse observes there is no discrepancy in the approaches between Dominion Energy Utah and FEI's resiliency decision-making. Moreover, we observe that resilience solutions will be bespoke to the specific situation that is being mitigated. In the case of Dominion Energy, a subset of their total customer base was subject to climate-driven supply interruptions and the company sought a resilience solution sized to address the needs of the at-risk customers.

Guidehouse also observes that of the seven identified measures put forth by New Jersey Natural Gas, one of them is the LNG Transmission Interconnection project. The goal of this project is to connect an existing LNG storage and vaporization facility directly to its natural gas transmission system. This is effectively aimed at improving the ability of an existing facility to serve as a resilience asset.

Issue 3: MIST and JP synchronous (underground storage) draw-replenishment rate.

In FEI's application, much is made of the contractual requirement for the T-South feed to U.S. customers at Sumas – over 60% of the capacity of T-South - be functioning if/when FEI were to draw from the Jackson Prairie and Mist underground stores. Clearly, the volume of gas draw available from both those stores (1,615 mmcf/day) is double FEI's worst-case requirement for its customers. The figures quoted by FEI for the total store at JP and Mist show that that draw could be sustained for far longer than the 2-3 days required to bring T-South back into service.

This begs the question as to why this draw arrangement cannot be re-negotiated such that this restriction be lifted.

Questions:

3.i Does the draw-replenishment cycle for feeds to U.S. customers need to be synchronous?

Response:

FEI interprets "draw-replenishment cycle" as the injection and withdrawal schedules from the Jackson Prairie Storage (JPS) and Mist facilities. The operators of these facilities have contractual arrangements with a number of counterparties that detail the terms and conditions for the amount of supply that each counter-party can inject or withdraw on a daily basis at the facility.

The withdrawal or injections do not have to occur at the same time, as each counterparty manages their contracted supply based on their own requirements. The net result of all the shippers will determine the amount of supply that is either physically injected or withdrawn out the storage facilities on a given day.

In general, during the spring and summer the counterparties are injecting gas supply back into these facilities in order to have sufficient storage available for the winter heating season.

3.ii Can this not be negotiated differently? (i.e. can a short-term draw be made up/ replaced on a (slightly – 2-3 days) delayed timetable? Agreement on that point would eliminate the entire need for this new tank and two expensive, energy-wasteful liquefaction and regasification steps.

Response:

The type of negotiation suggested in the preamble would not eliminate the need for the TLSE Project. In the event of a no-flow incident on T-South, there are no assurances that gas from the Jackson Prairie Storage and Mist facilities can physically flow to the Lower Mainland during the winter season. This was discussed in Section 3.5.4.3.1 of the Application (Access to JPS and

1 Mist Depends on Gas Physically Flowing on T-South), and is further explored in the responses to
2 BCUC IR1 16.14 and 16.16.

3

Issue 4: The worst-case scenario presented in this application is exaggerated.

In the 2018 T-South incident, only one – the 36"-diameter pipe - of the two looped pipelines exploded/ was breached/ put out of service. Because the two pipelines were in close proximity at the rupture point, CER ordered the second (30") pipe shut down as a precautionary safety measure. It was restored to 80% service pressure some 28 hours after the rupture of the larger (36" diameter) loop. Although the break also affected gas transmission service in Washington State, Puget Sound Energy switched its electricity generation to alternative fuels.

Questions:

4.i Is a 3-day outage an exaggeration of the worst-case outage situation- the T-South break was only partial, and that only for 28 hours?

Response:

A potential 3-day outage is not an exaggeration of the worst-case outage situation. A no-flow event could last longer than three days.

Any of the following, amongst other factors, could impact the duration of a gas supply disruption:

- 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 in 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.

As discussed in Section 1.2.1.3 of the Application, FEI's 3-day Minimum Resiliency Planning Objective was informed by the T-South incident, its understanding that future situations could exceed three days, and the significance of potential customer and broader socio-economic impacts that could occur as a result of an outage situation.

FEI has developed the following timeline to illustrate how a no-flow event could last three (or more) days. Note that the response times during an actual event could vary significantly from those shown here; the timeline below is intended to demonstrate just one plausible scenario. Also, the timeline below does not discuss the responses that FEI would take.

T = 0 (Initiating event): A T-South rupture with ignition occurs early on a winter morning in steep mountainous terrain. Early winter snows have arrived and although there are rough service roads into the area, none are plowed. The initial cause of the rupture is unknown (but is later attributed

to an undetected stress corrosion cracking feature). Similar to the October 2018 event, Westcoast also shuts-in the adjacent pipeline due to the uncertainty of its integrity.

T+10 minutes: Westcoast notifies FEI of the incident and that all gas flows on T-South are stopping.

T+6 hours (approximately 8 am on the first day): Westcoast visits the rupture site by helicopter to confirm the location of the incident. Due to the steep terrain there are no landing sites in the vicinity of the rupture. No easy access routes are identified. The cause of the rupture and the potential for damage to the adjacent pipe is still unclear. Westcoast declares *force majeure* and some transportation nominations are reduced while others are zeroed out.

T+18 hours (approximately 8 pm on the first day): Westcoast has been mobilizing heavy construction equipment throughout the day to the site. Some equipment has arrived along the access route to the site and begun to plow and prepare the service roads that provide access to the site. Both pipelines remain shut-in with zero flow forcing shippers to curtail their customers and to activate their emergency response and load shedding plans.

T+30 hours (approximately 8 am on the second day): More construction equipment and emergency response personnel are being staged in the field while Westcoast resumes its efforts to establish access to the site. Pressure in both pipelines continues to deteriorate as some Westcoast shippers continue to draw on Westcoast linepack to meet demand on their own systems.

T+42 hours (approximately 8 pm on the second day): Westcoast has established access to the pipeline right-of-way near the site of the incident and emergency equipment and personnel have been mobilized accordingly.

T+54 hours (approximately 8 am on the third day): A winter storm has moved into the region bringing heavy snowfall, limited visibility and temperatures of minus 20°C to the emergency response area. Westcoast halts emergency response activities in the field due to the weather conditions.

T+78 hours (approximately 8 am on the fourth day): The snow storm has passed leaving between 30+ centimetres of snow in the area. Westcoast resumes its field emergency response activities by clearing the access roads and right-of-way of snow. Because of the steep mountainous nature of the site and the resulting site conditions from the weather, construction equipment and emergency response personnel must be winched down a steep slope to the actual site of the failure.

T+90 hours (approximately 8 pm on the fourth day): Westcoast was able to partially excavate the NPS 36 pipeline (the pipeline that did not rupture but was shut-in for integrity reasons) overnight but more work needs to be done to complete the excavation and prepare the pipeline for an integrity inspection. NWP has shut down its compressor stations at its Huntingdon facility located at the Canada-US border because of low inlet pressures. All Westcoast shippers are

undertaking some degree of firm load shedding in response to deteriorating pressure and linepack on the Westcoast pipeline system.

4.ii Is such a large LNG storage tank really necessary? Please provide examples of gas utilities that have built LNG storage tanks as a 2-3-day supply resiliency step?

Response:

The following response has been provided by Guidehouse:

Guidehouse observes that resiliency solutions are bespoke to the risk that is being mitigated and therefore it will be rare that two resiliency solutions will be similar in size. Guidehouse is unaware of other gas utilities that have built LNG storage tanks with 2-3 day resiliency supply. What is similar, however, is the framework in which decision-making relative to tank size is determined.

4.iii Is the fact that most FEI customers will also have electrical service (and therefore have short-term alternatives for space and water heating) factored into the projected resiliency requirement?

Response:

FEI disagrees with the premise of the question that in the event of sudden, wide-scale gas outage during the winter season that large numbers of gas customers would have short-term alternatives. A no-flow event could result in outages to hundreds of thousands of customers in the Lower Mainland. This would quickly exhaust any local inventory of portable space heaters, electric hot water tanks, and electric hot plates. Even if, hypothetically, all of these devices were available to gas customers, assuming that each device consumes approximately 1500 watts, this would collectively represent hundreds of megawatts of added load on the BC Hydro system.

As such, this consideration did factor into FEI's assessment of its resiliency requirements and was included by PwC in their assessment of the impacts of a widespread natural gas outage. Electrical service does not negate the requirement for reliable and resilient natural gas service.

Natural gas meets a significantly larger portion of BC's peak demand than does electricity (approximately 18,000 megawatts of equivalent electric capacity for FEI[5], compared to

[5] "On January 14, 2020, the peak volume of gas delivered between 7:00 a.m. and 8:00 a.m. was equivalent to over 18,000 MW of electrical generating capacity, approximately 60% greater than the peak on the electric system during the same day and 50% larger than the entire hydroelectric generating capacity owned by BC Hydro (11,900 MW)."

approximately 10,000 megawatts for BC Hydro[6]). Electrical infrastructure, including generation, transmission, and distribution, is designed to specific capacity requirements just as FEI's natural gas infrastructure is designed to meet peak demand. During peak periods (such as extreme cold conditions in the winter), the capacity of BC's electrical system would be constrained, similar to how FEI's system capacity is constrained. A sudden and unexpected shift of space and water heating load from natural gas to electricity during cold winter conditions would place a demand on BC Hydro's system far higher than the typical loading this system would be expected to sustain, and could lead to an electrical system collapse as well.

4.iv Why does FEI need to be so different from other Canadian and American gas utilities, who mostly use underground storage and inter-utility support arrangements, as a resiliency mechanism?

Response:

The following response has been provided by Guidehouse:

The primary reason that the resiliency solution proposed by FEI is different from other Canadian and American gas utilities is that the identified options listed below are either insufficient to properly mitigate the risk or unavailable to FEI:

- Contracting for additional pipeline and underground storage capacity;
- Third-party commercial agreements for transportation and/or storage services;
- Utilizing line pack; and
- Industrial curtailment and demand response measures.

Guidehouse is unaware of inter-utility resource sharing agreements. Guidehouse observes that market rules in the US for release of excess firm capacity on a third party interstate pipeline would prohibit an arrangement whereby one gas utility could commit to providing firm capacity to another utility without making this short-term capacity release available to the entire market. Guidehouse also observes that declaration of a force majeure event involves a suspension of firm capacity rights as the interstate pipeline operator retains the ability to grant access to shippers to manage the force majeure event.

The following response has been provided by FEI:

Each utility utilizes the resiliency options available to it, which are not uniform across all jurisdictions. Like other utilities, FEI contracts for underground storage in BC (Aitken Creek Gas

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

[6] https://www.bchydro.com/news/press_centre/news_releases/2020/cold-snap-peak-demand.html.

Storage) and the US Pacific Northwest (Jackson Prairie and Mist). However, because there are no underground storage facilities on FEI's system, FEI requires pipeline capacity in order to transport the supply from the storage facilities to its major demand centers and is therefore exposed to failures on those pipelines. Accordingly, FEI has proposed above-ground on-system storage to enhance the resiliency of its system.

In Section 4.3.5.4 of the Application, FEI detailed why underground storage is not feasible around the major load centers in the Lower Mainland:

> Exploratory drilling took place in the late 1980s and early 1990s by a consortium called the Fraser Valley Gas Project, which included BC Gas (now FEI). Since 1991, following considerable public outcry regarding exploratory drilling, successive governments have indicated an unwillingness to consider underground natural gas storage in the Fraser Valley. Since 1997, the regulations under the Petroleum and Natural Gas Act do not allow for the exploration of or the granting of a lease for an underground natural gas storage reservoir in the Fraser Valley[7].
>
> The area of the Fraser Valley that has been deemed inapplicable for underground storage is shown in Figure 4-7 below:[8]

Figure 4-7: Exclusion Zone for Underground Storage

Finally, like other utilities, FEI does have inter-utility support arrangements in the form of mutual aid assistance, which was discussed in Section 3.4.2.2.1 of the Application:

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[7] *Petroleum and Natural Gas Storage Reservoir Regulation*, B.C. Reg. 350/97, s. 3 (deposited October 16, 1997).

[8] TLSE Application Section 4.3.5.4. "Storage Option 1 – Underground On-System Storage in the Fraser Valley.", p. 98.

FEI is a voluntary member of the Northwest Mutual Assistance Agreement (NWMAA), which is comprised of 18 member organizations that utilize, operate or control natural gas transportation and/or storage facilities in the Pacific Northwest.[9] The support provided by the NWMAA is on a best effort basis by the parties, and there are no commercial charges for a service that a party may provide. All participants within the agreement have a vested interest in maintaining a secure, reliable regional natural gas system, and recognize that combined assistance will minimize the impact and duration to affected regional markets under emergency conditions.[10]

[9] Includes BC, Alberta, Washington, Oregon, Nevada and Idaho.

[10] TLSE Application Section 3.4.2.2.1 "Phase 1 of the T-South Incident (October 9, 2018 To October 11, 2018).", p. 43.

Issue 5: Adverse effects of a worst-case outage scenario.

Other utilities' planning for outage events include detailed assessments of interruptible and curtailments effects on key industrial and commercial accounts (such as hospitals, community centres, large industry customers). SoCalGas has published case studies (https://www.socalgas.com/1443742022576/SoCalGas-Case-Studies.pdf) of U.S. gas company responses to flood, wildfire and hurricane extreme events (it maintains a fleet of tanker-trucks to re-supply local hospitals with CNG. It maintains close communications with local Emergency Response Management providers in isolating portions of its network as needed to reduce gas risks in extreme events).

Questions:

5.i Has FEI / Guidehouse done this analysis/ prepared such disaster-event supply plans? Are these factored into the customer cost-benefit calculations this request for 800mmBCF/day resiliency.

Response:

The following response has been provided by FEI:

FEI conducts ongoing and extensive disaster-event preparations. These plans address local, regional, and province-wide incidents resulting from multiple causes that may impact gas supply to customers. If a no-flow event were to occur on the T-South system during cold weather periods, FEI would have limited tools to respond in the Lower Mainland service area. Once available storage (including line pack and LNG at the existing Tilbury Base Plant) is depleted, FEI's only remaining response would be to shut off supply to hundreds of thousands of customers. FEI considers it appropriate to seek to avoid this outcome and on that basis has proposed the TLSE Project to enhance the resilience of the Lower Mainland system.

Please refer to the responses to BCUC IR1 8.2 and RCIA IR1 5.2 for a discussion of the cost-effectiveness of the TLSE Project when compared to alternate solutions.

The following response has been provided by Guidehouse:

The scope of the Guidehouse engagement did not include conducting a cost/benefit calculation of various disaster response supply plans.

5.ii Does the (redacted) PWC report (Appendix B) analysis factor such alternative energy availability into its models, findings and conclusions?

Response:

The following response has been provided by PwC:

Scenario bounds were defined based on the notable conditions that would create a material step change in impact for one or more stakeholder groups in BC. These were identified by collecting information from external (impacted sectors / stakeholder groups) and internal (FEI) interviews, but may inherently be informed by previous disruption events that stakeholders have identified and considered in their own risk management plans. Our analysis did not then explore the efficacy of stakeholder risk management plans which may or may not present risk similar to FEI's system resiliency.

As part of the stakeholder interviews, natural gas consumers were asked about the type of backup energy available, the organization's ability to operate on backup energy sources, and the duration which backup fuel supplies would be expected to last in the event of a natural gas supply disruption.

The intent of the study was to assess the potential impact of natural gas disruption and provide the province and the energy industry with data to help weigh the costs and benefits of different infrastructure investments to enhance system resiliency in the province. PwC was not engaged in FEI's resiliency planning.

Issue 6: Linepack is ignored.

The Guidehouse report largely dismisses linepack as a possible source of emergency supply. However, a 50- mile (80km) section of 42-inch (107 cm) transmission line operating at about 1,000 pounds of pressure contains about 200 million cubic feet of gas - enough to power a kitchen gas range for more than 2,000 years (or 365,000 ranges for 2 days, FEI's outage scenario).

However, "*when considering the peak design day demand in FEI's service territory, approximately 871 million cubic feet per day, this translates into about 5.5 hours of supply*". (source: Guidehouse Report , P. 12). The linepack of 1000km. of 30" T-South @ 1,000psi from Station 2 ->Summit Lake-> Vancouver: (5.5* 1 * 10*225/441) = about 28 hours supply to FortisBC's distribution system. Most of FEI's Eagle Mountain 12" pipeline to Victoria (and planned 24" pipeline 50 km.to Woodfibre) is at a high-pressure 2160 psi.

Questions:

6.i How much supply (i.e. duration in worst-case weather) is represented by the linepack of T-South and the 2130psi Fortis distribution system (from the T-South interchange at Sumas to Victoria)? This assumes a worst-case T-South break close to its Southerly limit at Sumas.

Response:

FEI is unclear on the request, but interprets the question as requesting information relating to the line pack in FEI-operated transmission systems between Huntingdon (Sumas) and Victoria. This would include FEI's Coastal Transmission System (CTS) and Vancouver Island Transmission System (VITS). A line break immediately upstream of Huntingdon would not allow FEI access to any line pack in the Westcoast T-South system.

The table below provides the information requested based on FEI transmission models of the CTS and VITS and provides a duration based on a daily flow of 871 MMcf/day until the system is completely depleted.

FEI emphasizes that while useful in illustrating the volumes of gas typically contained in the systems, such a scenario, serving peak demand from line pack for the duration described in the table below, is infeasible for sustainable operation and would result in hydraulic collapse and an extended system outage for all customers served by the system. The full line pack of either system cannot be used to depletion without collapsing the system to 0 psig. In a transmission system that is in sustained operation, a small fraction of the total line pack can be consumed and then replenished in the daily operational cycle so that on average, over daily periods, there is no net contribution to the operation of the system. In addition, if a supply disruption occurs during the portion of the cycle when the useful line pack has not yet been replenished it is not available for supporting the supply shortfall. Moreover, as discussed in Section 3.5.4 of the Application, there are limits on when and how much gas from the VITS can flow eastwards into the Lower Mainland. As a result, line pack contributions are not considered as an available resource for resiliency planning purposes.

System Line Pack with Estimated Time to <u>Complete System Collapse</u>

System	Total Line Pack (MMcf)	Supply Duration (hours) under CTS Peak Demand
Coastal Transmission System	131.3	3.6
Vancouver Island Transmission System	156.2	4.3

6.ii Would this not be used as a primary source of supply in any emergency situation? If so, how many hours of service is represented by this linepack?

<u>Response:</u>

Please refer to the response to MS2S IR1 6i.

Issue 7: T-South reliability - Enbridge's resiliency plan for T-South.

See Enbridge T-South Expansion & Reliability Program - https://www.enbridge.com/~/media/Enb/Documents/Projects/TSouth/FS_TSouth_ReliabilityandExpansionProgram.pdf?la=en. This work, known as the T-South Reliability and Expansion Program, is currently under way. It involves Enbridge installing new, or replacing and decommissioning old compressor station units with more reliable and efficient units, as well as undertaking smaller upgrades and operational maintenance at various facilities along the system. These upgrades are being undertaken as part of operating a safe and reliable natural gas pipeline system and will accommodate increased customer demand on the system. (The latter may have been initiated after the Canadian Energy Regulator (CER) fingered Enbridge's postponement of routine pipeline inspections as a major contributory factor in the 2018 outage event https://www.theprogress.com/news/undetected-cracks-blamed-for-enbridge-gas-pipeline-blast-in-b-c-in-2018/).

Questions:

7.i Has FEI / Guidehouse done this analysis/ factored these improvements into this request for 871mmcf/day resiliency, the size of the resiliency tank proposed in this application?

Response:

Please refer to the response to BCUC IR1 1.11 for an explanation of how FEI is aware of Westcoast's T-South Reliability and Expansion Program, and how FEI does not consider this expansion to have any impact on the Application because it will not enhance FEI's system resiliency.

7.ii Is it not Enbridge's – not FEI's- responsibility to maximize the resilience of its line?

Response:

FEI, as a shipper on the Westcoast T-South system, expects Westcoast to take appropriate steps to maintain the integrity of the T-South system. However, despite whatever steps are taken by Westcoast, a disruption on the T-South system can occur (as discussed in the responses to BCUC IR1 1.3 and 1.5) and have significant consequences for FEI and its customers (e.g. widespread service outages). FEI considers it appropriate to address this risk as part of its own planning.

Please also refer to the response to Sentinel IR1 10.

7.iii Please outline why FEI believes that the T-South Reliability and Expansion Program will not provide sufficient reliability so as to make this (Tilbury) storage increase unnecessary

Response:

Please refer to the response to MS2S IR1 7.i.

7.iv Please describe the discussions that have taken place with Enbridge with regard to FEI's concerns about the reliability of the T-South service.

Response:

Please refer to the response to BCUC IR1 1.6.1 which includes a description of FEI's discussions that have taken place with Westcoast.

Please also refer to the response to BCUC IR1 1.3 for potential sources of supply interruptions of the T-South system.

Issue 8: Capacity expansions of the Tilbury plant 1971-2028.

Tilbury's peak-shaving plant has been coping with the winter-time gas demand needs of BC's customers since 1971. In that time, BC's population has increased 126% (from 1971's 2,240,470 to today's total of 5,071,336). Shown below are the successive OIC-mandated, ratepayer-funded expansions of storage, liquefaction and regasification capabilities at Tilbury, whose role as a peak-shaving plant has not changed in that half-century. This proposal significantly modifies that role – from peak-shaving short-term demand fluctuations to backup supplier of gas services in case of supply disruption.

FortisBC – Tilbury Expansion Phases

In-service Year	Phase Name	Liquefaction capacity (tonnes LNG)	Storage capacity (m^3 / (tonnes)	Comments
1971 -	Base Station	60 tonnes/day (22,000 tonnes/year)	28,000m^3 (12,000 t)	Storage refill time: ~200 days May be removed in
2019 -	Phase 1A	700 tonnes/day (256,000 tonnes/year)	46,000m^3 (20,000 t)	OIC 557 (2013) directed BCUC to bypass the requirement for a CPCN. Phase 1A's stated intention was to support RS46 (truck transport) sales to BC Ferries and truck fleets. Storage refill time : ~30 days.
2023 -	Phase 1B	2,000 tonnes/day (730,000 tonnes/year)	-	OIC 749 (2014) directed BCUC to bypass the normal requirement for a CPCN for Phase 1B. It excluded storage capacity expansion. Aggregate storage refill time through Phase 1B : ~12 days.
2024-2028 -	Phase 2	7,700 tonnes/day (~ 2.8 million tonnes/year)	142,000m^3 (64,000 t)	Stated intentions of this expansion are (i) to add resiliency to Tilbury's peak-shaving role; (ii) provide LNG as fuel to vessels in West coast ports and; (iii) supply bulk exports to prospective Asia-Pacific customers. The proportions are unclear.
Cumulative Totals		***10,460 tonnes/day (~ 3.82 million tonnes/ year)***	***216,000m^3 (96,000 t)***	Phase 2 storage refill time: ~9.2 days

Source: FortisBC Tilbury LNG Phase 2 Expansion: Initial Project Description, submitted to BC EAO, June 2020; * Storage and liquefaction numbers revised per FEI's letter to BC EAO of April 22, 2021.

Questions:

8.i Is this expansion pattern really for the benefit of BC ratepayers… or is it a thinly-veiled attempt to have BC ratepayers fund FEI's adventures into LNG exports and bunkering LNG-ready vessels in West Coast ports? Please explain and elaborate on why the latter characterisation is invalid.

Response:

The TLSE Project that is the subject of this proceeding is a resiliency investment that will significantly improve FEI's ability to maintain continuity of service in the event of a gas supply disruption to FEI's system and is for the benefit of FEI's BC customers. The TLSE Project, sized at 3 BCF, also provides valuable ancillary benefits for system operations and customers.

The TLSE tank is a component of the Tilbury Phase 2 LNG Expansion project that is currently undergoing Environmental Assessment. For additional detail on the relationship between the

TLSE Project and Tilbury Phase 2 LNG Expansion project, please refer to the response to BCUC IR1 23.2. To summarize that response, in part:

- The TLSE Project is a resiliency investment and the need for it is not dependent on the Liquefaction Facility component of the Tilbury Phase 2 LNG Expansion Project;
- The Liquefaction Facility component of Tilbury Phase 2 LNG Expansion Project is not dependent on the approval or construction of the TLSE tank; and
- However, the TLSE Project does offer some potential flexibility where a portion of the storage could potentially be used to support the Liquefaction Facility. If the TLSE tank is used it would benefit FEI's customers through payments back to FEI made by the entity developing and operating the Liquefaction Facility.

8.ii By seeking to have ratepayers fund this storage tank, would this not create an unlevel playing-field with other potential LNG suppliers in BC (LNG Canada, Woodfibre LNG, Cedar LNG etc.)? Please explain why / why not.

Response:

The proposition in the question is incorrect. As discussed in the responses to the BCUC IR1 23 series, any entity that might contract with FEI for the unutilized LNG storage capacity to supply the non-regulated LNG export market would do so at terms that are subject to BCUC oversight and follow rate design and cost allocation principles. As a result, there is no advantage given to any FortisBC affiliate.

Issue 9: Future gas demand (in BC, for LNG exports).

FEI's submission argues (P.109) that gas demand in its local market will continue to increase in the next decade at least. The application makes the case that, as BC's population - especially in the Lower Mainland - grows over time, gas demand will inevitably increase and the resiliency need will grow.

However, climate actions by municipal councils (like recent by-law revisions by the elected Councils of Vancouver, North Vancouver (both City and District), West Vancouver and Squamish, to encourage non- fossil fuel heating in new buildings threaten to severely impact FEI's basic business model. An example of this effect is shown in this recent picture of a Vancouver "net-zero home" redevelopment.

BC has also instituted "Step Code" revisions to its Province-wide building code to institute new thermal- efficiency requirements for all new residential, commercial and institutional construction. These, when combined with Provincial Government's subsidies for Low-Cost Energy Systems (LCES) encouraging fuel-switching from fossil-fueled furnaces and water heaters to heat pumps and solar electrification, are expected to significantly reduce gas demand. Metro Vancouver's Clean Air Plan - improving building energy efficiency and heating buildings mostly with electricity, not gas - will remove 850,000 tonnes of GHGs by 2030. And much more by 2050.

FortisBC has recently been identified as a member of a national "Consortium to Combat Electrification," run out of the Energy Solutions Center, a trade group based in Washington housed in the offices of the American Gas Association. The presentation slides of this group's recent meeting identified 14 other utilities involved in the effort and said the group's mission was to "create effective, customizable marketing materials to fight the electrification/anti-natural gas movement". That ambition seems seriously at odds with the BC Government's energy policy, its legislated emissions targets and measures, and the public interest in eliminating the causes and mitigating the effects of climate change.

Also, BC Ferries – FEI's largest Rate Schedule 46 FEI client for Tilbury and Mount Hayes LNG– has announced plans to electrify its short-haul inter-island ferry fleet, and recently launched its newest (sixth) member of this battery-electric fleet. This represents an about-face from previous plans to develop its fleet to be powered by LNG. Coldstar and GFL, trucking-fleet customers of Fortis' CNG station in Langford (Vancouver Island), have threatened to refuse long-term contracts and/or sell their fleets of CNG-powered trucks if FEI doesn't lower its price for the fuel to below profitable levels.

The four largest global LNG import markets—China, the European Union, Japan, and South Korea—all introduced carbon-neutrality aspirations in 2020. This will, over time, serve to diminish demand, and pricing, for LNG imports. Table 2.1 in IEA NZE report –shown below - charts the likely future for fossil fuel pricing and demand in Asia. These prices are well below their US$8-$10 cost to produce and ship LNG from Canada.

Table 2.1 ▷ Fossil fuel prices in the NZE

Real terms (USD 2019)	2010	2020	2030	2040	2050
IEA crude oil (USD/barrel)	91	37	35	28	24
Natural gas (USD/MBtu)					
United States	5.1	2.1	1.9	2.0	2.0
European Union	8.7	2.0	3.8	3.8	3.5
China	7.8	5.7	5.2	4.8	4.6
Japan	12.9	5.7	4.4	4.2	4.1

The IEA Report also states[11] that "*No new natural gas fields are needed in the NZE beyond those already under development. Also not needed are many of the liquefied natural gas (LNG) liquefaction facilities currently under construction or at the planning stage. Between 2020 and 2050, natural gas traded as LNG falls by 60% and trade by pipeline falls by 65%*". As reported in the July 2021 LNG Industry Magazine (an influential LNG industry publication) "*IEA's report came to the startling conclusion that the world has to get off gas. In summary, the IEA stated that: beyond projects already committed as of 2021 there are no new oil and gas fields approved for development in the major pathway. Many of the LNG liquefaction facilities that are currently under construction or at the planning stage are not needed. Between 2020 and 2050, gas traded as LNG will fall by 60%. During the 2030s, global gas demand will decline by more than 5% per year*

[11] IEA Special Report titled "*Net Zero by 2050 – a roadmap for the Global Energy Sector*", Pages 102-103.

on average, meaning that some fields may be close prematurely are shut temporarily. The IEA concludes that the gas industry will decline by 5% per annum compound and stranded assets will abound. Essentially, the IEA is ringing the bell the gas is now I declining industry globally".

Adding to the uncertainty over LNG market demand is the recent BC Supreme Court decision in the Yahey (Blueberry River First Nations) v. BC Government case. That judgement found that successive BC Governments have hugely infringed Indigenous rights guaranteed by Treaty 8, and ordered the BC Government to cease issuing new drilling, mining and forestry-industry permits in the area, which happens to include most of the gas-rich Montney formation. The end results of this seminal judgement are as yet unclear, but it puts the future of the (mostly fracked) gas supply to FEI (and others) in jeopardy, and will likely raise the price of gas feedstock to any coastal LNG facility, destroying gross margins for LNG. Investors, already skeptical about BC's fledgling LNG industry, will be even less likely to want to buy into it.

Questions:

9.i Given the public's overwhelming support for climate actions by Government, Industry and others, why does Guidehouse foresee increasing demand. or "peak" gas, (i) for BC demand? and ; (ii) for LNG bunkering and; (iii) for LNG exports?

Response:

FEI has responded to this question, since it is responsible for forecasting load.

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.

9. ii Please comment on how the IEA report and the Blueberry River FN decision will affect FEI's plans for expanding the Tilbury LNG facility. Especially comment on the potential restriction of gas supply to the project, should drilling permits in Treaty 8 territory be curtailed.

Response:

The present CPCN Application is in relation to the TLSE Project, which is a storage facility and associated regasification being developed by FEI for resiliency purposes. It is not in respect of other facilities being developed at Tilbury. As such, this response is confined to the TLSE Project.

The *Yahey* decision will not affect FEI's plans for the TLSE Project because FEI does not anticipate the decision will reduce the need for natural gas supply. The TLSE Project is intended to support the resiliency of the system used to meet the demand for natural gas. Please refer to the response to MS2S IR1 9.iii for discussion on the IEA Report.

9.iii Please explain how, if the IEA's scenario prevails, FEI would avoid having this investment become a stranded asset, and how it would protect the public's interest should that circumstance transpire.

Response:

FEI disagrees with the suggestion that the TLSE Project will become a stranded asset. The TLSE Project will provide resiliency that is required immediately, and will continue to be required for the foreseeable future. In fact, given the role FEI's gas system will serve in meeting provincial emissions targets, the need for increased resiliency becomes more pronounced as BC transitions to a low-carbon energy system.

As noted in FEI's Clean Growth Pathway[12] and the Guidehouse Pathways to 2050[13] reports, the gas delivery system has significant GHG abatement potential flowing from the ability to deliver low-carbon energy and incorporate innovative technologies. The Pathways to 2050 report shows how continuing to use the gas delivery system to service buildings, industry, and transportation with a combination of renewable and low-carbon gases, increased investment in energy efficiency and targeted electrification can achieve BC's climate targets while saving British Columbians over $100 billion in costs. Please also refer to the response to BCUC IR1 63.1 for additional discussion on how the TLSE Project aligns with provincial energy policies.

The IEA's Net-Zero Emissions scenario (NZE) is an indicative scenario outlining the scope and scale of technology deployment, behavioural shifts, and policies that would be needed at the global scale to achieve net-zero emissions. However, the IEA has stated that this is one of many possible net-zero futures and that there is considerable uncertainty on the make-up of technologies to achieve net-zero emissions.[14] The IEA NZE scenario provides directional instruction; however, a BC-focused evaluation is required to outline the specific opportunities and

[12] https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/clean-growth-pathway-brochure.pdf.

[13] https://www.cdn.fortisbc.com/libraries/docs/default-source/about-us-documents/guidehouse-report.pdf?#:~:text=(FortisBC)%20developed%20its%20Clean%20Growth,BC's%20electricity%20and%20gas%20infrastructure.

[14] https://www.iea.org/commentaries/a-closer-look-at-the-modelling-behind-our-global-roadmap-to-net-zero-emissions-by-2050.

challenges of pathways to achieve net-zero. In this context, FEI believes that the resilience of its energy system that will be enabled by the TLSE Project remains a critical priority.

The NZE also highlights that there is no one-size-fits-all for the gas delivery system. With regard to the use of electric and hybrid gas heat pumps in the buildings sector, the IEA states:

> Not all buildings are best decarbonised with heat pumps, however, and bioenergy boilers, solar thermal, district heat, low-carbon gases in gas networks and hydrogen fuel cells all play a role in making the global building stock zero-carbon-ready by 2050. Bioenergy meets 10% of space heating needs by 2030 and more than 20% by 2050.[15]

The IEA's findings are aligned with the Pathways to 2050 report indicating that renewable gas content exceeding 75 percent is required by 2050. The IEA states that:

> Biomethane demand grows to 8.5 EJ, thanks to blending mandates for gas networks, with average blending rates increasing to above 80% in many regions by 2050. Half of total biomethane use is in the industry sector, where biomethane replaces natural gas as a source of process heat. The buildings and transport sectors each account for around a further 20% of biomethane consumption in 2050. [16]

FEI recognizes that significant evolution of the provincial energy system must be undertaken to align with the province's 80 percent GHG reduction objective. FEI is taking meaningful steps to align with and deliver on this commitment. However, as FEI has also demonstrated, specific BC-focused solutions must be recognized to guide investment and planning of the provincial energy system to achieve the province's low-carbon goals. The provincial climate plan, CleanBC, also recognizes that significant GHG reductions will come from FEI's infrastructure in the form of renewable gases, low-carbon transport, and energy efficiency investments by 2030. For example, CleanBC clearly describes how at least 75 percent (1.5 MT) of the GHG reductions expected from buildings will come from renewable gas and a significant portion of the remaining 25 percent (0.5 Mt) will come from the FEI's energy efficiency solutions.[17]

While no detailed BC-focused net-zero scenarios have yet been released by either the Province or independent organizations, a number of studies have looked at 80 percent emissions reduction by 2050 which aligns with CleanBC's target (e.g., the Guidehouse Pathways to 2050 report, the BC Hydrogen Study[18], and the BC Hydrogen Strategy[19]). Furthermore, the Canadian Institute for

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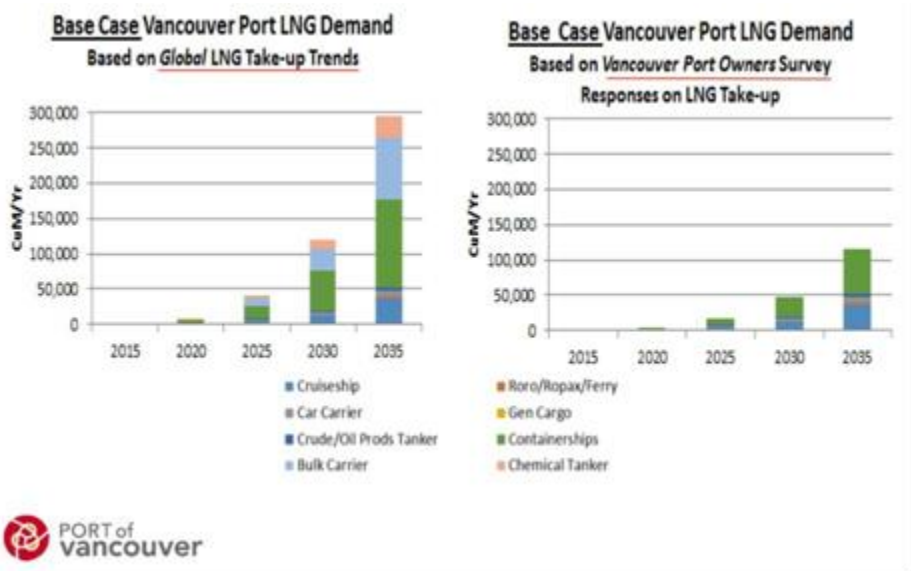
[15] https://iea.blob.core.windows.net/assets/beceb956-0dcf-4d73-89fe-1310e3046d68/NetZeroby2050-ARoadmapfortheGlobalEnergySector_CORR.pdf, pp.145.
[16] Ibid, pp. 78.
[17] CleanBC Full Report Updated March 2019. Page 66
[18] https://www2.gov.bc.ca/assets/gov/government/ministries-organizations/zen-bcbn-hydrogen-study-final-v6.pdf.
[19] https://www2.gov.bc.ca/assets/gov/farming-natural-resources-and-industry/electricity-alternative-energy/electricity/bc-hydro-review/bc_hydrogen_strategy_final.pdf.

Climate Choices examined net-zero pathways for Canada.[20] Each of these reports recognizes that renewable and low-carbon fuels delivered by the gas system have significant potential for expansion and could be an important component of the low-carbon energy system of 2050.

[20] https://climatechoices.ca/wp-content/uploads/2021/02/Canadas-Net-Zero-Future_FINAL-2.pdf.

Issue 10: Markets for an expanded Tilbury's production.

As outlined in FEI's EA application, which is included in FEI's March 25 CPCN application, increased resiliency of gas service to BC customers is not the only objective of FEI's CPCN request for this storage tank. Aside from serving roughly 1.1 million BC customers, FEI is proposing to use this expansion to service (i) Local LNG bunkering demand from vessels in the Port of Vancouver; and (ii) LNG exports to Pacific Rim countries. In exploring the demand for the former, the Port of Vancouver (POV) commissioned a 2017 study by Lloyd's Register (https://www.portvancouver.com/wp-content/uploads/2015/05/LNG-Bunkering-NSLC-April-2017.pdf) of the likely demand for this service. The results, reproduced graphically opposite, indicate that, at best, demand would not reach 300,000 m3 (~130,000 tpa) of LNG per annum until 2035. A survey of Vancouver port owners suggested far less (110,000 m3, ~ 45,000 tpa).also by 2035. This may, in part, be attributed to the high cost of retrofitting vessels to store and burn LNG in lieu of high-sulphur (but cheap) bunker fuel– most vessel owners are taking the less costly route of retrofitting SO2 scrubbers to their bunker oil-fuelled engines.



Additionally, the World Bank has recently issued a report on LNG use as a bunker fuel replacement in world shipping. The issue the report addressed was:

'Liquefied natural gas (LNG) used as a bunker fuel has the potential to offer important reductions in atmospheric pollution—that is, air pollutants and greenhouse gas (GHG) emissions - from ships. Compared to traditional oil-derived bunker fuels such as heavy fuel oil (HFO), LNG clearly emits significantly lower quantities of sulfur oxides (SOx), nitrogen oxides (NOx), and particulate matter (PM). At the same time, it also contains up to 30 percent less carbon per unit of chemical energy (calorific value). Because of this lower carbon content, the use of LNG results in carbon dioxide (CO2) emissions at combustion that are lower than for traditional oil-derived bunker fuels usually burned in ship engines.

This lower carbon content of LNG allows for a theoretical reduction in GHG emissions, yet it remains unclear whether there is a true holistic lifecycle GHG benefit of using LNG relative to oil-derived bunker fuels. The reason for this is that LNG is effectively liquefied methane, and methane is itself a highly potent GHG. Over 20-year and 100-year time horizons, methane is respectively 86 times and 36 times more potent a GHG than CO2 (IPCC 2013). Therefore, any GHG emissions from unburnt methane released to the atmosphere - called methane leakage - can diminish or even entirely offset the theoretical GHG benefit of the use of LNG. In the current literature, different GHG emissions factors for LNG (depending on the varying methane leakage assumptions applied to LNG production pathways and its use on board vessels) reflect this uncertainty.

This leads to a wide range of outcomes in the literature with regard to the GHG benefits from the use of LNG - or disbenefits, if the emissions of methane are assumed to be high. To test the consequences of different scenarios of LNG use, the GHG benefits or disbenefits are not presumed either way. Instead, the consequences of a foreseeable range of methane leakage, GHG emissions, and machinery efficiencies across the lifecycle are analyzed to place bounds on the size of the GHG benefits or disbenefits. These are then discussed in the context of the maritime transport sector's climate targets".

Citation:

"Englert, Dominik; Losos, Andrew; Raucci, Carlo; Smith, Tristan. 2021. The Role of LNG in the Transition Toward Low- and Zero-Carbon Shipping. World Bank, Washington, DC. © World Bank. https://openknowledge.worldbank.org/handle/10986/35437 License: CC BY 3.0 IGO

Its summary conclusions (http://hdl.handle.net/10986/35437) are noteworthy, and include :

"The analysis in this report concludes that LNG is likely to have a limited role as a bunker fuel, with any demand for LNG rapidly declining after 2030. Therefore, to minimize the potential loss of returns, industry stakeholders should consider LNG's questionable long-term competitiveness as a bunker fuel when developing their future business strategies. Furthermore, in light of a world with more and more commitments by public and private players to net zero GHG emissions by mid- century, industry stakeholders should also take into consideration the evolving climate policy landscape and the rising societal pressure in and outside the shipping sector when counting on a significant uptake of LNG as a bunker fuel. Niche-market investments in LNG are likely to face increasing headwinds through the course of the 2020s in such a context".

This report by an authoritative body – the World Bank - speaks to a strong possibility that the Tilbury expansion could quickly become a stranded asset, impacting the investment made by ratepayers in its construction and operation.

In the matter of LNG exports to Pacific Rim countries, data from FEI's website showing this ambition is reproduced below. Entering this highly competitive market dominated by Oil & Gas majors is new territory for FEI, whose previous best export prospect, Hawaii Electric, signed a 15-year MOU with Fortis for 800,000 tpa of LNG in 2016, only to have Governor Ige declare

(https://www.offshore-energy.biz/hawaii-governor-against-lng-power-generation/) that Hawaii should focus on developing renewable energy rather than building LNG import facilities. Hawaii's Public Utilities Commission eventually denied permission for the project.

Asia is the primary export target for the world's 350 MTPA LNG industry, absorbing ~ 70% of world supply. But the market is currently oversupplied, prices are well below total cost, and competition from leading suppliers with LNG plants in Qatar, Australia, Russia, the U.S. and, lately, Africa, is intense. A recent CERI study (https://ceri.ca/assets/files/Study_172_Full_Report.pdf) indicates that Canadian LNG is not competitive in the marketplace. Another (https://www.sciencedirect.com/science/article/pii/S0301421520304389?via%3Dihub), focusing on the economics and public benefits of a BC LNG project, Woodfibre LNG, also shows it to be unprofitable and incapable of delivering public benefit to BC. Around the world, there are ~ 60 LNG facilities, most much larger than what is proposed here, awaiting final investment decision. If even half of them were to proceed to completion, they would double the world's supply of LNG by the end of the decade. This in a global LNG market struggling to grow by 3.5% p.a.- the most recent year (2020) saw a 1% increase. Those suppliers have the advantage of major economies of scale, greatly lessening FEI's prospects of financial success in this capital-intensive commodity business.

Questions:

10.i Given the facts outlined above, why does FEI believe – contrary to the opinions of many experts - an expanded Tilbury facility serving LNG bunkering and world LNG demand can be a public benefit to BC customers?

Response:

The subject of this proceeding, the TLSE Project, is aimed at resiliency, and the benefits to FEI's customers are described throughout the Application. FEI is not seeking approval for facilities to serve LNG bunkering or LNG exports in this proceeding.

10.ii FEI's guaranteed return of 8.75% p.a. on $770 Million in equity capital for the storage and regasification components of this project is $61 Million per annum – approximately $61 per ratepayer per year, not including operating and depreciation costs. Although the potential for maximizing shareholder value (through its guaranteed ROE of 8.75% on invested capital) exists for FEI in pursuing these opportunities, how can BC ratepayers possibly benefit from subsidizing these adventures?

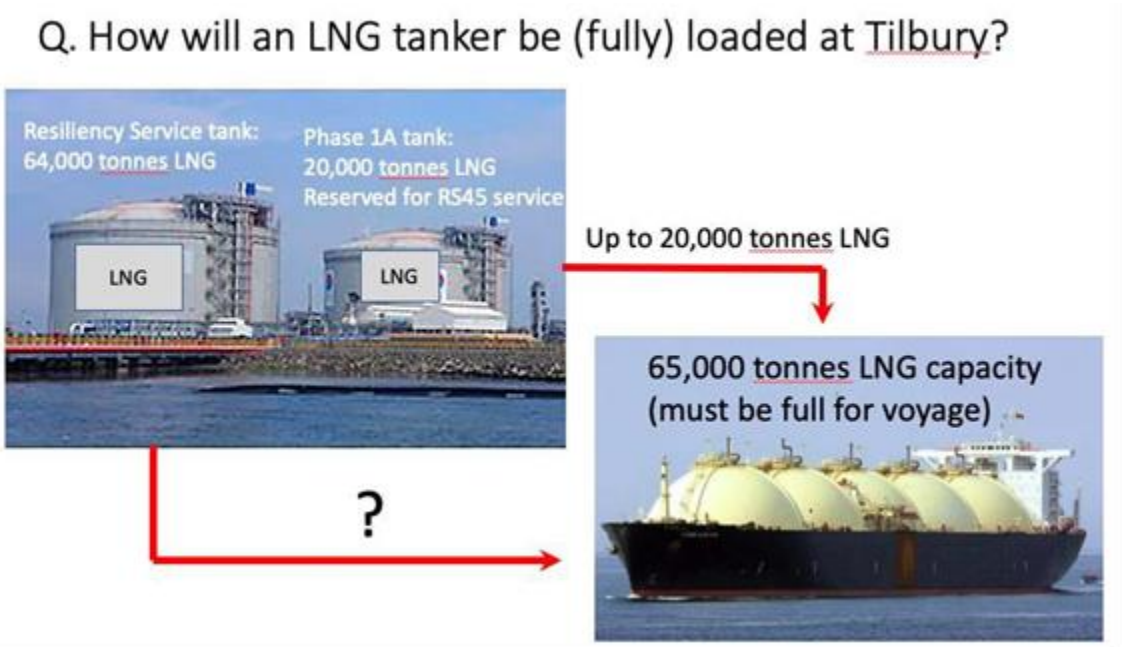
Response:

FEI has described the need for the TLSE Project, and the benefits to customers, in the Application in detail.

The primary benefits to FEI's customers from the TLSE Project relate to resiliency. The TLSE Project will help FEI avoid the significant costs and consequences of an uncontrolled shutdown resulting from a 3-day no-flow event on the T-South system, and provide a margin beyond that minimum threshold to help manage through more common gas supply and demand events in a subsequent period of partial flows on T-South. The TLSE Project also offers additional benefits in terms of flexibility to accommodate future load growth and provide ancillary support such as mitigation of third-party storage risk, improved security of supply, and increased operational flexibility and efficiency. Please refer to Section 3 of the Application which discusses the necessity of resiliency investments and the economic, societal, and environmental consequences of an outage on FEI's system. Please also refer to Section 4.4 of the Application which discusses the ancillary benefits to FEI's customers in addition to the resiliency benefits.

Issue 11: LNG vessel loading at Tilbury.

In the Phase 2 expansion described in the March 25th CPCN submission and the Project description submitted to BC EAO, the WesPac Marine Jetty project (MJP- now owned by a Fortis subsidiary) predicted LNG vessel traffic of ~ 122 LNG tankers and 90 LNG barges annually at the jetty to service LNG bunkering and export needs– see below extract from WesPac's detailed project description.



Typical medium- sized LNG tankers– numbering most of the 541 (2019 figure) active LNG tankers in the worldwide LNG fleet – have a cargo capacity of 125,000 – 175,000 m3 of LNG[21]. Because of the sloshing hazard[22], these vessels need to be full when voyaging, especially on trans-ocean voyages. The Phase 1A tank holding 46,000 m3 (20,000 tonnes) will **only** half-fill an LNG tanker of average capacity. Nor will it fill an LNG tanker of the ~90,000 m3 (40,000 tonnes) size WesPac/Fortis is proposing. Because there are so few of that capacity in the worldwide fleet. WesPac stated that it would likely need to commission new build tankers of that dimension, and also need a relaxation of the PoV regulations regarding allowable beam widths of vessels plying the Lower Fraser.

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[21] A typical modern LNG ship is approximately 300 meters (m) (975 feet) long, 43m wide (140 feet) wide and has a draft of about 12 m (39 feet). LNG ships vary in cargo capacity, from 1,000 cubic meters to 267,000 cubic metres, but the majority of modern vessels are between 125,000 cubic metres and 175,000 cubic metres capacity. For safe navigation in narrow waterways, these require large tugs, tethered fore and aft to the LNG carrier, that have bollard-pull ratings for 100 tonnes minimum. We know only one such tug that regularly operates in Port of Vancouver.
Source: Giignl https://giignl.org/sites/default/files/PUBLIC_AREA/About_LNG/4_LNG_Basics/giignl2019_infopapers3.pdf

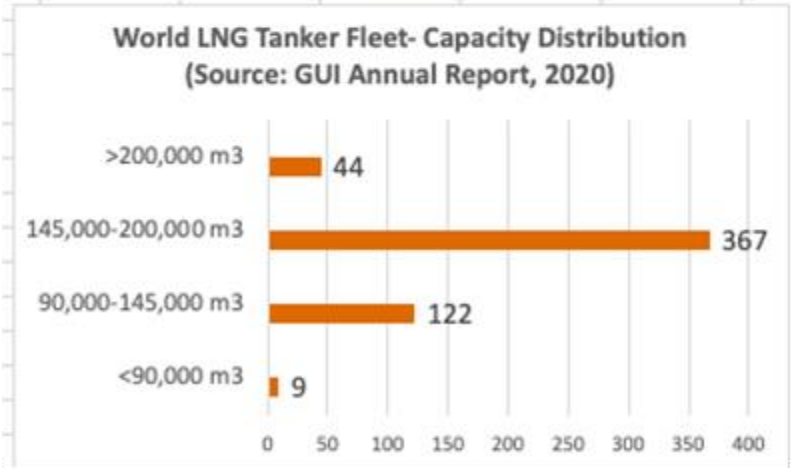
[22] LNG vessels normally operate in a fully laden condition or with a minimum of cargo (heel) during the ballast voyage. In a fully laden condition the typical filling level is greater than 95% of the tank height, and in ballast condition less than 10%. The current design (tank insulation and scantlings) is effective in preventing sloshing impact loads when the vessel is carrying heel only. Source: http://www.liquefiedgascarrier.com/sloshing.html

Table 3-2: Typical Specifications of LNG Carriers, Barges and Current Deep-Sea Traffic

Specifications (Approximate)	Project LNG Barge	Project LNG Carrier	Typical Panamax sized Container Ship
Length (m)	106	242	180-220
Beam width (m)	16.5	38	32
Draft (m)	5.1	10	12
Capacity to ship LNG (m^3)	4,000	90,000*	n/a
Dead weight tonnes (DWT)	NA	Up to 47,000	50,000 to 90,000

*Note: The marine jetty and marine safety items described and evaluated in this Project Description are for LNG Carriers with capacities of up to 90,000 m^3. This size vessel exceeds the current beam width dimension limits for vessels on the Fraser River. Although the vessel dimension policies are under review by PMV in response to the widening of the Panama Canal, dimensions exceeding a beam width of 32.25 m are currently only allowed via an exception from PMV. The beam width currently approved by PMV is 32.25 m. WesPac has requested PMV to evaluate allowing a beam of up to 38.0 m for LNG ships that call at the jetty. PMV has granted exemptions for non- LNG vessels wider than 32.25 m in the past.

In general, WesPac intends to deliver LNG to LNG carriers and barges berthed at the jetty. The receivers of LNG will be required to arrange for marine transportation. The exact number of vessel calls at the jetty will depend on market conditions during operation, but it is estimated that up to up to 122 LNG carrier (of various sizes) calls and 90 LNG barge calls could occur at the jetty per year.



According to the International Gas Union, which reports every year on the world of LNG, including its fleet of LNG carriers, the capacity of the LNG fleet is concentrated in the range of 145,000 m3-200,000 m3, as shown opposite. These have a loaded draught of 13m.-plus, which will restrict them from traversing the Lower Fraser in low-water /slack tide conditions.

WesPac, in its EA submission regarding the Marine Jetty proposal, stated that the LNG tankers visiting Tilbury would be sized in the 90,000 m3 range. As the chart shows, there are only 9 of those representing less than 1.7% of the worldwide fleet of 542 LNG tankers. For that reason, WesPac was proposing to commission building several wide-beamed, shallow-draught LNG tankers capable of sailing, fully-loaded, down the Fraser and over the 11m. draught limitation of the Massey Tunnel.

Questions:

11.i Does FEI foresee using the large "resiliency" storage tank for filling LNG tankers? If so, won't that leave ratepayers' resiliency needs short once the LNG tanker has departed with the contents of the 46,000m3 Phase 1A tank and much of the 162,000 m3 "resiliency" tank's LNG?

Response:

Of the 3 Bcf of storage provided by the TLSE Project, 2 Bcf is required to meet the Minimum Resiliency Planning Objective. Accordingly, FEI will maintain 2 Bcf in the TLSE tank for resiliency purposes at all times. As noted in Section 4.4.1.5.5 of the Application, the additional 1 Bcf provides resiliency above the minimum requirements, while also providing an opportunity to potentially reduce customer rates through the ability to contract storage space in the new tank. Please also refer to the responses to the BCUC IR1 23 series.

11.ii Alternatively, will FEI/TMJ hold the departing tanker for the several days it will take to have Tilbury LNG production from a restored T-South supply refill the "resiliency" storage tank?

Response:

Please refer to the response to MS2S IR1 11.i.

For clarity, there is no specific provision in the TLSE design for import of LNG from a loaded ship.

11.iii Why do ratepayers need to pay for all of this tank if some (or maybe most) of it will be used for private Rate Schedule 46 (RS46) business?

Response:

The TLSE Project will be used to enhance the resiliency of supply to the Lower Mainland as described in Section 4 of the Application. The existing Tilbury 1A tank is used primarily for LNG sales.

Rate Schedule 46 not a "private" rate schedule; rather, it is a BCUC-approved rate schedule, under which FEI makes LNG available to the public. The benefits of these sales flow back to all ratepayers as per established utility ratemaking principles and by regulation (Special Direction 5 to the BCUC).

11.iv How will FEI/TMJ be dealing with the restricted supply of LNG tankers capable of negotiating the Lower Fraser and berthing to load at Tilbury?

Response:

FEI and the entity pursuing the Tilbury Marine Jetty project (TMJ) are separate entities. FEI cannot comment on TMJ's business plans, including its plans related to the supply of LNG tankers.

FEI does not plan to supply or operate LNG tanker vessels on the Lower Fraser and this is beyond the scope of the TLSE Project. The TLSE Project involves the construction of a new tank and regasification units to increase the resiliency of the natural gas supply system to customers in the Lower Mainland.

11.v Will (as WesPac had planned to do) FEI/TMJ be commissioning LNG tanker newbuilds of the~90,000 m3 dimension?[23] specially built for the restrictions of the Lower Fraser?

Response:

FEI and the entity advancing TMJ are separate entities. FEI has no plans to commission LNG tanker newbuilds as part of the TLSE Project, or otherwise.

[23] The fleet is relatively young and vessels under 20 years of age make up 91.1% of the overall fleet, which is aligned with developments and growth in recent years in liquefaction projects. Newer vessels are larger and more efficient, with far superior project economics for their operational lifetime. The global fleet is young, as only 11 active vessels are aged 30 years or older, including three that have already been converted to FSUs. At the end of 2019, there were approximately 20 vessels laid-up around the world.

Issue 12: Transparency of language (i.e. a lack thereof).

Section 4.4.1.5.5 , "LARGER TANK PROVIDES THE POTENTIAL TO REDUCE CUSTOMER RATES" of FEI's CPCN application states that:

"The construction of a 3 Bcf tank versus a 2 Bcf tank provides opportunities for load growth that would have the potential to reduce rates for customers. The construction of a new pipeline in BC will proceed when supported by load growth in the region. Additional pipeline capacity into the region could provide the opportunity for further expansion of the Tilbury site with additional liquefaction to support LNG for export. Discussions 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. LNG from Tilbury has a production carbon intensity up to 30 percent lower than global average LNG[24]. Its use can reduce GHG emissions from marine shipping by up to 27 percent compared to petroleum-based fuels. Further, its use can reduce industrial GHG emissions in China by 30 to 50 percent compared to domestic energy sources such as coal.101

This potential scenario provides significant future optionality and a potential reduction in FEI's customer rates in the scenario where a new pipeline into the Lower Mainland is constructed that follows an entirely separate corridor from the T-South system along with an expansion at the Tilbury site. FEI explains in further detail below.

While an uncertain and contingent event, the expansion of the Tilbury LNG site would likely include a large amount of liquefaction capacity up to 3 million tonnes per annum (approximately 12 times the size of Tilbury 1A and 60 times the size of the Tilbury Base Plant liquefaction). This amount of liquefaction capacity at the Tilbury LNG site could change FEI's operating paradigm, including its storage needs. For example, FEI could enter into a commercial arrangement to utilize a small amount of the bulk export liquefaction capacity to backstop liquefaction outages associated with Tilbury 1A and 1B liquefaction, thereby freeing up 1 Bcf of storage capacity from the Tilbury 1A tank. With the additional pipeline supply into the Lower Mainland, as discussed in Section 4.2.4.5 above, FEI could potentially further reduce its storage needs by entering into commercial arrangements to provide access to other contingency resources. This could potentially allow FEI to lease storage space to the export entity, thereby recovering a portion of the cost of service of the Project while maintaining an enhanced level of resiliency. Should this opportunity materialize, there is the potential to reduce FEI customers' costs; however, it is unlikely that a 2 Bcf tank under this scenario would free up enough space to take advantage of such an opportunity. Therefore, the construction of storage capacity above the minimum requirements enhances FEI's potential to reduce rates through storage lease opportunities".

Questions:

12.i Please provide a much clearer explanation of the point of this opaquely-worded, but seemingly important, section (preferably with fewer than seven occurrences of

[24] FEI- Tilbury GHG emissions https://iaac-aeic.gc.ca/050/documents/p80496/133941E.pdf(Table 6.1)

the word "potential"). Please explain what, exactly, FEI is proposing for the private-sector use of the publicly-funded resiliency tank, and what, if any, public benefit would be derived from that use.

Response:

FEI is not proposing any third-party use of the TLSE infrastructure at this time. The opportunity to contract out storage space in the TLSE tank was identified as one of the ancillary benefits from constructing a larger 3 Bcf tank (as discussed in Section 4.4.1.5 of the Application). Please also refer to the responses to the BCUC IR1 23 series for more details on how storage space in the TLSE tank could be contracted for the benefit of FEI customers.

12.ii For the latter, please explain how the reduction in "FEI customers' costs" would be tracked, audited and returned to Customers.

Response:

If TLSE tank storage contracting opportunities arise, the revenue generated from the contract would be tracked separately in a revenue account under "Other Revenue" that is part of FEI's revenue requirement. Other revenues are returned to FEI's customers through delivery rates in FEI's revenue requirements (i.e., other revenues reduce FEI's revenue requirement for delivering natural gas to customers). Other revenues are reviewed and approved by the BCUC on a regular basis as part of FEI's annual rate setting processes that determine FEI's delivery rates.

12.iii Now that Fortis is the owner of the marine jetty project, please explain how the statement "*Tilbury has a production carbon intensity up to 30 percent lower than global average LNG*" in its BCUC submission (P. 115) would change if upstream emissions are included/ the word "production" is excluded. We refer FEI to P. 6 of the May 9, 2019 presentation by WesPac Marine Jetty consultant Golder & Associates) , which stated that upstream GHG emissions associated with producing, treating and transporting the gas to the expanded Tilbury plant and marine jetty, would be in the range of 1.7 -2.4 million tonnes per annum.

Response:

For clarity, FEI is not the owner of the TMJ, nor is liquefaction part of the TLSE Project. However, FEI's statement in Section 4.4.1.5.5 of the Application explains the potential for LNG to reduce global GHG emissions by displacing other fuels.

FEI's term 'production carbon intensity' is based on a lifecycle scope of all GHG emissions associated with the extraction, transmission and liquefaction of natural gas. 'Production' in this sense includes all emissions associated with the production of LNG. This excludes GHG emissions from the delivery of LNG to end-users and the consumption of LNG by those end-users. In this sense, the statement would remain unchanged if FEI excluded 'production' because upstream emissions are included in the definition of production.

Tilbury produces LNG using electricity from BC Hydro, whereas most global LNG is produced using power generated onsite by gas turbines, with associated CO_2 emissions. Because of this, the liquefaction process is much less carbon-intensive than the global average. For a more detailed description of the lifecycle emissions associated with Tilbury LNG, please refer to the following link:
https://talkingenergy.ca/topic/analysis-highlights-environmental-benefits-tilbury-lng-marine-fuel.

12.iv Will any volume of this storage tank, paid for by ratepayers, be used for FEI's private business interests?

Response:

As a regulated public utility under the *Utilities Commission Act*, FEI's business interests are regulated by the BCUC.

Please refer to the responses to the BCUC IR1 23 series for detailed information regarding the question of contracting out storage space in the TLSE tank. Any future contracting of storage space would itself be subject to BCUC oversight.

12.v Is this proposition attempting to convert ratepayers paying for this tank into unwitting investors in a risky venture to ship Tilbury LNG to Asia and bunker vessels in West Coast ports?

Response:

No. Please refer to the responses to the BCUC IR1 23 series for clarification of the TLSE Project and how it is connected to the Tilbury Phase 2 LNG Expansion Project EA, as well as for details on the potential to contract LNG storage space.

12.vi How would lease revenues be accounted for and remitted to ratepayers?

Response:

Please refer to the response to MS2S IR1 12.ii.

12.vii How would costs be allocated (between regulated and unregulated uses of the storage tank)?

Response:

Please refer to the response to BCUC IR1 23.3.

12.viii Would ratepayers be afforded an 8.75% guaranteed return on their investment?

Response:

In setting delivery rates, FEI uses its regulated return on equity (ROE) of 8.75 percent and equity thickness of 38.5 percent, as approved by BCUC Order G-129-16. FEI's ROE and capital structure are reviewed periodically by the BCUC. FEI notes that its allowed ROE is used for rate-setting purposes on a forecast basis, and does not guarantee that return, as many items can cause FEI's actual ROE to vary from that allowed for rate-setting purposes.

To the extent that investments are included in FEI's rate base (like the TLSE Project, if approved), FEI's allowed ROE and capital structure will be applied to them in setting rates. FEI's allowed ROE and capital structure is not applied to any projects outside of the regulated utility (such as the Liquefaction Facility).

Issue 13: Inconsistency of project applications.

FEI's applications to BCUC and to BC EAO /IAAC describe substantially different attributes of what appears to be the same project. The former (BC EA) describes a huge increase in liquefaction and storage and a new marine dock, the latter (BCUC) a huge increase in liquefaction and regasification, with no mention of the liquefaction or dock elements.

Initial Project Description- EA process*	Project Description- BCUC application (TLSE)
The Tilbury Phase 2 LNG Expansion Project (the Project) is being proposed to increase the production and storage of LNG to improve security of supply to FortisBC's approximately 1.1 million natural gas customers in BC and to supply incremental LNG to the marine transportation and export markets. The Project also introduces opportunities to upgrade existing infrastructure to current design standards and technologies and to align with the Government of BC's CleanBC Plan. The Project comprises an expansion of up to 142,000 cubic metres (m^3) (approximately 3.5 petajoules [PJ]) of LNG storage and up to 7,700 tonnes per day (t/d) of LNG production. The Project will receive natural gas at the Project Site through established pipeline systems. It will connect to FortisBC's existing LNG facilities (such as, vaporisation and gas send-out facilities) to support security of natural gas supply to gas utility customers and the proposed WesPac Midstream Ltd. (WesPac) Tilbury Marine Jetty project for marine LNG bunkering and LNG export.	FortisBC Energy Inc. (FEI or the Company) applies to the British Columbia Utilities Commission (BCUC), pursuant to sections 45 and 46 of the *Utilities Commission Act* (UCA), for a Certificate of Public Convenience and Necessity (CPCN) for the Tilbury Liquefied Natural Gas (LNG) Storage Expansion Project (referred to as the TLSE Project or the Project) as described in this application (the Application). FEI also seeks related approvals pursuant to sections 59 to 61 of the UCA: approval of a depreciation and net salvage rate for the proposed new LNG storage tank; and, approval of two new deferral accounts. The Project, which entails replacing the 50-year old Tilbury Base Plant with a new 3 Bcf LNG storage tank and 800 MMcf/day of regasification capacity at a cost of $768.998 million in as-spent dollars and including AFUDC, is a *resiliency* investment. That is, it will significantly improve FEI's ability to maintain continuity of service in the event of a disruption in the supply of natural gas to FEI's system. While primarily targeted at improving resiliency, it will also bring valuable ancillary benefits for system operations and customers.

Questions:

13.i Please explain why these applications, apparently for the same project, are so different in their descriptions? Please explain how this is not an attempt to zigzag through the EA/CPCN regulatory processes?

Response:

The Tilbury Phase 2 LNG Expansion Project as described in the environmental assessment is inclusive of, but not limited to, the TLSE storage tank. As noted in the response to BCSEA IR1 3.10, the Initial Project Description for the FortisBC Tilbury Phase 2 LNG Expansion project was filed early in the overall development of the TLSE Project resiliency solution. The need for, and purpose of, the Tilbury Phase 2 LNG Expansion Project (which includes but is not limited to the TLSE storage tank) is described in the updated Detailed Project Description. The description of the TLSE Project in the materials filed in this Application is accurate and up to date.

13.ii Please confirm that the Phase 2 expansion of Tilbury's LNG liquefaction capability (7,700 tpd) is in addition to the existing/planned (Base+ Phase 1B+ Phase 1B) capabilities totalling 10,460 tpd (3.82 MTPA).

Response:

Confirmed. However, FEI notes that this CPCN Application is in relation to a storage facility being developed by FEI for resiliency purposes, not the liquefaction facilities referenced in the question.

13.iii FEI/Tilbury Marine Jetty (TMJ) does not have a CER LNG export license. Please confirm that FEI/TMJ plan to transfer the 25-year export license from the 4.76bcm/ 3.45MTPA one WesPac Midstream got from NEB in May 2015? We note that, should LNG shipments not commence by May 2025, this license will automatically expire.

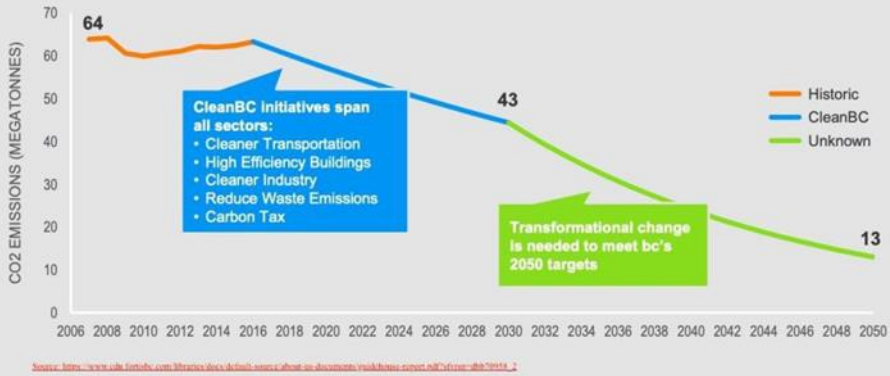
Response:

This CPCN Application is in relation to the TLSE Project storage and regasification facilities being developed by FEI, not the facility referenced in the question which is being developed by another entity. FEI does not need an export license for the TLSE Project.

Issue 14: BC climate plan and Government policy.

Spurred by reports from the UN's IPCC body and growing citizen concerns, Canada has declared a climate emergency. BC has (in part) followed suit with its "CleanBC" initiative. Back in 2007, at a time when British Columbia was thought of as an international leader in the effort to reduce planet-warming emissions, the Greenhouse Gas Reduction Targets Act was passed. That Act had a 2020 target of reducing GHG emissions by 33 per cent below those of 2007. BC has missed that mark by a mile, so the Government revised the Act, which now commits British Columbia to reduce GHG emissions as shown in the diagram below. Translated to numbers, that means BC's 64 million tonnes per annum (MTPA) of GHG emissions must be reduced 21 MTPA (to 43 MTPA) by 2030 and by 51 MTPA (to 13 MTPA) by 2050. That is a tall order.

FIGURE 1. BC GHG EMISSIONS AND TARGETS



Source: Government of Canada – Canada's Greenhouse Gas Inventory; Government of British Columbia – CleanBC; Guidehouse Analysis

On March 26th, the B.C. government announced its 2030 sectoral carbon reduction targets (from 2007 levels)

These were:

- transportation: 27% to 32%
- industry: 38% to 43%
- oil and gas: 33% to 38%
- buildings and communities: 59% to 64%

West Coast Environmental Law estimates that, as a sector, Buildings & Communities must reduce emissions to between 4.8 and 5.5 MTPA (59%-64% below the 2007 figure of 13.4 MTPA). That ambitious target will require extensive fuel-switching among homeowners – from gas-fired furnaces to electric heat- pump and other non-fossil fuel energy technologies. And a raft of lifestyle changes.

An eminent expert (Tom-Pierre Frappé-Sénéclauze, director, building and urban solutions, Pembina Institute) commented on the implications of this for the buildings sector in BC. *"Achieving a 2030 reduction target from the building sector set above 60% will necessitate rapid electrification of most natural gas heated homes and buildings in B.C. More than 80,000 dwellings*

will need to be upgraded each year with high efficiency heat pumps. Paired with upgrades to make our homes less drafty, better insulated and ventilated, this will increase the durability and safety of our homes, keeping them comfortable through extreme heat and deep freezes, while improving indoor air quality. It will also create 22,000 new clean jobs, and up to $50 billion in economic growth. B.C.'s next mega-project is a win-win-win for climate, health, and economy."

CleanBC[25] states that "*as we move forward, utilities will continue to support, encourage and enable the transition to clean energy as we ensure their policies align with the provinces electrification goals and omission reduction targets*". The expansion of Tilbury LNG would (per FortisBC's EA submission) release at least 230,000 tonnes directly from the Tilbury plant, which would place it among BC's top 20 point sources. This is coupled with upstream wellhead, flaring/venting and pipeline ("fugitive") emissions of ~ 2.4 million tonnes annually[26], and the ~14 million tonnes p.a. from shipping, regasification and end-use combustion.

Also, in reference to the BC Clean Energy Act –Fortis states: "*Section 46(3.1) of the UCA states that in considering whether to issue a CPCN, the BCUC must consider the applicable of British Columbia's energy objectives*".

Questions:

14.i How can this proposed expansion of BC's fossil-fuel infrastructure possibly be reconciled with Federal and Provincial government policies and legislation emphasizing the urgent need to move off fossil fuels and cut gas consumption roughly in half by 2030?

Response:

Please refer to the response to BCUC IR1 63.1 for discussion on how the TLSE Project aligns with provincial climate policies and legislation, which seek to reduce emissions by 40 percent by 2030 (not "cut gas consumption roughly in half by 2030").

14.ii Please explain how expanding the Tilbury facility, and directly emitting over 226,000 tonnes of GHGs annually into Metro Vancouver's air, can be reconciled with Federal and Provincial climate change policies?

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[25] CleanBC also states that: "British Columbia has set a target of reducing provincial greenhouse gas (GHG) emissions by 40% below 2007 levels in 20301. Subsequent targets call for reductions of 60% in 2040 and 80% in 2050. *Achieving these targets requires strong policies to shift BC's energy system towards low- and zero-carbon sources of energy and processes".*

[26] In a May, 2019 report commissioned by WesPac Midstream for its Tilbury jetty project (now owned by Fortis), consultant Golder & Associates estimated the annual upstream emissions associated with the Tilbury expansion at 1.75-2.4 million tonnes p.a. That would add ~ 4% to BC's total current GHG emissions of ~ 64 million tonnes per year.

Response:

The GHG emissions figure referenced in the question does not relate to the TLSE Project as its annual incremental emissions are expected to be minimal. Rather, the emissions in the question relate to the Liquefaction Facility in the Tilbury Phase 2 LNG Expansion Project. Please also refer to the response to BCUC IR1 63.1.

14.iii Please explain how these emissions can be reconciled with FortisBC's "30by30" emissions reduction target? (We note that Article 6 of the Paris Accord, which could allow trading of international carbon credits between countries, has been neither agreed nor ratified, and so such possible credits cannot be presented as arguments supporting fossil-fuel exports).

Response:

Please refer to the response to MS2S IR1 14.ii.

14.iv Please explain how this expansion is to be reconciled with Fortis Inc.'s own corporate-wide target of 75% reduction in GHG's by 2035 (compared to 2019 levels - https://www.fortisinc.com/sustainability/environment)?

Response:

As discussed in the response to the response to MS2S IR1 14.ii, the annual incremental GHG emissions from the TLSE Project are expected to be minimal. Regardless, Fortis Inc.'s corporate-wide emissions reduction target considers emissions from planned project additions like the proposed TLSE Project.

Issue 15: Reliability of the PWC Analysis (FEI Application, Appendix B).

This report, titled "*Fortis BC - the case for improved system resiliency June 2020*" is largely redacted in the released version available to intervenors and interested parties unwilling to sign FEI's NDA. However, there are several troubling aspects to any reliance on this report to justify this expansion, including:

- Small sample size: The findings and conclusions of the report are based on interviews with, at most, 22 customers – 9 industrial, 4 commercial, 9[27] institutional and 0 (zero) Residential. There were almost the same number of interviews (18) with FortisBC management. Deriving statistically-valid, accurate conclusions from such small samples is not at all possible. To be fair, PWC does highlight this as a serious deficiency of the report and its conclusions;
- The scenarios and impacts presented by PWC in the customer interviews were (i) a low impact scenario of a 4-day outage in cold-weather conditions and (ii) a high-impact scenario of a 6-week outage/production halt in cold-weather conditions. Neither is consistent with the 2-3 day resiliency scenario FEI is presenting in this application;
- The report states that "*Consumer interviews were selected to provide coverage of those sectors which are heavy natural gas users and represent a significant share of the BC economy. Combined, the consumer interviews covered sectors representing over 70% of the FEI system gas consumption*". However, the below analysis of FEI's published customer makeup and demand profiles show that statement to be a very questionable, if not misleading, statement;

From Fig.3-3 (P. 17) of FEI's 2020/2021 ACP BCUC LETTER L-31-20 COMPLIANCE REPORT

Customer Group	Rate Schedule	Group	Number	Average Usage p.a. (GJ)	Annual Usage (GJ)	% of Total Demand	Load Factor
1	1	Residential	934,667	86	80,381,362	51%	32%
1	2	Commercial	88,318	332	29,321,576	19%	31%
1	3	Commercial	6,333	3,612	22,874,796	14%	38%
1	23	Commercial	1,511	5,056	7,639,616	5%	37%
2	5	Industrial*	355	14,792	5,251,160	3%	46%
2	25	Industrial*	475	26,686	12,675,850	8%	56%
		Total	***1,031,659***		***158,144,360***	***100%***	

	Number	% of Customer Base	Annual Usage (GJ)	% of Total Demand	Avg. Monthly Usage/ Customer Group (GJ)
Customer Group 1	**Res. & Comm.**	1,030,829	99.92%	140,217,350	89%	11
Customer Group 2	**Industrial***	830	0.08%	17,927,010	11%	1,799.90
	Total	***1,031,659***	***100%***	***158,144,360***	***100%***	

*: Volumes for RS46 customers are apparently not included here

[27] BCIT is listed twice – it is unclear if these are for separate campuses, or a typo.

This analysis (sourced from FEI's 2020 ACP report) shows that, together, Industrial customers account for only 11% of total gas demand, while Commercial (38%) and Residential (51%) customers together account for 89%. Yet the PWC analysis included interviews with only 13 (about 0.0013%) of the Commercial and Residential customer base who together constitute 89% of FEI's gas demand. Because the economic and social impact figures are redacted in FEI's application, it is unclear how, or if, the PWC analysis dealt with this lopsidedness (technically called "sample bias") in the approach to information gathering. Lacking any supporting information to the contrary, it seems fair to conclude that PWC's conclusions cannot be relied upon for such an important decision.

- The report uses input-output analysis, a highly-controversial econometric tool when used to evaluate the economic impacts of resource-industry projects. Australian courts, which have seen much litigation of LNG projects proposals that used this technique for justification, have all but banned its use for cost-benefit analysis of resource projects (see https://www.pc.gov.au/research/supporting/input-output-tables/input-output-tables.pdf and https://www.smh.com.au/business/economists-blackened-by-coalmine-20140411-36irb.html and https://australiainstitute.org.au/post/expert-evidence-given-to-case-against-adani-coal-mine-at-carmichael/ and http://focusonline.ca/?q=node/695%20). https://www.pc.gov.au/research/supporting/inut-output-tables/input-output-tables.pdf. BC's experience with the tool is no less controversial – it formed the basis of the now-infamous 100,000 jobs, $100 Million heritage fund, debt-free BC LNG election promise in 2013 https://www.policyalternatives.ca/sites/default/files/uploads/publications/BC%20Office/2015/07/ccpa-bc_LNG_Employment_web.pdf and and https://www.straight.com/news/500321/martyn-brown-bcs-lng-con-job.
- The report uses a $138/tonne "social cost of carbon" number to estimate the socio-economic impact of increased GHG emissions due to the use of higher-emitting fuel substitutes in a supply outage. However, it fails to then factor the reduced emissions due to lower economic activity in a prolonged gas outage. This seems quite one-sided. Further, it fails to include the 2.7 million tonnes of annual GHG emissions from upstream (fracking, venting, flaring, pipeline fugitives and direct (at-plant) emissions that building and operating the Tilbury plant will trigger.

Question(s):

15.i Please explain how any statistical validity can be attributed to a report with such fundamental methodological and analytical flaws?

Response:

The following response has been provided by PwC:

We consider that the approach used in the analysis is appropriate and in-line with the approach taken in other studies of this type. This report and related analysis must be considered as a whole. Selecting only portions of the analysis or the factors considered by us, without considering all factors and analysis together, could create a misleading view of our findings. The preparation

of our analysis is a complex process and is not necessarily susceptible to partial analysis or summary description. Any attempt to do so could lead to undue emphasis on any particular factor or analysis.

Small sample size

While there are tens of thousands of gas customers in BC, very few would be able to robustly answer the interview questions required by the study, as doing so requires detailed and specific knowledge on issues including:

- How gas outages would impact production in their organization and others like it in the same sector;
- The extent of backup energy systems in place;
- Mitigating activities the organization would undertake; and
- How the mitigating activities would evolve over the short, medium and long term.

In practice, even a major organization with thousands of employees would likely have only a handful of employees able to answer these questions and therefore be included in the study population (e.g. the head of operations). Characterizing the survey population as "1 million" and the sample size as "0.0013%" is not correct as this implies every gas customer in BC has detailed operational knowledge of major gas users in BC.

On the approach more broadly, we note that other studies. conducted by governments and academics on the impact of energy outages, have adopted or advise adopting similar methodology which makes use of a sample of energy user interviews and surveys to estimate outage costs. These studies were reviewed by PwC and used to inform our methodology.

Previous studies adopting/advising a similar methodology on this topic include the following:

- A report commissioned by the UK government and conducted by ILEX Energy Consulting on the economic implications of gas supply interruptions to UK industry relied on interviews with the major companies and/or the trade organisations in each of the sectors that contain energy intensive industry.[28]
- A report authored by Ernest Orlando Lawrence Berkeley National Laboratory for the US Department of Energy provides a guidebook for electric utilities for estimating power system interruption costs.[29] The authors of the report recommend that direct cost estimates of power system interruptions from commercial and industrial users should be obtained from non-residential customers through telephone or in-person interviews with specific personnel that are familiar with the facility, operations and cost structure.

[28] Ilex Energy Consulting, "Economic implications of a gas supply interruption to UK industry – a report to DTI", Oxford, January 2006.

[29] Sullivan, Michael, et al. "Estimating power system interruption costs: A guidebook for electric utilities." 2018. https://eta-publications.lbl.gov/sites/default/files/interruption_cost_estimate_guidebook_final2_9july2018.pdf.

- A study published by Harvard University provides a number of methods to estimate outage costs, including surveys and interviews to provide information such that costs may be linked to duration, frequency, and timing of an outage.[30] According to that study, *industrial and commercial customers may be able to fairly accurately assess direct costs of an outage. (...) Further, customers (particularly in the residential sector) may have difficulty consistently valuing a hypothetical situation posed in a contingent valuation survey particularly if the hypothetical is unrealistic or they have little or no experience in such situations*.

Scenarios

Scenarios are hypothetical events used to evaluate potential impacts of supply disruption and were designed to be both realistic (i.e. a mix of less extreme to more extreme scenarios), while also considering an exhaustive range of parameters. 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.

The intent was that the study would assess the potential impact of natural gas disruption and provide the province and the energy industry with data to help weigh the costs and benefits of different infrastructure investments to enhance system resiliency in the province. PwC was not engaged in FEI's resiliency planning.

Input output modelling approach

Input-output modelling is a widely used approach by economists to measure economic impacts of different scenarios and it is recommended as a tool for doing so by the Government of Canada and governments around the World. For example, the Federal government lists input-output analysis as a tool to perform economic impact assessments in its documentation for the *Impact Assessment Act*[31].

[30] Centolella, Paul. "Estimates of the Value of Uninterrupted Service for The Mid-West Independent System Operator.", 2010. https://hepg.hks.harvard.edu/files/hepg/files/voll_final_report_to_miso_042806.pdf.

[31] Impact Assessment Agency of Canada, Analyzing Health, Social and Economic Effects under the *Impact Assessment Act*. Link: https://www.canada.ca/en/impact-assessment-agency/services/policy-guidance/practitioners-guide-impact-assessment-act/analyzing-health-social-economic-effects-impact-assessment-act.html.

Many published studies by the government of Canada also make use of this tool, examples include studies by Global Affairs Canada (GAC)[32], Innovation, Science and Economic Development Canada (ISED)[33], and the Canadian Space Agency[34].

The reason why input-output models are widely used is that they provide a consistent way to compare between scenarios and are often the most accessible tool for analyzing the short-term impacts of a shock on output and income. In a regional context, these models are often used for estimating distributional and short-term transitional impacts of a scenario on the economy[35].

Like every modelling approach input output models are a simplification of reality and have limitations. Choosing an appropriate modelling approach comes down to assessing which model comes with the least restrictive limitations given the scope of the analysis, the objective of the study, and the constraints and resources of the project. Based on the issue at hand and the scope of this study we consider that input-output modelling was the most appropriate approach to use.

The key critique of input output modelling, as referenced in the question through the links to the Australian government articles[36], is that when a major increase in demand is simulated the model assumption that there are no capacity constraints can distort the results. For example, if a large mine is constructed in a rural area then the assumptions of no labour constraints may not hold and in practice the increase in demand may not have the modelled impacts as constraints to labour may prevent delivery of the project or bid up prices and wages. This issue is specific to a positive demand shock, the PwC study simulates a negative demand shock so such capital and labour constraints would not be an issue.

The other article referenced in one of the questions submitted examines the BC government's claim that 100,000 jobs will be created from liquefied natural gas (LNG) projects in this province.[37] It should be noted that two major problems identified in the article are not relevant to the analysis prepared by PwC.

First, the economic impact of the BC LNG export sector was assessed using a custom built, hypothetical sector that does not currently exist. This is not the case for the natural gas distribution sector in BC which is modelled based on actual historic data published by the government of BC.

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[32] Canmac Economics Limited (2020), Economic impacts of international education in Canada - 2020 update, Report prepared for Global Affairs Canada. Link: https://www.international.gc.ca/education/assets/pdfs/economic_impact_international_education_canada_2017_2018.pdf.

[33] Innovation, Science and Economic Development Canada (2019), State of Canada's Aerospace Industry. Link: https://www.ic.gc.ca/eic/site/ad-ad.nsf/eng/h_ad03964.html.

[34] Euroconsult (2015), Comprehensive Socio-Economic Impact Assessment of the Canadian Space Sector, Report prepared for the Canadian Space Agency. Link: https://www.asc-csa.gc.ca/eng/publications/2015-assessment-canadian-space-sector.asp.

[35] U.S. Environmental Protection Agency (2010), Guidelines for Preparing Economic Analyses. Link: https://www.epa.gov/sites/default/files/2017-08/documents/ee-0568-50.pdf.

[36] Titled On input-output tables: uses and abuses, as well as quoted in expert evidence given to case against Adani coal mine at Carmichael, Australia: It (input-output modelling) is inappropriate for this sort of project assessment as it is mathematically certain to overstate employment effects as it assumes there is an infinite supply of skilled labour.

[37] https://www.policyalternatives.ca/sites/default/files/uploads/publications/BC%20Office/2015/07/ccpa-bc_LNG_Employment_web.pdf.

Second, as noted earlier, the input-output model's assumption of unlimited supply of labour and capital is not an issue in a negative demand shock.

$138/tonne "social cost of carbon" and not factoring in the reduction in CO2 from economic impacts.

Assessing the CO2 reduction resulting from the negative economic impacts of the gas outage or the Tilbury plant was not in the scope of this study and the PwC analysis focused only on the substitution effects from shifting to dirtier fuels as back-up in an event of natural gas disruptions.

15.ii With the identity of the interviewed customers removed, what is the fundamental issue with un- redacting the findings and conclusions of this foundational report, flawed though it most certainly is?

Response:

The issues of confidentiality, including with respect to the referenced report, were thoroughly canvassed at the outset of this proceeding. In Order G-161-21, the BCUC made its determination with respect to confidentiality, including directing FEI to disclose confidential security-sensitive information contained in the Revised Confidential Application to interveners that sign the BCUC Confidentiality Declaration and Undertaking form and Revised NDA.

In the Decision attached to the Order, the Panel noted that FEI responded to intervener concerns regarding specific language in the proposed NDA, and considered the amendments in the Revised NDA to be reasonable. The Panel further stated that the: "[…] Revised NDA is proportionate in terms of providing protections to FEI without unduly burdening interveners. The Panel observes the requirement to sign such an NDA is consistent with the addition of 'conditions and safeguards' as provided by section 24.03 of the BCUC's Rules of Practice and Procedure."

15.iii Are we to assume, because no interviews with Residential customers were conducted, that ~ 1 million Residential customers, representing 51% of total gas demand and the overwhelming majority of the customer base, are irrelevant to this impact analysis?

Response:

The following response has been provided by PwC:

Residential customers are defined as one of four key consumer stakeholder groups within the study that will be impacted by a disruption. Each of the interviewees were residents of BC and many of the questions were linked to an individuals' personal experience as well as the knowledge of their institution/company. It is therefore incorrect to characterise the study as having ignored the impact on residents.

Moreover, a number of key impacts to the residential stakeholder group associated with the loss of gas supply, including risk of increased morbidity / mortality, and disruption of education / health / emergency services, were identified. These impacts were more appropriately defined by primary research and interviews with public services and institutions that play important roles in residential customer's lives (e.g., school district, waste management, health authority) and have a broad perspective on a large cross section of the residential stakeholder group that they serve.

The categorisation of industrial, commercial and institutional interviewees was related to application of these interviews to the economic analysis.

Please refer to the response to MS2S IR1 15.i (Small sample size) above.

15.iv Is there supporting data and analysis of the extent to which major customers (hospitals, MURBs, community centres etc.) have backup power facilities in-place, including the means to switch to alternate power sources (grid electricity, other fossil fuels, onsite generation)?

Response:

The following response has been provided by PwC:

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) interviews. Key interview questions included: experience of past natural gas disruptions (notably the Enbridge event), the impact of an outage on operations, mitigation processes in place (e.g. backup systems), costs incurred due to the disruption, and social and environmental implications. Our analysis did not then explore the efficacy of stakeholder risk management plans which may or may not present risk similar to FEI's system resiliency.

PwC has relied upon the completeness, accuracy, and fair presentation of all information and data obtained from the various sources in our report, which were not audited or otherwise verified.

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, laundry) may be limited.

15.v Do we have any substantive evidence from BC Hydro that, in a worst-case T-South rupture, its grid could not support the increased demand caused by customers using electricity for space and domestic hot water heating? Is there any evidence from other jurisdictions that supports that conjecture? (Note: As noted in BC's recent hot spell, BC Hydro's peak demand are increasingly for air conditioning in the hot Summer months, when gas demand is lowest)

Response:

Please refer to the response to MS2S IR1 4.iii which discusses the loads served by FEI's gas system as compared to BC Hydro's electric system during cold winter weather as well as the implications of a sudden shift in heating load during winter conditions.

Please also refer to the response to RCIA IR1 10.1 for discussion of FEI's engagement with BC Hydro in regard to impacts of a widespread gas outage on BC Hydro's electrical system.

Issue 16: The Phase 1A storage tank reserved for RS46 (tanker-truck sales).

As is shown in the Tilbury expansion history table (Issue 8), the 46,000m3 (20,000 tonne) Phase 1A tank was approved without a CPCN. The related Order in Council (OIC 557 2013) directed BCUC to bypass the normal requirement for a CPCN for it. This strongly suggests that BC ratepayers paid (or are paying) for the Phase 1A tank in their rates, for which FEI has garnered an 8.75% guaranteed annual return on the $400M-plus investment.

Question:

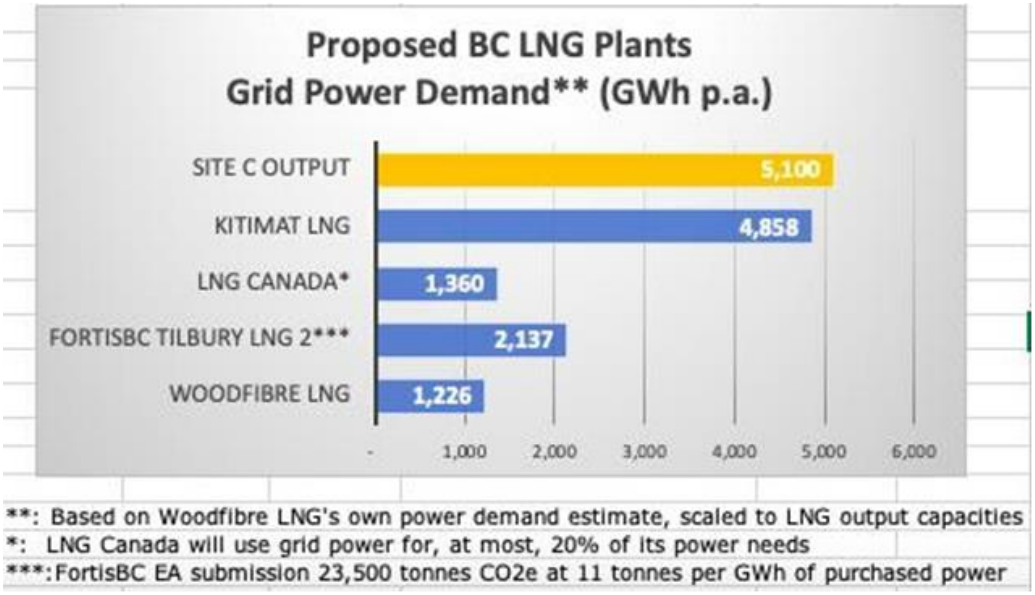
16.i Please explain why FEI now indicates in this application (P. 62) that the Phase 1A tank will be reserved for private RS46 sales, and not included in the resiliency requirement for this application …. or the cost returned to ratepayers through lower rates.

Response:

The Tilbury Phase 1A facilities were built pursuant to an Order in Council to support LNG sales under the BCUC-approved Rate Schedule 46, and as such that is its primary purpose. While any LNG in the Tilbury 1A tank at the time of an emergency may be used to avoid widespread outages, FEI cannot plan its emergency response based on the assumption that LNG will be available in the Tilbury 1A tank. During the normal course of business, FEI is actively making the LNG in the Tilbury 1A tank available to customers under Rate Schedule 46. Please also refer to the response to BCUC IR1 11.9.

Issue 17: Use of scarce electrical power, effects on consumer affordability.

According to its EA submission[38], Fortis plans to power the Tilbury expansion with grid electricity supplied by BC Hydro via its Arnott substation in Ladner/S. Delta. The quantity of power is not specified. However, the graph below shows Tilbury's estimated power consumption and those of the remaining proposed LNG plants in BC, and a reference to Site C's $16 Billion project, expected to come online by 2023.



According to CER[39], 66% of BC's 2017 1251PJ of energy consumption is provided by refined petroleum products (36%) and natural gas (30%) – and only 18% by cleaner electricity[40]. Transitioning to an electricity-powered economy – as is urgently required if BC is to meet legislated CleanBC emissions targets and deal effectively with climate change - will therefore place a premium on the judicious use of every megawatt of clean electrical power the province can generate.

In 2018, B.C. generated ~74,200 gigawatt hours (GWh) of electricity. Hydro's marginal cost of production , estimated at circa $0.13 per KWh in 2021, is far greater than its $0.06/Kwh Industrial rate for power. This is effectively a cross-subsidization by most /all of FEI's 1M+ ratepayers, most of whom are also BCHydro ratepayers (2M+, 98% of whom are residential customers).

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38 https://iaac-aeic.gc.ca/050/documents/p80496/133941E.pdf .P. 1-8

39 https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/provincial-territorial-energy-profiles/provincial-territorial-energy-profiles-british- columbia.html

40 BC's electricity generation is around 91% from hydroelectric sources. However, BC trades in electricity- importing when it is cheap to buy on the Mid-C trading hub, exporting when expensive. During the first 11 months of 2019, Powerex exported about 4.5 TWh of electricity and imported about 10.7 TWh-BC was a net importer. Through this may be a financial wind for BC, US electricity is not as clean as BC electricity, and this trade deficit makes electricity consumed in BC less clean than advertised, as this article explains.

Question(s):

17.i Roughly, what will Tilbury's (electrical) power requirements (MW, GWh p.a.) be for (i) Phase 1B; (ii) Phase 2 expansion phases of Tilbury LNG?

Response:

The maximum power consumption for the TLSE Project will occur during sendout activities. The corresponding power draw for operation of the four vapourizers, LNG pumps, and process control and safety systems will be approximately 6 MW. For greater certainty, this consumption only occurs at the times when maximum vapourization and sendout is in use, which is infrequent. During normal operations, the power required to operate the process control equipment and boil-off gas systems for the TLSE tank is approximately 0.5 MW.

As per the BC Hydro website, the average household in BC uses approximately 900 kWh per month[41]. The website also notes that the power consumption is based on a household not using electric heat, which could increase consumption five to six times over the winter months. When using the higher winter consumption number, this would correspond to a consistent load of approximately 7.5 kW per household. Therefore, the 6 MW Tilbury peak load is equivalent to approximately 800 electrically-heated homes. As such, this modest amount of power draw would have little impact on the electrical grid during a no-flow incident.

The electrical power requirements for Tilbury Phases 1B and 2 have not yet been determined, nor are they within the scope of the subject Application.

17.ii What amount of power will the 4 regasifiers draw?

Response:

Please refer to the response to MS2S IR1 17.i.

17.iii Given the future power needs of a decarbonizing BC economy, what impacts to customer electricity rates will this development have (if approved)?

41 https://www.bchydro.com/search.html#?cludoquery=What%20is%20the%20average%20power%20usage%20for%20a%20residential%20customer&cludopage=1.

Response:

As explained in the response to MS2S IR1 17.i, the electrical load related to the operation of the vapourizers and ancillary equipment will be approximately 6 MW, although the equipment is expected to run infrequently. In BC Hydro's draft 2021 IRP,[42] the regional demand of the South Coast region in the Accelerated Scenario to achieve the province's 2030 GHG reduction targets is projected at 7,726 MW in 2022 and 9,793 MW in 2030. As such, electricity consumption of the TLSE Project is insignificant and would amount to 0.08 percent of regional demand in 2022 and 0.06 percent in 2030. As such, the minimal additional load associated with the TLSE Project will have effectively no impact on electricity rates.

17.iv Will the power needed to run the regasifiers not be a drain on grid power availability to end-use customers who need to heat their homes in a T-South gas outage? … or

Response:

Please refer to the response to MS2S IR1 17.i.

17.v Alternatively, if the enormous power draw for Tilbury's liquefaction process were, because of the outage of T-South, to become available on BC Hydro's grid for customers to use to (electrically) heat their homes and cook their food, would customers not be better off than when competing for available electrical power with the regasification process?

Response:

There will be no "enormous power draw" associated with the operation of the TLSE Project assets. Please also refer to the response to MS2S IR1 17.i for a discussion of the power consumption associated with the TLSE Project.

[42] https://www.bchydro.com/content/dam/BCHydro/customer-portal/documents/corporate/regulatory-planning-documents/integrated-resource-plans/current-plan/draft-integrated-resource-plan.pdf.

Issue 18: Impact of FEI's LNG exports on local gas prices.

Exporting gas (which, in BC, is mostly fracked from Montney-formation shale deposits) will inevitably affect gas prices for BC ratepayers. When Australia began exports of its coal bed methane gas as LNG, local rates tripled amid supply shortages triggered by diverting the limited local supply to exports (see https://theconversation.com/australia-has-plenty-of-gas-but-our-bills-are-ridiculous-the-market-is-broken-125130). Shortages have been so damaging to the competitiveness of local industry that the state of Victoria in entertaining the ridiculous prospect of sanctioning two projects to import LNG into Australia, the world's second-largest LNG export country.

In its Sept. 2019 report entitled "Resilient Energy Infrastructure" (https://www.enbridge.com/~/media/Enb/Documents/Reports/Resilient_Energy_Infrastructure_report_FINAL.pdf), Enbridge opined that: "*We also see opportunity on Canada's West Coast. The October 2018 decision to move forward with LNG Canada, Royal Dutch Shell's large-scale project on Canada's West Coast, means Canada will become a large-scale exporter in what could be the first of several new LNG projects in British Columbia (BC).* ***LNG export from BC is anticipated to create uplift in natural gas supply prices within the WCSB****. In recent years, WCSB prices have been very low—or even negative— due to local supply exceeding local demand, and competitive supply alternatives*"

Question:

18.i How will FEI prevent this scenario/ a repeat of what happened in Australia – a tripling of local gas prices - from happening in BC?.

Response:

The North American natural gas markets are interconnected and FEI's customers generally pay commodity prices that are linked to North American natural gas prices, with the benchmark being the Henry Hub market price. In fact, the majority of FEI's gas supply agreements are currently indexed to AECO/NIT prices, which in turn are linked to Henry Hub.[43]

FEI does not have the ability to exercise market power to control the commodity price of natural gas in BC. Like all participants in the marketplace, FEI is subject to ongoing and dynamic market conditions that can influence the price of natural gas in the future. LNG developments in BC and across North America are just one of the many factors that can influence natural gas prices. In fact, in some cases, LNG developments can create liquidity in the market place and also support additional infrastructure to the benefit to FEI customers.

[43] Henry Hub is the official pricing point for natural gas futures on the New York Mercantile Exchange (NYMEX) and is used as the benchmark for the North American natural gas market.

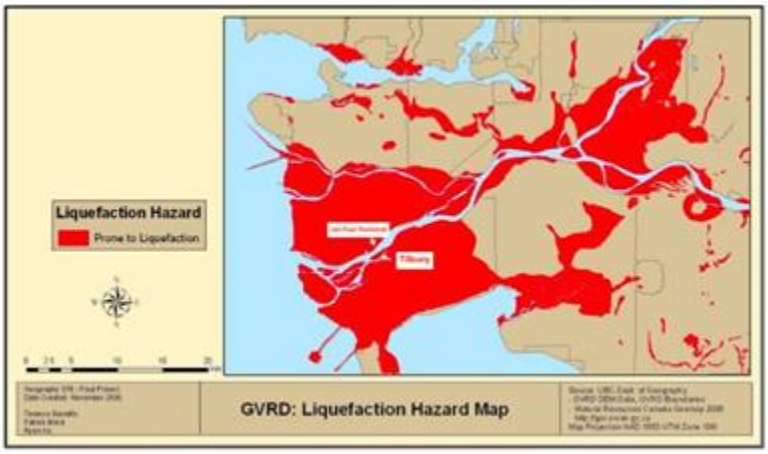
1 FEI has been and will continue monitoring the projects associated with LNG exports and, where
2 appropriate, will participate in any relevant review or regulatory processes to ensure its customers'
3 interests are protected.

Issue 19: Tilbury as a suitable location for a major LNG facility.

Tilbury Island, 22km. inland from the mouth of the Fraser, is not an ideal location for an LNG export terminal. It is:

- Within metres of a public roadway and an insecure public waterway (the Lower Fraser). These accesses greatly compromise the feasibility of a wide security perimeter for the site;
- On the flight path to/from a major airport (YVR);
- In the highest seismic liquefaction zone in BC. In the likely event of a significant seismic event, the Fraser delta would seem an improper place in which to locate a 43m-tall tank containing some 64,000 tonnes of flammable gas;
- Directly opposite a jet fuel storage facility serving YVR. This facility will have its own barge deliveries, of highly- flammable jet fuels, which must be synchronized with marine traffic serving Tilbury;
- At a height above sea-level of less than one metre, the site will be compromised if, as predicted by the IPCC and others, sea- level rises 1.8m. before AD2100;
- In a narrow channel, with five major bends to negotiate on the 22km. trip to open ocean at Sand Heads. These Port of Vancouver "clear transit areas" – see map opposite - will require that all other traffic must stop if an LNG tanker or towed LNG barge approaches one of these areas – a serious disruption to other marine and seaplane traffic in the channel;
- LNG tankers arriving at/leaving Tilbury will have to be accompanied by powerful (100-tonne bollard pull minimum) "steering" tugs attached fore and aft. Also, they must pass very close to buildings housing significant human populations in both Richmond and N. Delta. The risk of a spill due to a collision or terrorist attack, while small, is not zero, and must be weighed against any risks associated with FEI's T-South pipeline outage scenario;
- The tankers and accompanying tugs arriving at Tilbury will have to be turned around in a busy channel barely wider than the 275m. expected length of these tankers[44]. Vessel traffic in the vicinity of the Tilbury jetty will have to be halted during this tricky manoeuvre;. The dredging – to a depth of 11m. at the berth, will significantly impact fish migration and spawning activity in the Lower Fraser.
- The LNG industry group SIGTTO (Society for International Gas Tanker and Terminal Operators) strongly recommends against locating LNG facilities near human populations in narrow inland waterways with significant commercial, recreational and ferry traffic. Tilbury is such a location. In the U.S., there are regulations in place requiring a "Waterway Suitability Assessment" as a first regulatory step in the consideration of any new or expanded LNG facility. Regrettably, Canada has been slow to implement similar safety regulations.

[44] The length and draught of typical LNG tankers (275m,. 11m.) are double those of the typical Seaspan Ro-Ro vessel currently plying between Tilbury and Vancouver Island.



1

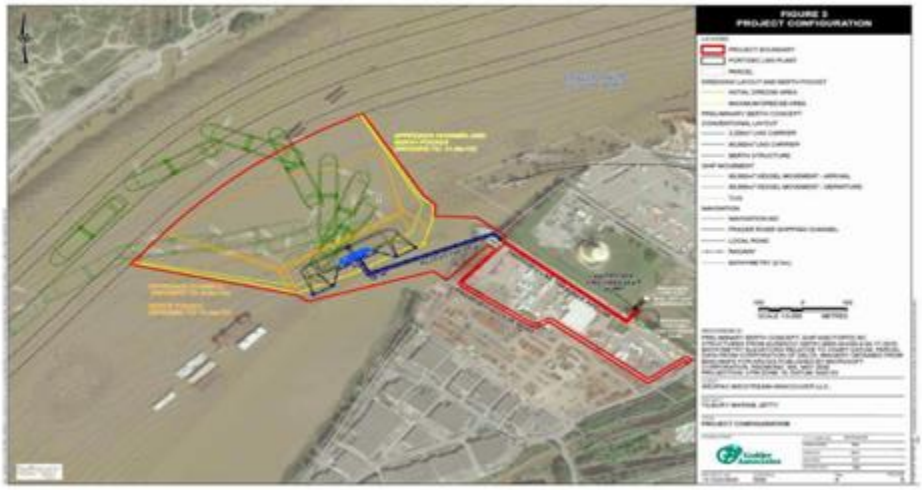
2

Image: TCZ-4 Clear Transit Areas

PORT INFORMATION GUIDE – Source: Vancouver Fraser Port Authority – May 2018 102

3
4

Turning LNG tankers & barges at Tilbury will be a safety challenge



Questions:

19.i Why not develop this massive LNG facility in a less safety-compromised site that respects SIGTTO guidelines for human safety (such as White Rock, Tsawwassen, outside the crowded Lower Mainland)?

19.ii Please indicate if FEI has assessed the relative risks of a rupture of T-South and an LNG spill incident on the Lower Fraser?

19.iii Given the paucity of FEI's experience in LNG shipping and SIGTTO'S 60-plus year history in that sphere, why is FEI, unlike several other BC LNG projects, not a SIGTTO member benefitting from SIGTTO's demonstrated expertise in the safe design, siting and operation of LNG terminals?.

Response:

The proposed TLSE storage tank is 3 Bcf, and will be located on a site where an LNG facility already exists. FEI has operated the Tilbury LNG facility safely since 1971, including the production, storage, and regasification of LNG for the benefit of FEI's customers.

As discussed in the response to BCUC IR1 24.3, the existing Tilbury LNG facility is already in a very good location from a hydraulic perspective for injection of gas into the Lower Mainland system for resiliency purposes. Other greenfield locations with similar hydraulic advantages would be unsuitable for the construction of any major facilities as the associated region is a highly developed and densely populated urban area.

FEI is unclear on the question associated with the "relative risks of a rupture of T-South and an LNG spill incident". Please refer to the response to BCUC IR1 1.5 for a discussion of the probability of an incident on the T-South system resulting a no-flow event. With respect to LNG spills, as discussed in the response to CEC IR1 37.2, the TLSE tank will be double-wall construction with full containment. It will be designed and constructed to modern codes and

practices to prevent releases of LNG to the environment. FEI considers it implausible that LNG could spill from the TLSE tank into the Fraser River.

The scope of the subject CPCN Application before the BCUC (the TLSE Project) does not include LNG shipping facilities.

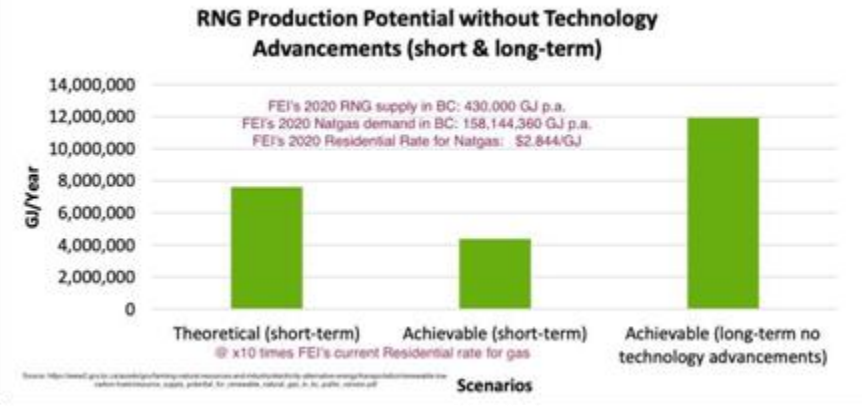
Issue 20: Renewable Natural Gas (RNG).

FEI has declared its "30by30" plan to reduce customer GHG emissions 30% by 2030.

As outlined by FEI on its website, the plan rests on 4 pillars, viz:

1. Greater energy efficiency (in homes, businesses and industry);
2. Increasing RNG (renewable gas- to 15% of its NG supply) ;
3. Global LNG (i.e. exports to trans-oceanic customers)
4. LNG-powered transportation (including bunkering of vessels capable of storing and burning LNG– displacing "dirtier" fuels).

Figure 1: RNG Production Potential without Technology Advancements at $28/GJ



As the BC-Government supplied graph above shows, the current supply of RNG is a tiny (0.3%) proportion of FEI's NG supply, and prospects for increasing it to 15% dim, even at prices 10 times that currently charged to BC customers.

Questions:

20.i What is the current level of customer emissions from FEI-supplied natural gas (NG)?

Response:

In 2020, the total amount of natural gas supplied through FEI's system (i.e., supplied by FEI and marketers) was 219 PJs. The emissions associated with this gas use is equivalent to 11.3 million tonnes CO2e.

With respect to Figure 1 in the preamble, FEI notes that it currently has approved RNG supply contracts in place to be delivered in 2022, which exceeds the theoretical short-term supply noted in the figure. In addition, FEI anticipates that by 2025, it will have over 24,000,000 gigajoules of renewable gas supply, which is double the long-term potential depicted in Figure 1. This demonstrates how quickly the technology landscape and potential for renewable gas is changing.

20.ii How much would this figure be reduced if 15% of the gas supply were RNG?

Response:

FEI interprets this question to be asking whether there is enough RNG supply available to achieve the 15 percent renewable gas target in CleanBC.

FEI confirms that there is enough RNG supply to meet, and potentially exceed, the 15 percent renewable gas target in CleanBC. Further, the volumes depicted in Figure 1 in the preamble represent a small component of the overall renewable gas supply potential available to FEI. Specifically:

1. The 15 percent mandate from the province not only includes RNG but also other zero or low carbon fuels such as hydrogen, syngas, and lignin which are all enabled for FEI to acquire under the Greenhouse Gas Reduction Regulation amendments made May 2021;
2. Figure 1 in the preamble is outdated as it only shows a component of RNG potential without technology advancements that have occurred. FEI already has an approved RNG supply contract with advanced conversion technology which is not depicted in this potential; and
3. Figure 1 in the preamble does not include supply potential from outside of the province. FEI has contracts and currently receives RNG from out of province projects, in a similar way that it receives conventional natural gas.

FEI is committed to meeting the 15 percent renewable gas target by 2030 and is diligently working on expanding its renewable gas supply. FEI received BCUC acceptance of 13 new RNG supply contracts in 2020 and has another 7 agreements signed to date in 2021 with BCUC acceptance for 3 of those agreements. Based on total agreements signed and accepted by the BCUC, FEI projects that by the end of 2021 it will have contracts for over 8,500,000 gigajoules of RNG annually—roughly 5 percent of FEI's total natural gas supply.

Additionally by 2025, FEI projects that it will have contracts in place for approximately 24,000,000 gigajoules of renewable gas—roughly 10 per cent of FEI's total natural gas supply—and enough to meet the natural gas needs of approximately 266,000 BC homes.

FEI is on track to meet the 15 percent renewable gas target and believes it is possible to exceed it, should the appropriate policies be in place.

20.iii How much NG (in tpa) is lost to leakages occurring between the Sumas interchange and customer end-points? (We assume that FEI would readily know this from mass-balance calculations of differences between Spectra/SCP-supplied quantities and customer billing data).

Response:

Unaccounted For (UAF) gas (sometimes referred to as Lost and Unaccounted For [LUAF] gas), refers to gas that is not specifically accounted for in the gas energy balance of receipts, deliveries, and operations use. UAF includes measurement variances and line loss of gas that is flowing in the transmission and distribution systems. Sources of UAF comprise, but are not limited to, system leakage, lost gas (gas lost as a result of utility and third-party activities, including gas theft), and measurement inaccuracies.

The following table summarizes the annualized gas receipts, gas deliveries, and UAF quantities related to the Lower Mainland area during the past five years.

Summary of Lower Mainland Annual Unaccounted For Gas for the Years 2016-2020

		2016	2017	2018	2019	2020	5-Year Average 2016-2020
Gas Receipts - Net Available For Deliveries	*(in TJ)*	117,311	131,358	125,562	128,902	128,954	
Gas Deliveries - Customer End-Points	*(in TJ)*	116,244	130,150	124,033	128,450	128,842	
Unaccounted For Gas	*(in TJ)*	1,067	1,208	1,530	453	111	
Unaccounted For Gas *(shown as % of Gas Deliveries)*		0.92%	0.93%	1.23%	0.35%	0.09%	0.70%

UAF, as discussed in the first paragraph, comprises various sources and the UAF quantities shown in the table above are not reflective of leakages. As such, the BC Ministry of Environment adopts a bottom-up approach in quantifying loss gas. This data is publicly available as part of FEI reporting to the Greenhouse Gas Emission Reporting Regulation and can be found the BC Ministry of Environment website.[45]

20.iv How much (roughly) of Fortis' 30by30 emissions reduction goal will be achieved with (i) local (i.e. BC) customers, with (ii) LNG bunker fuel customers and (iii) with foreign LNG customers?

Response:

FortisBC's 30BY30 target seeks to reduce its customers' GHG emissions by 30 per cent by 2030 from a 2007 baseline, which is approximately 3.9 million tonnes of CO2e. The largest opportunity

[45] https://www2.gov.bc.ca/gov/content/environment/climate-change/data/industrial-facility-ghg.

for greenhouse gas emissions reduction in the plan relates to renewable gas, which comprises approximately half of the total. As described in the response to MS2S IR1 20.ii, FEI projects that by the end of 2021 it will have contracts in place for approximately 8,500,000 gigajoules of RNG —roughly 5 percent of FEI's total natural gas supply. Additionally by 2025, FEI projects that it will have contracts in place for approximately 24,000,000 gigajoules of renewable gas—over 10 per cent of FEI's total natural gas supply.

The next largest sources in FortisBC's plan are LNG marine fueling and exports, energy efficiency, and zero and low carbon transportation. FortisBC expects that providing LNG to domestic and international customers could make up approximately one quarter of the 30BY30 target.

20.v Given that renewable natural gas (RNG) supply in BC is currently less than 0.3% of NG demand, how will FEI bring this up to the promised 15% that is part of its "30by30" plan for reducing customer emissions?

Response:

Please refer to the response to MS2S IR1 20.ii.

20.vi How many of FEI's 1M-plus customers have signed up for 100% RNG?

Response:

As of the end of July, 2021, FEI has 530 customers who are voluntarily buying 100 percent RNG. This is just over 5 percent of the total number of voluntary RNG customers.

20.vii Does FEI plan to use hydrogen in its fuel supply (pursuant to BC's recently announced strategy for the use of Hydrogen to replace NG? If so, what proportion of hydrogen can FEI's distribution system sustain (note: hydrogen is much more corrosive to steel piping than is NG, most of FEI's distribution piping is over 50 years old).

Response:

FEI plans to use hydrogen to displace natural gas in the gas system pursuant to the recent amendments to the Greenhouse Gas Reduction Regulation (GGRR).[46] The GGRR broadens the methods by which FEI can obtain renewable gases, including hydrogen, to fulfill CleanBC's 15 percent renewable gas target. With these changes, FEI will be able to invest in the purchase, production, and transportation of hydrogen gas.

FEI's gas system operates a cascading pressure regime that reduces the gas network operating pressure from the high pressure gas transmission system to the low pressure gas distribution system. FEI assumes that the reference to "distribution" in the IR question refers broadly to the conveyance of gas throughout the high pressure and low pressure parts of the gas system and does not specifically refer to the low pressure distribution system networks.

Since 2017, FEI has been engaged in ongoing international collaborations and joint industry initiatives which aim to share scientific knowledge and technical guidance to inform industry understanding of hydrogen use in different parts of the gas system. FEI is currently progressing a program of activities in BC including pilot projects to test how hydrogen interacts with gas network pipeline materials, components and network equipment and customer equipment for hydrogen blend concentrations in natural gas from 5 percent up to 20 percent by volume. FEI is also planning to conduct a system wide hydrogen impact assessment to determine the acceptable hydrogen content throughout the gas system and confirm hydrogen blend levels in the gas system that would be suitable for safe long term operation.

FEI's research indicates that a blend concentration around 5 percent by volume in the high-pressure transmission system and in the low-pressure distribution system, where sensitive equipment such as stationary combustion engines and compressed natural gas refueling stations may be present, would be an appropriate near-term starting point for hydrogen injection. There would be potential to blend at higher concentrations of up to 20 percent or more in the low pressure distribution network when constraints are not present or with suitable mitigation measures in place.

FEI considers that over the longer term, increases to the blend limit would be feasible with continuing research, regulatory amendments and codes and standard development, mitigation measures, and network upgrades. For example, a significant portion of FEI's low pressure distribution system is constructed from polyethylene pipeline and fittings which is compatible with 100 percent hydrogen.

Finally, hydrogen can be delivered in dedicated pipelines the same way that natural gas is today and hydrogen is already distributed around the world in thousands of kilometers of steel pipeline that are comprised of much the same materials and components as much of FEI's natural gas system. There are also various ongoing efforts currently focused on enabling hydrogen transport via repurposed high pressure transmission pipelines with a longer term goal being able

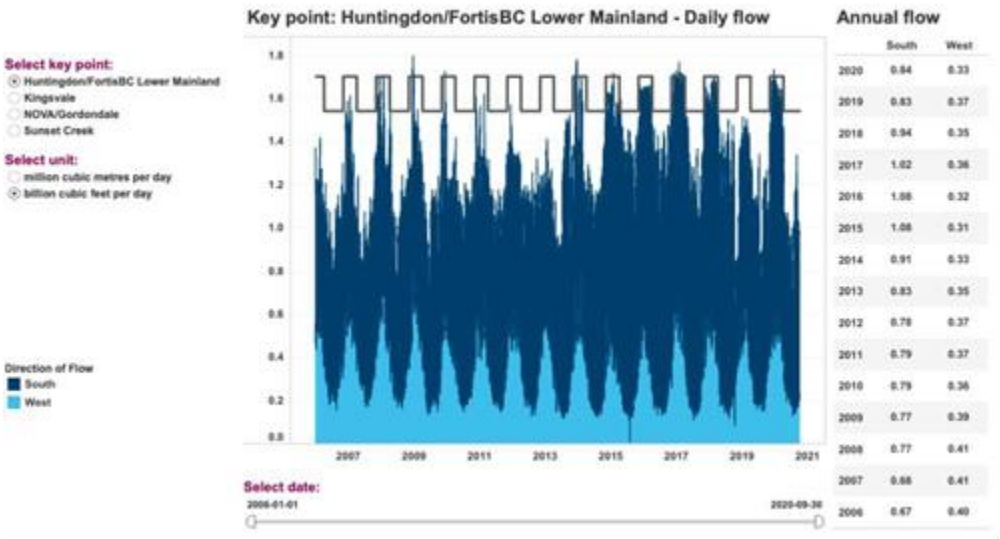
[46] 1 Amendments in the Greenhouse Gas Reductions (Clean Energy) Regulation (GGRR) now includes subsection 3.71, 3.8, section 6, 7, 8, 9 and 10. https://www.bclaws.gov.bc.ca/civix/document/id/oic/oic_cur/0306_2021.

1 transportation of 100 percent hydrogen with the perspective of developing long distance hydrogen
2 "backbone" pipeline systems using the existing natural gas system. Therefore, FEI is also
3 examining the feasibility of converting segments of existing natural gas networks supplying entire
4 regions to one hundred percent hydrogen service in the future.

5

Issue 21: Gas supply via Spectra pipeline.

The below graph shows the capacity utilization of the Spectra (now Enbridge) pipeline from 2007 through 2021 (measured at the Huntingdon/FortisBC interchange).



These data are publicly available through the Canadian Energy Regulator (CER). The darker blue segment shows the flow South to the U.S. via the Williams pipeline system, while the lighter blue shows Westward flows to FortisBC's distribution system. The solid line at the top shows the maximum capacity of the Spectra system.

Several conclusions may be drawn for this chart, including:

- Most of the line's capacity flows South across the U.S. border;
- The system appears to be close to or at maximum capacity, especially during the peak-demand Winter months;
- That pattern of near-capacity utilization has prevailed for 7 of the past 8 Winters (2020-2021 appears to have been the exception, because of lower U.S. diversion).

Question:

21.i Can FEI please explain how, if the Spectra pipe is indeed consistently at maximum Wintertime capacity, how FEI's adding some 4 million tonnes per annum (0.51 MTPA) of demand (and Woodfibre LNG another 2.1 MTPA (0.25 bcf/d)), will be at all possible?

Response:

Although FEI agrees that regional resources are fully utilized to meet existing customer demand during colder than normal winters, evaluating the capacity utilization provided on the Westcoast pipeline alone is not an accurate representation of the gas requirements in the region. Since

2015, the low commodity price at Station 2 has resulted in greater utilization of the Westcoast pipeline, regardless of the weather conditions. This gas supply may flow down to Huntingdon onto Williams Northwest Pipeline, and exit the region via the Gorge (west to east), displacing more expensive Rockies supply. When looking at the supply/demand balance in the I-5 corridor including the Lower Mainland Service area, FEI uses the T-South reports and Northwest Pipeline reports to get a more comprehensive view of the regional constraints and utilization of the existing pipeline paths.

That said, FEI does believe that new pipeline infrastructure is required in order to facilitate load growth opportunities. This is one of the reasons why FEI is assessing extending its existing SCP pipeline to the Lower Mainland. Until new pipeline infrastructure is added to the region, FEI has taken steps to mitigate the risk of future supply issues through its Annual Contracting Plan strategies. This was further discussed in the response to Sentinel IR1 30.

Issue 22: Social cost of carbon emissions.

The Canadian Government has estimated the social cost of carbon (GHG) emissions at $50-$213/tonne for 2025 (http://publications.gc.ca/collections/collection_2016/eccc/En14-202-2016-eng.pdf). A summary of the 2016 update is shown below.

Previous and Updated Canadian SCC Estimates for Period 2010 2050 (in C$ 2012[2] per tonne CO_2, discounted at 3%)[3]

Year	Previous central	Updated central	Previous 95th percentile	Updated 95th percentile
2010	27.6	34.1	108.6	131.5
2013	29.4	37.4	116.5	149.3
2015	30.7	39.6	121.8	161.1
2016	**31.3**	**40.7**	**124.5**	**167.0**
2020	33.9	45.1	135.1	190.7
2025	38.1	49.8	151.2	213.3
2030	42.2	54.5	167.4	235.8
2035	46.4	59.6	183.6	258.9
2040	50.5	64.7	199.6	281.9
2045	54.2	69.7	213.9	300.9
2050	57.8	74.8	228.0	319.8

According to documents submitted by FEI and WesPac Midstream, the Tilbury expansion (through Phase 2) will add – counting upstream (2.4MTPA), direct (0.24 MTPA) and jetty/tanker-related (0.1 MTPA) emissions - totalling around 2.7 million tonnes CO2e annually. leading to a cost in the range of $203- $575 million p.a.* or roughly $200- $630 per year for the average ratepayer.

($770 Million capital cost yielding 8.75% p.a. ROE =$68 Million p.a., plus $135-$575 Million social cost of carbon p.a.).

Question:

22.i At an additional cost to the average ratepayer of $200-$ 630 p.a., how can any net public benefit be derived from having ratepayers fund this $770 Million project?

Response:

FEI does not agree with the figures provided in the preamble or in the question. As discussed in Section 6.5 of the Application, the bill impact associated with the TLSE Project for a typical residential customer consuming 90 GJ per year is $6.12 per year over the 6 years from 2022 to 2027 and the levelized delivery rate impact is 6.67 percent or $0.301 per GJ over the life of the Project.

Please also refer to the response to MS2S IR1 14.ii for a discussion of Project-related emissions.