OWEN·BIRD
LAW CORPORATION

PO Box 49130
Three Bentall Centre
2900-595 Burrard Street
Vancouver, BC
Canada V7X 1J5

Telephone 604 688-0401
Fax 604 688-2827
Website www.owenbird.com

Direct Line: 604 691-7557
Direct Fax: 604 632-4482
E-mail: cweafer@owenbird.com
Our File: 23841/0204

February 28, 2019

VIA ELECTRONIC MAIL

British Columbia Utilities Commission
6th Floor, 900 Howe Street
Vancouver, B.C. V6Z 2N3

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

Dear Sirs/Mesdames:

Re: FortisBC Energy Inc. ("FEI") Certificate of Public Convenience and Necessity Application for the Inland Gas Upgrade Project ~ Project No. 1598988

We are counsel to the Commercial Energy Consumers Association of British Columbia (the "CEC"). Attached please find the CEC's first set of Information Requests to FEI with respect to the above-noted matter.

If you have any questions regarding the foregoing, please do not hesitate to contact the undersigned.

Yours truly,

OWEN BIRD LAW CORPORATION

Christopher P. Weafer

CPW/jj

cc: CEC
cc: FortisBC Energy Inc.
cc: Registered Interveners

COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA ("CEC")

INTERVENER INFORMATION REQUEST NO. 1 TO FORTISBC ENERGY INC.

FortisBC Energy Inc. Certificate of Public Convenience and Necessity Application for the Inland Gas Upgrade Project - Project No. 1598988

February 28, 2019

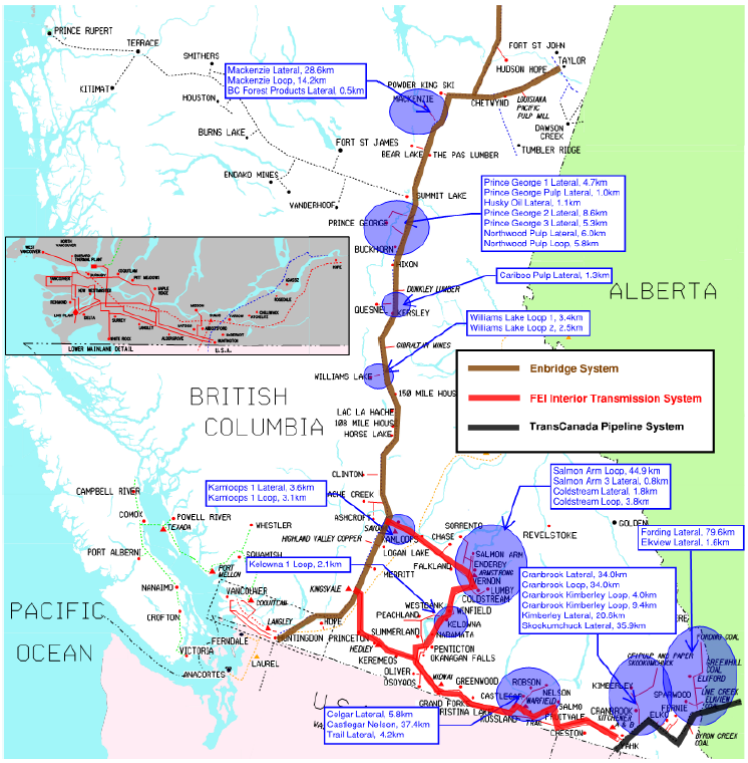
---

1. Reference: Exhibit B-1, page 1 and page 17, page 16 and page 23

1.1.1 CPCN for IGU Project

The IGU Project is needed to mitigate the potential for rupture failure due to corrosion on 29 transmission pipeline laterals on FEI's system that were constructed between 1957 and 1998, have a nominal pipe size (NPS) 6 or greater, operate as transmission[2] pipelines and are not capable of being in-line inspected (referred to in this Application as the 29 Transmission Laterals). FEI owns and operates approximately 3 thousand kilometres of transmission pressure (TP) pipelines in the province of British Columbia. The 29 Transmission Laterals collectively make up approximately 410 kilometres of pipe length. Because the 29 Transmission Laterals operate at transmission operating stress levels, there is a potential that corrosion in these pipelines, if left undetected, could result in rupture. FEI's current method of integrity verification for these laterals, Modified External Corrosion Direct Assessment (ECDA), will not detect active corrosion under circumstances found on FEI's system and therefore it is not an acceptable solution over the long term. As such, FEI is proposing alternate integrity management solutions that will mitigate the potential for rupture due to corrosion on the 29 Transmission Laterals.

Figure 3-1: Overview of the Transmission System in Interior British Columbia



[7] In addition to the 29 Transmission Laterals within the scope of the Project, FEI has one additional transmission lateral of NPS 6 or greater within its system (part of its Coastal Transmission System) operating at a stress of above 30 percent SMYS that does not already have ILI capability. This lateral is planned to be addressed through a separate project.

FEI first employed ILI technology in 1988 in selected mainline segments of the ITS. At that time, ILI tools provided much lower resolution data than is possible today and were available for only a limited range of pipeline diameters. By the early 2000s, higher resolution tools were becoming available and industry practice had evolved such that ILI was a widely-adopted operating practice for transmission pipeline operators. FEI 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 more recent years, and in alignment with other Canadian transmission pipeline operators, FEI's ILI practice has changed in the following areas:

- FEI has adopted new or improved ILI technologies to enhance capabilities with respect to imperfection detection and sizing;
- FEI has increased ILI frequency to provide increased statistical confidence in data analyses; and
- FEI has increased the numbers of pipelines subject to ILI, in part due to the commercialization of ILI tools over an expanding range of pipeline diameters, pipeline configurations and operating pressures.

1.1. What parameters did FortisBC Energy Inc. ("**FEI**") use to scope the current project? Please discuss and explain why FEI does not intend to address the single remaining lateral in the current project.

1.2. Are there other pipelines, regardless of size and operating stress, that FEI intends to provide with In-Line Inspection ("**ILI**") in the future?

1.2.1. If yes, could FEI generate cost efficiencies by incorporating any or all of the pipelines into the current project, or breaking the projects into geographic areas rather than using pipeline size and stress to identify the pipelines for remediation? Please explain and provide quantification if available.

1.3. Has, or does, FEI expect to experience similar corrosion in other portions of its system? Please explain why or why not.

1.3.1. If not, please explain what likely differentiates the Transmission Laterals in question (i.e. those that are experiencing corrosion and need upgrading) from other transmission lines in FEI's service area that do not experience corrosion and require upgrading.

1.3.2. If yes, please identify the areas in which FEI expects to see similar concerns.

1.3.3. If yes, how and when does FEI expect to address similar concerns in other areas.

1.3.4. If FEI is expecting to experience similar issues in significant portions of its remaining transmission pipelines, is the current CPCN application part of a larger overall project that is not yet before the Commission? Please explain.

2. Reference: Exhibit B-1, page 131 and FEI Long Term Gas Resource Plan page 186

9.3 *Long Term Resource Plan*

The Project is included in FEI's most recently filed long-term resource plan (LTRP). Referred to as the Transmission System Laterals In-Line Inspection Capability Project, the Project is described in section 6.4 of FEI's 2017 Long Term Gas Resource Plan (LTGRP) filed with the BCUC on December 14, 2017. At the time of filing the 2017 LTGRP, FEI was originally anticipating that the implementation of in-line inspection would be the primary means to mitigate the potential for rupture associated with corrosion on the laterals. Through further exploration of alternatives available to FEI, several other alternatives have since proven to be more cost-effective, as discussed in detail in Section 4 of this Application. The Project remains consistent with the 2017 LTGRP.

<u>Transmission System Laterals In-Line Inspection (ILI) Capability</u>

FEI operates transmission pressure laterals across the province served from either FEI operated transmission systems, the Westcoast pipeline or TransCanada and ranging from several hundred meters to several tens of kilometres in length. A total of more than 400 km of these pipeline laterals are between NPS 6 and NPS 10 and currently are not configured to allow ILI tools to be used as part FEI's pipeline integrity management programs. ILI

technology is an effective tool for detecting and subsequently repairing pipeline corrosion and defects prior to leaking or rupture. FEI is currently investigating the cost and justification to install tool launching and receiving facilities and remove existing pipeline obstructions on up to thirty-one lateral pipeline segments.

2.1. Did FEI assign quantification to the risk for any or all of the laterals? Please explain and provide quantification and overview of calculations.

2.2. Please provide FEI's definition of cost effectiveness as contemplated in the LTGRP for this project and how this was applied in this application.

2.3. Did FEI have a cost threshold against which it judged a project would or would not be cost-effective? Please explain.

2.3.1. If no, how did FEI determine whether or not each individual project, and the project as a whole, was appropriately cost justified against the risk.

2.4. Please quantify the number of areas of corroded pipeline on FEI's system that have breached and realized the risk in question for each of the last 2 years.

3. Reference: Exhibit B-1, page 5

1.2.2 Project Justification

The objective of the Project is to mitigate the potential for transmission pipeline rupture due to corrosion on the 29 Transmission Laterals. Rupture of a transmission pipeline could have significant safety, reliability, environmental and regulatory consequences and such an occurrence would be unacceptable to FEI, the public and its regulators.

3.1. Please provide a discussion of the urgency with which FEI believes the project must be undertaken and provide supporting evidence of the urgency to the extent it is available.

3.2. Please discuss the potential consequences of a rupture.

3.2.1. If the risk of a rupture would lead to a lack of service for a period of time, please project the number of customers that could be affected and the period for which they would be affected.

3.3. If the risk is of a rupture is a hazard to public, please describe the hazards and quantify the number of such risks that would be projected to occur in the next 3 years.

3.4. Please provide, and briefly summarize, a statistical risk assessment of the potential for a rupture due to corrosion on the 29 Transmission Laterals.

3.5. Please provide a discussion of each of the risks including safety, reliability, environmental and regulatory consequence and provide quantification for the consequences.

3.6. Please explain when FEI determined that there was a potential for rupture failure due to corrosion on the 29 Transmission Laterals and that an IGU project was necessary.

3.7. Did FEI engage a risk assessment professional to assess the extent of the risk?

3.7.1. If yes, please provide the name of the professional and any reports that were provided. Please provide confidentially if necessary.

3.7.2. If not, please explain why not.

3.8. Please confirm that FEI engaged Dynamic Risk Assessment Systems Inc. to study the likelihood of failure and potential failure impact in its application for the Huntingdon Station bypass CPCN, which had a capital cost of $7.6 million and affected 600,000 customers including multiple hospitals, emergency facilities, care homes, schools and public assembly facilities.

4. Reference: Exhibit B-1, page 5

> FEI has a comprehensive Integrity Management Program (IMP) as required by the BC Oil and Gas Commission (BC OGC). As part of the IMP, FEI's current strategy for detecting, assessing and monitoring the condition of its transmission pipelines relies primarily on the following two methods:
>
> 1. In-Line Inspection (ILI) – This method includes the insertion of a data collection device (commonly and variously referred to as an ILI tool, smart tool or pig) inside an operating pipeline to obtain indirect measurement and locations of imperfections such as metal loss, dents, and mechanical damage that may adversely affect the pipeline; and
> 2. Modified External Corrosion Direct Assessment (Modified ECDA) – This method employs above-ground cathodic protection (CP) surveys and coating evaluations, supplemented with integrity digs where warranted to evaluate asset condition.
>
> The 29 Transmission Laterals were not designed and constructed with ILI capabilities and have obstructions that prevent the clear passage of ILI tools. FEI is actively monitoring the condition of these 29 Transmission Laterals through Modified ECDA.
>
> FEI has identified limitations of Modified ECDA given the occurrence of the process of CP shielding on its pipeline system. Modified ECDA will not detect sites that may be experiencing active corrosion where CP shielding occurs. As such, FEI believes that the status quo is no longer acceptable over the long term.
>
> As corrosion is the leading cause of transmission pipeline failures in British Columbia, the Project is proposing several alternatives to the status quo that will provide for continued safe and reliable long-term operation of the 29 Transmission Laterals. The Project, completed proactively over a reasonable planning horizon and in consideration of the feasibility and benefits of alternate integrity management strategies, demonstrates FEI's commitment to continual improvement within its integrity management program, and is an appropriate response to the potential for rupture failure due to corrosion.

4.1. When ILI become a standardized method of detecting corrosion? What forms of inspection were used before ILI became standardized? Please explain.

4.2. After ILI became standardized, how many laterals were constructed and how many were constructed with obstructions preventing the use of ILI?

4.3. FEI states that it undertakes integrity digs where warranted. What are the conditions that result in FEI determining that an integrity dig is necessary?

4.4. How did FEI determine that cathodic protection ("**CP**") shielding is taking place? Please explain.

4.5. Is CP shielding a commonplace occurrence in gas pipelines, or should this be considered an unusual circumstance? Please provide the percentage on FEI's system for which CP shielding is taking place.

4.6. Is the CP shielding taking place along the full length of the pipelines or is it occurring in localized areas?

4.6.1. If it is occurring in localized areas is FEI able to pinpoint where the CP shielding is occurring? Please explain and provide the locations of where the CP shielding is occurring if it is occurring in localized areas.

4.7. How does FEI normally address CP shielding? Can CP shielding be repaired and/or repaired? Please explain.

4.8. If there are means to reduce or repair CP shielding, please provide an overview of the costs of doing so.

4.9. Please elaborate on how the presence of CP shielding prevents FEI from identifying corrosion.

4.10. FEI states that Modified ECDA as the status quo is no longer acceptable 'over the long term'. Please discuss whether or not FEI could phase in the necessary changes over a longer period of time, and be coordinated with other activities such as when other factors impact the pipeline, in order to reduce costs.

4.11. Is there a potential for FEI to experience operating savings as a result of the use of ILI, pressure regulating stations, pipeline replacement or any other aspect of the project? Please explain.

4.11.1. If yes, please identify each savings opportunity and quantify the savings.

4.11.2. If yes, please provide, with calculations, a quantitative analysis of the total potential operating savings over the lifetime of the project.

5. **Reference: Let's Talk Shielding**

http://www.canusacps.com/non_html/reference/WP_Oct2012_Shielding.pdf

However, the standard also "defines requirements for the following:

- Application procedure specifications.
- Pre-qualification trials.
- Pre-production trial.
- Inspection and testing plan.
- Quality assurance versus quality control."

The above elements ensure that a coating is properly installed rather than relying on CP to balance for expected deficiencies in installation quality. The question of shielding or non-shielding is never considered.

The question on some peoples' minds is: is shielding a real problem or a perceived issue? All good field joint coating systems have the potential to shield the CP system because good coatings must be good insulators with high dielectric strength and should not allow CP current to pass (through or along a path of absorbed electrolyte). Otherwise, the pipe could be left bare and protected with a very robust CP system.

5.1. The article by Robert Buchanan, Canusa-CPS, Canada discusses some aspects of CP shielding. Please comment on the article, and in particular the statement that 'All good field joint coating systems have the potential to shield the CP system because good coatings must be good insulators with high dielectric strength and should not allow CP current to pass'.

5.2. What is causing the CP shielding on FEI's system? Please explain.

6. Reference: Exhibit B-1, page 15

The objective of the IGU Project is to mitigate the potential for rupture due to corrosion on the 29 Transmission Laterals. As with all buried steel pipelines, the 29 Transmission Laterals are susceptible to corrosion, which is the leading cause of transmission pipeline incidents in British Columbia. Corrosion in transmission pipelines, which operate at a hoop stress of 30% or more of the specified minimum yield strength (SMYS) of the pipe, can result in a rupture, which can have significant safety, reliability, environmental and regulatory consequences. In alignment with the practices of its peer Canadian transmission pipeline operators and the expectations of the public and regulators, FEI is committed to adopting integrity management solutions to prevent ruptures due to external corrosion on its system.

There are multiple strategies available for operators to mitigate the potential for rupture on transmission pipelines due to external corrosion. FEI currently employs Modified External Corrosion Direct Assessment (ECDA) to detect, assess and monitor the condition of the 29 Transmission Laterals. Modified ECDA is a method of evaluating pipeline condition that relies on information collected from above-ground surveys (indirect inspection), and investigative digs (direct evaluation). Above-ground surveys can provide data regarding both cathodic protection (CP) system performance and the condition of the pipeline coating. However, this method is no longer an acceptable means to manage the potential for corrosion-related rupture of the 29 Transmission Laterals over the long term. FEI's inspection of its system has shown that active corrosion has occurred on cathodically-protected pipe due to a process called CP shielding. CP shielding is where the CP current is prevented from reaching the pipeline and where there is CP shielding, Modified ECDA will not detect sites that may be experiencing active corrosion.

6.1. Please explain if FEI is referring to a certain threshold level of corrosion, or if any corrosion at all represents a significant risk.

6.1.1. If FEI is responding to a certain threshold of corrosion, please provide a discussion with quantification of how corrosion is measured over time and assessed as creating risk.

6.2. Why does the Modified ECDA not detect sites that may be experiencing active corrosion?

6.3. If the ECDA does not detect active corrosion, why has FEI used the Modified ECDA in these 29 Transmission Laterals? Please discuss what can it be expected to detect and what it is used for by the utility.

6.3.1. If the Modified ECDA is being used successfully in other areas, please explain why it is not successful in this area/situation.

6.3.2. If it is not successfully used in other areas, please describe the steps that FEI has taken, or will be taking, to mitigate the risk with the other locations.

7. Reference: Exhibit B-1, page 18

3.3.1 Corrosion is the Leading Cause of Pipeline Failure

Pipeline failures can result from a number of causes such as damage by a third party, material defects and natural hazards. The leading cause of transmission pipeline failures in British Columbia is the deterioration of pipe condition caused by the time-dependent hazard of corrosion[9]. The BC OGC issued a Pipeline Performance Summary, 2016 Annual Report on November 23, 2017, identifying corrosion metal loss as the leading cause of failures of regulated pipelines for all years included in the report (i.e., 2011 to 2016) (Appendix C).

3.3.2 Evidence of External Corrosion on FEI's System

Through active pipe condition monitoring within its integrity management program, FEI has confirmed external corrosion on parts of its system and considers this to be a relevant hazard that requires ongoing management.

7.1. FEI discusses 'external' corrosion on its system as the concern in this application. Please provide an overview of any internal corrosion that FEI is aware of in the pipelines in question and discuss how FEI became aware of this corrosion.

8. Reference: https://www.capp.ca/publications-and-statistics/publications/322047

8.1. The Canadian Association of Petroleum Producers Best Management Practices provides the report 'Mitigation of External Corrosion on Buried Carbon Steel Gas Pipeline Systems' (July 2018) on its website at the above address.

8.2. On page 4, the report indicates that external corrosion is 'consistently ranked among the top 3 failure types'. Please verify this statement.

9. Reference: https://www.capp.ca/publications-and-statistics/publications/324144

9.1. The Canadian Association of Petroleum Producers Best Management Practices provides the report 'Mitigation of Internal Corrosion in Carbon Steel Gas Pipeline Systems' (September 2018) on its website at the above address.

9.2. Please briefly discuss the relevance of the report on mitigating internal corrosion to the current corrosion issues being addressed in this application.

9.3. The CAPP report identifies internal corrosion as being the 'ranked as the top failure type'. Please discuss whether or not external corrosion is equally significant in the types of failures experienced by pipelines in Canada.

9.4. The CAPP report identifies two types of internal corrosion: pitting and top-of-the line corrosion. To the extent that FEI is also aware of internal corrosion, please describe the type of corrosion that FEI is experiencing.

9.5. On pages 6 – 9, the CAPP report identifies various contributing factors (mechanisms and operations) to internal corrosion along with mitigation techniques for each. What are the underlying causes and/or contributing factors to the internal corrosion that FEI is experiencing in these Transmission Laterals if it is experiencing internal corrosion, hydrogen sulfide, carbon dioxide, oxygen, bacteria etc. or other? Please explain.

9.5.1. Please confirm that for the type of contributing factor being responded to in this project, FEI conducts the mitigation practices identified in the report.

9.5.2. If FEI does not apply the identified mitigation practices for the type of contributing factor(s), please explain why not.

10. Reference: Exhibit B-1, page 18

3.3.2 Evidence of External Corrosion on FEI's System

Through active pipe condition monitoring within its integrity management program, FEI has confirmed external corrosion on parts of its system and considers this to be a relevant hazard that requires ongoing management.

Proactive external corrosion management of buried steel pipelines is achieved primarily through external coatings in conjunction with CP. CP is the application of an electrical current to the pipeline to minimize the natural corrosion tendency of buried steel. CP provides a secondary defense where imperfections in the pipeline coating may exist. Industry and FEI's experience recognizes that, although CP is being applied to a pipeline, corrosion can still occur due to a process called CP shielding. CP shielding is where the CP current is prevented from reaching the pipeline, due to situations such as the presence of disbonded pipe coatings, large rocks, or foreign structures.

FEI has experienced CP shielding on its pipeline system. Specifically, 72 of 90 integrity digs conducted on FEI's in-line inspected transmission pipelines in 2017 showed evidence of active corrosion on cathodically protected pipe. This means that the CP current designed to prevent corrosion is being prevented in these cases from reaching the steel surface of the pipeline.

Further illustrating the presence of CP shielding in the FEI system is the NPS 20 Coquitlam to Vancouver pipeline. This pipeline required replacement as part of the Lower Mainland Intermediate Pressure System Upgrade Project in part due to CP shielding.

As FEI has demonstrated active corrosion on its system due to CP shielding, FEI must implement integrity management solutions to mitigate the potential for rupture due to this corrosion.

10.1. Please provide a map identifying the 90 integrity digs and the 72 instances of active corrosion.

10.2. Are the 72 instances of active corrosion likely indicative of active corrosion along the full length of the Transmission Laterals, or are they indicative of corrosion at particular locations or segments of the pipelines such as junctures, specific environments, types of pipeline coating materials, etc.? Please explain.

10.3. How often, and according to what criteria, does FEI typically conduct integrity digs throughout its service territory?

11. Reference: Exhibit B-1, page 20

Many of the 29 Transmission Laterals are single feed supply to many of the municipalities in the interior British Columbia regions collectively comprising approximately 167 thousand FEI customers. A pipeline rupture would result in loss of supply to end-use customers with economic consequences for residential, commercial and industrial customers. FEI estimates that an outage resulting from a rupture on the single feed laterals, depending on the severity, could range from weeks to months in order to repair, shutdown, purge the pipeline and relight customers. In addition, after the repairs have been completed, the lateral may be required to operate at a reduced pressure for a period of time until it is deemed acceptable to resume normal operating pressure.

11.1. Please provide an estimate of the size of the 'economic consequences and identify how they were calculated.

11.2. Has FEI prioritized the Transmission Laterals relative to each other, or relative to other pipeline improvements in the FEI service territory? Please explain.

12. Reference: Exhibit B-1, page 21

3.4.2 Limitations of ECDA Methods

Modified ECDA and ECDA are not capable of detecting corrosion in areas of CP shielding.[14] As discussed above, FEI's ILI activity has provided evidence of CP shielding on its pipeline system, which can lead to corrosion that would be undetected by ECDA methods. Modified ECDA and ECDA both involve the completion of above-ground surveys that rely on the detection and measurement of a signal (electrical current) discharging from the pipe surface. CP shielding not only prevents CP current from reaching the steel pipe surface, but also prevents the above-ground survey signal (current) from leaving the pipe. Therefore, no signal can be received and measured at the surface above the pipeline. The NACE Standard Test Method, "Aboveground Survey Techniques for the Evaluation of Underground Pipeline Coating Condition" (NACE Standard TM0109-2009, Item No. 21254) states:

> None of the aboveground coating evaluation techniques included in this standard are capable of detecting pipeline steel that is electrically shielded from the bulk electrolyte by disbonded coatings with no electrically continuous path to the electrolyte.

Consequently, if FEI was to continue only with Modified ECDA integrity management activities, FEI anticipates that CP shielding would result in corrosion sites remaining unidentified and therefore unmitigated.

Alternate integrity management strategies, including ILI, pressure regulation, and pipe replacement, are available for mitigating the potential for rupture that exists for transmission pipelines. Given the ineffectiveness of ECDA or Modified ECDA on a pipeline system with CP shielding, and the availability of other methods, FEI needs to assess other acceptable integrity management strategies.

12.1. Does, or can, FEI reasonably assume that there is corrosion wherever it determines that there is CP shielding? Please explain why or why not.

13. Reference: Exhibit B-1, page 21

3.4.3 Need to Assess Other Integrity Management Solutions

Given FEI's observation of corrosion on cathodically-protected pipe on its system and the limitations of Modified ECDA in detecting corrosion imperfections, FEI needs to assess and employ other integrity management solutions that will provide FEI the ability to mitigate the potential for rupture due to corrosion on the 29 Transmission Laterals.

As stated previously, FEI is required by the BC OGC to have an integrity management program. Through legislation, this integrity management program must address the life cycle of the pipeline system and be compliant with the CSA Z662-15, Section 3.2 and Annex N. Section 10.3 of CSA Z662-15 specifies that the integrity management program must include procedures to monitor for conditions that can lead to failures, to eliminate or mitigate such conditions, and to manage integrity data.

The BC OGC's expectations for transmission pipeline performance are defined in the *Oil and Gas Commission Activities Act* (OGAA) requirement to prevent all releases of product from operating pipelines. Section 37 (1) (a) of the OGAA states, "A permit holder, an authorization holder and a person carrying out an oil and gas activity must prevent spillage".[15]

The IGU Project is an appropriate, proactive response to FEI's obligations under the OGAA, with consideration to cost effectiveness in addition to a solution's ability to prevent ruptures, prevent leaks, and provide data for proactive lifecycle asset management decisions.

13.1. For how long has FEI been aware of corrosion on cathodically-protected pipe on its system and the limitations of Modified ECDA in detecting corrosion imperfections?

13.2. Please confirm that FEI is currently compliant with all the BC OGC regulations.

13.3. Please elaborate on the types of decisions that FEI is referring to in 'proactive lifecycle asset management decisions' and provide examples of how the data will be of assistance.

14. Reference: Exhibit B-1, page 22 and 23

FEI's current integrity management activities are implemented and reviewed as part of a comprehensive single management system that systematically addresses all hazards that can affect the integrity of the pipeline system. The management system is known as the Integrity Management Program – Pipeline (IMP-P).

The hazard groups included within the IMP-P are as follows:

- Third party damage;
- Natural hazards, which includes potential geotechnical, hydrotechnical and seismic issues;

- Pipe condition, which includes the time-dependent hazards of external corrosion and stress corrosion cracking;
- Material defects and equipment failures; and
- Human factors.

14.1. Does the hazard group, included within the IMP-P, include internal corrosion as well as external corrosion? Please explain.

14.1.1. If not, how does FEI address internal corrosion in its integrity management program? Please explain.

15. Reference: Exhibit B-1, page 23

FEI first employed ILI technology in 1988 in selected mainline segments of the ITS. At that time, ILI tools provided much lower resolution data than is possible today and were available for only a limited range of pipeline diameters. By the early 2000s, higher resolution tools were becoming available and industry practice had evolved such that ILI was a widely-adopted operating practice for transmission pipeline operators. FEI 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 more recent years, and in alignment with other Canadian transmission pipeline operators, FEI's ILI practice has changed in the following areas:

- FEI has adopted new or improved ILI technologies to enhance capabilities with respect to imperfection detection and sizing;
- FEI has increased ILI frequency to provide increased statistical confidence in data analyses; and
- FEI has increased the numbers of pipelines subject to ILI, in part due to the commercialization of ILI tools over an expanding range of pipeline diameters, pipeline configurations and operating pressures.

15.1. Was FEI an early adopter of ILI? Please explain.

15.2. Please describe how FEI utilized ILI in 1988 and the value of such use to FEI when the resolution data was lower than is available today.

16. Reference: Exhibit B-1, page 24 and https://www.innerspec.com/knowledge/emat-faqs/

Although not part of this Project, FEI is currently developing its strategy for adopting crack-detection capabilities through ILI. This work is proceeding as part of the Transmission Integrity Management Capabilities (TIMC) project, as described in FEI's Annual Review for 2019 Delivery Rates Application and responses to information requests. A quantitative risk assessment is underway for determining particular pipelines that will require modifications in order to accommodate EMAT tools[16], as well as their urgency and priority. FEI notes at this time that EMAT technology suitable for FEI's natural gas system is not yet available and/or commercialized for smaller diameter pipelines (e.g. less than NPS 12) and its development timeline is unknown. However, FEI's ILI retrofits will also be able to facilitate EMAT tool adoption if and when it is deemed necessary.

[16] Crack-detection in-line inspection tools are commonly referred to as "EMAT tools" as the technology relies upon electro-magnetic acoustic transducers. EMAT is a non-destructive testing technology that has applications in a wide range of industrial sectors. EMAT is generally used to assess the condition of manufactured objects and the technology is particularly effective for detection of stress corrosion cracking and disbonded coating. The EMAT generates an ultrasonic pulse within a metallic and/or ferromagnetic test object. The sound waves are generated in the material and thus no couplant is needed.

16.1. Please provide a brief overview of the difference between FEI's TIMC project and its current project.

16.2. Innerspec, at the webpage noted above, provides an overview of EMAT technology and states that

> 'EMAT is a relatively new technique still unexplored by many potential users. EMAT transducers also require high power and specific electronic equipment that is not widely available. As industry discovers the advantages of EMAT its use will spread to an increasing number of applications'.

To the extent that EMAT tools were available at this time, would they represent a potential alternative for consideration instead of the options currently under consideration in this application? Please explain.

16.2.1. If yes, did FEI consider working with the vendor to develop EMAT capability over this period of time? Please explain.

17. Reference: Exhibit B-1, pages 19 and page 25

3.3.3 Transmission Pipelines Operating Over 30 percent SMYS can Fail by Rupture

A pipeline's potential to fail by rupture due to corrosion can be determined by comparing the pipeline's operating hoop stress to the SMYS of the pipe. The operating hoop stress of a pipeline is the force per unit area exerted in the circumferential direction of the pipe wall due to the internal pressure of the fluid in the piping. The yield strength of a pipe is the level of stress where the pipe begins to permanently deform (yield). The SMYS of a pipe is the minimum yield strength prescribed by the specification or standard to which a material is manufactured.

A threshold of 30 percent for the ratio of a pipeline's operating hoop stress as compared to the SMYS of the pipe has been adopted by the Canadian Standards Association Oil & Gas Pipeline Systems standard, CSA Z662, as a delineator between a transmission pipeline and a gas distribution system.[10] 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"[11] 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.

[10] Transmission pipelines have an operating hoop stress of greater than or equal to 30% of the SMYS of the pipe, whereas distribution pipelines have an operating hoop stress less than 30%. FEI's operating pressure classifications of its system (e.g. Transmission Pressure (TP), Intermediate Pressure (IP), and Distribution Pressure (DP)), that have appeared in prior FEI submissions to the BCUC, are different from the operating stress-based classification that is applicable to this application. Some FEI TP assets are certified by the BC OGC to operate above 30 percent SMYS, while others are certified to operate below 30% SMYS.

An example of Canadian industry failure history is contained within a NEB letter to TransCanada PipeLines Limited (TCPL) on March 5, 2014 as part of Order SG-N081-001-2014. The letter and order, is included as Appendix F[17], pertains to the portion of TransCanada PipeLines Ltd.'s pipeline system known as Nova Gas Transmission Ltd. (NGTL). Within the letter accompanying the order, the NEB states:

> The National Energy Board (NEB or the Board) recently released its audit of TransCanada Pipelines Ltd.'s (TransCanada) integrity management program. In the audit, the Board noted potential safety concerns for pipelines, specifically in the NGTL system, that either have not or cannot be inspected using in-line tools. Since the conclusion of the NEB's information gathering component of the audit in August of 2013, there have been three ruptures and four leaks on TransCanada's NGTL system. Those lines that have been returned to service are currently operating under a 20% pressure restriction.
>
> The Board is concerned by this recent trend of pipeline releases. In order to proactively promote public safety and protection of the environment, the Board orders TransCanada to reduce its maximum operating pressure on the unpiggable pipelines previously identified by TransCanada to have the highest risk. The Board's intention with these pressure reductions is to encourage the conditions necessary for the continued safe operation of this network of natural gas pipelines, while proactively reducing the risk of future ruptures.

17.1. Please confirm or otherwise explain that FEI has not been directed by the OCG to conduct any particular risk mitigation activities for the laterals in question.

17.2. Under what circumstances does FEI expect that the OCG would direct FEI to conduct risk mitigation measures as proposed by FEI?

18. Reference: Exhibit B-1, page 18 and page 26

> **3.3.2 Evidence of External Corrosion on FEI's System**
>
> Through active pipe condition monitoring within its integrity management program, FEI has confirmed external corrosion on parts of its system and considers this to be a relevant hazard that requires ongoing management.
>
> Proactive external corrosion management of buried steel pipelines is achieved primarily through external coatings in conjunction with CP. CP is the application of an electrical current to the pipeline to minimize the natural corrosion tendency of buried steel. CP provides a secondary defense where imperfections in the pipeline coating may exist. Industry and FEI's experience recognizes that, although CP is being applied to a pipeline, corrosion can still occur due to a process called CP shielding. CP shielding is where the CP current is prevented from reaching the pipeline, due to situations such as the presence of disbonded pipe coatings, large rocks, or foreign structures.
>
> FEI has experienced CP shielding on its pipeline system. Specifically, 72 of 90 integrity digs conducted on FEI's in-line inspected transmission pipelines in 2017 showed evidence of active corrosion on cathodically protected pipe. This means that the CP current designed to prevent corrosion is being prevented in these cases from reaching the steel surface of the pipeline.

There are multiple strategies available for operators to mitigate the potential for rupture on transmission pipelines due to corrosion. The Project is proposing several alternatives to the status quo, including ILI and other cost effective solutions, including installation of pressure regulation facilities or replacement of the pipeline that will provide for continued safe and reliable long-term operation of these lines. The Project, completed proactively over a reasonable planning horizon and in consideration of the feasibility and benefits of alternate integrity management strategies, demonstrates FEI's commitment to continual improvement within its integrity management program, and is an appropriate response to the potential for rupture failure due to corrosion.

18.1. Is it FEI's contention that the transmission laterals are currently unsafe?

18.1.1. If yes, would it be appropriate for FEI to take immediate action such as closing or reducing pressure on any or all of the laterals at this time to prevent a rupture?

18.2. If no, at what point would FEI consider any or all of the transmission laterals as unsafe? Please elaborate and provide criteria for determining what conditions would render the pipelines to be considered unsafe and when such conditions would be likely to appear.

19. Reference: Exhibit B-1, page 27

These are:

1. Status Quo: Modified External Corrosion Direct Assessment (Modified ECDA);
2. Pipeline exposure and re-coat (PLE);
3. Hydrostatic testing program (HSTP);
4. Pressure regulating station (PRS);
5. In-line inspection (ILI);
6. Pipeline replacement (PLR); and
7. Robotic Inspection (ROB).

FEI evaluated the alternatives using a weighted scoring system based on three criteria: (1) Integrity and Asset Management Capability; (2) Project Execution and Lifecycle Operation; and (3) Financial. The alternative with the highest evaluated score was selected, except in cases where the scoring system produced similar results or where the highest scoring alternative was not the lowest cost, in which case FEI used subject matter experts to validate the scores and select a preferred alternative.

The status quo alternative was rejected because it does not meet the Project's objective of mitigating the potential for rupture failure due to corrosion. FEI rejected ROB as it is not considered proven and commercialized at this time. FEI also rejected the PLE and HSTP alternatives as not feasible due to a combination of lack of integrity management benefits, higher cost, and the disruption of service to customers. For some laterals, PRS was rejected in favour of other alternatives due to capacity limitations of some systems. In some cases, PLR was rejected in favor of other alternatives when the laterals were longer than 4.0 kilometres due to higher cost.

19.1. Please confirm that there are independent companies, such as Balboa Oil and Gas Inspection and Maintenance Service (https://www.balboa-im.com/services), that offer non-destructive testing for difficult to inspect pipelines.

19.2. Would it be possible for FEI to use a company such as the above (or others) to successfully conduct inspections?

19.2.1. If no, please explain why not.

19.2.2. If yes, did FEI consider outsourcing its pipeline inspection? Please explain why or why not.

20. Reference: Exhibit B-1, page 39

4.4.2 Robotic Inspection (ROB) Screened Out Based on Readiness

At this time, FEI does not consider robotic ILI tools to be proven and commercialized. The technology is not available for pipe sizes of NPS 6 (168mm) and FEI is only aware of a single vendor providing this service for larger pipe sizes. As described in Section 4.2.7, the batteries require recharging approximately every 450 metres. The required excavations at each recharge point each and every time the robotic tool is run is not desirable from a lifecycle operation perspective in terms of impact to the environment, Indigenous communities, and stakeholders.

As a result, the ROB alternative was screened out as not feasible and was not considered further in the evaluation process.

21. Reference: Balboa Oil and Gas Inspection and Maintenance Service claims to offer Robotic Pipeline Inspection on their website (see URL https://www.balboa-im.com/services) and claims to provide 'internal pipeline inspections using state-of the-art tethered and robotic instruments' (see URL https://www.balboa-im.com/about-us)

21.1. Please comment on whether or not FEI is referencing these services as being unavailable or if FEI is referring to other robotic inspection tools and service.

21.1.1. If FEI is referring to different robotic inspections, please elaborate on the types of ROB that are not yet proven or commercially feasible.

21.1.2. When does FEI expect that ROB could become proven and/or commercially available? Please provide a ballpark estimate. (i.e. 5 years, 1 decade, longer)

21.1.3. If ROB were to be proven and commercially available in the next 5 years or the next decade, would FEI consider these services to be an appropriate option to pursue? Please explain why or why not.

21.1.4. If yes, please provide FEI's views as to how the benefits and costs of using ROB will likely compare to the benefits and costs of the ILI program if ROB becomes proven and commercially available in the next five years, and the next decade.

21.1.5. If yes, please explain whether or not it could be worthwhile to postpone certain activities in order to employ robotic ILI in the near future.

21.2. Has FEI considered using ROB technology in a sample test of cases in parallel with ILI technology to determine its potential efficacy? Please explain.

22. Reference: Exhibit B-1, page 30 and page 43

4.2.2 Pipeline Exposure and Re-Coat (PLE) Alternative

This alternative involves exposing the entire length of a pipeline, performing a detailed inspection of the pipeline surface and assessing any imperfections, conducting required pipeline repairs, and completing a recoat of the entire pipe surface. The full length of the pipeline would then be re-buried and subject to site rehabilitation and future Modified ECDA. Large-scale in-ditch recoating of pipelines is a complex undertaking, and is not typically performed by operators due to high costs relative to other available solutions.

Initially, high level cost estimates were used to screen out technically feasible alternatives that were cost prohibitive and therefore considered to be not financially feasible[25]. Based on the high level cost estimates for the PLE alternative as shown below in Table 4-7, it is clear that the cost of the PLE alternative is either higher or comparable to other alternatives that were able to provide better integrity and asset management capabilities. FEI therefore did not pursue the PLE alternative further in the evaluation process.

Table 4-7: High Level Cost Comparison of PLE to Other Alternatives (2018$)

Lateral	ILI ($ millions)	PLR ($ millions)	PRS ($ millions)	PLE ($ millions)
BC Forest Products Lateral 168	6.7	3.3	3.7	4.2
Cariboo Pulp Lateral 168	5.1	3.8	3.4	6.1
Kamloops Lateral/Loop 168	11.2	12.4	N/A*	26.5
Salmon Arm 3 Lateral 168	5.1	2.8	N/A*	4.6

**PRS was not feasible for these laterals and as a result, no cost estimate was developed.*

22.1. Please provide a brief overview of the various alternatives, describing at a high level their general differences in the extent of ecological damage, impact on pipeline longevity, costs, benefits and/or other considerations that may or may not have been directly examined in the assessment of alternatives.

23. Reference: Exhibit B-1, page 39

4.4.3 Pressure Regulating Station (PRS) Screened Out for Some Laterals Based on Capacity Limitations

PRS was not viable for some laterals due to capacity limitations of some systems. By reducing the operating pressure of the pipeline, the capacity available to customers will change. Laterals where a PRS would impact existing firm customers or interruptible customer operations or prevent new additions of new customers to the lateral were not considered candidates for the PRS alternative. Below in Table 4-5 are the 29 Transmission Laterals and their PRS feasibility.

Table 4-5: Feasibility of PRS for the 29 Transmission Laterals

Line/Loop Full Name	PRS Feasibility
Mackenzie Lateral 168	Not Feasible
Mackenzie Loop 168	Not Feasible
BC Forest Products Lateral 168	Feasible
Prince George 3 Lateral 219	Feasible
Northwood Pulp Lateral 168	Feasible
Northwood Pulp Loop 219	Feasible
Prince George 1 Lateral 168	Not Feasible
Prince George Pulp Lateral 168	Feasible
Husky Oil Lateral 168	Feasible
Prince George 2 Lateral 219	Feasible
Cariboo Pulp Lateral 168	Feasible
Williams Lake Loop 1 and 2 168	Feasible
Kamloops 1 Lateral/Loop 168	Not Feasible
Salmon Arm Loop 168	Not Feasible
Salmon Arm 3 Lateral 168	Not Feasible
Coldstream Lateral 219	Feasible
Coldstream Loop 168	Feasible
Kelowna 1 Loop 219	Feasible
Celgar Lateral 168	Feasible
Castlegar Nelson 168	Feasible
Trail Lateral 168	Feasible
Fording Lateral 219/168	Not Feasible
Elkview Lateral 168	Feasible
Cranbrook Lateral 168	Not Feasible
Cranbrook Loop 219	Not Feasible
Cranbrook Kimberley Loop 219	Not Feasible
Cranbrook Kimberley Loop 273	Not Feasible
Kimberley Lateral 168	Not Feasible
Skookumchuck Lateral 219	Not Feasible

23.1. Please elaborate on the types of impacts that would be experienced by customers for each lateral for which it was not considered feasible to provide PRS as an option.

23.2. Could FEI support customers over the long term who may experience intermittent issues with other options such as Compressed Natural Gas? Please explain why or why not.

23.3. What are FEI's responsibilities to its interruptible customers, and how would this be impacted by reducing operating pressure?

23.4. Please identify on which laterals interruptible customers are present.

24. Reference: Exhibit B-1, page 46 and page 85

Table 6-3 presents the financial evaluation of the Project over a 66-year period (60 years post-Project and 6 prior years during the Project)[38]. The present value of the net cash flow of the Project represent (0.99%) of the present value of the incremental revenue requirement over 66 years[39]. Details of the financial evaluation of the Project as well as of each individual lateral can be found in the Financial Schedules as included in Confidential Appendices N-1 and N-2.

Table 6-3: Financial Analysis of the Project

	ILI	PLR	PRS	TOTAL
Number of Laterals per Type of Preferred Option	11	4	14	*29*
Total Charged to Gas Plant in Service ($ millions)	268.998	31.750	61.831	*362.579*
Abandonment / Demolition Costs ($ millions)	0.058	0.268	-	*0.325*
Total Project Deferral Cost	0.376	0.137	0.478	*0.991*
Total Project Cost ($ millions)	***269.431***	***32.154***	***62.310***	***363.895***
Rate Impact in 2025, when all assets enter Rate Base (%)	3.31%	0.29%	0.71%	*4.31%*
Levelized Delivery Rate Impact 66 years (%)	2.33%	0.22%	0.52%	*3.06%*
Levelized Delivery Rate Impact 66 years ($/GJ)	0.094	0.009	0.021	*0.124*
PV of Incremental Revenue Requirement 66 years ($ million)	320.577	29.898	71.615	*422.090*
Net Cash Flow NPV 66 years ($ million)	(1.67)	(1.04)	(1.48)	*(4.19)*

[38] The 60-year post-project analysis period was chosen based on the currently approved depreciation rate of Transmission Main pipeline at 1.47% (or 68 years) since the majority of the capital expenditure, especially for ILI and PLR, are tracked under the Transmission Main pipeline asset. For simplicity, the analysis period for post-project is rounded down to 60 years considering it still covers approximately 90 percent of the depreciation life of a Transmission Main pipeline. The 6 prior years is based on the construction schedule of the Project from 2019 to 2024.

24.1. Please explain why 60 years is considered simpler than 68 years.

25. Reference: Exhibit B-1, page 44 and page 47 and Appendix A page

Table 4-9: High Level Cost Comparisons of PLR to Other Alternatives for Longer Laterals (2018$)

Lateral	ILI ($ millions)	PRS ($ millions)	PLR ($ millions)
Mackenzie Lateral 168	27.6	N/A*	71.7
Mackenzie Loop 168	15.4	N/A*	35.6
Prince George 3 Lateral 219	8.2	1.2	20.9
Northwood Pulp Lateral 168	8.5	1.2	23.4
Northwood Pulp Loop 219	8.0	1.2	22.8
Prince George 1 Lateral 168	8.2	N/A*	18.4
Prince George 2 Lateral 219	8.6	3.5	27.1
Williams Lake Loop 1 168	3.8	1.7	13.2
Williams Lake Loop 2 168	5.4	1.7	9.8
Salmon Arm Loop 168	19.7	N/A*	105.4
Coldstream Loop 168	8.3	3.4	14.7
Kelowna 1 Loop 219	8.3	4.0	8.2
Celgar Lateral 168	6.7	3.5	22.6
Castlegar Nelson 168	36.0	5.3	109.6
Trail Lateral 168	12.3	3.6	20.7
Fording Lateral 219/168	64.0	N/A*	186.8
Cranbrook Lateral 168	10.6	N/A*	79.8
Cranbrook Loop 219	9.1	N/A*	79.8
Cranbrook Kimberley Loop 219	4.8	N/A*	15.7
Cranbrook Kimberley Loop 273	5.3	N/A*	27.6
Kimberley Lateral 168	13.2	N/A*	48.3
Skookumchuck Lateral 219	4.7	N/A*	84.3

**PRS was not technically feasible for these laterals and as a result, no cost estimate was developed.*

Table 4-10: Preferred Alternative for Each Lateral and Present Value of Incremental Revenue Requirement over 66-years of Analysis Period

Lateral	Length (kilometres)	ILI Present Value ($ millions)	PLR Present Value ($ millions)	PRS Present Value ($ millions)	Preferred Alternatives
Mackenzie Lateral 168	28.7	45.8	-	-	ILI
Mackenzie Loop 168	14.2	24.9	-	-	ILI
BC Forest Products Lateral 168	0.5	12.6	4.5	7.0	PLR
Prince George 3 Lateral 219	5.3	14.3	-	2.2	PRS
Northwood Pulp Lateral 168	6.0	15.4	-	2.2	PRS
Northwood Pulp Loop 219	5.8	14.1	-	2.2	PRS
Prince George #1 Ltl 168	4.7	14.2	-	-	ILI
Prince George Pulp Lateral 168	1.0	14.3	7.4	3.6	PRS
Husky Oil Lateral 168	1.1	16.4	5.5	3.6	PRS
Prince George #2 Lateral 219	8.7	15.8	-	6.3	PRS
Cariboo Pulp Lateral 168	1.3	10.5	5.3	6.5	PLR
Williams Lake Loop 168	5.9	15.7	-	6.0	PRS
Kamloops 1 Lateral & Loop 168	6.6	32.1	16.3	-	PLR
Salmon Arm Loop 168	44.9	33.6	-	-	ILI
Salmon Arm 3 Lateral	0.9	10.5	3.8	-	PLR
Coldstream Lat 219	1.8	13.2	8.5	5.9	PRS
Coldstream Loop 168	3.8	14.2	-	6.0	PRS
Kelowna 1 Loop 219	2.1	14.0	-	6.9	PRS
Celgar Lateral 168	5.8	11.7	-	5.9	PRS
Castlegar Nelson 168	37.4	54.2	-	9.0	PRS
Trail Lateral 168	4.2	19.0	-	5.9	PRS
Fording Lateral 219/168	79.7	102.3	-	-	ILI
Elkview Lateral 168	1.6	10.1	5.8	5.9	PRS
Cranbrook Lateral 168	34.0	22.3	-	-	ILI
Cranbrook Loop 219	34.0	20.5	-	-	ILI
Cranbrook Kimberley Loop 219	4.0	9.2	-	-	ILI
Cranbrook Kimberley Loop 273	9.4	10.7	-	-	ILI
Kimberly Lateral 168	20.6	23.3	-	-	ILI
Skookumchuck Lateral 219	35.9	13.8	-	-	ILI

25.1. Please provide the expected remaining life for each lateral. If the project affects the remaining life, please provide the remaining life both before and after the project.

25.2. The CEC notes that the ratio of PV in Table 4-10 and costs ($ 2018) in Table 4-9 varies somewhat between the laterals. For example, for the Castlegar Nelson lateral, the ratio of ILI PV ($54.2 million) to the ILI cost ($36 million) is approximately 1.51, whereas for the Cranbrook Lateral 168, the ratio of ILI PV (22.3 million) to ILI cost in 2018 $ ($10.6 million) is 2.1. Does the discrepancy in the ratios of the 2018 costs to the PV of the costs between the various laterals reflect the timing of the implementation, or is there some other reason? Please explain.

25.3. Certain laterals such as the BC Forest Products Lateral have a short length (0.5 km) but a relatively high cost ($4.5 million) resulting in a higher cost per km. Please discuss whether or not FEI could potentially find alternatives such as increased maintenance and inspection digs to reduce costs where the pipeline lengths are very short.

26. Reference: Exhibit B-1, page 69 and 70

5.3.4.3 Quantitative Risk Analysis and Contingency

Following the completion of the risk register a quantitative analysis using Monte Carlo Simulation was completed by Stantec to determine a distribution of possible cost outcomes associated with the existing scope of the Project at different levels of confidence. The Stantec analysis derived a risk adjusted P50 cost of $279 million representing a contingency of approximately 14.4%. Please refer to Confidential Appendix N-1 for further details on Stantec's methodology and results.

The Stantec cost estimate for the ILI component of the Project was developed assuming approximately 178 restrictive bends. The number of restrictive bends was determined by selecting a representative sample for some laterals and conducting above ground surveys (using line locating tools) and some sub-surface surveys. The surveys identified locations that were either an obstruction or not. Due to the limited capability of the investigations to quantify the most likely quantity of restrictive bends, FEI engaged Bramcon, an engineering and project management company, to undertake a simulation to assist in establishing the most likely number of bends.

The Bramcon analysis, as presented in Confidential Appendix L-2, recommends that the base estimate should be based on 200 restrictive bends. It is important to note that this analysis relates only to the number of restrictive bends and was done to assist in establishing a suitable contingency percentage. That is, considering the vintage of the 29 Transmission Laterals, the 200 restrictive bends is an indication of cost that is expected to be spent[33]. Essentially, any restrictive bend that is found becomes part of the Project's scope and must be replaced by the Project team. Using Bramcon's analysis to augment the results of Stantec's risk analysis, FEI determined a Project contingency of approximately 18 percent to achieve a P50 level of confidence.

FEI then engaged John Hollmann, principal/owner of Validation Estimating, to conduct a benchmarking analysis to provide a check of the adequacy of the Stantec contingency estimates for the Project risks over a multiyear execution timeframe. To conduct its check analysis, Validation Estimating relied on Stantec's cost, schedule and risk inputs and used a "hybrid" method to effectively cover both Project system risks and Project-specific risks (events and conditions).[34] The methodology is discussed in detail in Confidential Appendix L-3[35].

The results of the analysis conducted by Validation Estimating showed a wider range of cost outcomes over a similar confidence level when compared to those estimated by Stantec's analysis. The output of the Monte Carlo Simulation, assuming 0.75 correlation,[36] is as follows:

26.1. Please elaborate on how the vintage of the pipeline affects the number of restrictive bends.

26.2. Please provide Mr. Hollmann's credentials.

27. Reference: Exhibit B-1, Appendix O, EOA Northern and Central BC Sub-Region, page 1

1.1 Project Scope and Area

FortisBC identified preferred and alternative engineering options for each lateral. The Set 1 laterals and the associated preferred and alternative engineering options are listed in **Table 1.1**. The location of each lateral and anticipated construction footprints are shown in the Environmental Worksheets (**Appendix A**). The engineering options are described as follows:

- Pipeline replacement (PLR): The construction footprint is expected to be 30 m wide for the length of the pipeline. Pipeline replacement activities include:
  - Installation of a new pipeline in parallel with the existing pipeline
  - Deactivation and abandonment in place of the old line

27.1. Did FEI always select the next lowest cost option for the alternative option?

27.1.1. If no, please provide the basis on which FEI provided its alternative option for the Environmental Assessment.

28. Reference: Exhibit B-1, page 70 and page 71 and page 75 and page 76

5.4.1 Contractor Selection and Award

Given the scale and scope of the Project, FEI will use a project delivery method that utilizes separate contracts for engineering design and construction. The engineering design will be completed using a services contract for the complete design and development of bid packages.

These bid packages will then be used to seek tenders from contractors for the construction of the works. Depending on the results of the tendering process, one or more construction contracts will be awarded.

5.4.3 Engineering Detailed Design

Design activities will encompass all engineering calculations, validations, preparation of drawings and bid packages required to cover the Project needs. Some early engineering detailed design will commence in December 2018 due to the anticipated lead times for materials such as valves that are required in order to meet the proposed construction schedule. Engineering activities will be organized in order of priority, in relation to the fabrication/procurement lead times and scheduled date for each of the laterals.

Engineering designs to be completed are:

- ILI modifications (LA, RA, CVA, MLVA, bend and tee replacements, stopple upgrades);
- PLR alignment sheets and pipe specifications; and
- PRS components (Control valves, filters, telemetry, buildings and piping).

The engineering design activities will be completed by a consulting engineering firm acceptable to FEI. The design phase will be concluded by the final design review for each lateral, and the issued for construction drawings.

5.5 *Project Resources*

5.5.1 Project Management and Human Resources

Figure 5-4 outlines a functional organization chart for the execution of the Project. The project will be managed by FEI's Project management team and will include both internal and external personnel and use external engineering resources as required.

28.1. Please itemize and provide costs for all costs that will be conducted by third parties but will not be put out to tender.

28.2. For any contracts of over $1 million that are not put out to tender, please explain why they will not be tendered.

28.3. Please provide a description of FEI's standard practices with regard to tendering.

29. Reference: Exhibit B-1, page 78

> ***5.6.1.2 Ecological Environment***
>
> The Project design options are all located within or directly adjacent to existing ROW. The 29 Transmission Laterals overlap with watercourses, patches of mature trees, and areas with potential for plant communities at risk. Habitat for wildlife or plant species at risk overlaps with 24 of the 29 Transmission Laterals. Over 37 species of invasive plants are present in areas of existing disturbance along the laterals, especially near urban areas.
>
> Project design options were assessed for their potential impacts or effects on the ecological environment and options were selected to minimize disturbance to sensitive environmental features. Best practices will be applied to minimize any remaining potential negative impacts or effects on the environmental. Invasive plant management will be applied throughout Project construction to minimize the potential spread or introduction of invasive plants. Some vegetation removal will be required during site preparation and construction.
>
> Contaminated sites may be present along some laterals. Preliminary surveys identified the location and nature of potential contaminated sites. Further studies will be completed prior to construction to identify appropriate handling and disposal techniques.

29.1. Please provide an overview of the wildlife that will be impacted, identifying any species at risk.

29.2. Please provide an overview of the best practices that FEI will utilize to avoid impacts to wildlife during the project.

29.3. Please provide an overview of the plant communities that are considered at risk and could be impacted by the project.

30. Reference: Exhibit B-1, page 78

> **5.6.2 Socio-Economic Overview**
>
> As part of the Project's overall impact and risk assessment, FEI completed a socio-economic assessment.
>
> The Project will result in an overall positive impact to residents and businesses through the creation of additional employment within the Project scope, and the procurement of local materials and the use of local services, such as local lodging and dining. The Project will limit the potential for a loss or a disruption of gas supply and will improve the reliability of the natural gas system. Short-term disruption effects of the Projects are expected to be temporary and generally minor. Some of these impacts include minor traffic delays, access restrictions to sections of a public park and temporary parking restrictions to sections of business parking lots. FEI does not anticipate long term negative impacts as a result of the Project.

30.1. To the extent available, please briefly discuss and provide quantification for additional local employment to the extent available.

30.2. Has the natural gas system had reliability issues in the affected laterals? Please explain and provide evidence of the reliability issues.

31. Reference: Exhibit B-1, Appendix A page 17

1.1.11 Cariboo Pulp Lateral 168

The Cariboo Pulp Lateral begins near the North end of North Star Road in Quesnel and continues west to feed Cariboo Pulp & Paper, the sole customer served by the lateral.

Length of Pipeline (kilometres)		1.3
Outside Diameter(s) (millimetres)		168
Year of Construction		1972
ROW Width (metres)		10
Number of Customers	**Residential**	N/A
	Commercial	N/A
	Industrial	N/A
Important Factors in Execution and Lifecycle Operation		Property: • Additional ROW required Indigenous Community Consultation: • Tsihlqot'in National Government • Carrier Chilcotin Tribal Council • Lhtako Dene Nation • Lhoosk'uz Dene Nation • Ulkatcho First Nation Environmental: • Registered contaminated site • Occurrence of a plant species at risk Archaeological: • Moderate to high archaeological potential

	ILI	PLR	PRS
AACE Estimate Class	Class 3	Class 3	Class 3
Total Project Capital Costs, As-Spent, incl. AFUDC & Removal ($000s)	7,119	5,332	4,888
PV of Post-Project Incremental Sustainment Capital - 66 years ($000s)	1,915	-	1,443
PV of Post-Project Incremental Sustainment O&M - 66 years ($000s)	711	-	20
PV of Incremental Revenue Requirement - 66 years ($000s)	10,507	5,252	6,487
Levelized Rate Impact - 66 years (%)	0.08%	0.04%	0.05%

The table below shows the scoring of ILI, PLR, and PRS for each of the three criteria, and the overall weighted score:

	ILI	PLR	PRS
Integrity and Asset Management Capabilities	4.8	4.7	2.9
Project Execution & Lifecycle Operation	3.3	3.3	4.3
Financial	1.0	5.0	3.0
Overal Score	**3.2**	**4.5**	**3.2**

FEI recommends PLR as the preferred alternative for the Cariboo Pulp lateral as this alternative has the highest overall score. PLR is lower in terms of total PV of incremental revenue requirements over the 66-year analysis period.

PRS scored lower than PLR since the technical performance is not as high due to the fact that PRS would still be managing a vintage pipe. Since PLR is not the least expensive alternative, subject matter experts were called upon to provide input on alternatives for this lateral and concluded PLR will offer better technical superiority over PRS since it will be a new pipeline with modern coating while the PRS alternative will still be maintain a vintage pipeline, therefore, PLR was selected as the preferred alternative.

31.1. Why does FEI not include Cariboo Pulp and Paper as an industrial customer in the number of customers on summary of the Cariboo Pulp Lateral 168 in the first table cited?

31.2. Please elaborate on the costs included in the Post Project Incremental Sustainment capital and O&M, and why there were none included in the PLR option.

32. Reference: Exhibit B-1, Appendix A page 28 and Appendix I page 2

Financial	
Net Present Value (50 year) of Capital, O&M, and Retirement Cost	• Note: if values listed below are subject to change, all forumulas in Column Q of Sheet No. 10 must be modified (with all filters cleared prior to copying and pasting) • Score 5 = Option with the Lowest Net Present Value (50 year) • Score 4 = Option is 5% to 20% more expensive than Lowest NPV Option • Score 3 = Option is 20% to 50% more expensive than Lowest NPV Option • Score 2 = Option is 50% to 100% more expensive than Lowest NPV Option • Score 1 = Option is over 100% more expensive than Lowest NPV Option • Score 0 = No cost estimate was prepared for this Option

32.1. Please confirm that the Net Present Value ("**NPV**") includes Sustainment Capital as well as Project Capital costs.

32.1.1. If not confirmed, please explain why not.

32.2. Why did FEI utilize the NPV (50 years) of Capital, O&M and Retirement Cost instead of the 66 years used to calculate the PV of Incremental Revenue Requirement?

32.3. Why did FEI rely on whole numbers for its financial scoring as opposed to simple ratios of one option to another, or just the NPVs?

32.4. The FEI financial scoring system compares options to each other, but does not value total cost against pipeline length, number of customers or other absolute cost assessment. Please comment.

32.5. Does FEI typically rely on similar scoring when assessing projects? Please explain and identify any other financial scoring systems that FEI uses.

32.5.1. If FEI uses other scoring options, please explain why FEI is using this scoring system for this project.

33. Reference: Exhibit B-1, Appendix A page 30 and page 31

1.1.19 Celgar Lateral 168

The Celgar Lateral 168 begins west of Columbia Ave and 11st in the City of Castlegar, home to approximately 8000 residents. From here the lateral heads West right up to serve the Zellstoff Celgar Pulp Mill.

Length of Pipeline (kilometres)		5.8
Outside Diameter(s) (millimetres)		168
Year of Construction		1960
ROW Width (metres)		12-18
Number of Customers	**Residential**	N/A
	Commercial	N/A
	Industrial	2
Important Factors in Execution and		Operational Complexity:

33.1. Are the 8,000 residents in the City of Castlegar connected to the Celgar Lateral 168?

33.1.1. If yes, why are they not recorded in the Number of Customers recorded in the summary?

33.1.2. If no, how would they be impacted by a leak or rupture? Please explain.