**Doug Slater**
Director, Regulatory Affairs

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

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

**FortisBC**
16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (778) 578-3874
Cell: (778) 214-3842
Fax: (604) 576-7074
Email: doug.slater@fortisbc.com
www.fortisbc.com

September 4, 2019

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, B.C. V6Z 2N3

Attention: Mr. Patrick Wruck, Commission Secretary and Manager, Regulatory Support

Dear Mr. Wruck:

**Re: FortisBC Energy Inc. (FEI)**

**Project No. 1598988**

**Application for a Certificate of Public Convenience and Necessity for the Inland Gas Upgrade Project (the Application)**

**Response to the British Columbia Utilities Commission (BCUC) Information Request (IR) No. 3**

---

On December 17, 2018, FEI filed the Application referenced above. In accordance with BCUC Order G-153-19 setting out a further Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 3.

FEI notes that the next procedural step in the Regulatory Timetable is set for September 18, 2019, which is a placeholder for either a Streamlined Review Process (SRP) or for FEI's written final argument. Given that several key FEI individuals, including external counsel for FEI, are also directly involved in FEI's Multi-Year Rate Plan Application, FEI respectfully requests a delay to the Regulatory Timetable established by Order G-153-19. In order to allow FEI to adequately prepare for either an SRP or written final argument, FEI respectfully requests that the next procedural step follow with a minimum of two weeks from the Panel's determination on the appropriate next step.

If further information is required, please contact the undersigned.

Sincerely,

**FORTISBC ENERGY INC.**

***Original signed:***

Doug Slater

Attachments

cc (email only): Registered Parties

# A. PROJECT NEED AND JUSTIFICATION

**63.0 Reference: PROJECT NEED AND JUSTIFICATION**

**Exhibit B-2, British Columbia Utilities Commission (BCUC) 8.1.4, p. 75;**

**Exhibit B-1 (Application), Appendix E**

**Pipeline Rupture and Corrosion Imperfections**

In response to BCUC 8.1.4, FortisBC Energy Inc (FEI) states:

> Estimates of corrosion growth and failure pressure of corrosion imperfections are used by FEI in determining integrity dig sites in the years between in-line inspections, in determining the re-inspection intervals for in-line inspections, and for assessing the potential need for other mitigation activities.

Appendix E in the Application provides a description of FEI's in-line inspection (ILI) process. Data analysis performed by FEI on the ILI data include, among other things, "clustering of potentially interacting metal loss imperfections" and "estimation of a failure mode (i.e. leak or rupture) and failure pressure, if applicable, for reported imperfections."

63.1 Please provide the range of corrosion depths and defect lengths identified on FEI's system.

**<u>Response:</u>**

Through FEI's in-line inspection (ILI) activity, the following range of corrosion depths and lengths have been identified on FEI's system:

- Minimum corrosion depth = 1 percent (i.e., depth of metal loss expressed as a percentage of the total wall thickness of the pipe). This is in accordance with typical ILI vendor minimum tool specifications for detection and sizing of corrosion.
- Minimum corrosion length = 5 mm. This is in accordance with typical ILI vendor minimum tool specifications for detection and sizing of corrosion.
- Maximum corrosion depth = 86 percent (i.e., depth of metal loss expressed as a percentage of the total wall thickness of the pipe). This defect was identified on the Oliver – Trail 273 mm pipeline (NPS 10) in FEI's Interior service territory, and has been repaired.
- Maximum corrosion length = 1086 mm. This imperfection has been identified on the Oliver – Trail 273 mm pipeline (NPS 10) in FEI's Interior service territory. FEI's

engineering analysis has determined that this imperfection, in consideration of the associated metal loss (29 percent depth), has not warranted further action at this time.

63.2 Please discuss FEI's method to determine the effective defect length of a clustering of potentially interacting metal loss imperfections.

**Response:**

FEI utilizes a "6t x 6t" interaction rule in accordance with CSA Z662-19 Clause 10.10.2.1 for determining the effective defect length of a clustering of potentially interacting metal loss imperfections. If the distance between adjacent corrosion features is less than or equal to six times the nominal wall thickness (t) in the longitudinal and/or transverse directions, then these features are considered interacting and clustered to determine the effective defect length of the interacting corrosion features.

63.3 Please discuss the relationship between failure pressure, failure mode (leak or rupture) and defect length and depth.

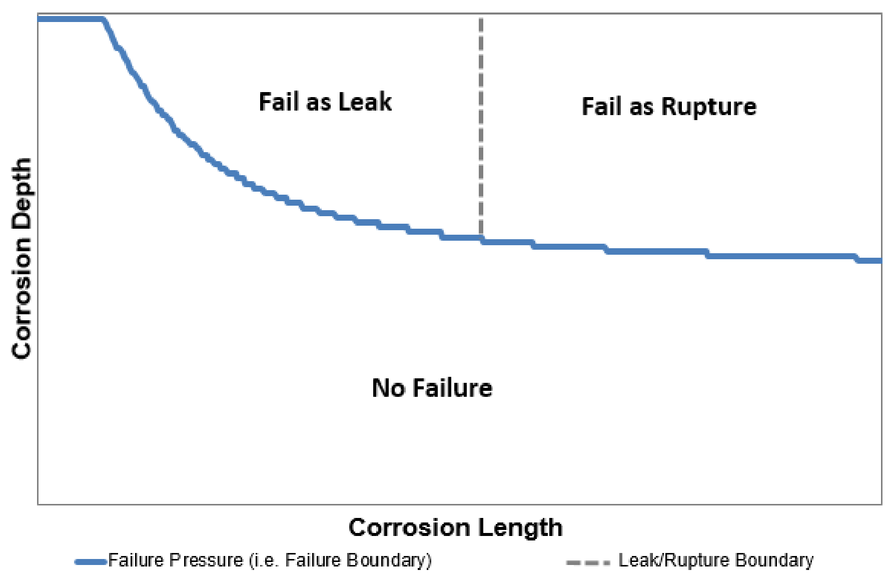
**Response:**

Figure 1 below shows the relationship between failure pressure, failure mode (leak or rupture) and corrosion length and depth. The curve represents the failure pressure, and hence the failure boundary, at varying corrosion lengths and depths. The dashed vertical line represents the boundary for the transition between the leak and rupture failure modes and is based on the predictive model described in the response to BCUC IR 3.63.4. The shape of the failure boundary curve and the location of the leak-rupture boundary line will vary depending on the pipe diameter, wall thickness, pipe grade, and operating stress level.

Figure 1 illustrates that a corrosion feature will:

- Not fail when its length and depth plots below the failure pressure curve;
- Fail as a leak if the feature plots at or above the failure pressure curve *and* on the left-side of the leak-rupture boundary; and
- Fail as a rupture if the feature plots at or above the failure pressure curve *and* on the right side of the leak-rupture boundary.

**Figure 1: Relationship between Failure Pressure, Failure Mode (Leak or Rupture) and Corrosion Length and Depth**




63.3.1 If possible, please provide graphs showing the relationship of failure pressure, the leak-rupture transition to defect length and depth. Please ensure the graphs cover the range of defect lengths and depths identified on FEI's system.

**Response:**

Figure 1 in response to BCUC IR 3.63.3 shows the relationship between failure pressure, failure mode (leak or rupture) and corrosion length and depth. Figure 2 below shows the range of corrosion lengths and depths identified on FEI's system, as provided in the response to BCUC IR 3.63.1. The range of corrosion lengths and depths identified on FEI's system occurred on the same pipeline; therefore, only one graph is provided. The blue curve represents the failure curve at current operating stress (45 percent SMYS) and the red curve represents the failure curve at 30 percent SMYS.

Although the maximum depth feature is plotted near the leak/rupture failure boundary, this feature did not fail, and FEI would not have expected it to fail, for the following reasons:

- The corrosion length measurement adopted by the CSA Z662-19 standard is conservative:

  All lengths and depths of the identified corrosion features were measured in accordance with CSA Z662-19 Clause 10.10.2.1. As shown in Figure 3, the maximum depth of a corroded area does not necessarily apply over the entire length of the corroded area.

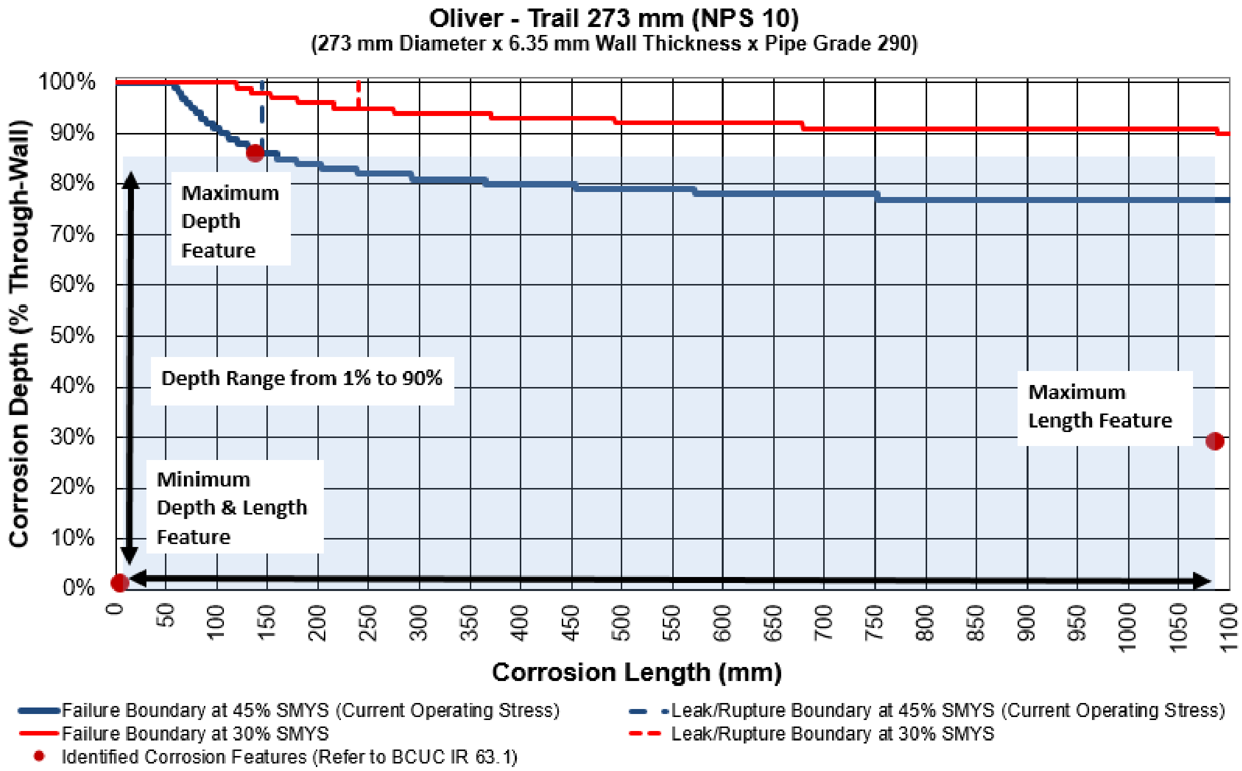
- Actual corrosion progresses with varying depths within the corrosion feature:

  Failure boundaries, in accordance with industry-adopted analysis methods, are established based on an assumption that a corrosion feature has uniform depth throughout its entire length. Actual corrosion does not progress uniformly, and would be expected to have a profile similar to what is depicted in Figure 3.

For instance, as shown in Figure 2, the maximum depth feature having 86 percent through-wall on Oliver – Trail 273 mm (NPS 10) has 139 mm in overall corrosion length, but only a fraction of the overall corrosion length actually has 86 percent through-wall depth (the “effective length”). Using this effective length, the actual plot of the maximum depth feature on Figure 2 would then move left and away from the blue failure boundary curve.

At the reduced operating pressure of 30 percent SMYS (as depicted by red failure curve shown in Figure 2 below), the corrosion features fall even further below the failure boundary. Features would have to be much longer and deeper to shift into the fail by leak or rupture area.

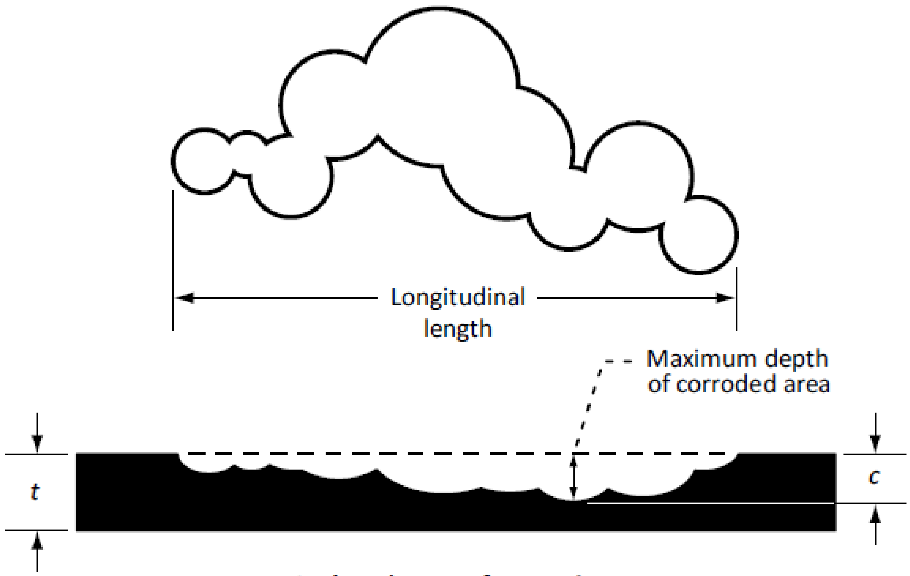
1 2 **Figure 2: Corrosion Length, Depth and Failure Pressure for Oliver – Trail 273 mm (NPS 10) Pipeline**




3

4

**Figure 3: Method of Deriving the Longitudinal Length of Corrosion (Excerpt from CSA Z662-19 Figure 10.1)**




**Isolated area of corrosion**

63.4 Please discuss FEI's method, including factors, assumptions and calculations to determine failure mode (leak or rupture) and failure pressure of a corroded pipeline.

**Response:**

To calculate the failure pressure of a corroded pipeline, FEI uses CSA Z662-19 Clause 10.10.2.6 (a) "the 0.85 dL method", which is commonly referred to in the industry as the ASME B31.G – Modified B31G method.

To determine failure mode (leak or rupture), FEI uses the rupture pressure prediction model recommended in CSA Z662-19 Annex O. The rupture pressure (rrp), which is the pressure resistance of a pipe containing a through-wall defect, is calculated as:

$$r_{rp} = \frac{2t\sigma_f}{MD}$$

In the above formula:

- $t$ is pipe wall thickness,
- $\sigma_f$ is flow stress defined based on the ultimate tensile strength ($\sigma_u$) for steel grades greater than Grade 241 (i.e. $\sigma_f = 0.9\ \sigma_u$),

- *M* is the Folias factor given in ASME B31.G – Modified B31G method (which is a function of the corrosion length and depth), and
- *D* is pipe diameter.

When the rupture pressure ($r_{rp}$) is less than or equal to the pipe internal pressure, a through-wall corrosion defect will lead to rupture.

63.5 Please provide details of any FEI assessment that required immediate pressure reduction to reduce the risk to personnel, the public and the environment.

**Response:**

FEI reduces the pressure on its pipeline system on a short-term basis for a number of reasons, such as:

- to achieve physical conditions necessary for an operational procedure:
  - A pressure reduction may be necessary when FEI is welding on in-service pipelines, such as when installing a pressure-containing sleeve over an imperfection or defect. A pressure reduction may be necessary to slow the cooling rate in the vicinity of the weld to achieve required metallurgical/material properties of the weld and associated heat-affected zone.
- to enhance the factor of safety during an operational procedure:
  - A pressure reduction may be necessary when exposing a pipeline with an ILI-identified imperfection, as there are some types of imperfections that can be at increased potential for failure as a result of the excavation activity. These include dents that have the potential to become unconstrained and “re-round” as backfill or an indenting object (e.g., a rock lodged against the pipe) is removed during excavation. Re-rounding of a dent can initiate or propagate a crack (or crack-like feature) within the dent which could lead to failure during excavation.
- to enhance factor of safety during pipeline operation:
  - In response to ILI-identified anomalies or other reduced-confidence operating conditions (e.g., a pipeline becoming exposed in a water crossing during high flow), it is common industry practice to implement a 20 percent pressure reduction. This increases the safety factor until such time as the required mitigation and/or repair can be completed.

In the circumstances described above, FEI has not had to reduce pressures to or below 30 percent of the SMYS, as a 20 percent pressure reduction was sufficient to effectively mitigate the short-term risks.

The PRS option as proposed in the Application for the 29 Transmission Laterals represents a long-term operating scenario, and is therefore different from the shorter-term scenarios above. Those laterals selected for PRS require a pressure reduction to below 30 percent SMYS to effectively mitigate the potential for rupture due to external corrosion over their life cycle.

63.5.1 Please confirm, otherwise explain, whether pressure was reduced to or below 30 percent specified minimum yield strength (SMYS).

**Response:**

Please refer to the response to BCUC IR 3.63.5.

**64.0 Reference: PROJECT JUSTIFICATION**

**Transcript Volume 1 (V-1), Workshop/Procedural Conference, pp. 38–39**

**Risk Assessment**

On page 38 of the Workshop/Procedural Conference transcript, Mr. Chernikhowsky states:

> So again, some form of risk assessment is always needed to determine the drivers for a project. And historically we've typically described those as being qualitative in nature. Based, again, on judgement. We don't necessarily numerically define probability or consequences. But we determine whether they're -- if you want to use the terminology low, medium, high, of that nature. And so, it's that type of determination that we use to whether the IGU project is necessarily (sic) or not. The need to conduct a quantitative risk assessment in a very fine grained manner, prioritize how quickly or where the work needs to happen, that was not necessary in the case of the IGU project.

64.1 Please provide the risk assessment (high, medium, low), if any, for each of the 29 laterals that FEI used to determine whether the Inland Gas Upgrade (IGU) project is necessary. If no such risk assessment was done, please explain why not and please reconcile this response with the above extract from the transcript.

**Response:**

In the case of the IGU Project, FEI's qualitative risk assessment utilized an "acceptable / unacceptable" criteria rather than a "high, medium, low" ranking and was performed on all 29 Transmission Laterals instead of on a lateral-by-lateral basis. The assessment found that:

- external corrosion is a relevant hazard (and the leading cause of transmission pipeline failures in British Columbia);
- there is a potential for transmission pipeline rupture due to external corrosion;
- rupture could result in significant consequences; and
- FEI's status quo method to mitigate the potential for external corrosion-related rupture of the 29 Transmission Laterals is now considered by FEI to be unacceptable over the long term.

Given the nature of the risk, and the potential consequences of a rupture, no further classification (e.g., high, medium, low) is necessary.

Table 1 below shows the components of the industry-accepted risk assessment process in CSA Z662-19, Annex B "Guidelines for risk assessment of pipeline systems" that was undertaken by FEI, and the evidence in this proceeding related to each component.

**Table 1: Evidence of Analysis following CSA Z662-19 Annex B Risk Assessment Process**

| Components of the CSA Z662-19 Annex B Risk Assessment Process | FEI Evidence for each Component |
|---|---|
| Risk Analysis: Definition of Objectives | • FEI's objective in the IGU Application is to evaluate external corrosion hazard management solutions for the 29 Transmission Laterals based on consideration of its legal and regulatory obligations, its assessment of relevant hazards to its pipeline system, its understanding of industry practice, as well as its knowledge of evolving technology available for assessing and managing pipeline condition (Sections 3.4.3, 3.4.4, and 3.4.5 of the Application) |
| Risk Analysis: System Description | • The 29 Transmission Laterals all operate at 30% SMYS or greater.<br>• The 29 Transmission Laterals represent a range of pipeline ages and coating types.<br>• In alignment with FEI's experience from its in-line inspected pipelines and integrity digs, it is probable that active external corrosion is present on the 29 Transmission Laterals due to cathodic protection shielding (Section 3.3 of the Application, BCUC IRs 1.4.1 and 1.8.2).<br>• The 29 Transmission Laterals are currently subject to monitoring and mitigation programs as part of FEI's Integrity Management Program for Pipelines, and have cathodic protection coverage (BCUC IRs 1.8.3 and 2.40.1). |
| Risk Analysis: Hazard Identification | • External corrosion is a valid hazard to FEI's transmission pipeline system (Sections 3.3.1 and 3.3.2 of the Application) |
| Risk Analysis: Frequency Analysis | • FEI's current method for managing external corrosion for the 29 Transmission Laterals (Modified ECDA) has limitations where CP shielding is occurring (Section 3.4.2 of the Application)<br>• FEI has demonstrated a frequency of CP shielding on its transmission pipeline system (Section 3.3.2 of the Application, BCUC IR 1.4.1)<br>• The leading cause of transmission pipeline failures in British Columbia is the deterioration of pipe condition caused by the hazard of corrosion (Section 3.3.1 of the Application) |
| Risk Analysis: Consequence Analysis | • Pipelines operating at 30% SMYS or greater have an accepted potential to fail by rupture due to causes such as external corrosion (Section 3.3.3 of the Application, BCUC IR 2.37.1)<br>• Rupture of a transmission pipeline could have significant safety, reliability, environmental and regulatory consequences and such an occurrence would be unacceptable to FEI, the public and its regulators (Section 3.3.4 of the Application) |

| Components of the CSA Z662-19 Annex B Risk Assessment Process | FEI Evidence for each Component |
|---|---|
| Risk Analysis: Risk Estimation | • The potential for occurrence of the hazard and associated rupture has been demonstrated; existing data sources do not enable FEI to precisely or unequivocally identify potential locations of external corrosion<br>• Limitations with FEI's current method for mitigating external corrosion have been demonstrated<br>• As such, FEI has determined that its status quo method to mitigate the potential for external corrosion-related rupture of the 29 Transmission Laterals is no longer acceptable over the long term (Sections 3.1, 3.4, and 3.5 of the Application, BCUC IR 1.4.3) |
| Risk Evaluation: Risk Significance | • A rupture of NPS 6 and larger transmission pipelines due to external corrosion represents unacceptable performance under FEI's IMP-P given the availability of proven and commercialized technology to detect external corrosion features and industry standard practice (BCUC IRs 1.4.3, BCUC IR 2.35.11, BCUC IR 2.36.2)<br>• A natural gas pipeline rupture on any of the 29 Transmission Laterals has the potential to result in significant safety, reliability, environmental and regulatory consequences (Section 3.3.4 of Application; CEC IR 1.3.2) |
| Risk Evaluation: Options Evaluation | • FEI has identified proven and commercialized technology alternatives to its status quo, or other cost-effective methods to mitigate the identified risk (Section 4 of the Application, BCUC IR 1.3.5) |

1

**65.0 Reference: PROJECT JUSTIFICATION**

**Transcript V-1, Workshop/Procedural Conference, pp. 11–13**

**Consequence of Pipeline Rupture**

On pages 11 of the Procedural Conference Transcript V-1, Mr. Chernikhowsky states:

> In the case of the Kelowna 1 Loop, that PIR, potential impact radius, works out to about 140 feet, and would encompass much of one of the buildings in that complex. As mentioned, individuals within this radius would expect serious injuries or worse. …

Further, on page 13 of the transcript, Mr. Chernikhowsky states:

> …we are proposing a small, pressure reducing station upstream of the pipeline, and this will effectively mitigate the risk of a rupture by reducing the operating pressure below the point where a rupture could occur.

65.1 Please provide the potential impact radius at 30 percent SMYS and explain whether it would encompass any part of the building complex.

**<u>Response:</u>**

If a rupture failure were to occur of the example pipeline referenced by Mr. Chernikhowsky at 30 percent of SMYS, the calculated potential impact radius would be approximately 135 feet and would encompass part of the building complex. FEI notes however, that this response (and question) only addresses the consequences component of the risk equation. Reducing the operating pressure to below 30 percent of SMYS is recognized within both industry and code as an effective method to reduce the probability of a pipeline rupture caused by corrosion to near zero. Since risk is equal to failure probability times failure consequences (as discussed in the response to BCOAPO IR 3.4.1), mitigating the failure probability effectively mitigates the net risk of ruptures due to external corrosion. It is on this basis that FEI has proposed PRS as a feasible and cost-effective solution for 14 of the 29 Transmission Laterals. Although pipeline rupture could occur due to causes other than corrosion (e.g. ground movement or third-party damage), the solutions proposed in the IGU project are not specifically intended to address these hazards.

FEI requested that JANA Corporation provide its independent, expert opinion in response to this question. JANA Corporation provides the following response:

- In comparing the effectiveness of ILI and pressure reduction to mitigate the external corrosion threat, a pressure reduction to below 30 percent SMYS would be expected to shift the failure mode due to external corrosion from a potential for rupture or leak to just failure by leak. Below 30 percent SMYS, the corrosion failure would be expected to occur through a pinhole leak (based on analysis of historical industry data) and, therefore, there would be no impact radius for a corrosion leak and the building complex would not be in the impact radius.

- The primary purpose of reducing the operating pressure to less than 30 percent SMYS is to reduce the probability of pipeline rupture due to corrosion as an alternate means to ILI of managing the identified corrosion threat (through consequence mitigation). Pipeline corrosion typically occurs over an area of the pipeline. If the corrosion area is long enough and deep enough and the operating pressure or energy in the pipeline is high enough, there is the potential for 'tearing' of the pipeline leading to rupture (above 30 percent SMYS, both rupture and pinhole leaks are observed, based on the specifics of the situation). If there is not enough energy in the pipeline to cause tearing, then failure is typically through a pinhole leak (at a specific point the corrosion is deeper and eventually penetrates the pipe wall, causing a small leak). This is like a fully inflated balloon being pricked with a pin and popping at high pressure compared to leaking at the pinhole when a partially deflated balloon is pricked – there is not enough stored energy to tear the balloon in the latter case. Below 30 percent SMYS, corrosion failures occur through the pinhole failure mode. These failures can be detected through leak surveys or through public odor calls, detected and repaired, hence mitigating the risk of failure due to corrosion for pipelines operating below 30 percent SMYS.

To illustrate JANA's response above, FEI provides photos from a recent leak that was detected and repaired on FEI's NPS 30 Fraser Gate IP line. This pipeline operates at 1200 kPa which corresponds to 29.9 percent of SMYS. Despite the extensive corrosion and metal loss (approximately 35 centimetres by 10 centimetres) that occurred under the CP shielded coating, the resulting failure was still only a pinhole leak. This leak was detected via an odour call. The fact that this pipeline leaked, rather than ruptured, is as expected due to the low operating stress of the pipe (below 30 percent of SMYS).

**Figure 1: Showing Extent of Fraser Gate NPS 30 Corrosion**

**Figure 2: Showing Fraser Gate NPS 30 Corrosion and Pinhole Leak**


65.2 Please confirm, otherwise explain, that it is possible for rupture to occur at or below 30 percent SMYS.

**Response:**

As stated in the response to BCUC IR 2.37.1, in very rare cases of selective seam weld corrosion in low-frequency electrical resistance welded seam welds or instances involving outside forces, pipelines operating at less than 30 percent of SMYS may result in rupture failure. Examples of outside forces include geotechnical ground deformation (e.g., seismic or slope movement) or third-party damage. Nonetheless, as reflected in CSA Z662-19 and as noted above, it is generally accepted in the industry that the rupture threat associated with external corrosion is appropriately mitigated if a pipeline is operating below 30 percent of SMYS.

FEI requested that JANA Corporation provide its independent, expert opinion in response to this question. JANA Corporation provides the following response:

Confirmed. General industry consensus and confirmed by the CSA Z662-19 Clause 12.1.1 and Clause 12.10.3.3 is that pipelines operating below 30 percent SMYS will fail by leak rather than rupture (please see response to BCUC 3.65.1). It is possible for rupture to occur, however, below 30 percent SMYS under specific rare conditions as reported by Rosenfeld and Fassett[1] (selective seam corrosion and low toughness conditions). A review of the NEB incident data base for incidents from 2009 – 2018 did not reveal any ruptures on pipelines operating below 30 percent SMYS.

[1] Study of Pipelines that ruptured while operating at a hoop stress below 30% SMYS, M.Rosenfeld, R. Fassett, PPIM, 2013

**66.0 Reference: PROJECT JUSTIFICATION**

**Exhibit B-17, Clarification of Procedural Conference Transcript, pp. 1–3**

**Quantitative Risk Assessment (QRA)**

On page 1 of Exhibit B-17, FEI states:

> FEI wishes to confirm that it is developing and implementing a segment-by-segment risk assessment process to determine the risk associated with all of FEI's BC OGC-regulated pipeline assets, including the 18 laterals that FEI proposes to install pressure regulating stations or replace such that they operate below 30 percent SMYS. In this regard, FEI is attaching FEI's latest quarterly report to the BC OGC on FEI's risk assessment process implementation.

On page 3 of the same exhibit, FEI provides a letter written to the BC Oil and Gas Commission (OGC) dated July 12, 2019. The second paragraph of that letter reads:

> …FEI's first iteration of the Quantitative Risk Assessment will apply to lines with in-line inspection data. This first iterations [sic] will assist in establishing the priority and urgency of upgrades to FEI's transmission mainlines for enabling in-line inspection with crack-detection (EMAT) tools. FEI will use its experience with the first iteration of the Quantitative Risk Assessment to identify and evaluate process improvements prior to undertaking further iterations that will be expanded to include FEI's other pipeline assets (i.e. BC OGC-regulated pipelines not currently subject to in-line inspection). Preliminary results have been presented by JANA to FEI in Q2 2019.

66.1 Please confirm, otherwise explain, that the statement in the preamble means that all laterals in the IGU Project will be included in the QRA being prepared by JANA Corporation.

**<u>Response:</u>**

The 29 Transmission Laterals in the IGU Project will not be included in the first iteration of the QRA performed by JANA Corporation, but will be included in subsequent iterations.

FEI is developing a risk assessment process that will be applicable to all of FEI's BC OGC-regulated pipeline assets, and will, in time, be implemented for all of these assets. However, the QRA currently being prepared by JANA Corporation is only the first iteration of the QRA development. This first iteration QRA will be conducted only on pipelines with ILI data.

FEI is including only pipelines with ILI data in the first iteration QRA for the following reasons:

- The first iteration will assist in establishing the priority and urgency of upgrades to FEI's transmission mainlines for enabling in-line inspection with crack-detection (EMAT) tools. EMAT tools are neither proven nor commercialized for pipeline diameters of the laterals included in the IGU Project.
- FEI will use its experience with this first iteration of the QRA to identify and evaluate process improvements prior to undertaking further iterations that will be expanded to include FEI's other pipeline assets (i.e. BC OGC-regulated pipelines not currently subject to in-line inspection).
- Quantitative risk assessment processes are data-intensive. ILI data improves the expected accuracy of results, in the absence of which a QRA would have to rely on such inputs as industry averages and engineering-based assumptions. There is more value for FEI's first iteration QRA to focus on those lines with sufficient condition assessment information to produce a meaningful differentiation in their risk estimate.

66.2 Please state when the "first iteration" of the QRA will be complete, and when the "second iteration" of the QRA will be complete.

**Response:**

FEI expects the first iteration of the QRA to be completed sometime in 2020 for inclusion in FEI's CPCN application for the TIMC project. Prior to formal completion, FEI expects to present the initial results from the first iteration QRA at a TIMC Workshop with BCUC and interveners in Q4 2019. FEI expects that refinements of the QRA will continue to be undertaken as FEI develops the TIMC project.

The timing for completion of FEI's second iteration QRA is unknown at this time. FEI currently envisions that its second iteration of a QRA will be undertaken utilizing internal resources as part of a sustainable, ongoing process. FEI is developing estimates of the required incremental resources and intends to include these estimates as part of a CPCN application for the TIMC project.

66.2.1 Please clarify which of the 29 laterals in the IGU Project will be included in the first iteration of the QRA, and which of the 29 laterals will be included in the second iteration of the QRA.

**Response:**

As discussed in the response to BCUC IR 3.66.1, none of the 29 Transmission Laterals in the IGU Project will be included in the first iteration of the QRA.

While FEI intends to perform a QRA on the 29 Transmission Laterals, it has not yet developed its plan for subsequent iterations of the QRA, and therefore, is unable to confirm the timing.

66.3 Please provide the “preliminary results” of the QRA that JANA provided to FEI in Q2 2019.

**Response:**

FEI will be presenting the first iteration QRA at a TIMC Workshop with the BCUC and interveners in Q4 2019. Before FEI presents the results, the data needs to be further reviewed, analyzed, validated, and refined so that FEI can confidently present it as accurate and representative of FEI’s system.

FEI also believes that the results of the first iteration QRA will not be helpful when considering the IGU Project for the following reasons:

1. The data from the first iteration QRA will not inform the external corrosion risk that FEI intends to mitigate on the laterals in the IGU Project. The data used in the first iteration QRA will include pipeline-specific condition data gathered through ILI, and therefore will be indicative of the external corrosion risk that has already been detected and managed by FEI. Therefore, the results will not reflect the risks related to the 29 Transmission Laterals where external corrosion has not been detected by ILI yet still requires mitigation.

2. The data from the first iteration QRA will not provide FEI with more or better information about the location or cause of the external corrosion risk on the 29 Transmission Laterals;

3. The data from the first iteration QRA will not inform or change the solutions available to FEI to mitigate the potential for rupture due to external corrosion on the 29 Transmission Laterals; and

4. The risk assessment results associated with the QRA do not relieve FEI of its duties and obligations under the CSA Z662 standard to mitigate the identified external corrosion hazard on the 29 Transmission Laterals.

However, in order to be responsive and to illustrate to the BCUC what kind of information can be extracted from the results of the QRA, FEI has asked JANA to provide the four figures below that were prepared for this response based on the current JANA analysis for the Trail – Castlegar 219 mm (NPS 8) pipeline. FEI selected this example as the pipeline is of similar diameter to the 29 Transmission Laterals and located in the Interior, yet also has had periodic inline inspections (unlike the 29 Transmission Laterals). The relevance of this example to the IGU Project is that the figures demonstrate that the risk profile of a pipeline without ILI data is very limited in comparison to the risk profile with ILI data. FEI notes that the graphs below represent current JANA analysis only, and are subject to change.

Figure 1 shows JANA's estimate of societal risk along this pipeline. The risk profile variations along the length of the pipeline correspond to changes in population density. FEI's Integrity Management Program for Pipelines defines the risk mitigation activities that are applicable to the full length of this pipeline. This includes in-line inspection to mitigate the potential for rupture due to external corrosion.

Figure 2 is an overlay of the information contained in Figures 3 and 4, again for the same Trail – Castlegar 219 pipeline. It illustrates the difference between two external corrosion rupture frequency models applied by JANA (further explained below), and the significant influence that data availability has on the overall quantitative risk assessment process.

Figure 3 shows JANA's estimate of potential rupture frequency due to external corrosion using only a historical model (i.e. using typical historical performance data from similar pipelines at other operators) and does not include in-line inspection data. The risk profile cannot be readily differentiated along the pipeline length due to the absence of in-line inspection data.

Figure 4 shows JANA's estimate of potential rupture frequency due to external corrosion, this time using a risk model that leverages in-line inspection data. With this additional ILI data the risk profile can now be differentiated along the pipeline length thereby allowing the pipeline operator to make quantitative risk informed integrity management decisions.

**Figure 1: Societal Risk Profile for TRA CAS 219 Using ILI Data for Corrosion**

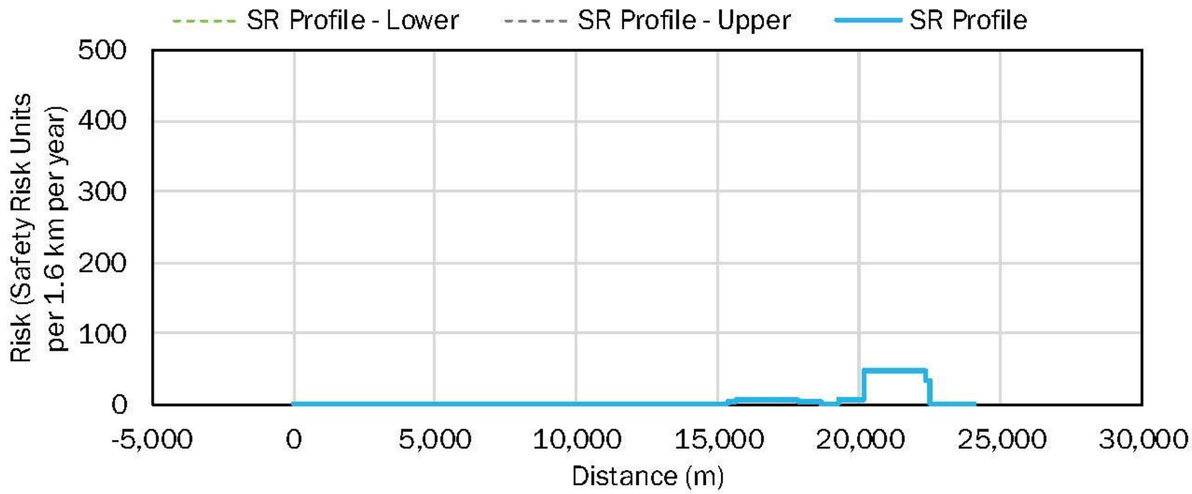



**Figure 1 Notes**

- The higher risk segments in the profile (e.g., at around 20 km) correspond to higher population densities around the pipeline.

**Figure 2: External Corrosion Rupture Frequency for TRA CAS 219 – Historical Model versus ILI**

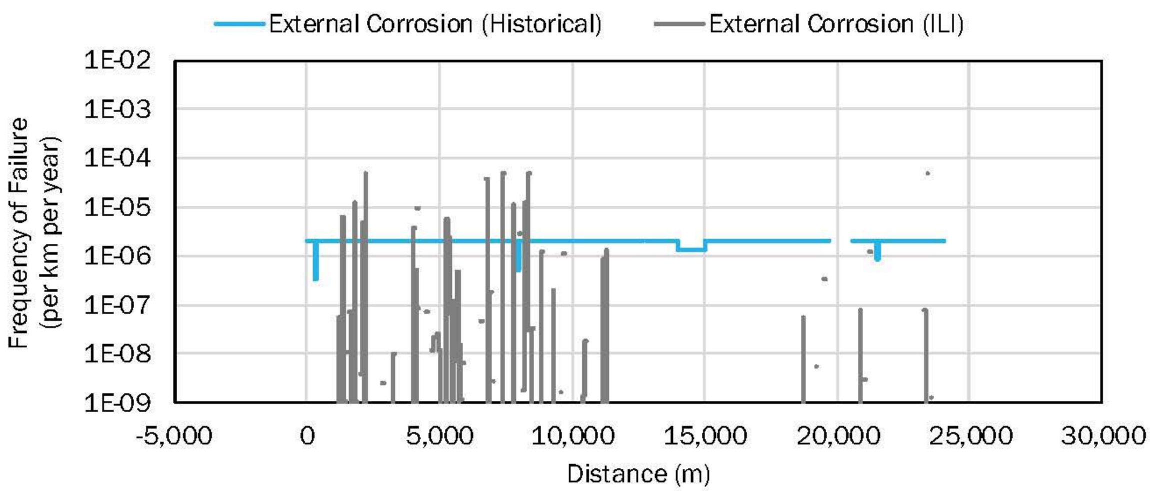



**Figure 2 Notes**

- The spikes in the External Corrosion ILI profile correspond to segments with corrosion indications reported by the ILI.
    - The magnitude of the spikes depends on the size and/or density of the corrosion indications.

**Figure 3: External Corrosion (Historical Model) Rupture Frequency Profile for TRA CAS 219**

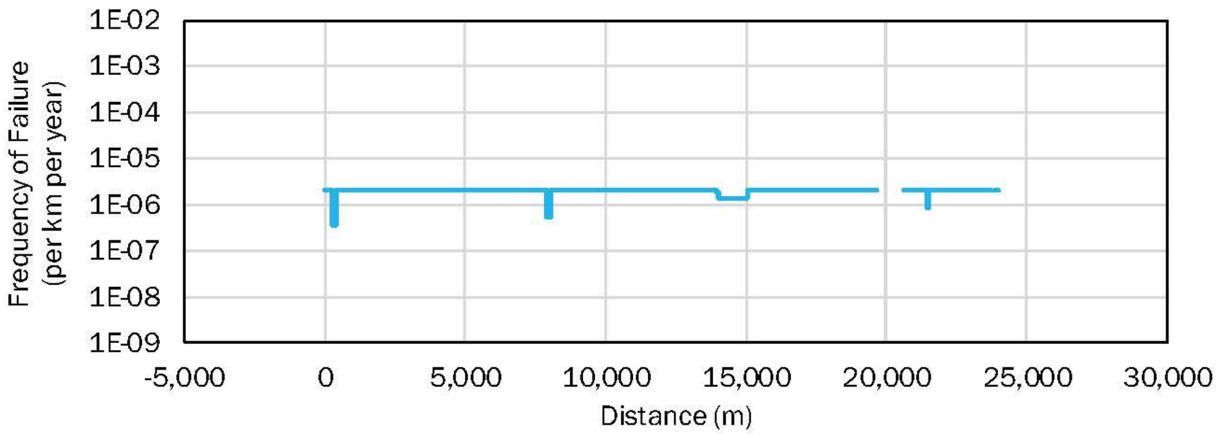
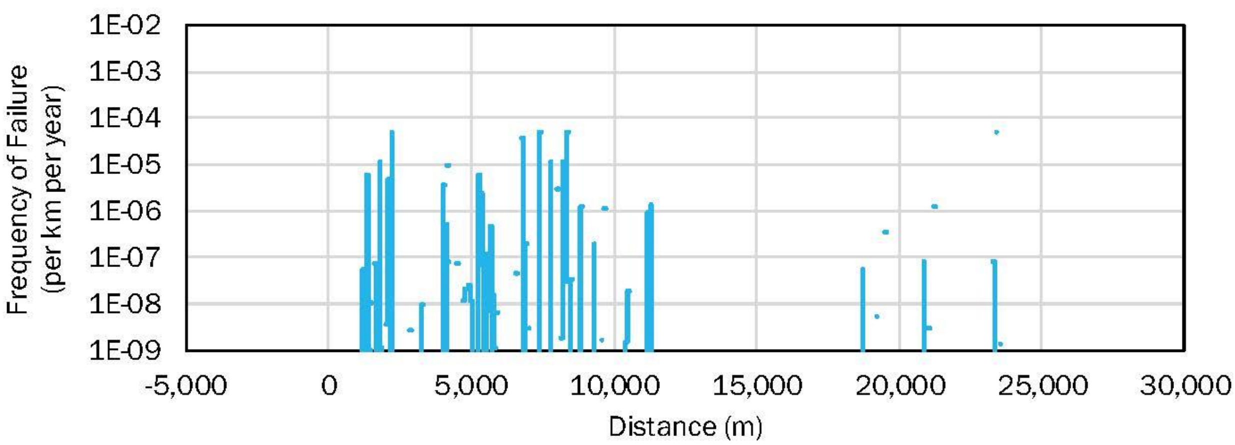



**Figure 4: External Corrosion (ILI) Rupture Frequency Profile for TRA CAS 219**




66.4 Please confirm, otherwise explain, that FEI intends to file the completed QRA with the BCUC.

**Response:**

Confirmed. FEI intends to include documentation of the quantitative risk assessment that it is undertaking as part of the development of the TIMC project in its CPCN application for the project.

66.5 Would a QRA potentially direct a different rupture mitigation action than what is currently being proposed for any of the 14 Transmission Laterals where Pressure Regulating Station (PRS) is proposed?

**Response:**

As explained in the response to BCUC IR 2.36.1, FEI's selection of alternatives for the IGU Project on the basis of the evaluation criteria described in Section 4.3.1 of the Application would not be altered or benefit from the results of a QRA.

FEI requested that JANA Corporation provide its independent, expert opinion in response to this question. JANA Corporation provides the following response:

> It is JANA's opinion that a QRA would not lead to a different mitigation action for external corrosion. Pipeline replacement, ILI and pressure reduction below 30 percent SMYS are effective mitigations for the external corrosion threat. The factors leading to selection of PRS installation over ILI or PLR would not be changed by a QRA.

**67.0 Reference: PROJECT JUSTIFICATION**

**Transcript V-1, Workshop/Procedural Conference, p. 79**

**BC OGC Written Confirmation**

On page 79 of the Procedural Conference Transcript V-1:

> THE CHAIRPERSON: Has FEI obtained any kind of confirmation from the B.C. Oil and Gas Commission that this is an appropriate way to deal with the 18 [laterals]? And that they are happy with what you are proposing?
>
> MR. CHERNIKHOWSKY: Yes, so I can confirm that I met with the B.C. Oil and Gas Commission and presented to them June 20 – subject to check.
>
> THE CHAIRPERSON: A week ago perhaps.
>
> MR. CHERNIKHOWSKY: Several weeks ago, and presented to the Oil and Gas Commission the proposed IGU project. Described to them the drivers for the project, and the proposed solutions, and they were supportive of it.

67.1 Please provide written confirmation from the BC OGC in support of the IGU Project.

**Response:**

Please refer to Attachment 67.1 for a copy of the letter from the OGC, dated August 26, 2019. In this letter, the BC OGC confirms that it supports FEI taking action to address its known integrity concerns and to ensure that it meets its requirements as a permit holder under the *Oil and Gas Activities Act.*

**68.0 Reference: PROJECT JUSTIFICATION**

**Transcript V-1, Workshop/Procedural Conference, p. 59**

**Modified External Corrosion Direct Assessment (ECDA) Integrity Digs**

On page 59 of the Procedural Conference Transcript V-1:

> MS. SIMON: Thank you. You indicated that you've completed ECDA for the 29 laterals, is that correct?
>
> MR. BALMER: So we either have or we're in the process of implementing ECDA, so that our methodology. We've conducted above ground surveys. We have not performed digs on all the lines. I don't know if that's clear on not.
>
> MS. SIMON: Yeah, that's helpful. So then my follow on question, in the presentation you provided a picture of corrosion found on one of the laterals.
>
> MR. BALMER: That's correct.
>
> MS. SIMON: That's correct? Okay. Have – the above ground part of the ECDA, have you identified other areas of external corrosion and have you investigated those?
>
> MR. BALMER: So we've identified a number of areas where the coating and cathodic protection surveys indicate corrosion. We also have other areas that are planned to be inspected with digs that have not been completed. So we're in – it's an ongoing integrity process and it's at various stages of completion for various pipelines.

68.1 Please provide the results of any ECDA-driven digs performed this year and whether any of those digs relate to the 29 laterals in the IGU Project.

**<u>Response:</u>**

FEI has performed 23 ECDA-driven digs to date in 2019. Nineteen of the 23 digs were performed on laterals included in the IGU Project, as indicated by the following table:

| Lateral | Lateral included in IGU Project? (yes/no) | Number of Digs Performed in 2019 |
|---|---|---|
| Mackenzie Lateral 168 | Yes | 7 |
| Mackenzie Loop 168 | Yes | 3 |
| BC Forest Products Lateral 168 | Yes | 2 |
| Prince George 3 Lateral 219 | Yes | 2 |
| Northwood Pulp Lateral 168 | Yes | 3 |

| Lateral | Lateral included in IGU Project? (yes/no) | Number of Digs Performed in 2019 |
|---|---|---|
| Northwood Pulp Loop 219 | Yes | 2 |
| Finlay Forest Product Lateral 60 | No | 2 |
| Finlay Forest Product Loop 114 | No | 1 |
| Mackenzie Lateral 88 | No | 1 |

FEI has not yet received detailed consultant inspection reports with respect to the above digs. However, based on the analysis completed by FEI to date, the results of the above digs are consistent with FEI's prior experience that Modified ECDA only provides locations of potential corrosion based on inferences from above-ground survey results, and cannot detect areas where CP shielding is occurring and therefore cannot detect where active corrosion may be occurring. Specifically, the results identified to date are as follows:

- FEI identified one corrosion feature. This feature was located beneath disbonded, but otherwise intact, single-wrap polyethylene tape. As polyethylene tape can fail in a way that can cause CP shielding, the above-ground survey indication that resulted in the dig selection was due to either this particular feature not being 100 per cent shielded, or a different non-shielding coating issue within the same excavation site. The metal loss at the location of the corrosion feature was approximately 18 per cent of the pipe wall.
- Two digs identified coating damage, presumably from prior undetected third-party activity.
- Eight digs identified pipeline fittings or appurtenances, over which it is difficult to achieve 100 percent coating coverage due to their irregular and sometimes difficult-to-reach surfaces. These include stopple fittings, anchor flanges, and valves.

68.2 Please provide the timeline for the implementation of any planned ECDA-driven digs that have not been completed, and whether any of those planned digs relate to the 29 laterals in the IGU Project.

**Response:**

Table 1 below contains a list of FEI's ECDA-driven digs that have been identified but not completed to-date, and identifies whether the dig is related to one of the 29 Transmission Laterals. Although these digs have been identified, they have not yet been analyzed for planning and scheduling. As explained in response to BCUC IR 2.46.4.1, FEI expects to complete these identified Modified ECDA digs during the term of FEI's proposed Multi-Year Ratemaking Plan (2020-2024).

The table below updates the dig information provided in Table 1 of BCUC IR 2.46.4 as follows:

- Digs that have been completed on the 29 Transmission Laterals are removed;
- New digs identified related to the 29 Transmission Laterals due to ongoing analysis have been added; and
- Modified ECDA digs identified on the remainder of FEI's transmission pipelines have been added.

**Table 1: Modified ECDA Digs Identified on FEI's Transmission Pipelines**

| Pipeline | Survey Chainage | Year Identified | Included in the IGU Project's 29 Transmission Laterals (yes/no) |
|---|---|---|---|
| Chase Lateral 88 | 12914 | 2018 | No |
| Coldstream Lateral 114 | 2099 | 2018 | No |
| Kamloops 1 Lateral/Loop 168 | 35.8 | 2018 | Yes |
| Kamloops 1 Lateral/Loop 168 | 2803 | 2018 | Yes |
| Kamloops 1 Lateral/Loop 168 | 2964 | 2018 | Yes |
| Kamloops 1 Lateral/Loop 168 | 2977 | 2018 | Yes |
| Kamloops 1 Lateral/Loop 168 | 3468 | 2018 | Yes |
| Kamloops 2 Lateral 114 | 324.2 | 2018 | No |
| Kamloops 2 Lateral 114 | 386 | 2018 | No |
| Kamloops 2 Lateral 114 | 441 | 2018 | No |
| Lafarge Lateral 114 | 3244.5 | 2018 | No |
| Westbank Lateral 114 | 1698 | 2018 | No |
| Westbank Lateral 114 | 24426.4 | 2018 | No |
| Salmon Arm Loop 168 | 26827 | 2019 | Yes |
| Sorrento Lateral 114 | 12487.1 | 2019 | No |
| Sorrento Lateral 114 | 12515.5 | 2019 | No |

**69.0 Reference: PROJECT JUSTIFICATION**

**Transcript V-1, Workshop/Procedural Conference, p. 61, 77.**

**Exhibit B-4, Section 2.1, p.12; FEI-City of Kelowna Operating Agreement, p. 2,3.**

**Distribution Pipeline definition**

On page 61 of the Procedural Conference Transcript V-1:

> MR. BALMER: Right. Exactly. So – and so we adopted – the Z662 is the standard that governs pipeline design and operation in Canada and that standard has a threshold between a gas distribution system, our pipelines that are operating at less than 30 percent SMYS or in this case we're reducing to below 30, 29.9 or lower, and it is based on studies. We did submit some references towards that. But really that's the – an industry accepted threshold for the likelihood to fall, I'll say to a level that warrants operation as a gas distribution system versus a transmission pipeline. So different levels of risk mitigation.

Further, on page 77 of the Procedural Conference Transcript V-1:

> MR. BALMER: So when I used that term "gas distribution system", that's a term that's used in the Canadian Standards Association, Z662 standard. And the definition for that is a pipeline operating below 30 percent SMYS. So it's a term that's used in that standard for a pipeline that has lower risk and that will fail by leak instead of rupture.

In its response to BCOAPO IR 1.2.1, FEI provides the Canadian Standards Association (CSA) Z662-19 definition of "a 'Distribution system, gas' as 'the main and service lines, and their associated control devices, through which gas is conveyed from transmission lines or from local sources of supply to the termination of the operating company installation…' "

Further in the same IR, FEI provides the CSA Z662-19 definition of "a 'Line, transmission' as 'a pipeline in a gas transmission system that conveys gas from a gathering line, treatment plant, storage facility, or field collection point in a gas field to a distribution line, service line, storage facility, or another transmission line' ". FEI states that that definition is relevant to this application since "This Application comprises laterals considered as part of FEI's transmission pipeline system."

Regarding Clause 12 Gas Distribution Systems, CSA Z662-19 provides a commentary that the application of Clause 12 should consider pipe dimension, pipe grade and intended operating pressure.

Within the terms of FEI Operating Agreements with interior municipalities (for example, FEI-City of Kelowna Operating Agreement approved by BCUC order G-99-19), a Distribution Pipeline "means pipelines operating at a pressure less than 2071 kilopascals (300 psi)" and a Transmission Pipeline "means a pipeline of FortisBC having an operating pressure in excess of 2071 kilopascals (300 psi)."

69.1 Please clarify how FEI determines whether an asset shall be considered a "Transmission Line" or a "Distribution Line".

**Response:**

FEI does not structure its operations by reference to a strict distinction between "Transmission Line" and "Distribution Line". FEI is subject to various legal requirements (e.g. statutes and regulations) that govern its operations, each of which can contain specific definitions or criteria that define its requirements. This is also the case with industry standards and codes of practice. Further, FEI's operating agreements and other documents use terms, definitions, and criteria that are applicable to the specific agreement or document which may not correspond to a term, definition or criteria used in a specific statute, regulation, industry standard or code of practice. As such, the use of certain terms and their definitions, including the terms "Transmission Line" and "Distribution Line" and their definitions vary depending on the context and application.

Examples of definitions and criteria that are applicable to FEI through its various legal requirements include:

- the *Oil and Gas Activities Act*, SBC 2008, c. 36 and regulations are applicable to pipelines operating at a pressure of 700 kilopascals (kPa) or greater;
- the *Gas Safety Regulation*, BC Reg 103/2004 (under the *Safety Standards Act*, SBC 2003, c. 39) is applicable to piping used to transmit natural gas at less than 700 kPa to consumers by a gas utility;
- the *Pipeline Regulation*, BC Reg 281/2010 (under the *Oil and Gas Activities Act)* and *Gas Safety Regulation* adopt Canadian Standards Association Oil & Gas Pipeline Systems standard Z662 (CSA Z662) requirements for the design, construction, operation and maintenance of FEI's piping systems. Under CSA Z662, many pipeline system lifecycle requirements are established on the basis of operating hoop stress of the pipe rather than operating pressure.

Of the various definitions and standards to which FEI is subject, the standard in CSA Z662 that is based on operating hoop stress of the pipe is most relevant to the IGU Project because the potential consequences associated with external corrosion (i.e. rupture vs. leak) are defined by whether a pipeline's operating hoop stress is 30 percent or greater of SMYS.

FEI clarifies that a gas distribution system is not defined in CSA Z662 as “a pipeline operating below 30 percent SMYS” as stated by Mr. Balmer on page 77 of the Procedural Conference Transcript V-1. As shown in FEI’s response to BCOAPO IR 1.2.1, page 12, CSA Z662-19 Clause 12.1.1 states: “Where specifically referenced, some requirements are applicable to piping for systems other than gas distribution systems, provided that any steel piping is intended to be operated at hoop stresses of less than 30 percent of the specified minimum yield strength of the pipe.” The definition for “Line, transmission” in CSA Z662 is: “a pipeline in a gas transmission system that conveys gas from a gathering line, treatment plant, storage facility, or field collection point in a gas field to a distribution line, service line, storage facility, or another transmission line.” It would therefore be possible for a Transmission Line that is operating at less than 30 percent of SMYS to be subject to the requirements of Z662 Clause 12, which is entitled “Gas distribution systems”.

As stated in footnote number 10 (on page 19) of the Application, FEI’s operating pressure classifications of Transmission Pressure (TP), Intermediate Pressure (IP), and Distribution Pressure (DP) that have appeared in prior FEI submissions to the BCUC are different from the operating stress-based classification that is relevant and applicable to this Application. FEI has many internal standards utilizing the following operating pressure-based definitions for TP, IP, and DP (as included in Appendix S, Glossary of Terms, from the Application):

- TP: Transmission pressure (2,070 – 9,930 kPag)[2]
- IP: Intermediate pressure (701 – 2,069 kPag)
- DP: Distribution pressure (70 – 700 kPag)

FEI has no plan to reclassify any of the transmission pipelines, including the 29 Transmission Laterals, as distribution lines (please refer to the response to BCUC IR 2.39.6). The 29 Transmission Laterals will all continue to operate at transmission pressure and will therefore fall under the jurisdiction of the BC Oil and Gas Commission and the *Oil and Gas Activities Act* and applicable regulations.

69.1.1 How does this determination impact the suitability of various integrity management strategies?

[2] Note that kPag stands for kilopascals at gauge pressure. Although the BC *Oil and Gas Activities Act* and FEI Operating Agreement definitions of “Distribution Pipeline” and “Transmission Pipeline” use kPa, FEI clarifies that this abbreviation also stands for kilopascals at gauge pressure. In the absence of the indication “gauge”, it is accepted industry practice that this is implied.

**Response:**

The definitions of a "Distribution Pipeline" and "Transmission Pipeline" in the terms of FEI's Operating Agreements with interior municipalities do not impact the suitability of FEI's integrity management strategies or FEI's regulatory requirements. Please refer to the response to BCUC IR 3.69.1.3.

FEI's integrity management strategies are developed to address specific hazards and are generally determined to be suitable for lines on the system, as follows:

- Particular third-party damage activities are generally suitable based on whether a line is installed within a right-of-way (typical for Transmission Lines) or in a road allowance (typical for Distribution Lines). The activities that are practicable for pipelines installed in a right-of-way (e.g. installation of signage, vegetation management) are different from pipelines installed in road allowances.
- Natural hazard activities are generally suitable based on whether a line is installed within a right-of-way (typical for Transmission Lines) or in a road allowance where the operating environment tends to be more controlled (typical for Distribution Lines). Seismic activities are determined on the basis of an estimation of the safety consequences.
- For the purposes of pipe condition activities, FEI's IMP-P differentiates assets by their operating hoop stress expressed as a percentage of the SMYS of the pipe. This is because the potential for rupture failure due to external corrosion is effectively mitigated for an asset operating at less than 30 percent of SMYS.
- Some material defects/equipment failure activities are implemented on a system-wide basis (e.g. gas quality management). Other material defects/equipment failure activities, such as preventative maintenance programs, are better suited to component-specific definition and are therefore defined based on component-specific analysis.
- Some consequence reduction activities are implemented on a system-wide basis (e.g. odorization). Other consequence reduction activities, such as leak management, are suitable depending on operating pressures (e.g. Transmission Line versus Distribution Line) or other factors that impact potential consequences associated with leaks (e.g. leak migration potential increases with factors such as surface cover).
- FEI's integrity management strategies for human factors (e.g. field quality) and core activities (e.g. asset design, pressure management) are generally practical for system-wide implementation.

69.1.2 How will FEI's application of the CSA Z662-19 standard change after the implementation of PRS?

**Response:**

FEI will continue to apply CSA Z662-19 to the transmission laterals after the implementation of PRS. However, because these laterals will be operating at less than 30 percent of SMYS, these assets will not require ILI to mitigate the current potential for rupture failure due to external corrosion. The laterals will instead be subject to recurring operational activities such as cathodic protection monitoring and leak detection. This is also the case for laterals selected for PLR because these new pipelines will also be operating at less than 30 percent of SMYS.

Please also refer to the responses to BCUC IRs 3.72.1 and 3.72.1.1.

69.1.3 Are the definitions within the FEI Operating Agreement terms applicable to the FEI IGU Project or do some other definitions apply? If the latter, please specify.

**Response:**

The definitions within the FEI Operating Agreement terms with interior municipalities are different from the classifications used in CSA Z662, which are the definitions relevant to the IGU Project. The definitions in the FEI Operating Agreement terms refer to pipeline operating pressure, while the classifications used in CSA Z662 in the context of the IGU Project are based on pipeline operating stress levels. Please refer to the responses to BCUC IRs 3.69.1 and 3.69.1.2.

In the FEI Operating Agreement terms, "Distribution Pipelines" are defined to include distribution and intermediate pressure gas lines (i.e. those gas lines operating at a pressure less than 2071 kilopascals (300 psi) and "Transmission Pipelines" are defined to include those gas lines having an operating pressure in excess of 2071 kilopascals (300 psi). These defined terms are used in the FEI Operating Agreement terms in the context of allocation of rights and obligations as between FEI and the specific municipality that is the party to the agreement. The definitions in an operating agreement may differ depending on the municipality. For example, the FEI-City of Surrey Operating Agreement (approved by BCUC Order G-18-19) contains different definitions for FEI's gas lines. In particular, "Gas Main" is a natural gas pipe operating at less than 700 kilopascals (100 psi) and "High Pressure Pipeline" is a natural gas pipeline operating at, or in excess of, 700 kilopascals (100 psi). These definitions are used in the context of the allocation of rights and obligations as between FEI and Surrey. The definitions used in a particular operating agreement do not impact FEI's regulatory obligations and are not intended and do not determine how FEI classifies its system for the purposes of integrity management (i.e. including design, construction, operation, and maintenance).

**70.0 Reference: PROJECT JUSTIFICATION**

**Exhibit B-16, p. 8; Transcript V-1, Workshop/Procedural Conference, pp. 13, 14, 15;**

**Exhibit B-10, Section 37.1, p. 22.**

**Suitability of PRS rupture mitigation option**

On page 8 of Exhibit B-16, FEI states:

> The Quantitative Risk Assessment (QRA) under development is not necessary to justify the IGU Project. Compliance with industry standard practise, and codes and regulation are sufficient to support the need for the IGU project.

On page 13 of the Procedural Conference Transcript V-1, Mr. Chernikhowsky states:

> Now, to reiterate, we have no reliable way to detect where corrosion is occurring. In this case, we could dig up and expose the pipeline, all two kilometers of it, it would be very impactful to landowners in the area, and instead, we are proposing a small, pressure reducing station upstream of the pipeline, and this will effectively mitigate the risk of a rupture by reducing the operating pressure below the point where a rupture could occur.

Further, on page 14 of the same transcript, Mr. Chernikhowsky states:

> So, where does a QRA fit into this picture? So, fundamentally a QRA is used for two purposes; to prioritize complex work, and activities that could not otherwise be addressed all at the same time, or to identify otherwise unknown risk, which we call “interacting threats” that we might not otherwise have been aware of due to their complexity.

Further, on page 15 of the same transcript, Mr. Chernikhowsky states:

> And to put it another way, the BC OGC has directed FEI to conduct a segment-by-segment risk assessment to assure that we have not missed anything, not to allow us to defer addressing known risks.

In its response to BCUC IR 37.1, FEI states that “In very rare cases of selective seam weld corrosion in low-frequency electrical resistance welded seam welds or instances involving outside forces, pipelines operating at less than 30 percent of SMYS may result in rupture failure.”

70.1 With respect to the PRS mitigation option, is FEI aware of any additional applicable hazards which when compounded with potential corrosion make reduction to below 30 percent SMYS an ineffective mitigation action?

**<u>Response:</u>**

No, FEI is not aware of any additional applicable hazards on the 29 Transmission Laterals which, when compounded with potential external corrosion, make reduction to below 30 percent

SMYS an ineffective mitigation action. Other hazards also addressed by the IGU Project are as discussed in the response to BCUC IR 2.41.1. As indicated in response to BCUC IR 2.35.7, FEI monitors all known or anticipated conditions that could result in failures and has proactive activities within its IMP-P to mitigate those hazards.

The rupture threat associated with external corrosion is appropriately mitigated if a pipeline is operating below 30 percent of SMYS; therefore, the PRS alternative as proposed in the Application is an effective threat mitigation strategy. This is reflected in CSA Z662-19 and is consistent with generally accepted industry practice.

FEI requested that JANA Corporation provide its independent, expert opinion in response to this question. JANA Corporation provides the following response:

- In comparing the options of ILI and pressure reduction for mitigation of corrosion threats, reduction to below 30 percent SMYS is typically considered by industry as an effective mitigation for corrosion as pipelines operating below 30 percent SMYS are considered to be significantly more likely to leak rather than rupture. This is supported by:
    - CSA Z662-19 delineation between distribution and transmission pipelines is 30 percent SMYS
    - 2004 ASME International Pipeline Conference Paper –"A review of the Time Dependant Behaviour of Line Pipe Steel, A. Cosham and P. Hopkins which indicates that full scale tests on part-wall (e.g. a corrosion defect that has not penetrated through the full thickness of the pipe) and through-wall defects (e.g. a corrosion defect that has penetrated through the full thickness of the pipe) showed that it is very unlikely that a part-wall defect will fail as a rupture at a stress level less than 30 percent.
    - Gas Research Institute Final Report No-00/0232, Leak versus Rupture Considerations for Steel Low-Stress Pipelines" statement:
        - "Given the results generated, the leak to rupture transition for corrosion defects in the low-wall-stress pipeline system can be taken as 30 percent of SMYS, a value that is conservative in comparison with in-service incidents."
    - As detailed in the response to BCUC IR 3.65.2, it is possible for rupture to occur, however, below 30 percent SMYS under specific rare conditions as reported by Rosenfeld and Fassett[3]. The specific cases they cite are for very long cracks possible with selective seam corrosion and very low toughness pipelines.

---

[3] Study of Pipelines that ruptured while operating at a hoop stress below 30% SMYS, M.Rosenfeld, R. Fassett, PPIM, 2013.

70.2 With respect to any pipe laterals installed prior to 1970, does operating at 30 percent SMYS or below reduce the risk to the same level regardless of pipe manufacturing standards at the time of installation or pipe welding standards at the time of installation?

**Response:**

FEI requested that JANA Corporation provide its independent, expert opinion in response to this question. JANA Corporation provides the following response:

> Not Confirmed. Operating below 30 percent SMYS reduces the risk for pre-1970s pipe versus its current risk when operating above 30 percent SMYS and implementation of an operating stress reduction below 30 percent SMYS is an accepted mitigation for all transmission pipelines regardless of their year of installation. While the general industry consensus is that reduction of pressure to below 30 percent SMYS will lead to leak rather rupture is not limited to specific pipeline construction dates, there is the potential that older pipelines could be more susceptible to the rare circumstances that could lead to rupture below 30 percent SMYS[4].

FEI adds that ruptures on pipelines operating below 30 percent SMYS are a very rare occurrence in the pipeline industry. While the residual risk that remains with pipelines that are operated below 30 percent SMYS can never be zero, operation of a pipeline below 30 percent SMYS addresses the primary hazard of external corrosion, and others as discussed in response to BCUC IR 2.41.1. This is a risk mitigation solution adopted by the pipeline industry and aligns with the CSA Z662 standard as a threshold differentiating between two classifications of assets that warrant substantively different approaches to their life-cycle integrity management.

70.3 Is FEI aware of any ruptures on any North American situated pipelines that were operating at or below 30 percent SMYS? If so, please specify.

**Response:**

4 “Study of Pipelines that ruptured while operating at a hoop stress below 30% SMYS, M.Rosenfeld, R. Fassett, PPIM, 2013.

FEI is anecdotally aware of ruptures on North American situated pipelines that were operating at or below 30 percent SMYS.

FEI requested that JANA Corporation provide its independent, expert opinion in response to this question. JANA Corporation provides the following response:

> An analysis of the NEB incident records for 2008-2018 did not reveal any reported ruptures <30 percent SMYS for Canadian pipelines. A 2013 report by Rosenfeld provides a summary of ruptures on pipelines below 30 percent SMYS for the US. There are 11 reported gas pipeline ruptures. None of these occurred due to external corrosion on the body of the pipe. Four occurred due to selective seam corrosion.
>
> For mitigation of the identified external corrosion threat, a reduction to below 30 percent SMYS is considered an effective approach as it will result in a pinhole leak and not rupture (consistent with industry experience). In the case of selective seam corrosion, a reduction to below 30 percent SMYS will also significantly reduce, though not fully eliminate the potential for rupture. This is because the leak rupture boundary is dependant on the operating pressure and the length and depth of the defect, and only very long and deep selective seam corrosion defects (which are very rare) would provide a situation in which rupture would occur and shorter more shallow defects would lead to leaks. This is why this type of rupture is a rare occurrence below 30 percent SMYS (with only four identified occurrences in the Rosenfeld report[5]).

[5] Study of Pipelines that ruptured while operating at a hoop stress below 30% SMYS, M.Rosenfeld, R. Fassett, PPIM, 2013.

## B. DESCRIPTION AND EVALUATION OF ALTERNATIVES

**71.0 Reference: PROJECT ALTERNATIVES**

**Exhibit B-1, Section 4.5.4, Table 4-10; Exhibit B-2, BCUC IR 8.2, Table 4**

**Table Consolidation**

In Table 4-10, page 47 of the Application, FEI provides a present value of each of the three project alternatives.

In its response to BCUC IR 8.2, FEI provides Table 4, a summary of each lateral, including coating type, age and the percentage of Class 3 sections, and other information.

71.1 Please consolidate these two tables into a single table, with a row for each lateral, by completing the table below:

| Lateral | ILI present value | PLR present value | PRS present value | Preferred Alternative | % Class 3 | Year Installed | Pipe Coating Type | Line length |
|---|---|---|---|---|---|---|---|---|
| | | | | | | | | |

**Response:**

Please refer to the consolidated table provided below. The present values shown in the consolidated table reflect the updated figures from the Evidentiary Update and Errata filed on April 5, 2019.

Please also refer to the response to BCUC IR 3.73.1.1 which demonstrates that the IGU Project cost would be approximately $140 million or 39 percent higher if the PRS alternative was not approved.

| Lateral | ILI Present Value ($ millions) | PLR Present Value ($ millions) | PRS Present Value ($ millions) | Preferred Alternatives | % of Class 3 Location | Year Installed | Pipe Coating Type | Length (kilometres) |
|---|---|---|---|---|---|---|---|---|
| Mackenzie Lateral 168 | 44.7 | n/a* | n/a** | ILI | 1% | 1996 | Extruded Polyethylene | 28.7 |
| Mackenzie Loop 168 | 25.2 | n/a* | n/a** | ILI | - | 1972 | Extruded Polyethylene | 14.2 |
| BC Forest Products Lateral 168 | 12.6 | 3.5 | 7.0 | PLR | - | 1996 | Extruded Polyethylene | 0.5 |
| Prince George 3 Lateral 219 | 14.3 | n/a* | 2.2 | PRS | - | 1970 | Extruded Polyethylene | 5.3 |
| Northwood Pulp Lateral 168 | 15.4 | n/a* | 2.2 | PRS | - | 1965 | Asphalt Enamel | 6.0 |
| Northwood Pulp Loop 219 | 14.1 | n/a* | 2.2 | PRS | - | 1995 | Extruded Polyethylene | 5.8 |
| Prince George #1 Ltl 168 | 14.4 | n/a* | n/a** | ILI | - | 1957 | Asphalt Enamel | 4.7 |
| Prince George Pulp Lateral 168 | 14.3 | 7.7 | 3.6 | PRS | - | 1964 | Asphalt Enamel | 1.0 |
| Husky Oil Lateral 168 | 16.4 | 5.6 | 3.6 | PRS | - | 1965 | Asphalt Enamel | 1.1 |
| Prince George #2 Lateral 219 | 15.8 | n/a* | 6.3 | PRS | - | 1972 | Extruded Polyethylene | 8.7 |
| Cariboo Pulp Lateral 168 | 10.5 | 5.5 | 6.5 | PLR | - | 1993 | Extruded Polyethylene | 1.3 |
| Williams Lake Loop 1/Loop 2 168 | 15.7 | n/a* | 6.0 | PRS | - | 1993 | Extruded Polyethylene | 5.9 |
| Kamloops 1 Lateral & Loop 168 | 32.1 | 15.8 | n/a** | PLR | 27%/31% | 1965/1979 | Asphalt Enamel | 6.6 |
| Salmon Arm Loop 168 | 32.6 | n/a* | n/a** | ILI | 12% | 1976 | Extruded Polyethylene | 44.9 |
| Salmon Arm 3 Lateral | 10.5 | 4.2 | 6.6 | PLR | - | 1981 | Extruded Polyethylene | 0.9 |
| Coldstream Lateral 219 | 13.2 | 9.3 | 5.9 | PRS | 49% | 1998 | Extruded Polyethylene | 1.8 |
| Coldstream Loop 168 | 14.2 | n/a* | 6.0 | PRS | 16% | 1989 | Extruded Polyethylene | 3.8 |
| Kelowna 1 Loop 219 | 14.0 | n/a* | 6.9 | PRS | 33% | 1976 | Extruded Polyethylene | 2.1 |
| Celgar Lateral 168 | 11.7 | n/a* | 5.9 | PRS | 4% | 1960 | Asphalt Enamel | 5.8 |
| Castlegar Nelson 168 | 54.2 | n/a* | 9.0 | PRS | 21% | 1957 | Asphalt Enamel | 37.4 |
| Trail Lateral 168 | 19.0 | n/a* | 5.9 | PRS | - | 1957 | Asphalt Enamel | 4.2 |
| Fording Lateral 219/168 | 102.8 | n/a* | n/a** | ILI | 6% | 1971 | Extruded Polyethylene | 79.7 |
| Elkview Lateral 168 | 10.1 | 5.9 | 5.9 | PRS | 19% | 1970 | Extruded Polyethylene | 1.6 |
| Cranbrook Lateral 168 | 21.2 | n/a* | n/a** | ILI | 9% | 1990 | Asphalt Enamel | 34.0 |
| Cranbrook Loop 219 | 20.8 | n/a* | n/a** | ILI | 9% | 1968 | Asphalt Enamel | 34.0 |
| Cranbrook Kimberley Loop 219 | 9.4 | n/a* | n/a** | ILI | - | 1992 | Asphalt Enamel | 4.0 |
| Cranbrook Kimberley Loop 273 | 10.9 | n/a* | n/a** | ILI | 21% | 1992 | Extruded Polyethylene | 9.4 |
| Kimberly Lateral 168 | 23.5 | n/a* | n/a** | ILI | 2% | 1962 | Asphalt Enamel | 20.6 |
| Skookumchuck Lateral 219 | 14.0 | n/a* | n/a** | ILI | - | 1968 | Asphalt Enamel | 35.9 |

* PLR was considered financially not feasible and was screened out for these laterals per Table 4-9 of Section 4.4.5 of the Application

** PRS was considered technically not feasible for these laterals and as a result, no cost estimate and present values were developed

**72.0 Reference: PROJECT ALTERNATIVES**

**Exhibit B-1, Section 5.1, Table 5-1; Exhibit B-2, BCUC IR 8.2, Table 4**

**PRS Alternative**

In Table 5-1 of the Application, FEI provides the preferred alternative for each of the 29 laterals.

In its response to BCUC IR 8.2, FEI provides Table 4, listing the percentage of Class 3 setions of each of the 29 laterals.

To summarize, the laterals with Class 3 sections that are proposed for the PRS alternative are:

- Coldstream Lateral 219, 49 percent Class 3
- Coldstream Loop 168, 16 percent Class 3
- Kelowna 1 Loop 219, 33 percent Class 3
- Celgar Lateral 168, 4 percent Class 3
- Castlegar Nelson 168, 21 percent Class 3
- Elkview Lateral 168, 19 percent Class 3

72.1 Please explain, in detail, how FEI proposes to perform integrity management on the laterals chosen for PRS.

**Response:**

Since the implementation of PRS will mitigate the potential for rupture due to external corrosion, these assets will not also require ILI to do the same. However, they will be subject to recurring operational activities including the application of CP, CP monitoring, and leak detection. FEI does not expect any changes to its other hazard management practices (e.g. third-party damage, natural hazards).

Please refer to the second table included in the response to BCUC IR 2.40.1 for a detailed listing of FEI's current monitoring activities for the 29 Transmission Laterals, including the laterals where PRS has been selected as the preferred alternative. These monitoring activities will continue to be required and performed at their current levels for the laterals where PRS is implemented.

72.1.1 Please explain how FEI will monitor and assess the pipeline wall condition of the laterals chosen for PRS. In your answer, please include monitoring and assessment of corrosion.

**Response:**

FEI's corrosion monitoring approach for pipelines operating at less than 30 percent of SMYS, which will include the pipelines chosen for PRS, is to perform CP monitoring, to record visual observations any time a pipeline may be exposed during its lifecycle, and to perform leak detection surveys. A significant condition monitoring program is only planned upon an occurrence of a relevant leak history. This approach aligns with CSA Clause 12.10.3.3 (d) as set out in the response to BCOAPO IR 1.2.1, which allows an operator to wait for a demonstrated leak history before implementing further integrity management activities on a pipeline operating at less than 30 percent of SMYS.

72.2 Please explain how FEI considered the potential impact of a rupture to the public for each lateral when choosing its preferred alternative.

**Response:**

FEI considers ruptures of its transmission pipelines as unacceptable. The ability of an alternative to mitigate the potential for rupture, regardless of the potential impact, was the primary objective in FEI's identification of PRS, ILI and PLR as technically feasible alternatives for the 29 Transmission Laterals. All three alternatives mitigate the potential for rupture due to external corrosion. Consequently, the evaluation criteria described in section 4.3.1 of the Application were applied when choosing the preferred alternatives.

72.3 Please explain whether the consequences of a leak or rupture are increased in Class 3 areas.

**Response:**

The potential safety-related consequences of a leak or rupture are increased in Class 3 areas due to increased population density and/or increased potential for people to congregate as compared to Class 1 and 2 areas. As discussed in Section 3.3.4 of the Application, a natural gas pipeline rupture has the potential to result in significant safety, reliability, environmental and regulatory consequences in any location. CSA Z662-19, Clause O.2.2.3.1 states that the human and environmental safety consequences of a small leak in a non-sour natural gas pipeline are insignificant.

**73.0 Reference: EVALUATION OF ALTERNATIVES**

**Exhibit B-2, BCUC IR 24.1; Exhibit B-1-2, Evidentiary Update, Table 4-10, p. 47**

**PRS Alternative**

In Table 4-10 on page 47 of the Evidentiary Update to the Application, FEI provides the following present value of incremental requirements analysis for each lateral and identifies the preferred alternative for each lateral:

| Lateral | Length (kilometres) | ILI Present Value ($ millions) | PLR Present Value ($ millions) | PRS Present Value ($ millions) | Preferred Alternatives |
|---|---|---|---|---|---|
| Mackenzie Lateral 168 | 28.7 | 44.7 | - | - | ILI |
| Mackenzie Loop 168 | 14.2 | 25.2 | - | - | ILI |
| BC Forest Products Lateral 168 | 0.5 | 12.6 | 3.5 | 7.0 | PLR |
| Prince George 3 Lateral 219 | 5.3 | 14.3 | - | 2.2 | PRS |
| Northwood Pulp Lateral 168 | 6.0 | 15.4 | - | 2.2 | PRS |
| Northwood Pulp Loop 219 | 5.8 | 14.1 | - | 2.2 | PRS |
| Prince George #1 Ltl 168 | 4.7 | 14.4 | - | - | ILI |
| Prince George Pulp Lateral 168 | 1.0 | 14.3 | 7.7 | 3.6 | PRS |
| Husky Oil Lateral 168 | 1.1 | 16.4 | 5.6 | 3.6 | PRS |
| Prince George #2 Lateral 219 | 8.7 | 15.8 | - | 6.3 | PRS |
| Cariboo Pulp Lateral 168 | 1.3 | 10.5 | 5.5 | 6.5 | PLR |
| Williams Lake Loop 168 | 5.9 | 15.7 | - | 6.0 | PRS |
| Kamloops 1 Lateral & Loop 168 | 6.6 | 32.1 | 15.8 | - | PLR |
| Salmon Arm Loop 168 | 44.9 | 32.6 | - | - | ILI |
| Salmon Arm 3 Lateral | 0.9 | 10.5 | 4.2 | 6.6 | PLR |
| Coldstream Lat 219 | 1.8 | 13.2 | 9.3 | 5.9 | PRS |
| Coldstream Loop 168 | 3.8 | 14.2 | - | 6.0 | PRS |
| Kelowna 1 Loop 219 | 2.1 | 14.0 | - | 6.9 | PRS |
| Celgar Lateral 168 | 5.8 | 11.7 | - | 5.9 | PRS |
| Castlegar Nelson 168 | 37.4 | 54.2 | - | 9.0 | PRS |
| Trail Lateral 168 | 4.2 | 19.0 | - | 5.9 | PRS |
| Fording Lateral 219/168 | 79.7 | 102.8 | - | - | ILI |
| Elkview Lateral 168 | 1.6 | 10.1 | 5.9 | 5.9 | PRS |
| Cranbrook Lateral 168 | 34.0 | 21.2 | - | - | ILI |
| Cranbrook Loop 219 | 34.0 | 20.8 | - | - | ILI |
| Cranbrook Kimberley Loop 219 | 4.0 | 9.4 | - | - | ILI |
| Cranbrook Kimberley Loop 273 | 9.4 | 10.9 | - | - | ILI |
| Kimberly Lateral 168 | 20.6 | 23.5 | - | - | ILI |
| Skookumchuck Lateral 219 | 35.9 | 14.0 | - | - | ILI |

In response to BCUC IR 24.1, FEI provided a project risk ranking of the 29 Transmission Laterals and a detailed explanation for each ranking based on various risk areas. With regard to the Transmission Laterals where PRS is the chosen alternative, the risk was ranked as either moderate or low.

73.1 Please provide a revised response to BCUC IR 24.1 for each of the 29 Transmission Laterals, where the proposed alternative is PRS but under a hypothetical scenario where FEI instead selected the second alternative for each of those laterals (i.e. either ILI or PLR). Please provide both the revised tabular risk rankings and a detailed explanation for each revised ranking based on the risk areas identified in BCUC IR 24.1.

**Response:**

Table 1 below provides a revised response to BCUC IR 1.24.1 and shows the project construction risk ranking from high to low for the hypothetical scenario where the second alternative is selected instead of PRS.

FEI selected the second alternative for the 14 laterals (where PRS was the preferred alternative) based on the second highest overall score for alternative selection provided in Appendix A of the Evidentiary Update of the Application, filed on April 5, 2019[6]. The original project construction risk ranking based on the preferred alternative from FEI's response to BCUC IR 1.24.1 is included in Table 1 for comparison. In every case, the selection of the secondary alternative increases the project risk for the 14 laterals from "low" to "high" or "moderate" (as shown by the highlighted orange rows). In general, this is due to the fact that PRS is a lower risk from a construction risk ranking perspective.

Table 2 below provides a summary of the overall alternative selection scores from Appendix A of the Evidentiary Update for the 14 laterals that have PRS as the preferred alternative (green highlights the preferred alternative and blue highlights the alternative with the second highest overall score).

To be consistent with the response to BCUC IR 1.24.1, the Project construction risk ranking is based on a risk scoring of "high" for scores higher than 20, "moderate" for scores between 11 and 20, and "low" for scores less than 10. The Project construction risk scores are calculated based on the risk areas anticipated during construction as identified in FEI's response to BCUC IR 1.24.1, which are:

- Project cost;
- Project scope and timeline;
- Consultation requirements;
- Environmental impact;
- Right of Way Requirements; and
- Permitting.

---

6 The exception is Elkview Lateral 168 which the second alternative is PLR which has a higher overall score than PRS. PRS was selected as the preferred alternative for reasons discussed in the response to BCUC IR 1.18.4.

Please refer to Table 3 below for the calculation of the revised Project construction risk score to reflect this hypothetical scenario.

Please also refer to the response to BCUC IR 3.73.1.1 for a comparison of costs for those laterals where PRS was the preferred alternative versus the secondary alternative.

**Table 1: Project construction risk ranking for the hypothetical scenario where the second alternative is selected instead of PRS**

| | Revised for BCUC IR 3.73.1 | | | Original BCUC IR 1.24.1 | | |
|---|---|---|---|---|---|---|
| Lateral | Second Alternative if PRS is the Preferred Alternative | Project Construction Risk Score | Project Construction Risk Ranking | Preferred Alternative | Project Construction Risk Score | Project Construction Risk Ranking |
| 22. Fording Lateral 219/168 | ILI | 28 | High | ILI | 28 | High |
| 13. Kamloops 1 Lateral & Loop 168 | PLR | 26 | High | PLR | 26 | High |
| 8. Prince George Pulp Lateral 168 | ILI | 25 | High | PRS | 13 | Moderate |
| 20. Castlegar Nelson 168 | ILI | 24 | High | PRS | 10 | Low |
| 14. Salmon Arm Loop 168 | ILI | 22 | High | ILI | 22 | High |
| 18. Kelowna 1 Loop 219 | ILI | 22 | High | PRS | 15 | Moderate |
| 1. Mackenzie Lateral 168 | ILI | 21 | High | ILI | 21 | High |
| 17. Coldstream Loop 168 | ILI | 21 | High | PRS | 14 | Moderate |
| 7. Prince George #1 Ltl 168 | ILI | 20 | High | ILI | 20 | High |
| 9. Husky Oil Lateral 168 | PLR | 20 | High | PRS | 6 | Low |
| 16. Coldstream Lat 219 | PLR | 20 | High | PRS | 14 | Moderate |
| 19. Celgar Lateral 168 | ILI | 20 | High | PRS | 9 | Low |
| 21. Trail Lateral 168 | ILI | 20 | High | PRS | 8 | Low |
| 4. Prince George 3 Lateral 219 | ILI | 19 | Moderate | PRS | 6 | Low |
| 5. Northwood Pulp Lateral 168 | ILI | 19 | Moderate | PRS | 9 | Low |
| 6. Northwood Pulp Loop 219 | ILI | 19 | Moderate | PRS | 9 | Low |
| 23. Elkview Lateral 168 | PLR | 19 | Moderate | PRS | 10 | Low |
| 28. Kimberly Lateral 168 | ILI | 18 | Moderate | ILI | 18 | Moderate |
| 12. Williams Lake Loop 168 | ILI | 18 | Moderate | PRS | 9 | Low |
| 24. Cranbrook Lateral 168 | ILI | 17 | Moderate | ILI | 17 | Moderate |
| 25. Cranbrook Loop 219 | ILI | 17 | Moderate | ILI | 17 | Moderate |
| 10. Prince George #2 Lateral 219 | ILI | 17 | Moderate | PRS | 10 | Low |
| 29. Skookumchuck Lateral 219 | ILI | 16 | Moderate | ILI | 16 | Moderate |
| 26. Cranbrook Kimberley Loop 219 | ILI | 16 | Moderate | ILI | 16 | Moderate |
| 27. Cranbrook Kimberley Loop 273 | ILI | 16 | Moderate | ILI | 16 | Moderate |
| 15. Salmon Arm 3 Lateral | PLR | 16 | Moderate | PLR | 16 | Moderate |
| 2. Mackenzie Loop 168 | ILI | 15 | Moderate | ILI | 15 | Moderate |
| 11. Cariboo Pulp Lateral 168 | PLR | 13 | Moderate | PLR | 13 | Moderate |
| 3. BC Forest Products Lateral 168 | PLR | 10 | Low | PLR | 10 | Low |

**Table 2: Summary of overall alternative scores (weighted average of technical, project execution, and financial) from Appendix A of Evidentiary Update (14 laterals with PRS as preferred alternative only)**

| Ref. | Lateral | ILI | PLR | PRS |
|---|---|---|---|---|
| 4 | Prince George 3 Lateral 219 | 3.2 | 2.8 | 4.0 |
| 5 | Northwood Pulp Lateral 168 | 3.2 | 2.7 | 3.9 |
| 6 | Northwood Pulp Loop 219 | 3.2 | 2.7 | 3.9 |
| 8 | Prince George Pulp Lateral 168 | 3.2 | 3.1 | 3.8 |
| 9 | Husky Oil Lateral 168 | 3.2 | 3.5 | 3.8 |
| 10 | Prince George #2 Lateral 219 | 3.3 | 2.8 | 3.9 |
| 12 | Williams Lake Loop 168 | 3.2 | 2.8 | 3.9 |
| 16 | Coldstream Lat 219 | 3.2 | 3.4 | 3.9 |
| 17 | Coldstream Loop 168 | 3.1 | 2.7 | 3.9 |
| 18 | Kelowna 1 Loop 219 | 3.1 | 2.7 | 3.9 |
| 19 | Celgar Lateral 168 | 3.6 | 2.8 | 3.8 |
| 20 | Castlegar Nelson 168 | 3.2 | 2.8 | 3.8 |
| 21 | Trail Lateral 168 | 3.1 | 2.8 | 3.8 |
| 23 | Elkview Lateral 168 | 3.6 | 4.5 | 3.8 |

**Table 3: Revised project construction risk score with second alternative selected for those laterals with PRS as the preferred alternative**

| | Revised for BCUC IR 3.73.1 | | | | | | | | | Original BCUC IR 1.24.1 | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Lateral | Preferred Alterantive (Second Alternative if PRS is the Preferred Alternative) | Project Risk Score | Risk Ranking | Project Cost | Project Scope and Timeline | Consultation Requirements | Environmental Impacts | ROW Requirements | Permitting | Preferred Alternative | Overall Risk Score | Risk Ranking |
| 22. Fording Lateral 219/168 | ILI | 28 | High | 5 | 5 | 5 | 5 | 4 | 4 | ILI | 28 | High |
| 13. Kamloops 1 Lateral & Loop 168 | PLR | 26 | High | 4 | 3 | 5 | 5 | 5 | 4 | PLR | 26 | High |
| 8. Prince George Pulp Lateral 168 | ILI | 25 | High | 4 | 5 | 3 | 5 | 4 | 4 | PRS | 13 | Moderate |
| 20. Castlegar Nelson 168 | ILI | 24 | High | 4 | 4 | 4 | 4 | 4 | 4 | PRS | 10 | Low |
| 14. Salmon Arm Loop 168 | ILI | 22 | High | 4 | 4 | 5 | 3 | 2 | 4 | ILI | 22 | High |
| 18. Kelowna 1 Loop 219 | ILI | 22 | High | 3 | 5 | 4 | 4 | 3 | 3 | PRS | 15 | Moderate |
| 1. Mackenzie Lateral 168 | ILI | 21 | High | 4 | 4 | 3 | 5 | 1 | 4 | ILI | 21 | High |
| 17. Coldstream Loop 168 | ILI | 21 | High | 3 | 4 | 3 | 4 | 4 | 3 | PRS | 14 | Moderate |
| 7. Prince George #1 Ltl 168 | ILI | 20 | High | 3 | 3 | 5 | 3 | 3 | 3 | ILI | 20 | High |
| 9. Husky Oil Lateral 168 | PLR | 20 | High | 3 | 2 | 3 | 4 | 4 | 4 | PRS | 6 | Low |
| 16. Coldstream Lat 219 | PLR | 20 | High | 3 | 2 | 4 | 4 | 4 | 3 | PRS | 14 | Moderate |
| 19. Celgar Lateral 168 | ILI | 20 | High | 3 | 3 | 3 | 4 | 4 | 3 | PRS | 9 | Low |
| 21. Trail Lateral 168 | ILI | 20 | High | 3 | 4 | 3 | 3 | 4 | 3 | PRS | 8 | Low |
| 4. Prince George 3 Lateral 219 | ILI | 19 | Moderate | 3 | 3 | 4 | 3 | 3 | 3 | PRS | 6 | Low |
| 5. Northwood Pulp Lateral 168 | ILI | 19 | Moderate | 3 | 3 | 3 | 4 | 3 | 3 | PRS | 9 | Low |
| 6. Northwood Pulp Loop 219 | ILI | 19 | Moderate | 3 | 3 | 3 | 4 | 3 | 3 | PRS | 9 | Low |
| 23. Elkview Lateral 168 | PLR | 19 | Moderate | 3 | 3 | 3 | 3 | 4 | 3 | PRS | 10 | Low |
| 28. Kimberly Lateral 168 | ILI | 18 | Moderate | 2 | 2 | 5 | 3 | 4 | 2 | ILI | 18 | Moderate |
| 12. Williams Lake Loop 168 | ILI | 18 | Moderate | 3 | 3 | 3 | 3 | 3 | 3 | PRS | 9 | Low |
| 24. Cranbrook Lateral 168 | ILI | 17 | Moderate | 2 | 2 | 5 | 5 | 1 | 2 | ILI | 17 | Moderate |
| 25. Cranbrook Loop 219 | ILI | 17 | Moderate | 2 | 2 | 5 | 5 | 1 | 2 | ILI | 17 | Moderate |
| 10. Prince George #2 Lateral 219 | ILI | 17 | Moderate | 3 | 3 | 3 | 2 | 3 | 3 | PRS | 10 | Low |
| 29. Skookumchuck Lateral 219 | ILI | 16 | Moderate | 2 | 2 | 5 | 3 | 2 | 2 | ILI | 16 | Moderate |
| 26. Cranbrook Kimberley Loop 219 | ILI | 16 | Moderate | 2 | 2 | 5 | 3 | 2 | 2 | ILI | 16 | Moderate |
| 27. Cranbrook Kimberley Loop 273 | ILI | 16 | Moderate | 2 | 2 | 5 | 3 | 2 | 2 | ILI | 16 | Moderate |
| 15. Salmon Arm 3 Lateral | PLR | 16 | Moderate | 2 | 1 | 3 | 3 | 5 | 2 | PLR | 16 | Moderate |
| 2. Mackenzie Loop 168 | ILI | 15 | Moderate | 3 | 2 | 3 | 3 | 1 | 3 | ILI | 15 | Moderate |
| 11. Cariboo Pulp Lateral 168 | PLR | 13 | Moderate | 2 | 1 | 3 | 1 | 4 | 2 | PLR | 13 | Moderate |
| 3. BC Forest Products Lateral 168 | PLR | 10 | Low | 2 | 1 | 1 | 1 | 1 | 4 | PLR | 10 | Low |

Table 4 below provides the detailed explanation for each revised ranking for the hypothetical scenario (i.e., the second alternative for the 14 PRS laterals) in the order of high to low project construction risk scoring. The risk explanation for the same laterals with PRS as the preferred alternative (as per BCUC IR 1.24.1) is also included for comparison.

**Table 4: Revised project construction risk explanation with second alternative selected for those laterals with PRS as the preferred alternative**

| Lateral | Revised for BCUC IR 3.73.1<br>Second Alternative if PRS is the Preferred Alternative | | | Original BCUC IR 1.24.1<br>Preferred Alternative (PRS) | | |
|---|---|---|---|---|---|---|
| 8. Prince George Pulp Lateral 168 | ILI | Considered high risk due to the requirement of a challenging HDD crossing of the Fraser River with a potential scope change to an aerial crossing if the HDD is not feasible. There is also potential for the Project cost to change subject to the number of modifications required. There is also limited space for available for a receiver barrel at the Prince George Pulp and Paper mill. Lastly, the lateral is in close proximity to the CN Rail. There are also registered contaminated sites, mature forested riparian areas and plant species at risk. | High | PRS | Considered moderate risk due to the CN rail crossing and lack of existing ROW at proposed PRS site. Overall the construction footprint of the PRS will be limited so FEI does not anticipate many complications on this lateral. | Moderate |
| 20. Castlegar Nelson 168 | ILI | Considered high risk because of the consultation requirements due to the large number of potentially affected land owners during construction. There is also potential for the project cost to change subject to the number of modifications required and challenging terrain. There are several registered archaeological sites and a large number of moderate to high archaeological potential sites along the ROW. Additionally, there are registered contaminated sites and critical habitat for caribou and woodpecker. Lastly, there are also several sites in the ALR that could result in longer permitting approval time. | High | PRS | Considered low risk due to the limited ground disturbance required for the PRS installation. The land acquisition will require negotiation because the PRS will be located on private land. | Low |

| Lateral | Revised for BCUC IR 3.73.1<br>Second Alternative if PRS is the Preferred Alternative | | | Original BCUC IR 1.24.1<br>Preferred Alternative (PRS) | | |
|---|---|---|---|---|---|---|
| 18. Kelowna 1 Loop 219 | ILI | Considered high risk due to the potential for the project cost to change subject to the number of modifications required, and a large amount of ground disturbance in a developed urban setting. There are also registered archaeological sites and areas of moderate to high archaeological potential along the ROW. Additionally there are riparian areas and fish bearing streams. | High | PRS | Considered moderate risk due to the land acquisition required on high valued property. The Kelowna Loop PRS will require an expansion of the existing ROW in Walmart's parking lot. The permitting may be more challenging than the other laterals since the proposed construction footprint will be in a high traffic area of Kelowna, and may result in more complex consultation requirements. | Moderate |
| 17. Coldstream Loop 168 | ILI | Considered high risk due to the potential for the project cost to change subject to the number of modifications required. A significant portion of the lateral is within areas of moderate to high archaeological potential. Additionally, the entire loop is within the ALR which could result in longer permitting approval time. Lastly, a portion of the lateral is within the legacy area of an old military camp where there may be unexploded explosive ordinances. | High | PRS | Considered moderate risk due to the proposed location of the PRS with unexploded ordinances (UXO) along ROW, areas of high archaeological potential confirmed. | Moderate |
| 9. Husky Oil Lateral 168 | PLR | Considered high risk due to the amount of ground disturbance to replace the full length of the pipeline in narrow corridors. A significant portion of the pipeline is adjacent to the CN Rail and crosses the rail where the pipe is located in road allowance between an NPS 42 water main and Husky Oil property which will require coordination with Husky Oil during construction. In addition, there are registered contaminated sites, a nearby Osprey nest and medium to high archaeological potential near the end of the lateral. | High | PRS | Considered low risk because the PRS will be installed on the Prince George Pulp Lateral so the Husky Oil lateral will not be impacted. | Low |

| Lateral | Revised for BCUC IR 3.73.1<br>Second Alternative if PRS is the Preferred Alternative | | | Original BCUC IR 1.24.1<br>Preferred Alternative (PRS) | | |
| --- | --- | --- | --- | --- | --- | --- |
| 16. Coldstream Lateral 219 | PLR | Considered high risk due to the large amount of ground disturbance adjacent to the Vernon Golf and Country Club course. There are also critical habitats for great basin spadefoot and two species of snake, registered contaminated sites and stream crossings. There is also a significant portion of the pipeline within the ALR that could result in longer permitting approval time. | High | PRS | Considered moderate risk due to the proposed location of the PRS on private property, areas of high archaeological potential confirmed. | Moderate |
| 19. Celgar Lateral 168 | ILI | Considered high risk due to the large amount of ground disturbance on challenging terrain and the potential for the project cost to change subject to the number of modifications required. There are species at risk occurrences including Grizzly bear habitat, ungulate winter range and a portion of the pipeline within the ALR that could result in longer permitting approval time. | High | PRS | Considered low risk due to the limited ground disturbance required for the PRS installation. The land acquisition will require negotiation because the PRS will be located on private land. | Low |
| 21. Trail Lateral 168 | ILI | Considered high risk due to the potential for the project cost to change subject to the number of modifications required and a large amount of ground disturbance on Teck owned property which will require coordination with Teck during construction. There are also several high archaeological potential sites throughout the lateral, with a nearby registered archaeological site. Additionally, there are also registered contaminated sites. | High | PRS | Considered low risk due to the limited ground disturbance required for the PRS installation. The land acquisition will require negotiation because the PRS will be located on private land. | Low |
| 4. Prince George 3 Lateral 219 | ILI | Considered moderate risk due to the potential for the project cost to change subject to the number of modifications required. There are also registered contaminated sites, and several moderate to high archaeological potential sites throughout the lateral. The consultation requirements will also be significant due to the number of affected landowners. | Moderate | PRS | Considered low risk because the PRS will be installed on the Northwood Pulp Lateral so the Prince George 3 Lateral will not be impacted. | Low |

| **Lateral** | **Revised for BCUC IR 3.73.1<br>Second Alternative if PRS is the Preferred Alternative** | | | **Original BCUC IR 1.24.1<br>Preferred Alternative (PRS)** | | |
|---|---|---|---|---|---|---|
| 5. Northwood Pulp Lateral 168 | ILI | Considered moderate risk due to the potential for the project cost to change subject to the number of modifications required. There are also critical habitats for fish species at risk and registered contaminated sites. Additionally, most of the lateral is within the ALR which could result in longer permitting approval time. | Moderate | PRS | Considered low risk due to the limited ground disturbance required for the PRS installation. The PRS will be located on crown land, and FEI anticipates minimal complications in acquiring ROW on crown land. | Low |
| 6. Northwood Pulp Loop 219 | ILI | Considered moderate risk due to the potential for the project cost to change subject to the number of modifications required. There are also critical habitats for fish species at risk and registered contaminated sites. Additionally, most of the loop is within the ALR which could result in longer permitting approval time. | Moderate | PRS | Considered low risk due to the limited ground disturbance required for the PRS installation. The PRS will be located on crown land, and FEI anticipates minimal complications in acquiring ROW on crown land. | Low |
| 23. Elkview Lateral 168 | PLR | Considered moderate risk due to the large amount of ground disturbance on Teck owned property which will require coordination with Teck during construction. There are also moderate to high archaeological potential sites. | Moderate | PRS | Considered low risk due to the limited ground disturbance required for the PRS installation. The land acquisition will require negotiation because the PRS will be located on private land. | Low |
| 12. Williams Lake Loop 168 | ILI | Considered moderate risk due to the potential for the project cost to change subject to the number of modifications required. There are also registered contaminated sites and old growth management areas. A large portion of the loop is within the ALR which could result in longer permitting approval time. | Moderate | PRS | Considered low risk due to the limited ground disturbance required for the PRS installation. The PRS will be located on crown land, and FEI anticipates minimal complications in acquiring ROW on crown land. | Low |
| 10. Prince George #2 Lateral 219 | ILI | Considered moderate risk due to the potential for the project cost to change subject to the number of modifications required. There are several moderate to high archaeological potential sites and a significant portion of the lateral is within the ALR which could result in longer permitting approval time. | Moderate | PRS | Considered low risk due to the limited ground disturbance required for the PRS installation. The land acquisition will be slightly more complex because the PRS will be located on private land. | Low |

73.1.1 If FEI does not consider either the ILI or PLR alternatives feasible for any of the Transmission Laterals where PRS is the chosen alternative, please explain why in detail.

**Response:**

Both the ILI and PLR alternatives are technically feasible for the laterals where PRS is the chosen alternative. However, in some cases, PLR was not considered to be cost effective when compared to the other technically feasible alternatives.

Table 4-10 of the Application shows the present values of ILI, PLR, and PRS for each of the 29 Transmission Laterals. The present value of incremental revenue requirements was not presented where PRS was not considered technically feasible or where PLR was not considered financially feasible. Please refer to the response to BCUC IR 3.71.1 for the present values of the feasible alternatives for each of the 29 Transmission Laterals. Please also refer to the response to BCUC IR 3.73.1 which provides the hypothetical scenario where the second alternative is selected instead of PRS for the 14 laterals.

Selection of PRS as the preferred alternative for 14 of the laterals provides lower construction project risk, compared to the hypothetical selection of ILI or PLR for the 14 laterals. Please refer to the response to BCUC IR 3.73.1 for further discussion of the increase in construction project risk.

The selection of PRS for the 14 laterals is also considerably less expensive than the hypothetical scenario where the secondary alternative of ILI or PLR is selected. Under the hypothetical scenario, the present value (per the Evidentiary Update filed on April 5, 2019) over 66 years increases by approximately $152 million (i.e., $420 million with PRS vs. $572 million without PRS). In terms of Project capital cost, the IGU Project increases by approximately $140 million higher if PRS is not chosen. Consequently, the estimated delivery rate impact of the Project would increase to 5.83 percent from 4.30 percent.

FEI notes the above cost impacts rely on the contingency and management reserve percentages for the Project. Because of the increased project construction risk associated with ILI and PLR, FEI expects that the contingency and management reserve will also increase. Should the BCUC approve ILI or PLR instead of PRS for any of the 14 laterals, FEI would need to perform the necessary development work required to generate revised contingency and management reserve figures that are consistent with the approved project construction risk.

| | Preferred Option as per Application ($ millions) | Project if PRS is not chosen ($ millions) |
|---|---|---|
| Present Value 66 years | | |
| ILI | 319.497 | 522.275 |
| PLR | 29.042 | 49.828 |
| PRS | 71.615 | - |
| TOTAL | 420.154 | 572.103 |
| Project Capital Cost (excl. Project Deferral Cost) | | |
| ILI | 267.987 | 446.985 |
| PLR | 30.375 | 53.432 |
| PRS | 61.831 | - |
| TOTAL | 360.193 | 500.417 |

In summary, if PRS is not chosen as the preferred alternative as proposed in the Application, both the total project cost and the construction risk for each of the 14 laterals would be considerably higher.

73.1.1.1 If PLR and ILI are not considered feasible, please explain how FEI would propose to address the risk of rupture failure due to corrosion on these laterals in the absence of PRS as an alternative.

**Response:**

Please refer to the responses to BCUC IRs 3.73.1 and 3.73.1.1.

**74.0 Reference: PROJECT ALTERNATIVES**

**Exhibit B-1, Section 4.2.5, p. 31**

**ILI Alternative**

In Section 4.2.5, on page 31 of the Application, FEI discusses ILI:

> ILI is highly regarded by operators as the data enables rehabilitation efforts to be focused on specific locations. ILI also enables proactive asset management by providing pipeline wall condition data (including changes over time) that can inform long-term asset planning.

74.1 Following conversion of laterals to ILI ready, please explain when FEI proposes to run ILI tools to determine pipeline condition and areas of corrosion.

**Response:**

The table below shows the ILI implementation schedule for those laterals selected for ILI:

| Calendar year following completion of construction-related activities | Activity |
|---|---|
| First calendar year | Pipeline cleaning |
| Second calendar year | In-line inspection with geometry and metal-loss tools |
| Second, third, and subsequent calendar years (depending on the priority and urgency established by ILI data analysis) | Integrity digs and any associated pipeline repairs (as required) |

# Attachment 67.1

BC Oil & Gas COMMISSION

August 26, 2019

**BC UTILITIES COMMISSION**
900 Howe Street
Vancouver, BC V6Z 2S9

*Subject: Project Justification, Transcript V-1, Workshop/Procedural Conference. P. 79 BCOGC Written Confirmation*

As you are aware, FortisBC Energy Inc. (FEI) is a permit holder with the BC Oil and Gas Commission (Commission). As a permit holder, FEI has certain obligations to maintain its pipeline infrastructure to accord with legislative, regulatory and code requirements, including:

> *Oil and Gas Activities Act,* [SBC 2008], c. 36
>
> 37(1) A permit holder, an authorization holder and a person carrying out an oil and gas activity must
>
> (a) Prevent spillage, and
>
> …
>
> CSA Z662:19 Oil and gas pipeline systems (excerpts only)
>
> 10.3.2.2
>
> Where an engineering assessment, the operating company's integrity management program, or observation indicates that portions of the pipeline system are susceptible to failure, the operating company shall either implement measures preventing such failures or operate the system under conditions that are determined by an engineering assessment to be acceptable.

FEI has advised the Commission that it has identified integrity concerns as a result of its assessments that require additional action to maintain suitable continued service. The Commission understands that the Inland Gas Upgrades Project will be part of FEI's plan to address the identified integrity concerns. The Commission is supportive of FEI taking action to address its known integrity concerns and to ensure that it meets its requirements as a permit holder under the Oil and Gas Activities Act.

Sincerely,

Nicole Koosmann
Vice President, Engineering, Energy Infrastructure, and Integrity

2950 Jutland Road
Victoria BC V8T 5K2

MAILING
PO BOX 9331 Stn Prov Govt
Victoria BC V8W 9N3

T 250.419.4400
F 250.794.5390

www.bcogc.ca