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February 16, 2023

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
Vancouver Centre II
2900 – 733 Seymour Street
Vancouver, BC
V6B 0S6

Attention: Christopher P. Weafer

Dear Christopher Weafer:

Re: FortisBC Energy Inc. (FEI)

Application for a Certificate of Public Convenience and Necessity (CPCN) for Approval of the Interior Transmission System Transmission Integrity Management Capabilities Project (Application)

Response to the Commercial Energy Consumers Association of British Columbia (CEC) Information Request (IR) No. 1

On September 20, 2022, FEI filed the Application referenced above. In accordance with British Columbia Utilities Commission Order G-18-23 amending the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to CEC IR No. 1.

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 Parties

1. Reference: Exhibit B-1, page 21

> ***3.2.3.2 Overview of FEI's Integrity Management Program – Pipeline (IMP-P)***
>
> FEI manages the integrity of its transmission pipeline systems with its IMP-P. FEI's IMP-P meets the requirements of the BC *Pipeline Regulation* under the *Oil and Gas Activities Act* (OGAA). The *Pipeline Regulation* requires FEI to employ a quality management system with a plan-do-check-act (PDCA) cycle designed to promote continual improvement of its integrity management activities. Implementation of a quality management system, founded on PDCA principles, is the internationally recognized way for an industry to improve its asset performance and reduce failures over the life of assets. As such, it has been embedded within Canadian pipeline regulations, standards and industry practices.
>
> FEI's IMP-P is a quality-driven program that anticipates, plans for and establishes practices for the management and mitigation of conditions that could adversely affect safety, reliability, or the environment during an asset's lifecycle. Examples of activities within the scope of FEI's IMP-P and related activities include the following:

1.1 Please confirm that FEI is currently compliant with all relevant pipeline regulations.

Response:

Confirmed. The ITS TIMC Project enables FEI to continue to meet its regulatory obligations, as set out in the response to BCUC IR1 7.1.

1.2 Please confirm that FEI is not required, nor has it been requested, to undertake the proposed project by any regulatory authority.

Response:

As discussed in Section 3.5.2 of the Application and the response to BCUC IR1 7.1, the regulatory provisions that apply to FEI's gas transmission pipelines are typically goal-oriented rather than prescriptive in nature. Therefore, while FEI has not been specifically requested by a regulatory authority to undertake the Project, the BCOGC has provided written support for FEI's TIMC projects, recognizing that they are in alignment with FEI's regulatory and legal responsibilities as a BCOGC permit holder. Further, given the availability of proven and commercialized EMAT ILI technology, FEI considers that the Project is required to maintain compliance with its regulatory obligations to address the threat of cracking on ITS pipelines, as identified in the system-level QRA undertaken by JANA and consistent with evolving industry practice.

2. Reference: Exhibit B-1, pages 33

> **3.4.2 FEI's Coastal, Interior and Vancouver Island Transmission Systems Were Assessed**
>
> JANA's investigation into the susceptibility of FEI's transmission pipelines to cracking threats focused on a total of 35 pipelines located within the three transmission systems that FEI operates, as shown in Figure 3-9 below. These transmission systems are comprised of a network of natural gas pipelines that deliver gas to local distribution systems, which supply customers in the southern parts of the province and Vancouver Island.

2.1 Please discuss whether or not FEI attempted, and/or has been able, to secure reduced pricing in any capacity as a result of addressing more than one transmission system over a short period of time.

2.1.1 If FEI did not attempt to secure reduced pricing from its suppliers due to the large size of the two projects, please explain why not.

2.1.2 If FEI did secure reduced pricing from any of its suppliers, please provide details and quantification of the cost reductions.

2.1.3 If FEI attempted to secure reduced costing from its suppliers, but was unable to do so, please explain why it was unsuccessful.

Response:

While the cost estimate provided for the ITS TIMC Project does not include any reduced pricing from FEI's suppliers or service providers, during the execution phase of the Project, FEI will seek to secure reduced pricing from its suppliers for materials and services to address projects on more than one transmission system over a short period of time. FEI's procurement practices are performed ethically and in accordance with prudent business practices to achieve the greatest overall value for the project(s) requirements. Further, whenever possible, FEI consolidates requirements across projects and utilizes existing agreements to achieve the greatest overall value for the project(s). FEI's procurement practices include working with vendors and manufacturers through a competitive bid process.

3. Reference: Exhibit B-1, page 16 and 36

> ***3.2.2.1 Modern Pipe Manufacturing Processes Result in Superior Pipe Materials***
>
> Steel and pipe manufacturing practices and processes have continually evolved and significant improvements have occurred since the early 1970s. Pipe manufactured prior to 1970 is often referred to as "vintage" pipe and pipe manufactured after 1970 is referred to as "modern" pipe. Vintage pipe can contain a larger quantity of manufacturing anomalies, with the majority of these anomalies occurring in the seam welds, which are also referred to as longitudinal welds. The quantity of manufacturing anomalies also varies with pipe manufacturer. Types of manufacturing anomalies are further discussed in Section 3.2.4.2.

> JANA's high-level conclusion was as follows:
>
> - Eleven of the 13 CTS mainline transmission pipelines were identified as susceptible to cracking threats;
> - Nine of the 12 ITS mainline transmission pipelines were identified as susceptible to cracking threats; and
> - None of the 10 VITS mainline transmission pipelines were identified as being susceptible to cracking threats.

3.1 Please explain whether or not FEI's initial selection of its pipe manufacturer has contributed to the current susceptibility to cracking threats.

<u>Response:</u>

FEI's initial selection of its pipe manufacturer adhered to all relevant regulations and utilized what would be considered to be high-quality processes at the time of manufacture for all its pipelines. Therefore, the initial selection of its pipe manufacturer (when compared to other manufacturers) has not contributed to the current susceptibility to cracking threats.

Specific manufacturing practices at the time of FEI's initial pipeline construction have nonetheless contributed to FEI's evaluation of susceptibility of its pipelines to cracking threats. For example, as explained in Section 3.2.2.1 of the Application: "Vintage pipe can contain a larger quantity of manufacturing anomalies, with the majority of these anomalies occurring in the seam welds, which are also referred to as longitudinal welds." Please refer to Section 3.2.4.2 of the Application for a description of crack-like imperfections in seam welds.

4. Reference: Exhibit B-1, page 16

> The majority of pipe in FEI's transmission systems was manufactured using one of two processes:
>
> 1. **Electric Resistance Welding**
>   The majority of pipelines in FEI's transmission systems that are nominal pipe size (NPS) 18 and smaller were manufactured using the electric resistance welding (ERW) process. The ERW process uses an electric current to bond two edges of steel to form a cylindrical pipe. This process was described in a publication by the American Society of Mechanical Engineers (ASME) as follows:[8]
>
>   > [ERW] is manufactured by cold-forming previously-hot-rolled strip to a circular shape, heating the two abutting edges by passing electric current through the interface as the edges come together, and effecting a bond between the edges as the molten or near-molten edges are forced together by mechanical means without the addition of any filler metal.
>
>   While the pipe is still hot, the material pushed out at the bond line, where the two edges of steel meet, is removed from the internal and external surfaces of the pipe, leaving both surfaces flat.

4.1 Please explain whether or not the manufacturing process has in any way contributed to the susceptibility to cracking or other potential defects.

4.1.1 If yes, please discuss whether or not FEI could have utilized different processes that would have resulted in reduced cracking potential.

Response:

Yes, as discussed in the response to CEC IR1 3.1, specific pipe manufacturing practices and processes have contributed to FEI's evaluation of susceptibility to cracking or other potential defects.

FEI could not have utilized different processes and confirms it used the most appropriate processes that existed at the time in its initial selection of pipe based on the best available information.

5. Reference: Exhibit B-1, page 20

> These threats and hazards can be:
>
> - **Time-dependent:** with the potential to impact the pipeline increasing over time if they are not appropriately mitigated (e.g., corrosion and cracking).
> - **Time-independent:** with a varying potential to impact the pipeline on a random basis and not linked to the passage of time (e.g., third-party damage and natural hazards); or
> - **Stable:** with the potential, in and of themselves, to impact the pipeline that does not change over time (e.g., manufacturing and construction imperfections that pass mill and pre-commissioning hydrostatic tests for a typical natural gas pipeline).

> All hazards have the potential to undermine the integrity of the pipeline and are controlled by physical and operational barriers. Physical barriers include depth of cover (i.e., how deep the pipeline is buried) and engineering design considerations, such as pipe wall thickness and

5.1 Please explain why ‘stable’ hazards can be considered as having the potential to undermine the integrity of the pipeline if they successfully passed mill and pre-commissioning tests. Are the tests not sufficient to ensure the integrity of the pipeline?

Response:

Stable hazards, in and of themselves, do not have the potential to undermine the integrity of the pipeline following completion of appropriate mill or pre-commissioning tests. However, these stable hazards can undermine the integrity of the pipeline in the event that they interact with time-dependent threats (e.g., external corrosion, dents, gouges, or cracking).

5.2 Of those threats and hazards of which FEI is aware, what percentage may be considered as ‘stable’?

Response:

For the purposes of transmission pipeline risk assessments, it is common for threats and hazards to be grouped as either “time-dependent”, “time-independent” or “stable”, as follows:

- **Time-dependent:** is a threat in which the estimated likelihood of failure will increase over time, even if all other influencing factors remain unchanged.
- **Time-independent:** is a threat in which, if all other influencing factors remain unchanged, the estimated likelihood of failure will not increase over time.
- **Stable:** is a threat that will not result in failure in and of itself unless it interacts with another threat.

The percentage of threats in each category will vary according to the model breakdown adopted in a risk assessment. FEI's baseline system-level QRA considered 22 percent of threats (5 of 23) to be "stable", as shown in the table below.

Threat from FEI's Baseline System-level QRA	Time-Dependent, Time-Independent, or Stable?
1 Body of pipe - External corrosion	Time-dependent
2 Body of pipe - Internal Corrosion	Time-dependent
3 Body of pipe - Stress Corrosion cracking	Time-dependent
4 Body of pipe - Excavation damage	Time-independent
5 Body of pipe - Previous damage	Time-dependent
6 Body of pipe - Vandalism	Time-independent
7 Body of pipe - Damage by vehicles	Time-independent
8 Body of pipe - Damage in water crossings	Time-independent
9 Body of pipe - Manufacturing defects	Stable
10 Pipe seam	Stable
11 Body of pipe - Construction defects	Stable
12 Girth welds	Stable
13 Wrinkle bend	Stable
14 Body of pipe - Lightning	Time-independent
15 Body of pipe - Heavy rains or floods	Time-independent
16 Body of pipe - Earth movements	Time-independent
17 Body of pipe - Incorrect operation	Time-independent
18 Main line valve – Equipment failure	Time-independent
19 Main line valve – External interferences	Time-independent
20 Main line valve – Incorrect operation	Time-independent
21 Flanges	Time-independent
22 Repair sleeve & clamp	Time-independent
23 Mechanical couplings	Time-independent

6. Reference: Exhibit B-1, page 20 and page 26

> - **Time-dependent:** with the potential to impact the pipeline increasing over time if they are not appropriately mitigated (e.g., corrosion and cracking).

> ### 3.2.4 Cracking Threats to FEI's System
>
> Cracking threats are considered "planar imperfections" that, due to a lack of volume, cannot be detected by FEI's current ILI tools. Cracks are considered planar because they are essentially two dimensional. Cracks have a measurable length and depth, but negligible width – similar to a crack in a car windshield. Corrosion and metal loss features (which FEI's current ILI tools can detect) are three dimensional, with a measurable length, depth and width. This results in a three-dimensional void in the pipeline wall – similar to a chip or "bulls-eye" in a car windshield. It is because of the lack of this third dimension that a crack cannot be detected by current ILI tools.
>
> Cracking threats affect the strength of a pipeline by effectively reducing the wall thickness of the pipeline. The two main types of cracking threats to FEI's system are SCC and crack-like imperfections in the seam weld of a pipeline. In addition, SCC and crack-like imperfections can interact with other time-dependent integrity threats, such as external corrosion, to compound integrity issues on a pipeline.

6.1 Please provide an approximation of the length and depth of a crack that would reasonably be considered as hazardous, and one that might not be considered as hazardous.

<u>Response:</u>

There is no single critical crack length and depth that would reasonably be considered hazardous. This is because the estimation of failure pressure of SCC or crack-like imperfections depends on various factors such as crack depth, crack length, crack shape, material toughness, pipe wall thickness, pipe diameter and pipe grade. The dimensions of a non-injurious imperfection can range from deep-and-short to shallow-and-long.

CSA SPE-225.7:22 (Managing Near-Neutral pH Stress Corrosion Cracking) provides some guidance on classifying the severity of SCC. In general, SCC imperfections with a depth of less than 10 percent wall thickness, regardless of their length, do not impact the safe operation of a pipeline. Similarly, SCC imperfections with a depth greater than 10 percent wall thickness will be subject to further integrity evaluation to determine whether they could fail at the operating pressure of the pipeline.

6.2 Over what period of time do cracks typically develop into cracks that may be considered as hazardous?

<u>Response:</u>

There is no typical period of time for cracks to develop into cracks that may be considered “hazardous”.

While there can be various methods for estimating crack growth rates, EMAT ILI is the most reliable method for assessing and monitoring actual crack growth on a pipeline over time. This method enables operators to undertake appropriate mitigation (e.g., integrity digs and repairs) prior to a crack becoming hazardous.

7. Reference: Exhibit B-1, page 25 and page 25

> - **Coastal Transmission System Transmission Integrity Management Capabilities (CTS TIMC):** The CTS TIMC is expected to be complete in 2024, and will expand FEI's ILI capabilities for cracking and crack-like imperfections to larger diameter transmission pipelines within its Coastal Transmission System (CTS), and specifically, lines with diameters between NPS 12 and NPS 42.

> For ILI tools to be suitable for FEI's pipelines, they must be able to operate within the variable flow rates on FEI's system. Unlike many other gas transmission systems where flow is dependent on the daily volumes contracted by midstream shippers, the flow through the FEI transmission system is almost entirely dependent on FEI's customer demand, which is temperature sensitive. For example, during peak winter months (typically November through March), gas flows in FEI's transmission pipelines are high compared to the shoulder and light-load seasons (typically approximately April to October). For this reason, FEI has limited windows during which it can run ILI tools. During periods of higher demand, gas flow rates can be sufficiently high that the ILI tool travels through the pipe at an excessive speed, resulting in either no data collection or degraded data collection.

7.1 Please summarize any key differences between FEI's approved CTS TIMC and that proposed for the Interior.

7.1.1 Please comment on why these differences are required.

<u>Response:</u>

The key difference between FEI's approved CTS TIMC Project and the proposed ITS TIMC Project is execution timing. FEI plans to complete construction of the CTS TIMC Project before starting construction on the proposed ITS TIMC Project. FEI prioritized its CTS TIMC Project because the CTS has a higher estimated overall safety risk as compared to the ITS. As explained in Section 3.4.4.2 of the Application, the relative risk due to cracking is lower on the ITS, as compared to the CTS, primarily due to the lower population densities surrounding the ITS pipelines.

Otherwise, the CTS TIMC and ITS TIMC Projects have the same project objective to enhance FEI's integrity management capabilities to mitigate cracking threats on transmission pipelines it has found to be susceptible to cracking. Both projects identified the same alternatives and used similar criteria to evaluate these alternatives, ultimately leading to both projects meeting this objective through the implementation of EMAT ILI.

With respect to EMAT ILI, FEI has adopted the same overall project specifications for the CTS TIMC and ITS TIMC Projects as follows:

- FEI requires the capability to introduce EMAT ILI tools into its pipelines;
- FEI requires that EMAT ILI tools can navigate through its pipelines;
- FEI requires that EMAT ILI tools can travel within their optimal velocity range; and

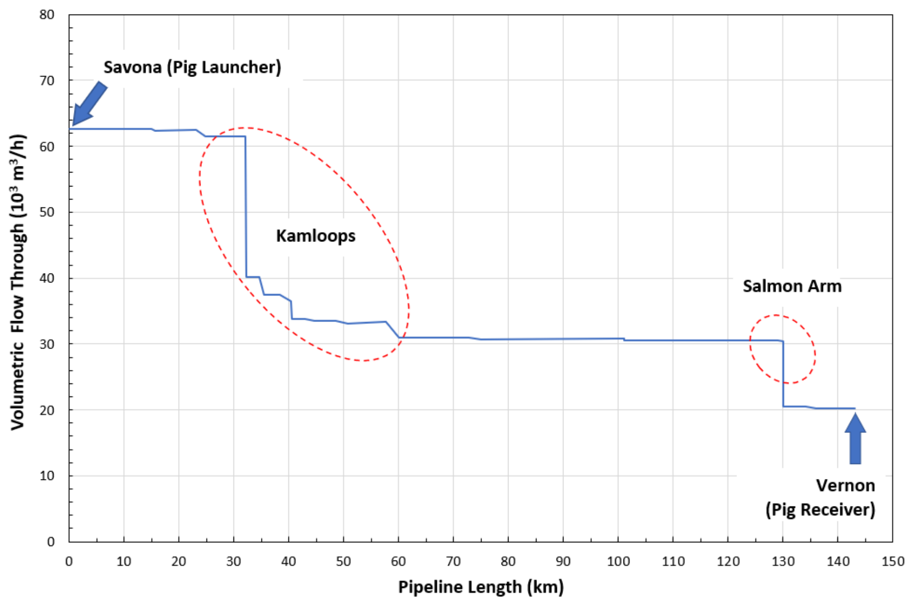
- FEI requires that it has the capability to operate its systems safely in the event that an integrity concern is detected by EMAT ILI tools.

7.2 Please summarize the significant differences between the coastal transmission system and the interior transmission system, and please explain how these differences have impacted the specifications for the Interior TIMC Project, if at all. For example, do differences in climate affect the need for TIMC; do differences in size of the Coastal and Interior Transmission Systems in any way impact the justification for the TIMC; do differences in pipeline materials or the status of existing cracking impact the need for or type of mitigation necessary?

Response:

The most significant difference between the CTS and ITS is their configuration. The CTS is a transmission system “network” with significant pipeline looping and interconnectivity spanning a relatively small geographic area. Conversely, the ITS is primarily linear in nature and spans a much larger geographic area. These differences in configuration lead to differing hydraulic conditions that had to be considered in planning the ITS TIMC Project because of their impacts to post-Project activities as described below:

- Due to the lack of interconnection and looping in the ITS, FEI’s ability to meet capacity requirements in the ITS during times where a pressure restriction is imposed is limited. This limitation resulted in FEI developing the operational strategy outlined in the response to BCUC IR1 1.2.1 to maintain capacity on the Savona to Penticton 323 mainline in a pressure reduced scenario, resulting in the need for a temporary PRS at the SN-4 Valve Assembly proposed in the ITS TIMC Project. Since this operational strategy is only feasible in 2026 or earlier, this also drove the Project execution schedule for the SAV VER 323 and VER PEN 323 pipelines comprising the mainline.
- The ITS pipelines are generally longer than CTS pipelines with control points typically located at the very start and/or the very end of the pipeline. As previously provided, the ITS pipelines operate over a much larger geographic area, where major load centres are further apart resulting in high variability in flow rates across the pipelines. The graph below, reproduced from the response to RCIA IR1 12.1, shows this variability in flow through the SAV VER 323 pipeline as it passes through major urban centres.



This variability in flow, combined with the long distances between control points, makes it a challenge to maintain ILI tool velocity within the optimal range during pigging operations. As such, the flow control stations (FCS) proposed in the ITS TIMC Project will have bidirectional operation and provide closer, more precise flow control points in the system. This bidirectionality will be used throughout the ILI run to assist in maintaining optimal tool travel velocities. Bidirectionality was not needed, and thus, not considered in the FCS design as part of the CTS TIMC Project.

The ITS configuration and hydraulics directly affect post-Project activities in the ITS, and thus, influenced some specific design considerations in the ITS TIMC Project. However, there is no fundamental impact to the overall project specifications of the ITS TIMC Project, as listed in the response to CEC IR1 7.1.

To address the issues raised in the examples from the question:

- Climate is not a factor in the need for the TIMC projects. Please refer to the response to BCUC IR1 6.2.2 for the relevant factors.
- Differences in the size of the CTS and ITS have not factored into FEI's justification for the TIMC projects.
- Differences in pipeline materials or the status of existing cracking have influenced FEI's assessment of susceptibility of its pipelines to cracking threats. Pipelines that are not susceptible to cracking do not need incremental crack mitigation and are excluded from the TIMC projects. This information does not impact the type of mitigation necessary.

FEI's CTS and ITS pipeline systems have the following similarities requiring both systems to be addressed by the TIMC projects:

- Both systems have pipelines that operate above 30 percent SMYS and have the potential to fail by rupture;
- Both systems have pipelines that are susceptible to SCC; and
- Both systems have pipelines with an outside diameter of NPS 10 and greater, for which EMAT tools are sufficiently proven and commercialized.

8. Reference: Exhibit B-1, page 30

> **3.3.3 Pilot Project Demonstrates that EMAT ILI Detects Previously Unknown Instances of Potential Cracking**
>
> As part of FEI's project development work, FEI is completing a pilot of EMAT ILI evaluations on two CTS pipelines. The EMAT ILI tool runs on these pipelines are complete; however, FEI is in the process of validating potential cracking detected by the EMAT tool. These instances of potential cracking on FEI's pipelines were not previously detected through opportunistic digs.
>
> The two pipelines chosen for the pilot, CPH BUR 508 and LIV PAT 457, had instances of cracking that FEI discovered during integrity dig activities, unrelated to investigating cracking. FEI determined that these pipelines could be modified to run EMAT ILI tools on a timeline suitable for informing the TIMC projects.

8.1 Did FEI conduct a pilot project on the Interior Transmission System?

8.1.1 If yes, what were the results?

8.1.2 If no, please explain why not.

<u>Response:</u>

FEI did not conduct a pilot project on the ITS. As described in Appendix D to the Application, FEI used the results of the EMAT ILI Pilot Project to inform the scope of the ITS TIMC Project. The learnings from the EMAT ILI Pilot Project were equally applicable to the ITS as to the CTS; therefore, there would have been insufficient value gained from undertaking an additional pilot project specific to the ITS.

9. Reference: Exhibit B-1, Appendix D, page 1

> ***FEI CONDUCTED AN EMAT ILI PILOT PROJECT TO SUPPORT DEVELOPMENT OF THE TRANSMISSION INTEGRITY MANAGEMENT CAPABILITIES (TIMC) PROJECTS***
>
> FEI identified two pipeline segments where it could undertake necessary system improvements within timelines practical to inform the development of the CTS and ITS TIMC Projects. This approach enabled FEI to incorporate further refinements and certainty into the scope and requirements of the projects. As such, FEI proceeded with the required alterations and baseline EMAT inspection of these two pipeline segments through a pilot project to inform FEI's development of the Projects. The two pipeline segments were:
>
> 1. LIV PAT 457
> 2. CPH BUR 508
>
> These pipelines were selected for the pilot project for the following reasons:
>
> - Both pipelines had experienced SCC which was found when conducting routine pipeline exposure activities, unrelated to investigating SCC;
> - Analysis of the behavior of geometry, MFL-A, and MFL-C tools indicated that the EMAT ILI tool would have no issues traveling through the pipelines, with only a minor likelihood of data loss; and
> - The pipelines could be configured for flow control and to operate at a reduced pressure, with relatively minor upgrades.
>
> Details of the alterations made to each of these pipelines are provided below, followed by a description of how this pilot project informed development and planning for the TIMC Projects.

9.1 Would it have been beneficial for FEI to have conducted testing on a pipeline where no SCC had been found in order to determine if TIMC is valuable where no SCC is anticipated? Please explain why or why not.

Response:

FEI identified pipelines to deploy EMAT ILI based on susceptibility, rather than whether SCC has been found during past integrity digs. As such, it would not have been any more or less beneficial for FEI to have conducted testing on a pipeline where no SCC had been found during past integrity digs, so long as that pipeline was deemed to be susceptible to cracking threats.

FEI selected two CTS pipelines for testing as part of the EMAT ILI Pilot Project because they:

- Could be modified to run EMAT ILI tools on a timeline suitable for informing the TIMC projects; and
- Met the criteria of being susceptible to cracking threats while having an outside diameter for which EMAT tools are proven and commercialized.

10. Reference: Exhibit B-1, Appendix D, page 7

> The magnitude of speed excursions using EMAT ILI tools cannot be determined until the first tool run is complete. As such, in order to ensure a prudent use of funds and avoid doing work unnecessarily, FEI did not include these heavy wall segments in the scope of the ITS TIMC Project. However, if the EMAT tool exhibits a speed excursion during the baseline run at one of these locations, FEI may need to replace the heavy wall piping causing the speed excursion, thus avoiding depreciated data for future runs. Alternatively, FEI may choose to address the integrity of the affected segment of pipe through the use of pipeline replacement or pipeline exposure and recoat alternatives. FEI will evaluate the method that will be applied to mitigate cracking threats on a case-by-case basis to determine the most cost-effective solution.

10.1 Please quantify the savings/benefits that FEI was able to achieve as a result of not including the heavy wall segments in the scope of the ITS TIMC.

<u>Response:</u>

As FEI did not prepare cost estimates for the replacement of these heavy-wall segments, FEI cannot quantify the associated costs that are not included in the scope of the ITS TIMC Project.

11. Reference: Exhibit B-1, page 40

> - Approximately one quarter of reported incidents occurred at 55 percent of SMYS or lower, with some circumferential SCC leaks occurring below 30 percent of SMYS (in presence of additional loading factors).

> Through information gathered during FEI's industry participation activities, FEI is also aware that its peer Canadian and American transmission pipeline operators have found, through their crack-detection ILI runs, potentially injurious SCC on pipelines operating below 50 percent of SMYS.

> CEPA has also stated that "based upon the data collected by CEPA member companies it is apparent that there was no absolute threshold operating stress value for SCC initiation or propagation."[22] This is supported by CEPA's failure record where ruptures had occurred at operating stress levels between 49 and 71 percent of SMYS. There were no reported SCC ruptures in the PHMSA or CEPA failure records below 30 percent of SMYS.

11.1 Please provide the data of the operating pressures for the ¼ of reported incidents occurring below 55% of SMYS.

Response:

The operating pressures for the ¼ of reported incidents[1] occurring below 55 percent of SMYS are as follows (in pounds per square inch, per the units used in the source data[2]):

Incident Date	Operating Pressure (PSI) at Time of Incident
5/29/2004	1,063
8/15/2004	665
11/5/2008	986
6/29/2010	450
2/2/2011	222
6/13/2013	815
3/19/2014	316
6/5/2016	857

11.2 Please provide further details of the data supporting the risk of rupture on pipelines operating between 30% and 50% of SMYS.

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1 Within the context of the report, the statement pertains to incidents from 2002-2016.

2 U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA), Gas Transmission & Gathering Incident Data, available at: https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data.

Response:

Risk of rupture depends on both the likelihood of a cracking rupture and the potential consequences of a cracking rupture. For the Baseline System-level QRA, in the absence of EMAT ILI data, the likelihood of cracking estimate relies on an analysis of industry historical failure data.[3]

The following table shows the sole stress corrosion cracking-caused rupture event in this PMHSA data set, between 2002 and 2016, on a pipeline operating between 30 and 50 percent of SMYS (Percent SMYS = 47 percent, and has been calculated based on information in the source data):

Incident Date	Operating Pressure at Time of Incident (PSI)	Pipe Diameter (inches)	Injuries	Fatalities
6/5/2016	857	12	None	None

With respect to CEPA failure records, this database is not publicly available and FEI does not have access to further details of the rupture that occurred at 49 percent of SMYS. The date of the reference paper from which this information was extracted (footnote 18 in Appendix B-1 to the Application) pre-dates FEI's participation with CEPA.

Please refer to Section 3.5.3.1 of the Application for information regarding the potential for rupture failure for pipelines operating at 30 percent SMYS and above.

[3] U.S. Department of Transportation, Pipeline and Hazardous Materials Safety Administration (PHMSA), Gas Transmission & Gathering Incident Data, available at: https://www.phmsa.dot.gov/data-and-statistics/pipeline/distribution-transmission-gathering-lng-and-liquid-accident-and-incident-data.

12. Reference: Exhibit B-1, page 40 and 41

> This analysis was conducted in conjunction with Dr. Chen of the University of Alberta, a recognized SCC expert researcher. Software developed by Dr. Chen, called *Pipe-Online*, was used for the analysis of SCC crack growth behaviour and to predict the remaining lifespan of a pipeline prior to cracks growing to failure. The analysis utilized pressure data from 54 pipeline locations in the CTS and ITS, 8 FEI detailed field inspection reports from integrity digs, and a summary of SCC findings from 14 dig excavations. The analysis considered a range of crack depths and lengths, which are reasonable approximations of what could be anticipated to be present in the FEI system. The analysis also considered a range of fracture toughness[24] values

> consistent with typical industry values. The analysis used these inputs, FEI's operating conditions, and the *Pipe-Online* software to project the time to failure of SCC cracks.
>
> The analysis estimated a range of potential time until failure from 5 to 85 years, indicating that there is the potential for SCC cracks to grow to failure under the operating conditions of the FEI system. While the lower bound timeframe of five years is considered highly unlikely (reflecting a combination of the longest, deepest crack with the lowest toughness pipeline), the analysis does indicate that SCC is a credible integrity threat that needs to be managed in a timely manner.

12.1 Please confirm or otherwise explain that the evidence related to Dr. Chen's work is the same as that which was included in the CTS evidentiary record.

12.1.1 If yes, would FEI agree that the evidence from the CTS proceeding related to Dr. Chen's work is acceptable for inclusion in this application?

12.1.2 If no, please explain why not.

<u>Response:</u>

Confirmed, Dr. Chen's work is the same as that which was included in the CTS TIMC evidentiary record. FEI also considers the evidence from the CTS TIMC proceeding related to Dr. Chen's work to be acceptable for inclusion as part of this Application.

13. Reference: Exhibit B-1, pages 39, 43 and Appendix E

Table 3-4: FEI ITS Pipelines: Occurrences of Cracking on FEI Pipe Identified Through JANA's Review of Selected Integrity Digs and Total Integrity Digs Analyzed

#	Line Name	FEI Name	SCC Susceptibility	Seam Weld Cracking Susceptibility	Integrity Digs with Cracking Threats	Total Integrity Digs Analyzed
1	SAV VER 323	Savona – Vernon 12"	Yes	Yes	50	92
2	VER PEN 323	Vernon – Penticton 12"	Yes	Yes	38	67
3	GRF TRA 273	Grand Forks – Trail 10"	Yes	Yes	138	228
4	OLI GRF 273	Oliver Y – Grand Forks 10"	Yes	Yes	79	163
5	PEN OLI 273	Penticton – Oliver Y 10"	Yes	Yes	13	23
6	TRA CAS 219	Trail – Castlegar 8"	Yes	Yes	11	76
7	KIN PRI 323	Kingsvale – Princeton 12"	Yes	Low	0	3
8	PRI OLI 323	Princeton – Oliver 12"	Yes	Low	2	12
9	YAH TRA 323	Yahk – Trail (ELK) 12"	Yes	Low	9	53
10	OLI PEN 406	Oliver – Penticton 16"	Low	Low	0	1
11	DUK SAV 508	Duke Tap – Savona C/S 20"	Low	Low	0	0
12	YAH OLI 610	Yahk – Rossland 24", Rossland – Oliver 24"	Low	Low	0	6

At the system level, the QRA estimates that the CTS has the highest risk followed by the ITS and then the VITS. As detailed in FEI's CPCN Application for the CTS TIMC Project, the QRA identified that cracking was the top driver of risk for the CTS pipelines. With respect to the ITS, JANA's model estimates that cracking threats are the second highest threat for seven of the ITS pipelines identified as susceptible to cracking threats and third highest threat for the other two susceptible ITS pipelines. However, cracking threats are the top contributor to safety risk and rupture rate for segments of all nine ITS pipelines identified as susceptible to cracking threats. These segments are typically located in lower population areas where the operating hoop stress of the pipeline is higher.[26]

Appendix E

FEI'S IMP-P ACTIVITIES

13.1 Please summarize why cracking was the top risk to the CTS pipelines, but not to the ITS pipelines.

Response:

Please refer to the response to BCUC IR1 3.1.1.

13.2 Please identify the first, second and third highest threat for each of the nine pipelines.

Response:

In the table below, FEI provides the first, second and third highest threat for each of the nine pipelines based on the “Safety Risk Summary” provided in Confidential Appendix B-2.

#	Line Name	Pipeline Full Name	Ranking of Safety Risks
1	SAV VER 323	Savona – Vernon 12”	1. Third Party Damage 2. SCC 3. Natural Hazards
2	VER PEN 323	Vernon – Penticton 12”	1. Third Party Damage 2. SCC 3. Natural Hazards
3	GRF TRA 273	Grand Forks – Trail 10”	1. Third Party Damage 2. SCC 3. Natural Hazards
4	OLI GRF 273	Oliver – Grand Forks 10”	4. Third Party Damage 5. SCC 6. Natural Hazards
5	PEN OLI 273	Penticton – Oliver 10”	7. Third Party Damage 8. SCC 9. Natural Hazards
6	KIN PRI 323	Kingsvale – Princeton 12”	1. Third Party Damage 2. Natural Hazards 3. SCC
7	PRI OLI 323	Princeton – Oliver 12”	1. Third Party Damage 2. SCC 3. Natural Hazards
8	YAH TRA 323	Yahk – Trail 12”	1. Third Party Damage 2. Natural Hazards 3. SCC
9	TRA CAS 219	Trail – Castlegar 8”	4. Third Party Damage 5. SCC 6. Natural Hazards

13.2.1 Appendix E outlines general activities FEI uses to manage third-party damage threats and natural hazards. For each pipeline, please identify which activities have been undertaken, and whether or not the threats have been or will be completely or largely mitigated by FEI.

Response:

Please refer to the response to BCUC IR1 3.3 for a detailed listing of activities FEI uses to manage third-party damage threats and natural hazards. These activities have been undertaken and continue to be undertaken on <u>every</u> transmission pipeline.

The activities FEI uses to manage third-party damage threats and natural hazards are appropriate mitigation of the threats of third-party damage and natural hazards for its transmission pipelines, reflecting factors such as FEI's current awareness of site-specific risks and current industry practice. FEI is nonetheless committed to continually improving and advancing its IMP, and will continue to explore practical and cost-effective activities to manage third-party damage threats and natural hazards.

14. Reference: Exhibit B-1, page 43

> The relative risk due to cracking is lower on the ITS, as compared to the CTS, primarily due to the lower population densities surrounding the ITS pipelines. In particular, lower population in the Interior compared to the Lower Mainland reduces the estimated safety consequences of a rupture. However, as discussed in Section 3.5.3 below, the potential consequences of a rupture can still be significant in unpopulated areas, including the risk of igniting forest fires and loss of gas supply for a potentially extended period – which could result in indirect safety consequences not considered by the QRA.

14.1 Please elaborate on the indirect safety consequences not considered by the QRA.

<u>Response:</u>

The QRA only considers immediate safety consequences of a failure (e.g., rupture safety consequences within the estimated potential impact radius) and excludes indirect consequences of a failure (i.e., consequences outside the estimated potential radius).

An example of an indirect safety consequence is where an ignited pipeline rupture burns trees in the immediate vicinity of the impact radius and, depending on various factors such as tree density and wind conditions, starts a forest fire that extends beyond the impact radius. A widespread forest fire has the potential to impact personal property and cause loss of life, but is not considered within the QRA because it is an indirect safety consequence, occurring outside the estimated potential impact radius.

Similarly, a rupture on a pipeline during certain times of the year has the potential to result in the loss of gas supply to customers far away from the impact radius of the rupture. Please refer to the response to CEC IR1 16.1 for a summary of potential customer impacts resulting from a rupture event. To respond to such an event, FEI would have to curtail or shut off large numbers of customers to balance the supply and demand associated with that pipeline system. During cold winter conditions, the potential exists for a loss of gas supply event to impact personal property (e.g., from bursting frozen water pipes in homes) and/or cause loss of life from lack of heat (among others). The gas supply impact of a pipeline rupture is another indirect safety consequence, and therefore, was not considered in the QRA because it results outside the estimated potential impact radius.

14.2 Please discuss whether or not it would be feasible to only address those ITS pipelines with the greatest risk, rather than all those being proposed.

Response:

It is not feasible for FEI to only address those pipelines with the greatest risk. The requirement for the incremental integrity management capabilities provided by the TIMC projects, including for the eight ITS pipelines, is as follows:

- FEI operates transmission pipelines that are susceptible to cracking threats;
- The outside diameters of these susceptible pipelines fall within the range for which there are proven and commercialized EMAT ILI tools; and
- The use of EMAT ILI has been adopted by industry as the most practical and cost-effective method to address cracking threats.

Cracking on susceptible pipelines can result in rupture failure of transmission pipelines, and FEI is obligated to monitor for conditions that can lead to failure regardless of the associated risk ranking.

15. Reference: Exhibit B-1, page 46

> In its Independent Report, Dynamic Risk concluded that cracking is a credible threat for FEI's transmission system that, if left unmitigated, could lead to pipeline rupture, stating:
>
> > SCC is a form of environmentally assisted cracking; wherein small surface cracks can form and grow over time. Cracks that continue to grow will frequently overlap and/or coalesce to become the equivalent of a large single crack in terms of their effect on the pressure carrying capacity of the pipe. Eventually such overlapping and coalescence can create a crack of sufficient size to cause the pipeline to leak or rupture. It is the independent pipeline integrity expert panel's view that SCC is a credible threat for FEI that if left unmitigated, could lead to pipeline failure.[27]
>
> Further, Dynamic Risk concluded that FEI's existing practices are not sufficient to manage the threat:
>
> > Currently, there is a gap in the existing FEI integrity management practices to address the threat of SCC, as opportunistic excavations alone are not sufficient to fully characterize, detect and manage the threat. The results of the quantitative risk assessment (QRA) demonstrate the risk of SCC to be highest on the CTS pipeline segments and it is the independent pipeline integrity expert panel's view that EMAT ILI is the most appropriate response and mitigation action to reduce risk and strengthen the overall integrity management program.[28]
>
> Dynamic Risk also endorsed the QRA, stating:[29]
>
> > The QRA performed on the three (3) transmission systems is in alignment and follows the approach defined in the CSA Z662-19 with hazard identification, frequency and consequence analysis, and risk estimation.
>
> While these conclusions of Dynamic Risk were developed specifically for the CTS TIMC Project, FEI contends that they also support the need for the ITS TIMC Project as set out in this Application.

15.1 Did FEI consider engaging Dynamic Risk in order to assess whether or not the risk to the ITS pipelines warranted mitigation to the extent proposed by FEI? Please explain why or why not.

<u>Response:</u>

FEI did not consider engaging Dynamic Risk in order to assess whether or not the risk to the ITS pipelines warranted mitigation to the extent proposed by FEI.

The premise of the question that a lower risk pipeline may not warrant mitigation is false. FEI's decision to adopt EMAT ILI is primarily due to:

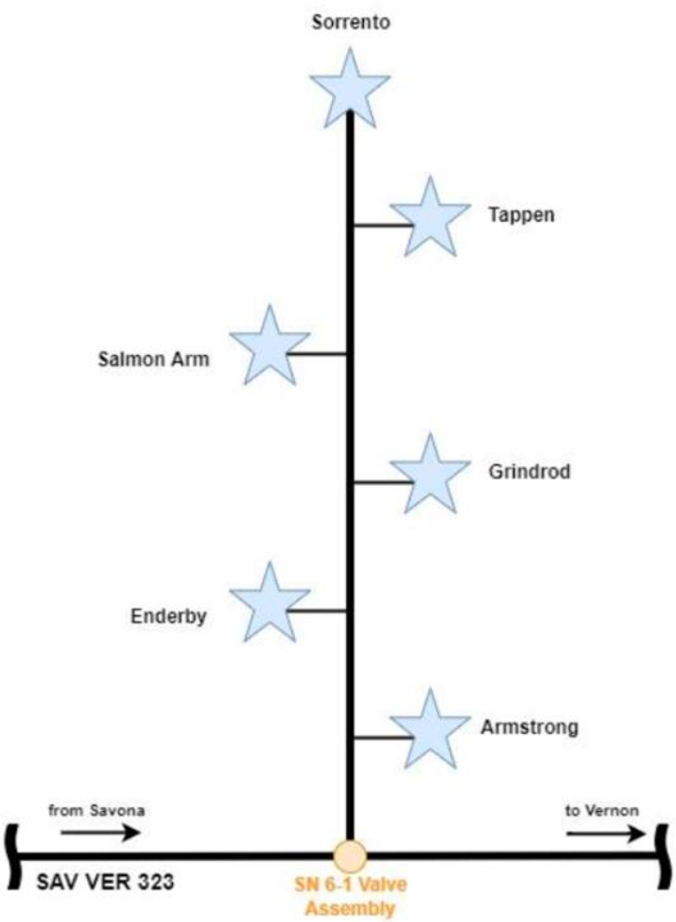
- The susceptibility of all of the selected pipelines in the TIMC projects to cracking threats, as informed by the JANA reports attached as Confidential Appendices B-1 and B-2 to the Application;

- FEI's Z662 obligations to monitor for threats that can lead to failures, as informed by FEI's participation on Z662 committees and through its conversations with regulators and industry; and
- Industry practice of using ILI technology where it is available, proven and commercialized, which FEI is aware of through its participation on industry committees and conversations with its industry peers. Specifically, transmission pipeline operators have adopted EMAT ILI as the most practical and cost-effective mitigation to avoid potential ruptures from cracking on SCC susceptible transmission pipelines to meet public, regulators' and their own companies' expectations of pipeline performance.

Dynamic Risk has already validated the need for the TIMC projects in its Independent Report (attached as Appendix O-1 to the Application). FEI has sufficient knowledge of these Project drivers without further validation from Dynamic Risk.

16. Reference: Exhibit B-1, page 55 and 56

Figure 3-14: Interior Communities Only Supplied by SAV VER 323



The extent of customer outages as a result of a rupture is greater when the demand for gas is higher. Demand is higher in fall and winter months when outside temperatures are colder. As such, during these months there is less capacity available to mitigate the extent of customer outages if a supply disruption occurs. Depending on the time of year and the location of a rupture along the SAV VER 323 and the connected VER PEN 323 pipeline, approximately 5,000 to 105,000 customers could lose service in communities between Savona and Penticton if a rupture were to occur. Depending on the time of year and location of the rupture, these customers could

experience an outage as short as days while the rupture is repaired, or as long as multiple months if the system pressure collapses and the system needs to be purged prior to regasification and service restoration.

The gas supply to many other Interior communities along the ITS pipelines is similar to the SAV VER 323 and VER PEN 323 pipelines, whereby the pipelines are typically unlooped and the flow of gas is restricted to a single direction through the fall and winter months. Thus, the potential reliability consequences of a failure, which can lead to additional safety consequences during colder months, are significant and support the need to enhance FEI's integrity management capabilities.

16.1 In Figure 3-14, FEI provides an example of potential impacts to interior communities supplied by SAV VER 323, which impacts nearly 14,000 customers. Please provide the total number of customers that could be affected for each pipeline.

16.1.1 Please identify the number of customers where the impacts may overlap, where they overlap, and a customer total if there are overlapping impacts.

Response:

The table below shows the largest customer impact for a rupture event coincident with peak demand on the system, grouping the pipelines where the customers impacted by a rupture on one pipeline affects customers on an adjacent connected pipeline.

There are no overlapping customer impacts possible between pipelines in different groupings. For example, none of the 20,500 customers that could be impacted by rupture on the PEN OLI 273 pipeline are also included in the 105,000 customers who could be impacted by a rupture of the VER PEN 323 pipeline.

Group	Pipeline	Approximate Customers Impacted
1	SAV VER 323	105,000
	VER PEN 323	
2	GRF TRA 273	2,650
	OLI GRF 273	
3	PEN OLI 273	20,500
4	KIN PRI 323	1,330
	PRI OLI 323	
5	YAH TRA 323	17,400

There are no overlapping customer impacts possible between pipelines in different groupings.

17. Reference: Exhibit B-1, page 58

> **4.2 ALTERNATIVES IDENTIFIED TO ENHANCE FEI'S CAPABILITIES TO MANAGE CRACKING THREATS ON FEI'S TRANSMISSION PIPELINES**
>
> FEI considered six alternatives to mitigate cracking threats on the 8 ITS pipelines identified as being susceptible to cracking threats. The six alternatives that are currently available to pipeline operators are:
>
> - **Alternative 1:** Stress Corrosion Cracking Direct Assessment (SCCDA);
> - **Alternative 2:** Pressure Regulating Station (PRS);
> - **Alternative 3:** Hydrostatic Test Program (HSTP);
> - **Alternative 4:** Electro-Magnetic Acoustic Transducer In-Line Inspection Program (EMAT ILI);
> - **Alternative 5:** Pipeline Replacement (PLR); and
> - **Alternative 6:** Pipeline Exposure and Recoat (PLE).

17.1 Are the alternatives the same as those considered for the CTS TIMC Project?

17.1.1 If no, please explain why not, and identify key differences.

Response:

Yes, the alternatives considered for the ITS TIMC Project are the same as those considered for the CTS TIMC Project.

18. Reference: Exhibit B-1, pages 70 and 73

Table 4-3: Summary of Alternatives Assessment

	Non-Financial			Financial
	Method Effectiveness	Implementation Complexity	Community and Environmental Impacts	Relative Cost
Alternative 1: SCCDA	×	✓	-	n/a
Alternative 2: PRS	✓	×	✓	n/a
Alternative 3: HSTP	-	×	~	n/a
Alternative 4: EMAT ILI	✓	✓	✓	✓
Alternative 5: PLR	✓	~	~	×
Alternative 6: PLE	✓	~	~	×

SCCDA cannot be counted on to reliably identify the most significant SCC defects on the pipeline; namely those that are most likely to fail. Therefore, on its own, the SCCDA method is not considered an effective approach to SCC integrity management and was not developed to manage crack-like imperfections in seam welds.

The National Association of Corrosion Engineers (NACE), which developed this approach, states that SCCDA is complementary to other inspection methods such as ILI or hydrostatic testing.[62] While SCCDA is not an alternative or replacement for these methods, it can be used to prioritize these other integrity methods "if SCC is found that is sufficient to warrant general mitigation."[63] Therefore, SCCDA can be used to assess pipelines to determine if SCC is a potentially significant threat that would then be mitigated through ILI or pressure testing; however, the analysis conducted by FEI to date has already identified that SCC is a credible threat for the specified lines.

Moreover, in its *Safety Study: Integrity Management of Gas Transmission Pipelines in High Consequence Areas*,[64] the U.S. National Transportation Safety Board made the recommendation to the U.S. Pipeline and Hazardous Materials Safety Administration (PHMSA) that they "develop and implement a plan for eliminating the use of direct assessment as the sole integrity assessment method for gas transmission pipelines". PHMSA stated that "SCCDA is not as effective and does not provide an equivalent understanding of pipe conditions with respect to SCC defects as ILI or hydrostatic pressure testing."[65]

FEI is also aware through its participation in industry groups that its peers do not regard this method as effective in comparison to the other alternatives identified for the ITS TIMC Project.

Ultimately, SCCDA cannot reliably identify the worst cases of SCC that can grow to failure and is therefore unable to achieve the Project Objective of mitigating cracking threats on the 8 ITS pipelines susceptible to cracking. On this basis, SCCDA was not considered further in the evaluation process.

18.1 Recognizing that SCCDA does not fully mitigate the cracking threats, is it reasonable to consider that SCCDA could make a significant contribution to reducing SCC in ITS pipelines for FEI?

18.1.1 Would SCCDA be reasonably considered as 'an improvement' over what is being done at this time? Please explain why or why not.

18.1.2 Please provide any order of magnitude estimates of cost for SCCDA for which FEI might have an understanding.

Response:

No, SCCDA would not make a significant contribution to reducing SCC in ITS pipelines. In particular, FEI does not consider SCCDA to be an improvement over its *status quo* as it would increase costs without increasing FEI's confidence that cracking has been mitigated on its pipelines. As included in Section 3.2.5 of the Application, SCCDA cannot predict the location of cracking and may result in undetected instances of cracking, including those cracks which are the most likely to fail.

Dynamic Risk's Independent Review of the CTS TIMC Project concurs with FEI's assessment. Section E.5.2 of the report includes: "While SCCDA is a suitable method for determine [sic] a pipeline's potential susceptibility to SCC, this method will not reliably identify or size the cracking on the CTS pipelines and should therefore not be considered as an alternative to EMAT ILI." Further, Dynamic Risk's response to RCIA IR2 9.2 in the CTS TIMC Proceeding[4] adds: "…the SCCDA approach may not address all pipeline conditions that contribute to the initiation and progress of SCC and therefore may not fully assess the potential significance of the SCC threat."

These statements are equally applicable to ITS pipelines.

FEI does not consider SCCDA to be a feasible alternative to address cracking threats on any of its susceptible transmission pipelines and, thus, it has not undertaken any level of cost estimate for this alternative.

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4 Included in Appendix O-2 of the Application.

19. Reference: Exhibit B-1, page 71 and page 75

- **Alternative 2:** PRS cannot be implemented to achieve hoop stresses below 30 percent of SMYS on any of the 8 ITS pipelines while maintaining reliable gas supply to customers. Refer to Section 4.4.2 below for further details.

4.4.2 Alternative 2: PRS Leads to System Capacity Limitations

PRS can be highly effective in reducing the likelihood for SCC to cause an in-service pipeline rupture, as these SCC threats would instead be expected to result in leaks. However, pressure reduction creates capacity limitations and significant operational challenges when applied to FEI's 8 ITS pipelines.

As shown in Figure 4-4, the 8 pipelines comprise three bi-directional sub-systems[66] within the ITS, operating between the following FEI facilities (indicated by yellow stars):

1. Kingsvale Control Station and Oliver Y Control Station;
2. Savona Control Station and Oliver Y Control Station; and
3. East Kootenay Exchange Control Station and Oliver Y Control Station.

Each control station is a pressure control point, whereby the pressure in the sub-system pipelines is currently controlled within its operating pressure. These stations could be used to reduce pressure further if the systems had sufficient capacity. As such, a pressure reduction in one sub-system does not limit the pressure and available capacity of another sub-system. However, as described in the following sections, when any of the sub-systems are operated at a reduced pressure, the capacity requirements under current peak day demand cannot be met and extensive system looping would be required to meet current and future gas supply needs. Pressure reduction on the sub-systems also impacts FEI's operational flexibility resulting in a reduced ability to plan and perform maintenance and construction work, establish line pack needs, move gas through the system, and respond to upset conditions.

19.1 Please explain whether the pressure regulating stations could be operated in such a way as to permit higher capacity during peak day conditions while preserving the mitigation benefits for the balance of the year.

Response:

The PRS alternative mitigates risk of rupture by reducing pressure in the pipelines to less than 30 percent of SMYS throughout the year. Since the pipeline pressures must be increased to levels above 30 percent of SMYS to achieve the required capacity levels on a peak day, the pressure regulating stations cannot be operated in any way that meets capacity requirements while providing the needed rupture mitigation.

FEI designs its pipelines to deliver gas to all delivery points at or above minimum delivery pressures under peak day conditions. For a given minimum delivery pressure at a delivery point, the capacity of the pipeline feeding that delivery point is primarily a function of the inlet pressure to the pipeline. During peak day conditions, the capacity requirement, and therefore the inlet pressure requirement for the pipeline is at its highest.

While FEI recognizes that rupture risk would be mitigated at times when the system is operating at less than 30 percent SMYS, operating within this pressure limitation for only part of the year is not an acceptable project alternative as it does not offer mitigation of cracking at those times when the system pressure is increased. In particular, FEI would not meet its regulatory obligations or be in alignment with industry practice during those times. As such, FEI considers long-term operation in this manner to be unacceptable.

19.2 Could FEI reduce risk by reducing the pressure to a level greater than 30%, while still maintaining capacity? Please explain why or why not.

Response:

As discussed in Section 3.5.3.1 of the Application, 30 percent of SMYS is the threshold accepted by FEI and the Canadian pipeline industry for when a pipeline will leak instead of rupture. As such, reducing the SMYS to a level greater than 30 percent would not provide sufficient mitigation of cracking threats over the life-cycle of its transmission pipelines and would not sufficiently reduce FEI's pipeline rupture risk. Therefore, FEI would still need to consider a method for crack mitigation, such as EMAT ILI, PLR or PLE on the ITS pipelines.

19.3 Please identify and explain any options available to FEI to increase capacity such that the PRS option could be implemented.

Response:

FEI would consider the same options to increase capacity at lower pressures as it would to improve system capacity in response to increasing demand. Projects to compensate for the capacity reduction resulting from a PRS option would be substantial, resulting in a project much more costly than the proposed ITS TIMC Project.

At a reduced system pressure (or for a higher system demand), FEI's facilities must transport the demand through the system with a lower overall pressure loss in order to maintain the minimum pressures required to operate the downstream systems, and ultimately, enable delivery to customers. These options include:

- Pipeline looping to reduce pressure losses incurred by the gas flow;
- Installation of compressor facilities to rebuild system pressure lost;
- Peak shaving gas injection within the system, such as provided by LNG facilities, to rebuild system pressure and avoid pipeline pressure loss with a more local supply; or
- A combination of these options.

20. Reference: Exhibit B-1, pages 76 and 77

4.4.2.1 Sub-System 1 between Kingsvale Control Station and Oliver Y Control Station

The first sub-system operates between the Kingsvale Control Station in Kingsvale, BC and the Oliver Y Control Station in Oliver, BC via the KIN PRI 323 and PRI OLI 323 transmission pipelines. These pipelines provide gas to approximately 2,700 existing customers in local communities surrounding the pipelines. However, the majority of capacity on the KIN PRI 323 and PRI OLI 323 pipelines is used to provide additional gas to FEI's CTS. While FEI sources most of the gas needed for the CTS from northern BC via Enbridge's transmission pipeline system, as shown in Figure 4-5, the KIN PRI 323 and PRI OLI 323 pipelines are able to deliver gas from TC Energy in Alberta to the Lower Mainland via FEI's NPS 24 Southern Crossing Pipeline and Enbridge's transmission pipeline system. Thus, the KIN PRI 323 and PRI OLI 323 pipelines provide an alternate source of supply to the CTS and are capable of providing support in the event of a supply interruption from Enbridge north of Kingsvale.

As described in Section 4.2.2, Alternative 2 involves permanently lowering the maximum operating pressure of a pipeline such that the resultant hoop stresses are reduced to below 30 percent of SMYS. The KIN PRI 323 and PRI OLI 323 operate at a maximum hoop stress level of 59 percent of SMYS. The pressure reduction required to achieve a hoop stress below 30 percent of SMYS would result in FEI being able to supply only approximately 30 percent of the gas that can be delivered to the CTS currently. As such, in the event of a supply interruption on the Enbridge transmission system north of Kingsvale, FEI would be further limited in its ability to support the CTS.

20.1 It appears that key sub-system 1 concerns relate to the ability for FEI to serve its CTS customers. What alternatives would be available for FEI to serve CTS customers?

<u>Response:</u>

FEI is typically able to deliver a maximum of 105 million standard cubic feet per day (MMSCFD) of gas to Enbridge's transmission system at Kingsvale which is used as a portion of the total supply required for the CTS and other communities between Kingsvale and Huntingdon. A permanent reduction in the operating pressures of the KIN PRI 323 and PRI OLI 323 pipelines (as proposed in Alternative 2) would result in FEI being able to provide only a fraction of the current delivery to the Lower Mainland. As such, FEI would need to source additional supply in the open market to replace the balance of the gas. This would be challenging and costly given that the Enbridge T-South pipeline system is fully contracted and can be constrained during the winter when there is high gas demand. As a result, FEI would need to pay some premium to a counterparty to obtain their capacity from the T-south pipeline system or expose FEI customers to significantly higher and more volatile supply at the Huntingdon/Sumas market.

21. Reference: Exhibit B-1, page 80

> Recognizing that the ITS pipelines are generally unlooped and pressure reductions on these pipelines result in capacity constraints, similar to those described in Section 4.4.2, FEI would need to consider alternate ways to supply customers serviced by the ITS pipelines, such as pipeline looping which can be costly and lengthy to complete.

21.1 Please provide order of magnitude costing for pipeline looping, and relate that to the cost of the current project.

Response:

FEI clarifies that excerpt from the Application referenced in the preamble relates to pipeline looping to support an HSTP alternative.

A hydrostatic testing program has similar elements to an EMAT ILI program in that testing would be required to be completed on a recurring interval. Further, as noted in Section 4.4.3 of the Application, FEI may be required to implement a 20 percent pressure reduction when the pipeline is put back into service to establish a factor of safety on any integrity features that remain in the untested segments of the pipeline. This pressure reduction may be required through winter when the pipeline is required to be back in service to support higher gas demands. As explained in the response to BCUC IR1 10.1, FEI has the ability to implement a 20 percent pressure reduction through the winter on most of the ITS pipelines with minimal customer impacts over the next 7 years when baseline EMAT ILI runs are planned; however, not in perpetuity due to capacity constraints.

Unlike EMAT ILI, hydrostatic pressure testing does not provide any information on crack growth rates, the formation of new cracking or the location of cracking that has not failed out during the pressure test. As such, there is no way for FEI to predict whether a failure will occur and plan to proactively remove the crack defect prior to the next test interval. Thus, FEI would be required to loop a portion of its system, or install another type of capacity improvement (e.g., compression), to maintain capacity during future HSTP intervals.

FEI is unable to identify what exact percentage of the system would require looping for the HSTP alternative without further and extensive analysis. However, in order to be responsive, assuming 10 percent of the ITS pipelines (corresponding to approximately 75 km of pipeline) required looping, then the magnitude of costs would be in the hundreds of millions of dollars.[5] As such, the looping component of an HSTP alternative would be at least an order of magnitude higher than the proposed ITS TIMC Project. FEI notes that both the order of magnitude cost for HSTP and the ITS TIMC Project cost do not include recurring program activities, such as performing ILI tool runs or hydrostatic tests, that would contribute to the total lifecycle cost of the alternatives.

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5 This order of magnitude estimate is based on a cost per km calculated from the Alternative 5: PLR cost provided in the CTS TIMC Project.

22. Reference: Exhibit B-1, page 81 and page 82

Table 4-4: NPV Cost Comparison of CTS TIMC Alternatives (2020$)

	Alternative 4: EMAT ILI ($ millions)	Alternative 5: PLR ($ millions)	Alternative 6: PLE ($ millions)
Net Present Value of Total Capital and O&M Cost[75]	$307	$1,811	$1,902

Based on the order of magnitude differences in cost between the alternatives, and recognizing that the total length of the 11 CTS pipelines was approximately 254 km and the total length of the 8 ITS pipelines is approximately three times longer (752 km), FEI did not consider it a prudent use of funds to undertake another cost estimate of these alternatives for the ITS TIMC Project.[76]

Table 4-5: Relative Cost Comparison of Three Remaining Alternatives (using NPVs from CTS TIMC Project)

	Alternative 4: EMAT ILI	Alternative 5: PLR	Alternative 6: PLE
Relative Cost	1	5.9	6.2

22.1 FEI states that it would not be a prudent use of funds to undertake a cost estimate for the ITS alternatives, and instead relies on the information from the CTS Project. What is the approximate cost of undertaking a preliminary cost estimate for the ITS alternatives?

<u>Response:</u>

Based on its PLR and PLE cost estimates obtained during the development of the CTS TIMC Project, FEI estimates the cost of undertaking a preliminary cost estimate (i.e., Class 5) for each alternative to be between approximately $45 and $60 thousand per estimate. FEI estimates six months would be required to produce the estimates.

23. Reference: Exhibit B-1, page 86

> While FEI has been running geometry, MFL-A and MFL-C tools in the ITS pipelines for many years, EMAT ILI tools have a different set of system readiness criteria as they are generally longer than other ILI tools and require different conditions for a successful run. The system readiness criteria for EMAT ILI tools are set out in Appendix F, and can be summarized as follows:
>
> - **Can the EMAT ILI tools be introduced into the pipelines using existing infrastructure?** The existing launching and receiving facilities were designed to accommodate geometry, MFL-A and MFL-C ILI tools which are generally shorter than EMAT ILI tools. Modifications are required to the existing ILI launchers and receivers to accommodate EMAT ILI tools.
> - **Can the EMAT ILI tools successfully navigate these pipelines and, in particular, are there any locations on these pipelines where a certain feature or pipeline geometric feature can stop the tool from navigating through them?** A feature which may not have been a problem for the geometry, MFL-A and MFL-C tools may be a problem for the EMAT ILI tools because EMAT ILI tools are longer, heavier and operate at slower speeds which may react differently to changes in conditions than these other tools. Based on analysis from historical MFL-A and MFL-C ILI tool runs, as well as FEI's EMAT ILI pilot project, FEI expects the EMAT ILI tool to successfully navigate the ITS TIMC pipelines.

23.1 What is the approximate proportion of capital in the Project that is being spent on infrastructure to accommodate the EMAT ILI tools?

Response:

To meet the Project objectives outlined in Section 4.1 of the Application, all components of the ITS TIMC Project are required to improve the ITS infrastructure in order to accommodate the EMAT ILI tools. Specifically, the capital cost estimate with contingency for the ITS TIMC Project is $71.894 million in as-spent dollars as shown on Line 6 of Table 6-1 of the Application (excluding the deferral costs, financing costs, and income tax recovery), which represents approximately 85 percent of the total Project cost of $84.588 million.

23.2 Please confirm, or otherwise explain, that FEI is not aware of any ILI tools likely coming on to the market that are smaller, or might otherwise be able to make use of the existing infrastructure.

Response:

Confirmed. FEI is not aware of any EMAT ILI tools likely coming on to the market that are short enough to be used in its existing ITS ILI tool launcher and receiver facilities. The sensor configurations of EMAT tools result in them being longer than the existing ILI tools currently used by FEI in the ITS.

24. Reference: Exhibit B-1, page 90

> Currently, when FEI does not obtain data or only degraded data from ILI tool runs due to speed excursions, FEI manages integrity by:
>
> - Relying on data from a complementary technology previously run successfully in the line, with additional conservatism applied, where available;
> - Relying on data from a prior successful run(s) of the same technology, with additional conservatism applied, where available; and
> - Undertaking an analysis that adds conservatism for those segments where a degraded data specification is available from the vendor. If a vendor does not provide assurance of the degree of accuracy of ILI data (i.e., through a data specification), the information is not suitable for integrity decision-making.
>
> Therefore, to reduce speed excursions that compromise FEI's ability to collect quality data as much as practicably possible, the Project will replace heavy-wall pipe that is known to have caused speed excursions in the past when undertaking MFL-C ILI runs. FEI determined that it could use historical MFL-C tool data to anticipate EMAT ILI tool behaviour through its EMAT ILI

24.1 Does heavy wall pipe always cause speed excursions, or should this be considered as more of a risk?

24.1.1 If heavy wall pipe does not always cause speed excursions, what proportion of the time can it be expected to result in degraded data?

Response:

Heavy-wall pipe always changes the speed ILI tools travel. Frequently, this results in a "speed excursion" where the tool travels outside its optimal velocity range resulting in lost or degraded data. As discussed further in the response to BCUC IR1 9.1, heavy-wall pipe always presents a risk to achieving an acceptable EMAT ILI tool run. Therefore, as explained in the response to BCUC IR1 8.6, FEI and other pipeline operators examine their systems prior to running in-line inspection tools with the intention of optimizing the potential for successful tool runs.

24.2 How long does it take for a single run to be completed on an average length pipeline?

Response:

As provided in Appendix F to the Application (System Readiness Criteria), the optimal travel velocity for an EMAT ILI tool is between 1 and 2 m/s, whereas the optimal travel velocity for an MFL-C tool is between 1 and 3 m/s. The following table provides the expected times, to the nearest hour, to complete EMAT and MFL-C tool runs on each ITS pipeline considering an average travel velocity of 1.5 m/s and 2 m/s, respectively.

Line Name	Approximate Length (km)	Average Time to Complete EMAT Run (hr)	Average Time to Complete MFL-C Run (hr)
SAV VER 323	143	26	20
VER PEN 323	99	18	14
GRF TRA 273	60	11	8
OLI GRF 273	95	18	13
PEN OLI 273	30	6	4
KIN PRI 323	67	12	9
PRI OLI 323	95	18	13
YAH TRA 323	163	30	23

24.3 FEI states that when it obtains degraded data it sometimes relies on data from prior successful runs of the same technology, which implies variability in the degradation from one run to another. Could FEI repeat ILI runs where the information is extensively degraded and potentially get better data from the combination of more than one set of data? Please explain why or why not.

Response:

Repeat ILI runs, whether performed over a shorter or longer-term period, can produce variability in data degradation. While a combination of more than one set of data (from repeat ILI runs) could potentially provide better data than a single data set, a repeat ILI would not be expected to produce a significantly different result in the absence of addressing a controllable factor (e.g., addressing heavy-wall pipe to minimize the potential for speed excursions).

Variations in tool velocity, pipeline cleanliness and tool performance can all produce variability in data degradation from one ILI run to another. For example:

- Tool velocity can vary from one run to another due to gas flow conditions in the pipeline at the time of the ILI tool run. Customer gas use varies from day to day and over the duration of the ILI tool run.
- Tool velocity can vary from one run to another due to changes in piping, for example by undertaking modifications to heavy-wall pipe to minimize the potential for speed excursions.

- Pipeline cleanliness can fluctuate over time and can contribute to variability in data degradation, despite FEI taking all reasonable proactive steps.
- Vendor tool performance can vary between runs. Variability in performance exists between different vendors. Also, the same vendor may be able to take steps to reduce friction and enhance speed control from one run to another.

Ultimately, while some variability can be controlled by an operator, other aspects cannot be controlled (e.g., customer gas use during an ILI tool run).

25. Reference: Exhibit B-1, page 95

> **5.4.4 Pressure Regulation Is Required to Support EMAT ILI Activities**
>
> As described in detail in Section 3.5.2, FEI's statutory and regulatory obligations align with FEI's efforts to take additional measures to mitigate the risk of failure on the 8 ITS pipelines due to cracking threats. As the extent of the threats is unknown until after the successful EMAT ILI run and initial data analysis, FEI must consider and be ready to implement additional operational changes to safeguard the system through pressure reduction.

25.1 Does FEI expect to provide information to the Commission regarding the extent of SCC threats following its initial ILI runs? Please explain and, if yes, explain when this could be expected to occur.

<u>Response:</u>

FEI's integrity management activities are under the regulatory review, oversight, and authority of the BCUC, BC OGC, and the NEB. Visibility of FEI's activities to the BCUC, including the extent of SCC threats and mitigation and maintenance work to address SCC threats, will occur through FEI's future BCUC regulatory proceedings, including future Revenue Requirements and Annual Review proceedings.

25.2 Does FEI expect to provide information to the Commission regarding mitigation and maintenance work planned to address SCC threats, and, if so, when might this information be made available to the Commission?

<u>Response:</u>

Please refer to the response to CEC IR1 25.1.

26. Reference: Exhibit B-1, page 99

Table 5-1 Project Schedule

Activity	Date
CPCN Preparation	Sep 2021 to Aug 2022
CPCN Filing	Sep 2022
CPCN Approval	Q3 2023
Contractor Selection and Award	
Engineering Services Contractor Selection and Contractor Negotiation	Sep 2023 to Nov 2023
Construction Contractor Selection and Contract Negotiation	Jul 2024 to Jan 2025
Permitting for ITS TIMC	
Municipal and Community Consultation	Aug 2022 to May 2025
Indigenous Communities Consultation	Aug 2022 to Apr 2025
Landowner Consultation & Communication	Mar 2023 to Feb 2024
Federal Permits (Department of Fisheries and Oceans)	May to Dec 2024 (Phase 1) Mar to Sep 2025 (Phase 2)
OGC Permits	Oct 2023 to Feb 2024 (Early Works) Feb 2024 to Mar 2025 (Phase 1) Mar 2025 to Mar 2026 (Phase 2)
ALC Permits	Feb 2024 to Mar 2025 (Phase 1) Mar 2025 to Mar 2026 (Phase 2)
MFLNRORD Permits	Sep 2023 to Feb 2025 (Phase 1) Sep 2024 to Jan 2026(Phase 2)
Ministry of Transportation and Infrastructure Permits	Mar 2024 to Aug 2025
Municipal and Regional District Permits	Aug 2024 to Jan 2025 (Phase 1) Jun 2025 to Oct 2025 (Phase 2)
Utility Permits & Approvals	Aug 2024 to Jan 2025 (Phase 1) Jun 2025 to Feb 2026 (Phase 2)
Environmental and Archaeological Permits	Nov 2023 to Apr 2025 (Phase 1) Feb 2025 to Apr 2026 (Phase 2)

Activity	Date
ITS TIMC CONSTRUCTION	
Engineering Detailed Design	Nov 2023 to Aug 2024 (Phase 1) Sep 2024 to Apr 2025 (Phase 2)
Procurement and Manufacturing	
Long Lead Items	Apr 2024 (both Phases)
Facilities, Electrical, and Instrumentation	Jan 2025 (Phase 1) Aug 2025 (Phase 2)
Fabrication	Mar 2025 to Apr 2025 (Phase 1) Mar 2026 to Apr 2026 (Phase 2)
Mobilization to Site	April 2025 (Phase 1) April 2026 (Phase 2)
Site Installation	
Construction	Apr 2025 to Sep 2025 (Phase 1) Apr 2026 to Sep 2026 (Phase 2)
Restoration and Demobilization	Sep 2025 (Phase 1) Sep 2026 (Phase 2)
Project Close Out	Sept 2026 to Mar 2027

26.1 Please discuss whether or not there could be benefits, such as valuable learnings or improved resource availability, that could be achieved from delaying the Project until after the CTS Project is complete and has conducted its first runs.

26.1.1 If yes, why has FEI not delayed the Project until after the CTS project is complete?

26.1.2 If no, please discuss the ramifications of delaying the Project.

26.1.3 Alternatively, could there be benefits available from delaying the CTS Project until after the smaller ITS Project is complete?

Response:

FEI does not see any benefits that could be achieved from delaying either the CTS TIMC or the ITS TIMC Projects.

First, FEI does not expect any valuable learnings that would change the current timeline or sequencing of the TIMC projects. As discussed in Appendix D to the Application, FEI incorporated the results from the EMAT ILI Pilot Project into its scoping of the ITS TIMC Project. FEI does not expect the learnings from the CTS TIMC Project or the ITS TIMC Project to be materially different from the learnings of the pilot project and therefore waiting for the results from TIMC projects will not add any value over what has already been achieved through the EMAT ILI Pilot Project.

Second, with respect to improved resource availability, FEI is not proposing to undertake construction work for the CTS TIMC and ITS TIMC Projects concurrently. Construction of the CTS TIMC Project is scheduled to be complete by the end of 2024 and, as laid out in Table 5-1 of the Application, construction of the ITS TIMC Project is scheduled to begin in 2025. Therefore, FEI does not expect the two projects to compete for construction resources.

While FEI did not identify any benefits to delaying the ITS TIMC Project, such a delay would have downsides. In particular, delaying the ITS TIMC Project would delay gathering information about cracking on FEI’s ITS pipelines, and therefore, would delay mitigating any existing threats on the system. This would be especially problematic as cracking threats are time dependent, meaning the likelihood of a failure increases over time.

27. Reference: Exhibit B-1, page 102

> **5.7.3 Land Acquisition**
>
> The Project will require fee-simple temporary construction working space and access rights. Certain sites will also require permanent expansion in order to allow for the modifications to be completed. FEI will develop a land management plan to assess the required properties and prioritize the access agreements based on risk and impacts to the Project schedule. In order to reduce the potential uncertainty associated with securing ROW Access Rights, FEI will notify the affected landowners beginning in Q2 2023 based on the land management plan. Upon granting of the CPCN, FEI will complete the confirmation of temporary workspace acquisition and ROW access rights with all affected landowners. The following tables identify land requirements for the pipeline and facilities scope to aid construction activities.

27.1 Please explain the extent to which FEI requires landowner cooperation in order to secure ROW Access Rights.

Response:

FEI prefers to work with landowners when acquiring ROW Access Rights on fee-simple lands. In cases where new land rights are required, FEI pays landowners financial compensation based on the fair market value of a right of way, taking into account property-specific considerations where necessary. In addition, FEI will work with landowners and may consider property-specific conditions or modifications to mitigate project impacts. Despite this, FEI prepares for situations where landowners are non-receptive or uncooperative. In these cases, FEI may review the access requirements and consider various alternatives, if any, before relying on its expropriation rights.

27.2 What, if any, ‘potential uncertainties’ can occur with securing ROW Access Rights.

Response:

The primary uncertainty that FEI faces as it works to acquire land rights is related to the timing of when access rights are secured. When working with landowners to secure ROW Access Rights and temporary workspaces, specific property-related issues can arise that require additional investigation and thus require more time to resolve, such as local archeological and/or environmental considerations. FEI works with landowners to understand their current or future land uses and conditions, and uses this information to reduce project impacts. However, negotiations with landowners can involve legal and other expert support and can be lengthy as property-specific details are considered. FEI aims to mitigate timing uncertainties by engaging with landowners early in the process.

FEI believes that starting landowner discussions in Q2 2023 will provide for the time necessary to complete the required agreements for the ITS TIMC Project.

28. Reference: Exhibit B-1, pages 108 – 109

> **5.9 PROJECT COST ESTIMATE**
>
> FEI, in conjunction with the FEED engineering and cost estimation consultant (Tetra Tech), developed the cost estimate for the Project using AACE International Recommended Practices Nos. 18R-97 and 97R-18 as guides. The AACE Class 3 cost estimate is based on quantities developed from designs and material take-offs (MTOs) completed by Tetra Tech. Tetra Tech then used these quantities as the basis to establish the direct and indirect costs.
>
> The Tetra Tech estimate includes:
>
> - Engineering services, including regulatory, procurement, fabrication and construction support
> - Engineering sub-contracts, such as survey and geotech
> - Materials
> - Pipeline and stations direct construction costs
> - Pipeline and stations indirect construction costs
> - Construction sub-contracts
> - Construction support services.

28.1 Please provide the process by which FEI selected Tetra Tech for the FEED engineering and cost estimate.

Response:

FEI prepared a Scope of Work package outlining the objectives, services, key project roles and qualifications required to prepare the FEED engineering and cost estimate. This was distributed to three pre-qualified pipeline engineering consultants with which FEI has long-term master services agreements and are currently working on other major projects. The proponents provided a proposal outlining their organizational qualifications, proposed project team, rates, availability and schedule to perform the Scope of Work. FEI reviewed the three proposals, evaluated the proposals on a best value basis, and ultimately, selected Tetra Tech as the preferred proponent.

28.2 What, if any, other roles will Tetra Tech undertake in the Project?

Response:

The agreement FEI entered into with Tetra Tech was limited to the Scope of Work for the FEED study and cost estimate. Subsequent detailed engineering work on the ITS TIMC Project will follow a similar procurement process, as described in the response to CEC IR1 28.1, to select the preferred proponent.

29. Reference: Exhibit B-1, page 109

FEI completed the portion of the Project cost estimate related to owner's costs, which includes the following:

- Construction Management
- Engineering
- Environmental / Archaeological
- External Relations (Community Relations, Indigenous Relations, Communications)
- Health & Safety
- Legal
- Operations Support
- Procurement & Contract Management
- Project Management
- Project Services
- Property Services
- Regulatory / Permitting

29.1 Did FEI generally utilize the same staff to develop the owner's cost estimate as was used for the CTS project?

29.1.1 If no, please explain why not.

<u>Response:</u>

Confirmed. FEI generally used the same staff to develop the owner's cost estimate as it used on the CTS TIMC Project, except where regionalized resources were better-equipped to provide input.

30. Reference: Exhibit B-1, page 110

Table 5-5: Project Capital Budget

Line	Item	Amount ($millions)
1	Construction Cost Estimate (Contractor + FEI)	$50.231
2	Owners Costs (FEI)	$8.133
3	**Subtotal Construction Base Cost Estimate ($2022-Q2)**	**$58.364**
4	CPCN Application Costs	$0.400
5	Pre-Construction Development Costs	$3.665
6	Contingency	$5.900
7	**Subtotal Project Cost Estimate ($2021-Q4)**	**$68.328**
8	Cost Escalation Estimate	$7.630
9	Management Reserve	$5.000
10	**Sub-Total Project Cost Estimate (As-Spent)**	**$80.958**
11	AFUDC	$4.513
12	Income Tax Recovery[84]	$(0.883)
13	**Total Project Cost Estimate (As-Spent)**	**$84.588**

5.9.1.2 Cost Estimate Validation

Cost estimate quality assurance, verification, and independent estimating were completed as follows:

- Internal reviews of Tetra Tech's assumptions, deliverables and document quality checks;
- Verification reviews involving both Tetra Tech and FEI team members throughout the estimate development process to confirm that the estimate assumptions were valid;
- Independent external review of the Class 3 cost estimate was done by Universal Pegasus International (UPI), an engineering consultant, to verify from an engineering perspective that the estimate criteria and requirements were met and a documented, reasonable estimate was developed; and
- Independent external estimate completed by Pipestone Projects, a company that specializes in construction planning and estimating, in order to verify from a construction perspective that suitable construction strategy, cost basis and estimating methodology were utilized to provide a detailed, representative estimate.

30.1 Please elaborate on what is meant by verifying 'from an engineering perspective that the estimate criteria and requirements were met.'

Response:

Verifying "from an engineering perspective" means that Universal Pegasus International (UPI) confirmed engineering activities, such as P&ID drawings, site plot plans, and that demolition drawings, proper tools and methods were used. UPI also verified that the cost estimate criteria and requirements had been met and that a comprehensive and reasonable estimate had been developed. The independent review completed an unbiased check of the cost data, assumptions, productivity factors, schedule and exclusions used in developing the estimate.

30.2 Please identify any aspects of the cost estimate, particularly that which were prepared by FEI, that were not subject to an external, independent review.

Response:

The areas of the base cost estimate that were not subjected to an external, independent review include the construction costs prepared by FEI in Line 1 of Table 5-5 of the Application for the modification to control and safety systems (Section 5.4.4.2 of the Application), the SN-4 pressure regulating station (PRS)[6] (Appendix G-4 to the Application), and the owner's costs prepared by FEI in Line 2 of Table 5-5 of the Application.

All other aspects of the base cost estimate were subject to an external independent review.

6 SN-4 PRS design and cost estimate was modified from the Cary Rd Station PRS design and cost estimate prepared by Tetra Tech and reviewed by UPI.

31. Reference: Exhibit B-1, page 112

> ***5.9.2.3 Risk Quantification & Contingency Analysis***
>
> FEI retained an independent expert Validation Estimating LLC, USA (Validation Estimating, John Hollmann), a company that provides services in estimate validation, risk analysis and contingency, to complete a contingency estimation and a quantitative analysis using an integrated parametric and expected value methodology. This analysis is described in the report titled "ITS
>
> ---
>
> Validation Estimating facilitated a series of risk workshops to evaluate the systemic and project-specific risks with the extended project team and identify critical risks. Following the workshops, the independent expert quantified the contingency, using probabilistic methods to provide a distribution of possible cost and duration outcomes, to adequately address Project risks over a multi-year execution timeframe. This risk quantification applies a hybrid approach that combines a parametric model analysis for systemic risks based on empirical knowledge, and an expected value analysis for project specific risks, which assesses probability of occurrence and integrates anticipated cost and schedule impacts. The hybrid approach is in accordance with and is aligned to the following AACE International Recommended Practices:
>
> - 40R-08 Contingency Estimating – General Principles;
> - 42R-08 Risk Analysis and Contingency Determination Using Parametric Estimating; and
> - AACE 113R: Integrated Cost and Schedule Risk Analysis and Contingency Determination Using Combined Parametric and Expected Value.
>
> The risk analysis was used to establish a contingency percentage of 10.1 percent ($5.9 million) at the P50 confidence level, based on the current understanding of the Project's risk profile. A recommendation for the management reserve for the project has also been included in the risk analysis. The recommended P50 confidence level management reserve for the project is $5.0 million, which is 8.6 percent of the base cost estimate value.

31.1 Did FEI use a competitive bid process in order to select Validation Estimating to complete their contingency estimation and quantitative analysis?

31.1.1 If no, please explain why not.

<u>Response:</u>

No, FEI did not use a competitive bid process to select Validation Estimating. FEI selected Validation Estimating to undertake this work because the principal (John Hollmann) is an internationally recognized third party risk management expert with extensive experience in contingency estimation and quantitative risk analysis and is the lead author of the applicable AACE International Recommended Practices. The cost of the work undertaken for the ITS TIMC Project was approximately $15 thousand.

Moreover, FEI has used Validation Estimating for contingency estimation and quantitative risk analysis in all of its recent major projects (i.e., the Inland Gas Upgrades, Pattullo Gasline Replacement, Okanagan Capacity Upgrade, Tilbury LNG Storage Expansion, and CTS TIMC CPCNs). In the BCUC's decision in the CTS TIMC application, the Panel also accepted and was satisfied with FEI's approach to cost estimating, including the contingency and escalation estimate prepared by Validation Estimating, an independent external party.[7]

Mr. Hollmann's credentials are as follows:

- Registered professional mining engineer and a certified cost professional (CCP; formerly called Certified Cost Engineer), in addition to being a Certified Estimating Professional (CEP) and a Decision and Risk Management Professional (DRMP). He has a Bachelor of Science degree in Mining Engineering from the Pennsylvania State University and a MBA from the Indiana University of Pennsylvania.
- Fellow of AACE (2006) and received the Lifetime Achievement Award in 2018, its highest honor.
- Lead editor and primary author of the ACCE Total Cost Management Framework, for the First Edition published in 2006.
- Principal of Validation Estimating LLC since 2005.
- Prior to forming Validation Estimating LLC in 2005, Mr. Hollmann managed the downstream Cost Engineering Committee (CEC) and cost and schedule metrics programs of Independent Project Analysis, Inc. (IPA) for 7 years. Before IPA, he was a senior estimator with Eastman Kodak where he helped lead their development of cost estimating processes, systems, tools and data (Kodak was a combined chemical and manufacturing company). Prior to that, he was a Senior Project Control Engineer with Fluor Daniel, Inc. working in the industrial, refining, and pipeline sectors.
- Author of a book titled Project Risk Quantification (2016), technical articles, and AACE International Recommended Practices on cost estimating, risk analysis and contingency determination. Refer to the following link for a list of Mr. Hollman's publications (Articles by J. Hollmann - validest.com).

7 Decision and Order C-3-22, p. 38.

32. Reference: Exhibit B-1, page 114

Table 5-7: ILI Activities

Activity	Cost Type	Timing
Run EMAT ILI Tools in the ITS: With the required pipeline and facility alterations complete, FEI will schedule and run the EMAT ILI tools in each pipeline. It is estimated that these tools will need to be run at least every seven years to monitor the growth of crack-like threats to the pipeline and to provide information on where FEI needs to respond to and repair any crack-like threats. The actual run frequency for each pipeline will be determined after the initial baseline run, once the condition of the pipeline (with regards to the crack-like features) is better understood.	Capital	Initial runs to begin in 2026. Runs will continue through the useful life of the asset.
Perform Integrity Digs and Repairs: Informed by the information gathered by the EMAT ILI tool runs, FEI will perform Integrity Digs to validate the data and repair integrity concerns on the pipeline. Interpretation of the EMAT ILI tool data is iterative and consists of a review of the data and then field validation. There may be multiple phases of integrity digs associated with the same EMAT ILI tool run, with the information gathered from the validation digs fed back into the data analysis.	Flow-through O&M	2026 through 2035 Integrity Digs for validation and repair will start shortly after the EMAT ILI run, and may continue up to three years after the run.
In-Ditch Inspection of EMAT ILI Tool Blind Spots: If, once the validation digs are complete, there remain sections of the pipeline with deficiencies in the collected data (blind spots), FEI will evaluate the sections to determine whether further work needs to be done to ensure adequate risk identification and mitigation. This evaluation will be based on the following factors: 1. The severity of the data degradation; 2. The condition of the rest of the pipeline; 3. The percent coverage of the tool; and 4. The location of the blind spots. Where required by the evaluation, discrete projects will be raised to mitigate SCC risk at these blind spots. A committee of FEI subject matter experts will determine the length of pipe that needs to be addressed and the method that will be applied to mitigate SCC. Integrity management methods including pipeline replacement (PLR) or pipeline exposure and recoat (PLE) may be used in localized applications where blind spots have occurred and where altering the pipeline to obtain high quality EMAT ILI data is not feasible.	O&M or Capital, in accordance with FEI's Capitalization Policy	2027 through 2035 The Final Report for the EMAT ILI run is a key input for defining these projects, and is likely to take two to three years to receive following a tool run.

32.1 Please confirm or otherwise explain that the EMAT runs would not be conducted continually, but will instead be run on some sort of schedule of approximately once every seven years.

Response:

Confirmed. FEI is currently forecasting that EMAT will be run on each pipeline on a schedule of once every seven years.

32.2 Over what period of time will FEI be able to complete all the pipeline runs in the ITS?

Response:

Please refer to the response to BCOAPO IR1 1.1.

32.3 Why is seven years likely the appropriate length of time for repetition to monitor the growth of crack line threats to the pipeline?

Response:

Canadian pipeline standards are generally not prescriptive in nature, thereby affording operators the flexibility to determine appropriate re-inspection intervals for pipeline assets and inspection technologies, including EMAT ILI. A re-inspection is typically undertaken to assess for any new cracks and the potential growth of previously identified cracks, but can also serve other purposes, such as allowing an operator to obtain data from a more modern tool.

Although the actual length of time interval for monitoring cracking threats will be line-specific, FEI has identified seven years as an approximate re-inspection timeframe based on its prior ILI experience and understanding of industry practice.

In the table below, FEI provides examples from publicly available sources quantifying a re-inspection interval for ILI generally (and not necessarily specific to cracking risk):

Source	Excerpt	Relevance
CSA SPE-225.5:22, Metal Loss Inline Inspection Tool Validation Guidance Document, 1st Edition, January 2022[8]	Section 6.2.2, page 34, "Furthermore, a lengthy interval (e.g. more than 5 years) between ILI inspections or the use of very different technologies can make matching difficult if not impossible."	This indicates a consensus among CEPA members (who developed this document) that "more than 5 years" is a "lengthy interval" for a re-inspection with an ILI tool and for matching defect and/or imperfection information between ILI inspections.

8 https://www.csagroup.org/store/product/CSA%20SPE-225.5%3A22/.

Source	Excerpt	Relevance
Transportation Safety Board of Canada, Pipeline Transportation Safety Investigation Report P18H0088, Pipeline rupture and fire, Westcoast Energy Inc., Prince George, British Columbia, 09 October 2018[9]	4.1 Safety action taken From 4.1.2 Westcoast Energy Inc. "The maximum re-inspection interval for EMAT in-line inspections for all L2 pipeline segments was set to 6 years. Further, Westcoast has implemented a more conservative approach in responding to pipeline inspection data that may identify areas requiring closer monitoring or earlier maintenance work."	FEI's re-inspection interval range is consistent with this quantification of a re-inspection interval from Westcoast Energy Inc.
US Code of Federal Regulations Part 192 – Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards[10]	§192.937 "What is a continual process of evaluation and assessment to maintain a pipeline's integrity? […] An operator must reassess a covered segment on which a baseline assessment is conducted […] by no later than seven years after the baseline assessment of that covered segment unless the evaluation under paragraph (b) of this section indicates earlier reassessment." §192.939 "What are the required reassessment intervals? […] The maximum reassessment interval by an allowable reassessment method is seven years."	Part 192 contains federally regulated requirements for US gas transmission pipelines. FEI's assessment of industry practice in Canada, while not similarly prescribed in a Canadian standard or regulation, does align with this prescriptive US pipeline regulation. This provides an indication that FEI's range of re-inspection frequency is common. FEI notes that there are provisions in the US standard that allow for an extension of the maximum re-inspection interval up to 10 years for transmission pipelines inspected with ILI tools, although this requires the performance of supplemental inspections.

32.4 What would be the most frequent cycle that pipeline runs could be usefully conducted?

Response:

The use of a re-run can be diminished if an insufficient length of time has passed for new cracks or crack growth to form, and therefore, for tool-reported information to be differentiated from tool measurement error. Although the typical industry re-inspection interval is between five to seven years for all ILI tool re-runs, FEI is informally aware of an EMAT ILI re-inspection interval as short as two years.

[9] https://www.tsb.gc.ca/eng/rapports-reports/pipeline/2018/p18h0088/p18h0088.html.
[10] https://www.ecfr.gov/current/title-49/subtitle-B/chapter-I/subchapter-D/part-192.

32.5 What would be the approximate cost of a future run of the EMAT ILI tools?

Response:

As noted in the response to BCUC IR1 13.2, a single EMAT ILI tool run can range from $1.5 to $2.5 million (inclusive of both FEI's costs and contractor costs).

32.6 Is there any equipment such as PIGS (as opposed to infrastructure) that will essentially sit idle for 7 years, between runs?

32.6.1 If yes, please identify the equipment.

32.6.1.1 How does FEI intend to care for such equipment?

32.6.1.2 Could FEI share or rent the equipment to other natural gas companies? Please explain why or why not.

Response:

FEI is not aware of any equipment, including pipeline inspection gauges (PIGS), that will sit idle for the interval between ILI runs, EMAT or otherwise. FEI and the pipeline industry contract with in-line inspection vendors for the running of ILI tools and the subsequent translation/interpretation of the raw signal data obtained by the tools into pipeline condition information. ILI tools are generally owned and operated by ILI vendors, not FEI. As such, these vendors manage the utilization and maintenance of the tools.

33. Reference: Exhibit B-1, page 118 and 121, and Appendix P page 7

The ITS TIMC Project will result a cumulative delivery rate impact of 0.72 percent by 2028 when all assets as well as all closing costs have entered FEI's rate base. Please refer to Section 6.5 for further discussion on the delivery rate impact and equivalent bill impact to typical residential customers. Over 70-year analysis period (i.e., 65 years for the average service life of the assets plus 5 prior years for the project), the PV of the incremental revenue requirement is approximately $93.621 million and the levelized delivery rate impact is 0.54 percent or $0.027 per GJ.

Table 6-3: Financial Analysis of the Project

Line	Particular	TOTAL	Reference (Confidential Appendix J, Financial Schedule)
1	Total Charged to Gas Plant in Service ($ millions)	85.161	Schedule 6, Sum of Line 43 (2022-2027)
2	Total Project Deferral Costs, Net of Tax	(0.574)	Schedule 9, Line 8 (2023)
3	*Total Project Cost - Excl. Sustainment Capital ($ millions)*	*84.588*	*Line 1 + Line 2*
4	Sustainment Capital	103.062	Schedule 6, Sum of Line 43 (2028-2091)
5	*Total Project Cost - incl. Sustainment Capital ($ millions)*	*187.650*	*Line 3 + Line 4*
6			
7	Incremental Rate Base in 2028 ($ millions)	81.004	Schedule 5, Line 19 (2028)
8	Incremental Revenue Requirement in 2028 ($ millions)	6.860	Schedule 1, Line 11 (2028)
9	*PV of Incremental Revenue Requirement 70 years ($ millions)*	*93.621*	*Schedule 10, Line 25*
10	Net Cash Flow NPV 70 years ($ millions)	4.227	Schedule 11, Line 17
11			
12	Delivery Rate Impact in 2028 (%)	0.72%	Schedule 10, Line 28 (2028)
13	*Levelized Delivery Rate Impact 70 years (%)*	*0.54%*	*Schedule 10, Line 32*
14	Levelized Delivery Rate Impact 70 years ($/GJ)	0.027	Schedule 10, Line 45

Table 6-5: Summary of Delivery Rate Impact of the Project

	2024	2025	2026	2027	2028
Annual Delivery Margin, Incremental to Approved, Non-Bypass ($ millions)	(0.195)	(0.173)	3.099	6.782	6.860
% Increase to Approved Delivery Margin, Non-bypass	*(0.02%)*	*(0.02%)*	*0.32%*	*0.71%*	*0.72%*
Incremental % Delivery Rate Impact (Year-over-Year)	*(0.02%)*	*0.00%*	*0.34%*	*0.38%*	*0.01%*
Average Annual % Delivery Rate Impact (5 years, 2024 - 2028)	0.14%				
Average Annual Delivery Rate Impact (5 years, 2024 - 2028), $/GJ	0.007				
Cumulative % Delivery Rate Impact (5 years, 2024 - 2028)	0.72%				
Cumulative Delivery Rate Impact (5 years, 2024 - 2028), $/GJ	0.035				

1.2 Based on the 10-year renewable gas supply forecast reproduced above, what percentage (by energy) of the gas in the CTS will be hydrogen in: i) 2030; ii) 2040; and iii) 2050.

<u>Response:</u>

By 2030, FEI expects that there will be minimal hydrogen in the gas flowing in the CTS pipelines. FEI cannot know at this time what the precise percentage of hydrogen in the gas in each CTS pipeline will be in 2040 or 2050, but FEI expects that methane (whether from conventional or renewable sources) will continue to exceed 80 percent by volume of the gas transported by the CTS pipelines for at least 20 years. Additional amounts of hydrogen to support FEI's low-carbon diversified pathway may also be transported by other new or repurposed infrastructure.

33.1 Please provide additional data supporting the 65 years average service life of the asset, and discuss whether or not the average service life considers technological obsolescence.

<u>Response:</u>

The 65-year average service life of the transmission mains pooled assets is based on FEI's most recent depreciation study (2017 Depreciation Study), which was approved by Order G-165-20 as part of FEI's 2020-2024 MRP Application. FEI notes this approach is consistent with the financial analysis of FEI's past CPCN applications, most recently the CTS TIMC Project CPCN application.

Technological obsolescence is one of the many considerations in determining the recommended average service life as well as the resulting depreciation rates for each asset class in the depreciation study. As explained in the 2017 Depreciation Study, the average service life is based on historical data observed from the assets within the same pooled account (i.e., transmission mains in the case of the ITS TIMC Project), indications from the utility's management and operations, as well as professional judgement (i.e., Concentric, who completed the 2017 Depreciation Study). Specifically, Concentric noted that considerations were given on wear and tear, deterioration, action of the elements, inadequacy, *obsolescence*, decay, changes in the art, changes in demand, and the requirement of public authorities.

With regard to the potential impact of hydrogen blending on the used and useful life of FEI's pipeline, this was addressed in the CTS TIMC Project CPCN proceeding and is also applicable to the ITS TIMC Project. The CTS and ITS pipelines are capable of safely transporting a blend of hydrogen and the pipelines will continue to be used and useful even if hydrogen blends are introduced into the pipelines.[11] Furthermore, the EMAT ILI tools will continue to be needed and used on the CTS and ITS pipelines for integrity purposes regardless of whether the pipeline is transporting a blend of hydrogen or not. As such, FEI has no reason to believe the ITS pipeline or the assets associated with the ITS TIMC Project will become stranded over the 65-year post-Project analysis period.

Given the reasons above, the use of a 65-year average service life is reasonable and appropriate for the purposes of evaluating the financial impact due to the ITS TIMC Project. This was also accepted by the BCUC in its decision on the CTS TIMC Project:[12]

> While the Panel has raised concerns about the potential impact of future hydrogen blending on the used and useful life of FEI's pipelines as already discussed earlier, the Panel also finds FEI's use of a 70-year analysis period based on a 65-year post-Project analysis period to be reasonable as it reflects the average service life of transmission mains pooled assets in FEI's 2017 Depreciation Study.

33.2 Please discuss the use of the 70-year analysis period in light of FEI's statement that it can only state that methane will exceed 80% by volume of gas for 20 years, and cannot predict the amount of hydrogen by 2040 or 2050.

[11] Decision and Order C-3-22, pp. 39 to 41.
[12] Decision and Order C-3-22, p. 50.

Response:

The statement referenced in the preamble is referring to the potential blend of hydrogen in FEI's system and that FEI is unable to predict the amount of hydrogen in the system after 2040 or 2050; the statement is not suggesting that FEI's system will not be used and useful after 2040 or 2050. As discussed in the response to CEC IR1 33.1 and in the CTS TIMC Project CPCN proceeding, FEI's pipelines are expected to remain used and useful regardless of the amount of hydrogen that is blended into the system. As such, the use of a 70-year analysis period (65-year post-Project analysis period plus 5 years for construction) is reasonable and appropriate.

33.3 Please conduct a PV analysis, and levelized delivery rate analysis over 30 years, 40 years and 50 years.

Response:

As explained in the responses to CEC IR1 33.1 and 33.2, the ITS pipelines will continue to be used and useful regardless of the potential hydrogen blending in the future; thus, the use of a 65-year post-Project analysis period is reasonable and appropriate.

However, in order to be responsive, FEI has provided Table 1 below which shows the PV of incremental revenue requirement and levelized delivery rate impact over a 30-year, 40-year, and 50-year period. FEI notes there is no material difference in the levelized delivery rate impact for the different analysis periods when rounded to two decimal places.

Table 1: ITS TIMC Project Financial Analysis over 30, 40, 50, and 70-year Periods

	30 Years	40 Years	50 Years	70 Years (As-Filed)
Total PV of Annual Revenue Requirement ($000s)	73,653	83,066	88,023	93,621
Levelized % Increase on 2022 Delivery Rate	0.52%	0.54%	0.54%	0.54%

34. Reference: Exhibit B-1, page 121 and 122

> The ITS TIMC Project will result in an estimated cumulative delivery rate impact of 0.72 percent by 2028 when all construction and closing costs are complete and all capital costs have entered FEI's rate base. The average annual delivery rate impact over the five years from 2024 to 2028 is estimated to be 0.14 percent annually or $0.007 per GJ annually. For a typical FEI residential customer consuming 90 GJ per year, this would equate to an average bill increase of approximately $0.63 per year over the five years, or $3.15 cumulatively by 2028.
>
> **6.6 CONCLUSION**
>
> In summary, the ITS TIMC Project has a Total Cost Estimate of $84.588. million and will result in an estimated delivery rate impact of 0.72 percent in 2028 when all construction is complete and after all assets are placed in service. For a typical FEI residential customer consuming 90 GJs per year, this would equate to an approximate average bill increase of $3.15 per year.

34.1 To the extent that the project assets were not able to be used and useful after 2040, or any other period before 65 years, due to technological changes or other concerns related to the use of natural gas, how would FEI expect to address the stranded assets?

Response:

As discussed in the response to CEC IR1 33.1, FEI has no reason to believe the ITS or the assets associated with the ITS TIMC Project will become stranded over the 65-year post-Project analysis period. Therefore, FEI has not developed a plan to address the unlikely hypothetical scenario in which they become stranded. If such a scenario were to develop, it would not be specific to the ITS or the ITS TIMC Project and would be addressed at that time.

35. Reference: Exhibit B-1, page 124 and 132

> FEI retained Wood Environment and Infrastructure Solutions[88] to complete an EOA of the ITS TIMC Project, comprised of 3 Pipeline Events within the existing rights of way and 13 alterations to existing Facilities.[89] The EAO report is provided as Appendix K to the Application. The EOA identifies the potential impacts to the biophysical environment from the Project and provides a basis for the completion of additional assessments and preparation of environmental management plans prior to construction commencement.
>
> **7.3 ARCHAEOLOGY**
>
> FEI retained Wood Environmental and Infrastructure Solutions to complete an AOA of the Project, filed as Appendix L of the Application, to assess archaeological and/or cultural heritage resources within the Project area. The AOA determined the necessity and, as required, the scope of, additional archaeological assessments (e.g., AIA) prior to, or concurrent with, the commencement of any ground disturbing activities.

35.1 Please provide an approximate cost for the Environmental Overview Assessment (EOA) report and the Archaeological Overview Assessment (AOA).

<u>Response:</u>

The approximate cost of the Environmental Overview Assessment (EOA) report, including desktop and field studies was $61 thousand.

The approximate cost of the Archaeological Overview Assessment (AOA) report, including desktop and field studies was $70 thousand.

35.2 Please provide the process used to select Wood Environment and Infrastructure Solutions (Wood) to complete the EOA and the AOA.

<u>Response:</u>

Wood Environment and Infrastructure Solutions (now WSP), an existing FEI contractor and provider of technical services on an as and when basis, were selected as they were capable of providing both environmental and archaeological services for the CPCN. Due to their ability to meet project timelines, a project decision was made to directly award each scope of work to WSP.

35.3 Please explain whether or not FEI achieved cost savings by using a single company for the two reports, and if so, please quantify the savings.

Response:

Yes. FEI achieved cost savings of approximately $5 thousand in project management fees by using a single company for the two reports. In addition, internal cost and time savings were achieved by FEI through managing only one contract and having one point of contact with WSP.

36. Reference: Exhibit B-1, page 124 and 85

> FEI retained Wood Environment and Infrastructure Solutions[88] to complete an EOA of the ITS TIMC Project, comprised of 3 Pipeline Events within the existing rights of way and 13 alterations to existing Facilities.[89] The EAO report is provided as Appendix K to the Application. The EOA identifies the potential impacts to the biophysical environment from the Project and provides a basis for the completion of additional assessments and preparation of environmental management plans prior to construction commencement.

Table 5-2: Pipelines Within Project Scope

Pipeline	Approximate Length (km)	Number of Alterations	Summary of Alterations
Savona Vernon 323	143	1	Replacement of one approximately 80 metre heavy wall pipe segment and bends on either side of the crossing at Cherry Creek (kP 16.9).[81] Replacement pipe and fittings to match upstream and downstream line pipe wall thickness. **(Event 1)**
Vernon Penticton 323	99	N/A	No mitigations required.
Penticton Oliver 273	30	N/A	No mitigations required.
Oliver Grand Forks 273	95	N/A	No mitigations required.
Grand Forks Trail 273	60	N/A	No mitigations required.
Kingsvale Princeton 323	67	2	Replacement of two 2.5 metre heavy wall pipe segments at kP 39.4. Replacement pipe to match upstream and downstream line pipe wall thickness. **(Event 29)** Replacement of one heavy wall above ground valve assembly at block valve assembly KO-3[82] (kP 47.7). Replacement to match upstream and downstream line pipe wall thickness. This includes replacement of bends, fittings and other heavy wall features. **(Event 31)**
Princeton Oliver 323	95	N/A	No mitigations required.
East Kootenay Link 323	163	N/A	No mitigations required.

36.1 Please confirm that the 'Pipeline Events' addressed by Wood refers to Event 1, Event 29, and Event 31 shown in Table 5-2.

<u>Response:</u>

Confirmed. The 'Pipeline Events' addressed by WSP refer to Event 1, Event 29, and Event 31 shown in Table 5-2.

36.2 Please confirm or otherwise explain that, to the extent that additional work was required beyond that currently anticipated, FEI would have additional Environmental studies conducted prior to completing the work.

Response:

If a project scope change occurred that substantially changed the Project footprint, additional environmental studies may be required, and would be conducted prior to completing the additional work.

FEI notes that additional work could be required for two reasons: (1) a design scope change could occur during the detailed engineering phase of the Project; and (2) there could be a minor scope change due to construction activities.

At this time, FEI does not anticipate any design or construction scope change to the Project.

36.3 Please confirm that such studies would be included in the existing contingency.

Response:

As discussed in the response to CEC IR1 36.2, there could be two reasons to conduct the additional environmental studies. Any additional environmental studies required in the field due to construction scope changes are included in the existing Project contingency. However, the existing contingency does not include any cost items which are outside the Project scope as proposed in the Application. Therefore, if FEI is required to conduct any additional environmental studies due to a design scope change, it will not be covered by the existing Project contingency.

1 **37. Reference: Exhibit B-1, page 127**

Twenty APECs were identified in the contaminated sites study area as occurring on or around Project Facilities and are summarized in the EOA (Appendix K) and in Table 7-2 below. No APECs were identified as occurring on or around the Pipeline Events. Prior to or during construction, these soils will be assessed to assist in identification of appropriate disposal facilities.

Table 7-2: Registered Contaminated Sites and APECs Overlapping with Project Facilities

Facility	APEC Address	Distance from Facility	Description
Savona Compressor Station	Tunkwa Lake Road, Savona	Onsite	Compressor station 1998: Remediation of hydrocarbon contaminated soil 2011: Hazardous waste generator (flammable liquids)
Penticton Gate Station	401 Warren Avenue E, Penticton	Onsite	1994: Remediation of soils containing mercury
Penticton Gate Station	Structurlam 402 Warren Avenue E, Penticton	Approx. 32 m south	Manufacturer: Hardwood veneer and plywood 1995: PCB storage 1997: PCB storage
Penticton Gate Station	Acklands Grainger 445 Warren Avenue E, Penticton	East adjacent	2014: Waste storage of various contaminants
Penticton Gate Station	Aphill Industries 465 Warren Avenue E, Penticton	Approx. 35 m east	1988: Sheet metal work 2012: Site profile registered
Penticton Gate Station	Waycon Manufacturing 485 Warren Avenue E, Penticton	Approx. 45 m northeast	1987: Machine shop
Penticton Gate Station	1945 Government Street	Approx. 98 m northwest	2013: Certificate of Compliance issued by the Ministry for former Imperial Oil bulk station
Penticton Gate Station	#1 – 2025 Government Street	Approx. 20 m northwest	1995: Waste generation – waste oil, batteries, and antifreeze
Penticton Gate Station	Alcast Foundry #5 – 2025 Government Street	Approx. 45 m northwest	1986: Metal product manufacturing
Penticton Gate Station	AccuTruss Industries 2060 Government Street	North adjacent	2012: Site profile registered; above ground storage tanks.
Penticton Gate Station	Thorcast Inc. 2130 Government Street	60 m south	1987: Stainless steel manufacturing

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Facility	APEC Address	Distance from Facility	Description
Penticton Gate Station	Thor Cast Inc. 2170 Government Street	Approx. 90 m south	1989: Metal manufacturing
Penticton Gate Station	1980 Barnes Street	Approx. 125 m northeast	2007: Notice of Independent Remediation Completion (no additional information)
Penticton Gate Station	Pederson Metals and Salvage 2000 Barnes Street	Approx. 115 m northeast	1995: Waste generator
Penticton Gate Station	#102 – 2001 Barnes Street	Approx. 25 m northeast	2008: Metal manufacturing
Penticton Gate Station	380 Cherry Avenue	Approx. 50 m northwest	1999: Waste oil generating
Penticton Gate Station	444 Okanagan Avenue E.	Approx. 94 m north	2011: Waste oil generating 2013: Waste oil and toxic waste generating 2014: Waste oil generating
Penticton Gate Station	Petro Canada Bulk Plant Facility 466 Okanagan Avenue E.	Approx. 104 m northeast	1992 – 1993: Partial site remediation complete 1995: Waste oil and gasoline
Oliver Y Control Station	8702 & 8704 Highway 97 Oliver	Onsite	2012: Waste batteries, paints, corrosive liquids, and waste oil
Kingsvale Control Station	Suttie Road	Onsite	Current land use: Enbridge Compressor Station Pole mounted transformer with unknown PCB concentrations
East Kootenay Exchange	N/A	Onsite	Current land use: Natural gas exchange facility

FEI will undertake further assessment of APECs during the detailed engineering phase of the Project to minimize the risk they may pose to the Project's construction costs and schedule.

37.1 Please explain whether or not the parties originally causing the contamination are responsible for any or all of the remediation activities that may be required.

37.1.1 If no, please explain why not.

37.1.2 If no, is FEI responsible for remediating the sites? Please explain.

Response:

The *Environmental Management Act* (EMA) (Division 3) and *Contaminated Sites Regulation* (CSR) (Part 7), establish the framework for determining who is responsible for remediation of contaminated sites. Where FEI is not determined to be a "responsible person" under EMA and the CSR, it would not be responsible for remediating the entirety of a contaminated site.

If contamination is encountered on FEI-owned property, and FEI is determined to be a responsible person under the EMA and the CSR, then FEI could be required to remediate areas of the FEI property to be disturbed during construction activities. FEI would not be required to remediate the entire site at the time of Project construction; however, if the property is considered "high-risk" then the remediation of high-risk conditions could be required.

If contamination is encountered on FEI-owned property and it is determined that a third-party is responsible for the contamination (i.e., contamination migrating from a neighbouring property), FEI could be required to remediate areas of the FEI property to be disturbed during construction activities. FEI could, through legal action and following the completion of remediation, attempt to recuperate the costs of remediation from the responsible person(s).

38. Reference: Exhibit B-1, page 129

Table 7-4: Plant Species and Ecological Communities in Proximity to Project Facilities

Facility	Name	Distance from Facility	Conservation Status
Ecological Communities			
SN-7	Black cottonwood / common snowberry – roses ecosystem	1.0 km	Red listed
SN-17 Valve Assembly	Common cattail Marsh ecosystem	0.3 km	Blue listed
	Black cottonwood / common snowberry – roses ecosystem	0.1 km	Red listed
Plant Species			
Princeton Crossover Station	White western groundsel	0.9 km	Red listed

38.1 Please provide context for plant species that are 'blue' or 'red' listed.

Response:

Red and Blue listings are a provincial conservation status rank for species and ecosystems through the BC Conservation Data Centre. "Red" is equivalent to extirpated, endangered or threatened. "Blue" is equivalent to special concern.

39. Reference: Exhibit B-1, Appendix K, page 1 and page 30

> **1.0 Introduction**
>
> This report describes the results of an Environmental Overview Assessment (EOA) carried out by Wood Canada Limited (Wood) for FortisBC Energy Inc. (FEI). The proponent is proposing upgrades at 15 existing components of their Interior Transmission System (ITS) to support ongoing delivery of energy to FEI customers. The completion of the EOA consisted of a desktop study of relevant biophysical and contaminant information, and where possible, field surveys at selected FEI components. This report summarizes the results of this work to assess the biophysical and contaminant risks present at each locality. This has subsequently been used to provide recommendations to mitigate possible adverse environmental effects from the proposed upgrades.

> The proposed crossing area was in a degraded condition; however, a number of potential sensitives exist. Based on the channel morphology and the size of the bedload substrate (up to 35 cm), it must be assumed that high-flow and flooding events regularly occur within the channel. Management of flows around the work area will be key in meeting environmental objectives. As the stream is fish bearing, complete isolation of the worksite and a subsequent fish salvage will likely be required.

39.1 Please explain whether or not FEI could have the opportunity to effect improvements in the lands in or around their work areas, rather than only focusing on mitigating possible adverse environmental effects from this or any other projects that FEI undertakes.

39.1.1 If yes, what activities would FEI need to undertake to identify and consider opportunities for benefitting the environment during work activities?

Response:

FEI considers opportunities to improve the lands in or around the project footprint in order to mitigate possible adverse environmental effects on a project-by-project basis. However, currently for the ITS TIMC Project, FEI has not found it reasonable or appropriate to undertake improvements on land outside of the Project footprint.

39.1.2 FEI has already undertaken a significant study of the environment for this Project, and intends to be working in the area. Could the current report be cost-effectively amended such that areas for beneficial changes could be identified and planned for the project?

Response:

Any amendment to the current report to include enhancement opportunities outside of the Project footprint would require environmental overview studies to determine current conditions, establish improvement opportunities, and identify permitting requirements. FEI believes this would result in additional costs and schedule delays to the Project as proposed in the Application, and therefore, would not be considered a cost-effective amendment.

39.2 Could the information contained in this report potentially be beneficial for other parties interested in improving the environment?

39.2.1 If yes, does FEI or Wood have any intention or ability to share the information publicly or privately for the benefit of the environment? Please explain.

<u>Response:</u>

The EAO report is publicly available on the BCUC's website and much of the information contained within the report comes from publicly available data sources such as BC Conservation Data Centre, iMapBC, and eFaunaBC. While the information contained in the EOA report could potentially be beneficial for other parties, FEI notes the following disclaimer from WSP included in the EOA Report:

> Any disclosure of this report to a third party is subject to this disclaimer. The report was prepared by Wood at the instruction of, and for use by, our client named on the front of the report. It does not in any way constitute advice to any third party who is able to access it by any means. Wood excludes to the fullest extent lawfully permitted all liability whatsoever for any loss or damage howsoever arising from reliance on the contents of this report. We do not however exclude our liability (if any) for personal injury or death resulting from our negligence, for fraud or any other matter in relation to which we cannot legally exclude liability.

40. Reference: Exhibit B-1, page 146

Table 8-3: Questions, Issues, and Concerns by Indigenous Groups

Indigenous Group	Summary of questions, issues or concerns	Next Steps/follow-up
Esh-kn-am Cultural Resource Management	• **July 12, 2021:** FEI received a response letter by email requesting onsite Field Tech monitoring during the AIA work at pipeline and facility locations due to high potential for unrecorded archaeological sites and knowledge of culturally sensitive areas. • **July 13, 2021:** FEI shared the information received with the consultant identified in Section 7. The consultant confirmed they made note of the comments received and that a representative was confirmed for the PFR Preliminary Field Reconnaissance (PFR) field work.	• FEI will continue to provide updates as the Project moves forward and will provide opportunity for onsite Field monitoring as outlined in Section 7.3 during the AIA works at locations identified, once field work is scheduled.
Lower Nicola Indian Band (LNIB)	• **June 8, 2021:** LNIB advised FEI of various types of LNIB traditional uses that have or do occur at or near all the sites listed in the notification; identified culturally sensitive areas within 1km of two facilities where construction is planned; and requested for FEI to share information on LNIB's Cultural Heritage Policy with FEI's consultants prior to the AOA and EOA • **August 4, 2021:** FEI provided the LNIB Cultural Heritage Policy information to the consultant identified in section 7 for review in advance of field visits.	• FEI will continue to provide updates as the Project moves forward, along with opportunities to participate in planned field work activities as outlined in section 7.3.

40.1 Please explain whether or not there are any significant outstanding concerns raised by Indigenous Groups or others at this time, or if they are generally resolved to the current status of the Project.

40.1.1 If there are any outstanding issues of significance, please identify and provide a brief discussion.

Response:

At this time, there are no outstanding concerns or issues raised by Indigenous groups related to the current status of the Project.