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June 7, 2019

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

On December 17, 2018, FEI filed the Application referenced above. In accordance with BCUC Order G-79-19 setting out a further Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 2.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Doug Slater

Attachments

cc (email only): Registered Parties

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A. PROJECT NEED AND JUSTIFICATION

35.0 Reference: PROJECT JUSTIFICATION
Exhibit B-2, BCUC 1.3.1 & Attachment 6.5, pp. 2, 3
Risk Analysis and Evaluation

In response to British Columbia Utilities Commission (BCUC) IR 1.3.1, FortisBC Energy Inc. (FEI) states:

> Based on FEI's existing methods and the information available on the 29 Transmission Laterals, FEI's assessment is that there is not a material difference in the integrity risk level of the laterals. All of the 29 Transmission Laterals are subject to the same potential for rupture due to external corrosion that may go undetected by FEI's current integrity management techniques. FEI's ability to prioritize amongst the Transmission Laterals based on risk level is limited because the available condition information is comprised of limited quantities of integrity digs and failure records (rather than in-line inspection), and this information does not provide any indication of systemic issues on any particular lateral.

On page 2 of Attachment 6.5, the BC Oil and Gas Commission (OGC) states:

> The risk associated with gas pipelines owned and operated by FortisBC can vary according to location, material type, pressure, current condition, and age. FortisBC has shown no systematic process to determine risk (i.e., the likelihood of failure resulting from hazards and severity of such events or failures) and no process to analyse the hazards, their potential interactions, and overall impact on risk…the Commission requires FortisBC to commit, develop and implement a risk management process for operating pipelines. This must be carried out to fully meet the requirements of the risk assessment non-compliance and meet CSA Z662-15 Clause 3.4.

Further, on page 3 of Attachment 6.5, the BC OGC states: "The Commission [BC OGC] requires a quarterly update in the progress toward completing this corrective action until completed and an estimated completion date."

35.1 Please confirm, otherwise explain, whether FEI agrees with the BC OGC finding that risk associated with FEI's pipelines can vary according to location, material type, pressure, current condition and age.

Response:

Confirmed. FEI agrees that the risk associated with FEI's pipelines can vary according to location, material type, pressure, current condition and age.

35.2 Please confirm, otherwise explain, whether FEI agrees with the BC OGC finding that FEI has shown no systematic process to determine risk and no process to analyse the hazards, their potential interactions and overall impact on risk.

Response:

FEI agrees with the BC OGC that FEI has shown no systematic quantitative process to determine risk and no quantitative process to analyse the hazards, their potential interactions and overall impact on risk. FEI continues to believe that the qualitative process used to date has been effective in managing the hazards and risks to FEI's pipeline system. Further, a systematic quantitative process is not required to determine whether the IGU Project is required (please refer to the response to BCUC IR 2.36.1). Notwithstanding this, FEI agrees that continual improvements are appropriate in order to meet evolving regulatory expectations for risk assessment as published in Clause 3.4 of the CSA Z662-15 standard.

35.3 Please discuss in detail FEI's response to the BC OGC letter, including the planned activities to address the risk assessment non-compliance and the estimated completion date communicated to the BC OGC.

Response:

This response also addresses BCUC IRs 2.35.3.1, 2.35.4, 2.35.4.1, 2.35.5, and 2.36.1.2.

FEI responded on December 8, 2017 to the BC OGC's November 16, 2017 letter and has been providing the OGC with quarterly updates since April 2018 on FEI's progress towards completing the corrective action plan required by the BC OGC related to risk assessment. Please refer to Attachment 35.3 for copies of the following correspondence:

- FEI's letter to the BC OGC dated August 11, 2017 (as referenced by the BC OGC in its November 16, 2017 letter) is included as Attachment 35.3 A.

- FEI's letter to the OGC dated December 8, 2017 is included as Attachment 35.3 B.
- FEI's quarterly update to the BC OGC dated April 25, 2018 is included as Attachment 35.3 C.
- FEI's quarterly update to the BC OGC dated July 12, 2018 is included as Attachment 35.3 D.
- FEI's quarterly update to the BC OGC dated November 19, 2018 is included as Attachment 35.3 E.
- FEI's quarterly update to the BC OGC dated March 28, 2019 is included as Attachment 35.3 F.

In its letter of December 8, 2017, FEI acknowledged the BC OGC's direction to develop and implement a segment-by-segment risk assessment process to determine the risk associated with its pipeline assets in BC. Consistent with FEI's previous discussions with the BC OGC, FEI outlined the activities that it had completed or had underway with JANA Corporation to develop a business case and organizational implementation plan for a quantitative risk assessment (QRA) process. As FEI stated in its August 11, 2017 letter to the BC OGC, FEI's vision at the time was to demonstrate by 2020 that its Transmission Pipeline Integrity is managed through a quantitative risk-based approach. FEI remains committed to this vision and believes that its first iteration of a quantitative risk assessment will meet the risk assessment requirements set out by the BC OGC in its November 16, 2017 letter.

FEI's quarterly updates beginning April 25, 2018 have kept the BC OGC apprised of FEI's further work on its initiative with JANA Corporation to develop a QRA approach to managing transmission pipeline integrity. In its March 28, 2019 quarterly update to the BC OGC, FEI noted that it was working closely with JANA with regard to data-related improvement and a QRA of FEI's transmission pipeline assets, and that FEI's first iteration of a segment-by-segment risk assessment process will be demonstrated through this work.

As discussed in FEI's response to BCUC IR 1.6.6, FEI is developing the first iteration of the QRA as part of its Transmission Integrity Management Capabilities (TIMC) project. The first iteration of the QRA will include:

- an estimation of probability of failure for each of the threats included in FEI's Integrity Management Program (external corrosion, third-party damage, stress corrosion cracking, etc.); and,
- potential location-specific safety, security of supply (outage), environmental, regulatory and reputation consequences for each potential failure type (small leak, large leak, rupture).

The risk assessment will combine the calculated probability and consequence of failure to estimate operational risk on a segment-by-segment basis (a segment being a section of pipeline with common risk factors). The segment-by-segment risk estimates will then be used for prioritization of data quality improvement, risk analysis refinement and/or risk mitigation efforts.

FEI's Phase 1 of its TIMC development, which is comprised of the activities directly associated with the QRA, occurs primarily within 2018 and 2019. FEI therefore expects that it will be able to review the first iteration of the QRA with the BC OGC by early 2020.

While FEI's first iteration of a QRA will produce a segment-by-segment risk assessment in compliance with the BC OGC's risk assessment requirements, the QRA approach to integrity management will require ongoing risk assessment and risk management for the TIMC project and as part of FEI's IMP-P generally, as required by CSA Z662 Clause 3.4. FEI is therefore developing estimates of the required incremental resources as part of the TIMC project. The timing for executing these continual improvements will be dependent on the regulatory process, amongst other requirements.

35.3.1 Please provide a copy of any correspondence between FEI and BC OGC regarding plans and progress to address the risk assessment non-compliance.

Response:

Please refer to the response to BCUC IR 2.35.3.

35.3.2 Please describe, with rationale, any changes to the initial planned activities to address the risk assessment non-compliance or the estimated completion date.

Response:

FEI's initial planned activities and timeline to address the requirements of the BC OGC have not changed.

35.4 Please discuss any risk assessment activities FEI has completed since the BC OGC letter.

Response:

Please refer to the response to BCUC IR 2.35.3.

35.4.1 If planned risk assessment activities have not been completed, please explain why not.

Response:

Please refer to the response to BCUC IR 2.35.3.

35.5 Please provide a summary of any additional risk assessment activities that would need to be carried out to fully meet the requirements of the risk assessment non-compliance and provide an estimated completion date.

Response:

Please refer to the response to BCUC IR 2.35.3.

35.6 Please provide FEI's rationale for proposing the Inland Gas Upgrade (IGU) Project prior to completion of the risk assessment activities.

Response:

Please refer to the response to BCUC IR 2.36.1 for a discussion of why completion of the risk assessment activities is not required for the IGU Project.

35.7 Please discuss whether FEI assessed the likelihood of failure resulting from pipeline hazards including external corrosion, third-party damage, geotechnical, seismic and human error.

Response:

FEI has not conducted an explicit estimation of the likelihood of failure resulting from pipeline hazards including external corrosion, third-party damage, geotechnical, seismic and human error for the 29 Transmission Laterals, nor the potential location-specific consequences (safety and security of supply) for each potential failure type (leak and rupture). Regardless of the likelihood of failure, CSA Z662-15 requires FEI to eliminate or mitigate external corrosion on the system. In compliance with CSA Z662-15, FEI monitors all known or anticipated conditions that could result in failures and has proactive activities within its IMP-P to mitigate those hazards. This includes the ongoing identification and mitigation of geotechnical, hydrotechnical, and seismic hazard sites along its transmission pipelines. The table below illustrates this with examples of hazards, the conditions that can result in failure and activities that FEI employs to mitigate the hazards.

Table 1

Examples of Pipeline hazards	Examples of Conditions that Could Result in Failure	Examples of Mitigation
Third-party damage	Third-party excavation within a transmission pipeline right-of-way	Pipeline patrol Permits Inspections
Natural hazards – Geotechnical / Hydrotechnical	Observation or measurement of slope movement in the vicinity of a pipeline system*	Pipe relocation Pipe replacement Slope stabilization
Natural hazards – Seismic	Transmission pipelines with a projected loss of containment resulting from a 1 in 2475 year return period seismic event*	Pipe relocation Pipe replacement Localized ground reinforcing
Pipe Condition – Corrosion	External corrosion resulting in a through-wall defect.	In-line inspection Cathodic protection Pipe replacement/retrofits (e.g., the IGU Project)

Please also refer to FEI's response to BCUC IR 2.36.1 for a discussion of why a quantitative risk assessment (QRA) is not required for the IGU Project.

35.7.1 If so, please provide any assessment of the potential hazards.

Response:

Please refer to the response to BCUC IR 2.35.7.

35.7.2 If not, why not?

Response:

Please refer to the response to BCUC IR 2.35.7.

35.8 Please discuss whether FEI assessed the potential location-specific consequences (safety and security of supply) for each potential failure type (leak and rupture).

Response:

Please refer to the response to BCUC IR 2.35.7.

35.8.1 If so, please provide the potential consequences of a pipeline failure (leak and rupture) for all laterals and all lateral segments.

Response:

Please refer to the response to BCUC IR 2.35.7.

35.8.2 If not, why not?

Response:

Please refer to the response to BCUC IR 2.35.7.

35.9 Please discuss whether there are different regulatory or technical requirements for gas transmission pipelines in areas of higher population density.

Response:

The CSA Z662-15 standard uses the term "Class Location" to classify the geographical area surrounding a pipeline according to its approximate population density and/or the potential for people to congregate. The potential class location designations range from Class 1 (least populated areas) to Class 4 (most populated areas).

CSA Z662-15 includes prescriptive requirements with respect to the design and construction of pipelines in varying population densities. While various design and construction parameters can vary by class location, the primary parameters by class location are as follows:

- pipeline operating stress (in general locations[1])
    - Class 1: maximum operating stress is 80% SMYS
    - Class 2: maximum operating stress is 72% SMYS
    - Class 3: maximum operating stress is 56% SMYS
    - Class 4: maximum operating stress is 44% SMYS
- minimum pressure for a post-construction hydrostatic test
    - Class 1 and Class 2: minimum test pressure is 125% of intended maximum operating pressure
    - Class 3 and Class 4: minimum test pressure is 140% of intended maximum operating pressure

[1] In some specific locations (e.g., road crossings) the maximum operating stresses may be lower.

The responses to increased population densities during the operation and maintenance of pipeline systems are less defined by the CSA standard. Examples are as follows:

- A guidance note to CSA Z662-15 Clause 9.9.6 suggests that population density, among other things, should be reviewed when considering inspection techniques (e.g., ILI) to monitor the effectiveness of a pipeline system's corrosion control program. The CSA Z662-15 standard does not provide further explicit guidance as to how an operator should consider population density with respect to monitoring of corrosion control. However, this clause has existed in the CSA Z662 standard since 2003 or before, at a time when in-line inspection was not at an equivalent level of adoption by the pipeline industry as it is today. FEI, in alignment with its peers, is using in-line inspection techniques to monitor the effectiveness of a transmission pipeline system's corrosion control program in areas of both high population density and low population density. With respect to the IGU Project, FEI has based its proposed adoption of in-line inspection for monitoring (or, where more cost effective, alternative integrity management solutions) on the basis of mitigating the potential for rupture due to external corrosion on the entirety of the 29 Transmission Laterals and the availability of proven and commercialized technology

- CSA Z662-15 Clause 10.5.3.2 requires that pipeline signage be placed with consideration to, among other things, population density.

- CSA Z662-15 Clause 10.6.1.2 requires that the frequency of pipeline patrols be determined with consideration to, among other things, population density.

- CSA Z662-15 Clauses 10.10.2.5 and 10.11.2.3 require that the acceptance and repair of external corrosion imperfections be subject to a safety factor based on a pipeline's class location.

- CSA Z662-15 Clause 12.10.3.3 requires that the frequency of leak survey program for distribution pipeline systems be determined with consideration to, among other things, population density.

35.9.1 If so, please provide details of the different requirements.

Response:

Please refer to the response to BCUC IR 2.35.9.

35.10 Please discuss whether FEI identified any additional integrity assessment actions that could refine/validate the condition of the laterals such as tethered in-line inspection and integrity digs.

Response:

Further condition assessments are not required to determine whether FEI needs to mitigate the potential for rupture due to external corrosion or to prioritize its work on the 29 Transmission Laterals. FEI has not identified any additional integrity assessment actions that could refine/validate the condition of the 29 Transmission Laterals. As discussed in the response to BCUC IR 2.36.1, FEI considers it neither prudent nor technically necessary to undertake further condition assessment activities on these laterals prior to undertaking the IGU Project. Undertaking additional assessments would not provide value, irrespective of the scope, scale, or potential impacts of the IGU Project, and would instead result in unnecessary delays to the safety and reliability improvements afforded by the Project.

35.10.1 If so, please explain FEI's method for determining the additional integrity assessment actions needed to assess the condition of the laterals.

Response:

Please refer to the response to BCUC IR 2.35.10.

35.10.2 If so, please compare the cost and benefits of additional integrity assessment actions to FEI's proposed alternatives (in-line inspection [ILI], Pipeline Replacement [PLR] and Pressure Regulating Station [PRS]).

Response:

Please refer to the response to BCUC IR 2.35.10.

35.10.3 If not, why not?

Response:

Please refer to the response to BCUC IR 2.35.10.

35.11 Please explain how long it would take FEI to perform a qualitative risk assessment based on findings from historical digs on similar pipelines and the known hazards and consequences on the 29 laterals.

Response:

The Application, as confirmed and clarified by FEI's responses to information requests, contains FEI's qualitative risk assessment based on findings from historical digs on similar pipelines and the known hazards and consequences on the 29 Transmission Laterals.

FEI has detailed the need for the IGU Project based in part on findings from historical digs on FEI's in-line inspected pipelines as discussed in section 3.3.2 of the Application and in FEI's response to BCUC IR 1.4.1. Based on observations on its system, FEI has demonstrated that there is a likelihood of unpreventable, active external corrosion on cathodically-protected pipe. FEI has also demonstrated that there is the potential for rupture failure due to this external corrosion as the 29 Transmission Laterals operate at hoop stress levels greater than 30 percent of SMYS. As discussed in the Application and in FEI's response to CEC IR 1.3.2, the potential consequences associated with a pipeline rupture are significant.

Given FEI's demonstration of a risk of failure, and given that a rupture of its NPS 6 and greater transmission pipelines due to external corrosion represents unacceptable performance under FEI's IMP-P, FEI's qualitative risk assessment is that the IGU Project is necessary and should be completed within a 5-year time horizon as proposed in the Application.

35.11.1 Please explain the implications for the Inland Gas Upgrade (IGU) Project (e.g. cost, timing, scope) and how FEI would adjust its approach to the upgrades.

Response:

Please refer to the response to BCUC IR 2.35.11 for a discussion of how the IGU Project is based on FEI's qualitative risk assessment as described in FEI's Application and responses to information requests.

36.0 Reference: PROJECT JUSTIFICATION

Exhibit B-2, BCUC 1.3.1, p. 10 & Attachment 6.5

Quantitative Risk Assessment

In response to BCUC IR 1.3.1, FEI states:

> FEI is currently responding to direction from the BC OGC to develop a method to conduct **quantitative** risk assessments, as discussed in response to BCUC IR 1.6.5. FEI is undertaking the first iteration of a quantitative risk assessment (QRA) of its transmission pipelines as part of Phase 1 of its Transmission Integrity Management Capabilities (TIMC) CPCN development. This QRA is required for the purposes of that project, as described in Section 12.4.1.1 of FEI's Annual Review of 2019 Rates application. However, this QRA is not required to justify the need for the IGU Project and, given FEI's limited condition assessment information on the 29 Transmission Laterals due to lack of ILI data, FEI's ability to prioritize amongst the laterals is expected to remain limited. (Emphasis added)

36.1 Please elaborate on the direction from the BC OGC to develop a method to conduct quantitative risk assessments (QRA) for operating pipelines.

Response:

This response also addresses BCUC IRs 2.35.6, 2.35.10, 2.36.1.1, 2.36.2, and 2.36.3, and BCOAPO IRs 2.1.1, 2.1.2, 2.2.1, 2.3.1, 2.6.1, and 2.6.2.

FEI clarifies that its reference to a direction from the BC OGC to develop a method to conduct a quantitative risk assessment (QRA) is a reference to the BC OGC's direction to "develop and implement a segment-by-segment risk assessment process to determine the risk associated with its pipeline assets in BC". See the BC OGC's letter to FEI dated November 16, 201, included as Attachment 6.5 to FEI's responses to BCUC IR No. 1.

As FEI already has a qualitative process to determine the risk associated with its pipeline assets, and because FEI has determined that the best approach to respond to the BC OGC's direction is to develop a QRA, FEI has sometimes referred to the BC OGC's direction as a direction to conduct a QRA. As discussed in FEI's response to BCUC IR 2.35.3, FEI's quarterly updates to the BC OGC have all referred the BC OGC to FEI's work towards a QRA.

As FEI stated in its response to BCUC IR 1.3.1 quoted above, the QRA is not required to justify the need for the IGU Project and, given FEI's limited condition assessment information on the 29 Transmission Laterals due to lack of ILI data, FEI's ability to prioritize amongst the laterals is expected to remain limited.

As the BCUC and interveners have continued to express interest in a QRA for the IGU Project, FEI retained JANA Corporation to provide an independent, expert opinion on the following:

- the value of performing a QRA of the 29 transmission laterals for the purposes of the IGU Project justification; and
- the value of performing a QRA to assess scheduling and prioritization of the IGU project.

JANA Corporation is a recognized pipeline industry expert, and the consultant that FEI engaged to conduct the Integrity Data and Quantitative Risk Assessment phases for the TIMC project. The curriculum vitae of Dr. Ken Oliphant and Wayne Bryce, principals of JANA Corporation, who are primarily responsible for the responses below, are provided as Attachment 36.1A to this response. JANA Corporation provided the following responses to FEI's requests:

JANA's Technical Opinion on Impact of a QRA on Justification of Inland Gas Upgrade (IGU) Project

FEI requested that JANA provide a 3rd Party expert opinion regarding the value of performing a QRA of the 29 transmission laterals for the purposes of the IGU Project justification.

JANA's technical opinion is that a QRA would not change the justification for the IGU project as the project is driven by FEI's stated need to meet regulatory requirements (compliance) and Industry Standard Practice (ISP). As detailed in "Integrating QRA Outputs into Pipeline Integrity Management Decision-Making"[3], it is JANA's opinion that a QRA is not required to justify investments required to meet Compliance- and ISP-driven Integrity Management activities and that these activities should be addressed regardless of the outputs of a QRA.

JANA's Technical Opinion on Impact of a QRA on Scheduling/Prioritization of IGU Project

FEI requested that JANA provide a 3rd Party expert opinion regarding the value of performing a QRA to assess scheduling and prioritization of the IGU project.

JANA's technical opinion is that, given the short project timeline of five years for the IGU project, a QRA would not materially impact the timeline or scheduling of these activities. First, given that the justification for the IGU project is driven by FEI's stated need to meet regulatory requirements (compliance) and Industry Standard Practice (ISP), a QRA would not change the requirements for the IGU project. It is JANA's opinion that a QRA is not required to justify investments required to meet Compliance and ISP driven Integrity Management activities and that these activities should be addressed regardless of the outputs of a QRA[3]. Second, given the short timeline of the project, it is JANA's opinion that

scheduling and prioritization will be driven by logistical concerns and not risk given the small difference in risk reduction expected for conducting the work, for example, in Year 2 versus Year 3.

[3] http://www.janatechnology.com/integrating-qra-outputs-into-pipeline-integrity-management-decision-making

Please refer to Attachment 36.1B for JANA's response and a copy of the reference report, "Integrating QRA Outputs into Pipeline Integrity Management Decision-Making".

FEI adds the following discussion of why a QRA is not required for the IGU Project.

As risk is equal to the probability of an undesirable event occurring, multiplied by the consequences of that event occurring, a quantitative risk assessment requires reasonable estimates of both the probability and potential consequences of failure. Estimating the probability of a failure is typically more challenging than estimating the potential consequences because the estimated failure rates for transmission pipelines vary depending on the availability of high-quality asset condition data. If only low-quality, less-granular data is available, then assumptions must be made during the risk estimation, which is reflected in larger uncertainty or error bounds around the estimated failure rates.

In the case of the 29 Transmission Laterals within the scope of the IGU Project, the available asset condition data is low quality and not granular. This is due in particular to the absence of ILI data. There is also limited failure history available to differentiate between each of the 29 Transmission Laterals. While the 29 Transmission Laterals represent a range of pipeline ages, the attribute of age, in isolation, is not an accurate method for differentiating failure likelihood.

The estimated failure rates for the 29 Transmission Laterals would therefore likely be based on generic historic failure rates developed from publicly-available failure databases (for pipeline systems that may or may not accurately reflect FEI's operating conditions), and would need to be caveated with large uncertainty or error bounds. For this reason, the failure rates would not have a sufficient level of accuracy to enable a meaningful differentiation of estimated quantitative risk of failure over the 5-year implementation timeline of the IGU Project.

Further, undertaking additional condition assessment activities on the 29 Transmission Laterals in an attempt to improve the quality of the QRA would not be helpful for the following reasons:

- Random control digs do not provide FEI confidence that external corrosion features or other integrity issues are identified on pipelines generally or on the 29 Transmission Laterals. This is because the location of random control digs is randomly selected, and not targeted to a specific site for the purposes of addressing any particular integrity concern. A random control dig provides information on a small segment of a much longer pipeline and therefore provides no statistically significant information on the condition of the pipeline as a whole, because the factors that affect pipeline condition vary from segment to segment across the length of the pipeline.

- Modified ECDA digs provide reduced confidence to FEI given that above-ground surveys can not detect areas where CP shielding is occurring.

- Information from ILI inspection on other pipelines cannot be used to target control digs, due to the varying causes of corrosion or other integrity concerns. In short, the fact that an issue may be found in one location, does not mean that it is likely to occur in similar locations on other pipelines.

- As discussed more fully in FEI's response to BCUC IR 2.47.2, tethered in-line inspection would not be feasible as it would require a shutdown of the pipeline.

Given the uncertainties associated with an estimated probability of failure for the 29 Transmission Laterals, the results of a QRA would not be precise enough to have any meaningful impact on project scope of work, timing or prioritization. Therefore, 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, and the scope, cost and execution schedule for the IGU Project would not be altered or benefit from the results of a QRA.

36.1.1 Was the direction given subsequent to the BC OGC letter dated November 16, 2017?

Response:

Please refer to the response to BCUC IR 2.36.1.

36.1.2 Did FEI provide the BC OGC with progress reports towards completing a QRA and an estimated completion date? If not, why not?

Response:

Yes. Please refer to the response to BCUC IR 2.35.3 and the attachments to that response for FEI's progress reports to the BC OGC.

36.2 Please explain why the QRA is required for the purpose of the TIMC Project but is not required to justify the need for the IGU Project.

Response:

FEI retained JANA Corporation to provide an independent, expert opinion on BCUC IR 2.36.2.

JANA Corporation provides the following response:

JANA's Technical Opinion on Need for QRA for TIMC Project versus IGU Project

FEI requested that JANA provide a 3rd Party expert opinion to address BCUC IR 2.36.2 "Please explain why the QRA is required for the purpose of the TIMC Project but is not required to justify the need for the IGU Project".

JANA's technical opinion is that:

- A QRA would not change the justification for the IGU project as the project is driven by FEI's stated need to meet regulatory requirements (compliance) and Industry Standard Practice (ISP). It is JANA's opinion that a QRA is not required to justify investments required to meet Compliance and ISP driven Integrity Management activities and that these activities should be addressed regardless of the outputs of a QRA[3].

- An Integrity Management (IM) QRA[3] of the 29 Transmission Laterals in the IGU Project would be beneficial for ongoing Integrity Management (IM) of the laterals. Such a QRA is most beneficial after completion of the initial in-line inspection runs so that a clearer picture of risk can be obtained.

- The QRA for the TIMC project is not being used to justify the requirements to conduct Integrity Management activities for cracking threats (Stress Corrosion Cracking and seam threats) as, similar to the IGU project, this requirement is driven by Compliance and Industry Standard Practice (ISP)[3]. The QRA for the TIMC project is driven by several other factors:

    - The interconnected nature of the mainline transmission systems (versus the single line nature of the laterals) makes for a much more complex system and much more complex analysis of potential scenarios for which the QRA is intended to support the analysis and consider integrity, capacity and resiliency[3]

    - As initial analysis identified that line looping will likely be necessary to enable management of the cracking threats in the Coastal Transmission System (CTS) and Inland Transmission

System (ITS), the QRA was run to assess risk in the pipeline systems to consider further potential risk reductions that could be achieved with the line looping (e.g. increased resiliency, reduced operating pressures, etc.). The retrofits and modifications to the laterals required to enable inline inspection, as proposed in the IGU, do not afford those same opportunities.

- FEI's commitment to begin the process of integrating QRA into its overall asset and integrity management process

Please refer to Attachment 36.1B for JANA's response and a copy of the reference report, "Integrating QRA Outputs into Pipeline Integrity Management Decision-Making".

Further to JANA's response above, FEI provides the discussion below of the reasons for conducting a QRA for the TIMC project and why they are not applicable to the IGU Project. FEI notes that the TIMC project is still under development and considerations might evolve.

The QRA will provide a comprehensive understanding of system risk which will identify priority lines for mitigation of stress corrosion cracking and other crack-like imperfections. For this purpose, the QRA is assessing approximately 70,000 individual pipeline segments, and providing over 4 million risk estimate outputs. This will inform the TIMC project as follows:

- The QRA will inform FEI's determination of the TIMC project scope of work. When planning system improvements to enable crack management, FEI will also be evaluating opportunities to improve system resiliency where the incremental investment can be justified from a risk reduction perspective.

- The QRA will also inform FEI's determination of the TIMC project implementation and prioritization. FEI anticipates that resource and schedule optimization for CPCN development and project implementation will play a role in its determination of which project(s) will comprise its first TIMC CPCN application. It is possible that a project to address a higher risk pipeline, if more complex and requiring more time for CPCN development, may be applied for later than a project to address a lower risk pipeline

In contrast, as discussed in FEI's response to BCUC IR 2.36.1 and JANA's expert opinion above, a QRA would not impact the cost, scope of work or prioritization for the IGU Project. The IGU Project addresses the risk of a pipeline rupture due to undetectable external corrosion on its NPS 6 and larger transmission laterals. Rupture of its NPS 6 and larger transmission pipelines due to external corrosion represents unacceptable performance of its IMP-P given the availability of proven and commercialized technology to detect external corrosion features and industry standard practice.

As discussed in the response to BCUC IR 1.3.7, FEI scheduled the order of execution based on the duration required to complete the laterals due to scope, length, operational limitations, and

approval requirements. FEI has developed the schedule of the IGU Project based on optimizing the use of resources and to gain efficiencies in execution. FEI does not believe there would be any material impact from a safety perspective by prioritizing the laterals differently.

36.3 Please discuss the potential additional information that the QRA could provide regarding the 29 Transmission Laterals and how this information could be used in the development of the IGU Project in terms of refinement of the cost, scope and timing of the project.

Response:

Please refer to the response to BCUC IR 2.36.1.

36.4 Please explain how long it would take to complete a QRA for the 29 Transmission Laterals and provide a detailed cost estimate for that work.

Response:

A QRA is a complex undertaking and FEI considers that the development of an accurate cost estimate and schedule for the IGU Project is not feasible within the time available for this response. The QRA being undertaken as part of the TIMC project will take over a year to complete at an approximate cost of $11 million. Given FEI's experience with the TIMC project to date, FEI's order of magnitude estimate for a QRA covering the 29 Transmission Laterals could potentially be completed over a timeframe in the order of months, and for a cost in the order of hundreds of thousands of dollars or potentially more. For reasons discussed in FEI's response to BCUC IR 2.36.1, FEI has not identified value in such an undertaking for the purposes of the IGU Project.

37.0 Reference: PROJECT JUSTIFICATION

Exhibit B-1, Section 3.3.3, p. 19

Potential Failure by Rupture

On page 19 of the Application for a Certificate of Public Convenience and Necessity (CPCN)

for the Inland Gas Upgrade Project (Application), FEI states:

> It is generally accepted by FEI and the Canadian pipeline industry that a pipeline operating at or above 30 percent SMYS has a potential to fail by rupture, whereas a pipeline operating below 30 percent SMYS would have a potential to leak. The CSA Z662 delineation is supported by a 2004 ASME International Pipeline Conference Paper entitled "A Review of the Time Dependent Behaviour of Line Pipe Steel" by Andrew Cosham and Phil 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.

37.1 Please confirm, or otherwise explain, that the generally accepted practice of operating pipelines at or below 30 percent specified minimum yield strength (SMYS) to prevent rupture is based specifically on the potential for rupture due to time based plastic deformation of defects such as cracks or notches in the pipe wall, not specifically corrosion.

Response:

Not confirmed. The generally accepted practice of operating pipelines below 30 percent specified minimum yield strength (SMYS) to prevent rupture applies to defects such as cracks or notches which may exhibit brittle fracture behavior, as well as to defects that deform plastically such as corrosion. Corrosion imperfections are generally considered blunt flaws and tend to fail in plastic collapse or leak. Therefore, the generally accepted practice of operating pipelines at or below 30 percent of SMYS will also mitigate the potential for rupture of external corrosion-related features.

FEI's adoption of the 30 percent of SMYS threshold is consistent with the CSA Z662-15 standard and industry practices.

Please refer to the response to BCOAPO IR 1.2.1 for discussion of relevant CSA Z662-15 clauses, specifically Clauses 12.1.1 and 12.10.3.3 (d).On page 19 of the Application, FEI referenced the paper entitled "A Review of the Time Dependent Behaviour of Line Pipe Steel" which is consistent with the CSA Z662-15 standard. This reference does not contain an explicit

conclusion that 30 percent of SMYS is an acceptable stress level to avoid risk of rupture in all cases, including corrosion.

However, FEI notes the following statement in the industry document "Leak versus Rupture Considerations for Steel Low-Stress Pipelines", Gas Research Institute Final Report No-00/0232, 2001[2]:

> "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."

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 Z662-15 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.

37.2 Please discuss whether the referenced paper entitled "A Review of the Time Dependent Behaviour of Line Pipe Steel" concludes that 30 percent SMYS is an acceptable stress level to avoid risk of rupture in all cases, including corrosion.

Response:

Please refer to the response to BCUC IR 2.37.1.

37.3 Please provide any supporting studies that apply the 30 percent SMYS to the prevention of ruptures due to general corrosion.

Response:

Please refer to the response to BCUC IR 2.37.1.

[2] Leak versus Rupture Considerations for Steel Low-Stress Pipelines", GRI Final Report No-00/0232, 2001. Document available for purchase at https://sales.gastechnology.org/000232.html.

37.4 Please confirm, otherwise explain, whether FEI is confident that there will not be a rupture scenario at an operating pressure below 30 percent SMYS where there is significant or extensive corrosion.

Response:

Please refer to the response to BCUC IR 2.37.1.

38.0 Reference: PROJECT JUSTIFICATION

Exhibit B-2, BCUC IR 11.1; Exhibit B-1, p. 23

Transmission Pipeline Integrity Program

On page 23 of the Application, FEI states that it "expanded its ILI program during this period through a five-year program to retrofit its Coastal Transmission System mainline pipelines for ILI. This retrofit program and other supporting integrity management activities were referred to as the Transmission Pipeline Integrity Program (TPIP)."

In response to BCUC IR 11.1, FEI provided the following table summarizing the TPIP expenditures:

	Order C-15-01		Order C-3-02		Order C-4-03		Order C-5-04	
Year	Plan ($000)	Actual ($000)	Plan ($000)	Actual ($000)	Plan ($000)	Actual ($000)	Plan ($000)	Actual ($000)
2001	9,692	9,174						
2002	5,397	4,593	3,766	3,636				
2003		273	3,703	1,644	8,742	8,870		
2004		(52)		2,663			60	40
2005/06							3,672	3,725
Totals	**15,089**	**13,988**	**7,469**	**7,943**	**8,742**	**8,870**	**3,732**	**3,765**
Variance		(7.3%)		6.3%		1.5%		0.9%

Order C-15-01 states the following in Recitals E, F and G, respectively:

> On October 17, 2001, BC Gas met with Commission staff and staff of the Oil and Gas Commission to discuss the TPIP;
>
> Oil and Gas Commission staff support the TPIP;
>
> The Commission considers that the Integrity Management Program is generally necessary and in the public interest, but is only prepared to approve a CPCN for those expenditures that are reasonably well defined at this time.

38.1 Please compare the current IGU Project and the TPIP, including the project scope, project plan and timeline, project risks, and regulatory process.

Response:

This response also addresses BCUC IR 2.38.2.

FEI (or BC Gas Inc., as it was called at the time) filed its Transmission Pipeline Integrity Program (TPIP) Application for a Certificate of Public Convenience and Necessity in July 2001 (TPIP Application). Based on a review of available documentation related to the TPIP, the project scope, project plan and timeline, project risks and project costs are more defined for the IGU Project than they were for the TPIP, while the regulatory process for the IGU Project appears more rigorous due to the BCUC's 2015 CPCN Guidelines. Notably, FEI has developed an AACE Class 3 level of definition cost estimate for the IGU Project as required by the 2015 BCUC CPCN Guidelines, which was not completed for the TPIP Application.

The following table provides further discussion for each of the project elements referenced in the information request, plus degree of cost estimate development:

Project Element	TPIP	IGU Project	Comparison and/or discussion
Project Scope	Primarily comprised of expenditures to retrofit larger diameter Lower Mainland transmission mainlines for in-line inspection. Total length of pipelines mitigated ≈ 250 km	Primarily comprised of expenditures to retrofit smaller diameter Interior laterals for in-line inspection, or to implement alternate cost-effective methods for mitigating the potential for rupture due to external corrosion. Total length of pipelines mitigated ≈ 400 km	The TPIP and IGU Project are conceptually similar, given that both projects involve a significant amount of pipeline retrofitting work to enable in-line inspection. The TPIP project was focused on larger diameter mainlines, while the IGU Project is focused on small diameter laterals. However, the detailed project scope is more developed for the IGU Project compared to what is indicated in the TPIP Application.
Project plan and timeline	The TPIP Application does not indicate the initiation and/or completion of environmental assessments, stakeholder and indigenous community consultation, and project planning. The TPIP was proposed over a 5-year period.	FEI prepared its Application for the IGU Project based on the 2015 Certificate of Public Convenience and Necessity Application Guidelines, issued on February 12, 2015 (Order Number G-20-15). This includes an understanding of factors affecting the project plan and timeline, such as environmental assessments, consideration of stakeholder and indigenous community consultation, and involves significant amount of project planning.	The project plan and timeline is more developed for the IGU Project compared to what is indicated in the TPIP Application.

Project Element	TPIP	IGU Project	Comparison and/or discussion
		FEI proposes the IGU Project over a 5-year period.	
Project risks	Project risks were not defined in TPIP Application.	Project risks and mitigation strategies were developed and are included in Appendix L of the IGU Project Application, including the development of contingency and reserve amounts based on a Monte Carlo analysis.	The degree of project risk understanding and mitigation plan is more developed for the IGU Project compared to what is indicated in the TPIP Application.
Regulatory process	The TPIP Application was developed and submitted in accordance with utility practice and the regulatory procedures established at the time. Rather than awarding a 5-year decision with respect to FEI's financial request, the BCUC required annual CPCN submissions.	FEI's IGU Project Application meets the requirements of the 2015 Certificate of Public Convenience and Necessity Application Guidelines. FEI believes that it has provided required deliverables to enable a CPCN determination that covers the full extent of the project scope, timeline, and cost.	In comparison to the TPIP Application in 2001, FEI's IGU Project Application conforms to the BCUC's 2015 Certificate of Public Convenience and Necessity Application Guidelines.
Cost estimate accuracy	As per Section 2.0 "Summary" of the TPIP Application, FEI included the following descriptor with respect to its cost estimate, "in 2001 dollars, with uncertain accuracy". Further, under Section 7.0 "Plan Cost" it was noted that: "The accuracy of several elements of this estimate is low and cannot practically be improved at this time, as detailed information is not currently available."	As required by the 2015 Certificate of Public Convenience and Necessity Application Guidelines, FEI's forecast expenditures for the IGU Project are in accordance with a Class 3 level of definition as defined in the latest revision of the AACE International Recommended Practices.	FEI considers the estimated expenditures for the IGU Project to be better defined than what was developed for the TPIP Application.

1
2
3

38.2 Please explain if FEI considers the project expenditures for the IGU project to be better defined than at the time of the TPIP program review process.

Response:

Please refer to the response to BCUC IR 2.38.1.

39.0 Reference: PROJECT JUSTIFICATION

Exhibit B-2, BCUC 1.8.2, pp. 75 to 85; Exhibit B-5, CEC 1.30.2, p.81

General Description of Transmission Laterals on FEI's System

In response to BCUC 1.8.2, FEI provided tables for transmission pipeline information including the dimensions and material characteristics of the pipe, age, type of coating, leak history and location of the pipeline, as related to population density and whether the pipeline is equipped for ILI.

These tables show the recorded failure caused by external corrosion, the number of recorded failures caused by other than external corrosion for each of the 29 laterals, as well as other transmission pipelines on FEI's system.

In response to CEC 1.30.2, FEI identified ten recorded incidents involving release of gas from its operating history of the 29 Transmission Laterals that may have impacted their reliability. The ten incidents occurred between 1973 and 1996.

39.1 Please provide the total number of transmission pipelines (including the 29 Transmission Laterals) that are not in-line inspection capable.

Response:

There are 101 transmission pipelines (including the 29 Transmission Laterals) on FEI's system that are currently not in-line inspection capable. These pipelines are listed in Tables 4 and 5 of the response to BCUC IR 1.8.2.

39.2 Please provide the total number of transmission pipelines, in addition to the 29 Transmission Laterals, which are operating at pressures above 30 percent SMYS and are not in-line inspection capable.

Response:

All transmission pipelines listed in BCUC IR 1.8.2 Table 5 are operating at pressures above 30 percent of SMYS based on maximum operating pressure (MOP). Therefore, 72 transmission pipelines, in addition to the 29 Transmission Laterals, are operating at pressures above 30 percent of SMYS and are not in-line inspection capable.

39.3 Please provide details for the one recorded failure on the 29 Transmission Laterals caused by external corrosion (Fording Lateral 219/168)

Response:

The one recorded failure on the 29 Transmission Laterals caused by external corrosion is detailed below:

Pipeline	Fording Lateral 219
Date of Incident	October 4, 1996
Station	10+322 m
Area	Rural (CSA Z662 Class 1)
Operating Pressure	6281 kPa
Design Pressure	7384 kPa
Pressure At Failure	Not Available
Failure Type	Leak
Failure Cause	External Corrosion
Details	Leak detected during routine leak survey. Leak was caused by a pitting corrosion.
Repair	Welded full encirclement repair sleeve over corrosion pit. Radiographic and magnetic particle inspections were performed on the completed repair sleeve.

39.3.1 Please describe the routine leak survey method used to detect the leak.

Response:

FEI is unable to confirm the methodology used for this particular leak survey from 1996. However, based on the year of leak and FEI's historic operating practice, it is expected that the leak was identified through an over-the-line survey (i.e., walking over the line) with a combustible gas indicator (CGI) leak detection unit.

39.3.2 Please explain whether any supplemental integrity digs were performed to assess the condition of the pipeline after the leak was identified.

Response:

This response also addresses BCUC IR 2.39.3.2.1 and CEC IRs 2.39.2 and 2.39.2.1.

Undertaking integrity digs on laterals was not part of FEI's commonly adopted integrity management practices in the late 1990s and no records exist to indicate that supplementary integrity digs were performed to assess the condition of Fording Lateral 219 after the leak was identified in 1996. At this time, there is no evidence of a systemic issue on the Fording Lateral or other data warranting supplemental integrity digs.

39.3.2.1 If not, why not?

Response:

Please refer to the response to BCUC IR 2.39.3.2.

39.4 Please confirm that since 1996 there has been no recorded incident involving release of gas from FEI's operating history of the 29 Transmission Laterals that may have impacted reliability or safety.

Response:

Confirmed.

39.5 Please identify any recorded failures on FEI's system that resulted in pipeline rupture.

Response:

This response also addresses BCUC IRs 2.39.5.1 and 2.39.5.2.

FEI has identified ten recorded failures on FEI's system that resulted in transmission pipeline rupture as shown in the table below. One rupture was caused by a combination of external corrosion and natural hazard (slope movement in this case), while the other ruptures were caused by either third party damage or natural hazards. The pipeline operating pressure as a percentage of SMYS at the time of failure is not available in FEI's records for these incidents.

Year	Pipeline Name	Hazard Category
1960	Trail Castlegar 219	Natural Hazards
1970	Savona Penticton 323	3rd party Damage
1973	Salmon Arm Lateral 114	3rd party Damage
1975	Penticton Oliver 273	3rd party Damage
1981	Fernie Lateral 88.9	3rd Party Damage
1983	Prince George 1 Lateral 168	3rd party Damage
1983	Kingsvale Oliver 323	Natural Hazards
1984	Oliver Grand Forks 273	External Corrosion / Natural Hazards
1988	Trail Castlegar 219	Natural Hazards
1992	Yahk Trail 323	Natural Hazards

39.5.1 Please explain whether the rupture was caused by external corrosion or another hazard.

Response:

Please refer to the response to BCUC IR 2.39.5.

39.5.2 Please provide the pipeline operating pressure as a percentage of SMYS at the time of failure.

Response:

Please refer to the response to BCUC IR 2.39.5.

39.6 Please discuss whether any of the transmission pipelines, including the 29 laterals, will be reclassified as distribution pipelines.

Response:

Currently there is no plan to reclassify any of the transmission pipelines, including the 29 Transmission Laterals, as distribution pipelines. However, those laterals selected for PRS or PLR will be operated at less than 30 percent of SMYS and, as such, will be managed and operated in accordance with the CSA Z662-15 standard Clause 12 “Gas distribution systems.” Please refer to FEI’s response to BCOAPO IR 1.2.1 for relevant excerpts from Z662-15 standard Clause 12.

40.0 Reference: PROJECT JUSTIFICATION

Exhibit B-5, CEC IR 17.1, p. 52

Modified External Corrosion Direct Assessment (ECDA)

In response to CEC 1.17.1, FEI states that it "is already taking steps to monitor and mitigate hazards on the 29 Transmission Laterals in accordance with BC OGC requirements, including by advancing the IGU Project." [emphasis added]

40.1 Please describe, other than the IGU Project, FEI's monitoring program for the 29 Transmission Laterals. Please provide this information by year and by lateral.

Response:

FEI's monitoring program for the 29 Transmission Laterals, at the present time, is in accordance with its Integrity Management Program for Pipelines (IMP-P). FEI's plans are subject to ongoing review and modification as more information becomes available.

FEI's condition monitoring of the 29 Transmission Laterals is currently through Modified ECDA (i.e., status quo), with the following schedule for Indirect Inspections (refer to section 4.2.1 of the Application for further details of this step of the Modified ECDA process):

Pipeline	Year of Next Indirect Examination (as part of Modified ECDA)
1. Mackenzie Lateral 168	2026
2. Mackenzie Loop 168	2026
3. BC Forest Products Lateral 168	2026
4. Prince George 3 Lateral 219	2025
5. Northwood Pulp Lateral 168	2025
6. Northwood Pulp Loop 219	2025
7. Prince George 1 Lateral 168	2025
8. Prince George Pulp Lateral 168	2025
9. Husky Oil Lateral 168	2025
10. Prince George 2 Lateral 219	2025
11. Cariboo Pulp Lateral 168	2019
12. Williams Lake Loop 168	2019
13. Kamloops 1 Lateral/Loop 168	2027
14. Salmon Arm Loop 168	2028
15. Salmon Arm 3 Lateral 168	2028
16. Coldstream Lateral 219	2027
17. Coldstream Loop 168	2027

Pipeline	Year of Next Indirect Examination (as part of Modified ECDA)
18. Kelowna 1 Loop 219	2027
19. Celgar Lateral 168	2025
20. Castlegar Nelson 168	2023
21. Trail Lateral 168	2025
22. Fording Lateral 219/168	2023
23. Elkview Lateral 168	2023
24. Cranbrook Lateral 168	2023
25. Cranbrook Loop 219	2023
26. Cranbrook Kimberley Loop 219	2023
27. Cranbrook Kimberley Loop 273	2023
28. Kimberley Lateral 168	2023
29. Skookumchuck Lateral 219	2023

Although not relevant to the time-dependent condition of the 29 Transmission Laterals, FEI has also included information below for other IMP-P activities considered as providing a "monitoring" function. In the case of these activities, the inspection frequency is also provided.

Lateral	Monitoring Frequency				
Monitoring Activity	Every month	Every 6 months	Annual	Every 5 years	Greater than 5 years
1. Mackenzie Lateral 168					
Cathodic Protection System Monitoring	x		x		
Geotechnical and/or Hydrotechnical Site Monitoring*			x	x	x
Ground or Aerial Patrol of ROW			x		
Ground or Aerial Patrol of ROW Class 3	x				
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Under water crossing inspection			x		
Valve maintenance			x		
2. Mackenzie Loop 168					
Cathodic Protection System Monitoring	x		x		
Ground or Aerial Patrol of ROW			x		

Lateral	Monitoring Frequency				
Monitoring Activity	Every month	Every 6 months	Annual	Every 5 years	Greater than 5 years
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Valve maintenance			x		
3. BC Forest Products Lateral 168					
Cathodic Protection System Monitoring	x		x		
Ground or Aerial Patrol of ROW			x		
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Valve maintenance			x		
4. Prince George 3 Lateral 219					
Cathodic Protection System Monitoring	x		x		
Geotechnical and/or Hydrotechnical Site Monitoring*			x		x
Ground or Aerial Patrol of ROW			x		
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Under water crossing inspection			x		
Valve maintenance			x		
5. Northwood Pulp Lateral 168					
Cathodic Protection System Monitoring	x		x		
Geotechnical and/or Hydrotechnical Site Monitoring*				x	x
Ground or Aerial Patrol of ROW			x		
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Valve maintenance			x		
6. Northwood Pulp Loop 219					
Cathodic Protection System Monitoring	x		x		
Geotechnical and/or Hydrotechnical Site Monitoring*				x	x
Ground or Aerial Patrol of ROW			x		

Lateral	Monitoring Frequency				
Monitoring Activity	Every month	Every 6 months	Annual	Every 5 years	Greater than 5 years
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Valve maintenance			x		
7. Prince George 1 Lateral 168					
Cathodic Protection System Monitoring	x		x		
Geotechnical and/or Hydrotechnical Site Monitoring*			x		x
Ground or Aerial Patrol of ROW			x		
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Valve maintenance			x		
8. Prince George Pulp Lateral 168					
Aerial / Bridge Crossing Inspection		x			
Cathodic Protection System Monitoring	x		x		
Geotechnical and/or Hydrotechnical Site Monitoring*					x
Ground or Aerial Patrol of ROW			x		
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Valve maintenance			x		
9. Husky Oil Lateral 168					
Cathodic Protection System Monitoring	x		x		
Ground or Aerial Patrol of ROW			x		
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Valve maintenance			x		
10. Prince George 2 Lateral 168/219					
Cathodic Protection System Monitoring	x		x		
Geotechnical and/or Hydrotechnical Site Monitoring*				x	x
Ground or Aerial Patrol of ROW			x		

Lateral	Monitoring Frequency				
Monitoring Activity	Every month	Every 6 months	Annual	Every 5 years	Greater than 5 years
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Valve maintenance			x		
11. Cariboo Pulp Lateral 168					
Cathodic Protection System Monitoring	x		x		
Ground or Aerial Patrol of ROW			x		
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Valve maintenance			x		
12. Williams Lake Loop 168					
Cathodic Protection System Monitoring	x		x		
Geotechnical and/or Hydrotechnical Site Monitoring*					x
Ground or Aerial Patrol of ROW			x		
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Valve maintenance			x		
13. Kamloops 1 Lateral 168					
Cathodic Protection System Monitoring	x		x		
Geotechnical and/or Hydrotechnical Site Monitoring*				x	x
Ground or Aerial Patrol of ROW			x		
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Valve maintenance			x		
14. Salmon Arm Loop 168					
Cathodic Protection System Monitoring	x		x		
Geotechnical and/or Hydrotechnical Site Monitoring*					x
Ground or Aerial Patrol of ROW			x		

Lateral	Monitoring Frequency				
Monitoring Activity	Every month	Every 6 months	Annual	Every 5 years	Greater than 5 years
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Valve maintenance			x		
15. Salmon Arm 3 Lateral 168					
Cathodic Protection System Monitoring	x		x		
Ground or Aerial Patrol of ROW			x		
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Valve maintenance			x		
16. Coldstream Lateral 219					
Cathodic Protection System Monitoring	x		x		
Ground or Aerial Patrol of ROW			x		
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Valve maintenance			x		
17. Coldstream Loop 168					
Cathodic Protection System Monitoring	x		x		
Ground or Aerial Patrol of ROW			x		
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Valve maintenance			x		
18. Kelowna 1 Loop 219					
Cathodic Protection System Monitoring	x		x		
Geotechnical and/or Hydrotechnical Site Monitoring*				x	
Ground or Aerial Patrol of ROW			x		
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Valve maintenance			x		

Lateral	Monitoring Frequency				
Monitoring Activity	Every month	Every 6 months	Annual	Every 5 years	Greater than 5 years
19. Celgar Lateral 168					
Cathodic Protection System Monitoring	x		x		
Geotechnical and/or Hydrotechnical Site Monitoring*					x
Ground or Aerial Patrol of ROW			x		
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Valve maintenance			x		
20. Castlegar Nelson 168					
Cathodic Protection System Monitoring	x		x		
Geotechnical and/or Hydrotechnical Site Monitoring*			x	x	x
Ground or Aerial Patrol of ROW					
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing					
Valve maintenance					
21. Trail Lateral 168					
Cathodic Protection System Monitoring	x		x		
Ground or Aerial Patrol of ROW			x		
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Valve maintenance			x		
22. Fording Lateral 219/168					
Cathodic Protection System Monitoring	x		x		
Geotechnical and/or Hydrotechnical Site Monitoring*			x	x	x
Ground or Aerial Patrol of ROW			x		
Ground or Aerial Patrol of ROW Class 3	x				
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Under water crossing inspection			x		

Lateral	Monitoring Frequency				
Monitoring Activity	Every month	Every 6 months	Annual	Every 5 years	Greater than 5 years
Valve maintenance			x		
23. Elkview Lateral 168					
Cathodic Protection System Monitoring	x		x		
Geotechnical and/or Hydrotechnical Site Monitoring*			x	x	x
Ground or Aerial Patrol of ROW			x		
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Under water crossing inspection			x		
Valve maintenance			x		
24. Cranbrook Lateral 168					
Cathodic Protection System Monitoring	x		x		
Geotechnical and/or Hydrotechnical Site Monitoring**			x	x	x
Ground or Aerial Patrol of ROW	x		x		
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Under water crossing inspection			x		
Valve maintenance			x		
25. Cranbrook Loop 219					
Cathodic Protection System Monitoring	x		x		
Geotechnical and/or Hydrotechnical Site Monitoring**			x	x	x
Ground or Aerial Patrol of ROW			x		
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Under water crossing inspection			x		
Valve maintenance			x		
26. Cranbrook Kimberley Loop 219					
Cathodic Protection System Monitoring	x		x		
Geotechnical and/or Hydrotechnical Site Monitoring**			x	x	x

Lateral	Monitoring Frequency				
Monitoring Activity	Every month	Every 6 months	Annual	Every 5 years	Greater than 5 years
Ground or Aerial Patrol of ROW			x		
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Valve maintenance			x		
27. Cranbrook Kimberley Loop 273					
Cathodic Protection System Monitoring	x		x		
Geotechnical and/or Hydrotechnical Site Monitoring*					x
Ground or Aerial Patrol of ROW			x		
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Under water crossing inspection			x		
Valve maintenance			x		
28. Kimberley Lateral 168					
Cathodic Protection System Monitoring	x		x		
Geotechnical and/or Hydrotechnical Site Monitoring*			x	x	x
Ground or Aerial Patrol of ROW			x		
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Valve maintenance			x		
29. Skookumchuck Lateral 219					
Cathodic Protection System Monitoring	x		x		
Geotechnical and/or Hydrotechnical Site Monitoring*					x
Ground or Aerial Patrol of ROW			x		
Leak Survey - Class 2, 3 (annual); Class 1 (every 5 years)			x	x	
ROW clearing				x	
Under water crossing inspection			x		
Valve maintenance			x		

1 * Note: Geotechnical and Hydrotechnical Site Monitoring occurs at varying frequencies, including 2 years,
2 4 years, 6 years, 8 years, and 10 years. For the purposes of this table, monitoring frequencies have been
3 rounded.

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41.0 Reference: PROJECT JUSTIFICATION

Exhibit B-1, Appendix C

BC OGC 2016 Pipeline Performance Annual Report

The BC OGC 2016 Pipeline Performance Annual Report lists "Incident Causes" of pipeline failures.

41.1 With reference to the BC OGC list, but excluding "External Interference", please identify which "Incident Causes" the IGU Project will address.

Response:

This response also addresses BCUC IRs 2.41.2, 2.41.3 and 2.41.4.

Table 41.1 below lists the BC OGC Incident Causes and describes which of these incidents will be addressed by the IGU Project and which are expected to be addressed by the TIMC project. FEI interprets BCUC IRs 2.41.2 and 2.41.4 as seeking information inclusive of "External Interference" and has therefore included this cause within its response.

Table 1: OGC Incident Cause and Applicability for IGU Project and TIMC Project

Incident Cause	IGU Project	TIMC Project
Metal Loss		
Corrosion Metal Loss	Addressed by IGU: The IGU Project will enable the use of metal loss in-line inspection tools (known as magnetic flux leakage or MFL tools) where in-line inspection is the preferred alternative for a transmission lateral. For laterals selected for PRS and PLR, FEI will address corrosion metal loss proactively through cathodic protection system monitoring, supplemented by leak survey. Further, for PRS and PLR laterals, which will operate below 30% SMYS, potential corrosion metal loss failures would be expected to fail as leak as opposed to rupture thereby reducing the consequences of a potential failure.	Potentially Addressed by TIMC: It is expected that pipelines to be addressed by the TIMC project will have existing metal loss in-line inspection programs. If not, this inspection capability would potentially be addressed or improved upon (e.g., by removal of obstructions) by the TIMC project.
Pipeline/Equipment Failure		
Cracking in Pipe	Addressed (in Part) by IGU: The IGU Project will enable the use of geometry in-line inspection tools	Expected to be Addressed by TIMC: It is expected that the TIMC project will enable the use of electromagnetic

Incident Cause	IGU Project	TIMC Project
	where in-line inspection is the preferred alternative for a transmission lateral. Geometry in-line inspection tools are used to identify dents, which can be locations of future cracking. For laterals selected for PRS and PLR, which will operate below 30% SMYS, potential cracking failures would be expected to fail as leak as opposed to rupture thereby reducing the consequences of a potential rupture.	acoustic transducer (EMAT) in-line inspection tools. EMAT tools are used to detect cracks, including stress corrosion cracking and crack colonies, within the EMAT tool detection capabilities. In conjunction with metal loss tools, EMAT tools are also used to detect interacting threats, such as cracks plus corrosion.
Pipe Fittings / Joint Failure	<u>Addressed by IGU:</u> The IGU Project will enable the use of MFL in-line inspections tools where in-line inspection is the preferred alternative for a transmission lateral. Weld imperfections will be addressed to the extent that they are within tool capabilities for detection and sizing. Failures on other fittings such as valves and flanges are addressed through leak surveys and maintenance programs. For laterals selected for PRS and PLR, which will operate below 30% SMYS, potential weld imperfections would be less likely to fail than for a higher operating stress pipeline.	<u>Expected to be Addressed by TIMC:</u> It is expected that the TIMC project will enable the use of EMAT in-line inspection tools. Weld imperfections will be addressed, if within the EMAT tool capabilities for detection and sizing. Also currently addressed by MFL inspections, if within the MFL tool specification threshold. Failures on other fittings such as valves and flanges are addressed through leak surveys and maintenance programs.
Miscellaneous Equipment	<u>Events not addressed by IGU or TIMC:</u> Miscellaneous equipment failures are addressed through maintenance programs.	
External Interference		
Third Party Interference Company Vandalism	<u>Prevention of events not addressed by IGU or TIMC:</u> Preventative measures include pipeline identification, BC One Call participation, permits, inspections, and vegetation management. FEI also performs pipeline patrol for timely identification and reporting of third party interference and/or security threats such as vandalism. The potential for inadvertent first-party damage is addressed through FEI's operational controls such as procedures and training. <u>Events addressed by IGU and TIMC as follows:</u> External interference damage not discovered through the preventative measures discussed above will be addressed by the IGU Project and TIMC to extent that these projects implement in-line inspection. For example, coating damage from third party interference could result in corrosion, dent and/or	

Incident Cause	IGU Project	TIMC Project
	cracks/gouges which can be detected by ILI tools. For laterals selected for PRS and PLR, which will operate below 30% SMYS, potential undetected damage would be less likely to fail than for a higher operating stress pipeline.	
Material Manufacturing or Construction		
	Prevention of events not addressed by IGU or TIMC: Preventative mitigation activities include construction quality assurance, materials procurement controls, and materials quality assurance procedures. Events not prevented addressed by IGU and TIMC as follows: Construction-related damage not detected or reported by construction quality assurance activities or other activities noted above will be addressed by the IGU Project and TIMC to extent that these project implement in-line inspection. For example, construction-related damage could result in corrosion, dent and/or cracks/gouges which can be detected by ILI tools. For laterals selected for PRS and PLR, which will operate below 30% SMYS, potential undetected defects or damage would be less likely to fail than for a higher operating stress pipeline. Defects in fittings or other components are also addressed through leak surveys and maintenance programs.	
Geotechnical failure		
	Regular activities to detect geotechnical failure include geotechnical/hydrotechnical hazard site identification, site monitoring/inspection, and site-specific mitigation where deemed necessary. Extent addressed by IGU and TIMC (supplementary to regular activities): Geotechnical failure will be or is expected to be addressed in part by the IGU Project and TIMC to the extent that these projects implement in-line inspection. Slope movements may be detectable by comparison of successive geometry in-line inspection data (e.g., shift in pipe location resulting in bending strain). Slope movement may also result in cracking or crack-like features within the EMAT tool capabilities for detection and sizing.	
Other Causes		
Improper Operation	Not addressed by IGU and TIMC: Addressed through field quality programs, including employee training.	
Overpressure	Not addressed by IGU and TIMC: Addressed through asset design, and pressure monitoring activities.	

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41.2 Please discuss how FEI plans to address those "Incident Causes" that the IGU program will not address.

Response:

Please refer to the response to BCUC IR 2.41.1.

41.3 With reference to the BC OGC list, but excluding "External Interference", please identify which "Incident Causes" the TIMC program will address.

Response:

Please refer to the response to BCUC IR 2.41.1.

41.4 Please discuss how FEI plans to address those "Incident Causes" that the TIMC program will not address.

Response:

Please refer to the response to BCUC IR 2.41.1.

B. PROJECT DESCRIPTION

42.0 Reference: PROJECT DESCRIPTION

Exhibit B-2, BCUC 1.8.1, pp. 31 to 62, BCUC 1.12.5.2, p.107

List of Integrity Digs Conducted by FEI

In response to BCUC 1.8.1, FEI provide tables of recorded in-line inspection or Modified ECDA driven integrity digs conducted by FEI on transmission pipelines from 2000 through 2018.

In response to BCUC 1.12.5.2, FEI states:

> The number of digs conducted annually is established based on consideration of many factors, including resource availability. In past years, FEI has prioritized known corrosion locations (i.e. integrity digs identified through in-line inspection) over potential corrosion locations as indicated by above-ground surveys.

42.1 Please provide the total number of in-line inspection driven integrity digs and the total number of Modified ECDA driven integrity digs from 2000 to 2018.

Response:

From 2000 to 2018, FEI performed 1089 in-line inspection driven integrity digs and 34 Modified ECDA driven integrity digs on transmission pipelines.

Table 1: Number of Integrity Digs from 2000 to 2018

Year	Dig Type		Yearly Total
	Modified ECDA	In-line Inspection	
2000	0	9	9
2001	0	77	77
2002	0	118	118
2003	0	114	114
2004	0	85	85
2005	0	85	85
2007	0	29	29
2009	10	34	44
2010	13	36	49
2011	3	47	50
2012	0	32	32
2013	0	47	47
2014	0	57	57

Year	Dig Type		Yearly Total
	Modified ECDA	In-line Inspection	
2015	2	67	69
2016	0	74	74
2017	5	90	95
2018	1	88	89
Grand Total	**34**	**1089**	**1123**

42.2 Please compare the average number of integrity digs per pipeline performed on in-line inspected transmission pipelines to the average number of integrity digs performed per pipeline on transmission pipelines not in-line inspected.

Response:

On average, between 2000 and 2018, approximately 27 digs were completed on in-line inspected transmission pipelines, whereas less than one dig was completed on transmission pipelines that are not in-line inspected.

Table 1: Average Number of Integrity Digs Performed per In-line Inspected vs. Not In-line Inspected Transmission Pipelines

Inspection Type	Number of Digs from 2000-2018	Number of Transmission Pipelines	Average Number of Integrity Digs Performed per Transmission Pipeline
In-line Inspected	1089	41	26.6
Not In-line Inspected	34	101	0.3

42.3 Please elaborate on the factors FEI considers in establishing the number of digs conducted annually.

Response:

When establishing the number of digs conducted annually, FEI considers the following technical factors:

- FEI's assessment of in-line inspection tool-reported data relative to CSA Z662-15 Clause 10.10 defect assessment criteria.
    - When FEI has specific knowledge of tool-reported features that may require repair in accordance with CSA Z662-15 criteria, FEI often considers this as reliable information warranting prioritized action, dependent on tool uncertainty.
- FEI's assessment of the potential for future rupture or leak from ILI tool-reported data.
    - When FEI's analysis demonstrates the potential for future failure of an ILI tool-reported feature, FEI often considers this as reliable information warranting prioritized action, dependent on tool uncertainty and analysis uncertainty, e.g. corrosion growth estimates.
- FEI's assessment of the need for ILI tool validation digs.
    - FEI requires dig data to assess tool performance, including the potential for tool reporting bias (i.e. tool uncertainty). The relative importance of this information to FEI's ILI analysis can vary depending on the pipeline and the particular tool run. FEI's professional judgement determines the necessity and priority of tool validation digs.
- Modified ECDA dig priority ranking (see FEI's response to BCUC IR 1.12.5.2).
    - The Modified ECDA dig priority rankings (i.e. high and medium priority) are terms used within the Modified ECDA process to indicate a priority relative to other Modified ECDA indications. They are not indicative of an overall priority outside of the Modified ECDA process.
    - Modified ECDA survey indications identify potential corrosion locations based on inferences from above-ground survey results, which themselves are based on cathodic protection system performance and coating quality of the buried pipeline.
    - FEI has reduced confidence in Modified ECDA digs as Modified ECDA above ground survey methods cannot detect areas where CP shielding is occurring.
    - As Modified ECDA is a process based on inferences and is limited by the presence of CP shielding on FEI's system, FEI has given lower priority to Modified ECDA excavations relative to in-line inspection-driven digs.
- Modified ECDA random control digs.
    - Random control digs do not provide FEI confidence that external corrosion features or other integrity issues are present on pipelines. This is because the location of random control digs is randomly selected, and not targeted to a

specific site for the purposes of addressing any particular integrity concern. A random control dig provides information on a small segment of a much longer pipeline and therefore provides no statistically significant information on the condition of the pipeline as a whole, because the factors that affect pipeline condition vary from segment to segment across the length of the pipeline.

- FEI has not prioritized Modified ECDA random control digs.

- All other available and relevant technical information.
  - All available and relevant technical information, including observations of potential hazards from sources supplementary to ILI and Modified ECDA (e.g. unauthorized external loading above a pipeline, visual observation of ground movement), must also be considered in FEI's determination of the number of digs conducted annually.

Non-technical factors such as resource availability, landowner impact, and cost effectiveness are also necessary considerations in FEI's determination of the number of digs conducted annually. As an example, advancing future excavations to the current year can, in some instances, provide an opportunity to reduce excavations occurring in successive years on a single landowner's property. It is typically more cost effective to complete multiple digs on a single crew mobilization to a particular area.

42.4 Please discuss FEI's rationale for prioritizing known corrosion locations identified through in-line inspection over potential corrosion locations identified through Modified ECDA.

Response:

FEI prioritizes its mitigation activities to known hazards as opposed to potential hazards to its pipeline system. In-line inspection tool results provide FEI with knowledge of known corrosion locations, along with an assessment of their size and depth. In contrast, Modified ECDA survey indications identify potential corrosion locations as inferred by the indirect inspection results (i.e., above-ground survey results), which are based on inferences regarding the level of cathodic protection system performance and coating quality of the buried pipeline. That is, the above-ground surveys are not direct measurements of level of cathodic protection at the pipe surface or precise measurements of coating condition. The surveys comprise electrical data obtained from above ground, from which the level of cathodic protection at the pipe surface and coating condition are inferred. There is therefore more certainty with respect to the value associated with in-line inspection integrity digs as opposed to Modified ECDA digs.

Please refer also to the response to BCUC IR 2.42.3.

42.5 Please discuss whether there has been a sufficient number of Modified ECDA driven integrity digs performed to determine the overall effectiveness of the Modified ECDA process.

Response:

The number of Modified ECDA driven integrity digs is not relevant to FEI's determination of the overall effectiveness of the Modified ECDA process. As included in the response to BCUC IR 1.4.1, FEI has demonstrated that it is probable that active corrosion is present on the 29 Transmission Laterals due to cathodic protection shielding. This is based on an assessment of in-line inspection driven digs between 2015 and 2018.

The evidence of CP shielding from FEI's in-line inspection digs has necessitated FEI's consideration of alternative mitigation strategies, such as those proposed in the IGU Project.

42.6 Please discuss whether FEI utilizes the findings from in-line inspection driven integrity digs to identify and prioritize potential corrosion locations on transmission pipelines without ILI.

Response:

No, FEI does not utilize the findings from in-line inspection driven integrity digs to identify and prioritize potential corrosion locations on transmission pipelines without ILI because there are many factors that contribute to initiation and growth of corrosion as listed in FEI's response to BCUC IR 1.8.1.1. Drivers that contribute to corrosion are unique to a specific site along a pipeline and may change with time, and therefore cannot be used to identify and prioritize locations of corrosion on other pipelines that are not in-line inspected.

ILI is the most effective method for identifying corrosion locations without having to speculate as to potential corrosion locations based on the numerous factors that may or may not have influenced corrosion initiation and growth.

42.6.1 If so, please describe the process.

Response:

Please refer to the response to BCUC IR 2.42.6.

42.7 Please explain what data informed FEI's decision to perform each of the Modified ECDA driven integrity digs conducted on transmission pipelines from 2000 to 2018.

Response:

Table 2.42.7 shows the data used to inform FEI's decision to perform each of the Modified ECDA driven integrity digs conducted on transmission pipelines from 2000 to 2018. No non-ILI driven digs occurred prior to 2009.

1 **Table 1: Description of Modified ECDA Driven Integrity Dig Decision**

Year	Pipeline Name	Station (m)	Dig Decision Description
2009	Castlegar Nelson 168	1.312	2005 Indirect Survey Data (CP Potential and Coating Condition Data)
2009	Castlegar Nelson 168	15.284	2005 Indirect Survey Data (CP Potential and Coating Condition Data)
2009	Savona Lateral 60	0.945	2005 Indirect Survey Data (CP Potential and Coating Condition Data)
2009	Coldstream Lateral 114	2.157	2005 Indirect Survey Data (CP Potential and Coating Condition Data)
2009	Kamloops 2 Lateral 114	0.279	2005 Indirect Survey Data (CP Potential and Coating Condition Data)
2009	Kelowna Lateral 114	1.99	2005 Indirect Survey Data (CP Potential and Coating Condition Data)
2009	Vernon Lateral 114	0.433	2005 Indirect Survey Data (CP Potential and Coating Condition Data)
2009	Kamloops 1 Lateral 168	2.233	2005 Indirect Survey Data (CP Potential and Coating Condition Data)
2009	Kamloops 1 Lateral 168	3.053	2005 Indirect Survey Data (CP Potential and Coating Condition Data)
2009	Kamloops 1 Loop 168	2.02	2005 Indirect Survey Data (CP Potential and Coating Condition Data)
2010	Kamloops 2 Lateral 114	0.09	2005 Indirect Survey Data (CP Potential and Coating Condition Data)
2010	Kamloops 2 Lateral 114	0.132	2005 Indirect Survey Data (CP Potential and Coating Condition Data)
2010	Castlegar Nelson 168	10.879	2007 Indirect Survey Data (CP Potentials only) 2010 Indirect Survey Data (CP Potential and Coating Condition Data)
2010	Castlegar Nelson 168	10.865	Results from the last CC Technologies CIS survey in 2007 Indirect Survey Data (CP Potentials only) 2010 Indirect Survey Data (CP Potential and Coating Condition Data)
2010	Kimberley Lateral 168	16.942	2007 Indirect Survey Data (CP Potentials only) 2010 Indirect Survey Data (CP Potential and Coating Condition Data)
2010	Kimberley Lateral 168	16.919	2007 Indirect Survey Data (CP Potentials only) 2010 Indirect Survey Data (CP Potential and Coating Condition Data)
2010	Kimberley Lateral 168	18.67	2007 Indirect Survey Data (CP Potentials only) 2010 Indirect Survey Data (CP Potential and Coating Condition Data)

Year	Pipeline Name	Station (m)	Dig Decision Description
2010	Kimberley Lateral 168	16.972	2007 Indirect Survey Data (CP Potentials only) 2010 Indirect Survey Data (CP Potential and Coating Condition Data)
2010	Kimberley Lateral 168	13.44	2007 Indirect Survey Data (CP Potentials only) 2010 Indirect Survey Data (CP Potential and Coating Condition Data)
2010	Kimberley Lateral 168	13.716	2007 Indirect Survey Data (CP Potentials only)
2010	Kimberley Lateral 168	13.978	2010 Indirect Survey Data (CP Potential and Coating Condition Data)
2010	Kimberley Lateral 168	13.515	2007 Indirect Survey Data (CP Potentials only) 2010 Indirect Survey Data (CP Potential and Coating Condition Data)
2010	Kimberley Lateral 168	13.616	2007 Indirect Survey Data (CP Potentials only) 2010 Indirect Survey Data (CP Potential and Coating Condition Data)
2011	Castlegar Nelson 168	16.137	2004 Indirect Survey Data (CP Potential and Coating Condition Data) 2010 Indirect Survey Data (CP Potential and Coating Condition Data)
2011	Castlegar Nelson 168	16.107	2004 Indirect Survey Data (CP Potential and Coating Condition Data) 2010 Indirect Survey Data (CP Potential and Coating Condition Data)
2011	Castlegar Nelson 168	16.162	2004 Indirect Survey Data (CP Potential and Coating Condition Data) 2010 Indirect Survey Data (CP Potential and Coating Condition Data)
2015	Nichol Port Mann 610	35.936	2004 Indirect Survey Data (CP Potential and Coating Condition Data) 2010 Indirect Survey Data (CP Potential and Coating Condition Data)
2015	Nichol Port Mann 610	35.499	2004 Indirect Survey Data (CP Potential and Coating Condition Data) 2010 Indirect Survey Data (CP Potential and Coating Condition Data)
2017	Prince George 1 Lateral 168	92	2015 Indirect Survey Data (CP Potential and Coating Condition Data)
2017	Prince George 1 Lateral 168	640	2015 Indirect Survey Data (CP Potential and Coating Condition Data)
2017	Prince George 1 Lateral 168	4397	2015 Indirect Survey Data (CP Potential and Coating Condition Data)
2017	Prince George Pulp Lateral 168	584	2015 Indirect Survey Data (CP Potential and Coating Condition Data)

Year	Pipeline Name	Station (m)	Dig Decision Description
2017	Prince George Pulp Lateral 168	800	2015 Indirect Survey Data (CP Potential and Coating Condition Data)
2018	Prince George 1 Lateral 168	3860	2015 Indirect Survey Data (CP Potential and Coating Condition Data)

42.8 Please describe follow-up investigations or remedial work FEI conducted on Kimberley Lateral 168 since 2010 and Castlegar Nelson 168 Lateral since 2011.

Response:

Follow-up investigations or remedial work conducted by FEI since 2010 for the Kimberley 168 Lateral and since 2011 for the Castlegar Nelson 168 Lateral are as follows:

- Kimberly Lateral 168:
  - Cathodic protection (CP) close-interval survey in 2012/13
  - Results indicated CP criteria was achieved over the full length of the pipeline; however, FEI notes that indirect inspection methods cannot detect the presence of CP shielding.
- Castlegar Nelson 168:
  - CP close-interval survey in 2013
  - Results indicated CP criteria was achieved over 96% of the pipeline. CP current output was increased and below-criteria segments were re-surveyed, confirming that cathodic protection was subsequently achieved; however, FEI notes that indirect inspection methods cannot detect the presence of CP shielding.

42.8.1 If no follow-up was conducted, please explain why.

Response:

Please refer to the response to BCUC IR 2.42.8.

43.0 Reference: PROJECT DESCRIPTION

Exhibit B-1, Section 5.2.3, p. 59

Pipeline Replacement

On page 59 of the Application FEI states, "PLR involves the installation of a new pipeline in parallel to the existing pipeline. The new pipeline would be designed to operate below 30 percent SMYS such that it mitigates the potential for rupture."

43.1 Please discuss FEI's rationale for designing new pipelines to operate below 30 percent SMYS if there is no present threat of rupture due to external corrosion and the pipeline can be monitored for degradation, as it will be in-line inspection capable.

Response:

FEI's rationale for designing the new pipelines to operate below 30 percent of SMYS is as follows:

- the rupture threat from all time-dependent threats (e.g., external corrosion, cracking) is mitigated over the full lifecycle of the pipeline;
- other threats, such as potential undetected construction damage (e.g., dents, gouges) would be less likely to fail in-service; and
- the cost difference between designing the four PLR projects with pipelines operating at above 30 percent of SMYS as compared to below 30 percent of SMYS is not material (refer to the response to BCUC IR 2.43.2).

43.2 Please discuss any cost savings if the four PLR projects were designed to operate above 30 percent SMYS. Please discuss any constraints, if any, that would prevent such redesign or operation.

Response:

FEI does not estimate there to be material cost savings to the IGU Project for designing any or all of the four PLR projects with pipelines operating above 30 percent of SMYS. To operate a pipeline over 30 percent of SMYS, FEI would incur additional costs associated with in-line inspection including the addition of launcher and receiver barrels at each end of the pipeline as well as ongoing in-line inspections.

When selecting pipe material, there are three parameters that affect the operating stress level for a given operating pressure: nominal pipe size, pipe grade and wall thickness. Since the nominal pipe size has already been selected (as established by required flow rates), the two other variable design parameters are pipe grade and wall thickness. Therefore, a pipeline operating above 30 percent of SMYS, relative to a pipeline operating at the same pressure below 30 percent of SMYS, will have a lower pipe grade or wall thickness (or both).

Currently, the pipe that is selected for the PLR projects is Grade 359. The cost variance between this grade and lower grades, such as 241 or 290, is minimal.

The wall thickness of pipe selected for the PLR projects is Schedule 40 wall thickness, a commonly manufactured wall thickness for each nominal pipe size. For example, Schedule 40 NPS 6 pipe has a wall thickness of 7.1mm. Should FEI require a specified wall thickness that deviates from the standard (i.e., be thinner than standard), then FEI would expect the manufacturing cost of the non-standard pipe to be higher.

Furthermore, the cost of materials is small relative to the total Project cost for the following PLR laterals:

Lateral	Material Cost	Total Cost	Material Cost %
BCF LTL	$ 104,020	$ 2,550,175	4%
SA3 LTL	$ 135,477	$ 3,025,950	4%
KA1 LTL/LOP	$ 741,607	$ 11,577,420	6%
CAR LTL	$ 189,570	$ 3,943,756	5%

As shown above, the material costs make up approximately 4 to 6 percent of the total pipeline replacement cost, and any fluctuations in the material cost would be minor.

44.0 Reference: PROJECT DESCRIPTION

Exhibit B-2, BCUC 1.11.4, p. 100

Coastal Transmission System Retrofitted with ILI

In response to BCUC 1.11.4 FEI states:

> FEI has experience, and has learned from, operational challenges with running ILI tools in retrofitted pipelines. For example, the TPIP retrofit program did not include removal of bend fittings, large wall thickness transitions, barring of tees and replacement of coupons in stopple fittings. Several of these obstructions preventing the clear passage of ILI tools have since been removed because they have either caused damage to ILI tools, resulted in tools becoming lodged in pipelines requiring them to be cut out, or caused speed excursions that have resulted in degradation or loss of ILI data. The scope of the IGU Project includes addressing and removing all the pipeline features that have resulted in operational challenges for FEI when running ILI tools in the past.

44.1 Please discuss whether specialty ILI tools such as low drag, multi-diameter and /or high internal diameter tolerance tools, which are specifically designed to overcome challenges in retrofitted pipelines, could achieve the objectives of the IGU Project.

Response:

This response also addresses BCUC IRs 2.44.1.1 and 2.44.2.

FEI works with its ILI vendors to utilize ILI tools it believes will offer the best opportunity to collect full resolution (high quality) and complete data on pipelines with challenges similar to those which are proposed to be retrofitted as part of the IGU Project. FEI's experience to date with "specialty tools" (specifically with low drag and high internal diameter tolerance tool design) is that they have not achieved full resolution or complete data collection. This work has been targeted at NPS 12 pipelines to date. Based on FEI's experience, FEI is not confident that solutions to overcome the challenges of inspecting NPS 6 and 8 natural gas pipelines without retrofitting will be available in the foreseeable future and therefore will not achieve the objectives of the IGU Project.

Based on FEI's experience inspecting NPS 6, 8, 10 and 12 diameter pipelines, the proposed retrofits increase FEI's confidence in the following:

- Achieving effective cleaning of the pipelines that can be impacted by excessive tool speeds. Ineffective cleaning can result in sensor lift-off and degraded/lost data in areas where debris is present;

- Utilizing proven, commercialized and effective ILI tools, available now and in the future, avoids limiting FEI's inspection capabilities to one tool/vendor/technology specifically designed to run in a particular pipeline; and

- Achieving full resolution data collection using multiple ILI technologies (Geometry, MFL, CMFL and potentially EMAT in the future) by eliminating/reducing speed excursions.

44.1.1 If not, please explain.

Response:

Please refer to the response to BCUC IR 2.44.1.

44.2 Please discuss how the use of these specialty ILI tools could influence the scope, modifications to laterals and cost of the IGU project.

Response:

Please refer to the response to BCUC IR 2.44.1.

C. DESCRIPTION AND EVALUATION OF ALTERNATIVES

45.0 Reference: ALTERNATIVES EVALUATION METHODOLOGY

Exhibit B-2, BCUC IR 1.1, 13.3

Expected Asset Financial Life

In response to BCUC IR 1.1, FEI provided a table showing the expected remaining asset financial life of each of the 29 Transmission Laterals.

FEI further states in response to BCUC IR 1.1:

> In the absence of external influences or identified integrity concerns such as corrosion, the physical life of a transmission pipeline can be longer than the financial end of life…FEI believes that in the absence of external interference some pipelines may have much longer lifespans dependent on their design, construction, maintenance, and monitoring...There is no definitive end of physical life based on the information available to FEI.

In response to BCUC IR 13.3, FEI provided a table showing the present value (PV) of the PRS alternative under the assumption that either PLR or ILI will be required as some point during the 66-year analysis period after PRS is implemented.

FEI further stated in response to BCUC IR 13.3, "The comparison showed that PRS would not provide the lowest PV of revenue requirements over a 66-year analysis period for five out of the 14 transmission laterals…"

45.1 Please discuss what the likely maximum physical life of a transmission pipeline would be. For instance, in FEI's experience, has any of its transmission pipelines' useful lives exceeded 100 years, 130 years (i.e. double the financial life), or more?

Response:

FEI retained JANA Corporation to provide an independent, expert opinion on the likely maximum physical life of a transmission pipeline. The curriculum vitae of Dr. Ken Oliphant and Wayne Bryce, principals of JANA Corporation, who are primarily responsible for this response, are included as Attachment 36.1 to FEI's response to BCUC IR 2.36.1.

JANA Corporation provides the following response:

JANA's Technical Opinion on Functional Lifetime of a Gas Transmission Pipeline

FEI requested that JANA provide a 3rd Party expert opinion regarding the useful life of a well-designed, constructed, operated and maintained transmission pipeline.

Based on JANA's awareness of transmission pipeline historical failure data and available industry literature, JANA's opinion is that there is not currently an industry-recognized finite lifetime for a well-maintained and appropriately assessed pipeline. This opinion is based on:

- Industry studies demonstrating that there is no time-dependent degradation of the fundamental properties of the steels used in natural gas pipelines[1]. The strength properties of steel pipelines, provided time-dependent threats such as corrosion are managed, will not degrade over time.

- An industry study, based on analysis of historical transmission pipeline failures, that concluded that "a well-maintained and periodically assessed pipeline can safely transport natural gas indefinitely[2]" That is, with proper application of Integrity Management approaches, there is no recognized finite lifetime for a transmission pipeline.

- JANA's analysis of PHMSA historical transmission pipeline failure data that confirms the analysis conducted in the above-referenced study..

[1] Clark, E.B., Leis, B.N., and Eiber, R.J., "Integrity Characteristics of Vintage Pipelines," Appendix C, The INGAA Foundation, Inc. 2005.

[2] The Role of Pipeline Age in Pipeline Safety, INGAA Foundation Final Report No. 2012.04

FEI provides the following key findings in the report cited by JANA: "The Role of Pipeline Age in Pipeline Safety":

KEY FINDINGS

Ultimately, the safety of a particular natural gas transmission pipeline is not necessarily related to its age because:

1. 85% of pipeline incidents reported to PHMSA from 2002-2009 occurred irrespective of the age of the pipeline, with just 15% related in some way to the age of the pipeline.
2. The properties of the steels which comprise natural gas pipelines do not change with time; that is, pipe does not "wear out."
3. The fitness of a pipeline for service does not necessarily expire at some point in time.
4. The integrity of those pipelines for which the fitness for service may degrade with the passage of time can be assessed periodically. Timely repairs - and other mitigation efforts - based on those assessments will ensure the pipeline's continued fitness for service.
5. A well-maintained and periodically assessed pipeline can safely transport natural gas indefinitely.

The opinion of JANA Corporation and the key findings of the report cited above support FEI's view that the common understanding in the industry is that natural gas transmission pipelines can have an indefinite useful life in the absence of external influences and depending on their design, construction, maintenance, and monitoring.

FEI's natural gas transmission pipelines came into service in British Columbia in 1957, meaning that FEI's oldest pipeline is approximately 62 years old. While FEI undertakes site-specific replacements or repairs over the life of its pipelines, there is no indication at this time that any of FEI's pipelines, including those installed in 1957, are approaching the end of their useful life. FEI's expectation is that its integrity management programs can extend the life of its pipelines indefinitely.

FEI is currently replacing the Coquitlam Gate IP pipeline as part of its Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) project. This pipeline was approved for replacement by the BCUC on the basis that it has an increasing frequency of gas leaks resulting from non-preventable and non-detectable external corrosion stemming from issues with the quality of the field-applied girth weld coating installation during the original construction of the Coquitlam Gate IP pipeline. Low operating pressures and the expected presence of inside diameter restrictions meant that in-line inspection (ILI) was not a viable alternative to pipeline replacement in that case.

The ILI options proposed in the IGU Project are expected to allow the indefinite extension of asset lifespans by allowing ongoing asset management strategies to be applied to the 29 Transmission Laterals.

45.2 In consideration of the remaining asset financial lives provided in the table in response to BCUC IR 1.1, please identify the transmission laterals which, in all likelihood, would require replacement during the IGU project's 66-year analysis period.

Response:

FEI does not determine or even consider the need for replacement of pipeline based on the remaining financial lives of an asset (i.e. the period for recovery of capital through depreciation expense).

As discussed in response to BCUC IR 1.1.1, the need of full replacement depends on factors such as third-party relocation requests, system alterations to meet operational needs, and integrity concerns. Based on FEI's experience from its own transmission pipelines that are currently being in-line inspected and from the limited information available regarding the condition of the 29 Transmission Laterals that are part of the IGU Project, FEI has no reason to project the actual service life of the 29 Transmission Laterals will be shorter than the financial life of 65 years[3]. Therefore, for those laterals that are selected for ILI or PRS, FEI has no reason to assume full pipeline replacement would be required for any of the 29 Transmission Laterals during the IGU Project's 66-year analysis period. To the contrary, FEI's expectation is that its integrity management programs can extend the life of its pipelines indefinitely.

45.3 Please further explain why, for the transmission laterals where PRS is the preferred alternative and which have limited remaining financial lives, it would not be more cost effective over the long term to select ILI or PLR as the preferred alternative. Please reference the specific circumstances of the applicable laterals when providing this response, preferably in a table format.

Response:

First, as discussed in the responses to BCUC IRs 1.1.1 and 2.45.1, the useful life of a transmission pipeline can be indefinite. Since there is no information or evidence to support the

[3] Absent third party relocation requests, system alterations for operational needs, or other non-integrity related considerations.

premise that any of the 14 transmission laterals selected for PRS will require replacement over the 66-year analysis period, it is not reasonable to account for future PLR or ILI costs when comparing alternatives for each individual lateral.

Second, even if one were to make the unfounded assumption that the laterals would need replacement at the end of their financial life, the financial analysis shows that PRS is still the lowest cost alternative in 9 of the 14 cases. As discussed in the response to BCUC IR 1.13.3, for 9 of the 14 transmission laterals (shown in the table below), implementing PRS today as part of the IGU Project plus implementing PLR or ILI in the future when the individual lateral reaches the end of its financial life of 65 years would continue to have the lowest PV of revenue requirements over a 66-year analysis period compared to implementing PLR or ILI today. As such, it is more cost effective over the long term to select PRS as the preferred alternative for these nine laterals, even if the costs of ILI or PLR are incurred at the end of the laterals' financial life.

Line / Loop ID	Lateral	ILI Present Value ($000s	PLR Present Value ($000s)	PRS plus ILI/PLR in Future Present Value ($000s)	Future Option if Preferred Altnative is PRS (ILI/PLR)	Assumed number of Years until (ILI/PLR)
4	Prince George 3 Lateral 219	14,315	-	11,265	ILI	16
5	Northwood Pulp Lateral 168	15,379	-	13,877	ILI	11
6	Northwood Pulp Loop 219	14,056	-	5,269	ILI	41
10	Prince George #2 Lateral 219	15,839	-	11,769	ILI	31
12	Williams Lake Loop 168	15,692	-	9,829	ILI	39
16	Coldstream Lat 219	13,159	9,334	7,742	PLR	44
17	Coldstream Loop 168	14,241	-	10,253	ILI	35
18	Kelowna 1 Loop 219	13,969	-	12,526	ILI	28
20	Castlegar Nelson 168	54,183	-	49,146	ILI	5

Third, for the remaining five laterals, where implementing PRS today plus PLR or ILI at the end of the existing pipeline's financial life is more costly in terms of PV of revenue requirements over a 66-year analysis period than implementing PLR or ILI today, there is no basis to assume that the five laterals will need replacement in the 66-year analysis period, let alone immediately at the end of the financial life of the lateral.

To provide further assurance to the BCUC, the table below provides a hypothetical sensitivity analysis on the PV of revenue requirements over a 66-year analysis period assuming the actual service life of the pipeline is 5 to 15 years longer than the financial life of 65 years. The alternative with the lowest PV of revenue requirements under each scenario is highlighted in orange in the table below.

The sensitivity analysis shows that PRS will be more cost effective:

- for Husky Oil Lateral 168 if the actual service life is between 0 and 5 years longer than 65 years;

- for Prince George Pulp Lateral 168 and Trail Lateral 168 if the actual service life is between 5 and 10 years longer than 65 years; and

- for Celgar Lateral 168 if the actual service life is between 10 to 15 years longer than 65 years.

For Elkview Lateral 168, implementing PRS today plus implementing PLR at least 15 years after the end of the financial life of 65 years continues to have a higher PV of revenue requirements than implementing PLR today over a 66-year analysis period. In addition, PRS has been selected as the preferred alternative over PLR for Elkview Lateral 168 for reasons other than financial, including less ground disturbance, and lower archaeological and environmental impacts, as discussed in the response to BCUC IR 1.18.4. Given that there is no evidence to support the notion that the Elkview Lateral 168 will need replacement due to its age, and for other non-financial reasons, PRS remains the preferred alternative for Elkview Lateral 168.

Overall, the sensitivity analysis shows that, depending on the actual service life of those 14 laterals that have PRS as the preferred alternative, implementing PRS today could still be more cost effective over the long term than implementing PLR or ILI today, even if one accepts the unfounded assumption that the actual life of the laterals is determined by its financial life as set in a depreciation study. To reiterate, however, FEI does not believe future PLR or ILI costs should be accounted for when comparing alternatives for each individual lateral since there is no definitive information or evidence to support the premise that any of the 14 transmission laterals selected for PRS will require replacement over the 66-year analysis period.

Line / Loop ID	Lateral	Scenario	ILI Present Value ($000s	PLR Present Value ($000s)	PRS plus ILI/PLR in Future Present Value ($000s)
8	Prince George Pulp Lateral 168	1) At end of Financial Life	14,331	7,727	9,387
		2) At end of Financial Life + 5 years	14,331	7,727	8,425
		3) At end of Financial Life + 10 years	14,331	7,727	7,605
		4) At end of Financial Life + 15 years	14,331	7,727	6,903
9	Husky Oil Lateral 168	1) At end of Financial Life	16,392	5,601	6,020
		2) At end of Financial Life + 5 years	16,392	5,601	5,570
		3) At end of Financial Life + 10 years	16,392	5,601	5,178
		4) At end of Financial Life + 15 years	16,392	5,601	4,833
19	Celgar Lateral 168	1) At end of Financial Life	11,731	-	13,314
		2) At end of Financial Life + 5 years	11,731	-	14,435
		3) At end of Financial Life + 10 years	11,731	-	12,960
		4) At end of Financial Life + 15 years	11,731	-	11,706
21	Trail Lateral 168	1) At end of Financial Life	19,043	-	19,823
		2) At end of Financial Life + 5 years	19,043	-	19,659
		3) At end of Financial Life + 10 years	19,043	-	17,265
		4) At end of Financial Life + 15 years	19,043	-	15,225
23	Elkview Lateral 168	1) At end of Financial Life	10,072	5,850	10,333
		2) At end of Financial Life + 5 years	10,072	5,850	9,460
		3) At end of Financial Life + 10 years	10,072	5,850	8,728
		4) At end of Financial Life + 15 years	10,072	5,850	8,223

45.4 Please discuss whether FEI will re-assess the condition of a lateral if integrity concerns such as external corrosion are confirmed on a PRS or ILI lateral.

Response:

This response also addresses BCUC IRs 2.45.4.1 and 2.45.4.2.

FEI has no expectation that a re-assessment of alternatives will be required as a result of integrity concerns being identified on a PRS or ILI lateral. As discussed in the responses to BCUC IRs 1.1.1 and 2.45.1, with appropriate asset and integrity management, the 29 Transmission Laterals can have an indefinite useful life. For those laterals selected for ILI, the capability to detect and localize potential imperfections along the length of a pipeline and to undertake site-specific mitigation or remediation provides both an effective integrity management strategy (i.e., for proactive failure prevention), as well as a cost-effective asset management strategy. These factors have contributed to in-line inspection becoming industry standard practice for natural gas transmission pipelines with a diameter of NPS 6 and greater.

FEI is required by the CSA Z662 standard to monitor for conditions that can lead to failures of its pipeline system over its lifecycle. Therefore, FEI will monitor and assess the condition of all laterals (e.g., CP monitoring, leak survey, etc.) as set out in the response to BCUC IR 1.17.1 and utilizing ILI data collection for ILI laterals. If imperfections to the pipeline are identified, FEI's decisions whether to undertake repair of identified imperfections would be in accordance with CSA Z662-15 Clause 10.10, "Evaluation of imperfections", for pipelines operating at 30 percent of SMYS or greater, or Clause 12.10.7, "Repair procedures for steel distribution pipeline systems", for pipelines operating at less than 30 percent of SMYS. These clauses contain the criteria and guidance upon which an imperfection is considered a defect requiring mitigation or remediation.

Acceptable site-specific mitigation or remediation methods for pipeline defects are defined in CSA Z662-15 Clause 10.11, "Permanent repair methods", and Clause 12.10.7, "Repair procedures for steel distribution pipeline systems". For transmission pipelines, mitigation or remediation typically involves the installation of repair sleeves (either pressure-containing or non-pressure-containing) or a discrete pipe replacement; for distribution pipelines, remediation may vary from pipeline recoating to a structural repair depending on site-specific circumstances. Where multiple acceptable repair methods are provided in the CSA Z662 standard, various technical and financial considerations are applied. For example, for difficult-to-access areas it may not be feasible to install a repair sleeve. A pipe replacement (i.e., a "cut-out" repair) may also be undertaken to obtain a sample for the purposes of laboratory testing.

Although considered highly unlikely, it is possible that the life-cycle economics of pipe replacement may be assessed as advantageous relative to undertaking site-specific mitigation or remediation. In this event, FEI expects that it would take steps to undertake pipeline replacement. However, this would not necessarily imply replacement of the full length of a given pipeline, as inspection results can be used to narrow the scope of a pipeline replacement.

45.4.1 If so, please outline FEI's approach if it learns, during the re-assessment in 45.4 above, that the condition of a PRS or ILI lateral requires further remediation.

Response:

Please refer to the response to BCUC IR 2.45.4.

45.4.2 If so, please describe FEI's criteria for determining whether a pipeline replacement will be required instead of remediation.

Response:

Please refer to the response to BCUC IR 2.45.4.

45.4.3 If a pipeline replacement is required, will FEI obtain CPCN approval

Response:

Other than the LMIPSU project discussed above, FEI has not required a full-length pipeline replacement for integrity-related reasons. However, FEI would apply for CPCN approval upon identification of any potential work that exceeded the CPCN threshold, subject to the regulatory requirements and/or FEI's CPCN threshold at that time.

46.0 Reference: ALTERNATIVES DESCRIPTION

Exhibit B-1, Section 1.12.6. pp. 108 to 112

Status Quo: Modified ECDA Alternative

In response to BCUC 1.12.6, FEI provides the number of integrity digs required by ANSI/NACE ECDA and Modified ECDA for each of the 29 Transmission Laterals.

46.1 Please confirm, otherwise explain, that the table shows the number of integrity digs required annually.

Response:

The table in the response to BCUC IR 1.12.6 shows a minimum estimate of the total number of integrity digs required in accordance with the ANSI/NACE ECDA and Modified ECDA methodologies, not the number of digs required annually.

46.2 Please explain why zero values were provided for certain laterals.

Response:

The laterals with zero values indicate that there are no medium or high priority digs identified following the ANSI/NACE ECDA or Modified ECDA criteria. The criteria for FEI's determination of medium and high priority digs through Modified ECDA is the equivalent to that used for the ANSI/NACE methodology, and is provided in the response to BCUC IR 1.12.5.2 (see tables labeled "FEI Modified ECDA Dig Priority Ranking" and "FEI Modified ECDA Indirect Inspection Indication Severity Classifications").

46.3 Please explain whether the "n/a" abbreviation represents not applicable or information not available.

Response:

The "n/a" abbreviation represents that information is not available. The information is not available at this time for those particular laterals because the Modified ECDA surveys are scheduled for future years.

Modified ECDA surveys are scheduled on an approximate 10-year frequency. The "year of next indirect examination (as part of Modified ECDA)" for each of the 29 Transmission Laterals is provided in the response to BCUC IR 2.40.1.

46.3.1 If information is not available, please explain why not.

Response:

Please refer to the response to BCUC IR 2.46.3.

46.4 Please identify in table form any high or medium priority integrity digs identified by Modified ECDA in the past 19 years that were not performed.

Response:

FEI clarifies that the response to BCUC IR 1.12.5.2 is a description of FEI's current criteria for selecting dig locations and the number of digs, and not FEI's process for the past 19 years. FEI has used this criteria since approximately 2016. Therefore, the Modified ECDA High Priority and Medium Priority digs identified in the response to BCUC IR 1.12.7 (included within FEI's response to BCUC IR 1.12.6) were identified in 2016 onward.

One Medium Priority dig identified on the Prince George Pulp Lateral 168 was completed in 2017. A table listing the remainder of the Modified ECDA High Priority and Medium Priority digs that have not yet been performed is included below.

Table 1: Modified ECDA High Priority and Medium Priority Digs Not Yet Performed

Pipeline	Dig Location (Chainage)	Modified ECDA Dig Priority	Year of Dig Identification
Mackenzie Lateral 168	52.6 m	Medium	2017
Mackenzie Lateral 168	24197 m	Medium	2017
Mackenzie Lateral 168	24087 m	Medium	2017
Mackenzie Lateral 168	26432 m	Medium	2017
Mackenzie Lateral 168	29118 m	Medium	2017

Pipeline	Dig Location (Chainage)	Modified ECDA Dig Priority	Year of Dig Identification
Mackenzie Loop 168	5949 m	Medium	2017
Mackenzie Loop 168	9732 m	Medium	2017
BC Forest Products Lateral 168	2.2 m	Medium	2017
BC Forest Products Lateral 168	434 m	Medium	2017
Prince George #3 Lateral 219	3626 m	Medium	2016
Prince George #3 Lateral 219	3670 m	Medium	2016
Northwood Pulp Lateral 168	695 m	Medium	2016
Prince George Pulp Lateral 168	1651 m	Medium	2016
Prince George Pulp Lateral 168	1671 m	Medium	2016
Prince George Pulp Lateral 168	1768 m	Medium	2016
Kamloops 1 Lateral/Loop 168	35 m	Medium	2018
Kamloops 1 Lateral/Loop 168	2964 m	Medium	2018
Kamloops 1 Lateral/Loop 168	2977 m	Medium	2018
Kamloops 1 Lateral/Loop 168	3410 m	Medium	2018
Kamloops 1 Lateral/Loop 168	3421 m	Medium	2018

Prior to 2016, integrity digs were selected on the basis of FEI analyst judgment with reference to industry standards. This previous analysis did not classify digs with a Modified ECDA Dig Priority Ranking of High Priority or Medium Priority. All of the required digs from this previous analysis were completed.

In preparing this response, FEI has identified an error in the table submitted in its response to BCUC IR 1.12.6. This error pertains to the first two rows of data only: 1. Mackenzie Lateral 168; and 2. Mackenzie Loop 168. Several High Priority and Medium Priority digs originally identified on the Mackenzie Lateral 168 and Mackenzie Loop 168 were reclassified following a correction to the cathodic protection system. Subsequent to this correction, four High Priority digs were reclassified as Medium Priority and three Medium Priority digs were reclassified as “not required”.

1 The applicable corrected rows for Mackenzie Lateral 168 and Mackenzie Loop 168 are shown
2 below:

Table 2: Corrected Rows for Mackenzie Lateral 168 and Mackenzie Loop 168

Line/Loop ID No.	Line/Loop Full Name	Length (km)	BCUC IR 1.12.6 and 1.12.6.1: Estimate of digs that would have been prescribed under the ANSI/NACE ECDA standard						BCUC IR 1.12.7: Digs identified by FEI's Modified ECDA standard	
			High Priority Digs (#)	Medium Priority Digs (#)	Control Digs	Process Verification Digs	Process Verification Digs resulting from reclassification	% of Control Digs and/or Process Verification Digs (BCUC IR 1.12.6.1)	High Priority Digs (#)	Medium Priority Digs (#)
1	Mackenzie Lateral 168	28.6	2	5	min. 4	min. 4	unknown	min. 53%	0	5
2	Mackenzie Loop 168	14.2	2	1	min. 2	min. 2	unknown	min. 57%	0	2

46.4.1 Please explain FEI's rationale for not performing any medium or high priority integrity digs identified by Modified ECDA.

Response:

As described in the response to BCUC IR 2.42.3, FEI has given lower priority to "medium" or "high" priority Modified ECDA digs relative to in-line inspection-driven digs. This is because the Modified ECDA method only provides locations of potential corrosion based on inferences from above-ground survey results and cannot detect areas where CP shielding is occurring. In contrast, in-line inspection (ILI) provides a more direct measurement of size and depth of imperfections and more certainty as to their existence.

The Modified ECDA dig priority rankings (i.e. high and medium priority) are terms used within the Modified ECDA process to indicate a priority relative to other Modified ECDA indications. They are not indicative of an overall priority outside of the Modified ECDA process.

Over the past number of years, FEI has been conducting increased levels of ILI driven integrity digs to manage and repair dents, imperfections and defects identified through running circumferential magnetic flux leakage ILI technology and the application of new defect assessment criterion as described in the FEI Annual Review for 2018 Rates Application (page 5).

FEI expects to complete the Modified ECDA "medium" and "high" priority integrity digs during the term of FEI's proposed Multi-Year Ratemaking Plan (2020-2024).

46.4.2 Please discuss FEI's progress towards completing any outstanding Modified ECDA driven integrity digs and provide an estimated completion date.

Response:

Please refer to the response to BCUC IR 1.46.4.1.

47.0 Reference: ALTERNATIVES DESCRIPTION

Exhibit B-1, Section 4.4.4.2. p. 42; Exhibit B-2, BCUC 15.2, p.146

Hydrostatic Testing Program (HSTP)

On page 42 of the Application, FEI states:

> Because HSTP requires the line to be shut-down, consideration of this alternative was limited to laterals with redundant looping or laterals with practical means of supporting downstream customers.

In response to BCUC 1.15.3.1, FEI states:

> Hydrostatic testing was ruled out for reasons of cost, significant operational complexity, and higher risk of outages into colder weather with associated increasing supply requirements should the testing result in pipeline failure.

47.1 Please discuss whether FEI considered scheduling hydrostatic testing to coincide with large industrial customer's planned shutdowns and facility maintenance.

Response:

This response also addresses BCUC IRs 2.47.1.1, 2.47.1.2 and 2.47.1.3.

No, FEI did not consider scheduling hydrostatic testing during industrial customers' planned shutdowns. The uncertainties associated with customers' future shutdown plans do not provide sufficient confidence to support the development of reliable forecasts of the supply requirements, cost estimates or project complexity over the life of a testing program. Specifically:

- The need for large industrial planned shutdowns are customer specific and vary from customer to customer and industry to industry;
- The current frequency and duration of planned customer shutdowns is not a reliable indicator of outages that may be experienced in the medium to longer term; and
- There is no certainty that the duration of a customer shutdown will align with the requirements needed for hydrostatic testing.

Further, even in the event that hydrostatic testing could be aligned within a planned customer shutdown window, a pipeline test failure (and associated urgent repair) resulting from the hydrostatic test could significantly extend the gas supply outage beyond the planned customer shutdown. Consequently, it would still be necessary to develop contingency plans for an alternate supply capability to be available to support the customer(s) load requirements.

As a result, FEI did not conduct an assessment of reduced supply requirements that could now be used to compare cost and benefits of conducting hydrostatic testing using compressed natural gas (CNG) as a means of supporting downstream customers.

47.1.1 If so, please provide FEI's assessment of supply requirements on each lateral during customer planned shut-downs.

Response:

Please refer to the response to BCUC IR 2.47.1.

47.1.2 If so, please compare the costs and benefits of conducting hydrostatic testing using compressed natural gas (CNG) as a means of supporting downstream customers.

Response:

Please refer to the response to BCUC IR 2.47.1.

47.1.3 If not, why not

Response:

Please refer to the response to BCUC IR 2.47.1.

47.2 Please discuss whether FEI considered tethered in-line inspection rather than hydrostatic testing to eliminate the risk of pressure testing resulting in pipeline failure.

Response:

This response also addresses BCUC IRs 2.47.2.1 and 2.47.2.2.

FEI did not consider tethered in-line inspection rather than hydrostatic testing (HSTP) to eliminate the risk of pressure testing resulting in pipeline failure for the following reasons:

- Deploying these tools would still require shutdowns of pipeline segments to be inspected, which would require alternate supply capability to be available for the customer. The complexity associated with arranging alternate supply, and the associated cost of such an undertaking, contributed significantly to FEI's discounting of the HSTP alternative (section 4.4.4.2 of the Application) and similarly weigh against any other alternatives involving shutdowns.

- The distance that tethered in-line inspection tools can travel within pipelines is limited by the pipeline geometry (e.g. cumulative degrees of bending), reducing the length possible to inspect within a single run. Due to this limitation, sections of pipelines would need to be inspected separately. Tethered in-line inspection could therefore take longer to accomplish than HSTP.

Given the complexities associated with implementing tethered in-line inspection, FEI has not identified sufficient benefit to warrant further consideration.

47.2.1 If so, please explain how FEI would conduct the tethered ILI.

Response:

Please refer to the response to BCUC IR 2.47.2.

47.2.2 If not, why not

Response:

Please refer to the response to BCUC IR 2.47.2.

48.0 Reference: ALTERNATIVES EVALUATION METHODOLOGY

Exhibit B-2, BCUC IR 18.4, 18.5

Elkview Lateral 168

In response to BCUC IR 18.5, FEI provided the following table summarizing the individual category rankings for the Elkview Lateral:

	ILI	PRS	PLR
Integrity and Asset Management Capabilities			
Prevention of Ruptures	5	5	5
Prevention of Leaks	5	0	4
Proactive Asset Management	5	0	4
Technical Certainty	4	3	5
Project Execution & Lifecycle Operation			
Environmental	3	4	2
Lands & ROW	3	4	1
Consultation and Engagement Complexity	3	3	2
Operational Complexity	4	3	5
System Capacity & Customer Impacts	4	5	5
Project Execution Certainty	3	4	3
Financial			
PV of Incremental Annual Revenue Requirement	2	5	5

In response to BCUC IR 18.4, FEI stated:

> …FEI also considered that the ground disturbance over the construction footprint for the PRS would be significantly less than would be required to replace a 1.5 kilometres lateral. The PRS option also requires less coordination over Teck Coal lands and will have less archaeological and environmental impacts.
>
> As a result, FEI selected PRS as the preferred alternative for Elkview since it has a smaller immediate delivery rate impact, a comparable revenue requirement over the 66-year analysis s period, less ground disturbance over a smaller construction footprint than PLR, and less archaeological and environmental impacts.

48.1 Please confirm, or explain otherwise, that based on the rankings in the table provided in response to BCUC IR 18.5, FEI has prioritized the "Project Execution & Lifecycle Operation" category over "Integrity and Asset Management Capabilities."

Response:

FEI did not prioritize the "Project Execution & Lifecycle Operation" category over "Integrity and Asset Management Capabilities". The table provided in BCUC IR 1.18.5 shows the scores for the individual sub categories for each evaluation criteria. As indicated in Table 4-1 of the Application and reproduced below, "Integrity and Asset management Capabilities" has a higher ranking than "Project Execution and Lifecycle Operation."

Table 4-1: Overall Weighting of Evaluation Criteria

Evaluation Criteria	Weight
Integrity and Asset Management Capabilities	45%
Project Execution & Lifecycle Operation	20%
Financial	35%

48.2 Please confirm, or explain otherwise, that given FEI's limited information on the Elkview Lateral's condition, FEI cannot determine the probability that the pipeline will need to be replaced within the 66-year analysis period.

Response:

FEI cannot determine the probability that the Elkview Lateral will need to be replaced within the 66-year analysis period. However, for the reasons discussed in FEI's responses to BCUC IRs 1.1.1 and 2.45.1, FEI's expectation is that, with FEI's ongoing integrity management program, the Elkview Lateral will not require replacement during the 66-year analysis period for the IGU Project.

48.3 Please compare the coordination required over Teck Coal lands between the PRS and PLR alternatives.

Response:

PRS requires fee simple land acquisition for the installation of an above ground pressure regulating station. PLR requires right of way widening and temporary work space for a typical open trench pipeline installation which would be adjacent to Teck's mining activities. Both

alternatives require coordination and authorization from Teck for site access to perform onsite work such as surveying, archaeological impact assessment, geotechnical and construction. The PRS option is limited to the PRS site at the start of the lateral, whereas the PLR option has an impact along the entire 1.5 km length of the lateral. The PLR option therefore requires greater coordination over Teck Coal lands compared to the PRS alternative.

48.4 Please explain if FEI has had any discussions with Teck Coal regarding the IGU project. If yes, please explain the nature of the discussions and whether more than one project alternative was discussed (i.e. alternatives beyond PRS).

Response:

Yes, FEI had discussions with Teck Coal regarding the IGU Project. The initial discussions focused on explaining the overall application, the proposed work, the possible options and the preferred solution for the transmission lateral from which the customer is served. FEI also discussed the potential impacts of the preferred solution at a high level, but FEI and Teck Coal did not have detailed discussions regarding potential impacts of other alternatives. FEI committed to further dialogue and to make efforts to align its work during periods of the customer's scheduled maintenance where possible. Customer feedback was supportive and Teck Coal had no concerns as the potential work should have minimal impacts to their businesses. The customer requested that FEI remain in communication with respect to schedules of the proposed work and any potential impacts to their daily operations.

48.4.1 If FEI has had discussions with Teck Coal, please explain whether Teck Coal has expressed any opposition or support towards any project alternative.

Response:

FEI explained to Teck Coal the alternatives considered at a high level, and described the preferred alternative for the Project. Teck Coal was supportive of the IGU Project from a safety and reliability perspective and acknowledged that the preferred solution should have minimal impacts to their businesses. Although Teck Coal did not express any opposition to any alternative, if the preferred solution were to change and consequently could have a higher impact on their business, then Teck Coal may not be as supportive of the IGU Project.

48.5 Please explain if FEI will be required to engage/consult with other parties beyond Teck Coal as part of the Elkview Lateral project. If yes, please describe these other parties and the number of parties likely to be impacted by the project.

Response:

As PRS was chosen as the preferred alternative, Teck Coal will be the only directly affected customer on the Elkview Lateral. No other consultation/engagement is needed at this stage. If closer to construction FEI finds that there are any archeological or environmental impacts or new Crown Lands are needed to complete the PRS installation, FEI will engage with the Indigenous communities as part of the OGC permitting process. Please also refer to the response to BCUC IR 2.60.1.

D. PROJECT COSTS, ACCOUNTING TREATMENT AND RATE IMPACT

49.0 Reference: PROJECT COST ESTIMATE DETAILS
Exhibit B-2, BCUC IR 23.1; Exhibit B-1, p. 68, Footnotes 31, 32
Contingency and Management Reserve

In response to BCUC IR 23.1, FEI stated that it "has not previously included a management reserve in addition to contingency. However, FortisBC Inc. included a management reserve in the CPCN Application for the Replacement of the Corra Linn Dam Spillway Gates project…The Corra Linn project was the only project where a management reserve was applied."

Footnotes 31 and 32 on page 68 of the Application provide the AACE International Recommended Practices' definitions for Contingency and Management Reserve as follows:

- **Contingency** – An amount added to an estimate to allow for items, conditions, or events for which the state, occurrence, and/or effect is uncertain and that experience shows will likely result, in aggregate, in additional costs…

- **Management Reserve** – An amount added to an estimate to allow for discretionary management purposes outside of the defined scope of the project, as otherwise estimated. May include amounts that are within the defined scope, but for which management does not want to fund as contingency or that cannot be effectively managed using contingency.

49.1 Please explain why FEI is now including a management reserve in addition to contingency for this project, given that FEI has not previously included a management reserve.

Response:

This response also addresses BCUC IRs 2.49.2 through 2.49.4.

As stated in the Application, FEI included the management reserve in the estimate for the IGU Project given the risk profile of the Project and to account for possible scope changes or unknown future events which cannot be anticipated and which were not quantified in the risk register. The inclusion of a management reserve along with contingency in a project cost estimate is consistent with AACE recommended practices, the BCUC's CPCN Guidelines, and

practices used by other utilities in Canada (BC Hydro[4] and Manitoba Hydro[5]), including FortisBC Inc. (Corra Linn Dam Spillway Gates CPCN).[6]

As per the AACE definitions, contingency is an amount added to an estimate as an allowance for known risks that are likely to occur during the implementation of a project and is the uncertainty associated with an estimate for a defined scope of the Project. Some or all of the contingency amount is expected to be spent during project implementation. A management reserve, on the other hand, is an allowance for significant scope changes and/or unknown project related risks that have high consequence but a low likelihood of occurring that may materialize during project implementation.

As stated in the Application, due to the vintage of the 29 Transmission Laterals there is uncertainty with the number of restrictive bends. All restrictive bends must be replaced to allow ILI tool passage, even if they exceed the number allowed for in the Project cost estimate. There is no certainty as to location or type of bends but the likelihood of finding more than the estimated quantity is relatively low to medium considering the analysis done to date. Moreover, for a multi-year project implementation schedule, some additional risks in addition to those identified in the risk register, for which the occurrence and/or effect are unknown, could likely occur. The uncertainty and risks associated with the estimated quantity, along with the unknown risks over the multi-year implementation period, are expected to have a low to medium likelihood of occurrence but the consequences could be high. Therefore, in addition to the 17 percent contingency, FEI is including a management reserve of 11 percent.

Although a management reserve was not included in FEI's previous CPCNs, FEI took guidance from AACE Recommended Practice 44R "Risk Analysis and Contingency Determination Using Expected Value", which states:

> Contingency is only useful for funding risk impacts that represent a limited portion of the overall contingency funding (usually variable or continuous in nature). High impact/low probability risks (usually fixed or binary in nature) often cannot be effectively funded with contingency because, if the risk occurs, especially at its maximum impact, it may consume all of the contingency and much more. You can never put enough in the contingency account to cover such a risk, and if you do, you will likely kill the project economics even though the risk has a low probability of occurring.

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4 BC Hydro Ruskin Dam and Powerhouse Upgrade Project CPCN. https://www.bcuc.com/Documents/Proceedings/2011/DOC_27024_B-1_BCH-Ruskin-Dam-CPCN-Application.pdf

5 Manitoba Hydro's Capital Cost Estimate development for the Keeyask and Conawapa project http://www.pubmanitoba.ca/v1/nfat/pdf/hydro_application/appendix_02_4_developing_the_keeyask_and_conawapa_capital_cost_estimates.pdf

6 FBC Replacement of the Corra Linn Dam Spillway Gates CPCN – page 61 of the Application

Essentially, the use of contingency and management reserve is specific to a project's attributes and the project specific risks that are likely to be encountered. In the case of the IGU Project, which is to be executed over a multi-year period and with an uncertain scope quantity, it is appropriate and necessary to include a management reserve should high impact risks occur. FEI intends to use this methodology of allocating a contingency and a management reserve for future projects as required based on the risk profile and the quantification results in accordance with the CPCN guidelines, Section 5(vi).

Below is a table comparing the contingency percentages for previous FEI approved projects over the past 20 years with a project cost of $15 million or greater. The table does not include the 2014 Tilbury LNG Expansion as that project was approved with a fixed capital expenditure amount of $425 million by the BC Government under Direction No. 5 to the BCUC under OIC-557, subsequently amended with OIC-749 and OIC-162.

Year Approved	BCUC Order	Project Name	Contingency Percentage (%)
1999	C-7-99	Program Mercury Customer Information System (CIS)	20%
1999	G-51-99	Southern Crossing Pipeline Project CPCN	10%
2001	C-15-01, C-3-02, C-4-03, C-5-04	Transmission Pipeline Integrity Plan (TPIP) 2001 to 2005	15%
2005	C-3-06	Whistler Pipeline and NG Conversion CPCN	17%
2006	C-2-06	Vancouver Low Pressure CPCN	10%
2007	C-9-07	Mt Hayes LNG	6%
2009	C-2-09, G-122-12	Fraser River South Arm Crossing CPCN	15%
2010	C-1-10, G-23-10	Customer Care Enhancement Project	11%
2015	C-11-15	Lower Mainland IP System Upgrade	15%
2019		IGU CPCN	17%

The project contingencies are an amount added to a cost estimate to provide a P50 level of confidence for a given scope. Contingency is based on the specific risks associated with the conditions and attributes of a particular project. While each project in the table above has unique risks, the broad comparison in the table suggests that the IGU Project includes a contingency percentage within the range of previous projects.

Compared to FEI's previous projects, the IGU Project is the only project which included a management reserve. As noted, with the management reserve, the IGU Project cost estimate provides a P70 level of confidence. Accordingly, it cannot be directly compared with the contingency percentages in the table given that there is no information to determine the

additional contingency or management reserve required to add to the previous project estimates to achieve a cost estimate with a P70 level of confidence.

Should the need arise to access the management reserve during Project execution, a request for additional funds will be submitted to the Executive Sponsor detailing the additional scope or conditions that have materialized. Upon approval from the Executive Sponsor, the Project baseline cost will be increased by the amount requested.

As an example, if FEI encounters more elbows in addition to the 180 included in the defined scope of the estimate, the Project Manager would seek approval from the Executive Sponsor to utilize the management reserve to fund the cost required to replace the additional elbows with induction bends. On the other hand, if the cost of materials increase through normal market drivers, then the contingency would be utilized to account for the difference in cost. If either the contingency or management reserve are accessed during the Project, the amount spent will be identified in the Project quarterly updates provided to the BCUC.

In summary, the IGU Project contingency and management reserve reflect the level of scope definition, conditions, and attributes of the Project. FEI does not consider them to be high when compared to previous CPCN projects but rather appropriate to reflect the uncertainty and risks associated with the IGU Project.

49.2 Please compare FEI's contingency percentage (both including and excluding the management reserve) to its previously approved projects' contingencies, including all CPCNs approved in the past 20 years with a project cost of $15 million or greater.

Response:

Please refer to the response to BCUC IR 2.49.1.

49.2.1 Please discuss whether the proposed contingency for the IGU Project is considered high compared to previous projects, particularly when factoring in the management reserve. If so, please provide the necessary justification.

Response:

Please refer to the response to BCUC IR 2.49.1.

49.3 Please explain in detail how the management reserve will be handled, including who will have access to it, how access to it would be approved, and how funds would be accessed.

Response:

Please refer to the response to BCUC IR 2.49.1.

49.4 Please describe in detail the difference in treatment, application and accounting/reporting between the contingency and the management reserve, using a hypothetical scenario related to the IGU Project.

Response:

Please refer to the response to BCUC IR 2.49.1.

E. ENVIRONMENT AND ARCHAEOLOGY

50.0 Reference: ENVIRONMENT AND ARCHAEOLOGY

Exhibit B-1, p. 76; Exhibit B-2, BCUC IR 26.3

Environmental Permitting

In response to BCUC IR 26.3, FEI confirms that the best management practices and mitigation measures described in Section 6 of the Environmental Overview Assessment (EOA) report are sufficient to ensure that any concerns regarding terrestrial resources, aquatic resources and species at risk are sufficiently addressed.

On page 96 of the Application, Table 7-2 shows the expected environmental permits by lateral for the preferred engineering options.

50.1 Please confirm if the best management practices and mitigation measures described are requirements for the permit approvals as identified in Table 7-2 of the Application.

Response:

The best management practices and mitigation measures described in Section 6 of the Environmental Overview Assessment (EOA) report will form part of the project's Environmental Management Plans (EMPs). Most of the environmental permits listed in Table 7-2 of the Application will require the submission of the EMP as part of the permit application package. Permits will list terms and conditions that must be followed during construction. If the permit requires compliance with the EMP as a permit term or condition, then the EMP (which includes best management practices and mitigation measures) becomes a regulatory permit requirement.

51.0 Reference: CONSULTATION

Exhibit B-1, pp. 98, 129; Exhibit B-2, BCUC IR 33.6, 33.7, 33.9

Archeological Overview Assessment

On page 98 of the Application, FEI states

The AOA [Archaeology Overview Assessment] concluded that the majority of the expected Project footprint is considered to have low archaeological potential due to the amount of previous disturbance. AIA has been recommended for ground disturbance activities in areas identified as moderate or high potential through the AOA process. Where the AOA identified potential for deeply buried cultural deposits, construction monitoring will be applied. Potential for deeply buried cultural deposits is present at specific sites along 13 of the laterals.

On page 129 of the Application, FEI states:

> Some concerns such as those related to sensitive areas require additional, site specific information that is not available at this early Project stage. FEI will continue to engage with those communities that have requested additional information with follow up meetings as the Project design becomes more certain.

In response to BCUC IR 33.6, FEI states:

> FEI notified Indigenous communities about the IGU Project, outlined the intended field work, and requested participation to provide information and comment. Indigenous communities were then contacted by the Project's Archaeological consultants and provided with an opportunity to participate in the AOA preliminary field reconnaissance (PFR) program.

In response to BCUC IR 33.7, FEI states:

> FEI has not had discussions with Indigenous communities specific to deeply buried cultural deposits to date. The Archaeological Overview Assessment (AOA) reports, as filed in Appendix P, identify areas with potential for deeply buried cultural deposits along the existing laterals. The AOA is based on preliminary engineering design; however, further design is required to identify if areas with potential for deeply buried deposits are within the expected Project footprint.

In response to BCUC IR 33.9, FEI states:

> Based on the AOA information and discussions with Indigenous groups to date, FEI has not identified any notable risks or issues related to sensitive areas that will require resolution.

51.1 Please explain what is meant by "construction monitoring", in the context of areas with potential for deeply buried cultural deposits.

Response:

In the context of areas with potential for deeply buried cultural deposits, "construction monitoring" will involve the archaeological team being on site to watch and guide the construction activities. This work will occur as part of the Archaeological Impact Assessment work, under a Heritage Conservation Act (HCA) permit. Actual requirements, such as the percentage of excavated soil that requires archaeological raking/screening, will be set out in the HCA permit application and permit. The archaeological team will consist of one or more professional archaeologists and one or more Indigenous Community archaeological monitors, depending on their availability and desire to participate.

51.1.1 Please discuss if and how construction monitoring is intended to mitigate any potential concerns of Indigenous communities with respect to deeply buried cultural deposits.

Response:

If Indigenous Communities express concerns with respect to deeply buried cultural deposits, this concern can be addressed during the development of the HCA permit application or if raised later, through the Archaeological Branch's HCA permit application review process. For example, an Indigenous Community can request a higher percentage of excavated soil be screened. In addition, when archaeological work is occurring, Indigenous Community archaeological monitors will be invited to be part of the archaeological team.

51.2 Please confirm if FEI's Archaeological consultants have contacted all Indigenous communities identified in Table 8-3 of the Application at all, and also since the filing of this Application.

Response:

Prior to the filing of this Application, FEI's archaeological consultant contacted each Indigenous community or a representative of the community in Table 8-3. For clarity, where a community is a member of a Nation, Tribal Council or Alliance, the larger group representative was contacted.

Since the filing of this Application, FEI's archaeological consultant has only had contact with the Lheidli - T'enneh Band who requested the Archaeological Overview Assessment (AOA) report and shapefiles, which were provided to the band.

FEI has also engaged directly with Indigenous communities following the filing of the Application.

51.2.1 If not confirmed, please explain.

Response:

Please refer to the response to BCUC IR 2.51.2.

51.3 Please explain why FEI has not had discussions with Indigenous communities specific to deeply buried cultural deposits to date.

Response:

FEI has not had discussions with Indigenous communities specific to deeply buried cultural deposits to date as, at this stage of project design or engineering, it is unclear if ground disturbance will be required in areas with the potential for deeply buried cultural deposits. Once further engineering is completed and it is determined that ground disturbance is required in those areas, the appropriate Indigenous Communities will be engaged.

51.3.1 Please explain if FEI considers that such discussions are necessary to determine whether or not there may be risks related to culturally sensitive areas and if so, the appropriate mitigation strategies.

Response:

FEI believes that such discussions with Indigenous communities are necessary. However, as noted in response to BCUC IR 2.51.3, at this stage of project design or engineering, it is unclear if ground disturbance would be required in areas with the potential for deeply buried cultural deposits.

The Archaeological Impact Assessment (AIA) is the mitigation strategy for impact to deeply buried cultural deposits if encountered during construction. At this time, the areas of potential for deeply buried cultural deposits have been identified as areas that require AIA work if ground disturbance is required. As noted in the Application, permits will be required under the Heritage Conservation Act in order to undertake detailed AIA activities.

51.3.2 Please discuss if FEI believes there would be benefits from sharing information from the Archaeological Overview Assessment (AOA) reports with potentially affected communities.

Response:

This response also addresses BCUC IR 2.51.4.

Confirmed. FEI believes there are benefits from sharing AOA reports with potentially affected communities. As discussed in the response to BCUC IR 2.51.2, FEI's archaeological consultant contacted all Indigenous communities to make them aware of this work.

Through the BC Oil & Gas Commission regulatory process that will be completed for each lateral, FEI must notify affected Indigenous communities as identified by the Consultative Area Database. FEI will include the AOA reports to each Indigenous community during this notification and engagement process.

51.4 Please confirm whether FEI will share information with indigenous communities regarding the results of the AOA? If not, why not?

Response:

Confirmed. Please refer to the response to BCUC IR 2.51.3.2.

F. CONSULTATION

52.0 Reference: CONSULTATION

Exhibit B-1, p. 76; Exhibit B-2, BCUC IR 28.1, 28.2

Landowners

On page 76 of the Application, FEI states:

> The Project will require fee-simple land acquisition, expanded ROW, temporary construction working space and access rights (Land Rights). FEI will develop a land management plan to assess the required properties and prioritize the acquisitions based on risk and impacts to the schedule.

In response to BCUC IR 28.1, FEI states:

> Where fee simple purchases are expected, potentially affected landowners have not provided a response or feedback to FEI's initial notification.

In response to BCUC IR 28.2, FEI states:

> Possible risks associated with the completion of fee simple land acquisition include:
>
> - The landowner not wishing to sell the property; or
> - The land owner having unreasonable expectations for compensation.

FEI will follow its standard practices with respect to the acquisition of fee-simple land and will seek to negotiate land acquisition agreements with each landowner at an appropriate compensation level. While FEI's objective is to reach mutually acceptable negotiated agreements with landowners, should an agreement not be reached, and the IGU Project construction could be delayed, FEI will take steps to expropriate the required land rights.

…

In terms of schedule impact related to expropriation, it is estimated to take between 6 weeks to 6 months depending on size and complexity to compile appropriate application documentation such as survey and appraisal. Early consideration of land acquisition difficulties will assist in commencing the expropriation process timeline as soon as possible to avoid construction schedule impacts.

52.1 Please discuss the extent to which FEI considers that early discussions with landowners is required to understand where land acquisition difficulties may arise, or to reduce the likelihood of the risks identified in the response to BCUC IR 28.2.

Response:

Early discussions with landowners is important to understanding any concerns they may have with respect to the pipeline design as it relates to their property. Additional time building relationships with the landowners to understand their concerns is key to negotiating a mutually acceptable agreement.

52.1.1 Please discuss whether the lack of response to FEI's early notification increases the risks identified in the response to BCUC IR 28.2.

Response:

The lack of response to FEI's early notification does not increase the risks identified in the response to BCUC IR 1.28.2. FEI's early notification described the IGU Project at a high level and did not include details regarding specific land requirements as they were not available at that time. As the Project is still in the early stages, initial discussions with property owners where FEI anticipates commencing negotiations to acquire fee simple land rights has not yet been undertaken. Please also refer to the response to BCUC IR 2.52.1.

52.1.2 Please describe additional consultation efforts that FEI plans to undertake with landowners, including timelines.

Response:

Further notification will be given to all affected property owners along each lateral one month prior to commencement of geotechnical and engineering studies. FEI will also be contacting property owners directly during the pre-construction phase to discuss acquisition of land, right of way, and working space requirements. During the construction phase, FEI will continue to be in contact with property owners to address any construction related issues that may arise.

52.2 Please briefly explain FEI's standard practices with respect to the acquisition of fee-simple land

Response:

FEI will identify the preferred site and conduct preliminary research of the parcel, including review of Land Title Survey Authority title report, BC Assessment and municipal bylaws and zoning. If the parcel meets the necessary project requirement, FEI will contact the property owner to commence negotiation for acquisition. Upon successful negotiations, FEI will enter into a Contract of Purchase and Sale with the property owner, subject to environmental and geotechnical reviews, as well as approval from all governing bodies. Once subjects of sale have been removed, FEI retains outside legal counsel to complete the conveyance**.**

52.3 Aside from risks to project schedule, please describe any other potentially negative consequences associated with the expropriation of land.

Response:

In addition to the risks to project schedule, the additional potentially negative consequences associated with the expropriation of land, whether a fee-simple or a statutory right of way interest, are (i) increased costs associated with the expropriation process itself; (ii) negative impacts to the ongoing relationship with the landowner and adjacent landowners; and (iii) uncertainty around the amount of compensation and the terms of the applicable agreement.

1. Increased Costs: In the event expropriation is necessary, FEI may incur increased process-related costs such as appraisal and external legal fees. These costs would be greater in the event of a contested expropriation. In addition, FEI may be required to compensate the landowner for the expenses incurred by the landowner in the expropriation proceedings, including the landowner's appraisal and legal fees.

2. Impacts to ongoing relationships: The expropriation process is inherently adversarial and may negatively impact the immediate and long term relationship with the landowner and the larger community. Where FEI expropriates a statutory right of way, FEI and the landowner enter into a contractual relationship that extends not only for the duration of the initial project; the relationship extends for the life of FEI's facilities within the right of way area. While an expropriation may result in FEI obtaining the necessary land rights required, it may also result in FEI having a more contentious relationship with the directly impacted landowner as well as adjacent landowners rather than the cooperative and positive working relationships that often result when FEI is able to negotiate a mutually acceptable agreement.

3. Uncertainty around the amount of compensation and the terms of the applicable agreement: With expropriation, there is a level of uncertainty with respect to the amount

of compensation that may become payable to the landowner and, in addition, where FEI is expropriating a statutory right of way interest, the terms of the statutory right of way agreement.

53.0 Reference: CONSULTATION

Exhibit B-1, p. 109; Exhibit B-2, BCUC IR 31.1, 31.2

Industrial Customer Consultation

On page 109, in section 8.2.4.2 of the Application, FEI outlines its industrial customer consultation to date. FEI states that the impacts upon industrial customers include minor traffic delays on construction routes and the potential for restricted access to peak demand gas use.

In response to BCUC IR 31.1, FEI states:

> The notification letters sent to industrial customers did not provide specific information regarding potential impacts. Instead, the letters indicated the potential for impacts. FEI received written responses from some industrial customers in regards to the letters and these written responses are included in the Application. FEI also conducted one-on-one discussions with industrial customers that are served directly from the impacted transmission laterals. The discussions focussed on explaining the proposed work, the possible options and the preferred solution for the transmission lateral from which that customer is served. FEI discussed the proposed work and the potential impacts at a high level. However, FEI believes there should be limited impacts to industrial customers both during and as a result of the work, which was also discussed during the calls. FEI committed to further dialogue and effort to align work during periods of the customers' scheduled maintenance where possible. Customer feedback was supportive and customers had no concerns as the potential work should have minimal impacts to their businesses. The customers requested that FEI remain in communication with respect to schedules of the proposed work and any potential impacts to their daily operations.

In its response to BCUC 31.2, FEI states:

> FEI has not received a response from all industrial customers that received the notification letter. However, FEI has spoken directly with all industrial customers that are served directly from the impacted transmission laterals, as discussed in BCUC IR 1.31.1.

53.1 Please confirm whether FEI was aware of the potential high-level impacts upon industrial customers at the time of sending the notification letters.

Response:

At the time of sending the notification letters, FEI was aware that the potential impacts to industrial customers were limited, such as the potential requirement to work with the industrial

customers to manage natural gas usage during construction. However, FEI did not yet have specific information such as the specific timing of potential work that might impact industrial customers.

FEI's consultation with industrial customers included two streams of communications depending on whether: (1) they are a landowner along a transmission lateral with existing FEI ROW, or (2) they are a landowner along a transmission lateral with existing FEI ROW and have an existing facility that consumes a significant amount of natural gas directly off a transmission lateral. The first group only received the notification letters, while the second group received both notification letters and received direct one-on-one discussions as they could be more impacted as a result of the work.

As stated in FEI's response to BCUC IR 1.31.1, the impacts of the IGU Project will be limited for industrial customers both during and as a result of the work. Per Appendix I of the Application, one of the criteria in the Alternative Evaluation for each lateral was System Capacity & Customer Impacts, which helped determine the optimal alternative for each transmission lateral to industrial customers. FEI is committed to ongoing communications with its customers, and FEI will work to align Project activities during periods of the customers' scheduled maintenance where possible.

Upon approval of the Application, FEI will send notification letters to all industrial customers, including to those customers that have not responded to FEI's initial notification letter or participated in one-on-one meetings, and will then adhere to the BC Oil & Gas Commission (OGC) consultation and notification requirements. The timing of the OGC-required notifications will be driven by the planning, design and annual construction schedule of the Project, as this will drive when permits will need to be in place to begin work.

53.1.1 If confirmed, please discuss why FEI did not decide to include this information in the letters.

Response:

Please refer to the response to BCUC IR 2.53.1.

53.2 Please identify where in the Application the written responses received from industrial customers are contained.

Response:

FEI inadvertently did not include the email responses in the Application as originally noted in the response to BCUC IR 1.31.1. FEI provides the email responses from industrial customers as Attachment 53.2.

53.3 Please discuss if and when FEI plans to follow up with industrial customers that have not responded to FEI's initial notification letter or participated in one-on-one meetings.

Response:

Please refer to response to BCUC IR 2.53.1.

53.3.1 Please discuss whether FEI considers that this approach will allow FEI to identify any potential concerns or issues from such customers.

Response:

FEI considers this approach sufficient to date. As stated in the response to BCUC IR 1.31.1, initial customer feedback was supportive and customers had no concerns, as the potential work should have minimal impacts to their businesses. FEI will continue to consult with the industrial customers that are served directly from the transmission laterals, and in particular, discuss the potential impact of gas supply restrictions during construction.

54.0 Reference: CONSULTATION

Exhibit B-2, BCUC IR 27.1, 32.1

High Impact Potential Laterals

In response to BCUC IR 27.1, FEI describes the consultation strategy for laterals with high impact potential, which includes the addition of an opportunity for community information sessions. FEI states, "At this time, only two local governments have requested public information sessions."

In addition, FEI states:

> For all laterals (including lower impact laterals), FEI will continue to communicate directly with impacted stakeholders, and will comply with all BC OGC permitting requirements, where applicable, which includes additional notifications specific to each lateral to key stakeholders prior to construction.

54.1 Please discuss whether to date, all local governments that are located near laterals with high impact potential have been explicitly offered the opportunity for community information sessions by FEI.

Response:

Local governments in some areas have expressed interest in discussing opportunities for public engagement once more detailed information is available (i.e., specific impacts have been identified) and would prefer this engagement to take place closer to construction. On this basis, FEI has not offered the opportunity for community information sessions for all high impact laterals to date.

54.1.1 If not, please explain and provide details of when FEI will offer the opportunity for community information sessions.

Response:

FEI will offer the opportunity for community information sessions when more detailed project information is available closer to the time of construction. Please refer to the response to BCUC IR 2.54.1.

In its response to BCUC IR 32.2, FEI provides an updated version of Table 8-2 that is contained in the Application. In its response to BCUC IR 32.1, FEI states:

> Some communities were not listed in Table 8-2 because responses were not received from those communities.
>
> …
>
> Tier One communities not listed in the updated Table 8-2 include Spallumcheen, Armstrong, Enderby, Salmon Arm as well as Columbia Shuswap Regional District. These communities are in close proximity to SAL LOP 168. They are not noted in Table 8-2 because FEI has not received a response from these communities. FEI considers the SAL LOP 168 to be classified as higher impact due to the number of potentially affected land owners, environmental factors including the route falling within critical habitat for the Great Basin Spadefoot, some species at risk occurrences, some locations with moderate to high archaeological potential and several sites are located in the Agricultural Land Reserve. While FEI has not received a response from the communities noted above, FEI intends to continue to engage closely with these municipal and regional governments and will address risk should they arise.

54.2 For the potential impacts identified above for SAL LOP 168, please discuss if FEI considers that these impacts may cause concerns or issues with the nearby communities.

Response:

FEI anticipates that some of the potential impacts identified for SAL LOP 168 may cause concern for nearby communities. FEI will work to incorporate local concerns into construction planning and will communicate how FEI will work to minimize construction impacts and to restore impacted areas. This will be accomplished through open, timely, transparent communication and engagement with community leaders, landowners, and those impacted by the Project.

54.2.1 Please explain whether any concerns or issues raised by these communities at a later date would likely be more challenging for FEI to address, or present any risks to the project timeline and budget.

Response:

FEI does not anticipate any significant concerns or issues will be raised by these communities at a later date that might present a risk to the project timeline and budget. FEI completed a risk assessment with internal subject matter experts to identify the likelihood and impacts for each identified risk for each lateral. The analysis included a variety of risk factors such as environmental, Indigenous considerations, public impacts, customer relationship history, access challenges, and types of land involved. These factors were all taken into account when FEI developed the Communications and Consultation strategy and corresponding Consultation budget. Should the risks materialize, the Project contingency is expected to be sufficient to mitigate the risks.

54.3 Please discuss if there are any other "Tier One communities" besides Spallumcheen, Armstrong, Enderby, Salmon Arm and Columbia Shuswap Regional District that are not included in the updated Table 8-2.

Response:

FEI confirms that all other "Tier One communities" were included in the updated Table 8-2 provided in the response to BCUC IR 1.32.2.

54.3.1 For any such communities, please explain the factors that caused FEI to classify the applicable lateral as "high impact potential."

Response:

Please refer to the response to BCUC IR 2.54.3.

54.3.1.1 Please discuss whether FEI considers that such impacts may cause concerns or issues in these communities.

Response:

Please refer to the response to BCUC IR 2.54.3.

54.3.1.2 Please discuss how FEI intends to understand whether there are any concerns or issues from these communities at a sufficiently early stage.

Response:

Please refer to the response to BCUC IR 2.54.3.

55.0 Reference: CONSULTATION

Exhibit B-2, BCUC IR 32.2; BCUC CPCN Guidelines,[7] p. 6

Municipal and Regional Government Consultation - General

In its response to BCUC IR 32.2, FEI provides an updated version of Table 8-2 that is contained in the Application. Under the "Actions since CPCN Application Filing" column, FEI notes that a letter was mailed on January 22, 2019 notifying that the CPCN application has been submitted to the BCUC.

On page 6 of the BCUC CPCN Guidelines, under Public Consultation, section (i) states:

> Overview of the community, social and environmental setting in which the project and its feasible alternatives will be constructed and operated, and of the public who may be directly impacted by the project and its feasible alternatives.

55.1 Please provide a copy of the letter mailed to local governments on January 22, 2019, notifying that the CPCN application has been submitted to the BCUC.

Response:

Please refer to Attachment 55.1 for a copy of the letter mailed to local governments on January 22, 2019.

55.2 Please explain whether FEI, in its consultation activities documented in the updated Table 8-2, provided information regarding feasible alternatives, other than FEI's preferred alternative.

Response:

During FEI's consultation activities, FEI provided stakeholders with an overview of the Project as a whole, which included information about each of the feasible alternatives for the 29 Transmission Laterals. Additional specific information about the preferred alternative in their respective area was provided.

[7] BCUC, 2015 Certificate of Public Convenience and Necessity Application Guidelines (February 2015), retrieved from https://www.bcuc.com/Documents/Guidelines/2015/DOC_25326_G-20-15_BCUC-2015-CPCN-Guidelines.pdf

55.2.1 Please discuss if any stakeholders expressed interest or requested information regarding other feasible alternatives.

Response:

During FEI's consultation activities, no stakeholder expressed interest or requested information regarding other feasible alternatives.

56.0 Reference: CONSULTATION

Exhibit B-2, BCUC IR 32.2

Municipal and Regional Government Consultation - Fernie

In its response to BCUC IR 32.2, FEI provides an updated version of Table 8-2 that is contained in the Application. For the meeting with representatives from Fernie, FEI identifies the following stakeholder interests:

> Attendees requested detailed maps of pipeline routes, inquired about rate impacts, and local procurement opportunities.

FEI notes the following "Next Steps" with respect to the meeting with Fernie:

> A follow-up meeting will be scheduled to address stakeholder interests as Project information becomes available. No date set at this time.

56.1 Please explain what is meant by "Project information" in this instance.

Response:

In this instance, Project information meant more detailed information on the construction locations and methods for each lateral as well as procurement opportunities. Since the meeting with the representatives from Fernie referred to in the preamble to the information request, FEI has provided more detailed Project information to the local government representatives for the Cranbrook and Sparwood areas, as well as the District of Sparwood.

56.1.1 Please discuss if the level of detail contained in the Application is sufficiently developed to address the stakeholder's interests identified by Fernie.

Response:

Between the information contained in the Application, and the more detailed construction plans that have since been developed, there is sufficient information to address the stakeholders' interests. This specific information has already been shared with many of the identified stakeholders on a lateral-specific basis.

56.1.2 Please explain why a follow-up meeting has not been set up at this time.

Response:

At the time of Application, no meetings were set up as FEI had just completed detailed mapping and construction plans. Since submission of its Application, FEI has set up meetings and discussed the Project with stakeholders from the Fernie meetings, including elected officials and staff from the Regional District of East Kootenay, the Regional District of Central Kootenay, the District of Sparwood and the City of Cranbrook.

57.0 Reference: CONSULTATION

Exhibit B-2, BCUC IR 32.2

Municipal and Regional Government Consultation - Sparwood

In its response to BCUC IR 32.2, FEI provides an updated version of Table 8-2 that is contained in the Application. For the meeting with the District of Sparwood, FEI notes the following stakeholder interests:

> The District requested Archeological and Environmental reports that were completed in the District. The District has requested shape files of the Project for their respective region.

FEI notes the following "Next Steps" with respect to the meeting with District of Sparwood:

> FEI provided maps of the Project and will send shape files of the Project a year before the construction date. FEI will also follow up with the environmental and archeological reports once they are complete.

57.1 Please confirm if the "Archeological and Environmental reports" referenced above are the same as the Archeological Overview Assessment and Environmental Overview Assessment, as contained in Appendix P and Appendix O of the Application respectively.

Response:

Confirmed. The "Archaeological and Environmental reports" noted in Table 8-2 as part of the response to BCUC IR 1.32.2, are in reference to the Archaeological Overview Assessment and Environmental Overview Assessments completed by FEI's consultants and contained in Appendix P and Appendix O of the Application respectively.

57.1.1 If confirmed, please discuss if FEI has followed up with the District of Sparwood to provide this information.

Response:

Confirmed. FEI has provided this information to the District of Sparwood.

57.1.1.1 If FEI has not followed up, please explain how it intends to understand any potential issues or concerns that may be raised by the District of Sparwood in a timely manner.

Response:

Please refer to the response to BCUC IR 2.57.1.1.

58.0 Reference: CONSULTATION

Exhibit B-2, BCUC IR

Municipal and Regional Government Consultation - Kamloops

In its response to BCUC IR 32.4.1, FEI states:

> In FEI's early discussions with the City of Kamloops, the City recognized the need for the gas line upgrade and that FEI has rights and obligations according to the existing ROW agreement. However, the City identified issues with the ROW widening request from 6m to 18m as per current FEI standards. The City has indicated that the widening of the ROW is subject to the approval of the City Council and the request for the 18m width could be denied due to public concerns. FEI will continue negotiating with the City for the ROW widening, temporary workspace, and access routes planning in more detail. FEI will submit additional information for review and approval by the City of Kamloops at the detailed engineering design phase.

58.1 Please explain the potential impact upon the IGU Project's cost and timelines if the City of Kamloops were to deny FEI's request to widen the right of way.

Response:

FEI will seek to negotiate a mutually acceptable agreement and resolution with the City of Kamloops, consistent with FEI standard practice with respect to the acquisition of land rights at an appropriate compensation level. Currently, FEI has an existing right of way in the park and FEI's use of the right of way area has been compatible with the City's use of the land as a park. FEI believes that this shared use can continue with an expanded right of way area.

While FEI's objective is to reach mutually acceptable agreements with landowners, including the City of Kamloops, should an agreement not be reached, and if the IGU Project construction could be delayed, FEI could take the steps to expropriate the required land rights. Please refer to the response to BCUC IR 1.28.2 for the potential impact of expropriation on cost and schedule of the IGU Project.

58.1.1 Please discuss whether FEI considers that community input session(s) would mitigate any public concerns associated with the widening of the right of way.

Response:

FEI believes that an informed and engaged public is important to mitigate potential concerns associated with widening of the existing right of way. Community input sessions can often be a productive venue to clarify and address public concerns and FEI intends to schedule these sessions in consultation with the City following approval of the IGU Project.

58.1.2 Please confirm by when FEI will need right-of-way approval from the City of Kamloops in order to avoid any delays to the IGU Project timeline.

Response:

FEI will better understand potential impacts during detailed design of the Project and intends to work with the City of Kamloops to obtain the necessary ROW widening. FEI aims to obtain the right of way approval from the City of Kamloops by June 2020 in order to avoid any delays to the IGU Project timeline.

59.0 Reference: CONSULTATION

Exhibit B-2, BCUC IR 32.2, 32.5.1

Municipal and Regional Government Consultation - Kimberley

In its response to BCUC IR 32.2, FEI provides an updated version of Table 8-2 that is contained in the Application. FEI notes:

> Before the Project begins, FEI will review impacts to the Rail to Trail nature trail and discuss plans to mitigate impacts with the District of Kimberley.

In response to BCUC IR 32.5.1, with respect to the "Rails to Trails" corridor, FEI states:

> If one or more of the lateral excavation sites were in close proximity to the trail, use of the trail may be impacted to ensure the safety of trail users. If this should happen, FEI will implement a safe detour around the construction zone. It may also be necessary to temporarily close a section of the trail should a detour not be possible.

59.1 Please confirm if these potential issues that may affect the trail remaining open have been discussed with the City of Kimberley.

Response:

Confirmed. FEI discussed with the City of Kimberly the potential issues that may affect the trail remaining open.

59.1.1 Please briefly outline the City of Kimberley's response to these issues, as applicable.

Response:

In discussions with the City of Kimberly, the City noted that they had closed the trail in early 2019 for bridge repairs. The City communicated that the public found reasonable alternate routes around the construction zone. The City requested that FEI keep in contact to determine if any closures would be necessary, and if closures were to occur, that FEI work with the North Star Rails to Trails Society to help inform the public.

60.0 Reference: CONSULTATION

Exhibit B-2, BCUC IR 33.1.1, 33.2, 33.3, 33.4, 33.4.1

Consultation with Indigenous Communities

In its response to BCUC IR 33.1.1, FEI states:

> FEI began engagement with Indigenous communities early to provide information about the project and gain understanding of the unique interests of each community and their traditional territory to identify potential issues around archaeological, historical, cultural and environmental areas that may be affected by the IGU Project. A summary of issues presented to Indigenous communities in meetings to date include:
>
> - potential for archaeological sites;
> - stream crossings; and
> - sensitive environmental areas.

In its response to BCUC IR 33.2, FEI states:

> This initial letter included a general overview of the Project, but did not describe details of the specific impacts by site, as Project details were still being developed at the time of notification. However, maps showing the lateral locations within each Indigenous communities' traditional territory were included. FEI will provide updated site specific Project details to impacted communities, as they become available.

In its response to BCUC IR 33.3, FEI states:

> The purpose of FEI's early engagement is to better understand the nature of the interests of the Indigenous communities in the area of each of the 29 Transmission Laterals. FEI's early engagement with Indigenous communities is not defined by high or low potential impact; instead, it seeks to gather feedback from the community knowledge holders on the nature of their interests.

In its response to BCUC IR 33.4, FEI provides a table that summarizes the Indigenous communities that did not respond to FEI's notification letter. In its response to BCUC IR 33.4.1, FEI states:

> While FEI has not received responses from all Indigenous communities, it will strive to maintain engagement and dialogue with communities during the application phase as per its Statement of Indigenous Principles. Should FEI

receive any concerns from Indigenous communities during this phase, it will work to mitigate those concerns in a respectful manner.

60.1 Please discuss whether FEI believes that, for the purposes of its early engagement, sending a notification letter without site specific details is sufficient to achieve a better understanding of the interests of the Indigenous communities in the area of each of the 29 Transmission Laterals.

Response:

FEI sent a notification letter with a map, specific to each lateral, to all Indigenous communities in May 2018. FEI believes that sending the letter without site specific details is sufficient to achieve a better understanding of the interests of the Indigenous communities in the area of the 29 Transmission Laterals, considering this letter with maps was the first part of a multi-stage, multi-year Indigenous engagement plan by lateral that also relies on the BC OGC Indigenous Engagement process.

The BCUC has previously acknowledged in the decision associated with Order C-11-15 the adequacy of this process and the responsibility for reciprocity from First Nations:

> The Panel finds that First Nations engagement efforts to date are acceptable. FEI has identified First Nations who assert rights in the project area, notified them of the projects and has been responsive to those First Nations who engaged with it. The Panel accepts FEI's position that to respect the First Nations administrative capacity, it provided updates to those First Nations who had engaged. The Panel is aware that there is a reciprocal responsibility on First Nations to engage with proponents.
>
> Moreover, FEI has outlined its plans for further engagement in conjunction with the OGC permit application process.
>
> The Panel notes that the OGC is the Crown agency responsible for First Nations consultation and that consultation is ongoing. FEI is only responsible for conducting preliminary discussions with identified First Nations and providing documentation for the OGC review process. The adequacy of First Nations consultation will be addressed by the OGC.

In order to receive its permit(s) from the BC OGC, FEI is tasked with engaging with First Nations but has not been delegated the duty to consult.

The chart below represents FEI's Indigenous engagement framework, including pre-application, for the first five laterals that are set to be the start of the Project and where site-specific details are known. FEI has separated the chart for ease of viewing into three phases:

- Phase 1 – pre-application engagement for the BCUC process;
- Phase 2 – pre-application engagement for the OGC process; and
- Phase 3 – post-application engagement (during construction and beyond permitting).

Each phase covers the areas of general engagement, archaeology, and procurement. FEI has taken into consideration any feedback from the First Nations into its project and procurement plans for these laterals, such as modifying the proposed Archeological and Environmental activities for these laterals. FEI expects to do a similar range of engagement, and inclusion of feedback, for the remaining laterals as site-specific details become known.

The amount of engagement will follow FEI's ranking of laterals, with more engagement occurring for laterals considered high impact. FEI also expects laterals ranked at a higher tier will require a greater proportion of the overall engagement budget. Through its early engagement, FEI does not believe there will be significant additional costs to include First Nation feedback in the areas of high impact potential laterals. While FEI's Application did not contain potential site-specific details, the Application is not meant to be used as the primary engagement tool. As the chart below demonstrates, FEI engages directly with Indigenous communities following a project filing.

As mentioned in the response to BCUC IR 1.33.3, FEI's early engagement was done to better understand the nature of interests from Indigenous communities. FEI's early engagement with Indigenous communities is not defined by whether the community is located in the area of a lateral with high, medium or low potential impact because FEI did not have site-specific details at the time of the notification letter being sent. FEI is being respectful of administrative capacity, and is currently engaging with First Nations where the site-specific details are known.

FEI established three tiers (high, moderate and low) to characterize the potential issues and impacts associated with each lateral. The laterals classified as 'high' are more complex in nature due to a variety of factors, such as potential environmental impacts, potential impacts to the public, potential customer impacts, potential impacts to Indigenous communities and permitting requirements. FEI therefore expects the laterals classified as 'high' to require more consultation effort, supporting communication materials, potential accommodation considerations for Indigenous Communities, etc., and thus to require higher costs compared to the laterals classified as moderate or low.

The Chart below represents an example of FEI's engagement to support the work scheduled to take place in 2020. The laterals below are either high or moderate impact. Yellow shaded boxes represent strategies completed, blue shaded boxes represent engagement activities to be completed that support regulatory approvals, and orange shaded boxes represent additional engagement opportunities to be completed that FEI plans to pursue to further support impacted Indigenous communities.

	Preferred Option	2017	2018	2019	2020	2021	2022	2023	2024
MAC LTL 168 / MAC LOP 168 (Construction Schedule)	**ILI**								
Phase 1: BCUC process									
CPCN Application Notification									
In-Person Meetings									
Community Engagement / Meetings									
Identifying Procurement Opportunities									
Arch/ Traditional Use Survey work Notification									
Environmental Survey Work Notification									
Procurement Participation									
CPCN Approval Notification									
Phase 2: OGC process									
OGC Process Requirements									
In-Person Meetings									
Procurement Opportunities									
Arch/ Traditional Use Survey work Notification									
Environmental Survey Work Notification									
Community Engagement / Meetings									
Procurement Participation									
Phase 3: Post-Permit process									
In-Person Meetings									
Community Engagement / Meetings									
Procurement Opportunities									
Procurement Participation									

	Preferred Option	2017	2018	2019	2020	2021	2022	2023	2024
FRD LTL 219 (Construction Schedule)	**ILI**								
Phase 1: BCUC process									
CPCN Application Notification									
In-Person Meetings									
Community Engagement / Meetings									
Identifying Procurement Opportunities									
Arch/ Traditional Use Survey work Notification									
Environmental Survey Work Notification									
Procurement Participation									
CPCN Approval Notification									
Phase 2: OGC process									
OGC Process Requirements									
In-Person Meetings									
Procurement Opportunities									
Arch/ Traditional Use Survey work Notification									
Environmental Survey Work Notification									
Community Engagement / Meetings									
Procurement Participation									
Phase 3: Post-permit process									
In-Person Meetings									
Community Engagement / Meetings									
Procurement Opportunities									
Procurement Participation									

	Preferred Option	2017	2018	2019	2020	2021	2022	2023	2024
CRK LTL 168 (Construction Schedule)	**ILI**								
Phase 1: BCUC process									
CPCN Application Notification									
In-Person Meetings									
Community Engagement / Meetings									
Identifying Procurement Opportunities									
Arch/ Traditional Use Survey work Notification									
Environmental Survey Work Notification									
Procurement Participation									
CPCN Approval Notification									
Phase 2: OGC process									
OGC Process Requirements									
In-Person Meetings									
Procurement Opportunities									
Arch/ Traditional Use Survey work Notification									
Environmental Survey Work Notification									
Community Engagement / Meetings									
Procurement Participation									
Phase 3: Post-permit process									
In-Person Meetings									
Community Engagement / Meetings									
Procurement Opportunities									
Procurement Participation									

	Preferred Option	2017	2018	2019	2020	2021	2022	2023	2024
CRK LTL 219 (Construction Schedule)	**ILI**								
Phase 1: BCUC process									
CPCN Application Notification									
In-Person Meetings									
Community Engagement / Meetings									
Identifying Procurement Opportunities									
Arch/ Traditional Use Survey work Notification									
Environmental Survey Work Notification									
Procurement Participation									
CPCN Approval Notification									
Phase 2: OGC process									
OGC Process Requirements									
In-Person Meetings									
Procurement Opportunities									
Arch/ Traditional Use Survey work Notification									
Environmental Survey Work Notification									
Community Engagement / Meetings									
Procurement Participation									
Phase 3: Post-permit process									
In-Person Meetings									
Community Engagement / Meetings									
Procurement Opportunities									
Procurement Participation									

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2

60.1.1 Please provide further details of how and when FEI intends to gain a better understanding of interests, or confirmation that there are no potential concerns related to the IGU Project, from the Indigenous communities that have not yet responded to FEI's notification letter.

Response:

Please refer to the response to BCUC IR 2.60.1.

60.1.1.1 For Indigenous communities that did not respond to FEI's notification letter, please explain whether any concerns or issues raised by these communities at a later date would be more challenging for FEI to address, or present any risks to the project timeline and budget.

Response:

Please refer to the response to BCUC IR 2.60.1.

60.2 Please discuss the extent to which FEI considers that the Application contains information regarding the potential site specific impacts of the IGU Project which may be useful to Indigenous communities.

Response:

Please refer to the response to BCUC IR 2.60.1.

60.2.1 Please confirm and explain whether FEI has shared an update with Indigenous communities of potential site specific IGU Project impacts since the filing of the Application.

Response:

Please refer to the response to BCUC IR 2.60.1.

60.2.1.1 If not confirmed, please explain at what stage of the IGU Project's development FEI intends to share an update of potential site specific IGU Project impacts with Indigenous communities.

Response:

Please refer to the response to BCUC IR 2.60.1.

60.3 Please explain why the extent of FEI's early engagement with Indigenous communities is not defined by whether the community is located in the area of a lateral with high, medium or low potential impact.

Response:

Please refer to the response to BCUC IR 2.60.1.

60.4 Please discuss if FEI's later planned consultation activities will involve a greater degree of engagement with Indigenous communities in areas of high impact potential.

Response:

Please refer to the response to BCUC IR 2.60.1.

60.4.1 Please explain if FEI has estimated a higher budget for future consultation activities with Indigenous communities in the area of high

impact potential laterals, compared to that of lower impact potential laterals.

Response:

Please refer to the response to BCUC IR 2.60.1.

60.4.2 Please provide a summary of the additional activities and costs that would have been (or will need to be) required to ensure feedback from all Indigenous communities in the area of high impact potential laterals prior to the BCUC's decision on the Application.

Response:

Please refer to the response to BCUC IR 2.60.1.

60.5 Please discuss whether FEI has modified, or intends to modify any aspects of its planning for the IGU Project based upon feedback received from its consultation with Indigenous communities.

Response:

Yes, as discussed in FEI's response to BCUC IR 2.60.1, FEI has taken into consideration feedback from its engagement with Indigenous communities into its project and procurement plans and expects to continue to do so as engagement continues and site-specific details become known.

61.0 Reference: CONSULTATION

Exhibit B-1, p. 127; Appendix R-3; Appendix R-4;

Exhibit B-2, BCUC IR 33.1

Consultation with Indigenous Communities - Follow-up Activities

Table 8-4 on page 127 of the Application provides a summary of FEI's consultation with Indigenous communities. In its response to BCUC IR 33.1, FEI provides an updated version of Table 8-4 that documents consultation actions undertaken with Indigenous communities since the filing of the Application. Under the "Actions since CPCN Application Filing" column, FEI notes that a letter was mailed on January 21, 2019, notifying that the CPCN application has been submitted to the BCUC.

61.1 Please provide a copy of the letter mailed to Indigenous communities on January 21, 2019 notifying that the CPCN application has been submitted to the BCUC.

Response:

Please refer to Attachment 61.1 for a copy of the letter mailed to Indigenous communities on January 21, 2019 notifying that the CPCN application has been submitted to the BCUC.

61.1.1 Please confirm that the letter was also mailed to those Indigenous communities that did not respond to FEI's initial notification letter.

Response:

Confirmed. FEI also mailed the letter to those Indigenous communities that did not respond to FEI's initial notification letter.

61.2 Please explain whether in its discussions with Indigenous communities, FEI provided information regarding feasible alternatives, other than FEI's preferred alternative.

Response:

As stated in the response to BCUC IR 2.55.2, during FEI's discussions with Indigenous communities and stakeholders, FEI provided an overview of the Project as a whole, which included information about each of the three feasible alternatives for the 29 Transmission Laterals. Additional specific information about the preferred alternative in their respective area was provided.

61.2.1 Please provide details if any Indigenous communities expressed interest or requested information regarding other feasible alternatives.

Response:

FEI did not receive any expressed interest or request for information regarding other feasible alternatives from Indigenous communities.

In Table 8-4, FEI notes that in a meeting with the Splats'in First Nation's Director, Title & Rights, the Director confirmed they would like to be kept informed about work on SAL LTL and SAL LOP as there is potential for impact to known traditional land use areas and unrecorded archaeological areas.

In Table 8-4, FEI also notes that in a meeting, the Osoyoos Indian Band had requested to see the environmental plan "once complete and review dig locations for culturally sensitive areas, not just archeological sites."

Appendix R-4 of the Application contains correspondence from Esh-kn-am Cultural Resources Management Services, which contains the following request:

> We do ask, that should any previously unrecorded archaeological sites or heritage sites such as camps, human remains or lithics be encountered during the tenure and development of this project, the following measures should be undertaken: a) Modify or stop any land-altering activities in the immediate vicinity of the

previously unidentified site so that it will not be adversely impacted; and b) Promptly inform Esh-kn-am CRMS of the existence and location of the newly discovered site(s) so that an acceptable mitigation strategy or further archaeological investigation may be agreed upon.

61.3 Please confirm and explain that information regarding the EOA and AOA, as included in the Application, have not yet been sent to or discussed with Indigenous communities that have expressed interest in these areas.

Response:

FEI has not yet forwarded the Environmental or Archaeological Overview Assessments to Indigenous communities but will follow through on these requests once Project scope, timelines, site specific impacts, and dig location data is confirmed.

61.3.1 Please discuss the extent to which the EOA and AOA contained in the Application would provide potentially useful information to Indigenous communities, particularly those that have expressed an interest in these areas.

Response:

It is difficult for FEI to determine what information any one Indigenous community would deem useful. The information contained within the EOA and AOA reports provides a preliminary description of the environmental and archaeological sensitivities, respectively, in the Project area. This information may be considered useful to some Indigenous communities, but may already be common knowledge to other Indigenous communities. The usefulness of this report to Indigenous Communities is that it documents these sensitivities in one report for each discipline respectively.

The information contained within the EOA was obtained from publically available data sources (i.e., provincial/municipal websites) and then field verified through preliminary site visits. This means that Indigenous Communities have access to the same environmental overview information as FEI (i.e., websites). Field verification could potentially be considered “new” information they would not have easy access to and therefore potentially considered useful.

The information contained within the AOA was obtained through the Remote Access to Archaeological Data (RAAD) and the Provincial Archaeological Report Library (PARL) systems, and then Preliminary Field Reconnaissance (PFR) was undertaken in areas where more information was required. Both the RAAD and PFR systems are available to Indigenous

governments/lands offices. This means that Indigenous Communities have access to the same archaeological overview information as FEI's archaeological consultant. The PFR results could potentially be considered "new" information they would not have easy access to and therefore potentially considered useful.

61.3.1.1 Please discuss how FEI intends to engage with Indigenous communities on these matters to ensure that interests and concerns can be understood and accommodated as necessary, in a timely manner that does not present risks to the IGU Project's timeline or costs.

Response:

Please refer to the response to BCUC IR 2.60.1.

In Table 8-4, FEI notes that in a meeting with the Westbank First Nation's Intergovernmental Affairs, Rights & Title and Referrals Coordinator, FEI advised that proposed work is for pressure regulating stations and additional land around the existing station will be required. FEI notes in its "next steps":

> FEI to follow up with Westbank First Nation Archaeology to discuss any concerns regarding land requirements.

61.4 Please confirm whether a follow-up with Westbank First Nation Archaeology has occurred.

Response:

Confirmed, FEI had a follow-up discussion with the Westbank First Nation Archaeology department regarding the status of the IGU Project. FEI and the Westbank First Nation Archaeology department agreed that, once the construction impact and station land requirements are confirmed and detailed design is available, a follow-up meeting would be held to review the Project scope and address any concerns that may come up.

61.4.1 If not confirmed, please explain when FEI intends to engage in follow-up discussions.

Response:

Please refer to the response to BCUC IR 2.61.4.

61.5 Please provide a brief description of Westbank First Nation's concerns regarding land requirements and any potential associated issues or risks that FEI may have to accommodate or mitigate.

Response:

Westbank First Nation has not yet communicated any specific concerns to FEI on land requirements but has asked that FEI follow up once detailed design information is available to identify any potential issues or risks. FEI will then work with the Westbank First Nation Archaeological department to develop agreed upon mitigation strategies, if required.

Appendix R-3 contains a response letter from the Ktunaxa Nation Council (KNC) dated November 15, 2018. KNC states:

> In closing, the KNC would like to set up another meeting with FortisBC to discuss our interests and learn more details about the project as it moves forward.

The updated Table 8-4 provided in the response to BCUC IR 33.1 indicates that the last meeting held with the KNC occurred on August, 29, 2018.

61.6 Please confirm and explain whether FEI has conducted a meeting with the KNC following its letter dated November 15, 2018.

Response:

FEI has had numerous meetings with the Ktunaxa Nation Council (KNC) since November 15, 2018 to discuss the Project. The meetings have been directly with Government departments of the KNC to discuss land impacts and cultural awareness, and also with KNC-owned businesses to discuss contracting opportunities.

61.6.1 If not confirmed, please explain how FEI intends to engage with the KNC to ensure that its interests are understood and accommodated as necessary, in a timely manner.

Response:

Please refer to the response to BCUC IR 2.61.6.

In Table 8-4, FEI identifies that Splats'in First Nation, Ktunaxa Nation Council and Neskonlith Indian Band expressed an interest in procurement and employment opportunities associated with the IGU Project. In its response to CEC IR 30.1, FEI states:

> At this time, FEI has not quantified the level of additional local employment; however, FEI will procure local materials and services wherever it is possible and economical to do so.

61.7 Please provide an estimate of when information regarding procurement and employment opportunities will be available and when this information will be provided to Indigenous communities.

Response:

Please refer to the response to BCUC IR 2.60.1.

62.0 Reference: CONSULTATION

Exhibit B-1, p. 122; Exhibit B-2, BCUC IR 33.4.1

BC OGC Consultation

On page 122 of the Application, FEI states:

> Although the duty to consult rests with the Crown, FEI may be delegated responsibility for certain aspects of the process by the Crown, including by the BC OGC. These aspects include engagement with identified Indigenous communities in a thorough, timely, and meaningful way.

In its response to BCUC IR 33.4.1, FEI states:

> The identified Indigenous communities will have a number of additional opportunities to comment on Project-specific impacts. During the BC OGC permitting process that will occur prior to construction, much more detailed Project information will be provided to the Indigenous communities for review and comment including up-to-date shape files, maps and environmental management plans. FEI supports consultation by the BC OGC by responding to technical questions where appropriate and attending meetings if requested.

62.1 Please confirm whether the BC OGC or any other agency of the Crown has delegated any aspects of their consultation duty to FEI, with respect to the IGU Project.

Response:

Neither the BC OGC nor any other agency of the Crown has delegated any aspects of their consultation duty to FEI with respect to the IGU Project. Please refer to the response to BCUC IR 2.60.1.

62.2 Please distinguish the objectives of FEI's early consultation efforts and the requirements of the BC OGC permitting process, with respect to FEI's engagement with Indigenous communities.

Response:

Please refer to the response to BCUC IR 2.60.1.

Attachment 35.3

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 592-7701
fortisbc.com

August 11, 2017

Bushra Waheed
Integrity Engineer
BC Oil and Gas Commission
#203 - 1500 Hardy Street
Kelowna B.C., V1Y 8H2

RE: Update on Risk Assessment

Dear Bushra,

Per our discussion at your offices on August 3, 2017, FortisBC is providing an update on its continuous improvement activities regarding Risk Assessment in the context of its Integrity Management Program.

The following activities have either been completed or are currently underway:

- October 27, 2016: FortisBC retained JANA Corporation to facilitate a workshop to develop a vision statement for risk management of transmission pipelines, along with goals and key drivers. The current vision, which could be subject to change, is that "*By 2020, FortisBC will be able to demonstrate that its Transmission Pipeline Integrity is being managed through a quantitative risk-based approach. Asset condition and decisions will be documented such that Risk Management is defensible.*"
- March 22-24, 2017: FortisBC retained JANA Corporation to facilitate a workshop primarily focused on developing a proposed methodology for risk analysis, including high-level process definition and data requirements.
- May – September, 2017 (in-progress): FortisBC retained JANA Corporation to perform a review of FortisBC's asset data to meet its goals related to risk management, including development of resource estimates to ensure appropriate data availability and data quality for implementation and sustainment.

The above work will support development of a business case and organizational implementation plan. Strategies for executing and financing this initiative will require evaluation by FortisBC and will be subject to some level of review by the BC Utilities Commission through the regulatory process.

Sincerely,

Bryan Balmer
Manager, System Integrity Programs
FortisBC Energy Inc.

cc: Janet Green, Manager, Gas System Assets
Paul Chernikhowsky, Director, Engineering Services

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December 8, 2017

Submitted via e-mail to: Gouri.Bhuyan@BCOGC.ca and Linda.King@BCOGC.ca

Gouri Bhuyan, Ph.D., P.Eng., FASME, FCAE
Supervisor, Integrity Management & Dam Safety
BC Oil & Gas Commission
#203 - 1500 Hardy Street
Kelowna B.C., V1Y 8H2

RE: Corrective Action Plan (CAP) Review by BCOGC

Dear Gouri,

In response to your letter dated November 16, 2017, FortisBC Energy Inc. (FEI) is acknowledging the stated requirement from the BC Oil & Gas Commission (BC OGC) for FEI to develop and implement a segment-by-segment risk assessment process to determine the risk associated with its pipeline assets in BC, and to move forward with suitable actions in a timely manner to meet the BC OGC's requirements. FEI further acknowledges that the BC OGC requires quarterly updates in the progress toward completing this corrective action until completed and an estimated completion date.

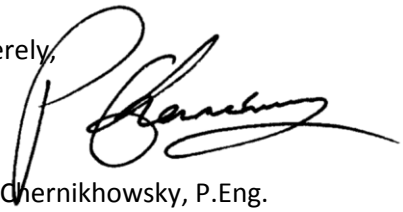
Building on the update provided in an August 11, 2017 letter to the BC OGC, the following activities have either been completed or are currently underway by FEI as part of its continual improvement activities regarding Risk Assessment:

- October 27, 2016: FEI retained JANA Corporation to facilitate a visioning workshop to develop goals and key drivers for risk management of transmission pipelines.
- March 22-24, 2017: FEI retained JANA Corporation to facilitate a workshop primarily focused on developing a proposed methodology for risk analysis, including high-level process definition and data requirements.
- May – October, 2017: FEI retained JANA Corporation to perform a review of FEI's asset data to meet its goals related to risk management, including development of resource estimates to ensure appropriate data availability and data quality for implementation and sustainment.
- November, 2017 – current: FEI retained JANA Corporation to advance higher priority and/or quick-win data-related initiatives, including definition of source records and quality measures, linear referencing system requirements, and data management requirements and procedures.

The above work is supporting development of a business case and organizational implementation plan. Strategies for executing and financing this initiative will require evaluation by FEI and will be subject to some level of review by the BC Utilities Commission through revenue requirements regulatory processes.

To enable sufficient time for internal and/or external review of a business case and organizational implementation plan, FEI will submit its first quarterly update to the BC OGC in April 2018 (for the preceding quarter).

Sincerely,



Paul Chernikhowsky, P.Eng.
Director, Engineering Services
FortisBC Energy Inc.

cc: Janet Green, Manager, Gas System Assets
Bryan Balmer, Manager, System Integrity Programs

FORTIS BC™

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
fortisbc.com

April 25, 2018

Submitted via e-mail to: Gouri.Bhuyan@BCOGC.ca and Linda.King@BCOGC.ca

Gouri Bhuyan, Ph.D., P.Eng., FASME, FCAE
Supervisor, Integrity Management & Dam Safety
BC Oil & Gas Commission
#203 - 1500 Hardy Street
Kelowna B.C., V1Y 8H2

RE: Quarterly update to BC OGC on risk assessment process implementation

Dear Gouri,

In response to a commitment to the BC Oil & Gas Commission (BC OGC) in a letter dated December 8, 2017, FortisBC Energy Inc. (FEI) is providing a quarterly update regarding its progress toward development and implementation of a segment-by-segment risk assessment process to determine the risk associated with its pipeline assets in BC.

Further to the update provided in the December 8, 2017 letter, the following activities have been undertaken by FEI during Q1 2018:

- December 2017: FEI's Executive Leadership Team provided directional support to proceed with development and implementation of a quantitative risk assessment process to determine the risk associated with pipeline assets in BC.
- January 2018 – current: FEI developed a high-level timeline and cost estimate for implementing its quantitative risk assessment process, and is moving toward receiving resource-commitment approval.
- March 2018 – Q2 2018: FEI retained JANA Corporation to develop a detailed execution plan to deliver data availability and data quality, including system(s) and procedures, for implementation and sustainment of a quantitative risk assessment process. A key deliverable of this work is an improved cost estimate for data enhancements.

FEI will submit its next update in July 2018 for the preceding quarter.

Sincerely,

Paul Chernikhowsky, P.Eng.
Director, Engineering Services
FortisBC Energy Inc.

cc: Janet Green, Manager, Gas System Assets
Bryan Balmer, Manager, System Integrity Programs

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
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July 12, 2018

Submitted via e-mail to: Gouri.Bhuyan@BCOGC.ca and Linda.King@BCOGC.ca

Gouri Bhuyan, Ph.D., P.Eng., FASME, FCAE
Supervisor, Integrity Management & Dam Safety
BC Oil & Gas Commission
#203 - 1500 Hardy Street
Kelowna B.C., V1Y 8H2

RE: Quarterly update to BC OGC on risk assessment process implementation – for 2018 Q2

Dear Gouri,

In response to a commitment to the BC Oil & Gas Commission (BC OGC) in a letter dated December 8, 2017, FortisBC Energy Inc. (FEI) is providing a quarterly update regarding its progress toward development and implementation of a segment-by-segment risk assessment process to determine the risk associated with its pipeline assets in BC.

Further to the update provided in Q1 2018, the following activities have been undertaken by FEI during Q2 2018:

- March 2018 –June 2018: FEI retained JANA Corporation to develop a detailed execution plan to deliver data availability and data quality, including system(s) and procedures, for implementation and sustainment of a quantitative risk assessment process. This work was completed.
- May 2018 – June 2018: FEI received and has been reviewing proposals for the following work:
    - Data-related improvements deemed necessary to enable a quantitative risk assessment process; and
    - A quantitative risk assessment of FEI's transmission pipeline assets.

FEI will submit its next update in October 2018 for the preceding quarter.

Sincerely,

Paul Chernikhowsky, P.Eng.
Director, Engineering Services
FortisBC Energy Inc.

cc: Janet Green, Manager, Gas System Assets
Bryan Balmer, Manager, System Integrity Programs

FORTIS BC™

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
fortisbc.com

November 19, 2018

Submitted via e-mail to: Gouri.Bhuyan@BCOGC.ca and Linda.King@BCOGC.ca

Gouri Bhuyan, Ph.D., P.Eng., FASME, FCAE
Supervisor, Integrity Management & Dam Safety
BC Oil & Gas Commission
#203 - 1500 Hardy Street
Kelowna B.C., V1Y 8H2

RE: Quarterly update to BC OGC on risk assessment process implementation – for 2018 Q3

Dear Gouri,

In response to a commitment to the BC Oil & Gas Commission (BC OGC) in a letter dated December 8, 2017, FortisBC Energy Inc. (FEI) is providing a quarterly update regarding its progress toward development and implementation of a segment-by-segment risk assessment process to determine the risk associated with its pipeline assets in BC.

Further to the update provided in Q2 2018, the following activities have been undertaken by FEI during Q3 2018:

- July 2018: FEI awarded contracts for the following work to JANA Corporation:
  - Data-related improvements deemed necessary to enable a quantitative risk assessment process; and
  - A quantitative risk assessment of FEI's transmission pipeline assets.
- July 2018 – present: work on both of the above-mentioned contracts is progressing. FEI's first iteration of a segment-by-segment risk assessment process will be demonstrated through this work.

FEI will submit its next update in Q1 2019 for the preceding quarter.

Sincerely,

Paul Chernikhowsky, P.Eng.
Director, Integrity Management and Damage Prevention
FortisBC Energy Inc.

cc: Janet Green, Manager, Gas System Assets
Bryan Balmer, Manager, System Integrity Programs

FORTIS BC

16705 Fraser Highway
Surrey, B.C. V4N 0E8
Tel: (604) 576-7000
fortisbc.com

March 28, 2019

Submitted via e-mail to: Gouri.Bhuyan@BCOGC.ca and Linda.King@BCOGC.ca

Gouri Bhuyan, Ph.D., P.Eng., FASME, FCAE
Supervisor, Integrity Management & Dam Safety
BC Oil & Gas Commission
#203 - 1500 Hardy Street
Kelowna B.C., V1Y 8H2

RE: Quarterly update to BC OGC on risk assessment process implementation – for 2018 Q4

Dear Gouri,

In response to a commitment to the BC Oil & Gas Commission (BC OGC) in a letter dated December 8, 2017, FortisBC Energy Inc. (FEI) is providing a quarterly update regarding its progress toward development and implementation of a segment-by-segment risk assessment process to determine the risk associated with its pipeline assets in BC.

Further to the update provided for Q3 2018, the following activities have been undertaken by FEI during Q4 2018:

- October 2018 – present: work on both contracts awarded to JANA Corporation (as listed in FEI's Q3 2018 update) is progressing. FEI's first iteration of a segment-by-segment risk assessment process will be demonstrated through this work. FEI has been, and will continue to work closely with JANA through completion of these contracts.

FEI's first iteration of a segment-by-segment risk assessment will be a quantitative risk assessment. This assessment methodology is data-intensive and analysis-intensive.

FEI will submit its next update in Q2 2019 for the preceding quarter.

Sincerely,

Bryan Balmer

Digitally signed by Bryan Balmer
DN: cn=Bryan Balmer, o=FortisBC Energy Inc., ou=System Integrity Programs, email=bryan.balmer@fortisbc.com, c=CA
Date: 2019.03.28 11:49:13 -07'00'

for

Paul Chernikhowsky, P.Eng.
Director, Integrity Management and Damage Prevention
FortisBC Energy Inc.

cc: Janet Green, Manager, Gas System Assets
Bryan Balmer, Manager, System Integrity Programs

Attachment 36.1

Ken Oliphant, Ph.D., P.Eng.

Executive Vice President & Chief Technology Officer
JANA Corporation

PROFILE

Dr. Ken Oliphant is Executive Vice President and Chief Technology Officer of JANA. "Dr. Ken" received his undergraduate degree in Chemical Engineering from the University of Toronto and his Ph.D. in Chemical Engineering from Queen's University. Prior to co-founding JANA, he spent his career at Rohm & Haas and AT Plastics. Ken's specific focus is in piping system risk assessment and management, performance validation and lifetime forecasting. Under Ken's technical leadership, JANA's Expert Team partners with gas pipeline operators to develop Integrity Management strategies based on JANA's state-of-the-art mechanistic-probabilistic risk modeling, allowing pipeline operators to make fully-informed decisions.

EXPERIENCE

JANA Corporation
1999 > Current

Executive Vice President & Chief Technology Officer

JANA was founded in 1999 as a testing laboratory for plastic piping systems. Over the next 15 years, JANA grew to be the largest hydrostatic testing lab in North America and the largest oxidative resistance testing lab in the world. In 2014, JANA sold its laboratory assets to NSF International and turned its entire focus to JANA's state-of-the-art risk models for gas pipeline systems. Emerging from JANA's 300,000,000 hours of plastic pipe testing experience, advanced reliability engineering tools from the aerospace and nuclear industries, and the performance modelling tools developed at JANA over the last two decades, JANA's risk models are used by North American gas pipeline operators to create Risk Assessments customized to an operator's specific piping network. JANA is proud to have made an impact on the integrity of natural gas pipelines serving over 51 million homes in the US and Canada.

Responsibilities:

- Works closely with Executive Team to provide the vision needed to support current and future business needs by building an innovative technological roadmap by setting short and long-term technical goals while ensuring alignment with company's strategy
- Leads all aspects of JANA's technology development
- Directs the company's technology strategic direction, development and future growth for platforms, partnerships and external relationships
- Provides leadership to a rapidly expanding Risk Model Development team in a fashion that supports JANA's culture, mission and values
- Actively researches leading edge technologies, conducts case studies and makes determinations on the direction of new technologies
- Outlines technical opportunities and risks to deliver technologies and identifies new innovations
- Collaborates with pipeline operators to develop high-level risk strategies to allow optimal integration of risk assessments into corporate decision-making processes

EDUCATION

Queen's University 1994	Ph.D. Engineering Chemistry
University of Toronto 1989	B.A.Sc. Chemical Engineering

INDUSTRY PARTICIPATION

Over his career, Dr. Oliphant has participated in the industry as follows:

Industry Associations

- Professional Engineers of Ontario (PEO)
- Association of Professional Engineers and Geoscientists of Saskatchewan
- Plastic Pipe Institute (PPI)
- Canadian Standards Association (CSA)
- American Gas Association (AGA)
- Canadian Gas Association (CGA)
- ISO TC138 (Plastics pipes, fittings and valves for the transport of fluids)
- ISO TC 251 (Asset Management)

Technical Leadership

- ISO TC138 Co-Chair, Canada
- ISO TC251 Subcommittee
- CSA B137 Distribution Subcommittee
- PPI Hydrostatic Stress Board
- CSA Z662

Regulatory Influence

JANA has supported its clients and their communities in the following regulated jurisdictions:

- Alberta
- California
- Virginia
- British Columbia
- Ontario
- Canadian Federal Code
- US Federal Code

PUBLICATIONS

- "Integrating QRA Outputs into Pipeline Integrity Management Decision-Making", Dr. K. Oliphant, P.Eng. and W. Bryce, P.Eng., JANA Corporation, 2019.
- "Bayesian Modeling for Integrity Management", Dr. K. Oliphant, P.Eng. and A. Zhong, JANA Corporation, American Gas Association 2019 Pipeline Risk Data Workshop, Albuquerque, 2019.
- "Incorporating Low Probability High Consequence Events into Risk Models", Dr. K. Oliphant, P.Eng., W. Bryce, P.Eng. and Dr. Vida Meidanshahi, JANA Corporation, American Gas Association 2019 Pipeline Risk Data Workshop, Albuquerque, 2019.
- "Modeling Risk for Optimal Legacy Cross Bore Inspections", D. Joyal and K. Oliphant, JANA Corporation, American Gas Association, Nashville, 2019.
- "Implementing Probabilistic/Quantitative Absolute Risk Models in Natural Gas Utilities", R. Gardner, Xcel Energy, W. Luff and K. Oliphant, JANA Corporation, American Gas Association, Nashville, 2019.

- "A Risk-Based Approach to Legacy Cross Bore Inspection Optimization", D. Joyal and K. Oliphant, JANA Corporation, Canadian Gas Association, Ottawa, 2019.
- "Risk-Based Inspection Optimization for Valve Inspections", P. Vibien, P.Eng., D. Joyal, Dr. K. Oliphant, P.Eng. and W. Luff, JANA Corporation, 12th International Pipeline Conference, Calgary, September 24-30, 2018.
- "A Framework for Pipeline and Storage Facilities Risk Modeling", Dr. K. Oliphant, P.Eng. and W. Bryce, P.Eng., JANA Corporation, 2018.
- "Integrating QRA Outputs into Pipeline Integrity Management Decision-Making", Dr. K. Oliphant, P.Eng. and W. Bryce, P.Eng., JANA Corporation, 2019.
- "OPEX Savings through Risk-Based Inspection Optimization", W. Luff and K. Oliphant, JANA Corporation, American Gas Association, Washington, DC, 2018.
- "Pipeline Risk Modeling – How Much Data do I Need?", W. Bryce P.Eng., Dr. K. Oliphant, P.Eng., JANA Corporation, American Gas Association, Orlando, 2017.
- "Power Law Analysis Implications of the San Bruno Pipeline Failure", Dr. K. Oliphant, P.Eng., W. Bryce, P.Eng., W. Luff, JANA Corporation, 11th International Pipeline Conference, Calgary, September 26-30, 2016.
- "RCA Framework for Gas Distribution Piping Assets", Dr. K. Oliphant, P.Eng., Sarah Chung, P.Eng., Bonnie Ng, JANA Corporation, American Gas Association, Phoenix, 2016.
- "Non-Destructive Inspection of Polyethylene Fusions and Electrofusions", Dr. Ken Oliphant, P.Eng. and Dalton Crosswell, JANA Corporation, American Gas Association, Phoenix, 2016.
- "Modeling the Consequences of Pipeline Risk", Dr. K. Oliphant, W. Bryce and W. Luff, JANA Corporation, American Gas Association, Phoenix, 2016.
- "A Critical Review of Pipeline Risk Modeling Approaches", William Luff, Dr. Ken Oliphant, Wayne Bryce and James DuQuesnay, JANA Corporation, American Gas Association, Phoenix, 2016.
- "Bowtie Risk Assessment of Electrofusion Fitting Installations", Dr. Ken Oliphant, P.Eng., James DuQuesnay, William Luff, JANA Corporation, American Gas Association, Phoenix, 2016.
- "An Absolute Risk Model Framework for Gas Pipelines", K. Oliphant, Ph.D., P.Eng., W. Luff, M.A.Sc., W. Bryce, P.Eng., JANA Corporation, American Gas Association, Phoenix, 2016.
- "A Risk Based Approach to Leak Survey Optimization", William Luff and Dr. Ken Oliphant, JANA Corporation, American Gas Association, Phoenix, 2016.
- "Structuring an Asset Management System for Compliance with Both API 1173 and ISO 55001 Requirements", Dr. K. Oliphant, P.Eng., JANA Corporation, G. White, PI Confluence, 2015.
- "A Risk Based Approach to Managing Aldyl Piping in Gas Distribution Systems", K. Oliphant, Ph.D., P.Eng., P. Vibien, P.Eng., W. Luff, MSc., P. Angelo, Ph.D., Jana, Aurora, ON Canada, Gene Palermo, Ph.D., Palermo Plastics Pipe Consulting, TN United States, Canadian Gas Association, 2015.
- "Long-Term Performance of Polyethylene Piping Materials in Potable Water Applications", Patrick Vibien, M.Sc., P.Eng., Sarah Chung, M.A.Sc., P.Eng., Sheyla Fong, Ken Oliphant, Ph.D., P.Eng., Jana Laboratories Inc., American Water Works Association, 2015.
- "Qualification Program for Electrofusion Fittings", Dr. P. Angelo, Dr. K.Oliphant and P. Vibien, JANA Corporation, American Gas Association, Grapevine, 2015.
- "Modeling Cross Bore Risk", Dr. K. Oliphant and Dr. P. Angelo, JANA Corporation, American Gas Association, Grapevine, 2015.
- "Managing Risk in Pipeline Installations", P. Vibien, Dr. K. Oliphant, Dr. P. Angelo and W. Luff, JANA Corporation, American Gas Association, Grapevine, 2015.

- "Inspection of Polyethylene Fusions and Electrofusions", Dr. Ken Oliphant, Dr. Peter Angelo and Patrick Vibien, JANA Corporation, Dr. Andy Burns and Dr. Michail Kalloudis, Impact Solutions, American Gas Association, Grapevine, 2015.
- "Bimodal PE's Contribution to the Life Expectancy Extension of Gas Distribution Pipelines", Dr. K.Oliphant, Dr. P. Angelo and P. Vibien, JANA Corporation, Dr. D. Chang and J. Brodil, The Dow Chemical Company, American Gas Association, Grapevine, 2015.
- "Alternate Test Methodology for Assessing PE Compound Performance in Potable Water Applications", Sarah Chung, M.A.Sc., P.Eng., Michael Conrad, Ph.D., Ken Oliphant, Ph.D., P.Eng., Jana Laboratories, 2011.
- "Impact of Potable Water Disinfectants on Polyethylene Pipe", Sarah Chung, M.A.Sc., P.Eng., Michael Conrad, Ph.D., Ken Oliphant, Ph.D., P.Eng., Jana Laboratories, June 2010.
- "Usage and Effects of Chlorine Dioxide on PEX Plumbing and Water Distribution Systems in North America", Sarah Chung, M.A.Sc., P.Eng., Sang Lee, Ken Oliphant, Ph.D., P.Eng., Jana Laboratories, 2010.
- "Service Life Evaluation of Polyethylene (PE) Water Pipes", David Woods, Ken Oliphant, Ph.D., P.Eng., Jana Laboratories, 2009.
- "ASTM F2023: A Decade Later", Sarah Chung, M.A.Sc., P.Eng., Ken Oliphant, Ph.D., P.Eng., Jana Laboratories, 2009.
- "Long-Term Performance of Polyethylene Piping Materials in Potable Water Applications", Patrick Vibien, M.SC., P.Eng., Sarah Chung, M.A.Sc., P.Eng., Sheyla Fong, Ken Oliphant, Ph.D., P.Eng., Jana Laboratories, September 2009.
- "DIMP for Plastic Gas Pipelines", Ken Oliphant, Ph.D., P.Eng., 2009 AGA Operations Conference, Pittsburg, PA.
- "The Mechanisms of Chlorine Dioxide Oxidation of Plastic Piping Systems", Sarah Chung, P.Eng., Tieqi Li, Ph.D., Ken Oliphant, Ph.D., P.Eng., Patrick Vibien, P.Eng., Budapest, 2008.
- "Characterizing Long-Term Performance of Plastic Piping Materials in Potable Water Applications", Sarah Chung, Tieqi Li, Ken Oliphant, Patrick Vibien, Magali Rozental-Evesque, Benjamin Rabaud, Budapest, 2008.
- "A Novel Methodology of Internal Notched Pipe Testing As An Accelerated Test For Plastic Piping Materials In Potable Water Applications", Sarah Chung, Dr. Tieqi Li, Dr. Ken Oliphant, Patrick Vibien, Plastic Pressure Pipes, Budapest, 2008.
- "The Mechanisms of Chlorine Dioxide Oxidation", S. Chung, T. Li, K. Oliphant, P. Vibien, Society of Plastics Engineers Annual Technical Conference (ANTEC), Milwaukee, 2008.
- "Characterizing Long-Term Performance of Plastic Piping Materials in Potable Water Applications", S. Chung, T. Li, K. Oliphant, P. Vibien, Society of Plastics Engineers Annual Technical Conference (ANTEC), Milwaukee, 2008.
- "What's New with Plastic Pipes?", E. Palermo, K. Oliphant, Plastics in Underground Pipes, Houston, 2008.
- "An Examination of Field Failures of Plastic Piping System Components in Potable Water Applications", S. Chung, T. Kosari, T. Li, K. Oliphant, P. Vibien, J. Zhang, Society of Plastics Engineers Annual Technical Conference (ANTEC), Cincinnati, 2007.
- "New Accelerated Slow Crack Growth Resistance Test Methodology for High Performance PE Materials", T. Kosari, K. Oliphant, P. Vibien, E. Lever, Plastic Pressure Pipes, Dusseldorf, 2007.
- "An Examination of the Relative Impact of Common Potable Water Disinfectants (Chlorine, Chloramines and Chlorine Dioxide) on Plastic Piping System Components", S. Chung, K. Oliphant, P. Vibien, J. Zhang, Plastic Pipe XIII, Washington DC, 2006.
- "False Arrest in Small Scale Steady State (S4) Rapid Crack Propagation Testing", T. Kosari, K. Oliphant, P. Vibien, T. Li, L. Moreno, P. Leevers, Plastic Pipe XIII, Washington, DC, 2006.
- "New Test Method to Determine Effect of Recycled Materials on Corrugated HDPE Pipe Performance as Projected by the Rate Process Method", G. Palermo, P. Vibien, K. Oliphant, T. Kosari, Plastic Pipe XIII, Washington DC, 2006.

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- "Environmental Factors in Performance Forecasting of Plastic Piping Materials – Chlorine Resistance Testing", K. Oliphant, S. Chung, J. Couch, J.D. Kim, and P. Vibien, Paper Presented at Plastics Pipe XII (PPXII), Italy, April 2004.
- "Forecasting the Long-Term Strength of Thermoplastic Piping Materials – A Review of the History, Current Status and Proposed Refinements to the Generally Accepted Methodology", K. Oliphant, Jana Laboratories, Aurora, ON, S. Mruk, Consultant, Paper Presented at Plastics Pipe XII (PPXII), Italy, April 2004.
- "Modeling Mechanisms of Brittle Oxidative Degradation to Ensure Plastic Pipe Material Performance", K. Oliphant, S. Chung, J.D. Kim, M. Toro, and P. Vibien, Paper Presented at Society of Plastics Engineers Annual Technical Conference (ANTEC), Chicago, USA, May 2004.
- "Oxidative Resistance of Sulfone Polymers to Chlorinated Potable Water, S. Chung, J. Couch, J.D. Kim, K. Oliphant and P. Vibien, Jana Laboratories Inc., Aurora ON, and J. Huang, M. Ratnam, W. Looney, Solvay Advanced Polymers Inc., Alpharetta, GA, Paper Presented at Society of Plastics Engineers Annual Technical Conference (ANTEC), USA, May 2003.
- "Chlorine Resistance Testing of Cross-linked Polyethylene Piping Materials", Society of Plastics Engineers Annual Technical Conference (ANTEC), San Francisco, USA, 2002.
- "Chlorine Resistance Testing of UV Exposed Pipe", K. Oliphant, S. Chung, J. Couch, and P. Vibien, Jana Laboratories Inc., Aurora, ON, 2002.
- "Environmental Factors in Performance Forecasting of Plastic Piping Materials", K. Oliphant, S. Chung, J. Couch, and P. Vibien, Paper Presented at Plastics Pipe XI (PPXI), Munich, Germany, September 2001.
- "Assessing Material Performance in Chlorinated Potable Water Applications", K. Oliphant, P. Vibien and J. Couch, Jana Laboratories Inc., Aurora, ON, W. Zhou, B. Zhang, and A. Chudnovsky, Fracture Mechanics & Materials Durability Laboratory, CME Department, UIC, Chicago, IL, Paper Presented at Plastics Pipe XI (PPXI), Munich, Germany, September 2001.
- "Melt Grafting of a Basic Monomer onto Polyethylene in a Twin Screw Extruder", K. Oliphant and W.E. Baker, Paper Presented at the 1994 Annual Technical Conference of the Society of Plastics Engineers, San Francisco, May 1-5, 1994.
- "Search for Non-oxidative, Hydrogen Abstracting Initiators Useful for Melt Grafting Processes", H. Xie, M. Seay, K. Oliphant and W.E. Baker, J. Appl. Polym. Sci., 48, 1199 (1993).
- "Ground Rubber Tire – Polymer Composites" (Review Chapter), K. Oliphant, P. Rajalingam, and W.E. Baker, "Plastic Materials Recycling", F. LaManta, ed., ChemTec Publishing, Toronto, 1993.
- "The Use of Cryogenically Ground Rubber Tires as a Filler in Polyolefin Blends", K. Oliphant and W.E. Baker, Polym. Eng. Sci., 33, 166 (1993).
- "Comparison of Batch Melt Grafting Kinetics with Model Systems", J. Felmine, K. Oliphant, K.E. Russell and W.E. Baker, Proceedings, Polymer Processing Society, 8th Annual Meeting, New Deli, India, March 24-27,1992.
- "Recycled Rubber Tire/Polymer Composites", P. Rajalingam, K. Oliphant and W.E. Baker, Presentation at the IUPAC International Symposium on Recycling of Polymers – Science and Technology, Marbella, Spain, September 18-20, 1991.
- "Recycling of Ground Rubber Tires in Polymer Blends using Reactive Compatibilization", K. Oliphant and W.E. Baker, Proceedings, Polymer Processing Society, 7th Annual Meeting, Hamilton, Ontario, Canada, April 22-24, 1991.

Wayne Bryce, P.Eng.

President & Chief Executive Officer
JANA Corporation

PROFILE

Wayne Bryce is President & CEO of JANA. Wayne is a Mechanical Engineer from McGill University in Montreal and has spent his entire career in the field of piping systems. Joining DuPont out of University, Wayne led the team that developed proprietary process technology saving $20 million in capital and reducing operating costs by over 30% annually. Following that success, Wayne launched a completely new product for DuPont and grew the market penetration of an established product line by 42%. In 1999, Wayne co-founded JANA, with a mission to ensure Better Pipelines for a Better World. Under Wayne's leadership, this Mission defines, directs and drives JANA. Wayne ensures that JANA invests deeply in developing the absolute best technology that empowers gas pipeline operators to genuinely manage their assets in a risk-informed manner and profoundly mitigate the inherent risks of operating pipeline assets.

EXPERIENCE

JANA Corporation
1999 > Current

President & Chief Executive Officer

JANA was founded in 1999 as a testing laboratory for plastic piping systems. Over the next 15 years, JANA grew to be the largest hydrostatic testing lab in North America and the largest oxidative resistance testing lab in the world. In 2014, JANA sold its laboratory assets to NSF International and turned its entire focus to JANA's state-of-the-art risk models for gas pipeline systems. Emerging from JANA's 300,000,000 hours of plastic pipe testing experience, advanced reliability engineering tools from the aerospace and nuclear industries, and the performance modelling tools developed at JANA over the last two decades, JANA's risk models are used by North American gas pipeline operators to create Risk Assessments customized to an operator's specific piping network. JANA is proud to have made an impact on the integrity of natural gas pipelines serving over 51 million homes in the US and Canada.

Responsibilities:

- Through consensus and support of Executive Team, directs the creation and implementation of strategic corporate business plans including financial goals and controls, product development and defined focus and value-added initiatives
- Sets direction with Executive Team in planning new business strategies
- Evaluates and advises on the impact of long-range planning, introduction of new programs/strategies and regulatory action
- Participates in the development of the corporation's plans and programs as a strategic partner
- Represents the company as required, including attendance of important functions, industry events and public meetings
- Builds strong relationships with key players (early adopters, thought leaders) in the various geographies and industries

EDUCATION

McGill University 1989 — B.Sc. Mechanical Engineering

INDUSTRY PARTICIPATION

Over his career, Mr. Bryce has participated in the industry as follows:

Industry Associations

- Professional Engineers of Ontario (PEO)
- Institute of Asset Management (IAM)
- Canadian Standards Association (CSA)
- ISO TC 138 (Plastics pipes, fittings and valves for the transport of fluids),
- ASME B31.8
- Canadian Gas Association (CGA)
- American Gas Association (AGA)
- Western Energy Institute (WEI)
- Plastics Pipe Institute (PPI)

Technical Leadership

- ISO TC138 Co-Chair, Canada
- Board of Directors, IAM Canada
- Gas Piping Technology Committee (GPTC)

Regulatory Influence

JANA has supported its clients and their communities in the following regulated jurisdictions:

- Alberta
- California
- Virginia
- British Columbia
- Ontario
- Canadian Federal Code
- US Federal Code

PUBLICATIONS

- "Integrating QRA Outputs into Pipeline Integrity Management Decision-Making", Dr. K. Oliphant, P.Eng. and W. Bryce, P.Eng., JANA Corporation, 2019.
- "Incorporating Low Probability High Consequence Events into Risk Models", Dr. K. Oliphant, P.Eng., W. Bryce, P.Eng. and Dr. Vida Meidanshahi, JANA Corporation, American Gas Association 2019 Pipeline Risk Data Workshop, Albuquerque, 2019.
- "Probabilistic Risk Models for DIMP", R. Gardner, Xcel Energy, W. Bryce, P.Eng. and Dr. K. Oliphant, P.Eng., JANA Corporation, American Gas Association 2019 Pipeline Risk Data Workshop, Albuquerque, 2019.
- "A Framework for Pipeline and Storage Facilities Risk Modeling", Dr. K. Oliphant, P.Eng. and W. Bryce, P.Eng., JANA Corporation, 2018.
- "Pipeline Risk Modeling – How Much Data do I Need?", W. Bryce P.Eng., Dr. K. Oliphant, P.Eng., JANA Corporation, American Gas Association, Orlando, 2017.
- "Power Law Analysis Implications of the San Bruno Pipeline Failure", Dr. K. Oliphant, P.Eng., W. Bryce, P.Eng., W. Luff, JANA Corporation, 11th International Pipeline Conference, Calgary, September 26-30, 2016.

- "Modeling the Consequences of Pipeline Risk", Dr. K. Oliphant, W. Bryce and W. Luff, JANA Corporation, American Gas Association, Phoenix, 2016.
- "A Critical Review of Pipeline Risk Modeling Approaches", William Luff, Dr. Ken Oliphant, Wayne Bryce and James DuQuesnay, JANA Corporation, American Gas Association, Phoenix, 2016.
- "An Absolute Risk Model Framework for Gas Pipelines", K. Oliphant, Ph.D., P.Eng., W. Luff, M.A.Sc., W. Bryce, P.Eng., JANA Corporation, American Gas Association, Phoenix, 2016.
- "Aldyl Piping Replacement Prioritization", W. Bryce, Jana Laboratories Inc., G. Palermo, Palermo Plastics Pipe (P^3) Consulting, Midwest Energy Association, 2014.
- "Managing Low Probability - High Consequence Pipeline Risk", W. Bryce, P.Eng., Dr. Ken Oliphant, P.Eng., JANA Corporation, Western Energy Institute, 2014.
- "Characterizing the Consequences of Pipeline Incidents", Dr. Ken Oliphant, P.Eng. and W. Bryce, P.Eng., Jana Laboratories Inc., 2013.
- "JP916: JANA Mode 3 Shift Functions", Dr. Ken Oliphant, P.Eng., W. Bryce, P.Eng., Sarah Chung, P.Eng., Jana Laboratories Inc., 2012.
- "Design and Safety Factors for PE 4710 Materials", Dr. Ken Oliphant, P.Eng. and W. Bryce, P.Eng., Jana Laboratories Inc., 2011.
- "PE Chlorine Validation Methodology", W. Bryce, P.Eng., Sarah Chung, M.A.Sc., P.Eng. and Dr. Ken Oliphant, P.Eng., Jana Laboratories Inc., 2011.
- "Integrity Management of Plastic Pipelines", K. Oliphant and W. Bryce, Jana Laboratories Inc., Aurora, ON, G. Palermo, Palermo Plastics Pipe (P^3) Consulting, Oak Hill, VA, Paper Presented at Society of Plastics Engineers Annual Technical Conference (ANTEC), Boston, USA, May 2005.
- "Chlorine Resistance Testing of Cross-linked Polyethylene Piping Materials", Society of Plastics Engineers Annual Technical Conference (ANTEC), San Francisco, USA, 2002.

Integrating QRA Outputs into Pipeline Integrity Management Decision-Making

Gas pipelines have been operated with a high level of safety for over a century. As with many industries, to ensure continued safe operation and increase pipeline safety, there is a shift from compliance-based management of safety to risk-based Integrity Management (IM). This has led to increasing movement in the North American gas pipeline industry towards quantitative risk assessment (QRA) approaches, with the outputs of QRAs being used to inform asset and integrity management decisions.

Moving from the traditional approach of managing pipeline safety to a risk-based IM approach is not as simple as simply running a QRA. While the QRA is the fundamental cornerstone of managing in a risk-based manner, there are a number of questions that arise in applying the actual QRA outputs to IM: "What is an acceptable level of risk[1]?"; "What are reasonable expenditures to reduce risk?"; "What factors, in addition to risk, need to be considered?"; "How does this fit into the regulatory framework?"; etc. Overall, if other industries are a guide, it will take decades to evolve to a full risk management regulatory framework that address these and other questions.

In the interim, however, QRAs are becoming more common and their outputs are beginning to be applied to IM decision making. This shift is bringing many of the highlighted questions to light. Properly applied, there are significant benefits to using QRAs, such as generating a measurable estimate of risk, ensuring risk is at acceptable levels, optimization of risk expenditures, etc. To properly apply these results, a framework for incorporating QRA outputs into the overall risk management/regulatory environment and decision-making process is required. To address this need, a general Quantitative Risk Assessment – Integrity Management (QRA-IM) framework has been developed by JANA and is presented below.

Overview of QRA-IM Framework

The QRA-IM Framework is comprised of two key components: (1) The Overall Decision-Making Framework in managing pipeline assets, where QRA outputs are integrated into the overall broader decision-making process and (2) The JANA Risk-Based Optimized Integrity Management Framework, which details more specifically how the QRA outputs are developed to feed into the overall broader decision-making process.

The approach for each of these two components is summarized below.

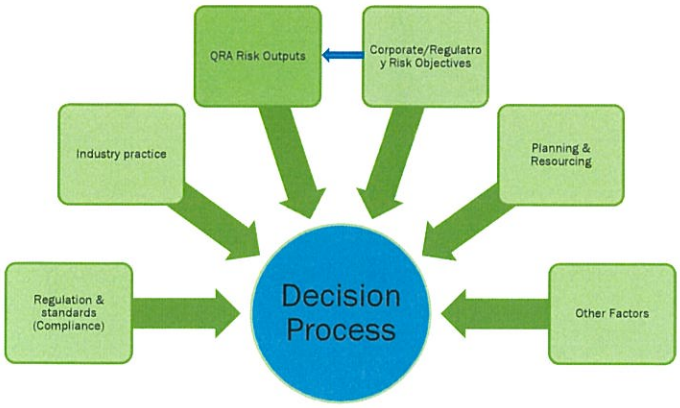
Overall Decision-Making Framework

A QRA provides one part of the information that feeds into the overall decision-making framework (**Figure 1**). Until a full risk management regulatory framework is developed, the use of QRA outputs needs to be considered and integrated into the existing compliance requirements, industry practices and regulatory environment. There are also planning and resourcing considerations among other factors that impact the decision-making process.

[1] Preliminary SED Staff Whitepaper on As Low As Reasonably Practicable (ALARP) Risk-informed Decision Framework Applied to Public Utility Safety, 2015.

Integrating QRA Outputs into Pipeline Integrity Management Decision-Making

Figure 1: Overall Decision-Making Framework



In terms of the overall decision-making process in managing pipeline assets, the following general process flow is recommended:

Regulation & Standards (Compliance)

- Compliance activities must be completed regardless of the results of any QRA. If AM or IM investments are required by regulation and standards, these must be conducted and a QRA is not required for justification as these are not asset risk-based decisions.

Industry Standard Practice (ISP)

- For industries where there are potential hazards that can impact the public, such as the gas pipeline industry, Industry Standard Practice (ISP) becomes a prudent benchmark for pipeline operators and their regulators. Operators are otherwise at risk of being found negligent if lawsuits result from an accident[2]. IM practices should, therefore, be consistent with evolving industry standard practice.

QRA Outputs

- Beyond Compliance and ISP, QRA outputs provide insight into further opportunities for risk reduction in the pipeline network. Asset risk forecasts, compared to the corporate and regulatory risk objectives, enable for further system-specific refinement of AM and IM investments beyond standard Compliance- and ISP-driven safety management. This raises a few important questions, such as: "What is "acceptable" risk?" and "Who determines acceptable risk?", etc. This is discussed further below.

Planning & Resourcing

- Once required activities/investments are identified through Compliance, ISP or QRA assessments, planning & resourcing impacts the potential prioritization and sequencing of activities. For Compliance- or ISP-driven investments, a QRA can provide a risk-based prioritization for long-horizon projects (e.g. long-term replacement programs) to facilitate removing risk from the pipeline system more quickly by prioritizing the highest risk areas to address first. For shorter-term projects, planning and resourcing optimization is likely the dominant factor.

Other Factors

- There may be other factors, for specific projects, that influence the decision-making process and these should be included on a case-by-case basis.

[2] S. Haine, Preliminary SED Staff Whitepaper on As Low As Reasonably Practicable (ALARP) Risk-informed Decision Framework Applied to Public Utility Safety, 2015.

Integrating QRA Outputs into Pipeline Integrity Management Decision-Making

JANA Risk-Based Optimized IM Framework

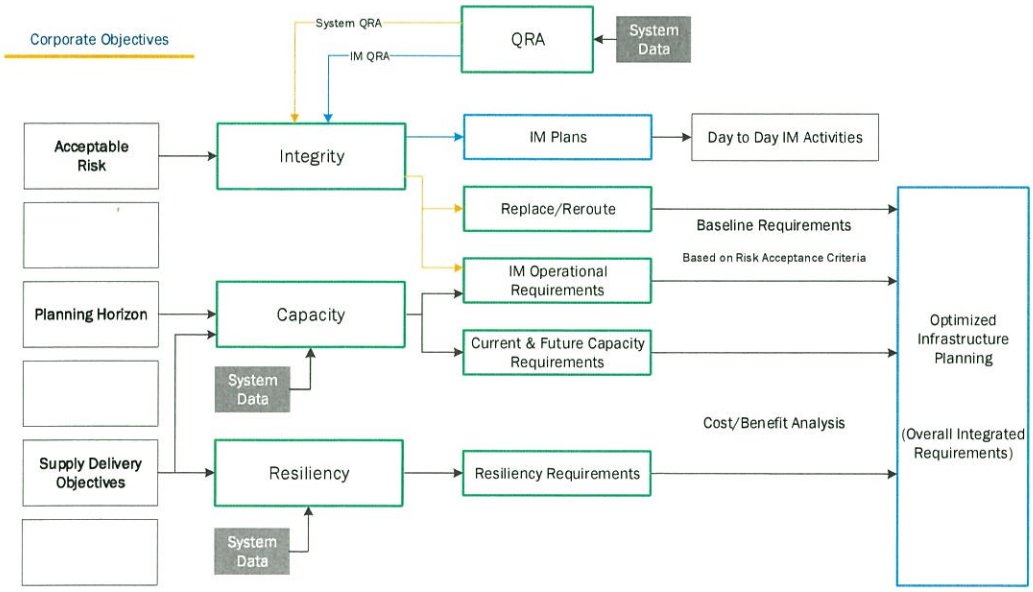
Industry research has demonstrated that, as the fundamental properties of steel do not degrade with time[3], a well-maintained and periodically assessed pipeline (i.e. one where proper IM is being applied) can safely transport natural gas essentially indefinitely[4]. The key requirements for Asset and Integrity Management, then, are:

- Structuring the pipeline system so that the required IM can be conducted
- Conducting the IM activities required to maintain safety and operability on an ongoing basis

These involve two different levels of decision-making: (1) at the system level (e.g. being able to run inspection tools for IM) and (2) at the day-to-day Integrity Management level (e.g. addressing the anomalies found with inspection tools). Both require different decision frameworks and different levels of risk assessment.

The overall framework is presented in **Figure 2**. There are two different risk inputs into the overall process: a System QRA and an IM QRA (addressing the system level and day-to-day IM activities, respectively). The System QRA considers risk across all threats to determine, when compared to acceptable risk criteria, what IM activities are required to achieve acceptable risk (IM Operational Requirements). Further, a System QRA also considers when all practical IM activities are applied and risk is still not at acceptable levels, where it may be necessary to consider pipeline replacement, pressure reduction, etc. An IM QRA considers risk on a more granular basis (e.g. detailed analysis of in-line inspection results) to identify the ongoing day-to-day IM activities (e.g. dig and repair pipe at a specific location).

Figure 2: JANA Risk-Based Optimized IM Framework



[3] Clark, E.B., Leis, B.N., and Eiber, R.J., "Integrity Characteristics of Vintage Pipelines," Appendix C, The INGAA Foundation, Inc. 2005.
[4] The Role of Pipeline Age in Pipeline Safety, INGAA Foundation Final Report No. 2012.04

Integrating QRA Outputs into Pipeline Integrity Management Decision-Making

At the system level there are three critical, interrelated, pipeline infrastructure requirements that need to be considered to meet current and future supply needs while ensuring continued safe, reliable operation of a pipeline:

Integrity
- Operational flexibility is required to conduct Integrity assessments and effect Integrity mitigations to maintain pipeline safety

Capacity
- Operational Capacity is required to meet supply requirements during peak demand and enable conducting Integrity Management activities

Resiliency
- Operational Resiliency is required to withstand disruptive events, provide continuity of service and rapidly restore essential functioning

Optimized infrastructure planning requires addressing these in a holistic way. The desired state is a resilient pipeline system that can reliably meet capacity requirements while providing the operational flexibility necessary to manage the integrity of the pipeline and maintain acceptable risk levels. The pipeline system must be operated with optimized capital and operating costs. This requires ongoing assessment and system upgrades as pipelines age, new integrity threats are identified, and populations change (impacting both capacity and integrity requirements).

The process considers the combined requirements for Integrity, Capacity and Resiliency in the following way:

- The Integrity Requirements Framework provides the required Integrity Management activities (e.g., ability to run in-line inspection (ILI), ability to reduce pressure to conduct repairs, etc.) to achieve desired reliability targets. These requirements are based on a System QRA.
- The Capacity Requirements Framework considers the system capacity and operational flexibility requirements needed to meet both overall supply demand and enable required Integrity Management activities (as identified by the Integrity Framework)
- The Resiliency Requirements Framework considers further system configuration/capacity requirements needed to minimize the impact of disruptive events (e.g., major system outage)

An Optimized Infrastructure Planning methodology takes the inputs from these three frameworks and holistically considers how best to address them based on consideration of potential mitigations and system changes.

Integrating QRA Outputs into the IM Decision Making Process

Developing a risk management regulatory framework for the North American gas pipeline industry is a process that will take time. In the interim, pipeline operators can take advantage of the benefits of applying QRA approaches to pipeline safety and Integrity Management. At the simplest level this requires:

- Ensuring regulatory compliance
- Operating in accordance with Industry Standard Practice
- Using QRA results to identify risk management opportunities beyond Compliance and ISP driven activities
- Using QRA results to prioritize long-term Compliance and ISP practices on the asset

Integrating QRA Outputs into Pipeline Integrity Management Decision-Making

Risk Criteria

As there are no currently defined risk acceptance criteria in the gas pipeline industry in Canada and the U.S., applying QRA outputs in the decision-making process will require some judgement on the part of operators and regulators. In general, there is a drive in the pipeline industry towards zero injuries and fatalities (no significant incidents). To apply QRA results in IM, this needs a more explicit definition in terms of specific risk acceptance criteria. There are several risk acceptance criteria that could be applied individually but, more likely, in some combination:

ALARP – As Low as Reasonably Practicable

- ALARP is a well-established approach to managing QRA outputs and has consensus standards established in the UK, Ireland and the Netherlands. ALARP is based on defining an upper criterion for unacceptable risk and a lower criterion for broadly tolerable risk; the region between the two is defined as the ALARP region. In the unacceptable risk region, risk must be reduced regardless of cost. In the ALARP region, risk must be reduced until broadly tolerable or until it is no longer practicable to reduce risk. "No longer practicable" needs to be defined, and in the UK typically means that costs are 2 to 10 times above the resulting risk reduction (i.e. up to $10 could be spent to reduce 1/10th of that value in risk). In the broadly tolerable region, no action is required beyond standard IM practices. There are many challenges with this approach and these are being considered both in California[5] and in Canada[6].

Impact Criteria (Consequence Criteria)

- Impact Criteria consider the potential impact of events and are used to define a boundary where risk is unacceptable regardless of the consequences. One such example would be if an operator considered transmission pipeline ruptures in an urban area to be unacceptable – in this case an operator might choose to redesign the pipeline to reduce pressure to below 30% SMYS to essentially eliminate rupture potential.

Cost-Benefit Criteria

- Cost-Benefit Criteria assess the costs of an activity versus the risk reduction of that activity. This approach is typically applied to non-life safety decisions to optimize operations (life-safety, particularly for public at risk, is more typically determined by ALARP[7] or Impact Criteria).

A combination of approaches – for example, using Impact Criteria for setting a bound on what is considered unacceptable (for example ruptures in an urban area) and then applying ALARP criteria to the remaining system risk – to determine what further activities may be required, is the most general and effective approach for a pipeline operator to protect all stakeholders.

[5] S. Haine, Preliminary SED Staff Whitepaper on As Low As Reasonably Practicable (ALARP) Risk-informed Decision Framework Applied to Public Utility Safety, 2015.
[6] There is currently a CSA Z662 Task Force exploring the development of the ALARP approach for incorporation into CSA Z662
[7] Cost-Benefit analysis is a part of ALARP with a multiplier (typically 2 – 10) applied in the ALARP region to the benefit (i.e. risk reduction)

JANA

(905) 726-8550 JANAtechnology.com
1-305 Industrial Pkwy S, Aurora, ON L4G 6X7

MEMO

To: Bryan Balmer, FortisBC

Date: June 7, 2019

Cc: Paul Chernikhowsky, FortisBC

From: Dr. Ken Oliphant
Executive VP & CTO

Re: IGU Responses

JANA's Technical Opinion on Functional Lifetime of a Gas Transmission Pipeline

FEI requested that JANA provide a 3rd Party expert opinion regarding the useful life of a well-designed, constructed, operated and maintained transmission pipeline.

Based on JANA's awareness of transmission pipeline historical failure data and available industry literature, JANA's opinion is that there is not currently an industry-recognized finite lifetime for a well-maintained and appropriately assessed pipeline. This opinion is based on:

- Industry studies demonstrating that there is no time-dependent degradation of the fundamental properties of the steels used in natural gas pipelines[1]. The strength properties of steel pipelines, provided time-dependent threats such as corrosion are managed, will not degrade over time.
- An industry study, based on analysis of historical transmission pipeline failures, that concluded that "a well-maintained and periodically assessed pipeline can safely transport natural gas indefinitely[2]" That is, with proper application of Integrity Management approaches, there is no recognized finite lifetime for a transmission pipeline.
- JANA's analysis of PHMSA historical transmission pipeline failure data that confirms the analysis conducted in the above-referenced study.

JANA's Technical Opinion on Impact of a QRA on Justification of Inland Gas Upgrade (IGU) Project

FEI requested that JANA provide a 3rd Party expert opinion regarding the value of performing a QRA of the 29 transmission laterals for the purposes of the IGU Project justification.

JANA's technical opinion is that a QRA would not change the justification for the IGU project as the project is driven by FEI's stated need to meet regulatory requirements (compliance) and Industry Standard Practice (ISP). As detailed in "Integrating QRA Outputs into Pipeline Integrity Management Decision-Making"[3], it is JANA's opinion that a QRA is not required to justify investments required to meet Compliance- and ISP-driven Integrity Management activities and that these activities should be addressed regardless of the outputs of a QRA.

JANA's Technical Opinion on Impact of a QRA on Scheduling/Prioritization of IGU Project

FEI requested that JANA provide a 3rd Party expert opinion regarding the value of performing a QRA to assess scheduling and prioritization of the IGU project.

JANA's technical opinion is that, given the short project timeline of five years for the IGU project, a QRA would not materially impact the timeline or scheduling of these activities. First, given that the justification for the IGU

[1] Clark, E.B., Leis, B.N., and Eiber, R.J., "Integrity Characteristics of Vintage Pipelines," Appendix C, The INGAA Foundation, Inc. 2005.
[2] The Role of Pipeline Age in Pipeline Safety, INGAA Foundation Final Report No. 2012.04
[3] http://www.janatechnology.com/integrating-qra-outputs-into-pipeline-integrity-management-decision-making

JANA
(905) 726-8550 JANAtechnology.com
1-305 Industrial Pkwy S, Aurora, ON L4G 6X7

project is driven by FEI's stated need to meet regulatory requirements (compliance) and Industry Standard Practice (ISP), a QRA would not change the requirements for the IGU project. It is JANA's opinion that a QRA is not required to justify investments required to meet Compliance and ISP driven Integrity Management activities and that these activities should be addressed regardless of the outputs of a QRA[3]. Second, given the short timeline of the project, it is JANA's opinion that scheduling and prioritization will be driven by logistical concerns and not risk given the small difference in risk reduction expected for conducting the work, for example, in Year 2 versus Year 3.

JANA's Technical Opinion on Need for QRA for TIMC Project versus IGU Project

FEI requested that JANA provide a 3rd Party expert opinion to address BCUC IR 2.36.2 "Please explain why the QRA is required for the purpose of the TIMC Project but is not required to justify the need for the IGU Project".

JANA's technical opinion is that:

- A QRA would not change the justification for the IGU project as the project is driven by FEI's stated need to meet regulatory requirements (compliance) and Industry Standard Practice (ISP). It is JANA's opinion that a QRA is not required to justify investments required to meet Compliance and ISP driven Integrity Management activities and that these activities should be addressed regardless of the outputs of a QRA[3].
- An Integrity Management (IM) QRA[3] of the 29 Transmission Laterals in the IGU Project would be beneficial for ongoing Integrity Management (IM) of the laterals. Such a QRA is most beneficial after completion of the initial in-line inspection runs so that a clearer picture of risk can be obtained.
- The QRA for the TIMC project is not being used to justify the requirements to conduct Integrity Management activities for cracking threats (Stress Corrosion Cracking and seam threats) as, similar to the IGU project, this requirement is driven by Compliance and Industry Standard Practice (ISP)[3]. The QRA for the TIMC project is driven by several other factors:
    - The interconnected nature of the mainline transmission systems (versus the single line nature of the laterals) makes for a much more complex system and much more complex analysis of potential scenarios for which the QRA is intended to support the analysis and consider integrity, capacity and resiliency[3]
    - As initial analysis identified that line looping will likely be necessary to enable management of the cracking threats in the Coastal Transmission System (CTS) and Inland Transmission System (ITS), the QRA was run to assess risk in the pipeline systems to consider further potential risk reductions that could be achieved with the line looping (e.g. increased resiliency, reduced operating pressures, etc.). The retrofits and modifications to the laterals required to enable inline inspection, as proposed in the IGU, do not afford those same opportunities.
    - FEI's commitment to begin the process of integrating QRA into its overall asset and integrity management process

Attachment 53.2

From: Thomson, Shelley
Sent: Wednesday, September 5, 2018 2:10 PM
To: 'Michelle.McLachlan@teck.com'
Cc: 'Pat.Murray@teck.com'; 'Sarah.Macpherson@teck.com'; 'Vien.Seneyavong@teck.com'
Subject: FW: [External Email] - FortisBC Gas Upgrades- Request for detailed plans
Attachments: Jul 20'18 FortisBC Gas Upgrades.pdf

Good afternoon Michelle,

Thank you for your email and for registering to receive updates on the Inland Gas Upgrades Project.

We will certainly make note of your request and would be happy to provide detailed plans that involve Teck property once the information is finalized and we confirm our schedules and timelines.

If you have any other questions, or would like additional information, please don't hesitate to contact us.

Shelley
Community & Indigenous Relations Manager
Shuswap-Nicola-Okanagan-Similkameen

From: Inland Gas Upgrades
Sent: Friday, August 10, 2018 8:17 AM
To: Thomson, Shelley <Shelley.Thomson@fortisbc.com>
Subject: FW: [External Email] - FortisBC Gas Upgrades- Request for detailed plans

---

From: McLachlan Michelle TRAIL <Michelle.McLachlan@teck.com>
Sent: Thursday, August 09, 2018 2:50 PM
To: Inland Gas Upgrades <InlandGasUpgrades@fortisbc.com>
Cc: Murray Pat TRAIL <Pat.Murray@teck.com>; MacPherson Sarah TRAIL <Sarah.Macpherson@teck.com>; Seneyavong Vien TRAIL <Vien.Seneyavong@teck.com>
Subject: [External Email] - FortisBC Gas Upgrades- Request for detailed plans

**** THIS IS AN EXTERNAL EMAIL **** Use caution before opening links / attachments.

Thank you for your letter of July 20, 2018 which I have attached for your reference.

We would ask that you please forward any detailed plans if they are available and, in particular, any that involve Teck owned property. We have registered to receive your updates on the project.

Thanks,

Michelle McLachlan
Casual
Teck Metals Ltd.
Direct Phone: +1.250.364.4124
Phone: 250.364.4222
Fax:
eMail: Michelle.McLachlan@teck.com
<www.teck.com

From: Thomson, Shelley
Sent: Wednesday, August 8, 2018 11:17 AM
To: 'joan.reinhardt@bchydro.com'
Subject: RE: [External Email] - RE: Follow up: FortisBC Inland Gas Upgrade project information request

Hi Joan,

I'm glad the information was helpful! I did another double check all of our lateral lists I found a couple more than I missed in my first email so this should be all of them now.

Please feel free to contact me if I can be of further assistance.

Have a great day!

ROW File #	Owner Name & Address	Property Address	Legal Description
FRD02-019 82G.076.047.1 to: FRD LTL 219 (15892.38) to: FRD LTL 219 (16174.60)	B C Hydro 13th Floor 800 - 333 Dunsmuir Street Vancouver, BC V6B 5R3	Michel Creek Rd Sparwood BC	PID: 013-286-781 L4 EXC PCL A (SEE 98070I) DL4588 KD LTO: Nelson Property / Subdivision 1358 SRW 8072 SRW-TP G5750
MACK-007 93O.025.064.1 to: MAC LTL 168 (20308.84) to: MAC LTL 168 (23269.77)		Mackenzie, BC	WITHIN BC HYDRO R/W PL17138 (SEE SRW 17136, 17138
MACK-010 93O.025.093.2 to: MAC LTL 168 (24329.11) to: MAC LTL 168 (25983.71)		Mackenzie, BC	BCR R/W PLAN 32952 (WITHIN BC HYD SRW 17293 SRW-TP F3526

Shelley
Community & Indigenous Relations Manager
Shuswap-Nicola-Okanagan-Similkameen

From: Reinhardt, Joan <Joan.Reinhardt@bchydro.com>
Sent: Wednesday, August 8, 2018 9:10 AM
To: Thomson, Shelley <Shelley.Thomson@fortisbc.com>
Subject: [External Email] - RE: Follow up: FortisBC Inland Gas Upgrade project information request

Good morning Shelley,

Thank you for the information below, that's exactly what I was looking for. I've determined that these properties are owned for generation/reservoir needs and I have forwarded your initial letter and information below to that department. You should be hearing from someone shortly.

Joan Reinhardt | Property Coordinator, Property Rights Services

BC Hydro
1401 Kalamalka Lake Road
Vernon, BC V1T 8S4

P 250-549-8566
E joan.reinhardt@bchydro.com

bchydro.com

From: Thomson, Shelley [mailto:Shelley.Thomson@fortisbc.com]
Sent: 2018, August 03 11:58 AM
To: Reinhardt, Joan
Subject: Follow up: FortisBC Inland Gas Upgrade project information request

Good morning Joan,

Thank you for your email of July 26th regarding the notification letter you received about our upcoming Inland Gas Upgrade project. You requested parcel information for BC Hydro property adjacent to natural gas lines we are proposing to do work. Let me know if the information outlined below is what you are looking for:

Lateral	Community	ROW File #	Owner Name & Address	PID
KA1 LTL 168	Kamloops		B C Hydro C/O Finance & Tax	PID: 008-823-359 L2 (PDD9261) DL2087 KD EXC P1812/11192 LTO: Nelson SRW RW296 SRW-TP 48608D
CAS NEL 168	Castlegar-Nelson	ML52-025 82F.043.057.1 to: CAS NEL 168 (23257.45) to: CAS NEL 168 (23469.96)	B C Hydro C/O Finance & Tax	PID: 008-823-375 L3 (PDD9261) DL2087 KD LTO: Nelson SRW RW296 SRW-TP 48608D
CAS NEL 168	Castlegar-Nelson	ML52-026 82F.043.057.1 to: CAS NEL 168 (23469.96) to: CAS NEL 168 (23690.39)	B C Hydro C/O Finance & Tax	PID: 008-850-143 PCL 4 (DD9265) DL2087 KD LTO: Nelson SRW RW296 SRW-TP 48851D

Please feel free to contact me directly if you have any further questions or need any additional information.

Have a great day!

Shelley Thomson
Community & Indigenous Relations Manager
Shuswap-Nicola-Okanagan-Similkameen
Phone: 250.868.4525
Cell: 250.718.7041

From: Transcanada <transcanada@bapg.ca>
Sent: Friday, June 22, 2018 3:25 PM
To: Inland Gas Upgrades
Subject: [External Email] - FortisBC Inland Gas Upgrade Project: TransCanada Pipelines Ltd.
Attachments: 676 FortisBC ReferralPackage Fortis.pdf

Follow Up Flag: Follow up
Flag Status: Completed

Categories: Blair

**** THIS IS AN EXTERNAL EMAIL **** Use caution before opening links / attachments.

Hi Blair,

We are the land use planning consultant for TransCanada pipelines. We review all relevant industry notifications and applications for development surrounding TransCanada infrastructure.

That being said, we received the attached and would like to be kept up to date on specific locations and any activity that may require excavation activities.

Thanks and have a good weekend!

RUSS LEEDHAM
Community Planner & Senior Planning Technician | MPlan, B.App.GIS, GISP
d | 403.692.4531
c | 403.615.5339
rleedham@bapg.ca

B&A Planning Group 600, 215 9th Ave SW | Calgary, AB T2P 1K3 | www.bapg.ca

Attachment 55.1

Name
Community & Aboriginal Relations

FortisBC Inc.
1975 Springfield Road
Kelowna, BC V1Y 7V7
Tel: phone
First.last@fortisbc.com
www.fortisbc.com

January 21, 2019

Municipality Name
Address
City, BC, Postal

Attention: *Contact*

Re: FortisBC Natural Gas Inland Gas Upgrade Project Update

On December 17 2018, FortisBC Energy Inc. (FEI) filed an Application for a Certificate of Public Convenience and Necessity for the Inland Gas Upgrade (IGU) Project. FEI is requesting approval to implement integrity management upgrades and retrofits on 29 existing transmission pressure natural gas pipelines in the interior of British Columbia. FEI has identified the IGU Project as part of its ongoing system integrity program which is needed to ensure continued safe and reliable service to our interior customers. Our intention is to improve reliability and provide greater operational flexibility to meet the current and future needs of our customers.

As a regulated utility, FEI must have projects like this reviewed and approved through a rigorous and transparent process with the BCUC. Some of the proposed work is planned to take place in *Municipality* so if you are interested in registering as an interested party or submitting a request to intervene in the application process, information on how to get involved can be found at www.bcuc.com. We have been informed that the registration deadline is set for February 14, 2019 and all related documents are filed on the public record on the "Current Proceedings" page the Commissions website.

If the application is approved, construction work will take place, section-by-section, between 2020 and 2024. If you would like to be kept informed of the project's progress, information can be found on our website at www.talkingenergy.ca/inlandgasupgrades.

If you have any questions regarding this project, feel free to contact me directly at *250.xxx.xxxx* or by email at *first.last@fortisbc.com*.

Sincerely,

Name
Community & Indigenous Relations Manager

Local Government	Address	Attention	CR Mgr
Cariboo Regional District	180 North 3rd Avenue, Suite D Williams Lake, BC V2G 2A4	John MacLean, Chief Administrative Officer	Matt
City of Kamloops	7 Victoria Street West Kamloops, BC V2C 1A2	David Trawin, Chief Administrative Officer	Matt
City of Prince George	1100 Patricia Blvd Prince George, BC V2L 3V9	Kathleen Soltis, City Manager	Matt
City of Quesnel	410 Kinchant Street Quesnel, BC V2J 7J5	Byron Johnson, Chief Administrative Officer	Matt
City of Williams Lake	450 Mart Street Williams Lake, BC V2G 1N3	Milo Macdonald, Chief Administrative Officer	Matt
District of Mackenzie	Bag 340 Mackenzie, BC V0J 2C0	Dean McKinley, Chief Administrative Officer	Matt
Fraser-Fort George Regional District	155 George Street Prince George, BC V2L 1P8	Jim Martin, Chief Administrative Officer	Matt
Thompson-Nicola Regional District	300 - 465 Victoria Street Kamloops, BC V2C 2A9	Sukh Gill, Chief Administrative Officer	Matt
City of Castlegar	460 Columbia Avenue Castlegar, BC V1N 1G7	Chris Barlow, Chief Administrative Officer	Blair
City of Cranbrook	40 - 10th Avenue South Cranbrook, BC V1C 2M8	David Kim, Chief Administrative Officer	Blair
City of Kimberley	340 Spokane Street Kimberley, BC V1A 2E8	Scott Sommerville, Chief Administrative Officer	Blair
City of Nelson	101 - 310 Ward Street Nelson, BC V1L 5S4	Kevin Cormack, City Manager	Blair
City of Trail	1394 Pine Avenue Trail, BC V1R 4E6	David Perehudoff, CAO / Financial Administrator	Blair
District of Elkford	Box 340 Elkford, BC V0B 1H0	Curtis Helgesen, Chief Administrative Officer	Blair
District of Sparwood	Box 520 Sparwood, BC V0B 2G0	Michele Schalekamp, Acting Chief Administrative Officer	Blair

East Kootenay Regional District	19 - 24th Avenue South Cranbrook, BC V1C 3H8	Shawn Tomlin, Chief Administrative Officer	Blair
Regional District Central Kootenay	Box 590 Nelson, BC V1L 5R4	Stuart Horn, Chief Administrative Officer	Blair
Regional District Kootenay Boundary	202 - 843 Rossland Avenue Trail, BC V1R 4S8	Mark Andison, Chief Administrative Officer	Blair
Central Okanagan Regional District	1450 KLO Road Kelowna, BC V1W 3Z4	Brian Reardon, Chief Administrative Officer	Shelley
City of Kelowna	1435 Water Street Kelowna, BC V1Y 1J4	Doug Gilchrist, City Manager	Shelley
City of Salmon Arm	Box 40 Salmon Arm, BC V1E 4N2	Carl Bannister, Chief Administrative Officer	Shelley
City of Vernon	3400 - 30th Street Vernon, BC V1T 5E6	Will Pearce, Chief Administrative Officer	Shelley
Columbia-Shuswap Regional District	Box 978 Salmon Arm, BC V1E 4P1	Charles Hamilton, Chief Administrative Officer	Shelley
North Okanagan Regional District	9848 Aberdeen Road Coldstream, BC V1B 2K9	David Sewell, Chief Administrative Officer	Shelley

Attachment 61.1

Name
Community & Aboriginal Relations

FortisBC Inc.
1975 Springfield Road
Kelowna, BC V1Y 7V7
Tel: 250-xxx-xxxx
First.last@fortisbc.com
www.fortisbc.com

January 21, 2019

Indigenous Community Name
Address
City, BC, Postal

Attention: *Contact* Email: *email address*

Re: FortisBC Natural Gas Inland Gas Upgrade Project Update

As a follow up to our letter dated May 7, 2018 regarding FortisBC's proposed Inland Gas Upgrades project, we would like to let you know that our Certificate of Public Convenience and Necessity (CPCN) application was submitted to the BC Utilities Commission (BCUC) on December 17, 2018.

This project is part of our ongoing system maintenance and involves making improvements to twenty-nine sections of our Interior natural gas system. Our intention is to improve reliability and provide greater operational flexibility to meet the current and future needs of our customers.

As a regulated utility, we must have projects like this reviewed and approved through a rigorous and transparent process with the BCUC. If *Indigenous Community Name* wish to register as an interested party or submit a request to intervene in the application process, information on how to get involved can be found at www.bcuc.com. We have been informed by the BCUC that the registration deadline is set for February 14, 2019. All related documents filed on the public record are on the "Current Proceedings" page on the Commissions website.

If the application is approved, construction work will take place, section-by-section, between 2020 and 2024. If you would like to be kept informed of the project's progress, information can be found on our website at www.talkingenergy.ca/inlandgasupgrades.

If you have any questions regarding this project, feel free to contact me directly at *250.xxx-xxxx* or by email *at first.last @fortisbc.com*.

Sincerely,

Name
Community & Indigenous Relations Manager

Lateral(s)	CR Manager	Region	First Nation
Mackenzie	Matt	North	Blueberry River First Nations
Kamloops	Matt	Thompson	Bonaparte Indian Band
Kamloops	Matt	Thompson	Bonaparte Indian Band
Kamloops	Matt	Central Interior	Boothroyd Band
Williams Lake	Matt	Central Interior	Canim Lake Band
Prince George, Quesnel	Matt	Central Interior	Carrier Chilcotin Tribal Council
Mackenzie	Matt	Northern	Doig River First Nation
Mackenzie	Matt	Northern	Halfway River First Nation
Prince George	Matt	North	Lheidli T'enneh First Nation
Quesnel	Matt	Central Interior	Lhoosk'uz Dene Nation
Quesnel	Matt	Central Interior	Lhtako Dene First Nation
Kamloops	Matt	Nicola	Lytton First Nation
Mackenzie	Matt	Northern	McLeod Lake Indian Band
Prince George	Matt	North	Nak'azdli Whut'en'
Prince George	Matt	North	Nazko First Nation
Kamloops	Matt	Nicola	Nlaka'pamux Nation Tribal Council
Williams Lake	Matt	Central Interior	Northern Secwepemc Tribal Council
Kamloops	Matt	Nicola	Siska Indian Band
Kamloops	Matt	Thompson	Skeetchestn Indian Band
Kamloops	Matt	Central Interior	Skuppah Indian Band
Kamloops	Matt	Central Interior	Spuzzum First Nation
Kamloops	Matt	Thompson	Stk'emlupsemc te Secwepemc Nation (SSN)
Kamloops	Matt	Thompson	Tk'emlups Band
Quesnel, Williams Lake	Matt	Central Interior	Tsilhqot'in National Government
Quesnel	Matt	Central Interior	Ulkatcho First Nation
Mackenzie	Matt	Northern	West Moberly First Nation
Kamloops	Matt	Thompson	Whispering Pines/ Clinton Band
Williams Lake	Matt	Central Interior	Williams Lake Indian Band
Williams Lake	Matt	Central Interior	Xats'ull First Nation
Kamloops, Williams Lake, Spallumcheen, Salmon Arm (PLR), Castlegar-Nelson	Shelley	Shuswap	Adams Lake Indian Band
Kamloops	Shelley	Nicola	Ashcroft Indian Band
Kamloops	Shelley	Nicola	Coldwater Indian Band
Kamloops	Shelley	Nicola	Cook's Ferry Indian Band
Kamloops, Kelowna	Shelley	Nicola	Esh-kn-am Cultural Resources Management Se
Kamloops, Williams Lake, Spallumcheen, Salmon Arm (PLR)	Shelley	Shuswap	Little Shuswap Lake Indian Band
Kamloops	Shelley	Nicola	Lower Nicola Indian Band
Kelowna, Coldstream, Spallumcheen, Castlegar-Nelson, Trail	Shelley	South Interior	Lower Similkameen Indian Band

Kamloops, Williams Lake, Spallumcheen, Salmon Arm (PLR), Castlegar-Nelson, Trail	Shelley	Shuswap	Neskonlith Indian Band
Kamloops	Shelley	Nicola	Nicola Tribal Association
Kelowna, Kamloops	Shelley	Nicola	Nooaitch Indian Band
Kelowna, Coldstream, Spallumcheen, Salmon Arm (PLR), Castlegar-Nelson, Trail	Shelley	South Interior	Okanagan Indian Band
Kelowna, Coldstream, Spallumcheen. Castlegar-Nelson, Trail	Shelley	South Interior	Okanagan Nation Alliance
Kamloops	Shelley	Nicola	Oregon Jack Creek Indian Band
Castlegar-Nelson, Trail, Celgar	Shelley	South Interior	Osoyoos Indian Band
Kelowna, Coldstream, Spallumcheen, Castlegar-Nelson, Trail, Celgar	Shelley	South Interior	Penticton Indian Band
Coldstream, Spallumcheen, Salmon Arm (PLR), Castlegar-Nelson, Celgar	Shelley	Shuswap	Splats'in First Nation
Kelowna, Coldstream, Spallumcheen, Castlegar-Nelson, Trail, Celgar	Shelley	Nicola	Upper Nicola Indian Band
Kelowna	Shelley	South Interior	Westbank First Nation
Castlegar-Nelson, Trail, Cranbrook, Kimberley, Elkford, Sparwood	Blair	Kootenay	Ktunaxa Nation Council
Castlegar-Nelson, Trail, Cranbrook, Kimberley, Elkford, Sparwood	Blair	Shuswap	Shuswap Band