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March 28, 2019

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
P.O. Box 49130
Three Bentall Centre
2900 – 595 Burrard Street
Vancouver, BC
V7X 1J5

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

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

On December 17, 2018, FEI filed the Application referenced above. In accordance with British Columbia Utilities Commission Order G-11-19 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to CEC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Doug Slater

Attachments

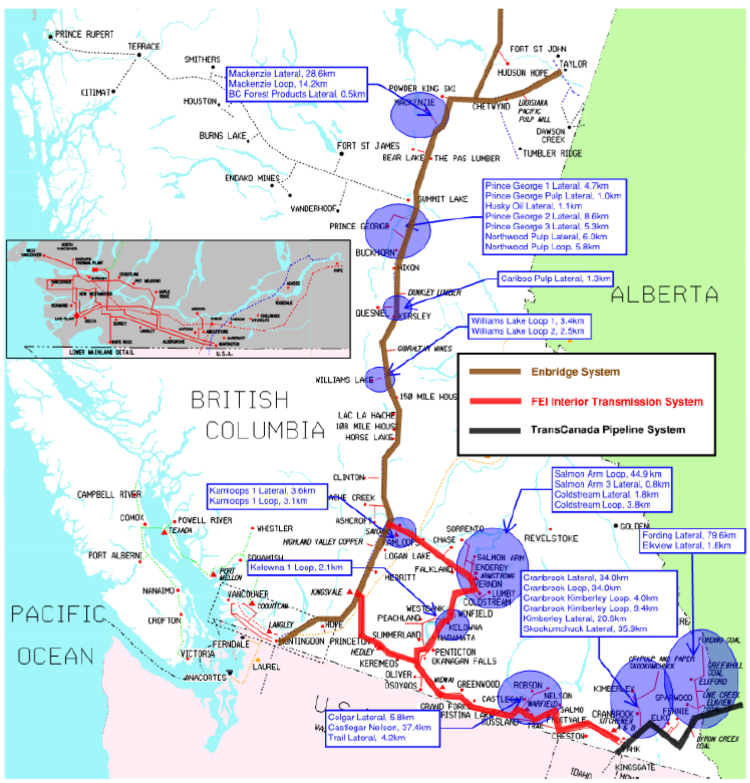
cc (email only): Commission Secretary
Registered Parties

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

1.1.1 CPCN for IGU Project

2 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

3 

4 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.

Response:

The IGU Project proposes integrity management solutions for assets meeting the following criteria:

- Nominal pipe size (NPS) of 6 or greater: this criterion was selected based on FEI's assessment that proven and commercialized in-line inspection technology exists for these pipelines. It also aligns with FEI's understanding of current industry practice for natural gas transmission pipeline operators.
- Operate as transmission pipelines: this criterion was selected due to the potential for failure by rupture that exists for pipelines operating at 30 percent SMYS or greater.
- Not currently capable of being in line inspected.

The single remaining transmission lateral is the Tilbury LNG Plant 168 mm lateral. Please refer to the response to BCUC IR 1.5.1 for a discussion of why this lateral was excluded from the Project scope.

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?

Response:

As described in the response to BCUC IR 1.6.1, different types of in-line inspection tools have different capabilities in the types of imperfections that they are intended to detect and size. For those laterals where the ILI alternative has been selected, the IGU Project will enable in-line inspection with Geometry, Magnetic Flux Leakage (MFL), and Circumferential MFL (CMFL) tools. At this time, FEI has no plans to provide other pipelines with Geometry, MFL or CMFL ILI capability.

The IGU Project addresses the potential for rupture due to external corrosion for all transmission pipelines operating at 30 percent SMYS or greater that are NPS 6 or greater, with the exception of one lateral that will be addressed through a separate project as noted in the Application and further described in the response to BCUC IR 1.5.1.

For transmission pipelines operating at 30 percent SMYS or greater that are less than NPS 6, FEI will continue to monitor technologies as they become available for mitigating the potential for rupture failure due to external corrosion and may determine that ILI is prudent in the future.

FEI is also currently developing the TIMC project to provide crack-detection ILI capability for selected transmission pipelines through the implementation of electro-magnetic acoustic transducer (EMAT) tools. Please refer to the response to CEC IR 1.16.1 for a description of the differences between the IGU and TIMC projects.

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.

Response:

Please refer to the response to CEC IR 1.1.2. The IGU and TIMC projects are the only identified projects related to improving FEI's ILI capabilities; however, as described in the response to BCUC IR 1.6.1, they are independent of each other and do not overlap in their scope.

As the TIMC project is under development, there is insufficient information available upon which to base an assessment of possible cost efficiencies by combining the projects. However, FEI does not expect efficiencies given that the IGU Project is focused on small diameter laterals and the TIMC project on larger diameter transmission mainlines.

As stated in the response to BCUC IR 1.3.1, FEI does not have condition assessment or other information that would support the need to expedite or delay the IGU Project timeline. As such, FEI does not believe it would be appropriate to defer the IGU Project to enable assessment of potential efficiencies.

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

Response:

Yes, corrosion can be experienced in any part of FEI's buried steel pipeline system and therefore FEI's integrity management program identifies external corrosion as a potential hazard to its entire buried steel pipeline system. Despite an expected reduction in corrosion prevalence for some pipelines (e.g. pipelines installed with Fusion Bonded Epoxy coating), FEI is required by CSA Z662-15, Clause 10.3.1, "to monitor for conditions that can lead to failures".

As such, FEI's approach to system-wide corrosion monitoring for its pipelines is as follows. Taken as a whole, this approach addresses all FEI pipelines.

Asset Class	Diameter Range (NPS)	System-Wide Corrosion Monitoring Approach
Transmission pipelines operating at greater than or equal to 30% SMYS	6 and greater	In-line inspection
Transmission pipelines operating at greater than or equal to 30% SMYS	Less than 6	Modified ECDA; however, FEI will continue to monitor technology available for mitigating the potential for rupture failure on these lines
Pipelines operating at less than 30% SMYS	Any	Integrity-related activities such as CP Surveillance, visual observation any time the pipeline may be exposed during its lifecycle, and leak detection are performed. A significant condition monitoring program (such as a regular in-line inspection program) or mitigation (replacement, reconditioning, or abandonment) is only planned upon an occurrence of a relevant leak history.

Please refer to the response to BCUC IR 1.4.1 for FEI's assessment of the potential for active corrosion on cathodically protected pipelines. The assessment covers a cross-section of pipeline ages and coating types.

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.

Response:

Please refer to the response to CEC IR 1.1.3.

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

Response:

Please refer to the response to CEC IR 1.1.3. FEI has identified external corrosion as a potential hazard to its entire buried steel pipeline system. Please also refer to BCUC IR 1.4.1 for FEI's assessment of the potential for active corrosion on cathodically protected pipelines in its system.

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

Response:

Please refer to the response to CEC IR 1.1.3 for FEI's approach to corrosion monitoring 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.

<u>Response:</u>

No, this Application is not part of a larger overall project that is not yet before the BCUC. Please refer to the responses to CEC IRs 1.1.2 and 1.1.3. It is possible in the future, however, that FEI may prioritize investment for providing ILI capability or other integrity management solutions for transmission pipelines operating at 30 percent SMYS or greater that are less than NPS 6 if the appropriate technology were to become proven and commercialized and industry standard practice were to include these smaller diameter pipelines.

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.

<u>Response:</u>

Please refer to the response to BCUC IR 1.3.1.

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.

<u>Response:</u>

FEI's use of the word "cost-effectiveness" for this project in the LTGRP was broad and, consistent with the BCUC's Resource Planning Guidelines, considered "the best overall outcome of expected impacts and risks for ratepayers over the long run."

FEI's definition of cost effectiveness used in the Application is reflected in the criteria used to evaluate the alternatives, and includes technical merit, project and life-cycle operational complexity, and cost, including consideration of the Present Value (PV) of Incremental Annual Revenue Requirement (over 66 years).

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

Response:

No. FEI believes that a cost threshold should not be established to judge whether a project would be cost-effective. FEI has an obligation to provide customers with safe and reliable service at the lowest reasonable cost. Additionally, the Company has legal and regulatory obligations to numerous other stakeholders to deliver energy in a safe, environmentally responsible, and reliable manner. In order to provide ongoing service to customers in the BC Interior region, and to mitigate the potential for rupture due to external corrosion on the 29 Transmission Laterals, FEI considers that the IGU Project is necessary and in the public interest.

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.

Response:

Given FEI's legal and regulatory requirements, its assessment of relevant hazards to its pipeline system, its understanding of industry practice, as well as its knowledge of evolving technology available for assessing and managing pipeline condition, FEI considers that the cost of the IGU Project is justified and in the public interest. The fact that FEI has identified a hazard on its system that can result in pipeline rupture failure, and that legal and regulatory requirements compel FEI to mitigate this hazard, and that there are commercially available, industry-standard alternatives to do so, lead FEI to conclude that the cost of the IGU Project is justified in consideration of the risk. FEI's analysis of all feasible alternatives against the evaluation criteria as presented in the Application means that the IGU Project will implement cost effective integrity management solutions for each of the 29 Transmission Laterals.

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.

Response:

FEI has not experienced corrosion leaks or ruptures on its transmission pipelines over the last 2 years. However, as explained in Section 1.2 of the Application, the objective of the IGU Project is to mitigate the potential for transmission pipeline rupture due to corrosion on the 29 Transmission Laterals as FEI has identified limitations with its current methods to detect, assess and monitor the condition of these laterals. Given that corrosion is a time dependent threat, FEI does not consider a lack of pipeline breaches in the last two years as indicative or relevant to the need for, or to the scheduling of, the IGU Project.

Please refer to the response to BCUC IR 1.8.2 which includes the leak history for FEI's transmission pipelines.

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.

<u>Response:</u>

Please refer to the response to BCUC IR 1.3.1.

3.2 Please discuss the potential consequences of a rupture.

<u>Response:</u>

As discussed in Section 3.3.4 of the Application, a natural gas pipeline rupture has the potential to result in significant safety, reliability, environmental and regulatory consequences. The following discusses these consequences.

- <u>Safety Consequences</u>: As noted in Section 3.3.4 of the Application, if the gas ignites, there can be significant safety impacts beyond the immediate area surrounding the pipeline. An ignited release can result in potential harm due to the ensuing fire and resulting thermal effects on people and property. The following is an excerpt from a Gas Research Institute Report GRI-00/0189, A Model for Sizing High Consequence Areas Associated with Natural Gas Pipelines, 2001, prepared by C-FER Technologies:

  > "The rupture of a high-pressure natural gas pipeline can lead to outcomes that can pose a significant threat to people and property in the immediate vicinity of the failure location. The dominant hazard is thermal radiation from a sustained fire (…)."

- <u>Reliability Consequences</u>: As noted in Section 3.3.4 of the Application, 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. Please refer to the response to CEC IR 1.3.2.1 for a further discussion of reliability-related consequences due to a rupture of the 29 Transmission Laterals.

- Environmental Consequences: As described in Section 2.2.4 of the Application, the environmental consequences associated with a pipeline rupture or a sudden and uncontrolled release of natural gas would be classified as a Level 2 Major or Level 3 Serious reportable incident by the OGC (Appendix D)[1]. In addition, the release of gas by rupture would result in major on-site equipment failure and hence would be considered a reportable incident under the Environmental Management Act Spill Reporting Regulation for transmission pipelines.

- Regulatory: In alignment with the Canadian transmission pipeline industry, FEI and the BC OGC considers that a failure by rupture of its natural gas pipelines to be a significant incident and not acceptable performance within its integrity management program. Please refer to the response to BCUC IR 1.9.1 for a discussion of the requirements of the CSA Z662 standard and FEI's obligations under OGAA, which are related to regulatory issues.

To illustrate the potential consequences of a natural gas pipeline rupture, the following are actual examples experienced by North American natural gas transmission pipeline operators. The incidents described below that occurred in the United States are included due to their influence on gas transmission pipeline operator practice and the regulatory environment in both the United States and Canada. With respect to safety consequences, the diameter and operating pressure of a given pipeline correlate to the size of the potential affected area in the event of an ignited rupture failure event. This means that a smaller diameter pipeline will impact a smaller area than a larger diameter pipeline.

On August 19, 2000, the El Paso Natural Gas Company, NPS 30 natural gas transmission pipeline ignited rupture occurred adjacent to a river crossing. The probable cause was identified as internal corrosion. The National Transportation Safety Board website, available at https://www.ntsb.gov/investigations/accidentreports/pages/PAR0301.aspx, states:

> "The released gas ignited and burned for 55 minutes. Twelve persons who were camping under a concrete-decked steel bridge that supported the pipeline across the river were killed and their three vehicles destroyed. Two nearby steel suspension bridges for gas pipelines crossing the river were extensively damaged."

- On August 7, 2000, the Westcoast Energy Inc. NPS 30 natural gas transmission pipeline, near the Zopkias Rest Stop at Exit 217 Coquihalla Highway, British Columbia,

[1] Also available online at: https://www.bcogc.ca/incident-classification-matrix.

ruptured. The National Transportation Safety Board of Canada website, available at http://www.bst-tsb.gc.ca/eng/rapports-reports/pipeline/2000/p00h0037/p00h0037.asp, states:

> "…a rupture occurred at a localized hard spot on the Westcoast Energy Inc. 762-millimetre outside diameter T-South Mainline at Mile Post 569.9 near the Zopkios rest stop at Exit 217, Coquihalla Highway, British Columbia. Several vehicles at the rest stop were damaged as a result of thrown debris from the explosion. There were no injuries. The Coquihalla Highway was closed to traffic for 3 ½ hours following the rupture."

- On September 9, 2010, the Pacific Gas and Electric Company, NPS 30 natural gas transmission pipeline ignited rupture occurred in a residential area in San Bruno, California. The probable cause was identified as "inadequate quality assurance and quality control in 1956 during its Line 132 relocation project" and an "inadequate pipeline integrity management program, which failed to detect and repair or remove the defective pipe section". The National Transportation Safety Board website, available at https://www.ntsb.gov/investigations/accidentreports/pages/PAR1101.aspx, states:

> "The rupture produced a crater about 72 feet long by 26 feet wide. The section of pipe that ruptured, which was about 28 feet long and weighed about 3,000 pounds, was found 100 feet south of the crater. PG&E estimated that 47.6 million standard cubic feet of natural gas was released. The released natural gas ignited, resulting in a fire that destroyed 38 homes and damaged 70. Eight people were killed, many were injured, and many more were evacuated from the area."

- On January 25, 2014, the TransCanada PipeLines Limited NPS 30 natural gas transmission pipeline ignited rupture occurred in an agricultural area. The cause pertained to a construction-related imperfection in a weld (constructed in 1960) that remained stable until being subject to increasing stresses during operation. Possible factors included weakened soil support around the pipeline during past excavation activity, frost effects, and pipe thermal contraction due to a prior absence of gas flow in the line. The rupture impacted nearly 4000 residents during a cold winter month with local temperatures as low as approximately minus 20 degrees Celsius. The Transportation Safety Board of Canada's website, available at http://bst-tsb.gc.ca/eng/rapports-reports/pipeline/2014/p14h0011/p14h0011.asp, states:

> "A crater measuring approximately 24 metres long by 12.5 metres wide was created, and debris was ejected approximately 100 metres from the rupture site. Natural gas burned for approximately 12 hours. Five residences in the immediate vicinity were evacuated, and Provincial

> Highway 303 was closed until the fire was extinguished. There were no injuries."
>
> "As a precaution, two adjacent pipelines, lines 400-2 and 400-3, were shut down, assessed, and returned to service on 26 January 2015. This resulted in the loss of natural gas service to 9 rural communities in Manitoba for approximately 80 hours."

- On January 10, 2018, the SaskEnergy (TransGas) NPS 6 natural gas transmission pipeline ruptured. The cause was identified as unreported damage. A SaskEnergy media release, available at https://www.saskenergy.com/About_SaskEnergy/News/news_releases/2018/Melfort%20Region%20Outage%20Release%20FINAL.pdf, states: "approximately 4,500 customers in Melfort, St. Brieux, Kinistino and surrounding rural areas lost natural gas service to their homes and businesses." This event also occurred during a cold winter month, with local temperatures as low as approximately the mid-minus 20s.
- On October 9, 2018, the Enbridge (Westcoast) NPS 36 natural gas transmission pipeline experienced an ignited rupture. The probable cause has not yet been determined. The Enbridge media statements, available at https://www.enbridge.com/media-center/media-statements/prince-george-pipeline-incident, state: "The BC Pipeline comprises of two pipelines, a 36-inch and a 30-inch, that run parallel to each other. Both pipelines were shut down following the rupture on the 36-inch line." (October 10, 2018) One of the two pipelines became operational on October 11, 2018; however the reduced pipeline capacity resulted in significant gas supply pressures to the Lower Mainland. This event, if it had occurred during colder temperatures, could have resulted in a loss of supply to the Lower Mainland and Vancouver Island.

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.

Response:

The following table summarizes the approximate number of customers that could be impacted by a pipeline rupture for each lateral segment. The time period of a service disruption, including the time to respond, make the site or area safe, conduct initial investigations, clear the site or area for repair, and obtain regulatory approval to recommission, varies based on the size of system and customers served and the integrity implications of the failure (i.e. pipeline condition monitoring that may be required post-incident to verify the appropriateness of continued operation of the pipeline). For smaller systems of less than 100 customers with no associated integrity issues to address it could take a week or two. For systems with tens of thousands of customers and additional integrity issues to address it could take months.

Approximate Affected Customer Count for each Lateral System

Line/ Loop ID No.	Line/Loop Full Name	Residential Customers	Commercial Customers	Industrial Customers	System Total
1	MACKENZIE LATERAL 168	1672	139	6	1817
2	MACKENZIE LOOP 168				
3	BC FOREST PRODUCTS LATERAL 168	n/a	n/a	1	1
4	PRINCE GEORGE 3 LATERAL 219	17716	1834	52	19602
5	NORTHWOOD PULP LATERAL 168				
6	NORTHWOOD PULP LOOP 219				
7	PRINCE GEORGE #1 LTL 168	1171	50	8	1229
8	PRINCE GEORGE PULP LATERAL 168				
9	HUSKY OIL LATERAL 168				
10	PRINCE GEORGE #2 LATERAL 219	17217	1596	44	18857
11	CARIBOO PULP LATERAL 168	n/a	n/a	1	1
12.1	WILLIAMS LAKE LOOP 168	5998	813	15	6826
12.2	WILLIAMS LAKE LOOP 168				
13.1	KAMLOOPS 1 LATERAL 168	15391	1588	36	17015
13.2	KAMLOOPS 1 LOOP 168				
14	SALMON ARM LOOP 168	11830	1136	24	12990
15	SALMON ARM 3 LATERAL	3426	261	9	3696
16	COLDSTREAM LAT 219	13357	1017	48	14375
17	COLDSTREAM LOOP 168				
18	KELOWNA 1 LOOP 219	29999	3235	48	33282
19	CELGAR LATERAL 168	n/a	n/a	2	2
20	CASTLEGAR NELSON 168	9657	10	61	10621
21	TRAIL LATERAL 168	3205	310	7	3522
22.1	FORDING LATERAL 219	2865	297	11	3173
22.2	FORDING LATERAL 168	1067	82	4	1153
23	ELKVIEW LATERAL 168	n/a	n/a	1	1
24	CRANBROOK LATERAL 168	12986	1187	21	14194
25	CRANBROOK LOOP 219				
26	CRANBROOK KIMBERLEY LOOP 219	4291	280	4	4575
27	CRANBROOK KIMBERLEY LOOP 273				
28	KIMBERLY LATERAL 168				
29	SKOOKUMCHUCK LATERAL 219	75	1	1	77

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.

<u>Response:</u>

Please refer to the response to CEC IR 1.3.2 for a description of potential safety hazards. Please also refer to the responses to BCUC IRs 1.3.1 and 1.6.7 for information related to quantitative risk assessment on the 29 Transmission Laterals.

Although FEI is unable to predict that such a safety hazard will occur in the next 3 years, FEI believes that the status quo for the 29 Transmission laterals is unacceptable over the long-term due to limitations of the Modified ECDA alternative in detecting corrosion, which could result in rupture and have significant safety, reliability, environmental and regulatory consequences.

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.

Response:

As discussed in the response to BCUC IR 1.6.7, a quantitative risk assessment was not considered necessary by FEI to justify or inform the IGU Project. FEI has proposed the IGU Project on the basis of the identified potential for failure by rupture due to corrosion on the 29 Transmission Laterals. FEI has also considered inputs such as its legal and regulatory obligations, its assessment of relevant hazards to its pipeline system, its understanding of industry practice, as well as FEI's knowledge of evolving technology available for assessing and managing pipeline condition.

Please also refer to the response to BCUC IR 1.3.1.

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

Response:

Please refer to the responses to CEC IRs 1.3.2 and 1.3.4.

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.

Response:

The need for a project to mitigate the potential for rupture failure due to corrosion was raised in August 2015. Preliminary work undertaken at that time focused on a review of industry practice and the state of in-line inspection tool evolution, as well as hydraulic analyses to determine whether flow rates in the laterals could be managed to achieve required in-line inspection tool travel speeds.

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

Response:

No. FEI has proposed the IGU project on the basis of the identified potential for failure by rupture on the 29 Transmission Laterals. FEI has also considered inputs such as its legal and regulatory requirements, its assessment of relevant hazards to its pipeline system, its understanding of industry practice, as well as FEI's knowledge of evolving technology available for assessing and managing pipeline condition. Engaging a risk assessment professional to conduct a quantitative risk assessment was not considered necessary by FEI to justify the IGU project. Please refer to the responses to BCUC IR 1.3.1 and CEC IR 1.3.8 that explain why quantitative risk assessment is not required to justify the need for the IGU Project.

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

Response:

Please refer to the response to CEC IR 1.3.7.

3.7.2 If not, please explain why not.

Response:

Please refer to the response to CEC IR 1.3.7.

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.

Response:

FEI confirms that Dynamic Risk Assessment Systems Inc. completed a "Quantitative Risk Assessment of Huntingdon Control Station" included as Appendix C of the Huntingdon Station Bypass CPCN Application.

The Huntingdon Station Bypass CPCN was based on the identification of the Huntingdon Station as a single-point-of-failure facility and the proposed bypass was necessary to provide redundancy to reduce the risk of loss of gas supply. As the project was designed to add redundancy to the system, FEI considered that a quantitative risk assessment was needed to support the justification of the project.

In the case of the IGU Project, FEI is not proposing to build redundancy into its system, but is proposing to mitigate an identified and known hazard on its system in the form of external corrosion which, if left undetected, could lead to rupture of any of the 29 Transmission Laterals. A quantitative risk assessment is not required to conclude that FEI must take reasonable steps to mitigate the potential for this known and identified hazard.

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.

<u>Response:</u>

As stated in Section 3.4.4.2 of the Application, 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. However, some transmission pipeline operators were implementing earlier iterations of ILI technology prior to the early 2000s for portions of their systems. ILI for small diameter pipelines such as NPS 6 was not considered to be industry standard practice until FEI began development of the Application.

Prior to ILI becoming standardized, FEI used a more reactive approach to corrosion management, which involved responding to a relevant leak history by performing activities such as above-ground cathodic protection surveys and integrity digs (similar to NACE/ANSI ECDA or Modified ECDA). For FEI's NPS 6 and larger pipelines operating at 30 percent SMYS or greater, NACE/ANSI ECDA or Modified ECDA is no longer an acceptable approach over the long term.

.

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

Response:

FEI has not constructed transmission laterals since ILI has become standardized for pipelines as small as NPS 6 and, therefore, FEI has not constructed any laterals 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?

Response:

Please refer to the response to BCUC IR 1.12.5.2.

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

Response:

Please refer to the response to BCUC IR 1.4.1.

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.

Response:

CP shielding is considered a common occurrence on older vintage pipelines where practices of the day with respect to coating application and construction practices, in general, were not likely subject to the same rigorous methods of inspection procedures as today.

Please refer to the response to BCUC IR 1.4.1 for FEI's assessment of the prevalence of CP shielding on its transmission pipeline system. FEI is unable to translate this into a percentage of its system (i.e. a percentage of the total length of pipe), as this would involve excavation of the entire system to assess whether active corrosion is occurring.

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

Response:

Please refer to the response to CEC IR 1.10.2.

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.

Response:

Please refer to the response to CEC IR 1.10.2.

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

Response:

Any sites with observed CP shielding (e.g. during integrity digs) are re-coated to FEI's current standards. This is the only repair method available to address CP shielding.

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

Response:

CP shielding can be repaired through coating repair as indicated in Section 4.4.5 of the Application and the response to CEC IR 1.4.7. This alternative is referred to as "Pipeline exposure and re-coat (PLE)" in the alternatives analysis presented in the Application. An overview of the associated costs of PLE is included in Section 4.4.5.

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

Response:

Please refer Section 3.4.2 of the Application for an elaboration on how the presence of CP shielding prevents FEI from identifying corrosion.

In summary, the indirect inspection step of an ECDA or Modified ECDA involves implementation of various surveys from the ground surface above a buried pipeline. These surveys rely on an electrical current or signal reaching the survey equipment which is located at or above the ground surface. Disbonded coatings, large rocks, or foreign structures are examples of situations where CP shielding can occur, as they prevent the CP current from reaching the pipeline. The same issues that prevent CP current from reaching the pipeline also block the survey-related electrical currents/signals from being received by the survey equipment.

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.

Response:

As discussed in the response to BCUC IR 1.3.1, the information available to FEI (also discussed in the responses to BCUC IRs 1.8.1 to 1.8.5) indicates that it is appropriate for FEI to implement the proposed IGU Project over a reasonable planning horizon. In establishing the proposed timeline for the IGU Project, FEI considered inputs such as the available condition information, FEI's understanding of industry practice, the availability of proven and commercialized in-line inspection technology, and project implementation considerations (refer also to the response to BCUC IR 1.3.7 for further details). FEI did not explicitly consider delaying the Project timeline, because it would reduce the efficiencies to be gained by executing as a single Project over a multi-year project and likely result in an increase in the overall cost (as discussed in BCUC Confidential IR 1.1.1). Further, an extension in the Project duration would delay FEI's ability to mitigate the potential for rupture failure due to corrosion of the 29 Transmission Laterals.

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.

Response:

FEI has not identified any operating savings as a result of the use of ILI, PRS, or PLR alternatives, or any other aspect of the IGU Project. ILI is an incremental activity to currently performed integrity management activities such as CP system monitoring and leak survey. Laterals where PRS was selected as a preferred alternative will continue to require their current integrity management activities plus the incremental operational and maintenance requirement for the new PRS stations. Laterals where PLR was selected as the preferred alternative will continue to require integrity management activities even though the pipeline is new, therefore, there is no incremental savings for PLR.

As indicated in the response to BCUC IR 1.9.1, the CSA Z662-15 standard requires that pipelines be monitored for conditions that can lead to failures. Although the PRS and PLR alternatives mitigate the potential for rupture due to external corrosion for these lines, they still require ongoing monitoring.

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

Response:

Please refer to the response to CEC IR 1.4.11.

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

Response:

Please refer to the response to CEC IR 1.4.11.

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'.

Response:

FEI agrees that the purpose of any pipeline coating is to insulate the steel pipe surface from surrounding electrolyte (e.g. groundwater). In the absence of a coating (and assuming a non-cathodically protected pipeline), water in direct contact with the steel pipe surface would be expected to result in corrosion.

The issue of CP shielding, as experienced by FEI and as discussed in the referenced article, relates to coating application and coating disbondment. Where certain coatings either have been poorly applied, have poor adhesion, or have failed in their adhesion over time, CP current cannot reach the pipe surface. FEI agrees that quality application of qualified products by qualified and competent applicators can reduce the risks of CP shielding. FEI's current coating products and application practices have been established to mitigate the potential for CP shielding, and it is FEI's expectation that CP shielding will not occur as a result of its current practices.

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

Response:

FEI believes that the quality of coating application and type of coatings applied in the past has resulted in observed coating disbondment, which has contributed to CP shielding on FEI's pipeline system. FEI has also found CP shielding due to the presence of rocks and foreign structures in the backfill adjacent to the pipeline, which can both damage the coating and/or prevent CP current from reaching the pipeline.

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.

<u>Response:</u>

As indicated in the response to BCUC IR 1.9.1, the CSA Z662-15 standard requires that pipelines be monitored for conditions that can lead to failures. FEI's obligation to monitor its transmission pipelines for corrosion is independent of any threshold level of corrosion and exists because FEI has verified external corrosion as a relevant hazard to its transmission pipelines through its operating experience.

Corrosion is the gradual deterioration of metal that results from a reaction with the environment, which changes the iron contained in pipe to iron oxide (rust). External corrosion occurs due to environmental conditions on the outside of a pipeline. If left untreated, the gradual deterioration can continue unabated until the pipeline fails. External corrosion is referred to as a time-dependent hazard because, once initiated, it can grow over time in extent and depth leading to pipeline failure resulting in significant safety, reliability, environmental and regulatory consequences.

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.

Response:

Please refer to the response to CEC IR 1.6.1.

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

Response:

Please refer to the response to CEC IR 1.4.9.

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.

Response:

FEI has used Modified ECDA on these 29 Transmission Laterals as it was the most appropriate tool identified at the time, with consideration to factors including legal and regulatory obligations, FEI's assessment of relevant hazards to its pipeline system, FEI's understanding of industry practice, as well as FEI's knowledge of evolving technology available for assessing and managing pipeline condition. All feasible alternatives to Modified ECDA were evaluated in the Application for the 29 Transmission Laterals.

ECDA does not detect active corrosion where CP shielding is occurring, but rather, it is intended to detect active corrosion where CP shielding is not occurring. As stated in the ANSI/NACE ECDA standard, "By identifying and addressing corrosion activity, repairing corrosion defects, and remediating the cause, ECDA proactively seeks to prevent external corrosion defects from growing to a size that is large enough to affect structural integrity." FEI has experienced success through its implementation of Modified ECDA in identifying areas where CP system improvements are necessary and where coating damage exists, both of which have the potential to contribute to the initiation and/or growth of corrosion.

In its use of Modified ECDA to "monitor for conditions that can lead to failures" (requirement per CSA Z662-15) for non-piggable pipelines, FEI has considered factors such as its understanding of industry practice and its knowledge of evolving technology available for assessing and managing pipeline condition. Modified ECDA comprises part of FEI's overall compliance strategy.

As included in response to CEC IR 1.1.2, for transmission pipelines operating at 30 percent SMYS or greater that are less than NPS 6, FEI will continue to monitor technology available for mitigating the potential for rupture failure due to corrosion on these lines and may determine that ILI is prudent in the future. In the interim, FEI will continue to apply Modified ECDA. This approach is prudent given industry practice and the available state of technology, although FEI will review this on an ongoing basis as part of its continual improvement of the Integrity Management Program – Pipelines.

Modified ECDA is not effective in instances where CP shielding is occurring. Please refer to response to BCUC IR 1.4.1 for FEI's assessment of CP shielding on its transmission pipeline system. As stated in Section 3.4.2 of the Application, "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" (for its transmission pipelines of NPS 6 and larger).

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.

Response:

Please refer to the response to CEC IR 1.6.3.

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.

<u>Response:</u>

Please refer to the response to CEC IR 1.6.3.

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.

Response:

FEI is not aware of internal corrosion of the 29 Transmission Laterals, or its transmission pipeline system in general. Please refer to the response to CEC IR 1.14.1.

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.

Response:

Confirmed.

However, FEI notes that the practices and experiences of the Canadian Energy Pipeline Association (CEPA) natural gas pipeline operators are typically more relevant to its system than CAPP. CAPP represents the Canadian upstream oil and natural gas industry. One of the more significant differences between CAPP and CEPA is that CAPP members transport more unrefined products. Transportation of unrefined products in pipelines can result in different hazards to the pipeline systems, as well as to the methods employed to mitigate those hazards.

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.

Response:

Internal corrosion is not considered a relevant hazard to FEI's Integrity Management Program – Pipelines. Please refer to the response to CEC IR 1.14.1. As such, the referenced report is not relevant to the IGU Project and 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.

Response:

CEPA's "2018 Transmission Pipeline Industry Performance Report" (available here: https://pr18.cepa.com/2017-performance-data/), contains information on the causes of pipeline incidents.

To summarize, the causes of pipeline incidents for CEPA members from 2013-2017 (includes significant and non-significant incidents) were as follows:

1. Metal loss: 31 percent (note that these statistics do not differentiate between external corrosion and internal corrosion)
2. Materials, manufacturing and construction: 25 percent
3. Cracking: 17 percent
4. Other: 12 percent
5. External interference: 8 percent
6. Geotechnical: 7 percent

Further, the National Energy Board's website contains a listing a pipeline ruptures of Canadian Regulated Pipelines (available here: https://www.neb-one.gc.ca/sftnvrnmnt/sft/pplnrptr/index-eng.html). For pipeline ruptures with the product listed as "Gas", and where there is an identified Sub-Cause (i.e. not listed as "under investigation), External Metal Loss (i.e. external corrosion) is a leading Sub-cause. There are no ruptures for gas pipelines in this data set due to the Sub-cause Internal Metal Loss (i.e. internal corrosion).

Product = Gas	
Rupture Sub-cause *	Total
Company Contractor	1
Defective Pipe Body	2
External Metal Loss	5
Fatigue	1
Hydrogen Induced Cracking	1
Stress Corrosion Cracking	6
Grand Total	16

* Note: the 4 Gas incidents listed in the spreadsheet as "under investigation" have been excluded from this table.

FEI agrees that external corrosion is 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.

Response:

Please refer to the response to CEC IR 1.9.2.

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.

Response:

Please refer to the response to CEC IR 1.9.2.

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.

Response:

Please refer to the response to CEC IR 1.9.2.

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

Response:

Please refer to the response to CEC IR 1.9.2.

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.

Response:

The 90 integrity digs locations are provided in three regional maps (Coastal, Interior and Vancouver Island) as shown below. Red balloon icons indicate active corrosion sites (72 instances) and yellow balloon icons indicate passive corrosion sites (18 instances, 6 in Coastal and 12 in Interior as shown in Figure 2).

Figure 1: Coastal Dig Locations (2 active and 6 passive corrosion sites)

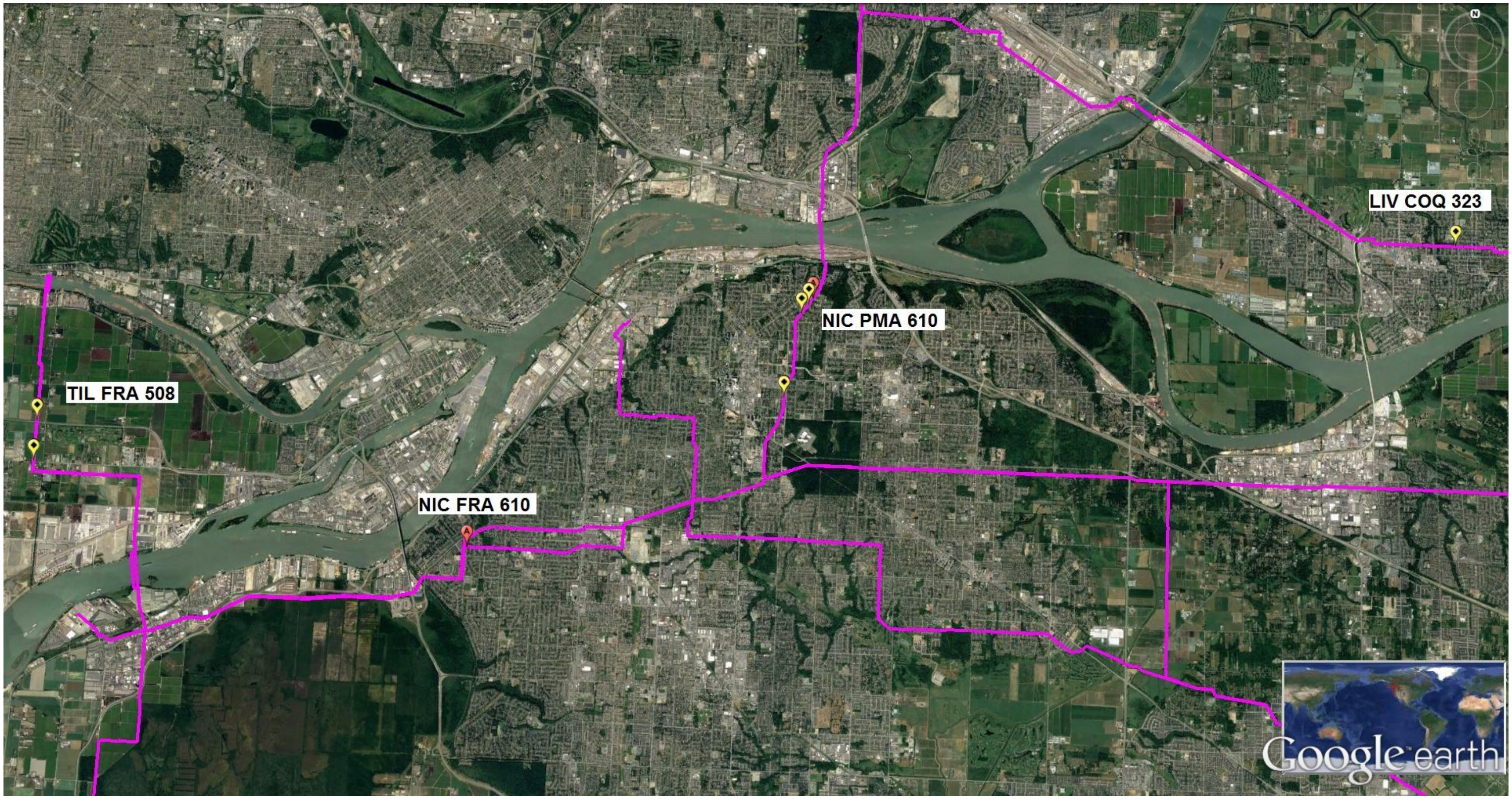


Figure 2: Interior Dig Locations (64 active and 12 passive corrosion sites)

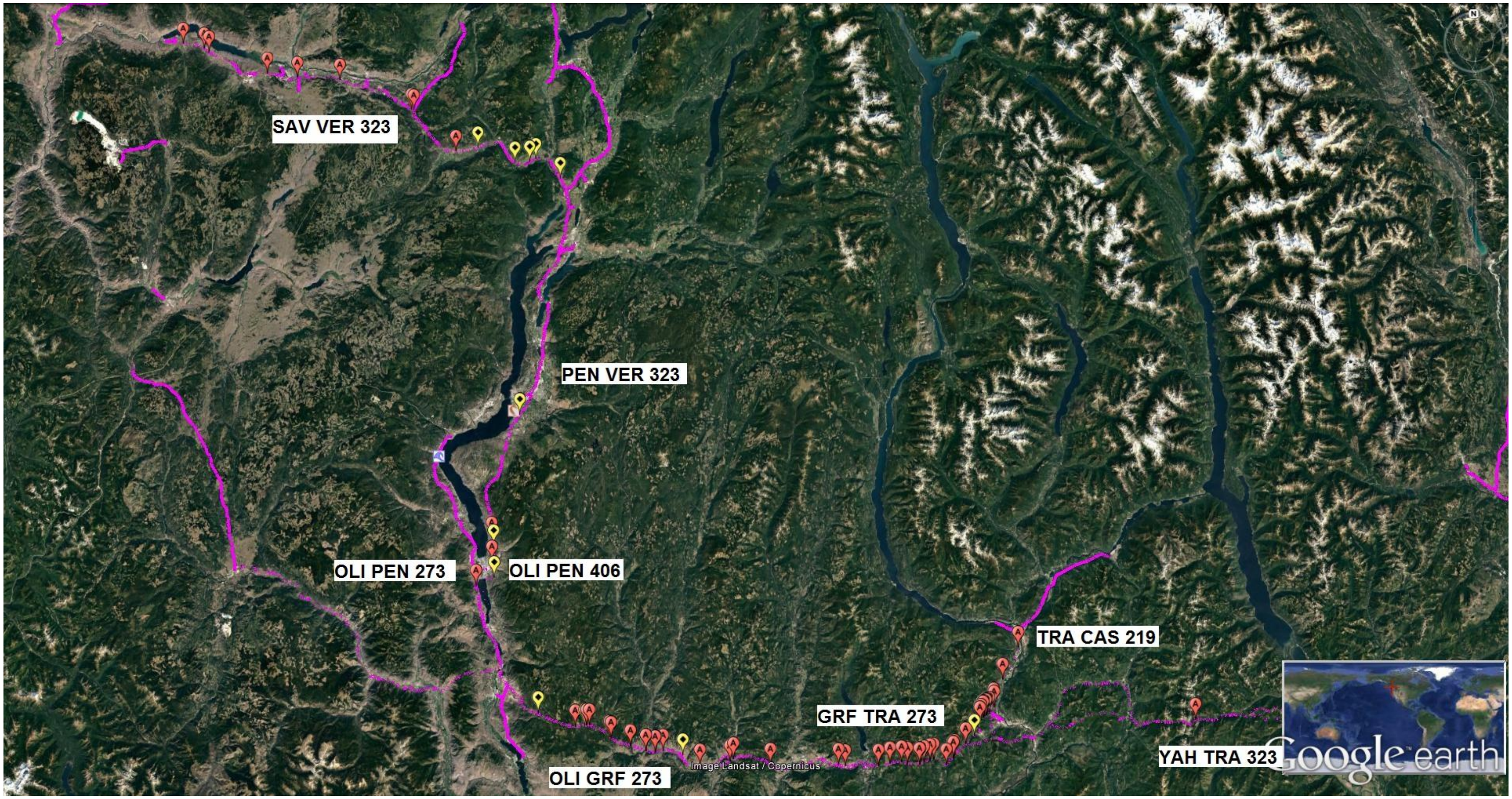
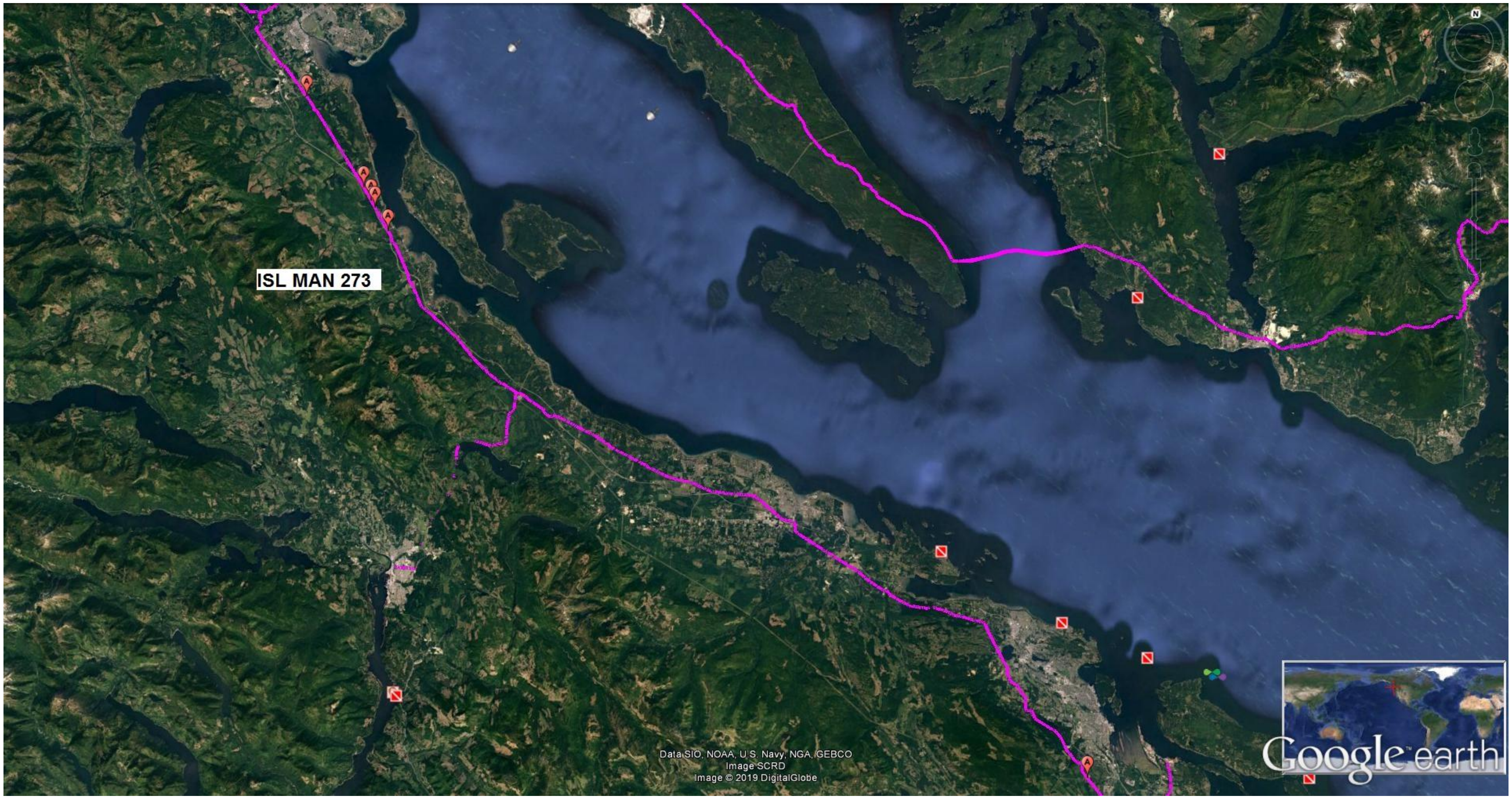


Figure 3: Vancouver Island Dig Locations (6 active corrosion sites)



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.

Response:

As discussed in response to BCUC IR 1.4.1, the instances of active corrosion indicate that it is probable that active corrosion is present on the 29 Transmission Laterals due to cathodic protection shielding. It is likely that this corrosion is present at locations along the length of the lines, but not along the full length of the 29 Transmission Laterals. FEI also does not have information that indicates that corrosion is at particular locations or segments such as junctures, specific environments, or types of pipeline coating materials.

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

Response:

FEI conducts integrity digs on its system on an annual basis. The following table, in the same format as that provided in response to BCUC IR 1.1.3 in the FEI Annual Review of 2019 Rates proceeding, is updated with 2018 actuals:

Reason for Digs	Number of Digs per Year								
	2011	2012	2013	2014	2015	2016	2017	2018	2019 Forecast
Dent digs (includes dig selections that were influenced by the strain-based criteria)	0	6	27	12	10	32	21	15	Under development (u/d)
Circumferential magnetic flux leakage in-line inspection digs	0	0	0	27	20	11	44	37	u/d
Other ILI digs	45	24	21	19	32	33	25	37	u/d
Non-ILI digs	9	8	4	4	2	0	8	1	u/d
Total Integrity Digs	**54**	**36**	**52**	**62**	**64**	**76**	**98**	**90**	**≈ 105 +/- 10%**

For digs conducted on in-line inspected pipelines, the criteria for selection of digs are as follows:

- reported imperfections which exceed requirements of CSA Z662;
- reported imperfections with an identified potential to exceed requirements of CSA Z662 (e.g. through corrosion growth and dent strain analysis);
- imperfections with an identified future potential to fail by leak or rupture (i.e. after applying estimated corrosion growth);
- sites determined by a Senior Integrity Engineer as required to assess tool performance; and
- sites determined by a Senior Integrity Engineer to provide additional data to the stress corrosion cracking (SCC) management program.

For digs on pipelines inspected through Modified ECDA, please refer to the response to BCUC IR 1.12.5.2.

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.

Response:

FEI has not completed any detailed analysis of the economic consequences of a pipeline rupture causing a gas supply loss for the IGU laterals. The consequences could vary widely depending on the pipeline diameter of the lateral, the location of the rupture along the lateral, the proximity of populated areas to the rupture location, the time of year, the severity of the prevailing weather conditions during any ensuing gas outage, the numbers and types of customers included in the outage, and factors such as the proximity and access of the customers impacted to support services outside of the outage area.

To provide a high level estimate of the potential range, FEI's 2015 CPCN application for the Lower Mainland Intermediate Pressure System Upgrade Projects (LMIPSU) included an extensive analysis of a variety of outage scenarios in FEI's Lower Mainland distribution systems. The analysis was included as Appendix A-5 of that application titled "Ruitenbeek, Economic Consequence Analysis" prepared by HJ Ruitenbeek Resource Consulting Limited. The methodology and assumptions of the analysis are described in Section 3 of that document. The economic consequences included cost associated with regulatory response, public relations, government relations, shut down and relight costs, revenue loss during the outage, some permanent loss of customers as a result of the incident occurring and service disruption costs to customers and the community as a result of a severe outage.

Several of the outage scenarios presented in the Economic Consequence Analysis have a similar range of impacted customers as are associated with the transmission laterals included in the IGU Project. For example, the Kelowna 1 lateral could have up to approximately 33,300 customer outages, the largest number of customer outages among the 29 Transmission Laterals. The Economic Consequence Analysis showed that an outage of 29,600 customers (IP Segment 13) had an economic consequence of just over $18 million. An outage on the Kelowna 1 Lateral 219, on the same basis might comparably have an economic consequence of approximately $20 million. Similarly a lateral like the Salmon Arm Loop 168, with up to approximately 13,000 impacted customers might have a similar economic consequence as IP Segment 6 or 7 (12,500 customers, $7.3 million) and have an economic cost of approximately $7.6 million.

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.

Response:

As explained in the response to BCUC IR 1.3.1, FEI has not prioritized the 29 Transmission Laterals relative to each other, but has generally scheduled the start date for the work on each lateral to achieve an earlier start date to complete the modifications during the Project proposed timeline (in consideration of other factors such as resource availability and geographic allocation as described in BCUC IR 1.2.3). Notwithstanding this, an approximate risk ranking is included in response to BCUC IR 1.24.1.

FEI has not prioritized the IGU Project relative to other pipeline improvements within its sustainment capital program. The IGU Project is reviewed through the CPCN process, which is separate from the process followed under FEI's sustainment capital program.

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.

Response:

Yes. When electrolyte (i.e. water) in the surrounding soil can contact the pipe wall, and where CP current cannot reach the pipe surface (i.e. shielding), corrosion may be occurring.

As included in response to CEC IR 1.5.1, CP shielding, as experienced by FEI, relates to coating application and coating disbondment. Where certain coatings either have been poorly applied, have poor adhesion, or have failed in their adhesion over time, CP current cannot reach the pipe surface. The presence of groundwater is common and expected for pipelines buried in soil, and it is generally accepted that all soils are corrosive.

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?

<u>Response:</u>

FEI has been aware of corrosion on cathodically-protected pipe since at least the time that it began applying in-line inspection technology on its system (1988, per Section 3.4.4.2 of the Application).

FEI has been aware of the limitations of NACE/ANSI ECDA and Modified ECDA in detecting corrosion imperfections since at least 2002, when the first iteration of the NACE ECDA standard was published. Please also refer to the response to CEC IR 1.6.3 for why FEI has used Modified ECDA over the past several years even though this methodology has limitations in detecting corrosion imperfections.

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

Response:

FEI is currently compliant with the BC OGC regulations; however, as noted in the response to BCUC IR 1.6.5, the BC OGC directed FEI to "develop and implement a segment-by-segment risk assessment process to determine the risk associated with its pipeline assets in BC", which FEI is currently undertaking.

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.

Response:

FEI's asset management processes endeavor to optimize the lifecycle value provided by its assets, including determining cost effective strategies for maintaining reliable delivery of natural gas to its customers. In the absence of actual condition data, there is no rational basis for asset management plans, thus assumptions must be made. For example, in the absence of adequate design, construction, maintenance, monitoring activities, and condition data, a pipeline operator may propose to replace assets based on their asset financial life.

FEI employs an optimized approach using proactive condition information, such as provided by ILI, when making investment decisions related to its transmission pipelines. Examples include:

- When evaluating impacts to its pipeline system due to third party activity and/or population encroachment, pipe condition information can be a determining factor as to whether mitigation (e.g. pipe replacement) needs to be performed or not.
- When planning pipeline upgrades, pipe condition information can inform the timing of such projects.
- As FEI's pipeline assets are aging, and the potential impacts of time-dependent hazards such as external corrosion are increasing, condition information is becoming increasingly relevant to all long-term planning activities at FEI. FEI improves its capabilities for developing mitigation strategies for transmission pipelines as the length of in-line inspected pipelines increases. Conversely, FEI reduces its exposure to reactive (and potentially sub-optimal) asset management decisions, such as those made upon a pipeline failure event.

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.

Response:

FEI transports only dry, sweet natural gas (i.e. nearly free of hydrogen sulfide and water content) in its transmission pipeline system. FEI's operating experience confirms that the natural gas in FEI's transmission pipeline system does not result in internal corrosion and therefore the hazard group includes only external corrosion within the Integrity Management Program – Pipelines (IMP-P). FEI's observations are validated through its in-line inspection activities. Therefore, internal corrosion is not considered a relevant hazard to its IMP-Pand has no corresponding mitigation activities.

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

Response:

Please refer to the response to CEC IR 1.14.1.

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.

Response:

No, FEI does not consider itself to be an early adopter of ILI. FEI monitors the industry for proven and commercialized technologies that can be used for in-line inspection so that the hazards and consequences associated with its pipeline system can be appropriately addressed. As such, FEI started using ILI technology when it was considered proven and commercialized. Similarly, FEI has determined that ILI technology is now available to address the potential for rupture due to corrosion for the IGU Project.

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.

Response:

A primary goal of FEI's adoption of ILI technology has been to mitigate the potential for rupture failure. While early metal loss tools did not have sufficient resolution to detect and size imperfections posing a leak threat to a pipeline, they did provide valuable information to operators for prevention of ruptures.

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.

Response:

The primary differences between the TIMC project and the IGU Project are with respect to the following:

- The types of in-line inspection capabilities they are providing:
  - The IGU Project is focused on providing ILI capability in small diameter lateral pipelines primarily for the detection and mitigation of external corrosion.
  - The TIMC project is focused on providing ILI capability primarily for the detection and mitigation of stress corrosion cracking and other crack-like imperfections.

  Please refer to the response to BCUC IR 1.6.1 for further discussion of ILI tools and their capabilities.
- The methodology being employed to identify the scope of work:
  - FEI determined that the transmission laterals in the BC interior region operating at 30 percent SMYS or greater have the potential to fail by rupture due to external corrosion and that different alternatives were available and prudent for

pipelines of NPS 6 and greater. FEI then evaluated these different alternatives to address the risk.

- FEI determined that the TIMC project warranted completion of a quantitative risk assessment (QRA), which will provide a quantified determination of the need and priority for adopting crack-detection tools for selected transmission mainlines. Please refer to the response to BCUC IR 1.6.7 for further discussion as to why the QRA is not related to the IGU Project Application.

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.

<u>Response:</u>

No, EMAT tools do not represent a potential alternative for consideration instead of the alternatives considered in the Application.

Please refer to the response to CEC IR 1.16.1. In-line inspection tools differ in the types of imperfections that they are intended to detect and size. As such, running EMAT tools in the 29 Transmission Laterals would not adequately mitigate the potential for rupture due to external corrosion.

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

Response:

Please refer to the response to CEC IR 1.16.2.

1 **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.

2

[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.

3

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.

4

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.

Response:

Confirmed. FEI would not expect to be directed by the BC OGC to conduct risk mitigation activities for the 29 Transmission Laterals, as FEI 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. Please refer to the response to BCUC IR 1.9.1 for a discussion of how the IGU Project supports FEI's compliance with its legal and regulatory obligations.

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

Response:

FEI considers it unlikely that the BC OGC would direct FEI to conduct specific risk mitigation measures as FEI is already following the hazard management approach outlined in CSA Z662-15 standard, Clause N.8.3 (b). However, if the BC OGC were to determine that FEI were not taking steps to meet its legal and regulatory obligations, it is possible that the BC OGC would issue direction to 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?

Response:

No, it is not FEI's contention that the 29 Transmission Laterals are currently unsafe. As part of its Integrity Management Program for Pipelines, FEI uses a number of available methods including, but not limited to, recurring operational activities such as leak survey and pipeline patrol as well as integrity monitoring through Modified ECDA to mitigate the risk of failure on the 29 Transmission Laterals. However, given the known limitations of these methods to detect external corrosion where there is cathodic protection shielding, the identified potential for pipeline rupture, the availability of mitigation solutions and, in particular, the common use of ILI for smaller diameter pipelines in the industry, FEI has concluded that steps should be taken to mitigate the potential for rupture due to external corrosion.

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?

Response:

Please refer to the response to CEC IR 1.18.1.

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.

Response:

While FEI does not consider the 29 Transmission Laterals to be unsafe, given FEI's awareness of limitations associated with Modified ECDA, the potential for failure by rupture due to corrosion in its pipelines operating at 30 percent SMYS or greater, and the availability of proven and commercialized technology to perform in-line inspection for NPS 6 pipelines and larger, FEI does not consider the status quo an appropriate operating practice over the long-term. Please refer to the response to CEC IR 1.3.2 for the potential consequences of a rupture.

The IGU Project is necessary to maintain compliance with legal and regulatory obligations and reflects FEI's assessment of relevant hazards to its pipeline system, FEI's understanding of industry practice, as well as FEI's knowledge of evolving technology available for assessing and managing pipeline condition.

As indicated in the response to CEC IR 1.17.2, if FEI were not taking steps to meet is legal and regulatory obligations, it is possible that the BC OGC would issue direction to FEI. FEI believes that such a direction could provide an indication that the level of safety for the 29 Transmission Laterals is potentially compromised.

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.

Response:

FEI confirms that there are independent companies that offer non-destructive testing for difficult to inspect pipelines. These non-destructive inspections typically use internal inspection tools similar to the ILI tools used by FEI with some significant differences as noted below:

- The majority of these tools require the pipeline to be out of service while being inspected.
- Unlike conventional ILI tools that use the gas flow to propel the tool through the pipeline, these tools use a tether and winch system or robotic crawler to move the smart pig through the pipe.

- These tools are usually used in short, difficult to inspect segments of pipe that can be taken out of service. For longer pipeline segments, and lines that cannot be taken out of service, conventional magnetic flux leakage (MFL) tools are typically used. FEI is aware of one robotic ILI vendor that can run its tools in in-service pipelines. Please refer to Section 4.2.7 of the Application for more details.

FEI uses independent pipeline inspection service companies that offer non-destructive inspection using inline inspection tools or intelligent pigs, which are electronic devices designed to travel in the inside of a transmission pipeline, while the line is in service, to inspect a pipeline for various types of anomalies. FEI understands that Balboa Oil and Gas Inspection and Maintenance Service does not offer robotic inspection at this time; however, the company does offer non-destructive testing for pipelines that are not in service.

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

Response:

No.

19.2.1 If no, please explain why not.

Response:

Please refer to the response to CEC IR 1.19.1.

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

Response:

Please refer to the response to CEC IR 1.19.1.

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.

Response:

FEI's statements in Section 4.4.2 of the Application were not in reference to these services as being unavailable to FEI.

As indicated in Section 4.4.2 of the Application, FEI is not aware of any robotic technology that is suitable for use within in-service natural gas pipelines for NPS 6 (168mm) or smaller pipe. FEI is aware of only a single vendor providing this service for larger pipe sizes. However, as mentioned in Section 4.2.7 of the Application, FEI expressed its concern with the degree of commercialization of this technology:

> "Current challenges associated with ROB tools are their lack of availability for pipe sizes of NPS 6 (168mm) and smaller, their degree of commercialization (FEI is aware of only a single vendor providing this service for pipe sizes larger than NPS 6), and their requirement for frequent charging."

As indicated in response to CEC IR 1.19.1, FEI has since contacted Balboa Oil and Gas Maintenance Service and has been advised that they do not offer robotic inspection at this time.

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.

Response:

Please refer to response to CEC IR 1.21.1.

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)

Response:

FEI is unable to provide a ballpark estimate as it has no information on which to base any estimate.

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.

Response:

If robotic inspection were to become proven and commercialized in the next 5 years or the next decade, becomes industry-accepted, and is a cost-effective means to conduct in-line inspections relative to alternatives, FEI would consider it as a feasible alternative.

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.

Response:

As included in Appendix E of the Application, potential feasible and cost effective applications for Robotic ILI are:

- Lower pressure pipelines or pipelines with insufficient flow to adequately propel a traditional ILI tool;
- Inspection of pipelines or pipeline segments where access is difficult or where the line could not be retrofitted to allow for ILI (e.g. below a water crossing or below an immovable structure); and
- Inspection of short pipeline segments where it may be more cost effective to run a Robotic ILI tool versus a traditional ILI tool.

Given FEI's assessment that ROB is currently not proven nor feasible, coupled with the uncertainty associated with a non-commercialized solution that has not been proven by the industry, it is not possible to evaluate the alternative further than was included in the Application.

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.

Response:

It would not be worthwhile to postpone the start date of the IGU Project in order to employ robotic in-line inspection as the timeline for robotic in-line inspection technology to become proven and commercialized is not known and uncertain at this time. Please refer to the response to CEC IR 1.4.10.

If FEI identifies a commercially feasible and industry accepted alternative to ILI during the implementation of the IGU Project, FEI would evaluate the alternative and advise the BCUC of the results and if any changes to the IGU Project were required.

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.

Response:

FEI considered using robotic inspection technology as a pilot (sample) test in parallel with ILI technology to determine its potential efficacy, but at this time the technology is not sufficiently proven and commercialized such that FEI cannot ensure with reasonable certainty that there would be financial and informational value in such an undertaking. FEI's future evaluation of robotic inspection technology may involve pilot testing.

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.

<u>Response:</u>

Pipeline integrity includes failure prevention, inspection and repair, and maintaining the pipeline so that it is fit for service. Alternative integrity management solutions include inline inspection (ILI), pipeline replacement (PLR), pressure regulation station (PRS), pipeline exposure (PLE), external corrosion direct assessment (ECDA), hydrostatic testing (HSTP). General differences between these alternatives relate to the project execution, prevention of ruptures and leaks, proactive asset management and lifecycle cost to implement.

A summary of the impacts as it relates ecological damage, longevity and other criteria are summarized below:

Activity/ Option	ILI	PLR	PRS	PLE	ECDA	HSTP
Ecological Damage	Low impact during construction and ILI digs	Moderate impact during construction	Low impact during construction	Moderate impact during construction	Low impact during assessment and digs	High impact during testing and repairs
Longevity	Significant increase	Significant increase	No increase (refer to BCUC IR 1.13.2)	Significant increase	Limited increase but not acceptable over the long term	Limited increase
Lifecycle Costs	Moderate Cost for Long Laterals (>5km)	Moderate Cost for Short Laterals (<5km)	Low Cost when feasible	High Cost	Low cost	High Cost when feasible
Benefits	High level of Integrity and Asset Management capabilities; Meets Project Objectives	High level of Integrity and Asset Management capabilities; Meets Project Objectives	Low level of Integrity and Asset Management capabilities; Meets Project Objectives	Moderate level of Integrity and Asset Management capabilities; Meets Project Objectives	Low level of Integrity and Asset Management capabilities; Doesn't meet Project Objectives	Low level of Integrity and Asset Management capabilities; Meets Project Objectives
Other Considerations	High level of project certainty and execution	High level of project certainty and execution	High level of project certainty and execution	Moderate level of project certainty and execution	Moderate level of project certainty and execution	Low level of project certainty and execution

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.

Response:

The following table summarizes the impacts customers on laterals not considered feasible for PRS could experience within the 20 year forecast if pressure on the Lateral system was regulated to below 30 percent SMYS of the pipe.

Customer Impacts on Laterals Where PRS is not Feasible

Lateral System	Line/loop Fill Name	Customers Impacted	Impacts
MacKenzie System	Mackenzie Lateral 168 Mackenzie Loop 168	2 Large Industrial Interruptible Customers	With PRS on the Mackenzie System, two large industrial operations on the system could be required to manage to less than half of their combined maximum observed consumption regardless of the pressure available at the lateral tap. A PRS would require these customers to significantly adjust the way they use natural gas currently in their business practices. They would move from periodic winter time curtailment to regular year round load management.
Prince George 1 System	Prince George 1 Lateral 168	5 Large Industrial Interruptible Customers	With PRS on the Prince George 1 System at the start of the Prince George 1 Lateral 168, five large industrial operations in the system would be required to manage to less than 17% of their combined maximum observed consumption regardless of the pressure available at the lateral tap. While these customers currently require some degree of load management, a PRS would remove access to a large amount of capacity currently available that these customers regularly consume. A PRS would require these customers to significantly adjust the way they use natural gas currently in their business practices. They would move from periodic curtailment when tap pressures provided lower capacity than their combined requirements to significant regular year round load management below their typical current combined consumption.
Kamloops 1 System	Kamloops 1 Lateral 168 Kamloops 1 Loop 168	2 Large Industrial Interruptible Customers	With PRS on the Kamloops 1 System, two large industrial operations in the system could be required to manage to less than their current maximum observed consumption regardless of the pressure available at the lateral tap. A PRS would require these customers to adjust the way they use natural gas currently in their business practices. A PRS would limit the ability to attract other new Interruptible customers to the Kamloops system.

Lateral System	Line/loop Fill Name	Customers Impacted	Impacts
Salmon Arm System	Salmon Arm Loop 168	Approx. 13,000 residential, commercial and industrial customers and 2 Interruptible customers	With a PRS on the Salmon Arm System at the tap location of the Salmon Arm Loop 168, the lateral system has insufficient capacity to support the existing customers and forecasted new customer attachments with firm service served by the system. The installation of a PRS would drive the need for new pipeline looping within the Salmon Arm System to restore the capacity capped by the installation of the PRS. This would be required to avoid winter time curtailment or wide spread supply shortfalls for significant number of firm customers served by the lateral.
Salmon Arm System	Salmon Arm 3 Lateral 168	No impact	This was overlooked in the final reassessment of PRS locations and incorrectly determined to be not feasible.
Fording System	Fording Lateral 219 Fording Lateral 168	4 Large Industrial Interruptible Customers	With PRS on the Fording System at the start of the Fording Lateral 219, four large industrial mining facilities in the system would be required to manage to less than 17% of their current maximum capacity limits regardless of the pressure available at the lateral tap. While these customers currently require some degree of load management, a PRS would remove access to a large amount of capacity currently available that these customers regularly consume. A PRS would require these customers to significantly adjust the way they use natural gas currently in their business practices. They would move from periodic curtailment when tap pressures provided lower capacity than their combined requirements to significant regular year round load management below their typical current combined consumption.
Cranbrook Kimberley System	Cranbrook Lateral 168 Cranbrook Loop 219	Approx. 14,200 residential, commercial and industrial customers	With a PRS on the Cranbrook Kimberly System at the TransCanada tap location of the Cranbrook Lateral 168 and Loop 219 the lateral system has insufficient capacity to support the existing firm customers and forecasted new customer attachments with firm service served by the system. The installation of a PRS would drive the need for new pipeline looping within the Cranbrook Kimberly System to restore the capacity capped by the installation of the PRS. This would be required to avoid winter time curtailment or wide spread supply shortfalls for significant number of firm customers served by the lateral.
Cranbrook Kimberley System	Cranbrook Kimberley Loop 273	1 Large Industrial Interruptible Customer	With a PRS on the Cranbrook Kimberly System at the tap location of the Cranbrook Kimberley Loop 273 one large industrial customer at the tail end of the lateral system could be required to manage to less than 70% of their current maximum observed consumption regardless of the supply pressure available at the TransCanada tap serving the lateral system. A PRS would require this customer to adjust the way they use natural gas currently in their business practices.

Lateral System	Line/loop Fill Name	Customers Impacted	Impacts
Cranbrook Kimberley System	Cranbrook Kimberley Loop 219 Kimberley Lateral 168	1 Large Industrial Interruptible Customer	With a PRS on the Cranbrook Kimberly System at the start of the Kimberley Lateral 168 and the Cranbrook Kimberley Loop 219, one large industrial customer at the tail end of the lateral system could be required to manage to less than 57% of their current maximum observed consumption regardless of the supply pressure available at the Transcanada tap serving the lateral system. A PRS would require this customer to adjust the way they use natural gas currently in their business practices.
Cranbrook Kimberley System	Skookumchuck Lateral 219	1 Large Industrial Interruptible Customer	With a PRS on the Cranbrook Kimberly System at the tap location of the Skookumchuck lateral, one large industrial customer at the tail end of the lateral system could be required to manage to less than 90% of their current maximum observed consumption regardless of the supply pressure available at the Transcanada tap serving the lateral system. A PRS would require this customer to adjust the way they use natural gas currently in their business practices.

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.

Response:

FEI might be able to support customers over the long term who may experience intermittent issues using options such as Compressed Natural Gas (CNG) and Liquefied Natural Gas (LNG). However, these options are dependent on the volume of gas required to support the network during those intermittent issues.

In the case of CNG, a permanent compression site would be required in a centralized location to meet requirements for filling CNG trailers, along with transportable de-compression systems. This would reduce travel time required in comparison to LNG. CNG trailers would be stationed at critical locations to support the network during a supply shortage. As the trailers are drawn down, a replacement trailer would need to be filled from the compression site, transported, and connected to the de-compression site.

As compared to CNG, pipeline supply capacity is a more effective, long-term solution to meet the requirements of industrial customers whose gas volumes can vary widely on a daily basis due to process needs and/or weather conditions, or to meet the needs of systems that are growing in customer numbers and peak demand. CNG presents a logistical challenge and could require unpredictable numbers of trailers per day along with a sufficient number of operators/drivers to meet customer needs, or be equipped and staffed to meet the anticipated peak demand on a constant basis. CNG trailers are currently able to haul approximately 350-380 GJ of gas per trailer. The site layout may be impractical for the required number of trailers to be positioned and readily available to feed the de-compression system. This could limit the demand that could be maintained by CNG at a particular site.

Please refer to the response to BCUC IR 1.15.3 for additional discussion of FEI's recent experience with delivering CNG by road (virtual pipeline).

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

<u>Response:</u>

As per its BCUC approved tariff, FEI is permitted to curtail or restrict gas supply to interruptible customers, for example, under colder weather conditions when core customers' demand increases. At the same time, interruptible customers expect FEI to provide a reasonable level of reliable service for the majority of the year. If these customers were curtailed or restricted too frequently, they would seek alternate fuels that they may view as more reliable and FEI could lose the customer and the load permanently.

PRS was not determined as a feasible solution for some laterals as the PRS would cause a reduction in capacity on those laterals and would result in a year round requirement for more frequent curtailment of customer loads such that FEI not would not be providing a reasonable level of reliable service. In some instances, a PRS would mean FEI could not meet supply needs for forecasted growth in the region served by those laterals. In those instances, PRS could not be done without also requiring a pipeline expansion to restore capacity on that lateral as it could no longer handle expected customer loads. Please refer to the customer impacts summarized in the response to CEC IR 1.23.1 for additional information.

23.4 Please identify on which laterals interruptible customers are present.

Response:

Every lateral included in the IGU Project, with the exception of the Coldstream Loop 168 and Coldstream Lateral 219, serves one or more interruptible customers directly connected to the lateral or transports gas to one or more Interruptible customers attached to downstream lateral pipelines or distribution systems. Some of these Interruptible customers have a firm capacity component to their agreement so only a portion of their capacity is received on an interruptible basis.

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.

Response:

In addition to 60 years being a rounded number, it was chosen in recognition of the life of the transmission pipelines being an estimate only, based on information known today. The life can be expected to vary in the future, but 60 years is reasonable both because it is close to the average 65 year life of transmission lines as discussed in FEI's response to BCUC IR 1.1.1 and is implicit in the 1.47 percent depreciation rate. It is also within the range of the average service life estimates among Canadian natural gas transmission companies which range from 60 years through 65 years[2].

Regardless, the difference in PV of the incremental revenue requirement between a 60 years and a 68 years evaluation period post-project (66 years vs. 74 years when including the six prior

[2] FEI Application for a Multi-year Rate Plan for 2020 to 2024, Appendix D2-1, page 3-7.

years) is immaterial considering the discounting of future costs beyond 60 years. Including eight additional years into the financial analysis adds less than one percent to the total project PV of incremental revenue requirement and will not change any of the alternative evaluations or conclusion.

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.

Response:

Please refer to the response to BCUC IR 1.1.1.

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.

Response:

There are various reasons why the ratio of PV over a 66-year period to capital cost in 2018 dollars varies amongst laterals. The timing of the implementation is one reason because construction will be completed at different times for each lateral (see Section 5.4 of the Application for Construction and Operating Schedule and Activities). For example, ILI for the Castlegar Nelson Lateral is estimated to be completed in 2024, while ILI for Cranbrook Lateral 168 is estimated to be completed in 2021.

Another reason is that the PV of revenue requirement does not only consider the capital cost of the lateral; it also considers future sustainment expenditures, such as ILI integrity runs and digs, PRS station incremental O&M cost, etc. For example, a longer lateral would, on average, have a higher number of ILI digs occurring than a shorter lateral. Also, a lateral that is completed earlier could have more ILI integrity runs over the 66-year analysis period than another lateral that is completed at a later date.

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.

Response:

In its Application, FEI evaluated seven feasible alternative integrity management solutions that could meet the Project's objective to mitigate the potential for rupture failure due to corrosion on the 29 Transmission Laterals. As explained in Section 1.2.3 of the Application, FEI applied the evaluation criteria on the feasible alternatives and determined that only Pressure Regulating Station (PRS), In-Line Inspection (ILI) and Pipeline Replacement (PLR) provided a technically feasible and cost effective means of achieving the Project goal of mitigating the potential for rupture due to corrosion.

For short laterals, the financial score of the PLR option was superior to the two other alternatives, ILI and PRS, and is therefore the preferred alternative. High level cost comparisons for each alternative for short laterals are available in Table 4-7 in the Application.

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.

Response:

The vintage of the pipelines speaks to the level of detail on the records rather than the construction practice of using more elbows or field bends. Many of the records show the alignment of the pipe and the specifications of the pipe; however, few drawings indicate whether field bends or elbow fittings were used when the alignment of the pipe changes directions.

With regard to the vintage of the pipe and construction practices, Figure 6 in Appendix 1 of Exhibit B-1-1 Confidential Appendix L-2, shows that there is no strong correlation between the vintage of the pipeline and the number of elbow fittings used versus field bends.

26.2 Please provide Mr. Hollmann's credentials.

Response:

Mr. Hollmann provided the following credentials.

Mr. Hollman is a registered professional mining engineer and a certified cost professional (CCP; formerly called Certified Cost Engineer), in addition to being a Certified Estimating Professional (CEP) and a Decision and Risk Management Professional (DRMP). He has a Bachelor of Science degree in Mining Engineering from the Pennsylvania State University and a MBA from the Indiana University of Pennsylvania.

Mr. Hollman is a Fellow of AACE (2006) and an Honorary Life Member of AACE (2011).

Mr. Hollmann is the lead editor and primary author of the ACCE Total Cost Management Framework, for the First Edition published in 2006.

He has been the principal of Validation Estimating LLC since 2005. Refer to Attachment 26.2A for a description of Validation Estimating LLC (https://www.validest.com/about.htm).

Prior to forming Validation Estimating LLC in 2005, he managed the downstream Cost Engineering Committee (CEC) and cost and schedule metrics programs of Independent Project Analysis, Inc. (IPA) for 7 years. Before IPA, he was a senior estimator with Eastman Kodak where he helped lead their development of cost estimating processes, systems, tools and data (Kodak was a combined chemical and manufacturing company). Prior to that, he was a Senior Project Control Engineer with Fluor Daniel, Inc. working in the industrial, refining, and pipeline sectors.

Mr. Hollmann has authored a number of books, technical articles, and AACE International Recommended Practices on cost estimating and risk analysis. Refer to Attachment 26.2B for a list of Mr. Hollman's publications (https://www.validest.com/library.htm).

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?

Response:

No, the evaluation completed did not always result in the next lowest cost alternative being selected for the second choice alternative. The alternative solution with the next highest rating to the preferred alternative was selected. As described in Section 4 of the Application, FEI evaluated each feasible solution using a scoring system consisting of Integrity and Asset Management Capabilities, Project Execution and Lifecycle Operation, and overall cost to determine preferred and alternative solutions.

The response to BCUC IR 1.18.5 provides an example of the evaluation process for the Elkview Lateral.

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

Response:

Please refer to the response to CEC IR 1.27.1.

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.

<u>Response:</u>

This response also addresses CEC IR 1.28.2.

FEI has not yet determined the items or quantified the amount of the goods or services that would be procured without the competitive bidding process. However, FEI's preferred method of acquiring goods and service is through a competitive bidding process. Pursuant to FEI's

Procurement Policy, goods and services over $25,000 are typically competitively bid unless there is sufficient justification and this justification must be documented and approved by the appropriate authority level (as identified in the FEI Authorities Policy). Sufficient justification may include circumstances where there is a single/sole source arrangement, where management believes that a direct negotiation will lead to greater value than a competitive process or where the business unit is able to demonstrate that the fair market value of the contract has been achieved (ie. multiple quotes have been received, etc.). Additionally, it is at the discretion of each member of the FEI Executive (VP, EVP, President/CEO) to apply additional conditions within his or her department beyond the requirements provided within the Procurement Policy. .

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

Response:

Please refer to the response to CEC IR 1.28.1.

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

Response:

As noted in the response to CEC IR 1.28.1, pursuant to FEI's Procurement Policy, competitive bidding is the preferred method of procurement. The project manager works with the Procurement Department (and legal counsel in certain circumstances) to determine the type of competitive bidding process that would be most appropriate for the goods or services being procured (ie. request for tender, request for proposal, etc.) and to produce a procurement package which is put out to the market once completed. Bids or proposals are then received, evaluated and a contract may eventually be awarded, or if none of the bids are compliant or within the expected range, then no contract is awarded. The evaluation methodology and criteria for a compliant bid are laid out in the procurement package and determined by the type and volume of goods and/or services being procured.

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.

Response:

The Environmental Overview Assessment (EOA) identifies potential interactions with wildlife, including species at risk, through desktop review and field reconnaissance. Please see Section 2.5 and Section 3 of the EOA reports included in Appendix O of the Application. The EOA is based on engineering design completed to date and further field investigations will be completed to support detailed engineering, permitting, and the development of lateral-specific management plans.

FEI has identified that eight of the rights-of-way interact with critical habitat polygons for wildlife. The wildlife species with critical habitat overlapping the rights-of-way are identified in Section 7.2.1.6 of the Application, and are Lewis's Woodpecker, Great Basin Spadefoot, Gopher Snake, Western Rattlesnake, and Caribou. The extent of overlap between the Project footprint and critical habitat polygons, and habitat features within the critical habitat polygons, will be determined during the detailed design phase of the Project.

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

Response:

Section 6 of the Environmental Overview Assessment Reports included in Appendix O of the Application lists guiding documents, best management practices, and mitigations measures that will be integrated into the lateral-specific management plans, where applicable. As discussed in the response to CEC IR 1.29.1, potential impacts to wildlife will continue to be considered throughout the detailed design phase of the Project.

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

Response:

Section 3 of the EOA reports included in Appendix O of the Application identifies plant communities at-risk with potential to interact with the Project. The EOA is based on the engineering design completed to date and further field investigations will be completed as part of the Project planning and execution.

The existing right-of-way for one lateral (SSK LTL 219) interacts with Wildlife Habitat Area (WHA) 4-117, for antelope-brush/bluebunch wheatgrass. The extent of overlap between the Project footprint and the WHA, if any, will be determined during the detailed engineering and design phase for this lateral. No other plant communities at risk have been identified in the planned Project footprint for any other preferred alternatives.

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.

Response:

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.

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

Response:

FEI has identified the following recorded incidents involving release of gas from its operating history of the 29 Transmission Laterals that may have impacted their reliability. Beyond what is provided in the table below, FEI has not located further details of the reliability impacts for these occurrences.

Year	Pipeline	Cause of Failure	Failure Type	Notes from Available Documents
1973	Fording Lateral 168/219	Third party damage	Leak	A bulldozer hit the pipeline

Year	Pipeline	Cause of Failure	Failure Type	Notes from Available Documents
1976	Castlegar Nelson 168	Natural hazard	Leak (assumed)	Mud and rock slide damaged NPS 6 transmission line. "A line break 6" Inland Natural Gas line in the vicinity of Roson near Selkirk College occurred April 7. Will lose 150 customers at Robson and will lose Selkirk College, and feed Nelson by line pack supplemented by propane storage line."
1977	Castlegar Nelson 168	Third party damage	Leak	A grader hit the pipeline. The pipeline failure was repaired with a plidco high pressure sleeve and continued in operation at reduced pressure.
1982	Fording Lateral 168/219	Third party damage	Leak	A road grader dug a hole into the NPS 6 pipeline buried on the road right-of-way. No one was injured. No damages. 6 to 7 feet of NPS 6 pipe was welded in and x-rayed.
1983	Prince George 1 Lateral 168	Third party damage	Rupture	Rupture of NPS 6 TP Lateral caused by caterpillar tractor Tractor operator thrown clear by rupture. No fatalities.
1984	Castlegar Nelson 168	Natural hazard	Leak (assumed)	Mud slide hit the pipeline
1986	Kamloops 1 Loop 168	Human error	Leak	Faulty weld
1988	Trail Lateral 168	Human error	Leak	Back-hoe hit (hired by Inland Natural Gas)
1992	Salmon Arm Loop 168	Third party damage	Leak	BC Hydro auger punctured pipeline Section of pipeline was cut-out
1996	Fording Lateral 168/219	External corrosion	Leak	Leak detected during routine leak survey.

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?

Response:

FEI notes that there was a typographical error in the table. Please see the corrected table below which reflects that a single industrial customer, Cariboo Pulp and Paper, is served by the Cariboo Pulp lateral 168. FEI will be filing an evidentiary update to the Application and will also make this correction in that filing.

<table>
<tr><td colspan="2">Length of Pipeline (kilometres)</td><td>1.3</td></tr>
<tr><td colspan="2">Outside Diameter(s) (millimetres)</td><td>168</td></tr>
<tr><td colspan="2">Year of Construction</td><td>1972</td></tr>
<tr><td colspan="2">ROW Width (metres)</td><td>10</td></tr>
<tr><td rowspan="3">Number of Customers</td><td>Residential</td><td>N/A</td></tr>
<tr><td>Commercial</td><td>N/A</td></tr>
<tr><td>Industrial</td><td>1</td></tr>
<tr><td colspan="2">Important Factors in Execution and Lifecycle Operation</td><td>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</td></tr>
</table>

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.

Response:

Both ILI and PRS require incremental costs for sustainment activities and O&M, whereas PLR requires neither incremental sustainment nor O&M costs.

As discussed in Section 4.3.1.3 of the Application, the following future incremental expenditures are included in the 66 year revenue requirement analysis:

- For PRS, future capital expenditures are included for the replacement of the measuring and regulating equipment, the building or enclosed structure for housing the measuring and regulating equipment, and/or the telemetry equipment. This is based on the currently approved depreciation rate for these assets, which is 2.41 percent (41 years), 2.29 percent (43 years), and 9.75 percent (10 years), respectively;
- For ILI, future capital expenditures are included for the ILI integrity runs and future O&M expenditures are included for the integrity digs as a result of each ILI integrity run. ILI integrity runs were assumed to occur on a 7-year cycle for each lateral selected with ILI as the preferred option; and
- For PRS, future O&M expenditures are included for the maintenance of the new PRS station.

It should be noted that all of the expenditures identified above are considered incremental to current expenditure levels (i.e. there would not be the additional ILI integrity runs if the lateral was not modified to be ILI capable).

For PLR, there is no future incremental capital expenditure. As discussed in response to BCUC IR 1.1.1, the financial end of life for a new transmission main pipeline is 65 years based on the currently approved depreciation study and, furthermore, a pipeline can have a longer (or shorter) physical life than its financial life. There is also no future change in the O&M expenditure included for PLR because the new pipeline will still require the current integrity management activities and therefore, no additional costs or savings due to a new pipeline (please refer to FEI's response to CEC IR 1.4.11).

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.

Response:

Confirmed.

32.1.1 If not confirmed, please explain why not.

Response:

Please refer to the response to CEC IR 1.32.1.

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?

Response:

The table referred in the preamble above from Appendix I of the Application has a typographical error as it should refer to 66 years instead of 50 years. The PV of incremental revenue requirement analyses for the IGU Project are determined based on a 66-year period. All financial analysis, include all financial models included in Appendix N-1 and N-2 are based on a 66-year analysis period. FEI will be filing an evidentiary update to the Application and will make this correction to Appendix I in that filing.

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?

Response:

If the alternative evaluation were dependent only on the financial consideration and customer rate impact, then the simple ratios or ranking of the alternatives by the NPVs would lead to the same result as the financial scoring system chosen by FEI. However, when the alternative evaluation is based on multiple criteria that weigh against each other, FEI considers it more appropriate to use a scoring system such as the one established for the financial criterion.

The whole numbers from 0 to 5 in FEI's financial scoring system are assigned based on the relative differences in PV of revenue requirements between alternatives in percentage. This financial scoring system is designed to avoid the multi-criteria scoring system suggesting an alternative that would be marginally more superior in terms integrity and asset management capabilities and/or project execution and lifecycle operation, but also far more expensive than another alternative which could achieve the same project objective. Based on FEI's multi-criteria scoring system, all preferred alternatives chosen by FEI, except for Elkview Lateral, are also the least expensive option in terms of PV of revenue requirement over 66 years. For Elkview, the difference in PV of revenue requirement between PLR and PRS for Elkview is considered immaterial at approximately 0.5 percent. Consequently, FEI selected PRS as the preferred alternative based on the rationale discussed in the response to BCUC IR 1.18.4.

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.

Response:

In developing the Project, FEI's objective was to determine the best solution for each of the 29 Transmission Laterals, which is why an evaluation of all options for each lateral was undertaken. This is the same approach that FEI would have taken had each lateral been considered as a separate project. With this objective, there is no need to compare the cost per pipeline length or cost per number of customers across each pipeline segment, as this would not change the decision that was being made.

The relevant comparison is the total cost of each alternative for each individual lateral that will mitigate the potential for rupture. The cost estimates developed for all feasible alternatives are based on known conditions of each lateral, including length (e.g. duration of construction required), number of bends (e.g. number of modifications required), regions (e.g. level of consultation, environmental & archaeological investigations required), etc. Each lateral has its own unique characteristics such that comparing total cost against pipeline length or number of customers would not provide useful information.

The criteria developed to evaluate alternatives was designed to account for the alternative's ability to achieve the primary objective of preventing the potential for rupture due to corrosion while also considering project execution and lifecycle operation and financial impact. Using this scoring system, the preferred alternative selected for each lateral, except for the Elkview Lateral, is also the least expensive alternative. For the Elkview lateral, please refer to FEI's response to BCUC IR 1.18.4 for the rationale for selecting PRS, which is marginally more expensive than PLR in terms of PV of the revenue requirement over 66 years.

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

Response:

Financial scoring of FEI projects typically relies on similar principles to analyze the Total Direct Capital Cost, Net Present Value (NPV), and Levelized Rate Impact of each option. Examples of this type of financial scoring can be found in other FEI applications, such as:

- Lower Mainland IP System Upgrade, Exhibit B-1, Section 3.2.3.2, available at https://www.bcuc.com/ApplicationView.aspx?ApplicationId=476;
- Huntingdon Station Bypass, Exhibit B-1, Section 4.3.1, available at https://www.bcuc.com/ApplicationView.aspx?ApplicationId=420;
- Muskwa River Pipeline Crossing, Exhibit B-1, Section 4.4.1, available at https://www.bcuc.com/ApplicationView.aspx?ApplicationId=422; and
- Kootenay River Crossing (Shoreacres), Exhibit B-1, Section 4.2.2, available at https://www.bcuc.com/ApplicationView.aspx?ApplicationId=278.

The Inland Gas Upgrades Project followed a similar approach, and required further refinement to the weighting to systematically analyze up to 3 options for each of the 29 laterals, with repeatable results. Appendix I page 2 as well as Tables 4-1 and 4-4 in the Application detail the financial scoring and weighting for the Project, respectively.

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

Response:

Please refer to the response to CEC IR 1.32.5.

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?

<u>Response:</u>

No. The lateral serves only 2 industrial customers located at the western end of the lateral. The residents of the City of Castlegar are connected to the nearby Castlegar-Nelson Lateral.

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

<u>Response:</u>

Please refer to the response to BCUC IR 1.33.1.

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

Response:

As discussed in the response to CEC IR 1.33.1, the Celgar Lateral 168 serves two industrial customers. The lateral extends generally westward through undeveloped areas in a cleared ROW bounded by forest until terminating at the mill sites of the industrial customers served. No populated structures exist in close proximity to the lateral. As a result, there may be no immediate safety impact to the public as a result of a leak or rupture on the lateral. A lateral rupture would result in a supply interruption to the two large industrial customers served by the lateral. There could be consequential economic impacts to the businesses and employees of these customers, as well as to those businesses and persons supplying services to them. As indicated in the Application, FEI estimates that an outage resulting from a rupture on a single feed lateral, 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.

Attachment 26.2A

Attachment 26.2A

VALIDATION ESTIMATING

about

John K. Hollmann PE CCP CEP DRMP is the owner and principal consultant of Validation Estimating, LLC

John has 35+ years of experience in the process, resource and infrastructure industries for owner, government, EPC, and research firms. John has experience in all areas of cost engineering and project control with an emphasis on cost estimating and risk analysis in support of owner investment decision making. John has particular expertise in work process assessment, developing and implementing practices and tools to fill process gaps, as well as training in those areas. With a volatile economy and mega-sized projects, risk quantification has become an increasing focus (his new book Project Risk Quantification (PRQ) was published in 2016). Most recently, John has been applying his expertise in the infrastructure industries (2nd edition of PRQ will be expanded to that scope). Validation Estimating's home base is Northern Virginia.

Professional Background

Prior to forming Validation Estimating LLC in 2005, John managed the downstream Cost Engineering Committee (CEC) and cost and schedule metrics programs of Independent Project Analysis, Inc. (IPA) for 7 years. He also initiated IPA's Upstream CEC and managed their Procurement Committee as well. John led IPA's research of Project Control best practices which was reported in a 2002 article in Chemical Engineering magazine; this is still the only industry research study to empirically demonstrate the economic value of Cost Engineering/Project Control.

Before IPA, John was a senior estimator with Eastman Kodak where he helped lead their development of cost estimating processes, systems, tools and data (Kodak was a combined chemical and manufacturing company). Prior to that, he was a Senior Project Control Engineer with Fluor Daniel, Inc. working in the industrial, refining, and pipeline sectors. John transitioned from principal mining engineering to cost engineering at Battelle Project Management Division which was integrating high level nuclear waste projects for the US DOE. John began his career as a mining engineer in underground coal mining and was the corporate mine planning engineer for Pennsylvania Mines Corp before leaving for Battelle. In all these experiences, John has been recognized for his unique conceptual ability to design and implement practical, integrative corporate and department level processes, systems and tools.

Cost Engineering, Total Cost Management and AACE International

Cost Engineering (see definition here) is a vital core competency for owner company capital asset and project system success. As such, John has put significant volunteer time into AACE International (the preeminent association for the cost engineering profession) and its efforts to develop industry standards and best practices. John was the lead author of AACE's Total Cost Management (TCM) Framework published in 2006. TCM is the first integrated process model to tie together up-front capital asset managment and execution phase project control for portfolios, programs and projects while linking them all back to business strategy. TCM is the key reference foundation for much of Validation Estimating's consulting in process improvement. In 2016, John's book Project Risk Quantification was published by Probabilistic Publishing.

John has served on the AACE Board of Directors, was a director of ICEC, and was Director of Recommended Practices for many years on AACE's Technical Board. He was also on the team that developed AACE's Cost Estimating Professional (CEP) certification. John received AACE's Award of Merit in 2008, and the Lifetime Achievement Award in 2018, its highest honor. John is currently an Honorary Life Member and Fellow at AACE. Most recently, John led the development of AACE's Decision and Risk Management Professional (DRMP) certification launched in 2013 (John holds certificate #001). John is a frequent presenter and has published many papers and articles. In 2017, he was made a member of the **Chemical Engineering Magazine Advisory Board** and in 2018 the GWU Masters in PM Advisory Board. He was a contributing author to Westney's Engineer's Cost Handbook published by CRC Press and AACE's Skills and Knowledge of Cost Engineering, 5th Edition. John is a registered professional mining engineer and a certified cost professional (CCP; formerly called Certified Cost Engineer) in addition to a CEP and DRMP. He has a BS degree in Mining Engineering from the Pennsylvania State University and a MBA degree from the Indiana University of Pennsylvania.

Clients Served

Oil & Gas/NOC/Refining

Aramco

Attachment 26.2A

BP
Chevron
DLA Piper (Expert Witness)
Ecopetrol
Husky
Lukoil Overseas
Northwest Redwater
Petro-Canada
Petronas
Suncor
Sunoco
Synenco
Syncrude

Chem/Bio/Agri/Pharms

Braskem
Cargill
Dow Corning
DuPont
Eastman
FMC
Medimmune
Praxair
Sasol
Simbol Materials

Mining/Metals

Antofagasta plc
Kinross Gold
Koff & Guerrero
Resource Capital Funds
Rio Tinto Alcan
Teck Resources
Vale
Votorantim

Power/Utility/Infrastructure

BC Hydro
Consumers Energy
DTE Energy
Emera
Enbridge
Hydro Quebec
Manitoba Hydro
Nalcor Energy
Nuon
Ontario Power
TransCanada
US Dept of Energy
Vattenfall
VMS Inc.

EPC Contractors

Bechtel
Black & Veatch
PT Thiess
Sinopec Engineering Group
SNC Lavelin

Attachment 26.2B

Attachment 26.2B

VALIDATION ESTIMATING

Library

PUBLICATIONS BY JOHN K. HOLLMANN PE CCP CEP DRMP

Books and Book Chapters

2017 - Chap 3:"Systemic Risks and Parametric Modeling" & "Chap 7: "Complexity Risk and Modeling Disorder": Handbook of Research on Leveraging Risk and Uncertainties for Effective Project Management (ed. Yuri Raydugin). IGI Global.
2016 - "Project Risk Quantification: A Practitioner's Guide to Realistic Cost and Schedule Risk Management" (Probabilistic Publishing).
Demonstration Parametric Models in Excel (per Chapter 11 of above book) (file in "Quick Links"-password provided with book purchase)
2015 - "Introduction" and "Strategic Asset Management" chapters in: Skills and Knowledge of a Cost Engineer, 6th Ed
2006 - "Total Cost Management Framework", Editor/Lead Author, 1st Edition (AACE's Technical Foundation)
2004 - "Asset Management" and "Skills Integration" chapters in: Skills and Knowledge of a Cost Engineer, 5th Ed
1997 - "Cost Estimating Methodologies", Chapter 2 of Westney's "The Engineer's Cost Handbook", CRC Press

Articles, Papers and Presentations

2017 - "Realistic and Practical Project Risk Quantification (without CPM)" , AACE Transactions
2017 - "Variability in Accuracy Ranges: A Case Study in the Canadian Power Transmission Industry", AACE Transactions
2016 - Overview of the book "Project Risk Quantification"; Presented at the 2016 AACE Annual Meeting
2016 - "Early History of Cost Engineering": Transactions and Cost Engr Journal, Mar/Apr 2017
2015 - "Study of Cost Engineering Salary and Demographic Data from the AACE 2013 Salary Survey"; self published
Model for above: Excel model of salary, bonuses and hourly rates from paper above
2015 - "Risk Analysis at the Edge of Chaos", Transactions and Cost Engr Journal, Jan-Feb 2015.
2014 - "Variability in Accuracy Ranges: A Case Study in the Canadian Hydropower Industry" AACE Transactions
2014 - "Improve Your Contingency Estimates for More Realistic Project Budgets", Chemical Engineering Mag, Dec 2014.
2012 - "Estimate Accuracy; Dealing with Reality", Transactions and Cost Engr Journal; Nov-Dec 2012.
2011 - "Cost Engineering's Added Value —Making Better Capital Investment Decisions", Cost Engineering Event
2010 - "Alternate Methods for Integrated Cost & Schedule Contingency Estimating", AACE Transactions
2009 - "Recommended Practices for Risk Analysis & Cost Contingency Estimating", AACE Transactions
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2002 - "A Planned Way for Smooth, Quick Startups", Cost Engineering Mag, Jul 2002
2002 - "Best Owner Practices for Project Control", AACE Transactions
2001 - "Controlling Project Costs", Chemical Engineering Magazine, Nov 2001
1996 - "Evolution of Estimating Systems at Kodak", AACE Transactions
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1994 - "A Building Square Foot Cost Estimating System", AACE Transactions
1989 - "Development of Conceptual Estimating Support Systems at Kodak", AACE Transactions
1987 - "Using Direct Measurement of Coal Core Methane Content in Mine Planning", Society of Mine Engineers Mine Ventilation Symposium

AACE International Recommended Practices

Authored or Co-Authored (contributed to many others as AACE Director of RPs from 2000-2013)
11R-88: REQUIRED SKILLS AND KNOWLEDGE OF COST ENGINEERING (ref: TCM-2006)
19R-97: ESTIMATE PREPARATION COSTS – AS APPLIED FOR THE PROCESS INDUSTRIES
40R-08: CONTINGENCY ESTIMATING-GENERAL PRINCIPLES
43R-08: RISK ANALYSIS AND CONTINGENCY DETERMINATION USING PARAMETRIC ESTIMATING
44R-08: RISK ANALYSIS AND CONTINGENCY DETERMINATION USING EXPECTED VALUE
47R-11: COST ESTIMATE CLASSIFICATION SYSTEM – AS APPLIED IN THE MINING AND MINERAL PROCESSING INDUSTRIES
58R-10: ESCALATION ESTIMATING PRINCIPLES AND METHODS USING INDICES
65R-11: INTEGRATED COST AND SCHEDULE RISK ANALYSIS AND CONTINGENCY DETERMINATION USING EXPECTED VALUE
68R-11: ESCALATION ESTIMATING USING INDICES AND MONTE CARLO SIMULATION
69R-12: COST ESTIMATE CLASSIFICATION SYSTEM – AS APPLIED IN THE HYDROPOWER INDUSTRY
71R-12: REQUIRED SKILLS AND KNOWLEDGE OF DECISION AND RISK MANAGEMENT
73R-13: ESTABLISHING LABOUR PRODUCTIVITY NORMS
96R-18: COST ESTIMATE CLASSIFICATION SYSTEM – AS APPLIED IN POWER TRANSMISSION
97R-18: COST ESTIMATE CLASSIFICATION SYSTEM – AS APPLIED IN PIPELINE
98R-18: COST ESTIMATE CLASSIFICATION SYSTEM – AS APPLIED IN ROAD AND RAIL TRANSMISSION
PDG-01: GUIDE TO COST ESTIMATE CLASSIFICATION