Sarah Walsh
Director, Regulatory Affairs

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

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

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

May 22, 2025

Residential Consumer Intervener Association
1130 W Pender Street
Vancouver, B.C
V6E 4A4

Attention: Samuel Mason, Consultant

Dear Samuel Mason:

Re: FortisBC Energy Inc. (FEI)

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

Response to the Residential Consumer Intervener Association (RCIA) Information Request (IR) No. 6

On December 29, 2020, FEI filed the Application referenced above and on October 24, 2024, FEI filed its Supplemental Evidence to the Application. In accordance with the regulatory timetable established in British Columbia Utilities Commission Order G-324-24 for the review of the Application, FEI respectfully submits the attached response to RCIA IR No. 6.

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

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Sarah Walsh

Attachments

cc (email only): Commission Secretary
Registered Interveners

71. Reference: Exhibit B-63 BCUC IR5 129.1

Underutilized Asset Risk – Decrease in Forecasted Demand

In response to BCUC IR5 129.1, FEI states:

> *FEI also provided a 5 percent annual load decline sensitivity (mDEP 5%) to model the potential impact of an extreme hypothetical scenario where the annual expected demolition rate more than doubled. FEI selected the 5 percent annual decline in response to the BCUC's commentary in the Adjournment Decision for FEI to further consider the potential for the transition towards a lower carbon future to affect the appropriate sizing of the TLSE Project. Unlike mDEP 2%, this sensitivity was not based on the 2022 LTGRP, but rather, was intended to represent an adverse and accelerated load decline scenario.*

71.1 Please compare the mDEP 5% scenario with the Deep Electrification scenario presented in the 2022 Long-Term Gas Resource Plan proceeding. If possible, please graph both scenarios.

Response:

Please refer to the response to BCOAPO IR6 5.2.

72. Reference: Exhibit B-63 BCUC IR5 129.4

Underutilized Asset Risk – Reallocation of Storage

In response to BCUC IR5 129.4, FEI states:

Conceptually, FEI's ability to reallocate storage volume between a resiliency reserve and gas supply is determined by two constraints: (1) the reallocation must not result in the operation that the volume was reallocated from no longer being able to perform its required function (e.g., gas supply volume should not be reallocated to a resiliency reserve if it will result in a shortfall in FEI's ACP); and (2) whether the facility specifications can utilize the reallocated volume for the desired purpose (e.g., if volume is to be reallocated from gas supply to resiliency, the facility must have an adequate sendout capacity to make use of the increased resiliency reserve). Given these two constraints, a larger facility would increase the ability to reallocate volume between the resiliency reserve and gas supply.

Supplemental Alternative 4A:

However, as the facility only has 400 MMcf/d of sendout capacity, which as discussed in Section 5.2.2.2 of Appendix C to the Supplemental Evidence is insufficient for the current system demand, this reallocation would violate constraint (2) above. FEI considers Supplemental Alternative 4A to have limited ability for reallocation (instead of no ability).

72.1 Please explain whether the constraints related to insufficient regasification and sendout capacity could be addressed in the future with the addition of regasification units (i.e. in the case of Supplemental Alternative 4A, add a third or fourth regasification unit to increase sendout capacity to 600 or 800 MMcf/d).

<u>Response:</u>

If provisions are made during design to accommodate future expansion, additional send-out capacity could be addressed in the future with the addition of regasification units up to 800 MMcf/d. If provisions are not made during design, it is still possible to expand send-out capacity, but it would be more costly and disruptive to plant operation as a complete redesign of the send-out system would be required.

However, although additional regasification capacity is possible in the future, Supplemental Alternative 4A only includes 1 Bcf of LNG storage. As shown in Section 4.5.1.5 of the Supplemental Evidence, 1 Bcf of storage would not be sufficient to materially mitigate the risk of a winter T-South no-flow event. Thus, although the regasification constraint could potentially be removed, FEI would still be left with a storage constraint.

73. Reference: Exhibit B-63 BCUC IR5 131.1

Off-system Storage

In response to BCUC IR5 131.1, FEI states:

> *The deliverability provided by an on-system LNG storage resource (i.e., 150-200 MMcf/d) is very valuable because the resource does not have to comply with the commercial arrangements as it relates to the nominations/scheduling windows of off-system resources. This is very important as the weather forecasts change and impact demands across the system. This is very important as the weather forecasts change and impact demands across the system.* [Underlining added]
>
> *Second, as illustrated in the figure below, based on the expected NW Natural recalls and the estimated in-service date of the expansion (Winter 2029/2030), the new deliverability from the North Mist Expansion Project will only replace existing deliverability that FEI will lose beginning in 2027/2028. Until the replacement Mist deliverability is in place, FEI will be short market area storage for 2 years (2027/2028 and 2028/2029) and will be exposed to short-term supply arrangements tied to the Sumas price (the only viable alternative to the lost deliverability). FEI has agreed to contract 50 percent of the expected total 4.3 Bcf and 130,000 Dekatherms per day (Dth/day) of capacity and deliverability from the North Mist Expansion Project.*
>
> …
>
> *Third, although the North Mist Expansion Project would provide enough storage capacity, it would not be enough deliverability to make up for what the Tilbury Base Plant provides to meet FEI's peak day requirements. The below graph illustrates the deliverability required from the Tilbury Base Plant and from FEI's Mist storage assets to meet FEI's Core Customer Peak Day load requirements. For example, as explained above, the 65,000 Dth of deliverability that FEI will receive from the North Mist Expansion Project only replaces the loss of FEI's existing Mist deliverability requirements due to the recalls. If FEI chose to contract 100 percent of the North Mist Expansion Project to replace the Tilbury Base Plant or the TLSE Project, FEI would still be short 80,000 Dth/day or 130,000 Dth/day, respectively.* [Underlining added]

Centra Gas Manitoba Inc. filed a description of its gas supply, storage, and transportation as part of its 2024/25 General Rate Application, which details its gas transportation and storage arrangements.

https://www.hydro.mb.ca/docs/regulatory_affairs/pdf/natural_gas/gra_2024_2025/09-0_tab_9_gas_supply_and_costs.pdf

73.1 Please identify other storage options (in addition to the remaining North Mist Expansion Project capacity) available to FEI that would provide or contribute to additional deliverability and provide the amounts of deliverability each could provide.

73.1.1 Please estimate the additional annual costs of these storage options.

Response:

There are no other viable storage options available to FEI that would provide or contribute to additional deliverability beyond the North Mist Expansion Project. In particular, any further expansion of the Mist storage facility would require a new pipeline to connect to Northwest Pipeline, which would have significant cost and permitting challenges. Further, as discussed in the response to CEC IR1 25.1, it is FEI's understanding that there are risks to future reservoir expansions at the Jackson Prairie Storage (JPS) facility; therefore, the owners of JPS (Puget Sound, Northwest Pipeline, and Avista) have no plans for future development.

73.2 Please provide the nomination cycles available to FEI on T-South, and explain whether additional intraday nomination cycles are available for deliveries from storage (per the Centra filing, similar to TC Energy offering additional nomination cycles for its Storage and Transportation Service on the Canadian Mainline[1]).

Response:

There are five nomination cycles on Westcoast T-South (timely, evening, and three intra-day cycles), which is standard for all North American transmission pipeline operators. Within each cycle, some pipeline operators can include additional "sub" cycles within the five standard day gas cycles (e.g., Northwest Pipeline). FEI can change its nominations within these five nomination cycles to manage the changes in demand (i.e., daily load fluctuations). Westcoast does not provide any additional "sub" cycles; however, the nomination cycles available to FEI are sufficient enough to manage changes in supply and demand from actual versus forecast weather, as it unfolds. The option to change the amount of nomination cycles and use off-system storage as a replacement for on-system LNG storage is not feasible nor cost-effective for the following reasons:

- FEI's off-system storage resources are intended to cover different demand characteristics compared to FEI's on-system storage. In Section 4.3.1.1 of the Application, and in the response to CEC IR1 46.1, FEI explained how its efficient supply portfolio strategy includes off-system storage resources to provide short- to medium-duration seasonal supply (i.e., 10 to 60 days), as well as on-system storage resources (i.e., Tilbury and Mt.

[1] https://www.tccustomerexpress.com/docs/ml_nominations/mainline-nomination-timelines-april-2016.pdf.

Hayes LNG facilities) which provide shorter duration supply (i.e., 1 to 10 days) to cover the winter demand associated with cold weather events.

- FEI's off-system storage resources are already primarily used for daily load balancing in normal operations. As discussed in the response to the BCUC IR1 22.1, FEI's on-system LNG storage resources can help with daily balancing; however, given the smaller size of these assets, their utilization is prioritized for cold weather events and/or emergency purposes.
- FEI's off-system resources (storage and commodity supply) require FEI to contract pipeline capacity on third-party pipelines. For example, FEI contracts for T-North and T-South pipeline capacity on T-South, in order to move its contracted supply to and from the Aitken Creek storage facility. If FEI chose to replace the Base Plant's peaking supply with off-system storage, FEI would have to contract additional capacity (i.e., 150 MMcf/d to replace the Tilbury Base Plant) on Westcoast and leave that capacity on standby during the winter, to mitigate the risks of a cold weather event. This would not be feasible, because FEI cannot replace this amount of supply in the commercial marketplace and, even if it were feasible, it would be extremely expensive. As discussed in the response to BCUC IR6 151.1, the unique versatility of on-system LNG is its ability to immediately respond (i.e., maximum deliverability) to cold weather events in real time.

73.3 Please confirm or otherwise explain whether the nomination cycles available to FEI would allow it to manage changes in demand due to deviations in weather from forecasted weather absent on-system LNG. That is, what are the implications of not replacing the Base Plant's peaking supply and instead using off-system storage. Please quantify the implications.

Response:

Please refer to the response to RCIA IR6 73.2.

73.4 Please identify any Canadian natural gas distribution utilities that do not utilize on-system storage.

Response:

FEI is not aware of which natural gas utilities in Canada make use of on-system storage. As discussed in the Guidehouse Report, resource requirements for utilities are influenced by the characteristics of the natural gas value chain, including midstream pipeline capacity and availability of storage (both off-system and on-system) and the load profile of the customer base.[2] Each utility's gas supply resource planning will differ based on these factors and their access to available resources.

FEI can confirm most gas utilities in the Pacific Northwest (PNW) utilize on-system LNG storage to manage peak day load increases, given their similar load profiles to FEI, and access to similar resources.

The following table[3] from the Northwest Gas Association provides a list of the peak storage deployed by PNW gas utilities as of 2024.

TABLE 2. Regional Storage Facilities

Facility	Owner	Type	Capacity (MDth)*	Max Withdrawal (MDth/day)**
Jackson Prairie, WA	Avista, PSE, NW Pipeline	Underground	25,448	1,196
Mist, OR***	NW Natural	Underground	21,385	641
	Underground Subtotal		**46,833**	**1,837**
Plymouth, WA	NW Pipeline	Peak (LNG)	2,296	305
Tilbury, BC	FortisBC Energy	Peak (LNG)	1,634	155
Mt. Hayes, BC	FortisBC Energy	Peak (LNG)	1,530	153
Portland, OR	NW Natural	Peak (LNG)	500	131
Newport, OR	NW Natural	Peak (LNG)	968	65
Nampa, ID	Intermountain Gas	Peak (LNG)	600	60
Tacoma LNG****	PSE	Peak (LNG)	538	85
Gig Harbor, WA	PSE	Peak (LNG)	11	3
	Peak Storage Subtotal		**8,077**	**957**
TOTAL STORAGE			**54,910**	**2,794**

---

2 Appendix A of FEI's Tilbury LNG Storage Expansion Project CPCN Application. "Guidehouse Report on Natural Gas System Resiliency."

3 2024 Gas Outlook, Northwest Gas Association. Sourced from Research And Data | Northwest Gas Association.

74. Reference: Exhibit B-63 BCUC IR5 119.2; Exhibit B-26 BCUC IR2 88.1; Exhibit B-28 RCIA IR2 39.4; Exhibit B-60 Supplemental Evidence pp.13,86

Liquefaction Capacity

In response to BCUC IR2 88.1, FEI states:

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

In response to RCIA IR2 39.4, FEI states:

> *FEI considers that 5 MMcf/day of liquefaction will be sufficient for the purposes of daily load balancing and peaking use for the following reasons:*
>
> - *Under normal operations, the supply for peaking use and daily load balancing would only come from the "third Bcf" of the TLSE Project. The 5 MMcf/day allocated for gas supply and operational benefits will provide FEI approximately 1.8 Bcf of supply (i.e., 5 MMcf x 345 days = 1,725 MMcf7);*
>
> …
>
> *If a no-flow event were to occur, the sufficiency of the 5 MMcf/day of liquefaction for replenishing the LNG inventory after T-South supply resumes will depend on the severity of the no-flow event. However, FEI may be able to utilize a portion (if not all) of the Tilbury 1A liquefaction capability (i.e., 28 MMcf/day), depending on the sales commitments to Rate Schedule 46 customers.*

On page 13 of the Supplemental Evidence, FEI states:

> *FEI is already decommissioning the Base Plant liquefaction equipment.*

On page 86 of the Supplemental Evidence, FEI states:

> *Using Tilbury 1A tank volumes for peaking supply is only possible at present because LNG sales growth has been slower than anticipated to date; however, the recent provincial and federal approvals of the Tilbury Jetty are a significant development because delays in the jetty approval had represented a significant sales constraint. FEI now expects RS 46 LNG sales to increase significantly and sell out Tilbury 1A as early as 2028.*

In its response to BCUC IR5 119.2, FEI states:

Any increased liquefaction capacity built as part of the Tilbury Phase 2 LNG Expansion Project will be dedicated to the customer or market that the plant is built to support, and would not be available to support FEI's non-LNG customers on a planned basis as part of its ACP. Further, the Tilbury 1A liquefaction facility was constructed to support the transportation fueling market (including marine fueling) and has sufficient capacity to maintain the required LNG inventory in the Tilbury 1A tank to support expected RS 46 sales. Similar to the increased liquefaction from the Tilbury Phase 2 LNG Expansion Project, Tilbury 1A storage will not be available to support FEI's non-LNG customers on a planned basis as part of its ACP. [Underlining added]

74.1 Considering that there is only 5 MMcf/d of reserved liquefaction available to fill TLSE, that any additional liquefaction to be built for Phase 2 will not be available for TLSE, and that LNG sales are increasing up to its maximum capability ("sell out Tilbury 1A as early as 2028") which will increase utilization of the total 33 MMcf/d of T1A liquefaction, please demonstrate how the existing T1A liquefaction is sufficient to support: 1) T1A LNG sales, 2) TLSE usage for peaking purposes (Supplemental Alternatives 7, 8, and 9), 3) the first fill of the TLSE resiliency reserve (2BCF), and 4) any refills of the TLSE resiliency reserve in a timely basis to be able to withstand a subsequent no-flow event the following winter.

Response:

The 5 MMcf/d reserved from Tilbury 1A to fill the TLSE tank will remain even when LNG from Tilbury 1A sells out. As such, there will always be liquefaction capacity available to fill the TLSE tank.

FEI address each of the specific questions posed by RCIA below:

1. **Tilbury 1A LNG Sales:** Tilbury 1A liquefaction, less the 5 MMcf/d reserved to fill the TLSE tank, was constructed to support RS 46 sales. Additional capacity contemplated through further expansion (e.g., Tilbury 1B) will address growing demand for LNG via RS 46.

2. **TLSE Usage for Peaking Purposes:** FEI clarifies that all of the Supplemental Alternative 7 LNG storage would be reserved for resiliency, rather than gas supply peaking. Supplemental Alternative 8 would have a 0.6 Bcf gas supply reserve and Supplemental Alternative 9 would have a 1 Bcf gas supply reserve. For both Supplemental Alternatives 8 and 9, if the gas supply reserve were fully depleted during the winter heating season, FEI would replenish that volume utilizing the 5 MMcf/d of production reserved from Tilbury 1A liquefaction. On a planning basis, FEI can refill the 1 Bcf of capacity dedicated to gas supply in 200 days. As the winter heating season runs from November 1 to March 31 (150 days), this would leave 215 days to refill the TLSE tank to replenish any LNG used to support gas supply during the winter heating season. As noted in the response to RCIA IR6 74.2, if the tank were depleted, FEI would leverage any surplus liquefaction capacity if it were available.

3. **First Fill of the TLSE Resiliency Reserve:** As noted in Section 5.3.1.4 of the Application, the initial filling of the 3 Bcf tank will rely on the utility reserve capacity plus any available capacity from the Tilbury liquefaction facilities (i.e., Tilbury 1A and Tilbury 1B). These facilities are intended to provide service to LNG customers under RS 46; however, as noted above, the capacity of Tilbury 1A and Tilbury 1B may not be fully subscribed initially or periodically during the year due to the inherent peaks and valleys associated with LNG sales.

4. **Refills of the TLSE Resiliency Reserve:** To the extent that the resiliency reserve was depleted following a no-flow event, LNG volumes remaining that were allocated to the gas supply reserve would likely be allocated to the resiliency reserve to manage any potential supply shortages that could materialize. Depending on the volume of LNG depleted during the resiliency event, FEI would then re-fill the resiliency reserve, leveraging any surplus liquefaction capacity to fill the TLSE tank more quickly, and would consider securing any short-term market area resources (i.e., Sumas term purchase), if available, to back up the 1 Bcf of gas supply reserve until it is also replenished.

74.2 Recognizing that the resiliency reserve and the peaking supply reserve of TLSE are notional, please confirm or otherwise explain whether FEI would prioritize the filling of TLSE's gas supply reserve over the resiliency reserve following a winter where both are depleted or nearly depleted. That is, FEI would use the approximate 200 day summer period to refill 1 BCF of gas supply reserve and forego filling the resiliency reserve?

Response:

FEI would prioritize replenishing the LNG reserve with the 5 MMcf/d of Tilbury 1A liquefaction capacity reserved to refill the TLSE tank following a winter where the entire 3 Bcf TLSE tank is depleted (e.g., where a winter T-South no-flow event has required all of the available LNG volumes). Depending on the volume of RS 46 sales at that time, FEI may also be able to use surplus Tilbury 1A liquefaction capacity (or capacity from Tilbury 1B if it is constructed and in service) to expedite replenishing both the resiliency and gas supply allocations within the TLSE tank.

Moreover, recognizing the limited time during the summer period to completely refill the TLSE tank from empty before the next winter season, FEI would likely try to secure less optimal short-term market area resources (i.e., Sumas term purchase), if available, to back up the 1 Bcf of gas supply reserve as liquefaction continued.

75. Reference: Exhibit B-63 BCUC IR5 120.1

Regulatory Shutdown Duration

In response to BCUC IR5 120.1 requesting any further evidence to support FEI's assumption that the duration of a regulatory shutdown of the intact T-South pipeline is 3 days following a rupture of the adjacent T-South pipeline, FEI states:

> *FEI's view that 3 days is a reasonable expectation for how long a regulatory shutdown will last was based on actual experience from the 2018 T-South Incident, and FEI believes that it remains a sound and meaningful data point, as previously affirmed by JANA.*

In addition to the failure of T-South in 2018, there have been a number of large diameter gas pipeline failures in Canada, including:

- TransCanada Pipelines Mainline near Rapid City, Manitoba in July 1995;
- TransCanada Pipelines Mainline near St. Norbert, Manitoba in April 1996;
- TransCanada Pipelines Mainline near Brookdale, Manitoba in April 2002;
- TransCanada Pipelines Mainline near Engleheart, Ontario in September 2009;
- TransCanada Pipelines Mainline near Marten River, Ontario in September 2009; and
- TransCanada Pipelines Mainline near Otterburne, Manitoba in January 2014.

75.1 Please provide the duration of the regulatory shutdown period for the above-noted pipeline failures, as well as any other major pipeline failures that FEI is aware of.

Response:

FEI provides the following response:

FEI conducted a review of the noted pipeline incidents, the results of which have been summarized in Table 1 below. Based on this review, FEI makes the following observations:

1. It is necessary to define a new shutdown type, a Precautionary Shutdown, and distinguish it from a Regulatory Shutdown. In a Regulatory Shutdown, which is what occurred during the 2018 T-South Incident and is what has been contemplated in FEI's analysis,[4] approval from a regulator (e.g., the CER) is required prior to returning the non-failed pipeline to service. In a Precautionary Shutdown, in contrast, the non-failed pipeline is shutdown; however, the decision to do so as well as the decision to return the pipeline to service is made by the operating company. Approval from the regulator is not involved.

2. In all but one of the referenced incidents (TransCanada Pipelines Mainline near Otterburne, Manitoba in January 2014), FEI classifies the shutdown of the non-failed

[4] Pipeline transportation safety investigation report P18H0088 Section 1.6.1 para 2.

pipeline as a Precautionary Shutdown rather than a Regulatory Shutdown. This is based on the respective Transportation Safety Board (TSB) reports making no mention of regulatory involvement in returning the non-failed pipeline segment to service. In contrast, in the incident FEI classifies as a Regulatory Shutdown (TransCanada Pipelines Mainline near Otterburne, Manitoba in January 2014), there is evidence that regulatory approval was required to return the non-failed pipeline segment to service.[5]

3. In the incident FEI classifies as a Regulatory Shutdown (TransCanada Pipelines Mainline near Otterburne, Manitoba in January 2014), the estimated Regulatory Shutdown duration is less than 2 days, which is similar to the Regulatory Shutdown that occurred in the 2018 T-South Incident (2 days).

4. In the remaining incidents, each of which FEI classifies as a Precautionary Shutdown, the estimated Precautionary Shutdown durations are typically less than 1 day. FEI does not consider there to be a need to revise the assumption of a 3-day Regulatory Shutdown based on this finding. This is due to the following:

    a. As Precautionary Shutdowns do not involve regulatory approval to return the non-failed pipeline to service, the timelines involved in obtaining the approval are avoided and thus do not contribute to the duration. As a result, all else being equal, Precautionary Shutdown durations are likely to be shorter than Regulatory Shutdown durations. Therefore, historical examples of Precautionary Shutdowns should not be used to inform the assumed Regulatory Shutdown duration.

    b. FEI expects that any future failure on T-South leading to the shutdown of an adjacent non-failed pipeline would be due to a Regulatory Shutdown, not a Precautionary Shutdown. It is expected that, as occurred in the 2018 T-South Incident, approval from the CER would be required prior to returning the pipeline to service. As such, FEI's assumption should be informed based on its understanding of Regulatory Shutdowns, not Precautionary Shutdowns.

Table 1: Summary of Pipeline Failure Incidents

Pipeline Failure Incident	Horizontal Pipeline Spacing	Failed Pipeline(s)	Non-Failed Pipeline(s) Shutdown	Shutdown Type	Estimated Non-Failed Pipeline Shutdown Duration
TransCanada Pipelines Mainline near Rapid City, Manitoba in July 1995[6]	100 cm, vertical (Line 100-5)	Line 100-4 Line 100-3	Line 100-5	Precautionary	3.5 Days
TransCanada Pipelines Mainline near St. Norbert, Manitoba in April 1996[7]	9.1 m	Line 100-2	Line 100-1	Precautionary	Less than 1 Day

5 Pipeline investigation report P14H0011 Pg. 12, Safety action taken, item 1.
6 Commodity Pipeline Occurrence Report, Report Number P95H0036.
7 Pipeline Occurrence Report P96H0012.

Pipeline Failure Incident	Horizontal Pipeline Spacing	Failed Pipeline(s)	Non-Failed Pipeline(s) Shutdown	Shutdown Type	Estimated Non-Failed Pipeline Shutdown Duration
TransCanada Pipelines Mainline near Brookdale, Manitoba in April 2002[8]	7.2 m (Line 100-3 to 100-4)	Line 100-3	Line 100-1 Line 100-2 Line 100-4	Precautionary	Less than 1 Day
TransCanada Pipelines Mainline near Engleheart, Ontario in September 2009[9]	10 m	Line 100-2	Line 100-1 Line 100-3	Precautionary	Line 100-1, Less than 1 Day Line 100-3, 14 Days
TransCanada Pipelines Mainline near Marten River, Ontario in September 2009[10]	20 m and 43 m	Line 100-1	Line 100-2 Line 100-3	Precautionary	Less than 1 Day[11]
TransCanada Pipelines Mainline near Otterburne, Manitoba in January 2014[12]	NA	Line 400-1	Line 400-2 Line 400-3	Regulatory	Less than 2 Days[13]

Exponent also provides the following response:

Exponent has reviewed FEI's response and agrees with it.

---

8 Pipeline Investigation Report P02H0017.

9 Pipeline Investigation Report P09H0074.

10 Pipeline Investigation Report P09H0083.

11 Pipeline Investigation Report P09H0083 does not include a time stamp for when Line 100-2 and Line 100-3 returned to service. The estimate of less than 1 day is based on the statement that these lines were "…quickly returned to normal service…" [Pipeline Investigation Report P09H0083, Pg. 7, Site Clean-Up and Pipeline Restoration, para 4]

12 Pipeline Investigation Report P14H0011.

13 Pipeline Investigation Report P14H0011 does not include a time stamp for when Line 400-2 and Line 400-3 returned to service. The estimate of less than 2 days is based on the following statements from the report:

- "At approximately 0115 Central Standard Time on 25 January 2014, a natural gas pipeline rupture and ignition occurred on TransCanada PipeLines Limited's 762 mm (30-inch) Line 400-1 at the site of Mainline Valve (MLV) 402 near Otterburne, Manitoba." [Pipeline Investigation Report P14H0011, Pg 1, Factual Information, para 1].
- "As a precaution, two adjacent pipelines, lines 400-2 and 400-3, were shut down, assessed, and returned to service on 26 January 2015 [sic]." [Pipeline Investigation Report P14H0011, Pg 1, Factual Information, para 4].
- "At the time of the occurrence… Line 400-3 was isolated at compressor station 41 and was not flowing." [Pipeline Investigation Report P14H0011, Pg 3, TransCanada's pipeline system, bullet 1].

Based on the above, the rupture occurred early in the morning on January 25th, and Line 400-3 was already isolated. The time at which Line 400-2 was isolated is not stated in the report. It is assumed that isolation occurred shortly after the rupture. Therefore, the start of the Regulatory Shutdown on Lines 400-2 and 400-3 is assumed to be approximately 0115 on January 25, 2014. As noted above, Lines 400-2 and 400-3 were then returned to service the following day, January 26th. No timestamp is provided, as such it is assumed that the lines returned to service at 1200 on January 26th. Based on the assumed start and end times, the duration is estimated as less than 2 days.