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March 28, 2019

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

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

Dear Mr. Wruck:

Re: FortisBC Energy Inc. (FEI)

Project No. 1598988

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

Response to the British Columbia Utilities Commission (BCUC) Information Request (IR) No. 1

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

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Doug Slater

Attachments

cc (email only): Registered Parties

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A. APPLICATION

1.0 Reference: CPCN FOR IGU PROJECT

Exhibit B-1 (Application), Section 1.1.1, p. 1; Appendix A

Useful Life of Transmission Laterals

On page 1 of the Application for a Certificate of Public Convenience and Necessity (CPCN) for the Inland Gas Upgrade (IGU) Project (Application), FortisBC Energy Inc. (FEI) states the following:

> 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 pipelines and are not capable of being in-line inspected (referred to in this Application as the 29 Transmission Laterals).

In Appendix A to the Application, FEI provides the year that each Transmission Lateral was constructed.

1.1 For each of the 29 Transmission Laterals, please provide the remaining useful life as of 2019. Please explain all inputs and assumptions used in determining the remaining useful life of each Transmission Lateral.

Response:

"Remaining useful life" can have two interpretations based on either the expected asset financial life or the expected asset service life. Each is discussed in turn below.

From an asset accounting perspective, the expected financial life of a transmission pipeline is 65 years based on FEI's 2014 Depreciation Study by Gannett Fleming Valuation and Rate Consultants Inc., approved by BCUC Order G-119-16. The expected financial life is also 65 years in FEI's 2017 Depreciation Study by Concentric filed in FEI's 2020-2024 Multi-Year Rate Plan Application. The table below shows the predominant year of construction[1] of each lateral and the remaining expected financial life as of 2019 assuming an expected financial life of 65 years for transmission pipeline.

[1] Some of the transmission laterals as part of the IGU CPCN had multiple segment built in different years. Predominant year of construction is based on the year that majority of the pipeline (in length) was built.

Line/Loop ID No.	Line/Loop Full Name	Preferred Alternative	Predominant Year of Construction	Weighted Average Age (Yrs)	Expected Remaining Asset Financial Life (Yrs)
1	Mackenzie Lateral 168	ILI	1966	52	13
2	Mackenzie Loop 168	ILI	1972	42	23
3	BC Forest Products Lateral 168	PLR	1970	50	15
4	Prince George 3 Lateral 219	PRS	1970	49	16
5	Northwood Pulp Lateral 168	PRS	1965	54	11
6	Northwood Pulp Loop 219	PRS	1995	24	41
7	Prince George 1 Lateral 168	ILI	1957	62	3
8	Prince George Pulp Lateral 168	PRS	1964	55	10
9	Husky Oil Lateral 168	PRS	1967	39	26
10	Prince George 2 Lateral 219	PRS	1965	34	31
11	Cariboo Pulp Lateral 168	PLR	1972	47	18
12	Williams Lake Loop 168	PRS	1993	26	39
13	Kamloops 1 Lateral/Loop 168	PLR	1965	47	18
14	Salmon Arm Loop 168	ILI	1976	36	29
15	Salmon Arm 3 Lateral	PLR	1981	38	27
16	Coldstream Lateral 219	PRS	1998	21	44
17	Coldstream Loop 168	PRS	1989	30	35
18	Kelowna 1 Loop 219	PRS	1976	37	28
19	Celgar Lateral 168	PRS	1960	59	6
20	Castlegar Nelson 168	PRS	1957	60	5
21	Trail Lateral 168	PRS	1957	60	5
22	Fording Lateral 219/168	ILI	1971	46	19
23	Elkview Lateral 168	PRS	1970	49	16
24	Cranbrook Lateral 168	ILI	1990	29	36
25	Cranbrook Loop 219	ILI	1968	44	21
26	Cranbrook Kimberley Loop 219	ILI	1992	27	38
27	Cranbrook Kimberley Loop 273	ILI	1992	27	38
28	Kimberly Lateral 168	ILI	1962	57	8
29	Skookumchuck Lateral 219	ILI	1968	51	14

The above table is based on the expected financial life of a transmission pipeline from an asset accounting perspective, as determined through periodic depreciation studies undertaken by depreciation experts.

The actual service life of a transmission pipeline can be longer or shorter than 65 years. The need for retirements or replacement is primarily impacted by factors such as third party relocation requests, system alterations for operating benefits, and integrity concerns. The physical age of the pipeline is not a threat to integrity and age itself does not cause pipeline failure.

In the absence of external influences or identified integrity concerns such as corrosion, the physical life of a transmission pipeline can be longer than the financial end of life. Consistent with its peer Canadian transmission pipeline operators, FEI believes that in the absence of external interference some pipelines may have much longer lifespans dependent on their design, construction, maintenance, and monitoring. As such, FEI is unable to forecast the remaining useful life of the 29 Transmission Laterals because it has no basis upon which to do so. The laterals do not have sufficient data (e.g. ILI) or a leak history on which to base an estimate of remaining useful life. There is therefore no definitive end of physical life based on the information available to FEI.

In making this statement, FEI has considered the following information (as included in the responses to BCUC IRs 1.8.1, 1.8.2, 1.8.3, 1.8.4 and 1.8.5):

- The available condition-related information regarding the 29 Transmission Laterals; and
- FEI's experience in monitoring the condition of approximately 2000 kilometres of in-line inspected transmission pipeline throughout FEI's service territory (discussed in Section 3.3.2 of the Application).

With respect to the IGU Project, FEI determined the need to mitigate the potential for rupture due to external corrosion on all pipelines of NPS 6 and larger and operating at 30 percent SMYS or greater based on its consideration of its legal and regulatory obligations, its assessment of relevant hazards to its pipeline system, its understanding of industry practice, as well as its knowledge of evolving technology available for assessing and managing pipeline condition. FEI has proposed the ILI, PRS, and PLR alternatives based on its consideration of the evaluation criteria described in Section 4.3.1 of the Application. FEI's recommendations have been made independent of asset age.

Please also refer to the response to BCUC IR 1.9.1 for FEI's evaluation that all proposed alternatives meet its legal and regulatory obligations, including those expressed within the Oil and Gas Activities Act and CSA Z662.

2.0 Reference: CPCN FOR IGU PROJECT

Exhibit B-1, Sections 1.1.1, 4.5.4, pp. 2, 47, Table 4-10

Combining 29 Laterals Under a Single CPCN

On page 2 of the Application, FEI states:

> The IGU [Inland Gas Upgrade] Project will construct assets or retrofit existing assets to implement cost-effective integrity management solutions for each lateral. Specifically, the IGU Project will:
>
> 1. Retrofit 11 laterals to provide in-line inspection (ILI) capability…;
> 2. Construct pressure regulating stations on 14 laterals to reduce the maximum operating pressure and resulting operating stress to below 30 percent of the specified minimum yield strength (SMYS) of the pipe…; and
> 3. Replace 4 laterals with new pipe designed to operate at a stress below 30 percent of the SMYS of the pipe…

Table 4-10 on page 47 of the Application shows that the present value (PV) of incremental revenue requirements for the 29 Transmission Laterals ranges from $2.2 million (Prince George 3 Lateral; Northwood Pulp Lateral/Loop) to $102.3 million (Fording Lateral).

2.1 Please discuss FEI's rationale for combining all 29 laterals under a single CPCN application.

<u>Response:</u>

FEI's rationale for combining all 29 Transmission Laterals under a single CPCN application was based on the fact that all 29 Transmission Laterals are part of a single program to mitigate the potential for rupture due to corrosion for pipelines meeting a common set of justification criteria, and will be executed and managed as one project. Presenting the 29 Transmission Laterals as a single CPCN is efficient from a regulatory perspective and necessary to demonstrate the need and scope of the IGU Project so that a determination of public interest can be made with an understanding of the magnitude of costs and scope of work.

The IGU Project is a program of integrity management solutions applicable to 29 transmission lateral pipelines meeting the following criteria:

- Located in the interior of British Columbia and have a nominal pipe size of NPS 6, 8, and 10 outer diameter;
- Do not have ILI capability; and

- Operating at a hoop stress of 30 percent or more of the specified minimum yield strength (SMYS) of the pipe.

The need to mitigate the potential for rupture due to corrosion and reduce the consequences of the associated risks is the same for each of the 29 Transmission Laterals. The alternatives explored for each lateral and the criteria used to determine the preferred alternative are also the same. The work for the IGU Project will be executed as one program to obtain efficiencies and flexibility in scheduling. FEI believes that it is more informative for the BCUC to have all project information at once to be able to compare all feasible alternatives and evaluate the IGU Project. Given the shared justification, alternatives analysis, and project execution strategy, FEI has treated the IGU Project as a single project in relation to the CPCN application.

It is more efficient to review all these shared aspects in one proceeding, rather than duplicate that effort in multiple regulatory proceedings.

2.2 Please discuss whether FEI considered grouping the laterals into smaller CPCN applications or separately applying for CPCNs for some of the Transmission Laterals due to the forecast project cost of some of the laterals, such as the Fording Lateral, or due to project risks/complexities.

Response:

FEI considered grouping the laterals into smaller CPCN applications based on the preferred alternatives selected. However, FEI believes that this would result in an inefficient review and execution of the Project for the reasons set out in the response BCUC IR 1.2.1. Also refer to FEI's response to BCUC IR 1.10.5 for why a separate CPCN for the Fording Lateral would not be beneficial.

Although FEI has treated the IGU Project as a single project in relation to the CPCN, when developing the annual schedule for the Project, FEI did consider factors such as the regional distribution of the Project, capacity limitations including industrial customers' requirements, scheduling constraints (such as windows of time where work can be undertaken on the laterals), cost efficiencies by managing as a single project, operational constraints (such as working on an in-service line), and contractor and resource limitations.

2.2.1 If yes, please explain the grouping options considered and why FEI determined that it would not be more reasonable to apply for separate CPCNs for some of the Transmission Laterals.

Response:

Please refer to the responses to BCUC IRs 1.2.1 and 1.2.2.

2.2.2 If no, please explain why not, including any potential drawbacks to this approach.

Response:

Please refer to the responses to BCUC IRs 1.2.1, 1.2.2 and 1.2.3.

2.3 If the British Columbia Utilities Commission (BCUC) did not approve a CPCN for all 29 Transmission Laterals (i.e. did not provide approval of all 29 Transmission Laterals under a single CPCN), please explain the implications for the IGU Project (e.g. cost, timing, scope) and how FEI would adjust its approach to the upgrades.

Response:

The IGU Project as a single CPCN is planned to be executed over multiple years in consideration of the regional distribution of Project, capacity limitations including industrial customers' requirements, scheduling constraints (such as windows of time where work can be undertaken on the laterals), cost efficiencies by managing as a single project, operational and construction complexity, and contractor and resource limitations. The execution of the 29 Transmission Laterals will be completed in a phased, year-by-year approach where detailed design, planning and procurement activities will occur the year prior to the work being undertaken. FEI plans to initiate detailed design and construction planning in 2019 for work scheduled to occur in 2020.

If the BCUC did not approve all 29 Transmission Laterals under a single CPCN, but instead approved them under separate CPCNs at the same time and according to the schedule set out in the Application, FEI does not anticipate impacts to the Project. If the BCUC delayed the provision of a CPCN for some laterals, FEI would need to evaluate the BCUC's determination and assess its options on how best to proceed. However, FEI expects that the lateral(s) in question would be removed from the scope of the IGU Project until the BCUC granted a CPCN for the lateral(s) or otherwise determined that the lateral(s) are in the public interest.

The work on some laterals would fall under the $15 million CPCN threshold established in Order G-120-15. If the BCUC were to decline a CPCN for one or more of these laterals as part of the IGU Project, FEI expects that it would request that the BCUC approve that the costs of the lateral(s) be added to the sustainment capital forecast recently filed as part of FEI's 2020-2024 Multi-Year Rate Plan (MRP).

A delayed issuance of a CPCN or other approval for some laterals would likely result in additional costs and Project rescheduling. Under this scenario, FEI would adjust its planned execution strategy for the IGU Project and plan the detailed design, planning, procurement and construction work for each lateral as it is approved. Once a CPCN or other approval is received, the scope for the lateral(s) in question would be added to the IGU Project scope.

If the CPCN or other approval for the lateral(s) in question were to occur after contract(s) for the IGU Project had been executed, FEI would have to separately issue the scope of work for the lateral(s) for contractor bid. FEI cannot provide an estimate of the magnitude of the cost impacts; however, the project team, engineering and contracting resources may not be optimized and efficiencies that could have been gained by executing the IGU Project as a single project would be lost.

The IGU Project would need to be rescheduled depending on when the BCUC would issue a CPCN or other approval for the lateral(s) in question, on the length and anticipated time to construct the proposed works, and any change in the determination of the preferred solution. This could result in a delayed completion for some laterals and a delay in achieving the integrity objectives of the IGU Project. Moreover, the risk of failure increases because the risk of rupture is directly linked to the time dependent threat of external corrosion.

In summary, if the BCUC were to break up the approval of the IGU Project, FEI would have to execute the work in a less efficient manner, at a higher cost to ratepayers, and with the potential for increased risk by not executing as a single project.

3.0 Reference: PROJECT JUSTIFICATION

Exhibit B-1, Section 1.2.2, p. 5; Exhibit A2-1

Risk Analysis and Evaluation

On page 5 of the Application, FEI states:

> FEI has a comprehensive Integrity Management Program (IMP) as required by the BC Oil and Gas Commission (BC OGC)…
>
> …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 alternative 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.

Section 1.5.4 of the BC OGC Compliance Assurance Protocol, provided as Exhibit A2-1, states:[2]

> The permit holder shall prioritize the pipelines/segments in order of risk level and shall implement an effective process for identifying and evaluating the available risk reduction options (CSA Z662 – Clause N.10) to prevent, manage, and mitigate risks where the chosen threshold of risk is exceeded.

3.1 Please describe any assessments to prioritize the 29 Transmission Laterals in order of risk level and provide the result of these assessments.

Response:

This response also addresses BCUC IRs 1.3.2, 1.3.3, 1.3.4, 1.3.6, 1.3.8 and 1.3.8.1, and CEC IR 1.2.1 and 1.3.1.

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

[2] BC Oil & Gas Commission Compliance Assurance Protocol – Integrity Management Program for Pipelines, April 2018, Version 1.9.

systemic issues on any particular lateral. Given the information available, FEI's assessment is that it is appropriate to implement the proposed scope of the IGU Project for all 29 Transmission Laterals proactively over a reasonable planning horizon.

FEI's Integrity Management Program – Pipelines (IMP-P) currently follows a hazard management approach, as recognized by Clause N.8.3 (b) of the CSA Z662 standard:

> "Where hazards that might lead to failure or damage incidents are identified, the operating company shall…implement and document measures for monitoring conditions that could lead to an incident with significant consequences and eliminate or mitigate such conditions…."

Taking into account FEI's obligations under the above standard, the planned 5-year implementation timeline for the IGU Project is a reasonable period over which to achieve proactive mitigation of the potential for rupture of the 29 Transmission Laterals. Further, FEI does not have condition assessment or other information that would support the need to expedite or delay the project timeline. In FEI's judgement, taking into account all the information available to it, and its legal and regulatory obligations, 5 years is a reasonable time frame over which to execute the IGU Project.

FEI has developed the detailed schedule for the IGU Project based on factors such as the regional distribution of the Project, capacity limitations including industrial customers' requirements, scheduling constraints (such as windows of time where work can be undertaken on the laterals), cost efficiencies by managing as a single project, operational constraints (such as working on an in-service line), and contractor and resource limitations. As discussed above, FEI has no information that indicates that there would be improvement from a safety or reliability perspective by prioritizing the laterals differently than currently planned.

Please refer also to the response to BCUC IR 1.6.3 regarding FEI's capabilities to successfully implement the IGU Project within the proposed timeline.

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

3.2 Please explain FEI's method for estimating the probability of transmission pipeline failure due to external corrosion and the severity of resulting consequences (i.e. leak and rupture).

Response:

FEI's current method for assessing transmission pipeline failures due to external corrosion and the severity of resulting consequences is not based on probabilistic estimates. Instead, FEI uses a deterministic procedure to estimate the growth rate of external corrosion features as described in BCUC IR 1.8.1.4 and linearly extrapolates growth until the features meet FEI's leak-based or rupture-based dig criteria.

The Quantitative Risk Assessment (QRA) process being developed by FEI as part of the Transmission Integrity Management Capability (TIMC) project will be based on estimation of probabilities and consequences of transmission pipeline failure. This risk management approach is in accordance with Clause N.8.3 (a) of the CSA Z662 standard. Clause N.8.3 states: "Where hazards that might lead to failure or damage incidents are identified, the operating company shall (a) assess and document the risks associated with such hazards (…); or (b) implement and document measures for monitoring conditions that could lead to an incident with significant consequences and eliminate or mitigate such conditions (…)".

FEI's Integrity Management Program – Pipelines (IMP-P) currently follows the hazard management approach recognized by Clause N.8.3 (b).

Please refer also to the responses to BCUC IR 1.3.1 and CEC IR 1.17.2.

3.3 Please define the levels of acceptable risk, thresholds for risk analysis refinement and risk reduction.

Response:

Please refer to the response to BCUC IR 1.3.1.

3.4 Please identify any lateral where an accepted level of risk is exceeded.

Response:

Please refer to the response to BCUC IR 1.3.1.

3.5 Please describe any assessments on the effectiveness of the IGU projects in reducing risk to an acceptable level.

Response:

As explained in the alternatives analysis in the Application, each of the alternatives was evaluated based on criteria which included its integrity and asset management capability and, in particular, the ability of the alternative to prevent rupture due to external corrosion. Alternatives that did not meet these criteria were screened out, as discussed in Section 4.4 of the Application. Based on FEI's legal and regulatory obligations, its assessment of relevant hazards to its pipeline system, its understanding of industry practice, and its knowledge of evolving technology available for assessing and managing pipeline condition, each alternative chosen as part of the IGU Project will mitigate the potential for failure by rupture due to external corrosion to an acceptable level.

In summary:

- ILI: Retrofitting laterals for ILI will enable FEI to conduct in-line inspection of these laterals which will enable FEI to detect external corrosion in these pipelines and take proactive steps to manage the potential for rupture due to external corrosion. For pipelines where commercially available ILI tools are available, in-line inspection is the industry standard approach to managing this hazard (see Section 3.4.4.2 of the Application). ILI is therefore considered by FEI to mitigate the potential for failure by rupture due to external corrosion to an acceptable level.

- PRS: Constructing a pressure regulating station will reduce the pressure on the lateral to below 30 percent of SMYS. It is accepted in the industry that pipelines operating below 30 percent of SMYS are not susceptible to rupture failure due to time-dependent hazards such as external corrosion (see Section 3.3.3 of the Application). PRS is therefore considered by FEI to mitigate the potential for rupture due to external corrosion to an acceptable level.

- PLR: Replacing a lateral with a new gas line that will operate below 30 percent of SMYS will also meet the project objective. As noted above, it is accepted in the industry that pipelines operating below 30 percent of SMYS are not at risk of rupture due to time-dependent hazards such as external corrosion (see Section 3.3.3 of the Application).

PLR is therefore considered by FEI to mitigate the potential of failure by rupture due to external corrosion to an acceptable level.

3.6 Please discuss how risk assessment results were used to determine an appropriate timeline for implementing the IGU projects.

Response:

Please refer to the response to BCUC IR 1.3.1.

3.7 Please confirm, or explain otherwise, that the IGU projects are scheduled in order of risk level.

Response:

FEI scheduled the order of execution based on the duration required to complete the laterals due to scope, length, operational limitations, and approval requirements. FEI has developed the schedule of the IGU Project based on optimizing the use of resources and to gain efficiencies in execution. FEI does not believe there would be any material impact from a safety perspective by prioritizing the laterals differently.

3.7.1 If not, please discuss whether there are any other factors such as permitting that impacts project order.

Response:

Please refer to the response to BCUC IR 1.3.7.

3.7.2 If not, please explain whether there are increased project or safety risks if the laterals are not prioritized.

Response:

Please refer to the response to BCUC IR 1.3.7.

3.8 Please discuss whether FEI considered expediting or delaying the project timeline.

Response:

Please refer to the response to BCUC IR 1.3.1.

3.8.1 If alternative project timelines were considered, please elaborate on the impacts to overall safety and project cost.

Response:

Please refer to the response to BCUC IR 1.3.1.

4.0 Reference: PROJECT JUSTIFICATION

Exhibit B-1, Section 1.2.2, p. 5

Limitations of Modified External Corrosion Direct Assessment (ECDA)

On page 5 of the Application, FEI states:

> FEI has identified limitations of Modified ECDA given the occurrence of the process of CP [cathodic protection] 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.

4.1 Please describe any assessments to evaluate the probability of active corrosion due to CP shielding on each of the 29 Transmission Laterals and provide the result of these assessments.

Response:

Due to the amount and quality of asset condition information available through in-line inspection, FEI has a better understanding of the pipeline condition of its in-line inspected pipelines compared to the condition of the 29 Transmission Laterals which cannot be in-line inspected. FEI cannot directly assess the prevalence of cathodic protection shielding on the 29 Transmission Laterals without performing in-line inspection and significant quantities of integrity digs.

Therefore, to estimate the potential for active corrosion due to cathodic protection shielding on the 29 Transmission Laterals, FEI assessed the results of its 2017 in-line inspection driven integrity digs as presented in Section 3.3.2 of the IGU application. These digs were on a cross-section of pipeline ages and coating types, and 72 of 90 of the integrity digs showed evidence of active corrosion on cathodically protected pipe.

Further, Table 1 below shows both in-line inspection and modified ECDA driven integrity dig data from 2015 to 2018. As shown in the table, of the 318 integrity digs conducted on FEI's transmission and lateral pipelines between 2015 and 2018, 232 showed evidence of active corrosion on cathodically protected pipe. Considering these digs sites represent a range of pipeline ages and coating types, it is probable that active corrosion is also present on the 29 Transmission Laterals due to cathodic protection shielding.

Table 1: Number of Active vs. Passive Corrosion Sites on Transmission Pipelines and Laterals

Year	Inspection Type	Number of Active Corrosion Dig Sites	Number of Passive Corrosion Dig Sites
2015	ILI	49	12
	Modified ECDA	0	0
2016	ILI	54	20
	Modified ECDA	2	0
2017	ILI	72	18
	Modified ECDA	3	5
2018	ILI	51	31
	Modified ECDA	1	0
Total		**232**	**86**

4.1.1 Please explain what data set was used to evaluate the probability of active corrosion due to CP shielding on each of the 29 Transmission Laterals, and the accuracy range of that data.

Response:

Please refer to the response to BCUC IR 1.4.1.

4.2 For each of the 29 Transmission Laterals, please identify any control digs (i.e. digs where there has been no indication of potential corrosion from the above-ground surveys).

Response:

FEI has not performed control digs on any of the 29 Transmission Laterals. FEI does not consider that random control digs provide sufficient value as they are not targeted to a specific site for the purposes of addressing any particular integrity concern.

As discussed in the response to BCUC IR 1.12.2, factors considered in FEI's assessment of the value associated with ECDA digs, and in its implementation of Modified ECDA in general, include the following:

- FEI's confidence in the degree of mitigation being achieved (i.e., effectiveness of the activity);
- Availability of alternative methodologies;
- FEI's understanding of industry practice; and
- Financial considerations (e.g. cost, availability of resources).

4.2.1 Please discuss whether results of these control digs confirmed active corrosion, and if so, please discuss any assessments to evaluate the extent and rate of corrosion.

<u>Response:</u>

Please refer to the response to BCUC IRs 1.4.1 and 1.4.2.

4.3 Please explain to whom the status quo is no longer acceptable.

<u>Response:</u>

The status quo is not acceptable to FEI over the long-term and, in FEI's view, should not be considered acceptable by the BCUC. As explained in the Application, FEI has identified external corrosion on its pipeline system that FEI is unable to reliably detect through its existing integrity management tools, and that can have significant consequences if left unaddressed. It is not acceptable to FEI to leave this significant known hazard unmitigated over the long term, when there are commonly used integrity management options available to manage them.

B. PROJECT NEED AND JUSTIFICATION

5.0 Reference: PROJECT DESCRIPTION

Exhibit B-1, Section 3.2, p. 16, Footnote 7

Geographical Location of the 29 Transmission Laterals

In footnote 7 on page 16 of the Application, FEI states the following:

> 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.

5.1 Please explain why the additional transmission lateral described in the above preamble is planned to be addressed through a separate project.

Response:

The transmission lateral in question is the Tilbury LNG Plant 168 mm lateral that takes vapourized gas from the LNG plant and injects it into the Coastal Transmission System. It is expected that this lateral will be retired as part of any further expansion of the Tilbury LNG plant, to be replaced with a larger diameter pipe. The scope and timing of that retirement is still under evaluation and is dependent on the scope and timing of the Tilbury LNG expansion. Any new pipelines installed in conjunction with the Tilbury LNG expansion would be designed and constructed to allow ILI. If the Tilbury LNG expansion does not proceed, then FEI would address the Tilbury LNG Plant 168 mm lateral under a separate replacement project at a time that aligns with the work proposed in the Application. Preliminary investigations indicate that the cost to replace this lateral would be approximately $3.5 million.

5.1.1 As part of the above response, please describe the aforementioned separate project, including when such a project is planned to be undertaken, and the scope and anticipated cost of the project.

Response:

Please refer to the response to BCUC IR 1.5.1.

6.0 Reference: INTEGRITY MANAGEMENT PROGRAM

Exhibit B-1, Sections 3.4.4.2, 5.1, pp. 24, 48–49;

FEI Annual Review for 2019 Delivery Rates, Exhibit B-2, Section 12.4.1.1, pp. 127–132; Exhibit B-3, BCUC IR 21

Transmission Integrity Management Capabilities (TIMC) Project

On page 24 of the Application, FEI states the following:

> 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…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.

In response to BCUC IR 21.4 in the FEI Annual Review for 2019 Delivery Rates proceeding (2019 Annual Review), FEI stated the following:

> FEI anticipates filing a long-term vision for adopting crack-detection capabilities within its in-line inspection program within the TIMC CPCN application. Given the complexities and timeline associated with developing Class 3 cost estimates in accordance with the BCUC 2015 CPCN Application Guidelines, it is possible that FEI, in its mid-2020 submission, may not apply for the full extent of anticipated system modifications that may eventually be warranted…
>
> …The pipelines requiring modification and details such as priority and detailed integrity management solutions are yet-to-be determined through the CPCN development process. Given this, any estimated capital cost is highly uncertain at this time. For business planning purposes, FEI is currently projecting expenditures associated with the TIMC project of $50 million in 2022, and $250 million in each of 2023, 2024, and 2025…

6.1 Please explain in detail how FEI's proposed IGU Project ties in, overlaps, or is otherwise correlated with its "long-term vision for adopting crack-detection capabilities within its in-line inspection program", as described in response to BCUC IR 21.4 in the 2019 Annual Review.

<u>Response:</u>

The IGU and TIMC projects are independent of each other and do not overlap in their scope, however, they do have similar benefits in that both will allow FEI to adopt proven commercialized in-line inspection technology in its transmission pipeline system for the prevention of rupture failures.

Different types of in-line inspection tools have different capabilities in the types of imperfections that they are intended to detect and size. The following table summarizes the respective capabilities for the primary industry-adopted in-line inspection tools:

	Geometry	Magnetic Flux Leakage (MFL)	Circumferential MFL (CMFL)	EMAT
Dents	X			
Wrinkles / Buckles	X			
Metal loss		X (axially-oriented features)	X (longitudinally-oriented features)	
Long seam weld location			X	
Girth weld location	X	X	X	X
SCC and crack-like features				X
Longitudinal seam weld flaws				X

For those laterals where the ILI alternative has been selected, the IGU Project will enable in-line inspection with Geometry, MFL, and CMFL tools, and will facilitate the potential future adoption of EMAT (i.e., crack-detection) tools.

The TIMC project is being developed to enable in-line inspection of prioritized transmission mainlines with EMAT tools. The inspection capabilities that will be provided by the ILI alternative within the TIMC project will be complementary to those provided by the ILI alternative within the IGU Project, and not overlapping.

Please also refer to the responses to BCUC IRs 1.10.1 and 1.10.1.1.

In Table 5-1 on pages 48–49 of the Application, it shows that FEI's preferred alternative for 11 of the 29 Transmission Laterals is ILI.

6.2 Please discuss whether the TIMC project and FEI's overall vision for adopting crack-detection capabilities within its in-line inspection program were factors in FEI's decision-making when determining what alternative should be proposed for each Transmission Lateral.

Response:

FEI has proposed the ILI, PRS, and PLR alternatives for the IGU Project based on the evaluation criteria described in Section 4.3.1 of the Application. These criteria and the chosen alternatives are consistent with FEI's overall vision for adopting crack-detection capabilities. As indicated in the responses to BCUC IRs 1.10.1 and 1.10.1.1, retrofitting transmission laterals for ILI facilitates the future adoption of EMAT tools. In addition, as indicated in the response to BCUC IR 1.6.1, the implementation of the PLR or PRS for laterals within the IGU Project will result in pipelines that operate at less than 30 percent of SMYS, which is expected to negate the need for running EMAT tools in these pipelines in the future. The new pipelines constructed under the PLR alternative will be ILI capable and therefore will also facilitate adoption of EMAT tools if needed.

6.3 Please discuss any potential challenges which FEI may face regarding: (i) resources; (ii) project timeline; (iii) financing; or (iv) other challenges if the Application is approved, given FEI's planned filing of the TIMC project CPCN in mid-2020 and in consideration of the significant size and scope of both projects.

Response:

FEI recognizes that the availability of suitably qualified and experienced resources is linked to the successful execution of a project according to the established schedule timelines. As such, FEI considers potential resource challenges during each phase of a project. Specifically, in the Risk Register for the IGU Project, FEI recognizes the following general Project risks: company factors, such as availability of internal resources (e.g. recruitment, succession planning, and turnover); external factors, such as limited availability of qualified resources in a competitive market; and industry risks, including both internal and external labour disruptions.

FEI also recognizes that with approval of the Application, preparation of a CPCN for the TIMC Application in mid-2020, and other ongoing major projects, there will be a need for additional resources going forward. As such, FEI has established a Major Projects group to manage and execute large capital projects from initiation to execution. The Major Projects group is staffed with internal resources with experience in developing and executing major projects. In addition, FEI has strong relationships with external professional services providers to complement its internal resource base.

FEI has also taken steps to initiate communications with some contractors to gauge their level of interest and their capabilities. FEI's has plans to manage the risk of a lack of labour availability as discussed in the response to BCUC Confidential IR 1.1.1.

FEI believes the financing requirements of the IGU and TIMC projects are manageable given FEI's current credit ratings which support the issuance of debt in the debt capital markets and the financial strength of its indirect parent company, Fortis Inc., to provide equity. Continued access to debt capital markets is premised on the expectation that FEI will continue to receive BCUC approvals to extend its Medium Term Note (MTN) Debenture Program and that debt capital markets will be stable and accessible at reasonable yields, which has been the prevailing environment for the past several years. This stable environment along with recent reasonable issuance yields mitigates the potential impact of a borrowing restriction arising from a debt covenant within its debenture borrowing agreement. In addition, FEI's $700 million committed credit facility provides some flexibility to manage capital requirements during periods of debt capital market volatility. Equity injections from Fortis Inc. will be required to finance the equity portion of the costs of the projects. The liquidity of Fortis Inc.'s common shares in the Toronto Stock Exchange (TSX) and the New York Stock Exchange (NYSE), together with its other share plans, provide an equity platform for FEI and affiliated companies to draw upon to finance its major capital projects. While the IGU and TIMC projects are relatively significant in size and scope, FEI has successfully utilized its existing financing arrangements to finance the recent construction of multiple significant capital expenditures including Tilbury Expansion Phase 1A, Lower Mainland Intermediate Pressure System Upgrade, Coastal Transmission System, and ongoing growth and sustainment capital.

FEI does not foresee any Project challenges beyond those identified in the Application and clarified through FEI's IR responses.

6.4 If the Application is not approved as applied for, what would the implications be, if any, on the TIMC project? Please discuss.

Response:

As indicated in the response to BCUC IR 1.6.1, the IGU Project and TIMC project are independent of each other and do not overlap. If the BCUC were to determine that the IGU Project, as applied for, was not in the public interest, FEI expects that it would continue development of the TIMC project as defined in the Annual Review for 2019 Rates application.

FEI provided the following table regarding the forecast TIMC project development costs on page 129 of the application in the 2019 Annual Review:

Table 12-1: CPCN Development Costs ($000s)

Line No.	Phase	2018	2019	2020	Total
1	Phase 1	$ 5,680	$ 5,710	$ 230	$ 11,620
2	Phase 2	-	19,000	11,000	30,000
3					
4	Total	**$ 5,680**	**$ 24,710**	**$ 11,230**	**$ 41,620**

In response to BCUC IR 21.7 in the 2019 Annual Review, FEI stated the following:

> In the case of Phase 1, FEI had not yet determined whether it would proceed with this work at the time of filing of the FEI Annual Review for 2018 Rates application. Shortly following the completion of the evidentiary update phase of that application, FEI received a direction from the BC Oil and Gas Commission to develop a quantitative risk assessment for its entire transmission pipeline system. As such, it was necessary to begin work on this initiative prior to filing of the Annual Review for 2019 Rates Application. Consequently, FEI is now seeking deferral approval for the costs to date, and the remaining costs to complete Phase 1.

6.5 Please provide (or provide the details of) the BC OGC direction described in the above preamble.

Response:

The BC OGC's direction resulted from FEI's participation in the BC OGC compliance assurance process for integrity management programs for pipelines as follows:

- May 2, 2014: FEI submitted its "Self Assessment Protocol – Integrity Management Programs for Pipeline Systems" to the BC OGC.
- May 15, 2015: FEI submitted its "Corrective Action Plan" to the BC OGC, which addressed the BC OGC's findings related to the following areas:
    - Management of Change;
    - Training and Competency;
    - Hazard Identification and Risk Assessment;
    - Internal Audits; and
    - Incident Investigation.

- 2015-2017: FEI submitted evidence of continual improvement in each of the above areas to the BC OGC. The BC OGC accepted FEI's corrective actions for each of the identified corrective action areas except "Hazard Identification and Risk Assessment".
- November 16, 2017: The BC OGC issued a letter (provided as Attachment 6.5) directing FEI to "develop and implement a segment-by-segment risk assessment process to determine the risk associated with its pipeline assets in BC", and to "move forward with suitable actions in a timely manner" to meet the BC OGC's requirements.

There were no findings related to FEI's adoption of Modified ECDA within its Integrity Management Program – Pipelines.

6.6 Please describe the quantitative risk assessment developed by FEI in detail.

<u>Response:</u>

FEI is in the process of developing and conducting a quantitative risk assessment of its transmission pipeline system as part of Phase 1 of the development of its TIMC project CPCN application. FEI is currently working with an external consultant on this assessment.

The risk assessment is planned to include estimation of probability of failure for each of the threats included in FEI's integrity management program (external corrosion, third-party damage, stress corrosion cracking, etc.) as well as potential location specific safety, security of supply (outage), environmental, regulatory and reputation consequences for each potential failure type (small leak, large leak, rupture). The risk assessment will combine the calculated probability and consequence of failure to estimate operational risk on a segment-by-segment basis (a segment being a section of pipeline with common risk factors). The segment-by-segment risk estimates will then be used for prioritization of data quality improvement, risk analysis refinement and/or risk mitigation efforts.

The first iteration assessment is being conducted using currently available asset data. The output of this analysis will also be used for assessment of capacity options and to support the TIMC project CPCN application. FEI expects that capacity improvements will be necessary to provide FEI with the capability to reduce the operating pressure of transmission pipelines for extended time periods, as discussed in Section 12.4.1.1 of FEI's Annual Review for 2019 Rates application.

6.7 Please explain if the quantitative risk assessment directed by the BC OGC relates to the Application as well as to the TIMC project.

Response:

The quantitative risk assessment directed by the BC OGC is not related to the IGU Project Application.

With respect to the IGU Project, FEI has determined the need to mitigate the potential for rupture due to external corrosion on all pipelines of NPS 6 and larger and operating at 30 percent SMYS or greater based on its consideration of its legal and regulatory obligations, its assessment of relevant hazards to its pipeline system, its understanding of industry practice, as well as its knowledge of evolving technology available for assessing and managing pipeline condition. Please refer also to the response to BCUC IR 1.3.7 for a discussion of the Project risk prioritization.

With respect to the TIMC project, FEI is undertaking a quantitative risk assessment (QRA) to support its assessment of the need for running crack-detection tools in selected pipelines within its transmission system, as well as their urgency and priority. This first iteration of a QRA is required for the TIMC project; however, it will also be presented to the BC OGC as demonstration of FEI's progression toward a quantitative risk management approach within its Integrity Management Program – Pipelines (IMP-P).

6.7.1 If yes, please explain in detail how the direction by the BC OGC impacted both the Application and the planned TIMC project.

Response:

Please refer to the response to BCUC IR 1.6.7.

6.7.2 If no, please explain why not.

Response:

Please refer to the response to BCUC IR 1.6.7.

6.8 Please explain if there has been any overlap in costs and resources between the work performed for the development of the Application and the work being performed for the Phase 1 and/or Phase 2 development of the TIMC project.

Response:

There has been no overlap in costs and resources between the work performed for the development of the IGU Project Application and the work being performed for the Phase 1 and Phase 2 development of the TIMC project. As discussed in the response to BCUC IR 1.6.1, the two projects are independent of each other.

6.8.1 If yes, please explain how these costs and resources have been shared/allocated between the two projects and if there is any risk that certain costs have been incorrectly allocated to the TIMC project development costs instead of the Transmission Laterals project or vice versa.

Response:

Please refer to the response to BCUC IR 1.6.8.

7.0 Reference: PROJECT DESCRIPTION

Exhibit B-1, Sections 3.4, 4.2.5, pp. 20, 31;

2019 Annual Review, Exhibit B-2, Appendix C4, p. 10; Exhibit B-3, BCUC IR 21.9

Integrity Management Program

On page 20 of the Application, FEI states that it has a comprehensive IMP as required by the BC OGC.

On page 10 of Appendix C4 to the application in the 2019 Annual Review, FEI stated that it "needs to continue to enhance its Integrity Management Program to manage aging infrastructure, meet the CSA Z662-15 standard, and adopt industry practices deemed appropriate to FEI's system."

In response to BCUC IR 21.9 in the 2019 Annual Review, FEI stated the following:

> The particular enhancements that are discussed [in Appendix C4], which pertain to the time period covered by Table C4-4 (i.e. 2014-2018), are unchanged from those that were discussed in response to BCUC IR 1.9.11 in the FEI Annual Review for 2017 Delivery Rates proceeding. At that time, FEI stated that the changes to its in-line inspection activity that were resulting in higher costs were as follows:
>
> …
>
> - FEI increased the number of transmission pipelines subject to in-line inspection. As an example, FEI performed initial baseline in-line inspections for a number of pipeline segments in the Lower Mainland. In addition to the in-line inspection costs, capital expenditures were incurred for retrofits to enable the loading/unloading and passage of the tools…
>
> …FEI is currently forecasting three pipeline segments for crack-detection in-line inspection in 2019, pending the results of front-end engineering design currently in progress to evaluate the timing and feasibility. It is not currently confirmed that the system modifications to manage tool speed within these pipelines, to accommodate tool length impacts on ILI operations, and to provide the capability to reduce the operating pressure of these pipelines for extended time periods without impacting customers will be feasible to implement in time to allow 2019 inspections to be carried out.

On page 31 of the Application, FEI states: "The ILI alternative requires retrofitting an existing pipeline to accommodate its inspection by removing any obstructions that may impede the clear passage of the ILI tool."

7.1 Please explain if, during FEI's 2014-2019 Performance Based Ratemaking (PBR) Plan Term, FEI has incurred sustainment capital expenditures as part of its annual formula capital spending on any transmission laterals to either (1) retrofit the lateral(s) to provide ILI capability; (2) construct pressure regulating stations; or (3) replace the lateral(s) with new pipe.

Response:

This response also addresses BCUC IRs 1.7.1.1, 1.7.1.2 and 1.7.2.

During the 2014-2019 PBR term, FEI did not incur Sustainment capital expenditures on any transmission laterals to (1) retrofit the lateral to provide ILI capability; (2) construct pressure regulating stations for the purpose of reducing operating pressure in a pipeline for an extended period of time; or (3) replace the lateral with new pipe. Neither has FEI included any of the capital activities on the 29 Transmission Laterals in its forecast of Sustainment capital expenditures in its 2020-2024 Multi-Year Rate Plan, which will be the relevant rate setting framework during the time period that the IGU Project will be undertaken. FEI's proposed activities to address the potential for rupture due to corrosion of smaller diameter laterals are not currently included within FEI's Sustainment capital activities and have therefore been brought forward to the BCUC for approval as a single CPCN in the Application.

The activities described in the preamble above, from FEI's response to BCUC IR 1.21.9 in the 2019 Annual Review for Rates, were undertaken to allow the inspection of larger diameter mainline pipelines in the Coastal Transmission System (CTS) in alignment with the scope of FEI's existing ILI program on the Mainland which has been primarily applied to larger diameter mainline pipelines. In contrast, the work proposed in the Application applies to smaller diameter transmission laterals that have not historically been subject to ILI, or alternate solutions like PRS and PLR that would alleviate the need for ILI. After the IGU Project is complete, future costs associated with ILI, pipeline upgrades, or pressure regulating station upgrades on the 29 Transmission Laterals will form part of FEI's Sustainment capital.

The projects related to enhancing ILI capabilities on CTS pipelines that were executed during the PBR term are described further in the table below.

Pipeline	Project Description	2014-2019 YTD Expenditure	Project Construction Year
Noons Creek to Eagle Mountain 610	Installation of pig barrels at either end of pipeline to allow ILI	$1.9 million	2014
Cape Horn to Burrard 508	Installation of additional pig barrels to create 2 inspection segments in order to reduce impact to BC Hydro during ILI	$3.3 million	2014
Nichol to Port Mann 610	Installation of pig barrels at either end of pipeline to allow ILI	$2.4 million	2015

Pipeline	Project Description	2014-2019 YTD Expenditure	Project Construction Year
Port Mann To Cape Horn 914	Installation of pig barrels at either end to allow ILI	$5.0 million	2015

FEI also constructs pressure regulating stations (TP/IP or TP/DP) that are used to reduce pressure for distribution to customers on a regular basis as part of Sustainment capital. The pressure regulating stations as part of the IGU Project are required for a new purpose (to reduce the operating pressure of the pipeline to mitigate potential for pipeline rupture) that have not been part of FEI's regular Sustainment capital activities to date.

7.1.1 If yes, please provide the following information for each applicable lateral:

- The year the capital expenditures were occurred;
- The amount of the capital expenditures; and
- The type of work that was performed (i.e. ILI, PRS [Pressure Regulating Station], PLR [Pipeline Replacement], other).

Response:

Please refer to the response to BCUC IR 1.7.1.

7.1.2 If FEI has incurred sustainment capital expenditures as part of its annual formula capital spending on certain transmission laterals, why did FEI include the spending on these activities within the PBR Plan formula capital spending as opposed to filing for CPCN approval?

Response:

Please refer to the response to BCUC IR 1.7.1.

7.2 If the activities and associated capital expenditures described in response to BCUC IR 21.9 in the 2019 Annual Review (as provided in the above preamble) are not related to the types of activities and capital expenditures proposed in the Application, please clarify the difference.

Response:

Please refer to the response to BCUC IR 1.7.1.

8.0 Reference: POTENTIAL FAILURE BY RUPTURE

Exhibit B-1, Section 3.3.2, p. 18

Evidence of External Corrosion on FEI's System

On page 18 of the Application, FEI states:

> 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.

8.1 Please provide a list of integrity digs conducted by FEI on transmission pipelines from 2000 through 2018 and the location of each integrity dig. Please identify any dig with corrosion and provide an assessment of the extent and rate of corrosion.

Response:

A list of recorded in-line inspection or Modified ECDA driven integrity digs conducted by FEI on transmission pipelines from 2000 through 2018 are provided below in Tables 1 and 2, respectively.

The location of each recorded integrity dig is identified with the corresponding pipeline name and reference girth weld (RGW) or chainage. The dig sites with corrosion have a corrosion extent larger than 0 mm in the last column of the tables. The corrosion extent is the sum of all corrosion feature lengths measured at each dig site.

The corrosion measurements are compared to in-line inspection data to validate tool performance within the in-line inspection data analysis process (Appendix E of the Application). FEI's analysis process has not identified a need for, or any value in, assessing the rate of corrosion for each dig site as it is not possible to know when the corrosion process was initiated or the consistency of growth (e.g., seasonal fluctuations). FEI estimates potential future corrosion growth through the methods discussed in the response to BCUC IR 1.8.1.4.

Table 2: List of Recorded In-line Inspection Driven Transmission Pipeline Integrity Digs and Corrosion Extent from 2000 to 2018

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2000	Cape Horn Burrard Thermal 508	1180	48
2000	Cape Horn Burrard Thermal 508	7210	433
2000	Cape Horn Burrard Thermal 508	7510	0
2000	Cape Horn Burrard Thermal 508	7540	384
2000	Cape Horn Burrard Thermal 508	7570	0

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2000	Cape Horn Burrard Thermal 508	7590	348
2000	Cape Horn Burrard Thermal 508	9650	0
2000	Cape Horn Burrard Thermal 508	10180	0
2000	Cape Horn Burrard Thermal 508	13720	0
2001	Cape Horn Burrard Thermal 508	1450	357
2001	Cape Horn Burrard Thermal 508	2860	325
2001	Cape Horn Burrard Thermal 508	3680	936
2001	Cape Horn Burrard Thermal 508	5100	34.8
2001	Cape Horn Burrard Thermal 508	5280	1227
2001	Cape Horn Burrard Thermal 508	5690	0
2001	Cape Horn Burrard Thermal 508	6080	2517
2001	Cape Horn Burrard Thermal 508	6090	945
2001	Cape Horn Burrard Thermal 508	7150	0
2001	Cape Horn Burrard Thermal 508	7270	1436
2001	Cape Horn Burrard Thermal 508	7280	122
2001	Cape Horn Burrard Thermal 508	7760	811
2001	Cape Horn Burrard Thermal 508	8070	840
2001	Cape Horn Burrard Thermal 508	8890	515
2001	Cape Horn Burrard Thermal 508	9950	70
2001	Cape Horn Burrard Thermal 508	13680	870
2001	Cape Horn Burrard Thermal 508	13700	1590
2001	Cape Horn Burrard Thermal 508	14550	4106
2001	Cape Horn Burrard Thermal 508	14690	101
2001	Cape Horn Burrard Thermal 508	14720	822
2001	Cape Horn Burrard Thermal 508	15000	230
2001	Cape Horn Burrard Thermal 508	16200	1030
2001	Grand Forks Trail 273	4410	10
2001	Grand Forks Trail 273	15750	1121
2001	Grand Forks Trail 273	18000	280
2001	Grand Forks Trail 273	18200	295
2001	Grand Forks Trail 273	19660	181
2001	Grand Forks Trail 273	20020	389
2001	Grand Forks Trail 273	20290	69
2001	Grand Forks Trail 273	21390	229
2001	Grand Forks Trail 273	21530	151
2001	Grand Forks Trail 273	23380	525

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2001	Grand Forks Trail 273	31330	547
2001	Grand Forks Trail 273	32800	676
2001	Grand Forks Trail 273	34330	382
2001	Grand Forks Trail 273	34450	123
2001	Grand Forks Trail 273	34460	330
2001	Grand Forks Trail 273	34520	74
2001	Grand Forks Trail 273	34650	91
2001	Grand Forks Trail 273	34820	339
2001	Grand Forks Trail 273	35410	1565
2001	Grand Forks Trail 273	35610	177
2001	Grand Forks Trail 273	35710	289
2001	Grand Forks Trail 273	35740	1106
2001	Grand Forks Trail 273	35910	66
2001	Grand Forks Trail 273	36440	337
2001	Grand Forks Trail 273	36760	894
2001	Grand Forks Trail 273	36770	189
2001	Grand Forks Trail 273	36780	1429
2001	Grand Forks Trail 273	37160	320
2001	Grand Forks Trail 273	37980	1322
2001	Grand Forks Trail 273	38940	1543
2001	Grand Forks Trail 273	39620	133
2001	Grand Forks Trail 273	39630	262
2001	Grand Forks Trail 273	40740	597
2001	Grand Forks Trail 273	40750	1202
2001	Grand Forks Trail 273	42920	163
2001	Grand Forks Trail 273	42930	408
2001	Oliver Grand Forks 273	9400	124
2001	Oliver Grand Forks 273	9440	50
2001	Oliver Grand Forks 273	9820	34
2001	Oliver Grand Forks 273	24707	25
2001	Oliver Grand Forks 273	43710	1432
2001	Oliver Grand Forks 273	46180	432
2001	Oliver Grand Forks 273	52810	208
2001	Oliver Grand Forks 273	55170	101
2001	Oliver Grand Forks 273	55920	149
2001	Oliver Grand Forks 273	56010	894

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2001	Oliver Grand Forks 273	56100	585
2001	Oliver Grand Forks 273	56710	155
2001	Oliver Grand Forks 273	56750	409
2001	Oliver Grand Forks 273	58920	325
2001	Oliver Grand Forks 273	58930	123
2001	Oliver Grand Forks 273	58970	232
2001	Oliver Grand Forks 273	59550	51
2001	Oliver Grand Forks 273	61550	86
2001	Oliver Grand Forks 273	62670	69
2002	Grand Forks Trail 273	8430	180
2002	Grand Forks Trail 273	8630	63
2002	Grand Forks Trail 273	8990	123
2002	Grand Forks Trail 273	9070	32
2002	Grand Forks Trail 273	9090	207
2002	Grand Forks Trail 273	9150	148
2002	Grand Forks Trail 273	18120	141
2002	Grand Forks Trail 273	18280	276
2002	Grand Forks Trail 273	19770	270
2002	Grand Forks Trail 273	19820	639
2002	Grand Forks Trail 273	19930	66
2002	Grand Forks Trail 273	20040	480
2002	Grand Forks Trail 273	20120	102
2002	Grand Forks Trail 273	20130	110
2002	Grand Forks Trail 273	20240	223
2002	Grand Forks Trail 273	20960	190
2002	Grand Forks Trail 273	21150	571
2002	Grand Forks Trail 273	21200	249
2002	Grand Forks Trail 273	21330	378
2002	Grand Forks Trail 273	21620	60
2002	Grand Forks Trail 273	21850	18
2002	Grand Forks Trail 273	22240	363
2002	Grand Forks Trail 273	22260	255
2002	Grand Forks Trail 273	26040	285
2002	Grand Forks Trail 273	37750	263
2002	Grand Forks Trail 273	40700	610
2002	Grand Forks Trail 273	40710	346

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2002	Grand Forks Trail 273	40720	650
2002	Grand Forks Trail 273	44220	72
2002	Grand Forks Trail 273	44570	557
2002	Grand Forks Trail 273	44950	278
2002	Livingston Coquitlam 323	990	174
2002	Livingston Coquitlam 323	3910	34
2002	Livingston Coquitlam 323	4520	190
2002	Livingston Coquitlam 323	4920	1120
2002	Livingston Coquitlam 323	6760	41
2002	Livingston Coquitlam 323	10150	155
2002	Livingston Coquitlam 323	10200	160
2002	Livingston Coquitlam 323	19230	0
2002	Livingston Coquitlam 323	20370	492
2002	Livingston Coquitlam 323	20930	0
2002	Livingston Coquitlam 323	4930	534
2002	Livingston Coquitlam 323	4940	100
2002	Livingston Pattullo 457	7910	2404
2002	Livingston Pattullo 457	7930	1606
2002	Livingston Pattullo 457	7940	450
2002	Livingston Pattullo 457	21590	1628
2002	Livingston Pattullo 457	21600	608
2002	Livingston Pattullo 457	21620	299
2002	Oliver Grand Forks 273	200	16
2002	Oliver Grand Forks 273	9290	32
2002	Oliver Grand Forks 273	11580	137
2002	Oliver Grand Forks 273	12690	201
2002	Oliver Grand Forks 273	21890	283
2002	Oliver Grand Forks 273	22960	166
2002	Oliver Grand Forks 273	23050	66
2002	Oliver Grand Forks 273	23480	160
2002	Oliver Grand Forks 273	23620	578
2002	Oliver Grand Forks 273	24210	68
2002	Oliver Grand Forks 273	28100	39
2002	Oliver Grand Forks 273	28130	103
2002	Oliver Grand Forks 273	28140	335
2002	Oliver Grand Forks 273	28190	274

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2002	Oliver Grand Forks 273	31060	82
2002	Oliver Grand Forks 273	31240	383
2002	Oliver Grand Forks 273	32260	384
2002	Oliver Grand Forks 273	32990	15
2002	Oliver Grand Forks 273	33000	168
2002	Oliver Grand Forks 273	33230	102
2002	Oliver Grand Forks 273	57540	827
2002	Oliver Grand Forks 273	57550	1257
2002	Savona Penticton 323	850	0
2002	Savona Penticton 323	7320	0
2002	Savona Penticton 323	8480	1177
2002	Savona Penticton 323	17270	0
2002	Savona Penticton 323	19770	3256
2002	Savona Penticton 323	24410	247
2002	Savona Penticton 323	25420	210
2002	Savona Penticton 323	25730	0
2002	Savona Penticton 323	29750	1787
2002	Savona Penticton 323	49200	74
2002	Savona Penticton 323	49220	77
2002	Savona Penticton 323	49230	76
2002	Savona Penticton 323	53090	54
2002	Savona Penticton 323	54810	46
2002	Savona Penticton 323	57330	0
2002	Savona Penticton 323	3925	1546
2002	Savona Penticton 323	5960	36
2002	Savona Penticton 323	6640	31
2002	Savona Penticton 323	12370	45
2002	Savona Penticton 323	27370	1152
2002	Savona Penticton 323	33800	219
2002	Savona Penticton 323	33810	463
2002	Savona Penticton 323	38670	150
2002	Savona Penticton 323	39520	707
2002	Savona Penticton 323	39530	904
2002	Savona Penticton 323	39540	690
2002	Savona Penticton 323	55690	729
2002	Savona Penticton 323	81350	106

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2002	Savona Penticton 323	83200	0
2002	Savona Penticton 323	92250	211
2002	Tilbury Benson 323	860	57
2002	Tilbury Benson 323	910	48
2002	Tilbury Benson 323	1130	74
2002	Tilbury Benson 323	1390	71
2002	Tilbury Benson 323	1400	244
2002	Tilbury Benson 323	2580	43
2002	Yahk Trail 323	1840	0
2002	Yahk Trail 323	12080	133
2002	Yahk Trail 323	14280	19
2002	Yahk Trail 323	14300	0
2002	Yahk Trail 323	30140	2317
2002	Yahk Trail 323	44020	0
2002	Yahk Trail 323	49260	16
2002	Yahk Trail 323	1920	0
2002	Yahk Trail 323	3490	0
2002	Yahk Trail 323	12280	7
2002	Yahk Trail 323	45020	0
2003	Livingston Pattullo 457	5760	225
2003	Livingston Pattullo 457	8120	929
2003	Livingston Pattullo 457	11850	30
2003	Livingston Pattullo 457	11860	239
2003	Livingston Pattullo 457	17600	1274
2003	Livingston Pattullo 457	17800	0
2003	Livingston Pattullo 457	17830	72
2003	Livingston Pattullo 457	19160	8.36
2003	Livingston Pattullo 457	19180	1569
2003	Livingston Pattullo 457	19600	120
2003	Livingston Pattullo 457	19840	868
2003	Livingston Pattullo 457	20070	1686
2003	Livingston Pattullo 457	20630	363
2003	Livingston Pattullo 457	20770	517
2003	Livingston Pattullo 457	20840	0
2003	Livingston Pattullo 457	20890	398
2003	Livingston Pattullo 457	21380	3267

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2003	Livingston Pattullo 457	21490	2317
2003	Livingston Pattullo 457	21540	1548
2003	Vernon Penticton 323	5260	1178
2003	Vernon Penticton 323	5270	183
2003	Vernon Penticton 323	5280	1689
2003	Vernon Penticton 323	10190	20
2003	Vernon Penticton 323	11220	1627
2003	Vernon Penticton 323	11230	323
2003	Vernon Penticton 323	16370	1337
2003	Vernon Penticton 323	16380	2073
2003	Vernon Penticton 323	33860	199
2003	Vernon Penticton 323	33870	4471
2003	Vernon Penticton 323	33880	502
2003	Vernon Penticton 323	33890	39
2003	Vernon Penticton 323	35000	350
2003	Vernon Penticton 323	35010	781
2003	Vernon Penticton 323	35140	1420
2003	Vernon Penticton 323	37210	2511
2003	Vernon Penticton 323	37220	8001
2003	Vernon Penticton 323	37230	1643
2003	Vernon Penticton 323	6080	0
2003	Vernon Penticton 323	9230	0
2003	Vernon Penticton 323	16390	14
2003	Vernon Penticton 323	19480	0
2003	Vernon Penticton 323	22360	0
2003	Savona Vernon 323	8400	28
2003	Savona Vernon 323	10240	106
2003	Savona Vernon 323	12270	0
2003	Savona Vernon 323	14230	177
2003	Savona Vernon 323	15490	0
2003	Savona Vernon 323	19660	146
2003	Savona Vernon 323	24170	1012
2003	Savona Vernon 323	27880	0
2003	Savona Vernon 323	32620	214
2003	Savona Vernon 323	33870	4677
2003	Savona Vernon 323	39060	847

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2003	Savona Vernon 323	45570	0
2003	Savona Vernon 323	58730	9
2003	Savona Vernon 323	58890	70
2003	Savona Vernon 323	59300	27
2003	Savona Vernon 323	62920	68
2003	Savona Vernon 323	63990	620
2003	Savona Vernon 323	66320	857
2003	Savona Vernon 323	70740	0
2003	Savona Vernon 323	74300	36
2003	Savona Vernon 323	81250	100
2003	Savona Vernon 323	81420	593
2003	Savona Vernon 323	81540	31
2003	Savona Vernon 323	109830	458
2003	Savona Vernon 323	110950	190
2003	Savona Vernon 323	111020	120
2003	Savona Vernon 323	111630	56
2003	Savona Vernon 323	111690	268
2003	Savona Vernon 323	111730	198
2003	Savona Vernon 323	66310	516
2003	Savona Vernon 323	66300	264
2003	Tilbury Fraser 508	5210	293
2003	Tilbury Fraser 508	6150	27
2003	Tilbury Fraser 508	6520	112
2003	Trail Castlegar 219	1010	782
2003	Trail Castlegar 219	1220	41
2003	Trail Castlegar 219	1230	76
2003	Trail Castlegar 219	3770	147
2003	Trail Castlegar 219	4150	116
2003	Trail Castlegar 219	5230	594
2003	Trail Castlegar 219	5440	39
2003	Trail Castlegar 219	5450	218
2003	Trail Castlegar 219	5920	582
2003	Trail Castlegar 219	5950	1798
2003	Trail Castlegar 219	5960	813
2003	Trail Castlegar 219	6040	32
2003	Trail Castlegar 219	6050	190

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2003	Trail Castlegar 219	6110	548
2003	Trail Castlegar 219	6120	3248
2003	Trail Castlegar 219	6130	2440
2003	Trail Castlegar 219	6140	531
2003	Trail Castlegar 219	6170	9
2003	Trail Castlegar 219	6180	343
2003	Trail Castlegar 219	6390	3188
2003	Trail Castlegar 219	6710	131
2003	Trail Castlegar 219	7030	47
2003	Trail Castlegar 219	5930	390
2003	Trail Castlegar 219	5940	439
2003	Yahk Trail 323	1800	45
2003	Yahk Trail 323	1850	30
2003	Yahk Trail 323	5220	9
2003	Yahk Trail 323	5680	65
2003	Yahk Trail 323	8210	17
2003	Yahk Trail 323	9640	12
2003	Yahk Trail 323	9660	12
2003	Yahk Trail 323	9780	233
2003	Yahk Trail 323	22730	0
2003	Yahk Trail 323	27170	1
2003	Yahk Trail 323	36910	277
2003	Yahk Trail 323	45250	2
2003	Yahk Trail 323	5210	42
2004	Grand Forks Trail 273	22180	333
2004	Grand Forks Trail 273	24910	818
2004	Grand Forks Trail 273	24960	160
2004	Grand Forks Trail 273	25680	331
2004	Grand Forks Trail 273	39380	374
2004	Grand Forks Trail 273	39390	80
2004	Grand Forks Trail 273	44940	523
2004	Grand Forks Trail 273	44960	555
2004	Grand Forks Trail 273	45380	1084
2004	Grand Forks Trail 273	46050	380
2004	Kingsvale Oliver 323	480	995
2004	Oliver Grand Forks 273	12880	891

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2004	Oliver Grand Forks 273	22520	555
2004	Oliver Grand Forks 273	22530	2331
2004	Oliver Grand Forks 273	28500	353
2004	Oliver Grand Forks 273	59580	588
2004	Oliver Grand Forks 273	65110	1558
2004	Penticton Oliver 273	2830	649
2004	Penticton Oliver 273	2960	929
2004	Penticton Oliver 273	6230	1024
2004	Penticton Oliver 273	6600	1558
2004	Penticton Oliver 273	7410	585
2004	Penticton Oliver 273	7450	86
2004	Penticton Oliver 273	7900	392
2004	Penticton Oliver 273	7940	338
2004	Penticton Oliver 273	12640	41
2004	Penticton Oliver 273	14400	3
2004	Penticton Oliver 273	15640	103
2004	Penticton Oliver 273	15830	1113
2004	Penticton Oliver 273	15840	600
2004	Penticton Oliver 273	16700	739
2004	Penticton Oliver 273	17080	1087
2004	Penticton Oliver 273	17090	1036
2004	Vernon Penticton 273	26490	592
2004	Vernon Penticton 273	34740	461
2004	Vernon Penticton 273	55390	17
2004	Kingsvale Oliver 323	9400	251
2004	Kingsvale Oliver 323	9410	215
2004	Kingsvale Oliver 323	9430	222
2004	Kingsvale Oliver 323	9660	202
2004	Kingsvale Oliver 323	12240	137
2004	Kingsvale Oliver 323	12400	707
2004	Kingsvale Oliver 323	56260	1476
2004	Kingsvale Oliver 323	58000	337
2004	Kingsvale Oliver 323	58720	69
2004	Savona Vernon 323	59600	909
2004	Savona Vernon 323	87130	1052
2004	Trail Castlegar 219	600	170

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2004	Trail Castlegar 219	1050	236
2004	Trail Castlegar 219	2960	456
2004	Trail Castlegar 219	2970	46
2004	Trail Castlegar 219	4040	484
2004	Trail Castlegar 219	4050	487
2004	Trail Castlegar 219	4910	119
2004	Trail Castlegar 219	4920	122
2004	Trail Castlegar 219	5260	176
2004	Trail Castlegar 219	6180	2996
2004	Trail Castlegar 219	6190	324
2004	Trail Castlegar 219	6210	254
2004	Trail Castlegar 219	6220	1407
2004	Trail Castlegar 219	6990	48
2004	Trail Castlegar 219	9350	359
2004	Trail Castlegar 219	9470	320
2004	Trail Castlegar 219	9560	59
2004	Trail Castlegar 219	10420	15
2004	Trail Castlegar 219	11620	161
2004	Trail Castlegar 219	14160	147
2004	Trail Castlegar 219	14170	1511
2004	Trail Castlegar 219	14180	1007
2004	Trail Castlegar 219	14200	432
2004	Trail Castlegar 219	14290	56
2004	Trail Castlegar 219	17560	588
2004	Yahk Trail 323	34580	20
2004	Yahk Trail 323	35950	133
2004	Yahk Trail 323	43060	0
2004	Huntingdon Nichol 762	1460	21
2004	Huntingdon Nichol 762	10170	1568
2004	Huntingdon Nichol 762	11350	225
2004	Huntingdon Nichol 762	13070	844
2004	Huntingdon Nichol 762	23340	899
2004	Huntingdon Nichol 762	24940	2996
2004	Huntingdon Nichol 762	25560	173
2004	Huntingdon Nichol 762	32850	1700
2004	Huntingdon Nichol 762	34340	2584

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2004	Huntingdon Nichol 762	37940	18
2004	Huntingdon Nichol 762	38040	3.27
2004	Huntingdon Nichol 762	45010	0
2004	Huntingdon Nichol 762	48140	50
2005	Grand Forks Trail 273	18280	669
2005	Grand Forks Trail 273	20310	446
2005	Grand Forks Trail 273	20730	32
2005	Grand Forks Trail 273	31190	1100
2005	Grand Forks Trail 273	31290	643
2005	Grand Forks Trail 273	37980	189
2005	Grand Forks Trail 273	38580	2734
2005	Grand Forks Trail 273	39410	429
2005	Grand Forks Trail 273	39710	899
2005	Grand Forks Trail 273	39770	401
2005	Grand Forks Trail 273	40310	804
2005	Grand Forks Trail 273	44390	706
2005	Grand Forks Trail 273	44800	232
2005	Grand Forks Trail 273	46200	660
2005	Grand Forks Trail 273	46480	2645
2005	Grand Forks Trail 273	46490	610
2005	Grand Forks Trail 273	46500	1129
2005	Grand Forks Trail 273	46510	1063
2005	Grand Forks Trail 273	46530	1461
2005	Grand Forks Trail 273	46540	1401
2005	Grand Forks Trail 273	46550	750
2005	Grand Forks Trail 273	46570	403
2005	Nichol Fraser 610	1080	935
2005	Nichol Fraser 610	1900	762
2005	Nichol Fraser 610	1920	0
2005	Nichol Fraser 610	6310	387
2005	Nichol Fraser 610	6320	207
2005	Nichol Fraser 610	6490	313
2005	Nichol Fraser 610	15980	0
2005	Nichol Fraser 610	18010	734
2005	Nichol Port Mann 610	1430	80
2005	Nichol Port Mann 610	1500	139

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2005	Nichol Port Mann 610	1660	276
2005	Oliver Grand Forks 273	23610	583
2005	Oliver Grand Forks 273	25120	373
2005	Oliver Grand Forks 273	33180	407
2005	Oliver Grand Forks 273	37310	187
2005	Oliver Grand Forks 273	37340	484
2005	Oliver Grand Forks 273	37880	59
2005	Oliver Grand Forks 273	37890	273
2005	Oliver Grand Forks 273	37900	395
2005	Oliver Grand Forks 273	37930	491
2005	Oliver Grand Forks 273	37940	350
2005	Oliver Grand Forks 273	37950	19
2005	Oliver Grand Forks 273	42130	391
2005	Oliver Grand Forks 273	42140	137
2005	Oliver Grand Forks 273	42150	11
2005	Oliver Grand Forks 273	42300	45
2005	Oliver Grand Forks 273	42770	89
2005	Oliver Grand Forks 273	42780	79
2005	Oliver Grand Forks 273	50290	90
2005	Oliver Grand Forks 273	50310	109
2005	Oliver Grand Forks 273	52420	464
2005	Oliver Grand Forks 273	56140	287
2005	Oliver Grand Forks 273	56150	4
2005	Oliver Grand Forks 273	56170	883
2005	Oliver Grand Forks 273	64480	305
2005	Oliver Grand Forks 273	71710	767
2005	Oliver Grand Forks 273	71720	576
2005	Savona Penticton 323	8450	662
2005	Savona Penticton 323	9550	523
2005	Savona Penticton 323	16770	261
2005	Savona Penticton 323	16780	973
2005	Savona Penticton 323	16800	2163
2005	Savona Penticton 323	16950	858
2005	Savona Penticton 323	16970	6419
2005	Savona Penticton 323	17450	303
2005	Savona Penticton 323	17480	426

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2005	Savona Penticton 323	17530	337
2005	Savona Penticton 323	17540	179
2005	Savona Penticton 323	17560	333
2005	Savona Penticton 323	17820	138
2005	Savona Penticton 323	18600	152
2005	Savona Penticton 323	20170	206
2005	Savona Penticton 323	20200	42
2005	Savona Penticton 323	40670	301
2005	Savona Penticton 323	40680	77
2005	Savona Penticton 323	50490	68
2005	Savona Penticton 323	88680	104
2005	Savona Penticton 323	98650	74
2005	Savona Penticton 323	16960	702
2005	Savona Penticton 323	20180	144
2005	Savona Penticton 323	20210	757
2007	Cape Horn Burrard Thermal 508	4970	490
2007	Cape Horn Burrard Thermal 508	4980	73
2007	Cape Horn Burrard Thermal 508	4990	897
2007	Cape Horn Burrard Thermal 508	7440	255
2007	Cape Horn Burrard Thermal 508	7450	595
2007	Cape Horn Burrard Thermal 508	7460	65
2007	Grand Forks Trail 273	7920	615
2007	Grand Forks Trail 273	17990	1515
2007	Grand Forks Trail 273	34270	1370
2007	Grand Forks Trail 273	37920	331
2007	Grand Forks Trail 273	37940	362
2007	Livingston Pattullo 457	8030	440
2007	Livingston Pattullo 457	8110	44
2007	Trail Castlegar 219	1230	938
2007	Trail Castlegar 219	1750	536
2007	Trail Castlegar 219	1760	283
2007	Trail Castlegar 219	3240	202
2007	Trail Castlegar 219	3610	47
2007	Trail Castlegar 219	4040	831
2007	Trail Castlegar 219	4050	522
2007	Trail Castlegar 219	5390	128

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2007	Trail Castlegar 219	5400	49
2007	Trail Castlegar 219	6040	365
2007	Trail Castlegar 219	6140	320
2007	Trail Castlegar 219	7820	801
2007	Trail Castlegar 219	8000	80
2007	Trail Castlegar 219	8250	142
2007	Trail Castlegar 219	8260	117
2007	Trail Castlegar 219	14190	1237
2009	Cape Horn Burrard Thermal 508	7580	637
2009	Campbell River Lateral 219	1530	15
2009	Campbell River Lateral 219	3650	20
2009	Campbell River Lateral 219	4890	20
2009	Campbell River Lateral 219	4950	13
2009	Campbell River Lateral 219	6880	0
2009	Campbell River Lateral 219	8160	0
2009	Campbell River Lateral 219	28490	0
2009	Grand Forks Trail 273	15880	350
2009	Grand Forks Trail 273	15900	185
2009	Grand Forks Trail 273	26660	1175
2009	Grand Forks Trail 273	26760	720
2009	Grand Forks Trail 273	40930	62
2009	Grand Forks Trail 273	45840	154
2009	Grand Forks Trail 273	46510	187
2009	Huntingdon Nichol 1677	2540	289
2009	Livingston Pattullo 457	5910	2290
2009	Livingston Pattullo 457	21850	4658
2009	Nichol Port Mann 610	1680	114
2009	Oliver Grand Forks 273	34710	633
2009	Oliver Grand Forks 273	64190	210
2009	Oliver Grand Forks 273	62550/62560	1139
2009	Vancouver Mainland 273	53440	0
2009	Vancouver Mainland 273	61960	48
2009	Vancouver Mainland 273	65140	0
2009	Vancouver Mainland 273	75630	0
2009	Vancouver Mainland 323	3370	74
2009	Vancouver Mainland 323	4030	52

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2009	Vancouver Mainland 323	4160	28
2009	Vancouver Mainland 323	4180	59
2009	Vancouver Mainland 323	4190	25
2009	Vancouver Mainland 323	4240	67
2009	Vancouver Mainland 323	4290	35
2010	Grand Forks Trail 273	8610	453
2010	Grand Forks Trail 273	18130	266
2010	Grand Forks Trail 273	20300	1046
2010	Grand Forks Trail 273	21660	149
2010	Grand Forks Trail 273	21670	46
2010	Grand Forks Trail 273	22160	325
2010	Grand Forks Trail 273	33960	1476
2010	Grand Forks Trail 273	38330	674
2010	Grand Forks Trail 273	39090	1232
2010	Grand Forks Trail 273	39450	343
2010	Grand Forks Trail 273	42730	19
2010	Grand Forks Trail 273	42850	24
2010	Grand Forks Trail 273	42870	186
2010	Grand Forks Trail 273	42880	25
2010	Grand Forks Trail 273	42910	75
2010	Vancouver Island Mainline 273	21370	75
2010	Vancouver Island Mainline 273	53180	16
2010	Vancouver Island Mainline 273	57030	0
2010	Vancouver Island Mainline 273	68400	0
2010	Vancouver Island Mainline 273	68470	61
2010	Vancouver Island Mainline 273	68940	0
2010	Vancouver Island Mainline 273	101140	24
2010	Vancouver Island Mainline 273	101170	0
2010	Livingston Pattullo 457	21660	1102
2010	Livingston Pattullo 457	22180	555
2010	Livingston Pattullo 457	22450	1477
2010	Vernon Penticton 323	34270	166
2010	Savona Penticton 323	34270	78
2010	Savona Penticton 323	89050	34
2010	Yahk Trail 323	1520	48
2010	Yahk Trail 323	1540	148

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2010	Yahk Trail 323	1560	88
2010	Yahk Trail 323	1580	63
2010	Yahk Trail 323	1600	43
2010	Yahk Trail 323	22450	38
2010	Yahk Trail 323	40720	44
2011	Cape Horn Burrard Thermal 508	9450	377
2011	Cape Horn Burrard Thermal 508	10140	19
2011	Grand Forks Trail 273	8150	1011
2011	Grand Forks Trail 273	25450	9
2011	Grand Forks Trail 273	29080	70
2011	Grand Forks Trail 273	32630	1276
2011	Grand Forks Trail 273	33450	251
2011	Grand Forks Trail 273	40320	324
2011	Grand Forks Trail 273	40640	191
2011	Grand Forks Trail 273	41000	326
2011	Grand Forks Trail 273	41030	269
2011	Grand Forks Trail 273	41290	314
2011	Grand Forks Trail 273	43760	573
2011	Grand Forks Trail 273	45140	393
2011	Grand Forks Trail 273	45170	160
2011	Huntingdon Nichol 762	13830	0
2011	Huntingdon Nichol 762	22880	18
2011	Huntingdon Nichol 762	34810	30
2011	Huntingdon Nichol 762	40750	486
2011	Huntingdon Nichol 762	48800	727
2011	Vancouver Island Mainline 273	21270	53
2011	Vancouver Island Mainline 273	21300	24
2011	Vancouver Island Mainline 273	69550	0
2011	Livingston Pattullo 457	14320	648
2011	Livingston Pattullo 457	21570	1630
2011	Oliver Grand Forks 273	9770	77
2011	Oliver Grand Forks 273	11620	162
2011	Oliver Grand Forks 273	20620	593
2011	Oliver Grand Forks 273	27970	267
2011	Oliver Grand Forks 273	31320	1468
2011	Oliver Grand Forks 273	46820	115

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2011	Oliver Grand Forks 273	56660	713
2011	Oliver Grand Forks 273	56680	279
2011	Oliver Grand Forks 273	64440	657
2011	Oliver Grand Forks 273	64450	278
2011	Penticton Oliver 273	7450	20
2011	Penticton Oliver 273	7460	216
2011	Grand Forks Trail 273	15870	350
2011	Port Alberni Lateral 168	2200	0
2011	Port Alberni Lateral 168	5810	8
2011	Vernon Penticton 323	30950	70
2011	Savona Penticton 323	79850	50
2011	Trail Castlegar 219	3020	1597
2011	Trail Castlegar 219	15460	45
2011	Yahk Trail 323	36300	1760
2011	Yahk Trail 323	36460	445
2011	Yahk Trail 323	39140	680
2012	Cape Horn Burrard Thermal 508	12930	106
2012	Cape Horn Burrard Thermal 508	15540	609
2012	Cape Horn Burrard Thermal 508	16200	727
2012	Grand Forks Trail 273	28190	518
2012	Grand Forks Trail 273	28590	1065
2012	Grand Forks Trail 273	38860	4356
2012	Grand Forks Trail 273	39790	1495
2012	Grand Forks Trail 273	40270	356
2012	Grand Forks Trail 273	40910	138
2012	Grand Forks Trail 273	44380	128
2012	Grand Forks Trail 273	46160	995
2012	Grand Forks Trail 273	46160	22
2012	Oliver Grand Forks 273	15040	0
2012	Oliver Grand Forks 273	15240	0
2012	Oliver Grand Forks 273	23500	992
2012	Oliver Grand Forks 273	23690	245
2012	Oliver Grand Forks 273	56280	92
2012	Oliver Grand Forks 273	60405	50
2012	Oliver Grand Forks 273	65350	0
2012	Oliver Grand Forks 273	65350	7

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2012	Trail Castlegar 219	4130	0
2012	Trail Castlegar 219	6140	5668
2012	Trail Castlegar 219	6110	1220
2012	Trail Castlegar 219	6150	3756
2012	Yahk Trail 323	70	331
2012	Yahk Trail 323	1780	407
2012	Yahk Trail 323	5440	72
2012	Yahk Trail 323	5510	250
2012	Yahk Trail 323	28690	400
2012	Yahk Trail 323	36880	2870
2012	Yahk Trail 323	44910	2425
2012	Yahk Trail 323	52690	60
2013	Cape Horn Burrard Thermal 508	5100	2790
2013	Cape Horn Burrard Thermal 508	8890	1005
2013	Cape Horn Burrard Thermal 508	14770	202
2013	Cape Horn Burrard Thermal 508	15000	229
2013	Cape Horn Burrard Thermal 508	15210	0
2013	Grand Forks Trail 273	1760	0
2013	Grand Forks Trail 273	2210	10
2013	Grand Forks Trail 273	44270	596
2013	Grand Forks Trail 273	46240	1195
2013	Grand Forks Trail 273	46370	265
2013	Livingston Coquitlam 323	1350	40
2013	Livingston Coquitlam 323	10440	155
2013	Livingston Coquitlam 323	17980	133
2013	Livingston Pattullo 457	6500	0
2013	Oliver Grand Forks 273	11630	473
2013	Oliver Grand Forks 273	14640	370
2013	Oliver Grand Forks 273	14950	320
2013	Oliver Grand Forks 273	19860	0
2013	Oliver Grand Forks 273	20270	562
2013	Oliver Grand Forks 273	20860	100
2013	Oliver Grand Forks 273	21460	299
2013	Oliver Grand Forks 273	56650	62
2013	Oliver Grand Forks 273	60750	134
2013	Oliver Grand Forks 273	67780	0

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2013	Penticton Oliver 273	7090	615
2013	Vernon Penticton 323	6650	15
2013	Vernon Penticton 323	8810	18
2013	Vernon Penticton 323	9420	487
2013	Vernon Penticton 323	15310	145
2013	Vernon Penticton 323	21160	123
2013	Vernon Penticton 323	25740	195
2013	Vernon Penticton 323	32420	0
2013	Vernon Penticton 323	34350	2027
2013	Vernon Penticton 323	34840	40
2013	Vernon Penticton 323	35320	264
2013	Vernon Penticton 323	58750	75
2013	Kingsvale Oliver 323	10650	0
2013	Kingsvale Oliver 323	24510	307
2013	Kingsvale Oliver 323	53960	0
2013	Kingsvale Oliver 323	55400	0
2013	Trail Castlegar 219	6140	0
2013	Trail Castlegar 219	4280	768
2013	Trail Castlegar 219	6220	603
2013	Yahk Trail 323	930	21
2013	Yahk Trail 323	7460	77
2013	Yahk Trail 323	30290	148
2013	Yahk Trail 323	36010	660
2014	Cape Horn Burrard Thermal 508	90	0
2014	Cape Horn Burrard Thermal 508	1180	46
2014	Cape Horn Burrard Thermal 508	7910	290
2014	Cape Horn Burrard Thermal 508	8060	710
2014	Cape Horn Burrard Thermal 508	8910	190
2014	Cape Horn Burrard Thermal 508	9770	97
2014	Grand Forks Trail 273	8240	420
2014	Grand Forks Trail 273	9230	514
2014	Grand Forks Trail 273	13320	0
2014	Grand Forks Trail 273	17660	367
2014	Grand Forks Trail 273	20010	265
2014	Grand Forks Trail 273	22170	979
2014	Grand Forks Trail 273	28590	382

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2014	Grand Forks Trail 273	28640	131
2014	Grand Forks Trail 273	31160	366
2014	Grand Forks Trail 273	31310	5533
2014	Grand Forks Trail 273	31970	1254
2014	Grand Forks Trail 273	32410	2502
2014	Grand Forks Trail 273	33780	1909
2014	Grand Forks Trail 273	36040	191
2014	Grand Forks Trail 273	39190	750
2014	Grand Forks Trail 273	39250	1845
2014	Grand Forks Trail 273	39740	161
2014	Grand Forks Trail 273	41910	1094
2014	Grand Forks Trail 273	43770	645
2014	Grand Forks Trail 273	45140	263
2014	Grand Forks Trail 273	45420	1464
2014	Grand Forks Trail 273	46640	532
2014	Kingsvale Oliver 323	16590	0
2014	Livingston Coquitlam 323	10410	0
2014	Livingston Coquitlam 323	21870	60
2014	Livingston Pattullo 457	14310	2844
2014	Livingston Pattullo 457	16560	586
2014	Livingston Pattullo 457	19430	807
2014	Nichol Fraser 610	5870	0
2014	Nichol Fraser 610	5940	175
2014	Nichol Fraser 610	5950	220
2014	Oliver Grand Forks 273	9770	77
2014	Oliver Grand Forks 273	20670	60
2014	Oliver Grand Forks 273	22080	323
2014	Oliver Grand Forks 273	23490	264
2014	Oliver Grand Forks 273	28110	131
2014	Oliver Grand Forks 273	28430	384
2014	Oliver Grand Forks 273	41340	0
2014	Oliver Grand Forks 273	48730	128
2014	Oliver Grand Forks 273	52430	298
2014	Oliver Grand Forks 273	53220	423
2014	Oliver Grand Forks 273	53590	380
2014	Oliver Grand Forks 273	58430	780

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2014	Oliver Grand Forks 273	61320	159
2014	Oliver Grand Forks 273	61460	306
2014	Oliver Grand Forks 273	62730	1503
2014	Oliver Grand Forks 273	65170	396
2014	Oliver Grand Forks 273	70620	60
2014	Penticton Oliver 273	14490	5696
2014	Vernon Penticton 323	35630	137
2014	Vernon Penticton 323	60800	87
2015	Cape Horn Burrard Thermal 508	7540	530
2015	Cape Horn Burrard Thermal 508	7700	255
2015	Cape Horn Burrard Thermal 508	12980	841
2015	Grand Forks Trail 273	9430	233
2015	Grand Forks Trail 273	16110	253
2015	Grand Forks Trail 273	18200	243
2015	Grand Forks Trail 273	19570	776
2015	Grand Forks Trail 273	21710	180
2015	Grand Forks Trail 273	22210	359
2015	Grand Forks Trail 273	22400	1638
2015	Grand Forks Trail 273	22420	1089
2015	Grand Forks Trail 273	24320	2294
2015	Grand Forks Trail 273	27700	206
2015	Grand Forks Trail 273	32480	125
2015	Grand Forks Trail 273	37360	1676
2015	Grand Forks Trail 273	38590	1117
2015	Grand Forks Trail 273	39580	1652
2015	Grand Forks Trail 273	42480	130
2015	Grand Forks Trail 273	43520	607
2015	Grand Forks Trail 273	43800	1685
2015	Grand Forks Trail 273	44070	313
2015	Grand Forks Trail 273	46320	64
2015	Grand Forks Trail 273	46360	258
2015	Vancouver Island Mainline 273	55520	9
2015	Vancouver Island Mainline 273	57700	32
2015	Vancouver Island Mainline 273	100910	0
2015	Livingston Coquitlam 323	4560	1365
2015	Livingston Coquitlam 323	10560	40

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2015	Livingston Coquitlam 323	12240	245
2015	Livingston Coquitlam 323	13960	122
2015	Livingston Coquitlam 323	15340	0
2015	Livingston Coquitlam 323	18120	347
2015	Nichol Fraser 610	6610	81
2015	Nichol Port Mann 610	1450	239
2015	Oliver Grand Forks 273	2010	190
2015	Oliver Grand Forks 273	17950	75
2015	Oliver Grand Forks 273	28320	377
2015	Oliver Grand Forks 273	28790	150
2015	Oliver Grand Forks 273	28930	182
2015	Oliver Grand Forks 273	38030	627
2015	Oliver Grand Forks 273	46180	72
2015	Oliver Grand Forks 273	46900	401
2015	Oliver Grand Forks 273	47000	250
2015	Oliver Grand Forks 273	55600	239
2015	Oliver Grand Forks 273	57560	307
2015	Oliver Grand Forks 273	59800	77
2015	Oliver Grand Forks 273	60500	136
2015	Oliver Grand Forks 273	62430	260
2015	Oliver Grand Forks 273	65140	356
2015	Penticton Oliver 273	5500	64
2015	Penticton Oliver 273	7530	151
2015	Penticton Oliver 273	11830	243
2015	Penticton Oliver 273	17710	255
2015	Penticton Oliver 273	22680	60
2015	Vernon Penticton 323	5840	0
2015	Vernon Penticton 323	60030	0
2015	Savona Penticton 323	16960	1072
2015	Savona Penticton 323	18070	77
2015	Savona Penticton 323	43550	226
2015	Savona Penticton 323	43850	38
2015	Trail Castlegar 219	16090	520
2015	Yahk Trail 323	41470	0
2015	Yahk Trail 323	51360	310
2015	Yahk Trail 323	83640	0

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2016	Cape Horn Burrard Thermal 508	10550	0
2016	Campbell River Lateral 219	1160	0
2016	Campbell River Lateral 219	26140	0
2016	Grand Forks Trail 273	14730	20
2016	Grand Forks Trail 273	16920	794
2016	Grand Forks Trail 273	17330	31
2016	Grand Forks Trail 273	20830	0
2016	Grand Forks Trail 273	21120	54
2016	Grand Forks Trail 273	25620	102
2016	Grand Forks Trail 273	27980	1234
2016	Grand Forks Trail 273	31310	1345
2016	Grand Forks Trail 273	32830	162
2016	Grand Forks Trail 273	37890	2271
2016	Grand Forks Trail 273	39040	238
2016	Grand Forks Trail 273	39370	842
2016	Grand Forks Trail 273	43740	2923
2016	Grand Forks Trail 273	43860	165
2016	Grand Forks Trail 273	44150	298
2016	Grand Forks Trail 273	44920	779
2016	Grand Forks Trail 273	46300	54
2016	Kingsvale Oliver 323	30580	85
2016	Livingston Coquitlam 323	6830	95
2016	Livingston Coquitlam 323	10030	8
2016	Livingston Coquitlam 323	12530	370
2016	Livingston Coquitlam 323	24190	129
2016	Livingston Pattullo 457	10120	610
2016	Livingston Pattullo 457	12040	77
2016	Livingston Pattullo 457	12660	1430
2016	Oliver Grand Forks 273	13490	233
2016	Oliver Grand Forks 273	20200	201
2016	Oliver Grand Forks 273	24200	99
2016	Oliver Grand Forks 273	25520	13
2016	Oliver Grand Forks 273	26410	112
2016	Oliver Grand Forks 273	28110	120
2016	Oliver Grand Forks 273	28240	447
2016	Oliver Grand Forks 273	28600	0

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2016	Oliver Grand Forks 273	31350	225
2016	Oliver Grand Forks 273	31460	0
2016	Oliver Grand Forks 273	32620	785
2016	Oliver Grand Forks 273	36130	457
2016	Oliver Grand Forks 273	42300	45
2016	Oliver Grand Forks 273	43390	440
2016	Oliver Grand Forks 273	56680	663
2016	Oliver Grand Forks 273	56790	400
2016	Oliver Grand Forks 273	61580	393
2016	Penticton Oliver 273	12290	0
2016	Vernon Penticton 323	2670	21
2016	Vernon Penticton 323	4440	0
2016	Vernon Penticton 323	5180	400
2016	Vernon Penticton 323	6740	0
2016	Vernon Penticton 323	15880	0
2016	Vernon Penticton 323	16600	1575
2016	Vernon Penticton 323	27010	0
2016	Vernon Penticton 323	27120	2
2016	Vernon Penticton 323	53010	38
2016	Vernon Penticton 323	58440	0
2016	Kingsvale Oliver 323	29460	0
2016	Savona Penticton 323	3280	1064
2016	Savona Penticton 323	16279	308
2016	Savona Penticton 323	24190	308
2016	Savona Penticton 323	39340	1002
2016	Savona Penticton 323	45450	0
2016	Savona Penticton 323	84810	0
2016	Trail Castlegar 219	380	140
2016	Trail Castlegar 219	3090	735
2016	Trail Castlegar 219	4920	195
2016	Trail Castlegar 219	5360	914
2016	Trail Castlegar 219	8610	109
2016	Vancouver Mainland 273	15260	0
2016	Vancouver Mainland 273	19370	195
2016	Yahk Trail 323	51170	206
2016	Yahk Trail 323	55780	0

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2016	Yahk Trail 323	96930	560
2016	Yahk Trail 323	99380	1702
2017	Grand Forks Trail 273	7840	6
2017	Grand Forks Trail 273	9240	456
2017	Grand Forks Trail 273	16090	277
2017	Grand Forks Trail 273	18400	515
2017	Grand Forks Trail 273	21190	392
2017	Grand Forks Trail 273	22390	1082
2017	Grand Forks Trail 273	24730	316
2017	Grand Forks Trail 273	24760	406
2017	Grand Forks Trail 273	24770	122
2017	Grand Forks Trail 273	25700	658
2017	Grand Forks Trail 273	26990	365
2017	Grand Forks Trail 273	27820	867
2017	Grand Forks Trail 273	31160	274
2017	Grand Forks Trail 273	33390	191
2017	Grand Forks Trail 273	33450	61
2017	Grand Forks Trail 273	33890	182
2017	Grand Forks Trail 273	37370	37370
2017	Grand Forks Trail 273	39780	157
2017	Grand Forks Trail 273	39790	1421
2017	Grand Forks Trail 273	43070	245
2017	Grand Forks Trail 273	43590	285
2017	Grand Forks Trail 273	44380	399
2017	Grand Forks Trail 273	44400	210
2017	Grand Forks Trail 273	44410	424
2017	Grand Forks Trail 273	44430	206
2017	Grand Forks Trail 273	44470	128
2017	Grand Forks Trail 273	44860	1001
2017	Grand Forks Trail 273	45140	93
2017	Grand Forks Trail 273	45270	251
2017	Grand Forks Trail 273	45400	280
2017	Grand Forks Trail 273	45950	199
2017	Vancouver Island Mainline 273	13100	39
2017	Vancouver Island Mainline 273	21550	492
2017	Vancouver Island Mainline 273	22340	135

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2017	Vancouver Island Mainline 273	22760	19
2017	Vancouver Island Mainline 273	24210	125
2017	Vancouver Island Mainline 273	79800	0
2017	Livingston Coquitlam 323	16340	164
2017	Nichol Fraser 610	6690	303
2017	Nichol Port Mann 610	1950	5
2017	Nichol Port Mann 610	3810	295
2017	Nichol Port Mann 610	4020	0
2017	Nichol Port Mann 610	4170	295
2017	Oliver Grand Forks 273	12900	206
2017	Oliver Grand Forks 273	20780	427
2017	Oliver Grand Forks 273	22650	1146
2017	Oliver Grand Forks 273	23030	577
2017	Oliver Grand Forks 273	23060	885
2017	Oliver Grand Forks 273	23630	506
2017	Oliver Grand Forks 273	28380	481
2017	Oliver Grand Forks 273	28800	445
2017	Oliver Grand Forks 273	28800	612
2017	Oliver Grand Forks 273	32920	296
2017	Oliver Grand Forks 273	36160	463
2017	Oliver Grand Forks 273	36190	217
2017	Oliver Grand Forks 273	38220	394
2017	Oliver Grand Forks 273	38290	1740
2017	Oliver Grand Forks 273	39760	177
2017	Oliver Grand Forks 273	44120	193
2017	Oliver Grand Forks 273	48830	198
2017	Oliver Grand Forks 273	55560	204
2017	Oliver Grand Forks 273	56540	448
2017	Oliver Grand Forks 273	64520	31
2017	Penticton Oliver 273	17730	498
2017	Oliver Penticton 406	17460	0
2017	Vernon Penticton 323	2200	3130
2017	Vernon Penticton 323	5590	270
2017	Vernon Penticton 323	7250	16
2017	Vernon Penticton 323	34870	0
2017	Savona Penticton 323	4530	1085

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2017	Savona Penticton 323	9710	520
2017	Savona Penticton 323	10960	244
2017	Savona Penticton 323	24680	165
2017	Savona Penticton 323	32880	671
2017	Savona Penticton 323	42590	121
2017	Savona Penticton 323	59600	0
2017	Savona Penticton 323	60260	161
2017	Savona Penticton 323	74300	0
2017	Savona Penticton 323	78840	0
2017	Savona Penticton 323	88870	0
2017	Savona Penticton 323	92210	1317
2017	Savona Penticton 323	93650	640
2017	Savona Penticton 323	101010	0
2017	Tilbury Fraser 508	5340	0
2017	Tilbury Fraser 508	6090	0
2017	Trail Castlegar 219	1240	232
2017	Trail Castlegar 219	1770	682
2017	Trail Castlegar 219	6990	287
2017	Trail Castlegar 219	14290	57
2017	Yahk Trail 323	53100	210
2018	Cape Horn Burrard Thermal 508	5050	0
2018	Cape Horn Burrard Thermal 508	8020	277
2018	Cape Horn Burrard Thermal 508	13450	557
2018	Cape Horn Burrard Thermal 508	15620	635
2018	Grand Forks Trail 273	21260	224
2018	Grand Forks Trail 273	31140	352
2018	Grand Forks Trail 273	44220	249
2018	Grand Forks Trail 273	44230	412
2018	Grand Forks Trail 273	44550	400
2018	Grand Forks Trail 273	44880	413
2018	Grand Forks Trail 273	46380	444
2018	Vancouver Island Mainline 273	16950	0
2018	Vancouver Island Mainline 273	26160	20
2018	Vancouver Island Mainline 273	65290	72
2018	Vancouver Island Mainline 273	82510	12
2018	Vancouver Island Mainline 273	87020	0

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2018	Vancouver Island Mainline 273	98610	0
2018	Kingsvale Oliver 323	14330	365
2018	Kingsvale Oliver 323	36510	5040
2018	Kingsvale Oliver 323	37250	4042
2018	Livingston Coquitlam 323	1520	22
2018	Livingston Coquitlam 323	2590	18
2018	Livingston Coquitlam 323	11840	372
2018	Livingston Pattullo 457	12520	1050
2018	Livingston Pattullo 457	14370	500
2018	Livingston Pattullo 457	16350	441
2018	Livingston Pattullo 457	21690	1283
2018	Nichol Port Mann 610	4520	30
2018	Oliver Grand Forks 273	23500	300
2018	Oliver Grand Forks 273	28250	388
2018	Oliver Grand Forks 273	46070	198
2018	Oliver Grand Forks 273	47000	243
2018	Oliver Grand Forks 273	47570	557
2018	Oliver Grand Forks 273	53100	80
2018	Oliver Grand Forks 273	56930	237
2018	Oliver Grand Forks 273	59770	134
2018	Penticton Oliver 273	3360	84
2018	Penticton Oliver 273	7820	52
2018	Penticton Oliver 273	7840	296
2018	Kingsvale Oliver 323	34380	28
2018	Kingsvale Oliver 323	39150	185
2018	Kingsvale Oliver 323	43500	1335
2018	Savona Penticton 323	5900	35
2018	Savona Penticton 323	5920	200
2018	Savona Penticton 323	8020	486
2018	Savona Penticton 323	9500	307
2018	Savona Penticton 323	9540	221
2018	Savona Penticton 323	9760	205
2018	Savona Penticton 323	16500	109
2018	Savona Penticton 323	19040	81
2018	Savona Penticton 323	22410	544
2018	Savona Penticton 323	33820	723

Year	Pipeline Name	RGW	Corrosion Extent (mm)
2018	Savona Penticton 323	35590	768
2018	Savona Penticton 323	35790	839
2018	Savona Penticton 323	35850	399
2018	Savona Penticton 323	37120	na
2018	Savona Penticton 323	40120	377
2018	Savona Penticton 323	42070	177
2018	Savona Penticton 323	42090	1311
2018	Savona Penticton 323	42150	101
2018	Savona Penticton 323	43640	141
2018	Savona Penticton 323	64840	47
2018	Savona Penticton 323	92120	32
2018	Savona Penticton 323	92230	45
2018	Savona Penticton 323	110800	111
2018	Savona Penticton 323	111150	136
2018	Savona Penticton 323	111170	24
2018	Tilbury Benson 323	3260	74
2018	Trail Castlegar 219	1510	317
2018	Trail Castlegar 219	3330	417
2018	Trail Castlegar 219	5300	324
2018	Trail Castlegar 219	5800	226
2018	Trail Castlegar 219	5920	161
2018	Trail Castlegar 219	6200	789
2018	Trail Castlegar 219	6210	11
2018	Trail Castlegar 219	7150	411
2018	Trail Castlegar 219	8160	784
2018	Trail Castlegar 219	8860	224
2018	Trail Castlegar 219	9050	633
2018	Trail Castlegar 219	13220	269
2018	Trail Castlegar 219	13270	36
2018	Trail Castlegar 219	15480	51
2018	Trail Castlegar 219	16100	64
2018	Yahk Trail 323	40200	1018
2018	Yahk Trail 323	87800	338

Table 3: List of Modified ECDA Driven Transmission Pipeline Integrity Digs and Corrosion Extent from 2000 to 2018

Year	Pipeline Name	RGW or Chainage (km)	Corrosion Extent (mm)
2009	Castlegar Nelson 168	1.312	117
2009	Castlegar Nelson 168	15.284	10660
2009	Savona Lateral 60	0.945	30
2009	Coldstream Lateral 114	2.157	0
2009	Kamloops 2 Lateral 114	0.279	204
2009	Kelowna Lateral 114	1.99	32
2009	Vernon Lateral 114	0.433	40
2009	Kamloops 1 Lateral 168	2.233	0
2009	Kamloops 1 Lateral 168	3.053	0
2009	Kamloops 1 Loop 168	2.02	35
2009	Nichol Port Mann 610	1680	114
2010	Kamloops 2 Lateral 114	0.09	350
2010	Kamloops 2 Lateral 114	0.132	26
2010	Castlegar Nelson 168	10.879	0
2010	Castlegar Nelson 168	10.865	294
2010	Kimberley Lateral 168	16.942	53
2010	Kimberley Lateral 168	16.919	0
2010	Kimberley Lateral 168	18.67	148
2010	Kimberley Lateral 168	16.972	830
2010	Kimberley Lateral 168	13.44	97
2010	Kimberley Lateral 168	13.716	39
2010	Kimberley Lateral 168	13.978	41
2010	Kimberley Lateral 168	13.515	72
2010	Kimberley Lateral 168	13.616	66
2011	Castlegar Nelson 168	16.137	0
2011	Castlegar Nelson 168	16.107	31
2011	Castlegar Nelson 168	16.162	35
2015	Nichol Port Mann 610	35.936	995
2015	Nichol Port Mann 610	35.499	3995
2017	Prince George 1 Lateral 168	92	869
2017	Prince George 1 Lateral 168	640	2242
2017	Prince George 1 Lateral 168	4397	0
2017	Prince George Pulp Lateral 168	584	0
2017	Prince George Pulp Lateral 168	800	870
2018	Prince George 1 Lateral 168	3860	1620

8.1.1 Please provide a root-cause analysis of the corrosion at each integrity dig where corrosion was identified on FEI's transmission system.

Response:

FEI records and considers various data sets during its integrity digs that are relevant to corrosion and other potential hazards. These include:

- Coating type;
- Coating condition, including potential coating disbondment;
- Vegetative region;
- Topography;
- Site position and slope percent;
- Mode of soil deposition;
- Dominant and minor soil type;
- Drainage at pipe depth;
- Groundwater presence and depth to groundwater;
- Soil resistivity;
- Long-seam weld position and type; and
- Data pertaining to cathodic protection deposits and/or corrosion products, including pH, colour, texture, and concentration.

FEI uses this data to check whether it is plausible to find corrosion at the dig site under the given conditions. FEI does not perform a separate root-cause analysis of corrosion at each integrity dig where corrosion is identified. This is because the data collected only represents the condition of the pipe and its surrounding environment at the time of the dig, which may be different from the conditions that existed when corrosion started. Given the numerous potential influences on the start and growth of corrosion on a buried pipeline, and the level of uncertainty associated with such an assessment, attempting a root-cause analysis at each integrity dig site would not provide value to FEI's in-line inspection activity.

8.1.2 For each integrity dig with identified corrosion, please provide costs to repair pipe, recondition or replace all or portions of the pipeline.

Response:

Please refer to the table below for recorded site-specific integrity dig costs for 2015, 2016, 2017 and 2018. FEI notes that its integrity dig costs are not collected in such a way to differentiate amongst excavation, inspection, repairs deemed to be an O&M expense, re-coating and site rehabilitation. In addition, prior to 2015, FEI only reported the total annual costs associated with integrity dig activity, as opposed to a specific cost for each dig site, so the information by site cannot be provided for those years.

Work Order Title (from financial reporting system)	Year of Integrity Dig	Recorded Costs against Work Order ($)
12" PEN-VER - metal loss	2015	14,076
2015 Integrity Excavation	2015	41,912
2015 Integrity Excavation	2015	26,272
24" Nichol - Ferguson - Chainage 3593.6	2015	72,025
10" Grand Forks-Trail - Weld 32490	2015	1,143
10" Grand Forks-Trail - Weld 9340	2015	39,688
10" Grand Forks-Trail - Weld 16110	2015	23,918
10" Grand Forks-Trail - Weld 18200	2015	53,569
10" Grand Forks-Trail - Weld 19570	2015	40,788
10" Grand Forks-Trail - Weld 21710	2015	17,406
10" Grand Forks-Trail - Weld 22210	2015	26,622
10" Grand Forks-Trail - Weld 22400	2015	47,610
10" Grand Forks-Trail - Weld 22420	2015	21,720
10" Grand Forks-Trail - Weld 24320	2015	35,023
10" Grand Forks-Trail - Weld 27700	2015	69,190
10" Grand Forks-Trail - Weld 27980	2015	4,822
10" Grand Forks-Trail - Weld 32480	2015	281,164
10" Grand Forks-Trail - Weld 37360	2015	14,645
10" Grand Forks-Trail - Weld 38590	2015	22,891
10" Grand Forks-Trail - Weld 39580	2015	35,692
10" Grand Forks-Trail - Weld 42480	2015	9,791
10" Grand Forks-Trail - Weld 43520	2015	12,017
10" Grand Forks-Trail - Weld 43740	2015	5,282
10" Grand Forks-Trail - Weld 43800	2015	15,704
10" Grand Forks-Trail - Weld 44070	2015	37,367

Work Order Title (from financial reporting system)	Year of Integrity Dig	Recorded Costs against Work Order ($)
10" Grand Forks-Trail - Weld 46320	2015	23,873
10" Grand Forks-Trail - Weld 46360	2015	27,898
10" Grand Forks-Trail - Weld 46440	2015	13,231
10" Oliver Y - Grand Forks - Weld 2010	2015	18,184
10" Oliver Y - Grand Forks - Weld 17950	2015	25,392
10" Oliver Y - Grand Forks - Weld 28320	2015	21,848
10" Oliver Y - Grand Forks - Weld 28790	2015	19,672
10" Oliver Y - Grand Forks - Weld 28930	2015	13,647
10" Oliver Y - Grand Forks - Weld 38030	2015	24,864
10" Oliver Y - Grand Forks - Weld 46180	2015	17,207
10" Oliver Y - Grand Forks - Weld 46900	2015	7,197
10" Oliver Y - Grand Forks - Weld 47000	2015	11,096
10" Oliver Y - Grand Forks - Weld 55600	2015	24,389
10" Oliver Y - Grand Forks - Weld 57560	2015	18,200
10" Oliver Y - Grand Forks - Weld 59800	2015	7,681
10" Oliver Y - Grand Forks - Weld 60500	2015	8,858
10" Oliver Y - Grand Forks - Weld 62430	2015	8,124
10" Oliver Y - Grand Forks - Weld 65140	2015	13,254
10" Penticton - Oliver Y - Weld 7530	2015	19,418
10" Penticton - Oliver Y - Weld 17710	2015	74,587
10" Penticton - Oliver Y - Weld 5500	2015	19,384
10" Penticton - Oliver Y - Weld 11830	2015	11,204
10" Penticton - Oliver Y - Weld 22680	2015	23,763
12" Penticton-Vernon - Weld 5840	2015	18,734
12" Penticton-Vernon - Weld 6740	2015	175
12" Penticton-Vernon - Weld 60030	2015	16,701
12" Savona - Vernon - Weld 3280	2015	542
12" Savona - Vernon - Weld 16960	2015	7,927
12" Savona - Vernon - Weld 18070	2015	9,989
12" Vernon-Penticton - Weld 4440	2015	966
12" Yahk - Trail (EKL) - Weld 41470	2015	14,513
12" Yahk - Trail (EKL) - Weld 51360	2015	64,315
12" Yahk - Trail (EKL) - Weld 55780	2015	8,855
12" Yahk - Trail (EKL) - Weld 83640	2015	20,728
8" Trail-Castlegar - Weld 16090	2015	52,722
8" Trail-Castlegar - Weld 3090	2015	23,793

Work Order Title (from financial reporting system)	Year of Integrity Dig	Recorded Costs against Work Order ($)
12" Savona - Vernon - Weld 43550	2015	31,509
12" Savona - Vernon - Weld 43850	2015	18,218
2015 Integrity Excavation	2015	42,084
12" Livingston - Coquitlam - Weld 18120	2015	1,534
24" Nichol - Ferguson - Weld 1450	2015	31,841
24" Nichol - Ferguson - Chainage 3549.9	2015	92,996
168 mm PG#1 Lateral - Chainage 92.6	2015	12,667
168 mm PG#1 Lateral - Chainage 3822.7	2015	26,399
168 mm PG#1 Lateral - Chainage 4397.3	2015	2,565
2015 Integrity Excavation	2016	80,415
12" Livingston - Coquitlam - Weld 6830	2016	22,088
12" Livingston - Coquitlam - Weld 10030	2016	17,139
12" Livingston - Coquitlam - Weld 12530	2016	35,168
12" Livingston - Coquitlam - Weld 24190	2016	36,793
18" Livingston - Pattullo - Weld 10120	2016	73,365
18" Livingston - Pattullo - Weld 12040	2016	36,436
18" Livingston - Pattullo - Weld 12660	2016	28,025
20" Cape Horn - Burrard - Weld 10550	2016	46,085
10" Watershed - Secret Cove Weld 15260	2016	14,475
10" Watershed - Secret Cove Weld 19370	2016	11,612
8" Campbell River Lateral Weld 1160	2016	8,616
8" Campbell River Lateral Weld 26140	2016	13,810
10" Grand Forks-Trail - Weld 39040	2016	22,408
10" Grand Forks-Trail - Weld 39370	2016	17,582
10" Grand Forks-Trail - Weld 43860	2016	15,977
10" Grand Forks-Trail - Weld 46300	2016	17,124
10" Grand Forks-Trail - Weld 44150	2016	7,786
10" Grand Forks-Trail - Weld 44920	2016	10,920
8" Trail-Castlegar - Weld 370	2016	28,493
8" Trail-Castlegar - Weld 5360	2016	43,594
10" Grand Forks-Trail - Weld 14730	2016	24,307
10" Grand Forks-Trail - Weld 16920	2016	23,693
10" Grand Forks-Trail - Weld 17330	2016	19,491
10" Grand Forks-Trail - Weld 20830	2016	28,176
10" Grand Forks-Trail - Weld 21120	2016	25,755
10" Grand Forks-Trail - Weld 25620	2016	25,883

Work Order Title (from financial reporting system)	Year of Integrity Dig	Recorded Costs against Work Order ($)
10" Grand Forks-Trail - Weld 27980	2016	266,052
10" Grand Forks-Trail - Weld 31310	2016	15,018
10" Grand Forks-Trail - Weld 32830	2016	23,975
10" Grand Forks-Trail - Weld 37890	2016	51,388
10" Grand Forks-Trail - Weld 37910	2016	8,853
10" Grand Forks-Trail - Weld 43740	2016	80,286
10" Oliver Y - Grand Forks - Weld 13490	2016	25,485
10" Oliver Y - Grand Forks - Weld 24200	2016	19,651
10" Oliver Y - Grand Forks - Weld 25520	2016	20,514
10" Oliver Y - Grand Forks - Weld 26410	2016	13,761
10" Oliver Y - Grand Forks - Weld 28110	2016	16,874
10" Oliver Y - Grand Forks - Weld 28240	2016	22,601
10" Oliver Y - Grand Forks - Weld 28600	2016	21,547
10" Oliver Y - Grand Forks - Weld 31350	2016	11,724
10" Oliver Y - Grand Forks - Weld 20200	2016	28,741
10" Oliver Y - Grand Forks - Weld 32620	2016	22,165
10" Oliver Y - Grand Forks - Weld 36130	2016	24,759
10" Oliver Y - Grand Forks - Weld 31460	2016	19,474
10" Oliver Y - Grand Forks - Weld 42300	2016	16,876
10" Oliver Y - Grand Forks - Weld 43390	2016	27,657
10" Oliver Y - Grand Forks - Weld 56680	2016	30,231
10" Oliver Y - Grand Forks - Weld 56790	2016	15,523
10" Oliver Y - Grand Forks - Weld 38030	2016	11,980
10" Oliver Y - Grand Forks - Weld 61580	2016	17,015
10" Penticton - Oliver Y - Weld 12290	2016	14,404
10" Penticton - Oliver Y - Weld 15870	2016	19,223
12" Penticton-Vernon - Weld 2670	2016	29,869
12" Penticton-Vernon - Weld 4440	2016	11,032
12" Penticton-Vernon - Weld 5180	2016	21,752
12" Penticton-Vernon - Weld 6740	2016	35,900
12" Penticton-Vernon - Weld 15880	2016	22,972
12" Penticton-Vernon - Weld 16600	2016	20,661
12" Penticton-Vernon - Weld 27010	2016	27,264
12" Penticton-Vernon - Weld 27120	2016	20,041
12" Penticton-Vernon - Weld 34870	2016	91,463
12" Penticton-Vernon - Weld 53010	2016	29,211

Work Order Title (from financial reporting system)	Year of Integrity Dig	Recorded Costs against Work Order ($)
12" Penticton-Vernon - Weld 58440	2016	26,216
12" Princeton-Oliver - Weld 29460	2016	47,072
12" Savona - Vernon - Weld 3280	2016	31,297
12" Savona - Vernon - Weld 16279	2016	64,242
12" Savona - Vernon - Weld 24190	2016	17,698
12" Savona - Vernon - Weld 39340	2016	37,403
12" Savona - Vernon - Weld 45450	2016	24,040
12" Savona - Vernon - Weld 84810	2016	23,599
16" SONG - Weld 17460	2016	32,615
8" Trail-Castlegar - Weld 3090	2016	222,018
8" Trail-Castlegar - Weld 8610	2016	16,611
12" Kingsvale - Oliver - Weld 30580	2016	24,783
12" Yahk - Trail (EKL) - Weld 51170	2016	18,489
12" Yahk - Trail (EKL) - Weld 55780	2016	33,703
8" Trail-Castlegar - Weld 4920	2016	20,407
ILI Integrity Excavation -Trail/Cast 219	2016	38,731
12" Yahk - Trail (EKL) - Weld 99380	2016	44,503
12" Yahk - Trail (EKL) - Weld 96930	2017	42,523
24" Nichol - Port Mann, Weld #1990	2017	73,027
24" Nichol - Port Mann, Weld #3850	2017	46,078
24" Nichol - Port Mann, Weld #4060	2017	66,338
24" Nichol - Port Mann, Weld #4210	2017	37,079
20" Tilbury - Fraser, Weld #4940	2017	36,299
20" Tilbury - Fraser, Weld #5680	2017	44,568
24" Nichol - Fraser, Weld #6710	2017	38,665
12" Livingston - Coquitlam, Weld #16340	2017	58,390
2015 Integrity Excavation	2017	67,779
2015 Integrity Excavation	2017	64,414
2015 Integrity Excavation	2017	19,614
2015 Integrity Excavation	2017	587
2015 Integrity Excavation	2017	43,737
2015 Integrity Excavation	2017	2,251
2015 Integrity Excavation	2017	61,469
ILI Inspection Digs VI10 2017	2017	30,114
10" Oliver Y - Grand Forks - Weld 12900	2017	52,522
10" Oliver Y - Grand Forks - Weld 20780	2017	27,939

Work Order Title (from financial reporting system)	Year of Integrity Dig	Recorded Costs against Work Order ($)
10" Oliver Y - Grand Forks - Weld 22650	2017	63,684
10" Oliver Y - Grand Forks - Weld 23030	2017	17,495
10" Oliver Y - Grand Forks - Weld 23630	2017	18,515
10" Oliver Y - Grand Forks - Weld 28380	2017	20,523
10" Oliver Y - Grand Forks - Weld 28800	2017	16,451
10" Oliver Y - Grand Forks - Weld 28810	2017	26,501
10" Oliver Y - Grand Forks - Weld 32920	2017	54,086
10" Oliver Y - Grand Forks - Weld 36160	2017	18,849
12" Savona - Vernon - Weld 4520	2017	31,932
12" Savona - Vernon - Weld 9710	2017	31,998
12" Savona - Vernon - Weld 10960	2017	9,042
12" Savona - Vernon - Weld 24680	2017	14,007
12" Penticton-Vernon - Weld 5590	2017	21,829
12" Penticton-Vernon - Weld 7250	2017	107,408
12" Penticton-Vernon - Weld 2200	2017	52,428
12" Savona - Vernon - Weld 32880	2017	34,655
12" Savona - Vernon - Weld 42580	2017	26,997
12" Savona - Vernon - Weld 60260	2017	30,962
12" Savona - Vernon - Weld 93650	2017	18,770
PG Pulp Lateral 168 - Int Dig	2017	7,378
PG Pulp Lateral 168 - Int Dig	2017	7,470
PG Pulp Lateral 168 - Int Dig	2017	10,263
PG Pulp Lateral 168 - Int Dig	2017	5,721
PG Pulp Lateral 168 - Int Dig	2017	8,784
PG Pulp Lateral 168 - Int Dig	2017	37,925
PG Pulp Lateral 168 - Int Dig	2017	14,329
PG #1 Lateral 168 - Int Dig	2017	39,690
PG #1 Lateral 168 - Int Dig	2017	30,327
PG #1 Lateral 168 - Int Dig	2017	27,112
PG #1 Lateral 168 - Int Dig	2017	65,056
10" Grand Forks-Trail - Weld 7840	2017	34,506
10" Grand Forks-Trail - Weld 9240	2017	31,637
10" Grand Forks-Trail - Weld 16090	2017	17,863
10" Grand Forks-Trail - Weld 18400	2017	15,220
10" Grand Forks-Trail - Weld 21190	2017	43,048
10" Grand Forks-Trail - Weld 22390	2017	38,165

Work Order Title (from financial reporting system)	Year of Integrity Dig	Recorded Costs against Work Order ($)
10" Grand Forks-Trail - Weld 24730	2017	14,048
10" Grand Forks-Trail - Weld 24760	2017	25,253
10" Grand Forks-Trail - Weld 25700	2017	9,737
10" Grand Forks-Trail - Weld 26990	2017	83,839
10" Grand Forks-Trail - Weld 27820	2017	192,094
10" Grand Forks-Trail - Weld 31160	2017	16,245
10" Grand Forks-Trail - Weld 33390	2017	35,567
10" Grand Forks-Trail - Weld 33450	2017	13,932
10" Grand Forks-Trail - Weld 33890	2017	18,060
10" Grand Forks-Trail - Weld 37370	2017	32,839
10" Grand Forks-Trail - Weld 39780	2017	13,231
10" Grand Forks-Trail - Weld 39790	2017	39,184
10" Grand Forks-Trail - Weld 43070	2017	22,062
10" Grand Forks-Trail - Weld 43590	2017	46,979
10" Grand Forks-Trail - Weld 44380	2017	9,908
10" Grand Forks-Trail - Weld 44390	2017	18,412
10" Grand Forks-Trail - Weld 44400	2017	23,490
10" Grand Forks-Trail - Weld 44430	2017	13,244
10" Grand Forks-Trail - Weld 44470	2017	13,492
10" Grand Forks-Trail - Weld 44860	2017	31,955
10" Grand Forks-Trail - Weld 45140	2017	29,943
10" Grand Forks-Trail - Weld 45270	2017	38,078
10" Grand Forks-Trail - Weld 45400	2017	33,767
10" Grand Forks-Trail - Weld 45410	2017	25,642
10" Grand Forks-Trail - Weld 45950	2017	22,107
10" Oliver Y - Grand Forks - Weld 23060	2017	10,374
10" Oliver Y - Grand Forks - Weld 36190	2017	14,783
10" Oliver Y - Grand Forks - Weld 38220	2017	24,012
10" Oliver Y - Grand Forks - Weld 38290	2017	4,523
10" Oliver Y - Grand Forks - Weld 39760	2017	14,463
10" Oliver Y - Grand Forks - Weld 44120	2017	33,450
10" Oliver Y - Grand Forks - Weld 48830	2017	46,539
10" Oliver Y - Grand Forks - Weld 55560	2017	9,575
10" Oliver Y - Grand Forks - Weld 56540	2017	15,185
10" Oliver Y - Grand Forks - Weld 64520	2017	14,495
12" Savona - Vernon - Weld 59600	2017	156,972

Work Order Title (from financial reporting system)	Year of Integrity Dig	Recorded Costs against Work Order ($)
12" Savona - Vernon - Weld 74300	2017	55,304
12" Savona - Vernon - Weld 78840	2017	12,136
12" Savona - Vernon - Weld 88870	2017	22,236
12" Savona - Vernon - Weld 92210	2017	57,043
12" Savona - Vernon - Weld 101010	2017	50,950
10" Penticton - Oliver Y - Weld 17730	2017	53,268
12" Yahk - Trail (EKL) - Weld 53100	2017	27,575
Trail to Castlegar Intg Dig Weld1240	2017	23,510
Integrity Dig Weld 1770 TRA-CAS-8"	2017	11,099
Integrity Dig Weld 6980 TRA-CAS-8"	2017	33,677
Integrity Dig Weld 14290 TRA-CAS-8"	2017	19,604
Integrity dig LIV-COQ weld 1520	2018	18,777
Integrity dig LIV-COQ weld 11840	2018	74,785
Integrity dig TIL-BEN weld 3260	2018	156,765
Integrity dig LIV-PAT weld 12520	2018	54,007
Integrity dig LIV-PAT weld 14370	2018	32,692
integrity dig LIV-PAT weld 16350	2018	31,439
Integrity dig LIV-PAT weld 21690	2018	47,531
integrity dig CAP-BUR weld 8020	2018	55,676
integrity dig CPH-BUR weld 13450	2018	34,876
integrity dig CPH-BUR weld15620	2018	39,610
integrity dig NIC-PTM weld 4520	2018	41,747
integrity dig NIC-FRA weld 9660	2018	3,193
Integrity dig LIV-COQ weld 2590	2018	3,425
12" Savona - Vernon - Weld 19040	2018	11,150
12" Savona - Vernon - Weld 35600	2018	8,003
VI10 2018 ILI Digs	2018	12,665
10" Penticton - Oliver Y - Weld 3360	2018	23,386
10" Penticton - Oliver Y - Weld 7840	2018	67,613
10" Oliver Y - Grand Forks - Weld 65690	2018	5,019
12" Vernon-Penticton - Weld 37190	2018	14,104
12" Savona - Vernon - Weld 5900	2018	34,899
12" Savona - Vernon - Weld 5920	2018	30,532
12" Savona - Vernon - Weld 8020	2018	8,571
12" Savona - Vernon - Weld 9500	2018	12,967
12" Savona - Vernon - Weld 9540	2018	7,974

Work Order Title (from financial reporting system)	Year of Integrity Dig	Recorded Costs against Work Order ($)
12" Savona - Vernon - Weld 9760	2018	8,810
12" Savona - Vernon - Weld 16500	2018	10,147
12" Savona - Vernon - Weld 22410	2018	22,124
12" Savona - Vernon - Weld 24680	2018	4,072
12" Savona - Vernon - Weld 33820	2018	50,031
12" Savona - Vernon - Weld 35790	2018	9,622
12" Savona - Vernon - Weld 35850	2018	8,103
12" Savona - Vernon - Weld 37120	2018	17,699
12" Savona - Vernon - Weld 40120	2018	11,779
12" Savona - Vernon - Weld 43640	2018	15,315
12" Savona - Vernon - Weld 64840	2018	7,948
12" Savona - Vernon - Weld 92120	2018	20,819
12" Savona - Vernon - Weld 92230	2018	7,728
10" Oliver Y - Grand Forks - Weld 23500	2018	12,508
10" Oliver Y - Grand Forks - Weld 28250	2018	22,471
10" Oliver Y - Grand Forks - Weld 46070	2018	16,097
10" Oliver Y - Grand Forks - Weld 47000	2018	9,493
10" Oliver Y - Grand Forks - Weld 47570	2018	40,929
10" Oliver Y - Grand Forks - Weld 53100	2018	15,281
10" Oliver Y - Grand Forks - Weld 56930	2018	16,258
10" Oliver Y - Grand Forks - Weld 59770	2018	19,394
10" Grand Forks-Trail - Weld 21260	2018	37,266
10" Grand Forks-Trail - Weld 31140	2018	26,523
10" Grand Forks-Trail - Weld 44220	2018	26,608
10" Grand Forks-Trail - Weld 44230	2018	18,144
10" Grand Forks-Trail - Weld 44550	2018	26,663
10" Grand Forks-Trail - Weld 44880	2018	40,873
10" Grand Forks-Trail - Weld 46380	2018	14,641
8" Trail - Castlegar - Weld 1510	2018	28,720
12" Yahk - Trail (EKL) - Weld 40200	2018	43,765
12" Yahk - Trail (EKL) - Weld 87800	2018	25,576
12" Kingsvale - Princeton - Weld 14330	2018	44,324
12" Kingsvale - Princeton - Weld 36510	2018	22,324
12" Kingsvale - Princeton - Weld 37250	2018	25,135
12" Princeton - Oliver - Weld 34380	2018	29,468
12" Princeton - Oliver - Weld 39150	2018	18,859

Work Order Title (from financial reporting system)	Year of Integrity Dig	Recorded Costs against Work Order ($)
12" Princeton - Oliver - Weld 43500	2018	22,277
8" Trail - Castlegar - Weld 3330	2018	36,317
8" Trail - Castlegar - Weld 5300	2018	17,201
8" Trail - Castlegar - Weld 5800	2018	112,200
8" Trail - Castlegar - Weld 5920	2018	20,979
8" Trail - Castlegar - Weld 6200	2018	22,535
8" Trail - Castlegar - Weld 6210	2018	19,720
8" Trail - Castlegar - Weld 7150	2018	19,912
8" Trail - Castlegar - Weld 8160	2018	21,081
8" Trail - Castlegar - Weld 8860	2018	12,814
8" Trail - Castlegar - Weld 9060	2018	30,930
8" Trail - Castlegar - Weld 13220	2018	20,875
8" Trail - Castlegar - Weld 13270	2018	21,398
8" Trail - Castlegar - Weld 15480	2018	19,376
8" Trail - Castlegar - Weld 16100	2018	134,011
12" Savona - Vernon - Weld 42070	2018	39,750
12" Savona - Vernon - Weld 42090	2018	120,101
12" Savona - Vernon - Weld 42150	2018	12,612
12" Savona - Vernon - Weld 110800	2018	13,727
12" Savona - Vernon - Weld 111150	2018	39,952
12" Savona - Vernon - Weld 111170	2018	11,389

8.1.3 Please discuss any statistical treatment of corrosion history on FEI's transmission system and provide results of data analysis.

Response:

FEI performs statistical analyses of each in-line inspection tool run as well as the imperfections reported by each tool run. The specific analyses performed by FEI are:

- Determination of in-line inspection tool measurement bias and uncertainty by comparing field imperfection measurements to in-line inspection tool reported imperfection dimensions:

  - This analysis enables FEI to make adjustments for potential non-conservative tool reporting bias and uncertainty greater than stated in the tool specification.
- Number of validation digs for each type of imperfection:
  - This analysis identifies any requirements for additional tool validation digs to increase confidence in the results of statistical analyses.

FEI performs other analyses as follows:

- Number and type of corrosion imperfections from one in-line inspection to another:
  - This analysis informs FEI's assessment of tool performance and its understanding of the potential improvement in tool sensors in identifying previously non-detected imperfections between successive in-line inspections.
- Corrosion feature density:
  - This analysis informs FEI's determination of site-specific mitigation strategy (e.g., repair of individual imperfections versus pipe replacement).

FEI's analyses described above have provided the following results:

- Reduction in failure occurrences on in-line inspected pipelines; and
- Improved ability to assess individual ILI tool run performance, and to make any necessary adjustments to its integrity dig program.

8.1.4 Please describe any studies to determine the probability of corrosion failure or the rate at which corrosion is proceeding on FEI's pipeline system and provide study results.

<u>Response:</u>

While no studies are available, within its in-line inspection analysis process (as described in Appendix E of the Application), FEI estimates corrosion growth over time using one of the following deterministic methods:

- Corrosion rate estimated by signal matching between in-line inspection tool runs by in-line inspection vendor when the same vendor and in-line inspection tool are used between runs;

- Time-based rate using pipeline age or, if known, corrosion initiation year (e.g., the year coating is compromised); or
- Typical upper bound growth used in the industry.

Corrosion failure is also estimated using a deterministic approach rather than a probabilistic approach. In a deterministic approach, a corrosion feature is grown linearly over time at a given growth rate until the feature meets FEI's dig criteria instead of estimating the probability of a feature meeting or exceeding the dig criteria.

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

8.2 For each transmission pipeline of FEI's system, please provide a general description of the pipeline including the dimensions and material characteristics of the pipe, age, type of coating (pipe and joint), leak history, location of the pipeline as related to population density and whether the pipeline is equipped for in-line inspection.

Response:

Please refer to the tables below for transmission pipeline information:

- Table 1: 29 Transmission Laterals
- Table 2: Other Transmission Pipelines

FEI provides the following notes to facilitate interpretation of the table:

- Pipe attributes shown are the most predominant type in the given pipeline.
- Location of the pipeline as related to population density is shown as percentage of Class 3 length.
- To present a more comprehensive view, failures include both leaks and ruptures. "Failures Caused by Other than External Corrosion" include such causes such as third-party damage and weld imperfections. These are not considered by FEI as relevant to this Application, as the proposed alternatives are not intended to mitigate the potential for these non-time-dependent failures.

Table 4: 29 Transmission Laterals

Pipeline Name	Line Length (kilometres)	Grade (MPa)	Wall Thickness (mm)	Year Installed	Age	Pipe Coating Type	Joint Coating Type	% of Class 3	In-line Inspection Capable?	Number of Recorded Failures Caused by External Corrosion	Number of Recorded Failures Caused by Other than External Corrosion
Mackenzie Lateral 168	28.6	241/290	4.8	1996	23	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	1	No	0	0
Mackenzie Loop 168	14.2	290	4.8	1972	47	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
BC Forest Products Lateral 168	0.5	290	4.8	1996	23	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Prince George 3 Lateral 219	5.3	317	4.8	1970	49	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Northwood Pulp Lateral 168	6.0	290	4.8	1965	54	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Northwood Pulp Loop 219	5.8	359	4.8	1995	24	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Prince George 1 Lateral 168	4.7	241	4.8	1957	62	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	1
Prince George Pulp Lateral 168	1.0	241/290	4.8	1964	55	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Husky Oil Lateral 168	1.1	290	4.8	1965	54	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Prince George 2 Lateral 168	8.6	241	4.8	1972	47	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Cariboo Pulp Lateral 168	1.3	241	4.8	1993	26	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Williams Lake Loop 1/Loop 2 168	5.9	241/359	4.8	1993	26	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Kamloops 1 Lateral/Loop 168	6.7	290	4.8	1965/1979	40/54	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	27/31	No	0	0
Salmon Arm Loop 168	44.9	290	4.8	1976	43	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	12	No	0	1
Salmon Arm 3 Lateral 168	0.8	290	4.8	1981	38	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Coldstream Lateral 219	1.8	290	4.8	1998	21	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	49	No	0	0

Pipeline Name	Line Length (kilometres)	Grade (MPa)	Wall Thickness (mm)	Year Installed	Age	Pipe Coating Type	Joint Coating Type	% of Class 3	In-line Inspection Capable?	Number of Recorded Failures Caused by External Corrosion	Number of Recorded Failures Caused by Other than External Corrosion
Coldstream Loop 168	3.8	290	4.8	1989	30	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	16	No	0	0
Kelowna 1 Loop 219	2.1	317	4.8	1976	43	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	33	No	0	0
Celgar Lateral 168	5.8	241	4.8	1960	59	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	4	No	0	0
Castlegar Nelson 168	37.4	241/290	4.8	1957	62	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	21	No	0	3
Trail Lateral 168	4.2	241	4.8	1957	62	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	1
Fording Lateral 219/168	79.6	241/290	4.8	1971	48	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	6	No	1	2
Elkview Lateral 168	1.6	290	4.8	1970	49	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	19	No	0	0
Cranbrook Lateral 168	34.0	290	4.8	1990	29	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	9	No	0	0
Cranbrook Loop 219	34.0	290	4.0	1968	51	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	9	No	0	0
Cranbrook Kimberley Loop 219	4.0	290	4.8	1992	27	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Cranbrook Kimberley Loop 273	9.4	359	4.8	1992	27	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	21	No	0	0
Kimberley Lateral 168	20.6	241/290	4.8	1962	57	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	2	No	0	0
Skookumchuck Lateral 219	35.9	290	4.0	1968	51	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0

Table 5: Other Transmission Pipelines

Pipeline Name	Line Length (kilometres)	Grade (MPa)	Wall Thickness (mm)	Year Installed	Age	Pipe Coating Type	Joint Coating Type	% of Class 3	In-line Inspection Capable?	Number of Recorded Failures Caused by External Corrosion	Number of Recorded Failures Caused by Other than External Corrosion
Cape Horn Burrard Thermal 508	8.0	290	7.1	1960/1964	55/59	Coal Tar	Coal Tar	100	Yes	0	0
Campbell River Lateral 219	49.5	414	5.5	1990	29	Extruded Polyethylene	Heat Shrink Sleeves	0	Yes	0	0
Crofton Lateral 168	5.1	359	7.0	1990	29	Extruded Polyethylene	Heat Shrink Sleeves	0	Yes	0	0
Duke Savona 508	3.5	414	8.2	1997	22	Polyethylene Tape	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	Yes	0	0
Grand Forks Trail 273	60.0	290	4.8	1957	62	Asphalt Enamel	Asphalt Enamel	4	Yes	3	2
Harmac Lateral 168	9.7	360	7.0	1990	29	Extruded Polyethylene	Heat Shrink Sleeves	37	Yes	0	0
Huntingdon Nichol 762	54.2	290	10.5	1964	55	Coal Tar	Coal Tar	100	Yes	0	0
Huntingdon Roebuck 1066	55.6	414	9.7	1977/1992	27/42	Coal Tar/ Fusion Bond Epoxy	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	100	Yes	0	0
Vancouver Island Mainline 273	156.0	448	6.4	1990	29	Extruded Polyethylene	Heat Shrink Sleeves	0	Yes	0	0
Vancouver Island Mainline 273	60.8	448	6.4	1990	29	Extruded Polyethylene	Heat Shrink Sleeves	8	Yes	0	0
Kingsvale Oliver 323	67.8	290	6.0	1972	47	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	Yes	0	0
Livingston Coquitlam 323	34.3	290	6.4	1958	61	Coal Tar	Coal Tar	100	Yes	0	6
Livingston Pattullo 457	29.9	290	6.4	1956	63	Coal Tar	Coal Tar	100	Yes	1	0
Little River North 273	23.7	448	10.4	1990	29	Fusion Bond Epoxy	Cold Applied Polymer Tape or Liquid Epoxy	0	Yes	0	0

Pipeline Name	Line Length (kilometres)	Grade (MPa)	Wall Thickness (mm)	Year Installed	Age	Pipe Coating Type	Joint Coating Type	% of Class 3	In-line Inspection Capable?	Number of Recorded Failures Caused by External Corrosion	Number of Recorded Failures Caused by Other than External Corrosion
Little River South 273	23.7	448	10.4	1990	29	Fusion Bond Epoxy	Cold Applied Polymer Tape or Liquid Epoxy	0	Yes	0	0
Mt Hayes Lateral 273	5.4	483	8.4	2010	9	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	Yes	0	0
Nichol Coquitlam 914	11.0	414	12.7	2000/2018	19/11	Fusion Bond Epoxy	Liquid Epoxy	100	Yes	0	0
Nichol Fraser 610	25.6	290/359	12.7/7.1	1958/1959	59/60	Coal Tar	Coal Tar	100	Yes	0	0
Nichol Port Mann 610	4.9	290	8.7	1958	61	Coal Tar	Coal Tar	100	Yes	0	0
Noons Creek Eagle Mountain 610	1.8	414	7.0	1992	27	Fusion Bond Epoxy	Heat Shrink Sleeve	100	Yes	0	0
Oliver Grand Forks 273	95.0	240	4.8	1957	62	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	7	Yes	17	5
Penticton Oliver 273	31.0	290	4.3	1957	62	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	7	Yes	0	0
Oliver Penticton 406	32.1	414	8.3	1994	25	Fusion Bond Epoxy	Heat Shrink Sleeve	3	Yes	0	0
Port Alberni Lateral 168	21.7	240	4.9	1990	29	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	15	Yes	0	0
Port Mann Cape Horn 914	1.3	414	15.2	2001	18	Fusion Bond Epoxy/ Abrasion Resistant Overcoat	Cold Applied Polymer Tape or Liquid Epoxy	0	Yes	0	0
Kingsvale Oliver 323	95.9	359	6.0	1972	47	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	Yes	0	3
Powell River North/South Loop 273	10.9	448	10.3	1990	29	Fusion Bond Epoxy	Cold Applied Polymer Tape or Liquid Epoxy	0	Yes	0	0
Roebuck Tilbury 914	12.8	414	8.9	1981	38	Coal Tar	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	100	Yes	0	0
Savona Penticton 323	143.5	240	4.8	1957	62	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	13	Yes	0	9

Pipeline Name	Line Length (kilometres)	Grade (MPa)	Wall Thickness (mm)	Year Installed	Age	Pipe Coating Type	Joint Coating Type	% of Class 3	In-line Inspection Capable?	Number of Recorded Failures Caused by External Corrosion	Number of Recorded Failures Caused by Other than External Corrosion
Secret Cove North 273	12.3	448	10.3	1990	29	Fusion Bond Epoxy	Cold Applied Polymer Tape or Liquid Epoxy	0	Yes	0	0
Secret Cove South 273	12.3	448	10.3	1990	29	Fusion Bond Epoxy	Cold Applied Polymer Tape or Liquid Epoxy	0	Yes	0	0
Texada Island 273	50.1	448	6.4	1990	29	Extruded Polyethylene	Heat Shrink Sleeves	0	Yes	0	0
Tilbury Benson 323	5.9	205	6.4	1960	59	Coal Tar	Coal Tar	0	Yes	0	1
Tilbury Fraser 508	10.5	290	7.1	1959	60	Coal Tar	Coal Tar	100	Yes	0	0
Tilbury Lng Plant 323	1.9	290	6.4	1970	49	Extruded Polyethylene	Heat Shrink Sleeves	100	Yes	0	0
Trail Castlegar 219	24.0	290	4.8	1957	62	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	14	Yes	4	3
Vancouver Mainland 273	132.1	448	6.4/7.6	1990	29	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	4	Yes	0	3
Vancouver Mainland 323	31.5	448	10.8	1990	29	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	Yes	0	0
Vernon Penticton 323	99.6	359	7.9	1957	62	Asphalt Enamel	Asphalt Enamel	23	Yes	0	2
Yahk Oliver 610	303.0	484	7.9	2000	19	Fusion Bond Epoxy	Cold Applied Polymer Tape or Liquid Epoxy	4	Yes	0	0
Yahk Trail 323	164.4	359	4.8	1975	44	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	3	Yes	0	3
108 Mile Lateral 60	0.1	240	3.9	1998	21	Unknown	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
150 Mile House 60	0.1	240	3.9	1995	24	Unknown	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Afton Mines Lateral 114	0.7	240	4.0	1976	43	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Armstrong Lateral 114	0.4	240	4.8	1957	62	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	100	No	0	0

Pipeline Name	Line Length (kilometres)	Grade (MPa)	Wall Thickness (mm)	Year Installed	Age	Pipe Coating Type	Joint Coating Type	% of Class 3	In-line Inspection Capable?	Number of Recorded Failures Caused by External Corrosion	Number of Recorded Failures Caused by Other than External Corrosion
Ashcroft Lateral 60/88/168	9.1	240	3.9	1993	26	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	2	No	0	0
Bear Lake Lateral 60	1.2	205	3.9	1964	55	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Byron Creek Lateral 114	11.6	240	3.2	1985	34	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Cache Creek Lateral 60	1.4	240	4.0	1971	48	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Chase Lateral 88	30.3	290	3.2	1985	34	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	1
Chute Lake Lateral 88	0.1	240	5.5	2002	17	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	100	No	0	0
Clinton Lateral 60	21.7	240	3.2	1969	50	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Coldstream Lateral 114	4.1	240	4.8	1969	50	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	11	No	0	0
Cominco Lateral 114	1.0	240	4.8	1958	61	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Creston Lateral 114	6.9	240	3.2	1962	57	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	14	No	0	0
Dallas Lateral 60	0.1	240	3.9	1972	47	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	100	No	0	0
Deadman Creek Lateral 26	0.1	205	2.9	1990	29	Unknown	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Dunkley Mills Loop 114	4.2	240	3.2	2004	15	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Dunkley Mills Lateral 60	5.7	240	3.2	1980	39	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0

Pipeline Name	Line Length (kilometres)	Grade (MPa)	Wall Thickness (mm)	Year Installed	Age	Pipe Coating Type	Joint Coating Type	% of Class 3	In-line Inspection Capable?	Number of Recorded Failures Caused by External Corrosion	Number of Recorded Failures Caused by Other than External Corrosion
Elko Lateral 88	0.9	240	4.0	1969	50	Unknown	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	1
Enderby Lateral 114	0.2	240	4.8	1957	62	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	100	No	0	0
Fernie Lateral South Loop 114	7.9	290	4.8	1998	21	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Fernie Lateral North Loop 88	12.0	290	4.0	1991	28	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Fernie Lateral 88.9/168	23.1	240	3.2	1962	57	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	1	4
Finlay Forest Industries Loop 114	4.2	205	3.9	1981	38	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Finlay Forest Industries Lateral 60	4.3	205	3.9	1966	53	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Fort Nelson Loop 114	0.7	240	4.0	1985	34	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Galloway Lateral 60	9.6	240	3.2	1981	38	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	1	0
Gibralter Mines Lateral 60	10.2	240	3.9	1971	48	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Grand Forks Lateral 114	0.9	240	4.8	1957	62	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Green Lake Lateral 33	0.0	240	4.5	1993	26	Unknown	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
High Country Estates Lateral 60	0.6	240	3.2	1975	44	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Hudson Hope Lateral 60	10.0	205	3.9	1965	54	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0

Pipeline Name	Line Length (kilometres)	Grade (MPa)	Wall Thickness (mm)	Year Installed	Age	Pipe Coating Type	Joint Coating Type	% of Class 3	In-line Inspection Capable?	Number of Recorded Failures Caused by External Corrosion	Number of Recorded Failures Caused by Other than External Corrosion
Highmont Mine Lateral 60	2.9	290	3.2	1979	40	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	1
Horse Lake Lateral 60	0.0	240	5.5	1993	26	Unknown	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	100	No	0	0
Highland Valley Lateral 114	16.3	240	3.9	1971	48	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Kamloops 2 Lateral 114	1.1	240	4.8	1957	62	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	68	No	0	0
Kimberley Lateral 114	2.2	240	3.2	1962	57	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	24	No	0	0
Kelowna 1 Lateral 114	2.1	240	4.8	1957	62	Polyethylene Tape	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	31	No	0	0
Knutsford Lateral 60	4.2	290	3.2	1984	35	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Lac La Hache Lateral 60	0.2	240	3.9	2002	17	Unknown	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Ladysmith Lateral 114	1.0	360	4.9	2008	11	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	44	No	0	0
Lafarge Cement Lateral 114	3.3	240	4.8	1969	50	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Logan Lake Lateral 60	0.7	205	3.9	1971	48	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Line Creek Lateral 114	2.8	240	4.0	1981	38	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Louisiana Pacific Lateral 114	9.4	205	4.0	1995	24	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Marysville Lateral 60	0.9	240	3.9	1962	57	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	100	No	0	0

Pipeline Name	Line Length (kilometres)	Grade (MPa)	Wall Thickness (mm)	Year Installed	Age	Pipe Coating Type	Joint Coating Type	% of Class 3	In-line Inspection Capable?	Number of Recorded Failures Caused by External Corrosion	Number of Recorded Failures Caused by Other than External Corrosion
Merritt Lateral 114	4.9	240	3.9	1957	62	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	13	No	0	0
Moan Road Lateral 60	0.7	240	3.9	1995	24	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Mt Hayes Lateral 114	5.4	360	4.5	2010	9	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
North West Energy Lateral 114	6.4	240	3.9	1993	26	Fusion Bond Epoxy	Heat Shrink Sleeve or Cold Applied Polymer Tape	0	No	0	0
Oliver Lateral 114	2.0	240	4.8	1957	62	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	87	No	0	0
Osoyoos Lateral 114	20.9	240	4.8	1957	62	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	3	No	0	0
Port Mellon Lateral 114	0.7	359	4.0	1990	29	Extruded Polyethylene	Heat Shrink Sleeves	0	No	0	0
Princeton Lateral 88	67.0	240	4.8	1968	51	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Powell River 114	1.1	360	5.5	1991	28	Extruded Polyethylene	Heat Shrink Sleeves	90	No	0	0
Quesnel 2 Lateral 114	2.8	290	4.0	1982	37	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Rossland Lateral 114	1.1	290	4.8	1957	62	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	45	No	0	0
Salmon Arm Lateral 114	44.3	240	4.8	1957	62	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	14	No	0	2
Savona Lateral 60	1.5	240	3.9	1958	61	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	58	No	0	0
Shoreacres Lateral 114	0.3	290	4.8	1993	26	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0

Pipeline Name	Line Length (kilometres)	Grade (MPa)	Wall Thickness (mm)	Year Installed	Age	Pipe Coating Type	Joint Coating Type	% of Class 3	In-line Inspection Capable?	Number of Recorded Failures Caused by External Corrosion	Number of Recorded Failures Caused by Other than External Corrosion
Silver Creek Lateral 60	6.7	290	3.2	1985	34	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Sorrento Lateral 114	24.7	290	3.2	1985	34	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	7	No	0	0
Spallumcheen Lateral 114	3.4	240	4.8	1995	24	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Sparwood Lateral 114	8.8	240	4.8	1969	50	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Summerland Lateral 114	16.0	240	4.8	1957	62	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	45	No	0	1
Swan Lake Lateral 60	1.6	240	3.9	1967	52	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Fort Nelson Tackama Forest Lateral 60	1.6	240	3.9	1975	44	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Tilbury Lng Plant 168	1.7	205	4.8	1971	48	Extruded Polyethylene	Heat Shrink Sleeves	100	No	0	0
Vernon 1 Lateral 114	0.6	240	4.8	1957	62	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	100	No	0	0
Westar Timber Lateral 60	1.0	290	3.2	1988	31	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Williams Lake Lateral 114	10.0	240	4.0	1957	62	Asphalt Enamel	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0
Wildwood Lateral 60	0.5	290	3.2	1982	37	Extruded Polyethylene	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0	0

8.3 Please describe any assessments to evaluate CP coverage at sites where corrosion was identified and provide the results of these assessments.

Response:

FEI's cathodic protection (CP) system evaluation and integrity dig programs are independent activities within its Integrity Management Program – Pipelines and are conducted independently due to their differing logistical and resourcing requirements. FEI's CP system evaluation ensures CP coverage for FEI's transmission pipelines, and FEI confirms that its transmission pipelines have CP coverage.

During all integrity digs, FEI observes cathodic protection deposits and/or corrosion products (including pH, colour, texture, and concentration) to evaluate whether active corrosion is occurring. The results of those assessments indicate that FEI is experiencing active corrosion on cathodically protected pipe.

8.3.1 On each occasion when CP was insufficient (CP system operating below NACE SP0169 criteria), please describe the CP issue and how it was resolved.

Response:

Please refer to the response to BCUC IR 1.8.3.

8.4 Please describe any assessments to evaluate soil conditions at sites where corrosion was identified, including soil type, pH, water content, and soil movement and provide the results of these assessments.

Response:

The Canadian Association of Petroleum Producers Best Management Practices report "Mitigation of External Corrosion on Buried Carbon Steel Gas Pipeline Systems" (July 2018), as referenced in the question for CEC IR 1.8.1, contains the following excerpt (Section 4.1): "Although the corrosion rates may vary, it is generally accepted that all soils are corrosive." FEI's assessment is that its transmission pipeline system performance is consistent with this statement. That is, corrosion is a relevant hazard regardless of soil type, pH, water content, and soil movement and as such further assessments are not required to make this determination.

As included in the response to BCUC IR 1.8.1.1, various data sets are recorded and considered during integrity digs and are used to check whether it is plausible to find corrosion at the dig site under the given conditions.

8.4.1 What steps has FEI taken or could it take to modify soil conditions so as to reduce corrosion rates at the locations where corrosion has occurred?

Response:

FEI does not believe it is practicable or cost-effective to modify the environment surrounding a pipeline in an attempt to influence the corrosion rate. FEI is not aware of any transmission pipeline operators who have considered this to be a feasible external corrosion management strategy.

8.5 Please describe any assessments to evaluate coating degradation or disbondment at the sites where corrosion was identified, including identification of any contributing factors such as excessive operating temperature, pipe movement, ground movement or excessive CP current, and provide the results of these assessments.

Response:

Please refer to the response to BCUC IR 1.8.1.1 for a list of data sets recorded and considered during FEI's integrity digs. FEI uses coating degradation or disbondment data in a qualitative manner to confirm the plausibility of corrosion imperfections at each dig site and to determine whether the information indicates localized system or operational issues such as a high gas outlet temperature from a nearby compressor station, soil subsidence/slope movement, or backfill impacting the coating.

Otherwise, FEI believes there is no evidence to suggest that further assessments to evaluate coating degradation or disbondment would add value to its Integrity Management Program for

Pipelines and its lifecycle operation of its transmission pipelines. As demonstrated through the evaluation of the PLE alternative in the Application (see Sections 4.4.4.1 and 4.5), undertaking extensive pipeline coating rehabilitation of an operating pipeline is inferior to other alternatives, based on technical factors as well as project execution and lifecycle operation. Therefore, the PLE alternative is not commonly applied by transmission pipeline operators.

Once coating degradation or disbondment occurs (absent a coating rehabilitation program), the remaining reasonable mitigation measures over the lifecycle of the asset are to continue to apply and monitor cathodic protection as well as to monitor for corrosion. In-line inspection provides an effective corrosion monitoring strategy.

Within its in-line inspection activity, FEI's repair decisions are currently made on the basis of the condition of the pipeline steel (e.g., the loss of wall thickness due to corrosion) rather than on the condition of coatings.

8.5.1 For each occasion where coating degradation or disbondment was a concern, please describe how it was resolved.

Response:

During all integrity digs, regardless of observed coating degradation or disbondment, the full length of inspected pipe is re-coated to FEI's current standards.

9.0 Reference: PROJECT JUSTIFICATION

Exhibit B-1, Sections 1.2.3, 3.4.3, pp. 6, 22

Integrity Management Program

On page 22 of the Application, FEI states:

> 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."

On page 6 of the Application, FEI states:

> The PRS alternative involves the construction of a pressure regulating station to lower the maximum operating pressure of the lateral to below 30% SMYS. When operating at these reduced stress levels, it is generally accepted that pipeline failures due to pressure-dependent hazards (e.g. corrosion) will have the potential to leak rather than rupture, significantly reducing the potential consequences of failure…
>
> …The PLR alternative involves replacing the existing pipeline with a new pipeline including accommodations for future ILI capability with limited retrofits. This option allows for the corrosion-related rupture potential to be mitigated by designing the pipe with an operating stress of less than 30 percent SMYS. When operating at reduced stress levels, it is generally accepted that pipeline failures due to pressure-dependent hazards such as corrosion will have the potential to leak rather than rupture, significantly reducing the potential consequences of failure.

9.1 Please discuss whether the CSA Z662 requirement to monitor for external corrosion that can lead to a pipeline failure, and to eliminate or mitigate external corrosion, is adequately addressed by: (i) the PRS alternative; and (ii) the PLR alternative.

<u>Response:</u>

This response also addresses BCUC IR 1.9.3.

All of FEI's proposed alternatives (ILI, PRS, and PLR) meet FEI's legal and regulatory obligations, including those expressed within the *Oil and Gas Activities Act* (OGAA) and CSA

Z662. In proposing the ILI, PRS, and PLR alternatives, FEI considered its legal and regulatory obligations, which include CSA Z662, 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.

Consistent with CSA Z662 requirements, FEI's primary objective with its Integrity Management Policy and Integrity Management Program for Pipelines (IMP-P) is to prevent failure incidents that could result in significant safety, environmental, and/or reliability consequences. FEI's IMP-P and the IGU Project address CSA Z662 requirements to monitor for external corrosion that can lead to a pipeline failure and to mitigate external corrosion.

For the purposes of its Pipe Condition activities, including ILI, FEI's IMP-P differentiates assets (and associated activities) by their operating hoop stress expressed as a percentage of the specified minimum yield strength (SMYS) of the pipe. This is because the potential for rupture failure due to external corrosion is mitigated for an asset operating at less than 30 percent SMYS. CSA Z662-15 Clause 12.1.1, under the main Clause 12 entitled "Gas distribution systems", states: "Where specifically referenced, some requirements are applicable to piping for systems other than gas distribution systems, provided that any steel piping is intended to be operated at hoop stresses of less than 30 percent of the specified minimum yield strength of the pipe."[3]

The PRS and PLR alternatives will result in laterals operating at less than 30 percent SMYS of the pipe. As with all FEI pipelines operating at less than 30 percent SMYS, these laterals will be subject to recurring operational activities, such as CP Surveillance and leak detection, in compliance with Clause 12, CSA Z662-15. Clause 12.10.3.3 (d) states:

> Where the condition of distribution or service lines, as indicated by leak records or visual observation, deteriorates to the point where they are not suitable in service, they shall be replaced, reconditioned, or abandoned.

Clause 12.10.3.3 (d) implies that it may be appropriate for an operator of a gas distribution system to wait for an occurrence of leaks on its system prior to implementing a significant condition monitoring program (such as a regular in-line inspection program) or mitigation (replacement, reconditioning, or abandonment). FEI's lifecycle integrity management strategies, including CP Surveillance and leak detection, for pipelines operated at hoop stresses of less than 30 percent of the SMYS balances Clause 12.10.3.3 (d) relative to FEI's obligation as a Permit Holder under Section 37 (1) (a) of the OGAA to "prevent spillage".

For further context, and in response to BCUC IR 1.9.3, the regulatory requirements for corrosion monitoring, CP surveillance and leak detection on a gas pipeline operating at a pressure below

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[3] Source: Clause 12.1.1, CAN/CSA Z662-15 – Oil and Gas Pipeline Systems. © 2015 Canadian Standard Association.

30 percent SMYS and on a gas pipeline operating at a pressure above 30 percent SMYS are detailed below.

The legal and regulatory provisions applicable to FEI's gas system assets are typically goal-oriented rather than prescriptive in nature. In other words, the requirements of pipeline operators are typically expressed as outcomes to be achieved rather than as descriptions of how to achieve those outcomes. An example of an outcome-based requirement for pipeline operators in British Columbia is from Section 37 (1) (a) of the OGAA, that requires Permit Holders to "prevent spillage"[4] associated with the operation of pipelines operating at or above 700 kPa. The OGAA applies to pipelines operating at or above 700 kPa, without consideration to the operating hoop stress (i.e., above or below 30 percent SMYS).

Section 3 (1) (a) of the British Columbia Pipeline Regulation (B.C. Reg. 147/2014) requires that pipelines be designed, constructed, operated, and maintained in accordance with the Canadian Standards Association (CSA) Z662[5] standard. The CSA Z662 standard is also typically outcome-based rather than prescriptive[6].

In the table below, FEI has excerpted what it believes are the most relevant CSA Z662 sections pertaining to corrosion monitoring, CP surveillance, and leak detection.

	Gas pipelines operating at greater than or equal to 30 percent SMYS	Gas pipelines operating at less than 30 percent SMYS
Corrosion Monitoring	CSA Z662-15, Clause 10.3.1 states: "The pipeline system integrity management program required by Clause 3.2 shall include procedures to monitor for conditions that can lead to failures, to eliminate or mitigate such conditions, and to manage integrity data." (Source: Clause 3.2, **CAN/CSA Z662-15 – Oil and Gas Pipeline**	For gas pipelines operating at less than 30 percent SMYS, CSA Z662-15, Clause 10.3.1 is superseded by CSA Z662-15, Clause 12.10.3.3, which only applies to piping operating at hoop stresses of less than 30% of SMYS,[8] and states: "Leak management shall be subject to the following requirements: … (c) Upon discovery, all leaks shall be immediately assessed and documented by

[4] "Spillage", as defined in the OGAA, means "petroleum, natural gas, oil, solids or other substances escaping, leaking or spilling from (a) a pipeline, well, shot hole, flow line, or facility, or (b) any source apparently associated with any of those substances."

[5] "CSA Z662", as defined in the Pipeline Regulation, means "the standard published by the Canadian Standards Association as CSA Z662, Oil and Gas Pipeline Systems, as amended from time to time." It is typically republished every 4 years, with the most recent version being released in June 2015 and hence is referred to as CSA Z662-15 in this Application.

[6] CSA Z662 Clause 1.4 states, "This Standard is intended to establish essential requirements and minimum standards for the design, construction, operation, and maintenance of oil and gas industry pipeline systems. This Standard is not a design handbook, and competent engineering judgment should be employed with its use."

	Gas pipelines operating at greater than or equal to 30 percent SMYS	Gas pipelines operating at less than 30 percent SMYS
	Systems. © 2015 Canadian Standard Association)[7]	competent personnel in accordance with the company's established guidelines to determine if a hazard exists. (…) (d) Where the condition of distribution or service lines, as indicated by leak records or visual observation, deteriorates to the point where they are not suitable in service, they shall be replaced, reconditioned, or abandoned." (Source: Clause 10.3.1, **CAN/CSA Z662-15 – Oil and Gas Pipeline Systems**. © 2015 Canadian Standard Association)[9]
CP Surveillance	CSA Z662-15, Clause 9.9.1 states: "At regular intervals, operating companies shall verify the satisfactory operation of their cathodic protection systems. CGA OCC-1, Section 4, shall be considered for monitoring and frequency guidelines." (Source: Clause 9.9.1, **CAN/CSA Z662-15 – Oil and Gas Pipeline Systems**. © 2015 Canadian Standard Association) [10]	CSA Z662, Clause 9.9.1 is also applicable to gas pipelines operating at less than 30 percent SMYS.
Leak Detection	CSA Z662-15, Clause 10.3.4.1 states: "Operating companies shall perform regular surveys or analyses for	CSA Z662-15, Clause 12.10.3.3 states: "Leak management shall be subject to the following requirements:

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8 Clause 12.1.2, CAN/CSA Z662-15 – Oil and Gas Pipeline Systems. © 2015 Canadian Standard Association.

7 With the permission of Canadian Standards Association, (operating as "CSA Group"), 178 Rexdale Blvd., Toronto, ON, M9W 1R3, material is reproduced from CSA Group's standard **CAN/CSA Z662-15 – Oil and Gas Pipeline Systems**. This material is not the complete and official position of CSA Group on the referenced subject, which is represented solely by the Standard in its entirety. While use of the material has been authorized, CSA Group is not responsible for the manner in which the data is presented, nor for any representations and interpretations. No further reproduction is permitted. For more information or to purchase standard(s) from CSA Group, please visit store.csagroup.org or call 1-800-463-6727.

9 Ibid.

10 Ibid.

	Gas pipelines operating at greater than or equal to 30 percent SMYS	Gas pipelines operating at less than 30 percent SMYS
	evidence of leaks." (Source: Clause 10.3.4.1, **CAN/CSA Z662-15 – Oil and Gas Pipeline Systems**. © 2015 Canadian Standard Association)[11]	(a) Operating companies shall establish, and document in their operating and maintenance procedures, provisions for regular surveys for detecting leaks. (…)" (Source: Clause 12.10.3.3, **CAN/CSA Z662-15 – Oil and Gas Pipeline Systems**. © 2015 Canadian Standard Association)[12]

9.2 Please discuss whether reducing operating pressure to below 30 percent SMYS is an appropriate, long-term response to FEI's obligations under OGAA.

Response:

Yes, reducing the operating pressure to below 30 percent SMYS is an appropriate, long-term response to FEI's obligations under OGAA. Please refer to the response to BCUC IR 1.9.1.

9.3 Please describe the regulatory requirements for corrosion monitoring, CP surveillance and leak detection on a gas pipeline operating at a pressure below 30 percent SMYS and on a gas pipeline operating at a pressure above 30 percent SMYS.

Response:

Please refer to the response to BCUC IR 1.9.1.

[11] Ibid.
[12] Ibid.

10.0 Reference: EMERGENCE OF ILI

Exhibit B-1, Section 3.4.4.2, pp. 23-24

Evolution of Integrity Management Technology and Activities

On page 24, FEI states

> 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 currently underway for determining particular pipelines that will require modifications in order to accommodate EMAT tools.

10.1 Please confirm, or otherwise explain, whether retrofitting for ILI would facilitate future adoption of EMAT tools.

Response:

Retrofitting for ILI will facilitate the ability for future adoption of EMAT tools. All Launcher/Receiver Assemblies (LRA) and fitting replacements will be designed and sized to meet current dimensional requirements for EMAT tools.

FEI notes, however, that EMAT tools are not currently available for natural gas transmission pipelines of nominal pipe size (NPS) 6 and NPS 8. Therefore, FEI has based its designs for this Project to accommodate tool lengths sized for EMAT tools that currently exist for larger diameter pipelines.

10.1.1 Please explain what additional work, if any, would be required before implementation of EMAT tools.

Response:

As included in Section 12.4.1.1 of FEI's Annual Review for 2019 Rates Application, future work that may be required before implementation of EMAT will be based on:

- Tool travel speed within the pipeline:
  - As compared to other currently adopted tools in FEI's inline inspection program, EMAT tools and technology require slower travel speeds inside of a pipeline. Complete data collection relies on adequate time being provided for signal travel

through the pipeline wall and for data collection by the tool. It is foreseeable that existing flow rates in FEI's pipelines may exceed EMAT tool specifications, requiring system-level modifications such as installation of pipeline loops to allow for necessary flow velocity control.

- As EMAT sensors must make direct contact with the internal surface of the pipe, they are designed with a tighter fit inside a pipeline as compared to other currently adopted ILI tools. The resulting increased drag forces have the potential to result in speed fluctuations that exceed tool specifications. It is therefore foreseeable that pipeline configurations (e.g., bends, wall-thickness transitions) that were not previously a concern may become an impediment to a successful EMAT inspection. Areas of concern would likely require pipe replacement to address EMAT tool incompatibilities.

- Tool length:
  - EMAT tools are typically longer than other ILI tools currently adopted by FEI. Tool length also contributes to increased drag forces. As above, this can result in pipeline configurations that were not previously a concern to become an impediment to a successful inspection.
  - Tool length may also necessitate modifications to launcher and receiver barrels used for loading and unloading ILI tools.
- Capability to reduce the operating pressure of transmission pipelines for extended time periods:
  - To enable appropriate engineering response to EMAT-identified anomalies and/or other time-dependent integrity concerns on its transmission pipeline system, FEI has determined that it needs to establish the capability to follow the common industry practice of implementing a 20 percent pressure reduction below the current operating pressure (which provides an equivalent safety factor of 1.25 to that current operating pressure) until such time that required mitigation and/or repair can be completed. To establish this capability without incurring interruption of customer supply could foreseeably require system modifications such as installation of pipeline loops.

10.2 Please confirm, or otherwise explain, whether the PLR alternative would facilitate future adoption of EMAT tools.

Response:

Please refer to the response to BCUC IR 1.10.1 and Section 5.2.3.6 of the Application. The PLR alternative will facilitate future adoption of in-line inspection (ILI), including current dimensional requirements for EMAT tools.

10.2.1 Please explain what additional work, if any, would be required before implementation of EMAT tools.

Response:

Please refer to the response to BCUC IR 1.10.1.1 for a description of future work that may be required before implementation of EMAT.

11.0 Reference: EMERGENCE OF ILI

Exhibit B-1, Section 3.4.4, pp. 22-23

Coastal Transmission System Retrofitted with ILI

On page 23 of the Application, FEI references its Coastal Transmission System mainline pipelines which have been retrofitted with ILI capability. FEI states: "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)."

11.1 Please discuss whether there were any material cost overruns in the TPIP.

<u>Response:</u>

This response also addresses BCUC IR 1.11.1.1.

TPIP expenditures were approved by BCUC Orders as presented in the table below. As shown by comparing actual expenditures to planned expenditures under each BCUC Order, there are no material cost overruns in the TPIP expenditures.

The following table provides a summary of TPIP expenditures, as approved by the indicated BCUC Orders:

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

11.1.1 If so, please explain the reason for any cost overrun and the variance to budget.

Response:

Please refer to the response to BCUC IR 1.11.1.

11.2 Please discuss whether there were any significant delays in the TPIP schedule.

Response:

There were no significant delays in the TPIP schedule.

11.2.1 If so, please explain the reason for any delay and impact to overall project schedule.

Response:

Please refer to the response to BCUC IR 1.11.2.

11.3 Please elaborate on any lessons learned through FEI's experience managing the TPIP.

Response:

FEI's experience managing the Transmission Pipeline Integrity Program from 2000 to 2005 resulted in lessons learned and improvements related to data collection, analysis, field inspection programs, and development of integrity plans that are specific to the unique requirements of each section of pipeline.

Data collection:

- FEI identified that CP shielding may necessitate future in-line inspection of pipelines not subject to ILI, and has reflected its learnings through this Application.

Analysis:

- FEI's experience in analyzing ILI data has informed its assessment of ILI as a preferred alternative on a technical basis.

Field inspection programs:

- FEI's experiences in implementing integrity digs has informed its scoring of relevant alternatives with respect to Project Execution and Lifecycle Operation.

Development of integrity plans specific to the unique requirements of each section of pipeline:

- Within this Application, FEI has recognized that each lateral warrants individual consideration to determine the most appropriate pipeline-specific integrity management solution.

Please refer to BCUC IR 1.11.4 for FEI's operational experiences, including learnings, related to running ILI tools in retrofitted pipelines, which includes pipelines retrofitted as part of the TPIP.

11.3.1 Please explain how these lessons learned influenced FEI's cost estimates and schedules for the IGU project.

<u>Response:</u>

Please refer to FEI's response to BCUC IR 1.11.3.

The ILI retrofit estimates for the IGU Project were founded on the criteria listed in the "Basis of Design and Engineering" in Section 5.2.1 of the Application. The criteria (e.g., replacement of all elbows or bends with a radius of curvature less than 1.5 D) was established based on current in-line inspection tool specifications, but also with consideration of FEI's operational experiences with running ILI tools in retrofitted pipelines as described in the response to BCUC IR 1.11.4.

11.4 Please discuss whether FEI has experienced any operational challenges with running ILI tools in retrofitted pipelines.

Response:

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

11.5 What is the typical cost for performing an ILI on a pipeline?

Response:

The cost for performing an ILI on a pipeline can range from $0.1 million (e.g., a shorter-length pipeline with minimal operational challenges) to over $1 million (e.g., a longer-length pipeline with significant operational challenges).

Further details on factors that affect the costs are described below:

- Vendor charges (including set up, mobilization, running the tool, analysis of data and production of field, preliminary and final reports) depend on:
  - Tool type (cleaning, geometry, conventional MFL, circumferential MFL, inertial mapping, EMAT);
  - Pipe diameter and length of line;
  - Condition of pipeline (e.g., repeat inspection vs. initial inspection); and
  - The services required (pipe movement assessment, corrosion growth assessment, detailed mechanical damage analysis, etc.).
- FEI operational costs (including crew and equipment to clean debris from within the pipeline, transport, load, track, and receive the ILI tool(s)) depend on:
  - Pipe diameter (equipment required);
  - Length of line (tool run time);

- The number of ILI tools to be run;
- Cleanliness of pipeline (number of cleaning runs required);
- The location of the line (mobilization, accommodations);
- Tool velocity requirements (tool dependent, tool run time); and
- Amount of effort required to achieve required flow rates (e.g., payment to 3rd parties to use gas in order for FEI to achieve faster and/or more predictable gas flow).

- Other contractor/supplier costs (cleaning of ILI tools and disposing of pipeline debris, provision of cleaning tools, transport and lifting of ILI tools); and
- FEI Integrity Engineering costs (tool selection, contract execution, and data analysis and integrity plan).

11.6 What are FEI's criteria for selecting the frequency of ILI inspection?

Response:

In accordance with FEI's internal standard 1062, "IMP-P: Threat Management for Piggable Pipelines", the frequency of ILI re-inspection is based on the following criteria:

- Type, number and size of anomalies detected in previous inspection;
- Confidence in results of previous inspection;
- Assessment of potential corrosion growth;
- Ability/need to do run to run comparisons using the same tool to identify growing anomalies.
- Ability/need to do run to run comparisons using the same tool to identify new mechanical damage (monitor effectiveness of third party damage prevention programs);
- Ability/need to do run to run comparisons using the same tool to identify pipeline movement (support natural hazard program, monitor effects of loading on or near the pipeline);

- Ability/need to do run to run comparisons using the same tool to identify new anomalies (for use in SCC management program, rehabilitation coating effectiveness monitoring, CP program effectiveness monitoring, identification of coating damage);
- Pipeline availability for in-line inspection due to operational constraints (bypasses, flow/load windows);
- Co-ordination of runs of same diameter pipelines to reduce tool mobilization cost;
- Scheduling of inspection runs (and subsequent dig programs) so that resource requirements are reasonably consistent year to year;
- Availability of new or improved inspections tools;
- Potential consequences of failure;
- Changes in operating conditions and construction of new sections within inspection segment (e.g., collection of baseline information, GPS information);
- Industry standard/leading practices; and
- Engineering judgment from Integrity Engineer(s).

FEI's re-runs of geometry and standard magnetic flux leakage tools are planned on a maximum 7-year interval.

C. DESCRIPTION AND EVALUATION OF ALTERNATIVES

12.0 Reference: ALTERNATIVES DESCRIPTION

Exhibit B-1, Section 4.2.1, p. 29

Status Quo: Modified ECDA Alternative

On page 29 of the Application, FEI states:

> Within its integrity Management Program – Pipelines (IMP-P), FEI's internal standard titled the 'IMP-P': Time-Dependent Threat Management of Non-Piggable Pipelines" (Appendices H-1 and H-2) contains modified version of the ANSI/NACE ECDA standard practice and is referred to as Modified ECDA…The primary difference between FEI's Modified ECDA and the ANSI/NACE ECDA is with respect to the determination of the required number of excavations. ECDA requires control digs where there has been no indication of potential corrosion from the above-ground surveys and requires supplementary digs where the information obtained from indirect inspections does not align with the results from direct examinations. FEI's Modified ECDA approach, instead, is less prescriptive and allows for variation in the number of digs performed based on FEI's assessment of the value of the dig.

12.1 Please provide the year that FEI implemented Modified ECDA.

<u>Response:</u>

FEI has been employing Modified ECDA since approximately 2005.

12.2 Please explain FEI's rationale for developing an internal standard ECDA (Modified ECDA).

<u>Response:</u>

This response also addresses BCUC IR 1.12.5.

FEI began applying Modified ECDA to its transmission pipeline system because of concerns that the extent of pipeline excavations required per the ANSI/NACE ECDA standard were not providing effective value. One concern was that applying the ANSI/NACE ECDA standard may result in unwarranted control digs and/or supplementary digs. A second concern was that application of the entire ANSI/NACE ECDA process may not be effective in mitigating the potential for external corrosion failure given that the electrical surveys used to measure levels of cathodic protection and coating quality are unable to detect areas that may be shielded from cathodic protection. This concern also applies to FEI's application of its Modified ECDA standard, but FEI considers that FEI's application of Modified ECDA allows it to meet its regulatory and legal obligations while remaining cost effective.

FEI mitigates the potential for failure of its transmission pipeline system through implementation of its Integrity Management Program – Pipelines (IMP-P). The IMP-P is a set of activities that 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.

Ideally, the value of each of FEI's integrity management activities would be determined by modeling the achieved reduction in risk, and comparing the risk reduction as a ratio to dollars spent (thus providing a measure of risk reduction per dollar spent). In absence of these capabilities, which in FEI's view are both difficult to quantify at this time and not a common practice amongst its peer operators, FEI instead uses a qualitative approach in assessing the value of its integrity management activities.

Factors considered in FEI's assessment of value associated with ECDA digs, and in its implementation of Modified ECDA in general, include the following:

- FEI's confidence in the degree of mitigation being achieved (i.e., effectiveness of the activity);
- Availability of alternative methodologies;
- FEI's understanding of industry practice; and
- Financial considerations (e.g., cost, availability of resources).

12.2.1 Please confirm, or explain otherwise, whether it is common industry practice to use a modified version of the ANSI/NACE standard.

Response:

FEI confirms that its Modified ECDA standard is consistent with industry practice in Canada. Through discussion with other companies' employees, FEI is informally aware of natural gas transmission pipeline operators (i.e., Canadian Energy Pipeline Association members) and natural gas utilities (i.e., Canadian Gas Association members) who have adopted a Modified ECDA approach.

Through its involvement in industry committees and other industry awareness activities, FEI is currently unaware of any Canadian natural gas transmission operators or natural gas utility operators that have adopted the ANSI/NACE ECDA standard without modification.

12.3 Please discuss whether FEI's use of Modified ECDA on its pipeline system complies with the applicable legislation and standards such as CSA Z662, as well as industry best management practice.

Response:

FEI's use of Modified ECDA complies with the applicable legislation and standards and with Canadian industry practice. Please refer to the responses to BCUC IRs 1.6.5, 1.9.1 and 1.12.2.1.

12.4 Please discuss whether FEI has participated in the Oil and Gas Commission's compliance assurance process for integrity management programs.

Response:

Confirmed. Please refer to response to BCUC IR 1.6.5.

12.4.1 If so, please discuss any findings for compliance and good practices along with supporting evidence, areas where additional information may be required, opportunities for improvement and observed non-compliances with respect to the use of Modified ECDA.

Response:

Please refer to the response to BCUC IR 1.6.5. There were no findings related to FEI's use of Modified ECDA.

12.4.2 If applicable, please discuss any corrective action FEI has taken or could take to address any identified non-compliance findings with respect to the use of Modified ECDA.

Response:

Please refer to the response to BCUC IR 1.6.5. There were no non-compliance findings with respect to the use of Modified ECDA.

12.5 Please discuss FEI's method for assessing the "value of the dig."

Response:

Please refer to the response to BCUC IR 1.12.2.

12.5.1 What is the typical cost of an integrity dig?

Response:

The scope of work required for integrity digs has significant variation depending on location, surface and subsurface conditions, depth, proximity to geographic features (i.e., river crossings, environmental zones, and highways), season, and the number of imperfections requiring visual inspection. Consequently, the cost of integrity digs can range from $10 thousand (e.g., for shorter-length excavation sites, sites easily accessible to equipment, work requiring minimal permits and environmental impacts, and requiring minimal site restoration costs) to over $150 thousand (e.g., for complex digs below a remote stream location).

12.5.2 What are FEI's criteria for selecting dig location and the number of digs?

Response:

As part of FEI's implementation of Modified ECDA, dig sites are identified by evaluation of above-ground cathodic protection survey and coating evaluation data.

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

The first table contains the criteria for identifying High or Medium Priority. The second table contains the criteria for classifying the indications (data) from the above-ground surveys ("Minor", "Moderate", or "Severe").

FEI Modified ECDA Dig Priority Ranking

High Priority	• Areas displaying multiple "severe" indications in close proximity • Areas with at least one "severe" indication, which is classified as severe by more than one indirect inspection technique • Areas with at least one moderate indication having a history of corrosion failure (leak)
Medium Priority	• Areas displaying multiple severe and moderate or multiple moderate indications in close proximity • Areas with minor indications having a prior leak history • Areas with isolated severe indications

FEI Modified ECDA Indirect Inspection Indication Severity Classifications

Above-Ground Survey Method	Analyzed Criteria	Minor	Moderate	Severe
Close Interval Survey - ICCP (CIS)	-850mV Polarized Criteria Applied	Minor dips where "Off" Potential more electro-negative than -850mV CSE	Medium dips where "Off" potential between -850mV and -750mV CSE	Large dips where "off" potential more electro-positive than -750mV CSE
	100mV Polarization Shift	100mV polarization shift achieved	50 to 99mV polarization shift achieved	0 to 49mV polarization shift achieved
	On/Off Shift	>= 100mV	50mV - 100mV	0-50mV

Above-Ground Survey Method	Analyzed Criteria	Minor	Moderate	Severe
Close Interval Survey - GCP (CIS)	-1V CSE "On"	Minor dips where potential more electro-negative than -1V CSE	Medium dips where potential between -1V and -850mV CSE	Large dips where potential more electro possitive than -850mV CSE
Current Attenuation Survey (ACCA)	% Current Drop	0 to 25%	25 to 40%	> 40%
	Attenuation mdB(mA)/m	0 to -2	-2 to -4	> -4
	% Attenuation	0 to 6%	6 to 10%	> 10%
AC Voltage Gradient Survey (ACVG)	dbuV	30 to 50 dbuV	50 to 70 dbuV	>70 dbuV
	mV (source)	30mV to 300mV	300mV to 3000mV	>3000mV
	mV (from baseline)	0-50mV	50mV to 150mV	>= 150mV
DC Voltage Gradient Survey (DCVG)	%IR	10 - 35%	35 - 50%	50 - 100%
	%IR in concert with sub-criteria CP	> 15%	5-15%	0-5%

12.6 Please provide in table format the number of integrity digs for each of the 29 Transmission Laterals that would have been prescribed under the ANSI/NACE ECDA standard.

<u>Response:</u>

This response also addresses BCUC IRs 1.12.6.1 and 1.12.7.

For those of the 29 Transmission Laterals that FEI has surveyed with all relevant above-ground survey methods, FEI has estimated in the table below the number of integrity digs that would have been prescribed under the ANSI/NACE ECDA standard. For those pipelines where the relevant surveys are scheduled in future years, an estimate is not feasible given the lack of available information to inform such an estimate.

FEI notes that there is significant uncertainty in any attempt to estimate the number of digs that would have been prescribed under the ANSI/NACE ECDA standard without actually applying the standard and undertaking all of the process steps involved. For example, one of the steps involved in the ANSI/NACE ECDA standard is to define “ECDA Regions”. An ECDA Region is defined in the ANSI/NACE standard as “A section or sections of a pipeline that have similar physical characteristics, corrosion histories, expected future corrosion conditions, and in which the same indirect inspection tools are used." If the number of regions determined through an ANSI/NACE pre-assessment were higher than FEI has estimated in the table, FEI's estimates of Control Digs and Process Verification Digs would be low.

Further, FEI notes that it is possible that Process Verification Digs may be required as a result of "reclassification". Reclassification is required by the ANSI/NACE ECDA standard if results from digs do not match expectations from above-ground surveys (as mentioned in Section 4.2.1 of the Application, under the description for Direct Examination). In the event of reclassification, FEI's estimates would also be low.

As such, FEI has characterized many of its estimates in the table below as "minimums". Additionally, future recurring digs required by the ANSI/NACE ECDA standard are not included in this table.

The table below also includes the percentage of the integrity digs prescribed under the ANSI/NACE ECDA standard that would be control digs, as requested by BCUC IR 1.12.6.1. It also includes the number of digs identified by FEI's application of its Modified ECDA standard, as requested by BCUC IR 1.12.7.

Line/Loop ID No.	Line/Loop Full Name	Length (km)	BCUC IR 1.12.6 and 1.12.6.1: Estimate of digs that would have been prescribed under the ANSI/NACE ECDA standard						BCUC IR 1.12.7: Digs identified by FEI's Modified ECDA standard	
			High Priority Digs (#)	Medium Priority Digs (#)	Control Digs	Process Verification Digs	Process Verification Digs resulting from reclassification	% of Control Digs and/or Process Verification Digs (BCUC IR 1.12.6.1)	High Priority Digs (#)	Medium Priority Digs (#)
1	Mackenzie Lateral 168	28.6	2	5	min. 4	min. 4	unknown	min. 53%	2	5
2	Mackenzie Loop 168	14.2	2	1	min. 2	min. 2	unknown	min. 57%	2	1
3	BC Forest Products Lateral 168	0.5	0	2	min. 2	min. 2	unknown	min. 67%	0	2
4	Prince George 3 Lateral 219	5.3	0	2	min. 2	min. 2	unknown	min. 67%	0	2
5	Northwood Pulp Lateral 168	6.0	0	1	min. 2	min. 2	unknown	min. 80%	0	1
6	Northwood Pulp Loop 219	5.8	0	0	min. 2	min. 2	unknown	100%	0	0
7	Prince George 1 Lateral 168	4.7	0	0	min. 2	min. 2	unknown	100%	0	0
8	Prince George Pulp Lateral 168	1.0	0	4	min. 2	min. 2	unknown	min. 50%	0	4
9	Husky Oil Lateral 168	1.1	0	0	min. 2	min. 2	unknown	100%	0	0
10	Prince George 2 Lateral 219	8.6	0	0	min. 2	min. 2	unknown	100%	0	0
11	Cariboo Pulp Lateral 168	1.3	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
12	Williams Lake Loop 168	5.9	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
13	Kamloops 1	6.7	0	5	min. 2	min. 2	unknown	min. 44%	0	5

			BCUC IR 1.12.6 and 1.12.6.1: Estimate of digs that would have been prescribed under the ANSI/NACE ECDA standard						BCUC IR 1.12.7: Digs identified by FEI's Modified ECDA standard	
Line/Loop ID No.	Line/Loop Full Name	Length (km)	High Priority Digs (#)	Medium Priority Digs (#)	Control Digs	Process Verification Digs	Process Verification Digs resulting from reclassification	% of Control Digs and/or Process Verification Digs (BCUC IR 1.12.6.1)	High Priority Digs (#)	Medium Priority Digs (#)
	Lateral/Loop 168									
14	Salmon Arm Loop 168	44.9	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
15	Salmon Arm 3 Lateral 168	0.8	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
16	Coldstream Lateral 219	1.8	0	0	min. 2	min. 2	unknown	100%	0	0
17	Coldstream Loop 168	3.8	0	0	min. 2	min. 2	unknown	100%	0	0
18	Kelowna 1 Loop 219	2.1	0	0	min. 2	nin. 2	unknown	100%	0	0
19	Celgar Lateral 168	5.8	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
20	Castlegar Nelson 168	37.4	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
21	Trail Lateral 168	4.2	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
22	Fording Lateral 219/168	79.6	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
23	Elkview Lateral 168	1.6	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
24	Cranbrook Lateral 168	34.0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
25	Cranbrook Loop 219	34.0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
26	Cranbrook Kimberley	4.0	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

			BCUC IR 1.12.6 and 1.12.6.1: Estimate of digs that would have been prescribed under the ANSI/NACE ECDA standard						BCUC IR 1.12.7: Digs identified by FEI's Modified ECDA standard	
Line/Loop ID No.	Line/Loop Full Name	Length (km)	High Priority Digs (#)	Medium Priority Digs (#)	Control Digs	Process Verification Digs	Process Verification Digs resulting from reclassification	% of Control Digs and/or Process Verification Digs (BCUC IR 1.12.6.1)	High Priority Digs (#)	Medium Priority Digs (#)
	Loop 219									
27	Cranbrook Kimberley Loop 273	9.4	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
28	Kimberley Lateral 168	20.6	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
29	Skookumchuck Lateral 219	35.9	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

12.6.1 What percentage of the integrity digs prescribed under the ANSI/NACE ECDA standard are control digs?

Response:

Please refer to the response to BCUC IR 1.12.6.

12.7 Please provide in table format the number of integrity digs for each of the 29 Transmission Laterals using the FEI Modified ECDA.

Response:

Please refer to the response to BCUC IR 1.12.6.

13.0 Reference: ALTERNATIVES EVALUATION METHODOLOGY

Exhibit B-1, Sections 4.1, 4.5.4, pp. 27-28, 46-47, Table 4-10

PRS Alternative

On page 27 of the Application, FEI states: "Where PRS was viable, it was chosen as the preferred alternative for all laterals except for one because it met the objective of the Project at the lowest cost and rate impact, and with limited ground disturbance and public impacts."

Table 4-10 on page 47 of the Application provides the PV of incremental revenue requirements over a 66-year analysis period for the 29 Transmission Laterals.

Table 4-10 also shows that PRS was selected as the preferred alternative for 14 of the laterals.

13.1 Please confirm, or explain otherwise, that all of the Transmission Laterals where PRS is selected as the preferred alternative will reach the end of their useful life before the end of the 66-year analysis period.

<u>Response:</u>

Please refer to the response to BCUC IR 1.1.1 for a discussion of remaining useful life.

From an asset accounting perspective, the expected financial life of a transmission pipeline is 65 years. On that basis, FEI confirms that the transmission laterals where PRS is selected as the preferred alternative would be fully depreciated before the end of the 66-year analysis period. However, as described in the response to BCUC IR 1.1.1, there are many factors that impact the actual physical life of a pipeline. Dependent on design, construction, maintenance and monitoring, the physical life of a pipeline may exceed its financial life.

13.2 Please explain if each of the 14 Transmission Laterals selected for the PRS alternative will require replacement during the 66-year analysis period.

<u>Response:</u>

At this time, FEI has no information or evidence to support the premise that any or all of the 14 transmission laterals selected for PRS will require replacement during the 66-year analysis period. Please refer to the response to BCUC IR 1.1.1.

13.2.1 If yes, please explain why the cost to replace the pipeline has not been included in the PV of incremental revenue requirement financial analysis for each of the laterals.

Response:

Please refer to the responses to BCUC IRs 1.13.1 and 1.13.2.

13.2.2 If no, please explain why replacement will not be necessary.

Response:

Please refer to the responses to BCUC IRs 1.13.1 and 1.13.2.

13.3 If the replacement cost of the pipeline at the end of 14 Transmission Laterals' useful life was factored into the financial analysis, would PRS still be the preferred alternative for each of the applicable laterals? Please explain and provide all supporting calculations and assumptions.

Response:

As stated in response to BCUC IR 1.13.2, FEI has no basis upon which to forecast replacement or modification for in-line inspection for these 14 transmission laterals when they reach the end of their financial life of 65 years. As a result, FEI does not believe future PLR or ILI cost should be accounted for when there is no definitive end of physical life based on the information available to FEI.

Notwithstanding this, in order to be responsive, for the 14 transmission laterals with PRS as the preferred option, the following table compares the PV of incremental revenue requirements over a 66-year analysis period between ILI, PLR, and PRS with the assumption that either PLR or ILI will be required at some point during the 66-year analysis period after PRS is implemented.

Please note the following assumptions used in this comparison:

- The future ILI or PLR will be required when the pipeline reaches the expected asset financial life of 65 years. Please refer to FEI's response to BCUC IR 1.1.1 for the expected remaining asset financial life of each lateral;
- FEI does not assume PLR is the only option in the future. For the purpose of this comparison, FEI chooses the least cost option between ILI and PLR for the future work; and
- For the capital cost estimate, FEI used today's capital cost estimate for PLR or ILI plus inflation.

Line / Loop ID	Lateral	Preferred Alternatives (As-Filed)	Alternative with the lowest PV of Revenue Requirement (When future ILI/PLR is included)	ILI Present Value ($000s	PLR Present Value ($000s)	PRS Present Value ($000s)	Future Option if Preferred Altnative is PRS (ILI/PLR)	Assumed number of Years until (ILI/PLR)
4	Prince George 3 Lateral 219	PRS	PRS	14,315	-	11,265	ILI	16
5	Northwood Pulp Lateral 168	PRS	PRS	15,379	-	13,877	ILI	11
6	Northwood Pulp Loop 219	PRS	PRS	14,056	-	5,269	ILI	41
8	Prince George Pulp Lateral 168	PRS	PLR	14,331	7,727	9,387	PLR	10
9	Husky Oil Lateral 168	PRS	PLR	16,392	5,601	6,020	PLR	26
10	Prince George #2 Lateral 219	PRS	PRS	15,839	-	11,769	ILI	31
12	Williams Lake Loop 168	PRS	PRS	15,692	-	9,829	ILI	39
16	Coldstream Lat 219	PRS	PRS	13,159	9,334	7,742	PLR	44
17	Coldstream Loop 168	PRS	PRS	14,241	-	10,253	ILI	35
18	Kelowna 1 Loop 219	PRS	PRS	13,969	-	12,526	ILI	28
19	Celgar Lateral 168	PRS	ILI	11,731	-	13,314	ILI	6
20	Castlegar Nelson 168	PRS	PRS	54,183	-	49,146	ILI	5
21	Trail Lateral 168	PRS	ILI	19,043	-	19,823	ILI	5
23	Elkview Lateral 168	PRS	PLR	10,072	5,850	10,333	PLR	16

The comparison showed that PRS would not provide the lowest PV of revenue requirements over a 66-year analysis period for five out of the 14 transmission laterals if PLR or ILI alternatives are required to be implemented when the lateral reaches the expected asset financial life of 65 years (highlighted in table above).

FEI has proposed PRS because it believes it is the most cost effective solution for these 14 transmission laterals to achieve the IGU Project objective of mitigating the potential for rupture failure while potentially deferring a higher cost alternative such as ILI or PLR indefinitely.

14.0 Reference: ALTERNATIVES DESCRIPTION

Exhibit B-1, Sections 4.2.4, 4.4.3, pp. 30, 39

PRS Alternative

On page 30 of the Application, FEI states: "PRS is not feasible for all laterals. Laterals determined to have insufficient capacity to meet the forecasted demand of current and future customers when pressure is regulated to below 30% SMYS are not suitable for PRS."

On page 39 of the Application, FEI states: "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."

14.1 Please describe the methodology and assumptions that FEI uses to calculate the required design peak demand and design capacity for the laterals.

Response:

Peak Demand Calculation:

FEI determines peak hour use per customer (UPC_{peak}) for non-industrial customers whose consumption meters are read monthly through an annual load gather assessment as described below. For industrial customers who will have hourly metering, a recent UPC_{peak} value is used to represent the maximum hourly rate of consumption measured at the customer meter. The lateral's current design peak demand is the sum of the customers in each rate schedule multiplied by the average UPC_{peak} for each rate schedule, plus the sum of the maximum hourly demand of all industrial customers on the lateral.

For laterals with Interruptible rate schedule industrial customers, the contracted firm component of the customers' demand (if any) is included. Then, only if sufficient capacity exists, any interruptible amount is included to the lesser of the remaining available capacity of the lateral or their measured maximum hourly demand. The lateral's future design peak demand equals the lateral's current design peak demand plus the sum of any forecasted incremental customer additions in each forecasted rate schedule multiplied by the average UPC_{peak} for each rate schedule. No change in industrial customer numbers or demand (either firm or interruptible) is included in future peak demand estimates. Industrial demand is represented at current known levels with no change over time.

In the load gathering process, billing information for the preceding two-year period is extracted for all customers. With a custom software application, the billing information for each customer and temperature information from the local weather zone index weather stations is reduced to a daily average demand for the customer for each billing period and an average mean daily temperature for the same billing period. For customers billed monthly, twenty-four "daily demand" versus "mean daily temperature" data points are determined from their most recent bi-annual consumption. A linear regression for each customer is performed on this data and the base load and slope (standard m^3/day/degree Celsius) is determined. The peak day demand for the customer equates to the customer's demand projected to the Design Degree Day (DDD) temperature value for the weather zone that the customer resides.

For capacity planning purposes, FEI currently divides its service territory into twenty-two unique weather zones with DDD values ranging from 27.8DD (mean daily temperature = -9.8°C) in the Comox (Vancouver Island) region to a 60.4DD (mean daily temperature = -42.4°C) in Fort Nelson (Northeast BC). The DDD peak day demand values are converted to a peak hourly demand by applying a peak hour factor (peak hour/peak daily demand) determined from a periodic assessment of local gate station hourly and daily flow variations under winter load conditions. From the uniquely calculated hourly UPC_{peak} determined for each customer, a "roll up" determining the current local regional average for each rate class is determined. FEI calculates UPC_{peak} values in sixty-six different local regions, each composed of one or more municipal districts. To smooth typical annual variances in the data, these regional average UPC_{peak} values for each rate schedule are averaged with the results of the preceding two years' annual load gather assessment values to produce a three year "rolling average" UPC_{peak} for each rate class within the region. These three year rolling average UPC_{peak} values are combined with current accounts and account addition forecasts to produce peak-hour load forecasts over a forecast period.

Available Capacity under Design Conditions:

FEI is assuming that by "design capacity" the BCUC is referring to a calculation of the available capacity under design conditions. The capacity of a pipeline or lateral system is variable and is not a fixed value. The capacity determined for a lateral system varies based on a number of parameters including the range of source pressure(s) at inputs to the system, the distribution of load or customer demand along the system, and is constrained by such parameters as the maximum operating pressure (MOP), minimum delivery pressures at key points, and in some cases gas velocities within the system. As a result, there is no defined "design" capacity, rather there is a range of capacity capabilities.

Given a specified set of these parameters, it is possible to determine if a pipeline system has sufficient available capacity to meet the expected peak demand. FEI does this regularly for lateral systems by assuming that, given the current customer peak demand distributed along the lateral and at the minimum expected source (tap) pressure, that all points of the lateral should remain at or above minimum delivery pressures and do not exceed reasonable gas velocities. In addition, FEI looks for future constraints on the system by adding forecasted load to the system models and determining either that the system has sufficient capacity to meet the future demand requirements or identifies if and when a constraint, such as a minimum delivery pressure at some point in the system cannot be met.

To calculate the available capacity for a lateral system, FEI has to make an assumption about where on the system model to add un-forecasted load to the lateral until at least one of the constraints can no longer be met. The assumption(s) about where to add the load will influence the calculated capacity of the system. For example, if the new load is distributed at multiple locations between the upstream and downstream endpoints of the system, then it is conceivable that a higher available system capacity could be calculated than if all the new load were added at the furthest downstream point.

In providing the capacity assessments for the IGU Project and in the following responses to BCUC IRs 1.14.2 and 1.14.3, FEI's System Capacity Planning made unique assumptions for each lateral system about where to apply load based on an understanding of localized constraints within the system. In general, additional load was added to the model at a single location near the farthest downstream point on the system while avoiding localized constraints (such as adding large loads on very small pipe) that would skew the results. This resulted in an appropriately conservative calculation of system capacity. This is relevant to the assessment of pressure regulating station (PRS) locations as it provides reasonable assurance that FEI is not over-estimating the remaining available capacity (or under-estimating the risk of capacity shortfalls) for locations where PRS alternatives were considered viable.

14.2 For each of the 29 laterals, please provide the capacity at current operating pressure and at an operating pressure equivalent to 30 percent SMYS.

Response:

Several of the 29 laterals are components of a larger lateral system in a local area that contribute collectively to the overall capacity. As a result, while a set of assumptions could be made and an independent capacity calculation done for each component, the result would not be meaningful to understanding the impact of PRS installations. As a result, some of the laterals in the following table are grouped together and in some cases, the grouped system includes other lateral pipe segments that are beyond the scope of the IGU Project (i.e., pipe diameter less than NPS 6). Also FEI assumes that by "capacity at current operating pressure", the BCUC means the capacity with the current maximum operating pressure (MOP) at the tap location of the lateral system.

Lateral Capacity Table

Lateral System	Line/loop Fill Name	Capacity at MOP (std. m³/hr)	Capacity at 30% SMYS (std. m³/hr)
MacKenzie System	Mackenzie Lateral 168	48,714	26,020
	Mackenzie Loop 168		
MacKenzie System	BC Forest Products Lateral 168	n/a[1]	107,036
Prince George 3 System	Prince George 3 Lateral 219	161,214	100,056
	Northwood Pulp Lateral 168		
	Northwood Pulp Loop 219		
Prince George 1 System	Prince George 1 Lateral 168	70,416	33,011
Prince George 1 System	Prince George Pulp Lateral 168	n/a[1]	81,990
	Husky Oil Lateral 168		
Prince George 2 System	Prince George 2 Lateral 219	78,781	55,115
Cariboo Pulp System	Cariboo Pulp Lateral 168	118,611	73,611
Williams Lake System	Williams Lake Loop 1 168	65,307	28,802
	Williams Lake Loop 2 168		
Kamloops 1 System	Kamloops 1 Lateral 168	160,399	91,876
	Kamloops 1 Loop 168		
Salmon Arm System	Salmon Arm Loop 168	41,787	31,638
Salmon Arm System	Salmon Arm 3 Lateral 168	n/a[1]	90,862
Coldstream System	Coldstream Lateral 219	74,784	47,358
	Coldstream Loop 168		
Kelowna Gate System	Kelowna 1 Loop 219	108,498	79,706
Celgar System	Celgar Lateral 168	52,949	45,453
Castlegar Nelson System	Castlegar Nelson 168	25,669	22,140
Trail System	Trail Lateral 168	28,087	24,020
Fording System	Fording Lateral 219	34,816	21,991
	Fording Lateral 168		
Fording System	Elkview Lateral 168	n/a[1]	84,530
Cranbrook Kimberley System	Cranbrook Lateral 168	61,858	32,570
	Cranbrook Loop 219		
Cranbrook Kimberley System	Cranbrook Kimberley Loop 273	39,794	28,863
Cranbrook Kimberley System	Cranbrook Kimberley Loop 219	39,786	25,915
	Kimberley Lateral 168		
Cranbrook Kimberley System	Skookumchuck Lateral 219	31,818	25,485

[1] Lateral will never see pressures at MOP under moderate to high flows due to pressure drop in upstream system

14.3 For each of the 29 laterals, please provide graphs of pipeline capacity (at current and reduced pressure) and the historical and the 20 year forecasted peak demand of: (i) firm customers; (ii) interruptible customers; and (iii) new customers.

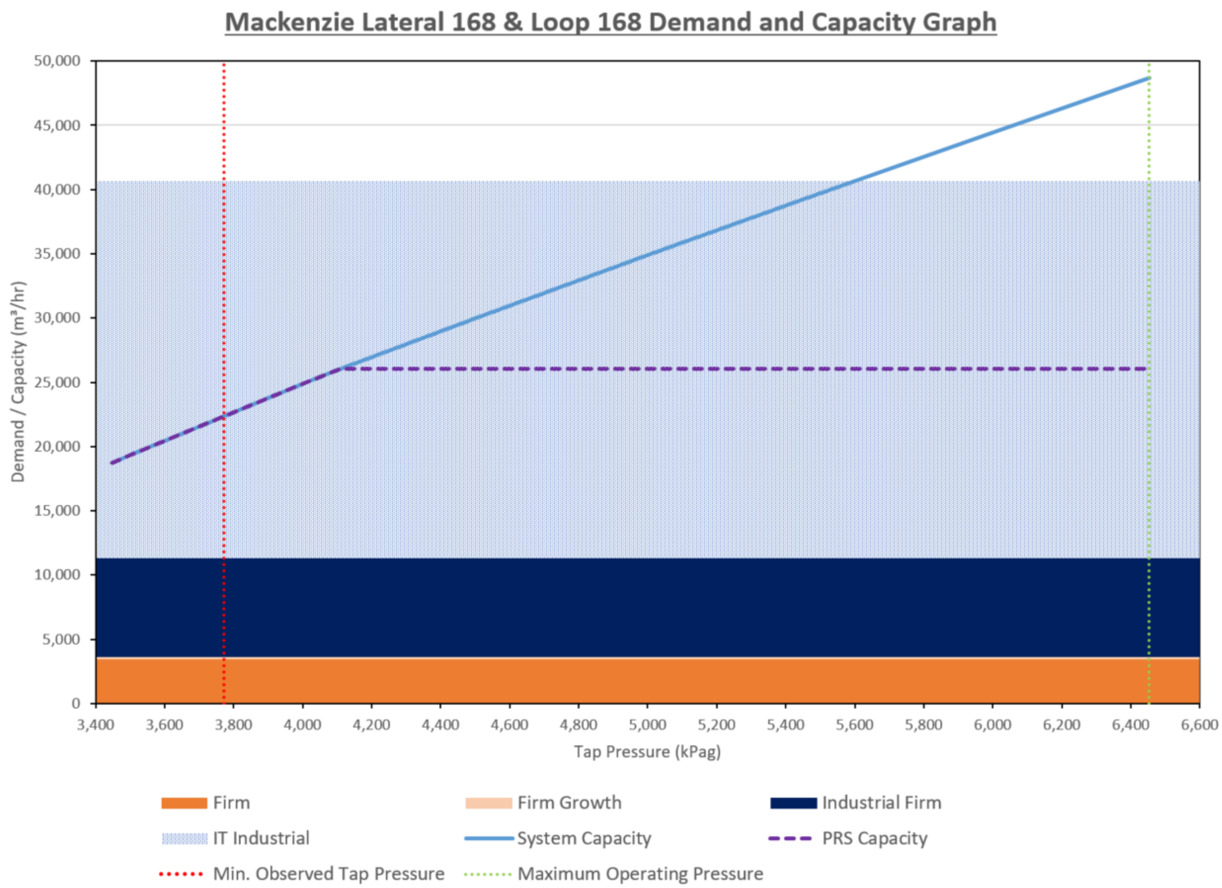
Response:

A portion of the response to this question is being redacted and filed confidentially with the BCUC. FEI is requesting that this information be filed on a confidential basis pursuant to Section 18 of the BCUC's Rules of Practice and Procedure regarding confidential documents adopted by Order G-15-19, as it contains confidential customer information which is specific and commercially sensitive to the customer and should not be publicly disclosed.

As these graphs are important to the understanding of PRS impacts, this response also addresses BCUC IR 1.14.4, which asks to quantify the impact that PRS would have on customers.

The graphs below expand on the information provided in the table in the response to BCUC IR 1.14.2, and separate out current firm customers' demand, forecasted growth in firm demand, industrial firm, and industrial interruptible (IT) in a stacked bar format that illustrates the cumulative demand. The information is grouped by lateral system. Note that in the lower pressure ranges in the capacity graphs below, the PRS capacity and the system capacity (without PRS) intersect and then at all lower pressures the PRS capacity and the system capacity follow the same declining capacity curve. The region of the graph where the two curves coincide indicates the operating conditions where the control valve would be fully open due to upstream pressures less than the set point (29.9 percent SMYS) of the PRS. In this operating area, the PRS is not limiting the capacity of the system. For the same reasons (because the control valve is fully open), any capacity upgrades that might be required to increase capacity to serve future increases in firm demand for tap pressures in this range would be no different in scale or scope with or without PRS and could not be addressed, for example, by removing the PRS.

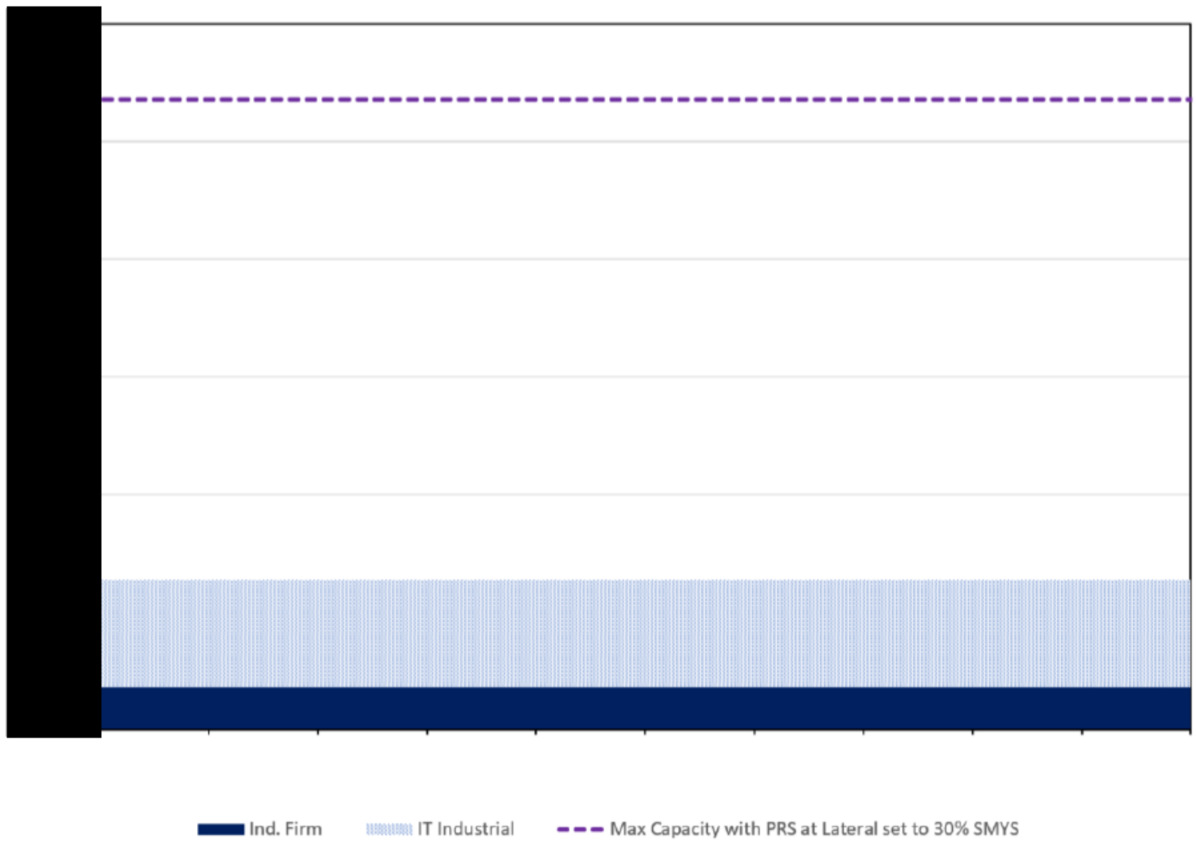
MacKenzie System:



The MacKenzie System including the MacKenzie Lateral 168, the MacKenzie Loop 168 and the downstream BC Forest Products Lateral 168 serves the community of MacKenzie and surrounding area. There are a few large industrial customers and some of those industrial customers consistently consume large quantities of gas on an interruptible basis. The total firm and industrial demand and forecasted growth in firm customer demand at a total of 11,300 m^3/hr remains well below the capacity cap estimated at just over 26,000 m^3/hr a PRS installed at the lateral tap would impose. This allows for reasonable additional un-forecasted growth in firm customers to continue with no additional system upgrades (recognizing that growth would erode available interruptible capacity).

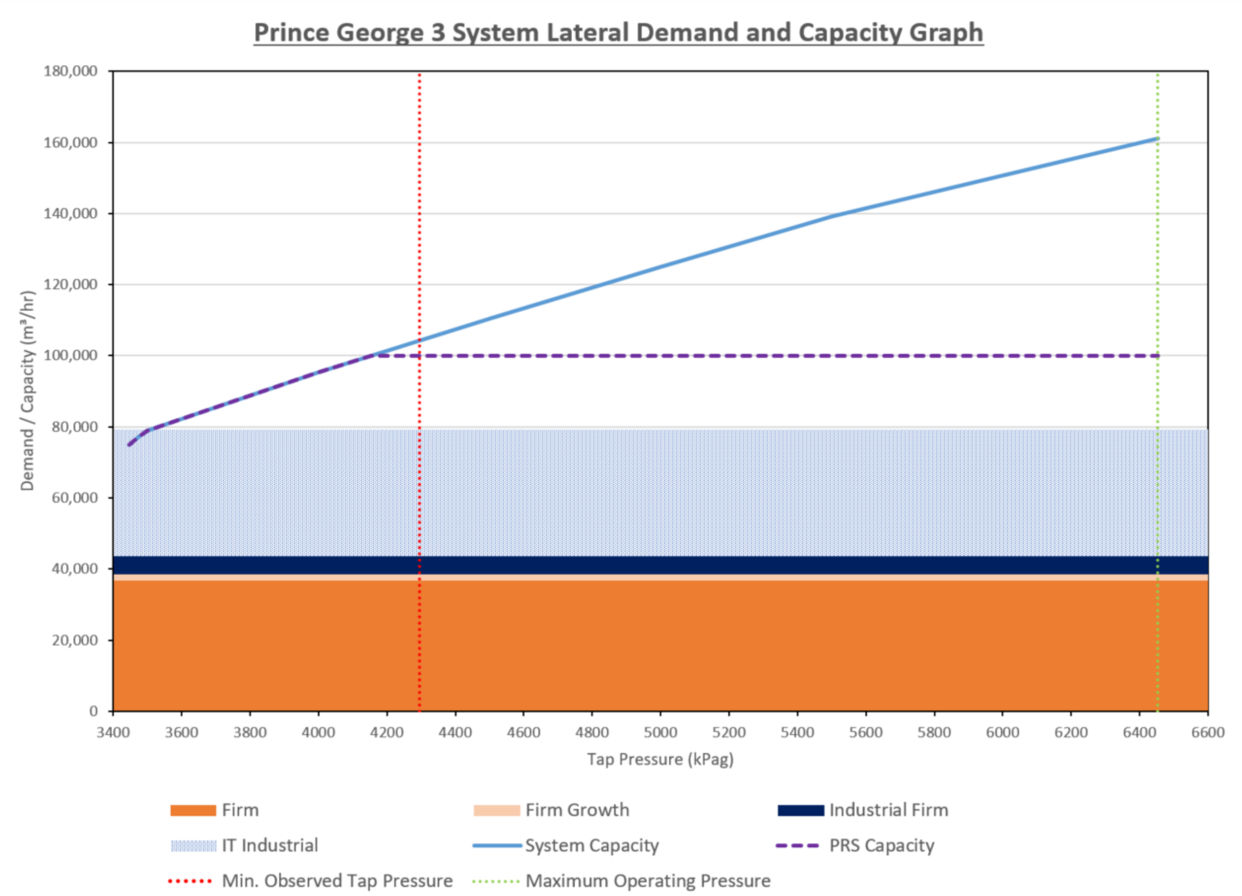
The capacity graph for the MacKenzie system illustrates that a PRS would cap available capacity such that regardless of the available tap pressure interruptible customers would be curtailed more severely and more often than is required at current operating pressures. The PRS alternative here would impose consequences on these existing customers and also likely allow no growth in additional interruptible customers. As a result of a PRS potentially impacting the established operations of existing FEI customers, PRS was considered not viable for the MacKenzie 168 Lateral and Loop.

BC Forest Products Lateral Demand and Capacity Graph



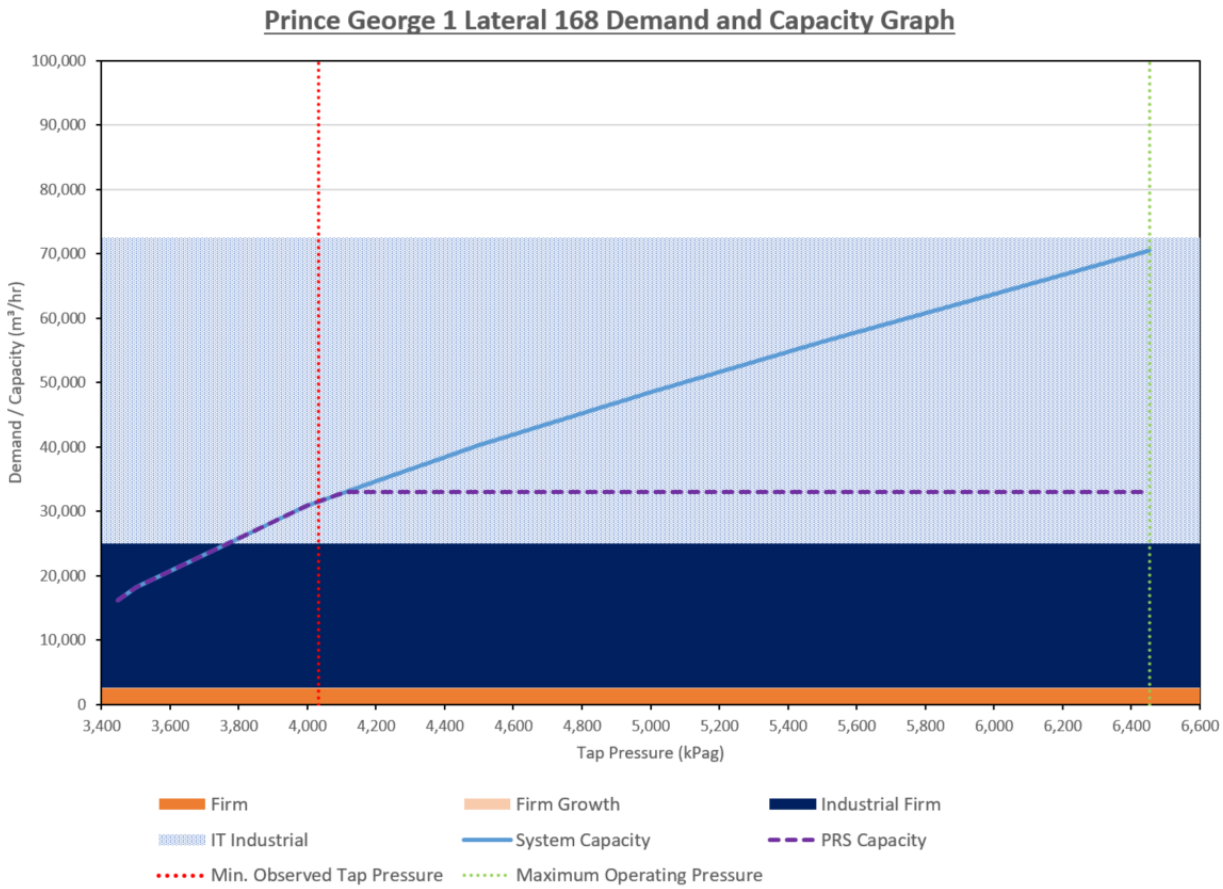
The BC Forest Products Lateral is a component of the MacKenzie System downstream of the MacKenzie Lateral 168 and Loop 168. The graph above illustrates that a PRS installed at the start of the lateral has capacity well above the requirements of the industrial customers served by the lateral. The pressure at the start of the lateral varies relative to the total MacKenzie System demand and will drop below the 30 percent SMYS pressure of the BC Forest Products lateral when the MacKenzie System demand requirements are at or near the peak demand levels shown in the preceding MacKenzie Lateral 168 and Loop 168 Demand and Capacity Graph. This previous graph includes the demand on the downstream BC Forest Products Lateral. A PRS will be fully open and not restrict throughput under conditions where the inlet pressure is below the set pressure (29.9 percent SMYS). As a result, FEI concluded that a PRS set to regulate at below 30 percent SMYS on the BC Forest Products lateral is viable and would not impact customers or drive additional future upgrades.

Prince George 3 System:



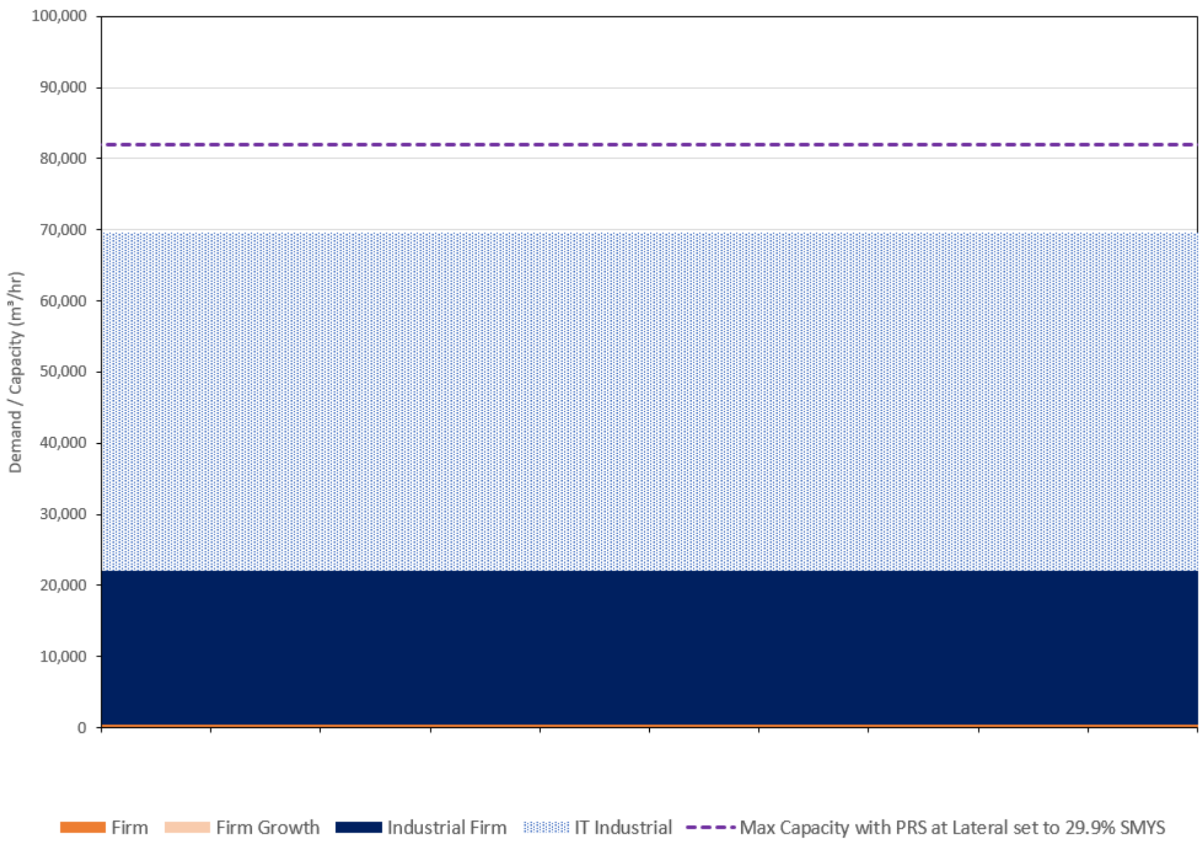
The Prince George 3 System is comprised of the Northwood Pulp Lateral 168, the Northwood Pulp Loop 219 and the Prince George 3 219 Lateral located downstream of the Northwood Pulp laterals. The system serves Gate Stations feeding a large portion of the Prince George distribution system and a large Pulp Mill facility. The total firm and industrial demand and growth in firm customer demand at a total of 43,575 m^3/hr remains well below the capacity cap of an estimated 100,000 m^3/hr a PRS installed at the lateral tap would impose. This allows for reasonable additional un-forecasted growth in firm customer demand to continue with no additional system upgrades. There is also room to increase the level of interruptible demand on the system from existing or new industrial customers as indicated by the gap between the total system demand and the capacity lines in the graph.

Prince George 1 System:



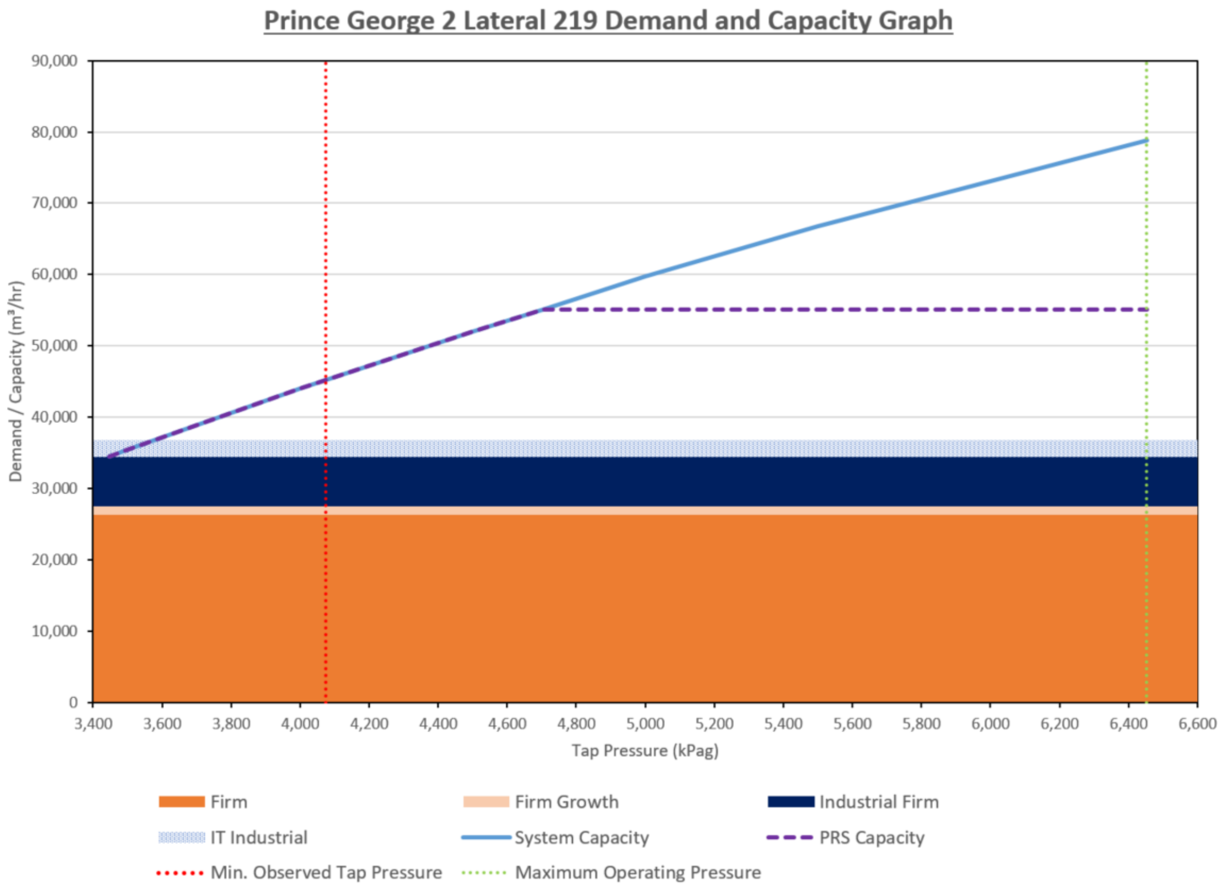
The Prince George 1 System consists of 3 laterals, the Prince George 1 Lateral 168, the downstream Prince George Pulp Lateral 168, and further downstream the Husky Oil Lateral 168. The lateral system serves 2 Gates Stations serving a portion of the Prince George distribution system and several large industrial customers with large interruptible industrial demand. The demand for the entire system is served through the Prince George 1 lateral. The lateral demand and capacity is shown above. This lateral with PRS at the tap would have much reduced capacity and could serve a much lower portion the existing interruptible demand on the system as indicated by the lower dash purple line on the graph. The interruptible customer demand is already managed year round to available capacity based on the Tap pressure and the installation of a PRS on this lateral would have a significant impact on the existing customers. Therefore, PRS was not considered viable for this portion of the Prince George 1 lateral system.

Prince George Pulp 169 and Husky 168 Lateral Demand and Capacity Graph



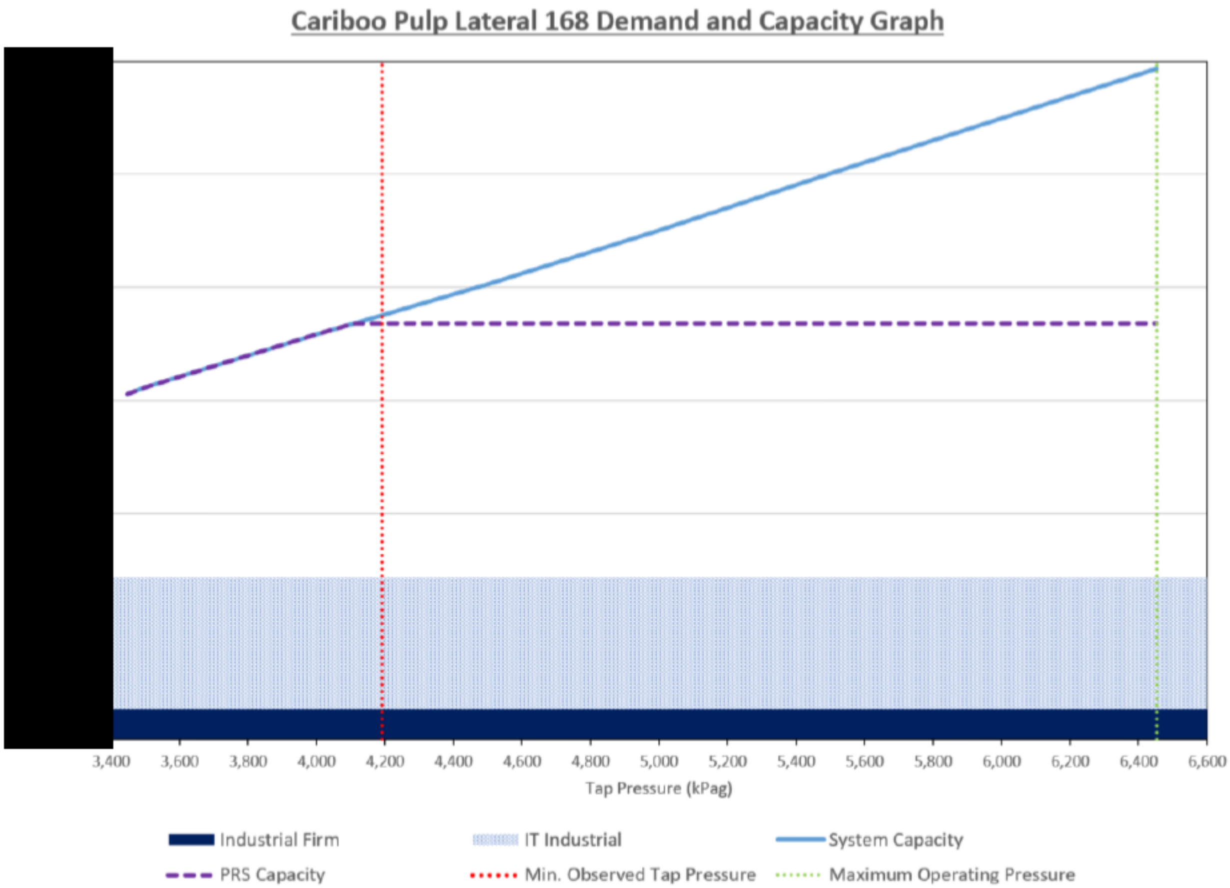
The Prince George Pulp Lateral 168 and Husky Lateral 168 is a component of the Prince George 1 System downstream of the Prince George 1 Lateral 168. The graph above illustrates that a PRS installed at the start of the lateral has capacity above the requirements of the industrial customers served by the lateral. The pressure at the start of the lateral varies relative to the total Prince George 1 System demand and will drop below the 30 percent SMYS pressure of the Prince George Pulp and Husky laterals when the Prince George 1 System demand requirements are at or near the peak demand levels shown in the preceding Prince George 1 Lateral 168 Demand and Capacity Graph. This previous graph includes the demand on the downstream Prince George Pulp and Husky laterals. A PRS will be fully open and not restrict throughput under conditions where the inlet pressure is below the set pressure. As a result, FEI concluded that a PRS set to regulate at 29.9 percent SMYS at the start of the Prince George Pulp lateral also serving the Husky Lateral is viable and would not impact customers.

Prince George 2 System:



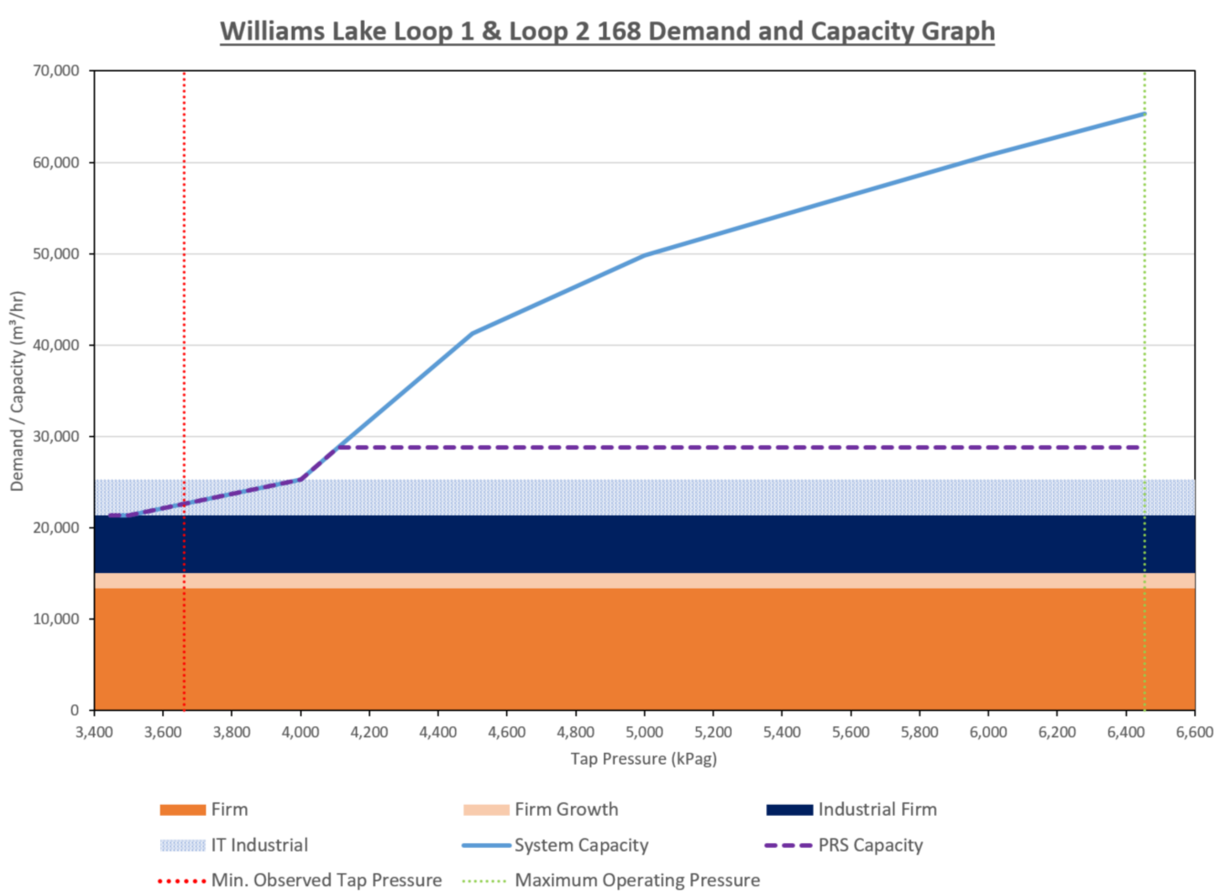
The Prince George 2 System is comprised of the single Prince George 2 Lateral 219. The system serves Gate Stations feeding a large portion of the Prince George distribution system including industrial customers in the southeast region of the city. The total firm and industrial demand and growth in firm customer demand at a total of 34,500 m^3/hr remains well below the capacity cap of an estimated 55,110 m^3/hr a PRS installed at the lateral tap would impose. This allows for reasonable additional un-forecasted growth in firm or interruptible customer demand to continue with no additional system upgrades as indicated by gap between the total system demand and the capacity lines in the graph.

Cariboo Pulp System:



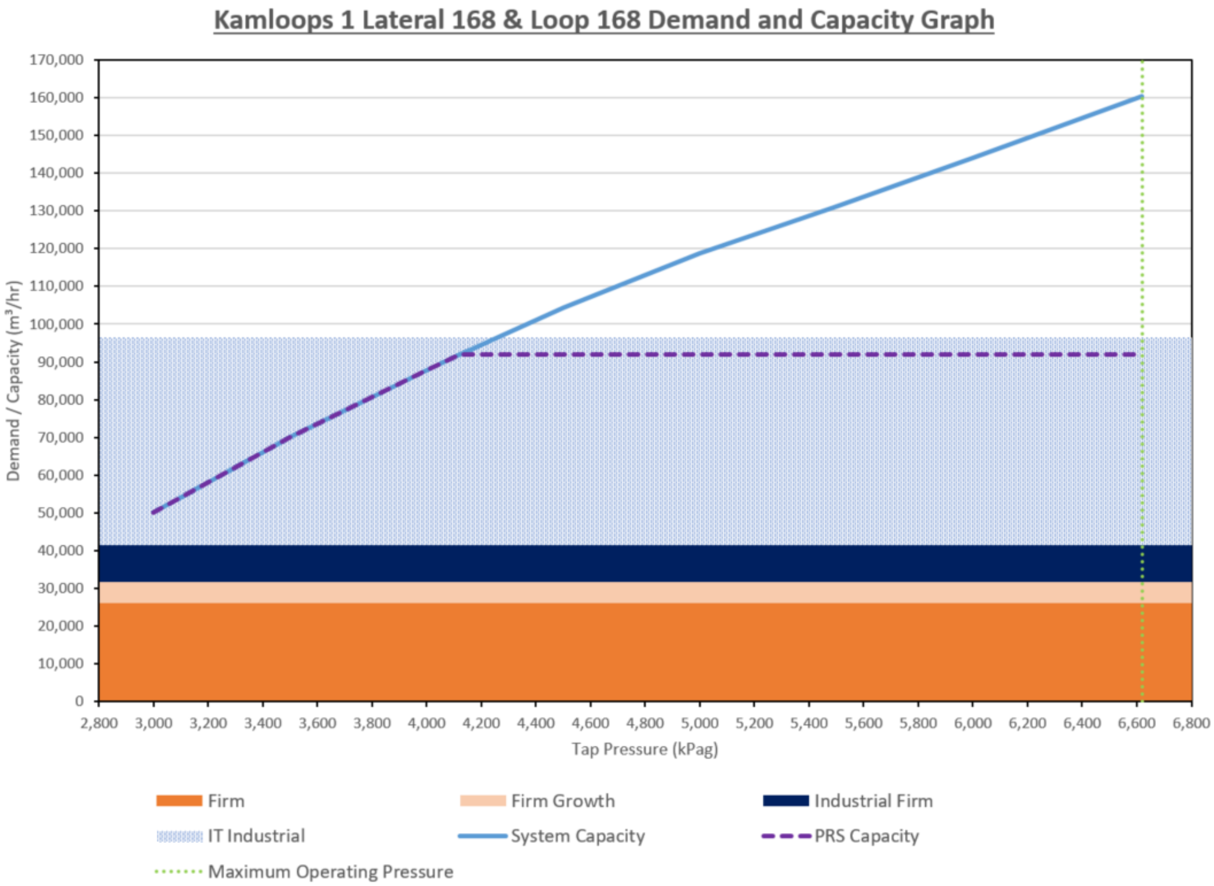
The Cariboo Pulp System is comprised of the single Cariboo Pulp Lateral 168. The lateral serves a single large industrial customer. This lateral capacity with a PRS at the tap allows for considerable growth in firm or interruptible demand as shown in the graph above. As a result, FEI concluded that a PRS set to regulate at below 30 percent SMYS at the start of the Cariboo Pulp Lateral is viable and would not impact current or future customer demand.

Williams Lake System:



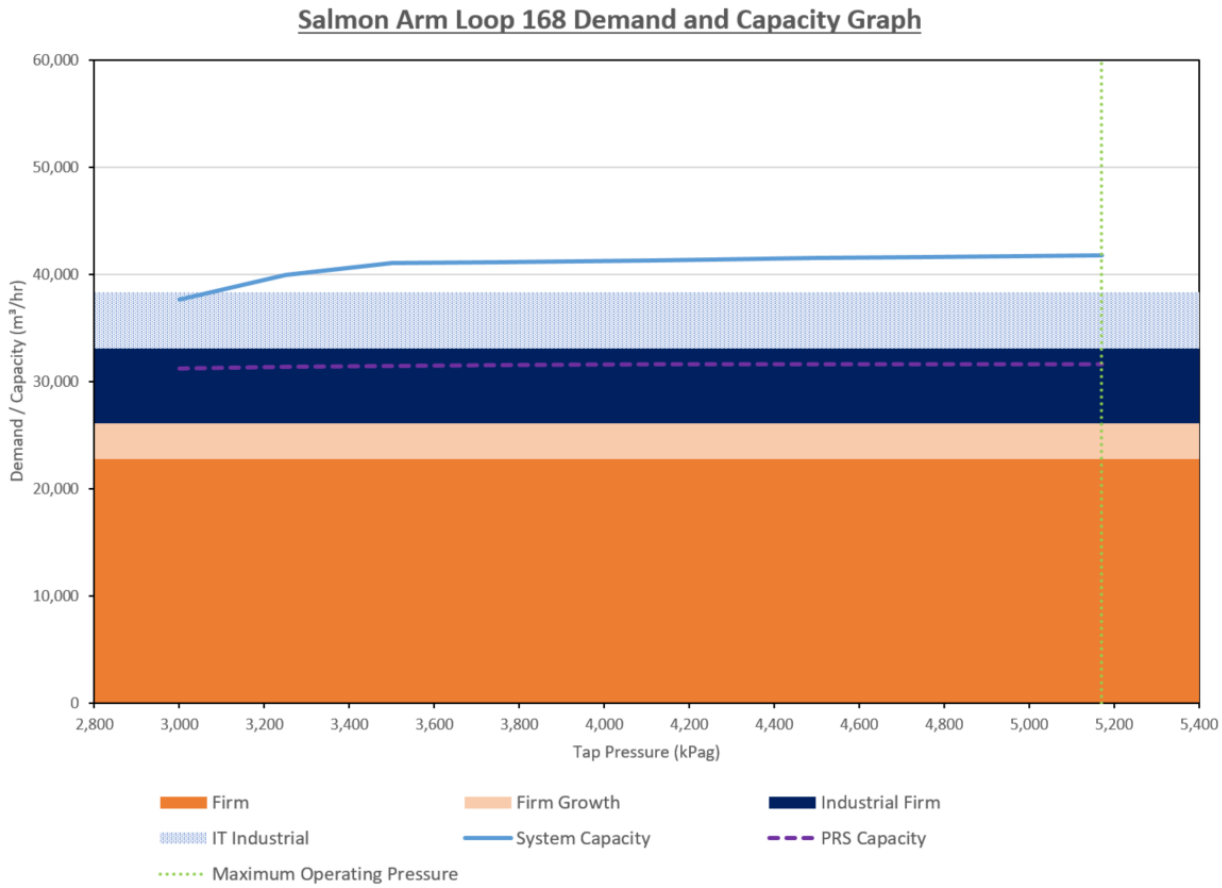
The Williams Lake System is comprised of Williams Lake Lateral 114, which is looped by the parallel Williams Lake Loop 1 168 from the Tap location to the Williams Lake Airport and then from the Williams Lake Airport onward by the Williams Lake Loop 2 168. The system serves six Gate Stations feeding the Williams Lake distribution systems and smaller industrial loads. The total firm and industrial demand and growth in firm customer demand at a total of 21,350 m^3/hr remains well below the capacity cap of an estimated 28,800 m^3/hr a PRS installed at the lateral tap would impose. This allows for reasonable additional un-forecasted growth in firm customer demand to continue with no additional system upgrades. There is also room to increase the level of interruptible demand on the system from existing or new industrial customers as indicated by the gap between the total system demand and the capacity lines in the graph.

Kamloops 1 System:



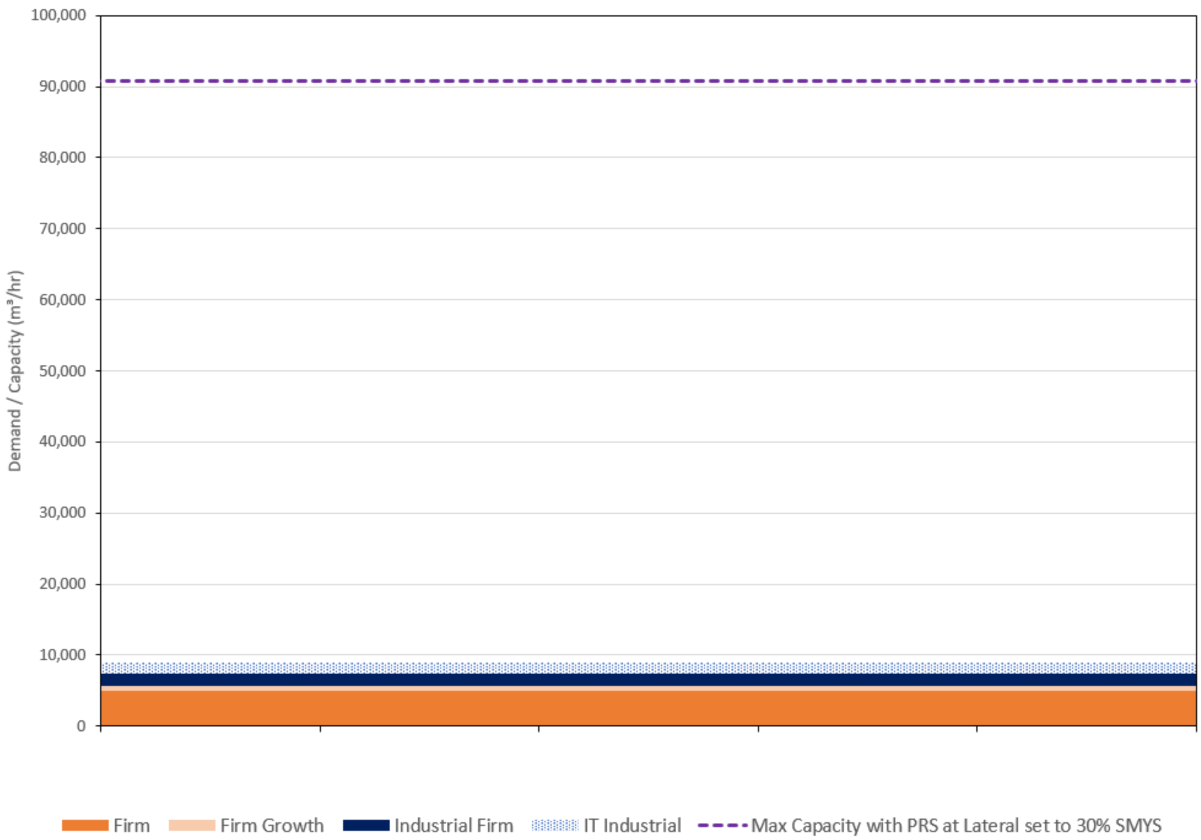
The Kamloops 1 System is comprised of the Kamloops 1 Lateral 168 and the Kamloops 1 Loop 168 serves large industrial customers and a major Gate Station that serves a significant portion of the Kamloops distributions system. The capacity graph for the Kamloops 1 system illustrates that a PRS would cap available capacity such that regardless of the available tap pressure interruptible customers could be curtailed more often than is required at current operating pressures. The PRS alternative here would impose consequences on these existing customers and also not attract growth in additional interruptible customers. As a result of a PRS impacting the established operations of existing FEI customers, PRS was considered not viable for the Kamloops 1 Lateral and Loop.

Salmon Arm System:



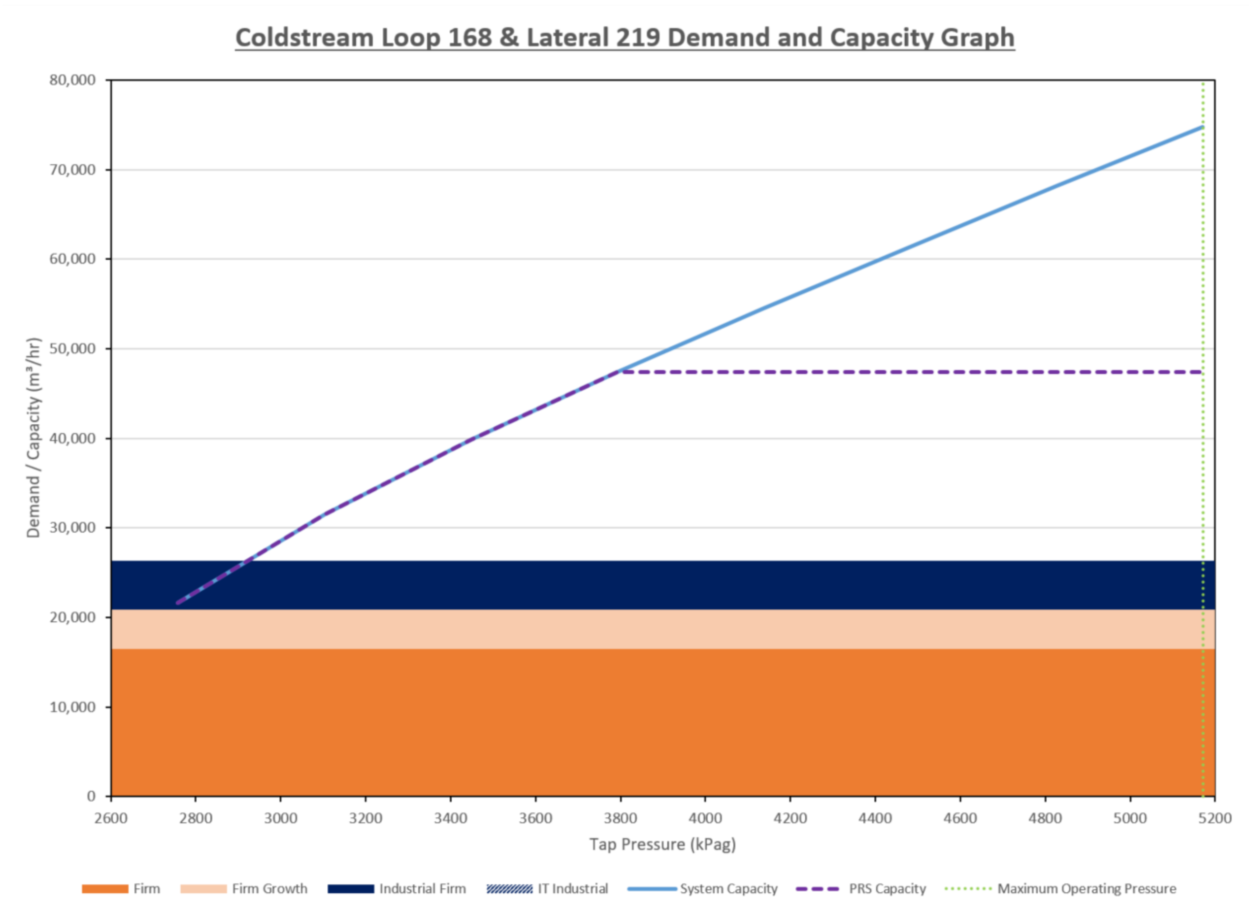
The Salmon Arm system consists of Salmon Arm Lateral 114 which is looped by the Salmon Arm Loop 168. These two pipelines together also feed the Salmon Arm 3 lateral downstream. The Salmon Arm System feeds multiple Gate Stations serving the communities of Armstrong, Enderby, Grinrod, Salmon Arm and Sorrento. The System include a Compressor Station just downstream of the start of the lateral. As a result, the capacity for the system does not vary considerably and remains fairly constant regardless of tap pressure as the compressor compensates for low tap pressure by boosting the system pressure back to the system maximum operating pressure (MOP). The installation of a PRS on the Salmon Arm Loop 168 to operate at 29.9 percent SMYS would require the compressor also to limit its discharge pressure to 29.9 percent SMYS. The capacity graph for the Salmon Arm System shows that PRS capacity would limit capacity to a level below what is required to meet firm customer demand. As a result of a PRS potentially impacting the established operations of existing FEI customers, PRS was considered not viable for the Salmon Arm Loop.

Salmon Arm 3 168 Lateral Demand and Capacity Graph



The Salmon Arm 3 168 Lateral feeds the Salmon Arm Gate station which serves a portion of the Salmon Arm distribution system. The graph above illustrates that a PRS regulating to 29.9 percent SMYS installed at the start of the lateral has capacity far above the requirements of the customers served by the lateral. The pressure at the start of the lateral varies relative to the total Salmon Arm System demand and will drop below the 30 percent SMYS pressure Salmon Arm 3 lateral when the total Salmon Arm System demand requirements are at or near the peak demand levels shown in the preceding Salmon Arm Loop 168 Demand and Capacity Graph. A PRS will be fully open and not restrict throughput under conditions where the inlet pressure is below the set pressure (29.9 percent SMYS). FEI recognized in preparing this response that, while PRS is viable for the Salmon Arm 3 lateral, the PRS alternative was not considered in the alternative selection process for this lateral. FEI is in the process off re-evaluating the financial and alternative analysis for this lateral. When FEI completes the evaluation, FEI will file an Evidentiary Update to the Application to the extent required.

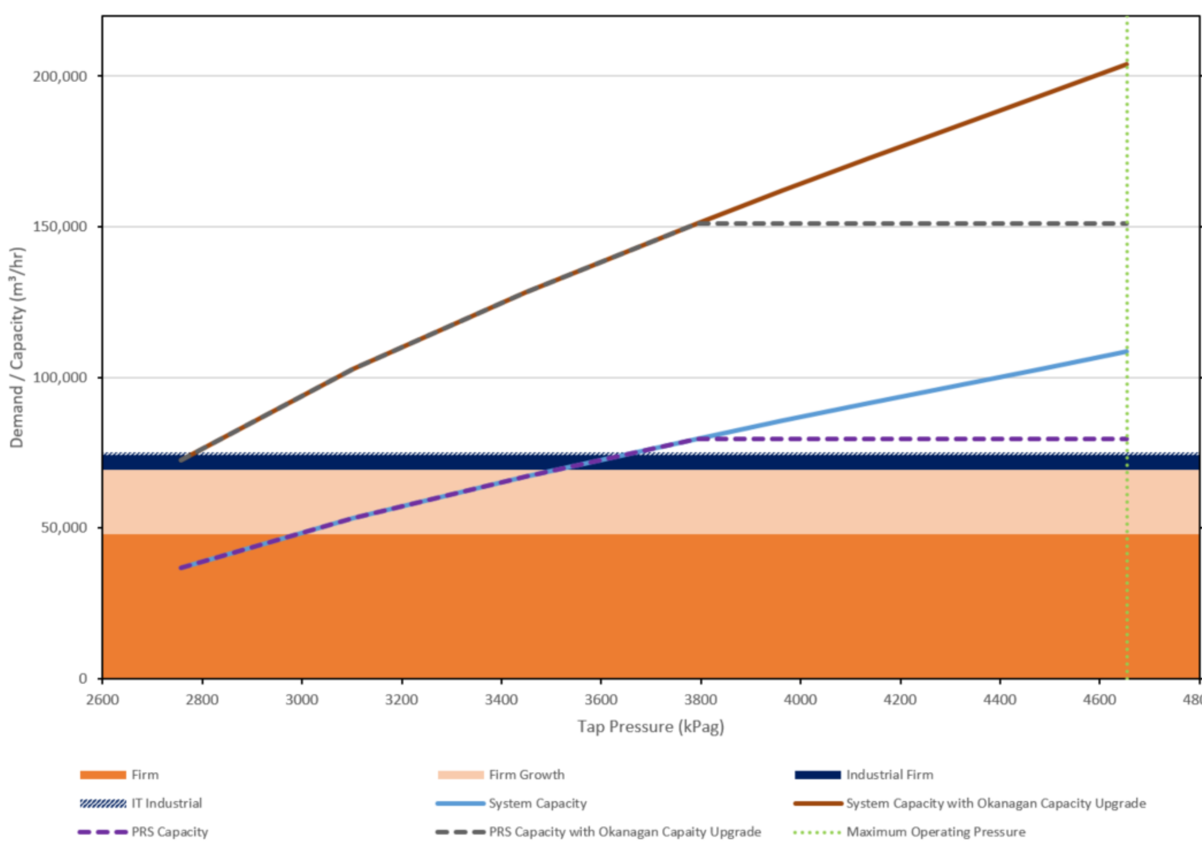
Coldstream System:



The Coldstream System is comprised of the Coldstream Lateral 114 looped by the Coldstream Loop 168 that both connect to the downstream Coldstream Lateral 219. Together these laterals feed one Gate Station serving a portion of the Vernon distribution system in addition to the communities of Coldstream Lavington and Lumby. The lateral capacity with a PRS at the tap allows for considerable growth in firm or interruptible demand as shown in the graph above. Due to the relatively high set point for the PRS relative to the range of pressures at the Coldstream location, there is a large range of where the PRS is not limiting the capacity of the system (i.e., the capacity curves coincide). As a result, FEI concluded that a PRS set to regulate at below 30 percent SMYS at the tap locations of the Coldstream System is viable and would not impact current or future customer demand.

Kelowna 1 System:

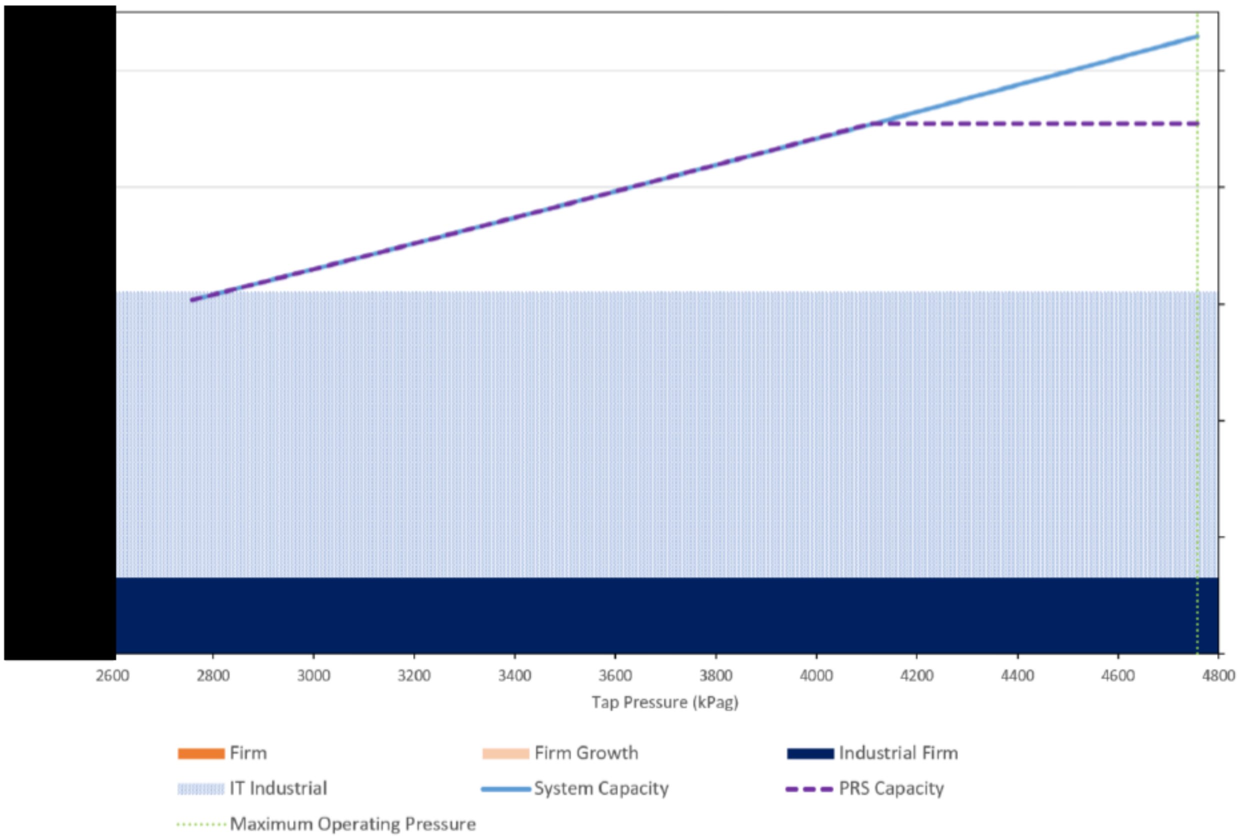
Kelowna 1 Loop 219 Demand and Capacity Graph



The Kelowna 1 System is comprised of the Kelowna 1 Lateral 114 and the Kelowna Loop 219. To serve the growth in firm demand FEI is planning to upgrade the Interior Transmission System serving the Kelowna area starting by 2022, this project is identified as the Okanagan Capacity Upgrade (OCU) Project. In addition to improving the operating pressure available in the central Okanagan, part of the upgrade scope includes replacing the Kelowna 114 lateral later in the 20 year forecast. The capacity graph above shows the capacity of the Lateral system with PRS prior to the anticipated upgrades as well as with PRS after the upgrades are in place. The capacity curves with PRS currently meets the Firm, Industrial Firm and interruptible demand and in the future with the Okanagan Capacity Upgrades, the capacity with PRS will continue to meet the future demand with room for additional un-forecasted growth in firm or interruptible customer demand. Due to the relatively high set point for the PRS relative to the range of pressures at the Kelowna location, there is a large range of where the PRS is not limiting the capacity of the system (i.e., the capacity curves coincide). As a result, FEI concluded that a PRS set to regulate at 29.9 percent SMYS at the tap locations of the Kelowna 1 System is viable and would not impact current or future customer demand.

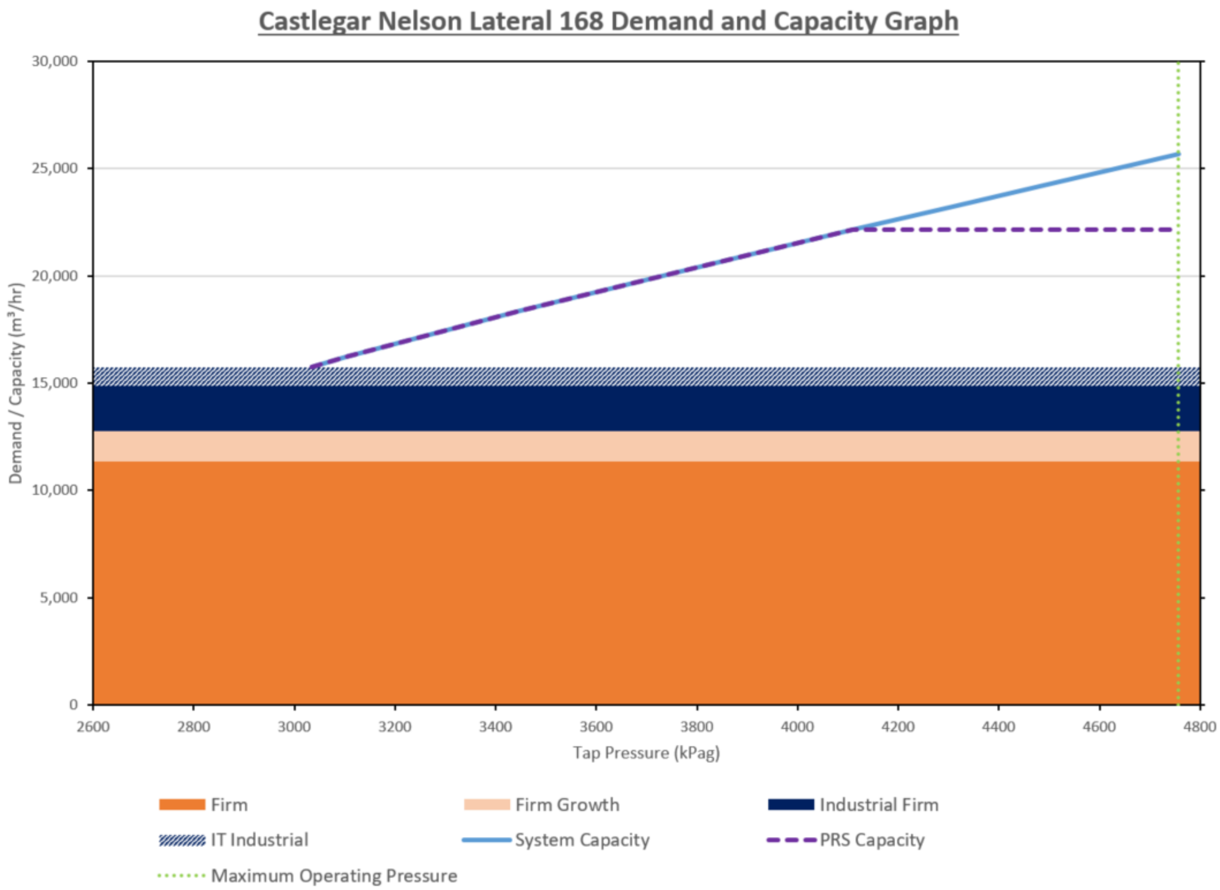
Celgar System:

Celgar Lateral 168 Demand and Capacity Graph



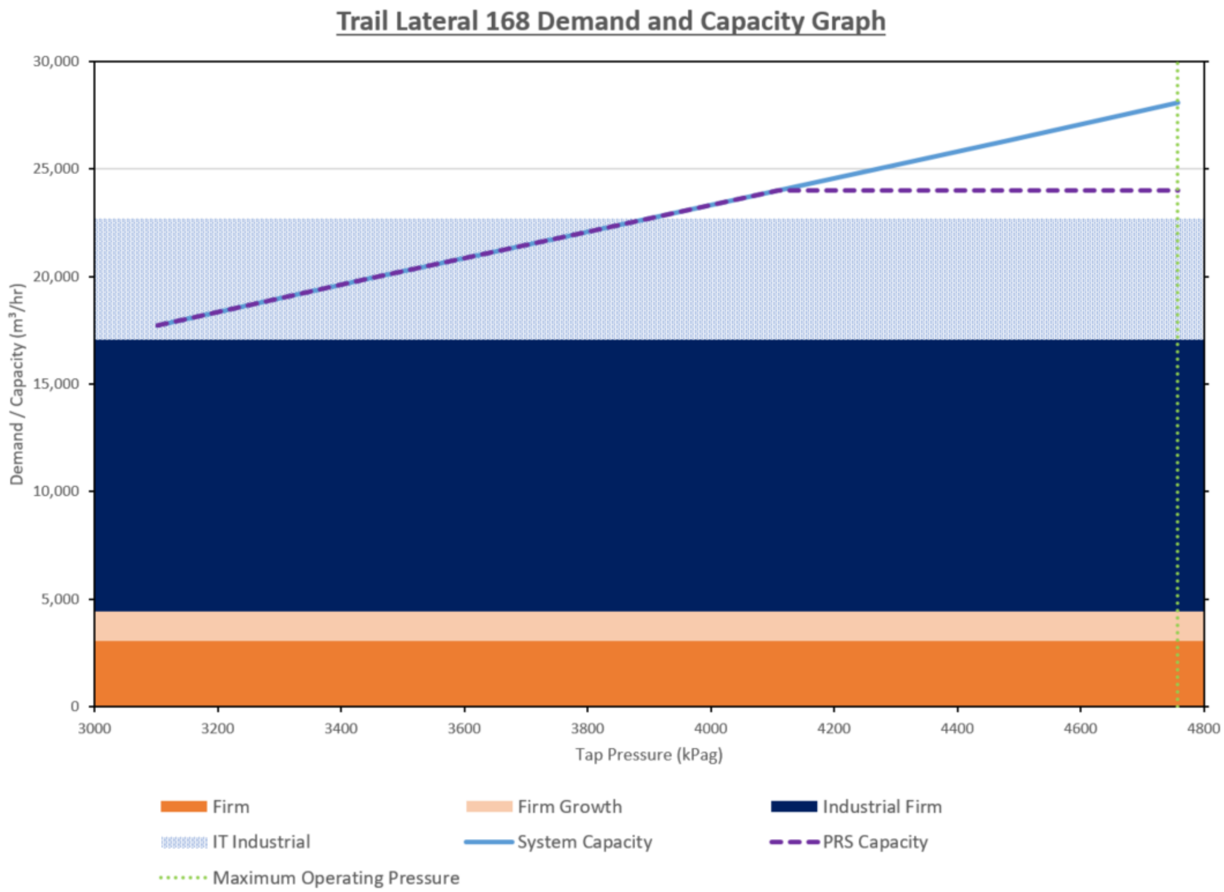
The Celgar system serve two large industrial customers. There are no non-industrial customers served. At this location, the PRS set point is high relative to the pressure normally seen at the Celgar tap location. A PRS will have the capacity to meet all current demand on the system with additional capacity to add firm or interruptible customer demand. As a result, FEI concluded that a PRS set to regulate at 29.9 percent SMYS at the start of the Celgar Lateral is viable and would not impact current or future customer demand.

Castlegar Nelson System:



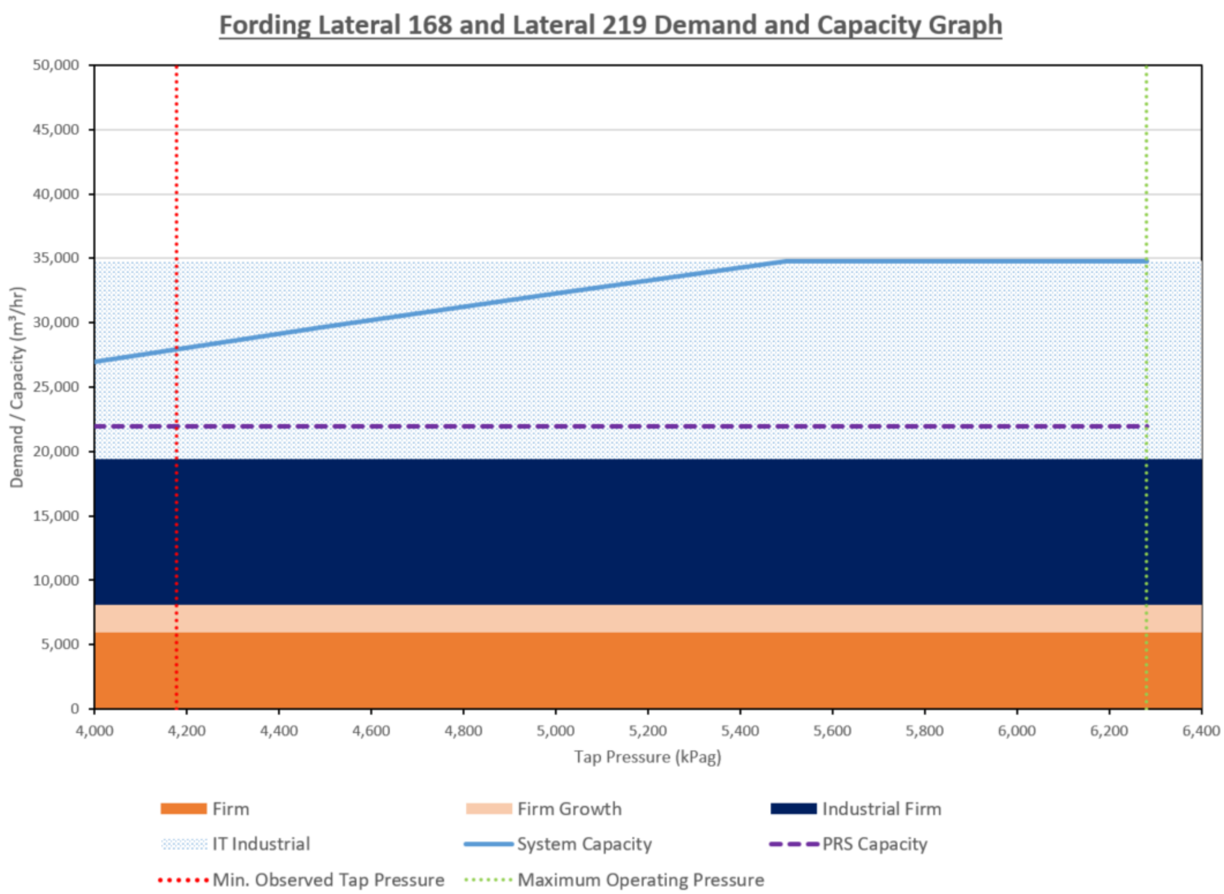
The Castlegar Nelson System feeds Gate Stations serving the distribution systems of Castlegar near the start of the lateral and Nelson located at the end of the lateral. At this location, the PRS set point is high relative to the pressure normally seen at the tap location. A PRS will have the capacity to meet all current demand on the system with additional capacity to add firm or interruptible customer demand. As a result, FEI concluded that a PRS set to regulate at below 30 percent SMYS at the start of the Castlegar Nelson Lateral is viable and would not impact current or future customer demand.

Trail System:



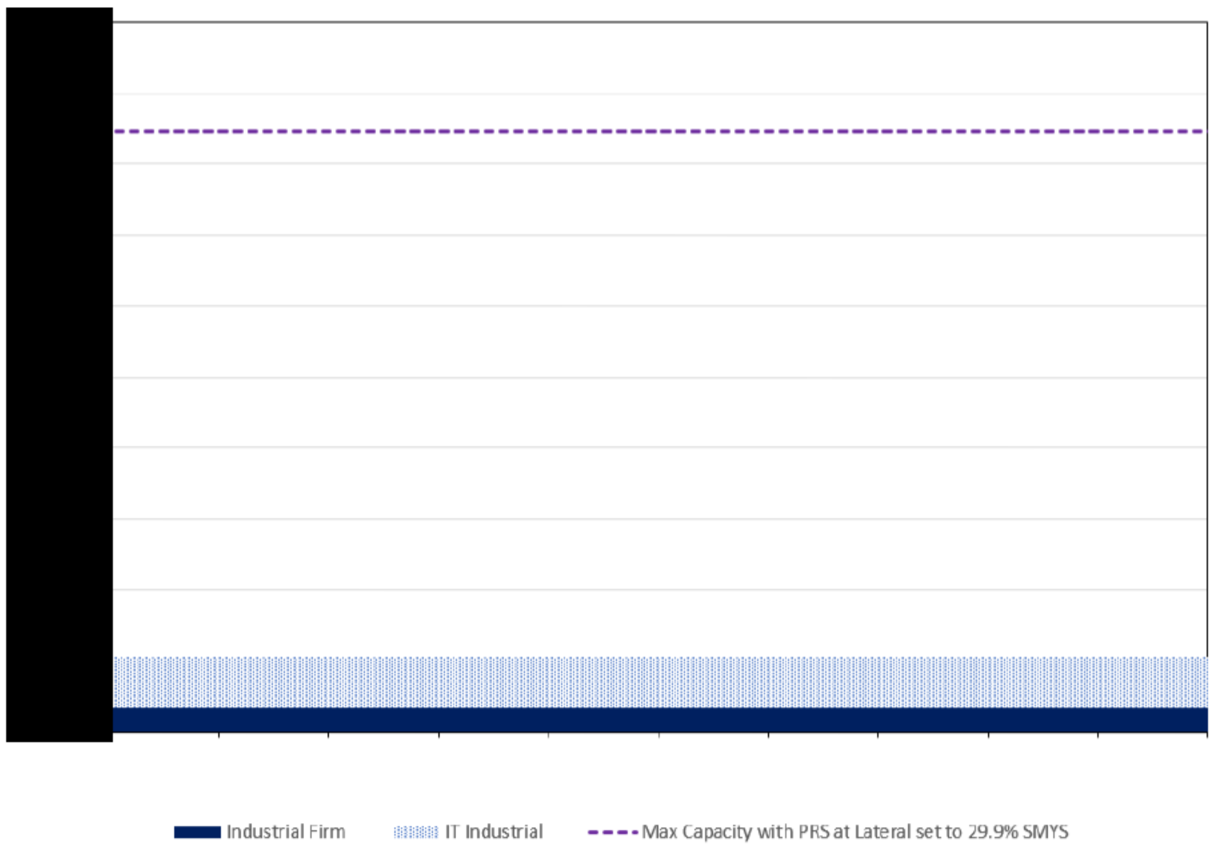
The Trail System is comprised of the Trail Lateral 168 and the Trail Lateral 114. The system feeds a Gate Station serving a portion of the distribution system of Trail and large industrial locations. A PRS will have the capacity to meet all current demand and forecasted growth on the system with moderate additional capacity to add firm or interruptible customer demand. As a result, FEI concluded that a PRS set to regulate at 29.9 percent SMYS at the start of the Trail Lateral is viable and would not impact current or future customer demand.

Fording System:



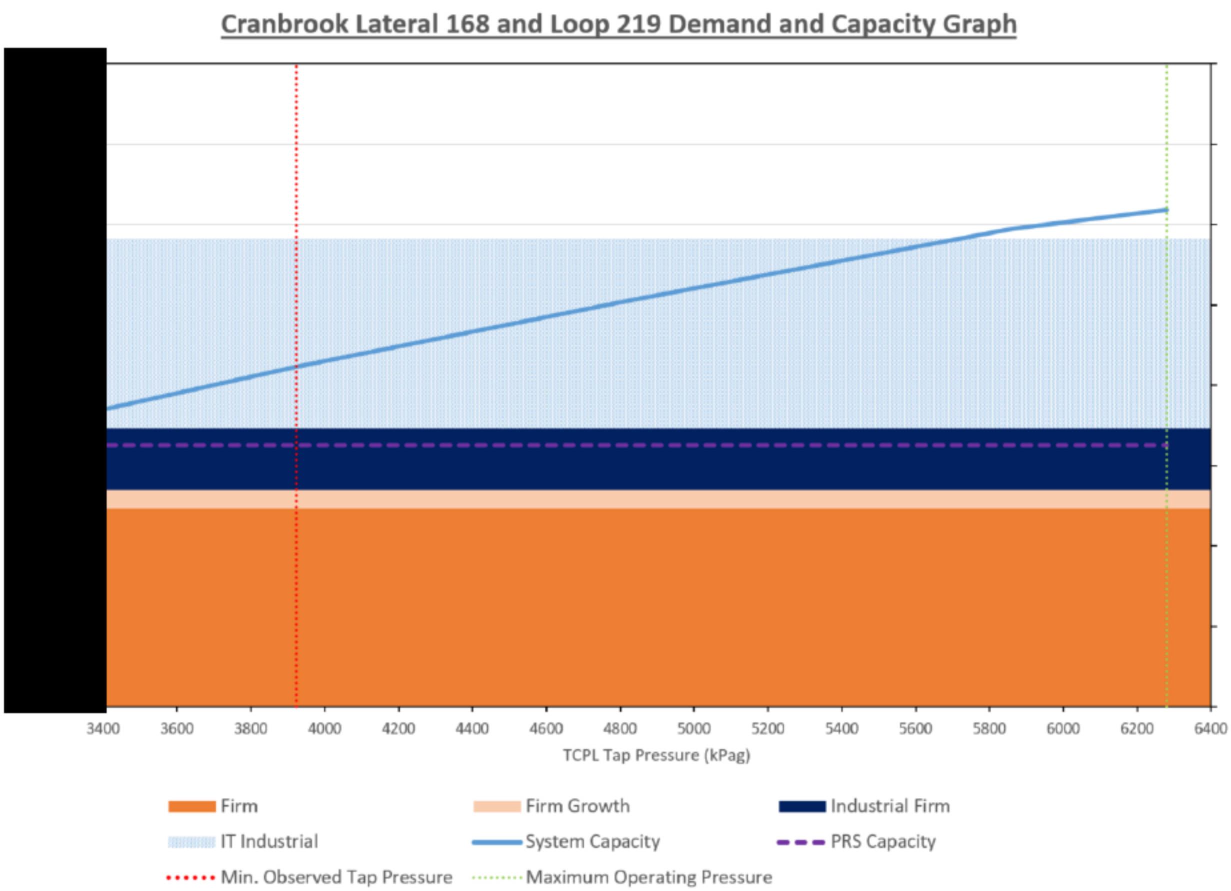
The Fording Lateral System is comprised of the Fording Lateral 219 which is partly looped by the Fording Loop 114 from the tap location to a location south of the community of Sparwood. At the end of the Fording Lateral 219 north of Sparwood, the Fording Lateral 168 continues on northward past the community of Elkford to serve large industrial mine sites. The Fording system feeds Gate Stations serving the communities of Sparwood and Elkford and several large industrial sites located at various points along the length of the system. The large industrial customers (mostly mining sites) have large firm industrial and interruptible loads and are currently actively managed year round to keep the interruptible demand within the available capacity of the system. The capacity graph above shows that the installation of a PRS at the TransCanada Pipeline (TCPL) Tap to the system would severely diminish the capacity available for these existing large volume customers. As a result of a PRS impacting the established operations of existing FEI customers, PRS was considered not viable for the Fording Lateral 219 and Fording Lateral 168.

Elkview Lateral Demand and Capacity Graph

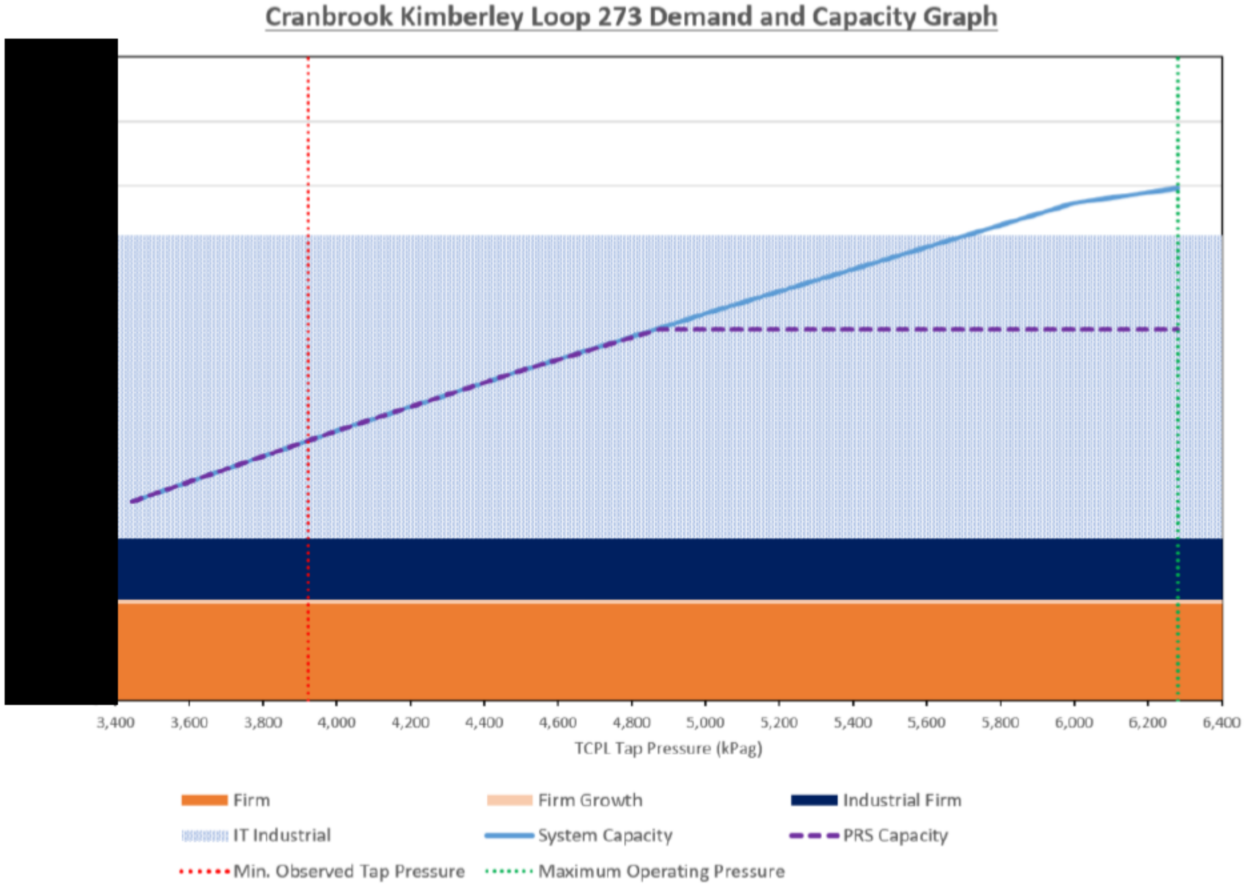


The Elkview Lateral 168 branches off the Fording Lateral System near the community of Sparwood and serves one industrial site. The graph above illustrates that a PRS installed at the start of the lateral has capacity above the requirements of the industrial customer served by the lateral. The pressure at the start of the lateral varies relative to the total Fording System demand and will drop below the 30 percent SMYS pressure of the Elkview lateral when the Fording System demand requirements are at or near the peak demand levels shown in the preceding Fording Lateral 168 and Lateral 219 Demand and Capacity Graph. This previous graph includes the demand on the Elkview lateral. A PRS will be fully open and not restrict throughput under conditions where the inlet pressure is below the set pressure. As a result, FEI concluded that a PRS set to regulate at 29.9 percent SMYS at the start of the Elkview lateral is viable and would not impact the industrial customer.

Cranbrook Kimberley System:

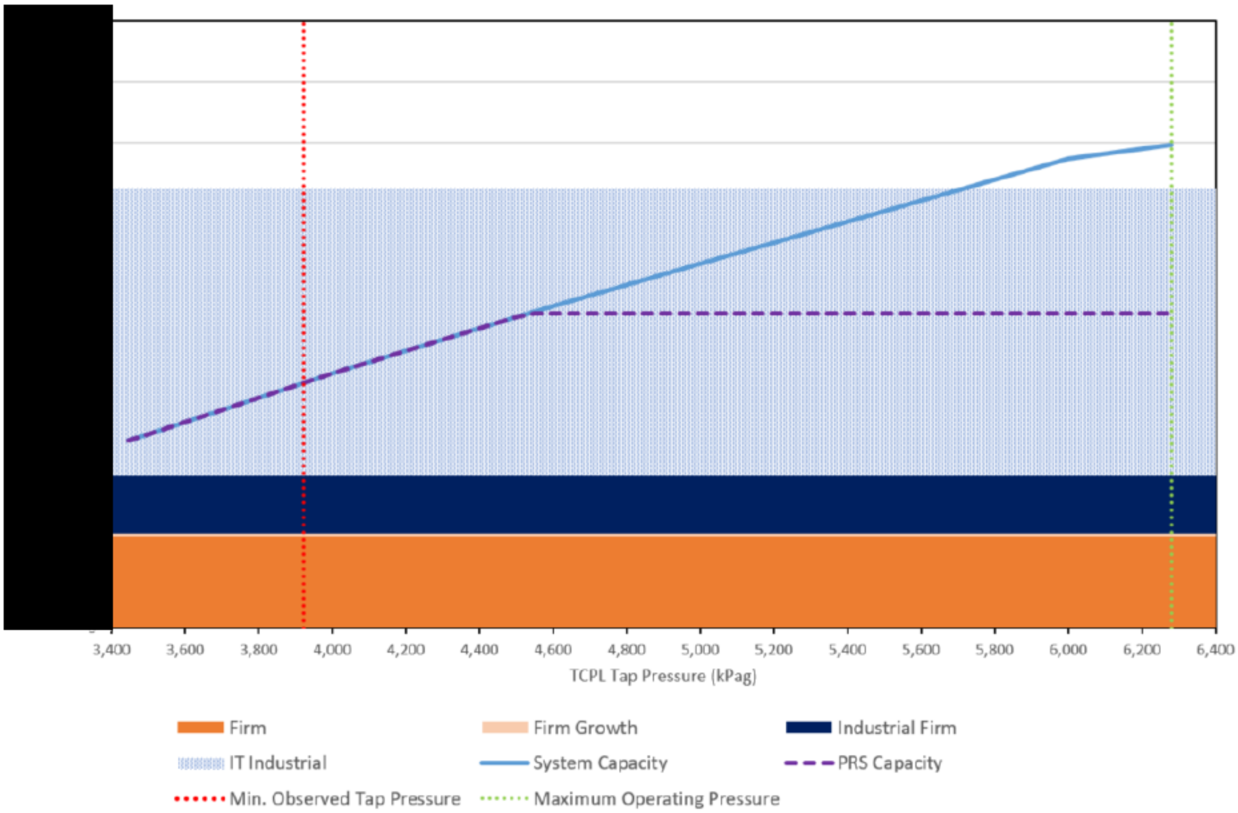


The Cranbrook Kimberley System starts at the TCPL and is comprised of the Cranbrook Lateral 168 which is looped by the Cranbrook Loop 219, which feeds into the Cranbrook Kimberley Loop 273, which in turn feeds the Kimberley Lateral 168 and the parallel Cranbrook Kimberley Loop 219. The Kimberley Lateral 168 ultimately feeds the Skookumchuck Lateral 219. Together these laterals feed Gate Stations serving the communities of Cranbrook, Marysville and Kimberley, several smaller Gate stations distributed along the system and a large industrial customer at the end of the Skookumchuck Lateral. The capacity graph above show that the installation of a PRS at the TranCanada Pipeline (TCPL) Tap to the system would severely diminish the capacity below that required to meet the Firm and Industrial Firm demand within the forecast period. As a result of a PRS impacting the established operations of existing FEI customers, PRS was considered not viable for the Cranbrook Lateral 168 and Loop 219.



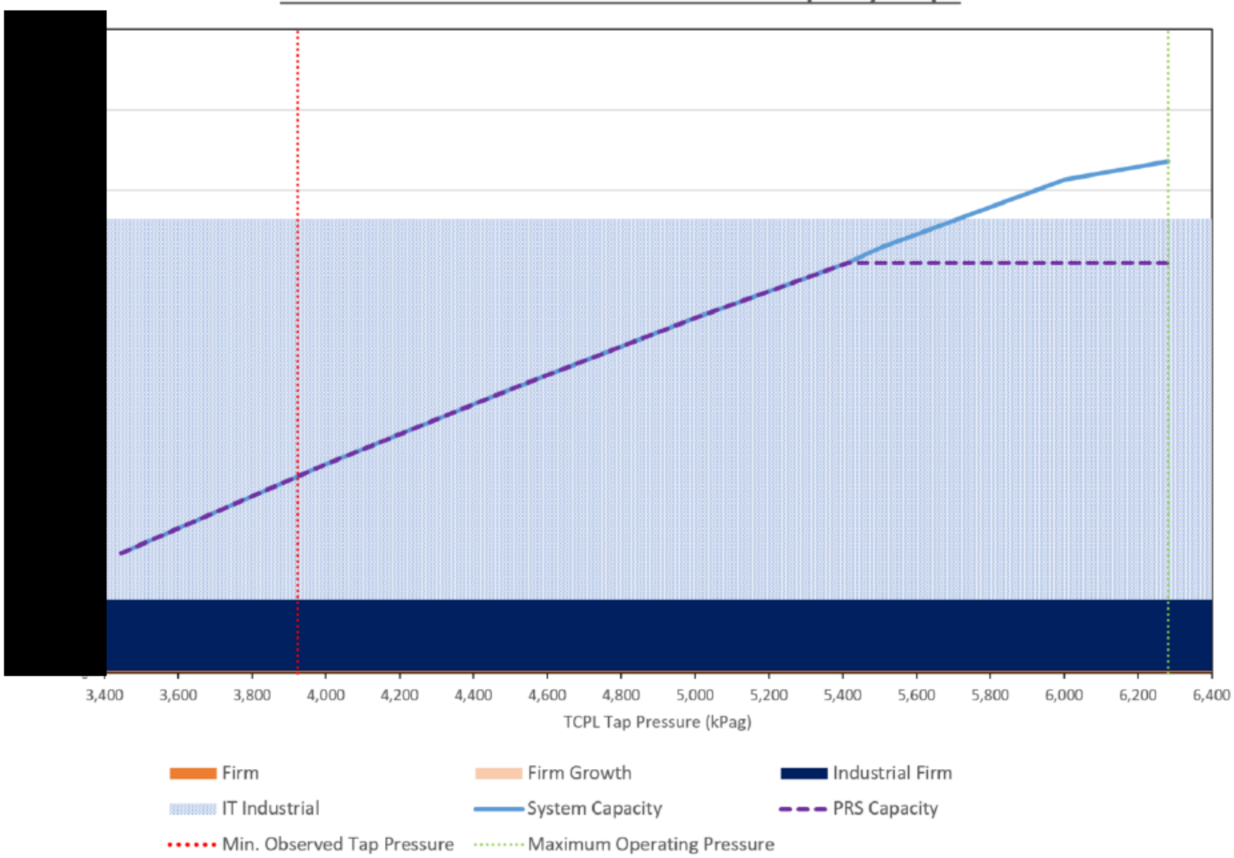
The Cranbrook Kimberley Loop 273 begins just downstream of the Cranbrook Gate station. The capacity graph for the Cranbrook Kimberley Loop 273 illustrates that a PRS at the start of that lateral would cap available capacity such that regardless of the available pressure at the TCPL tap, interruptible customers could be curtailed significantly more often than is required at current operating pressures. The PRS alternative here would impose consequences on these existing customers and also not allow for growth in additional interruptible customers. As a result of a PRS potentially impacting the established operations of existing FEI customers, PRS was considered not viable for the Cranbrook Kimberley Loop 273.

<u>Cranbrook Kimberley Loop 219 & Kimberley Lateral 168 Demand and Capacity Graph</u>



The Cranbrook Kimberley Loop 219 and the Kimberley Lateral 168 begins just downstream of the McPhee Control Station north of Cranbrook. The capacity graph for the laterals illustrates that using McPhee Control Station to regulate the lateral pressure to 29.9 percent SMYS at the start of that laterals would cap available capacity such that regardless of the available pressure at the TCPL tap, interruptible customers could be curtailed significantly more often than is required at current operating pressures. The PRS alternative here would impose consequences on these existing customers and also not allow for growth in additional interruptible customers. As a result of a PRS potentially impacting the established operations of existing FEI customers, PRS was considered not viable for the laterals.

Skookumchuck Lateral 219 Demand and Capacity Graph



The Skookumchuck Lateral 219 branches off the Kimberley Lateral 168 just south east of the city of Kimberley. The capacity graph for the laterals illustrates that using a PRS to regulate the lateral pressure to 29.9 percent SMYS at the start of that laterals would cap available capacity such that regardless of the available pressure at the TCPL tap the industrial customer at the end of the lateral would be curtailed more often than is required at current operating pressures. The PRS alternative here would impose consequences on this existing customer. As a result of a PRS potentially impacting the established operations of existing FEI customers, PRS was considered not viable for the lateral.

14.4 For each of the 29 laterals, please quantify the impact that PRS would have on firm customers, interruptible customers and new customers.

Response:

Please refer to the response to BCUC IR 1.14.3.

15.0 Reference: ALTERNATIVES THAT WERE SCREENED OUT

Exhibit B-1, Section 4.4.4.2, pp. 42, 43

Hydrostatic Testing Program (HSTP)

On page 42 of the Application, FEI states:

> Because HSTP requires the line to be shut-down, consideration of this alternative was limited to laterals with redundant looping or laterals with practical means of supporting downstream customers. Therefore, the HSTP alternative was considered in greater detail for five laterals that were most practical to implement and that were capable of being supplemented with LNG during the hydrostatic testing, or laterals that were able to be taken out of service without interruption to customers.

15.1 Please discuss whether hydrostatic testing in conjunction with ECDA is an appropriate, long-term response to FEI's obligations under OGAA.

Response:

As discussed in Section 4.4.4.2 of the Application, if it were feasible to implement a hydrostatic testing program (HSTP) conducted on an estimated recurring frequency of between 5 to 10 years (described in Section 4.2.3 of the Application) and in conjunction with ECDA, this could be considered an acceptable response to FEI's obligations under OGAA.

However, for the reasons discussed in Section 4.4.4.2 of the Application, (including amongst others, the associated complexity, potential environmental issues, and the inability to remove many of the lines from service to support HSTP), HSTP is not a feasible long-term solution for 24 of the 29 Transmission Laterals. Further, as discussed in Section 4.4.5 of the Application, for those laterals where it was technically feasible, HTSP is considered cost prohibitive when compared to other feasible alternatives as shown in Table 4-8.

15.2 Please discuss any assessments on the use of compressed natural gas (CNG) as a means of supporting downstream customers during line shut-down and provide assessment results.

Response:

A portion of the response to this question is being redacted and filed confidentially with the BCUC. FEI is requesting that this information be filed on a confidential basis pursuant to Section

18 of the BCUC's Rules of Practice and Procedure regarding confidential documents adopted by Order G-15-19, as it contains confidential customer information which is specific and commercially sensitive to the customer and should not be publicly disclosed.

The assessment of support to downstream customers for the IGU Project was conducted in 2017 and, at that time, FEI only considered CNG for very small demands and did not consider the use of CNG to support large industrial loads or distribution systems serving residential or small commercial customers. At the time, FEI had no experience with large volume CNG deliveries. In 2018, following the Enbridge pipeline rupture near Prince George, FEI gained new insight on the capability for large volume CNG delivery as discussed further in the response to BCUC IR 1.15.3.

However, FEI did not need to reassess CNG support in 2018 as Hydrostatic testing was ruled out earlier in the alternative analysis for reasons of cost, significant operational complexity and higher risk of outages extending into colder weather with associated increasing supply requirements should testing result in pipeline failure. Further, when CNG or LNG is required at more than one or two locations it may become too complex operationally to provide reliable supply. Refer to the response to BCUC IR 1.15.4 for additional discussion.

Information from the 2017 assessment is included below for laterals where small scale CNG supply was considered along with LNG for larger demands. The assessment assumes the cool mid-summer temperatures and/or operational adjustments needed to perform hydrostatic testing on each of the pipelines listed. For industrial customers, their firm contract demand and demand rates that met their actual consumption requirements 95 percent of the time over the last five years were identified. However, it was assumed that the industrial customer would need coordinated load management 5 percent of the time. The required consumption can be considerably higher than the values quoted below.

<u>WILLIAMS LAKE LOOP 168</u>

- This pipeline is looped – To maintain sufficient tail end pressure, this segment requires no LNG supplementation for the larger gate stations if pressure into the NPS 4 TP Lateral is at 4,156 kPag or higher on a 13 degree day (DD).

- To facilitate normal unrestricted operation of the one TP service, a 110 m^3 per day CNG tanker with maximum flowrate of 6 m^3/hr will be required at the site on a 8DD or warmer day.

<u>CASTLEGAR NELSON 168</u>

- Two TP services and eight gate stations require both CNG and LNG supply during hydro test.

- To facilitate normal unrestricted operation of the two TP services, a 100 m^3 per day CNG tanker with maximum flowrate of 5.5 m^3/hr will be required at each of these sites on an 8DD or warmer days.

- To facilitate normal unrestricted operation of the eight stations, the LNG requirements at each site on a 8DD or warmer day are listed below:

Station Name	LNG required (gallons/day)	LNG Vapourization Capacity (std m^3/hr)
Castlegar (10298)	5,920	755
Brilliant (10287)	2,590	330
Loff Road (10445)	300	40
Lazeroff Road (10473)	60	10
Shore Acres Road (10308)	670	85
Shasheen FT (10475)	70	10
Granite Road (10474)	360	50
Nelson Stn (10306)	24,770	3,160

<u>TRAIL LATERAL 168</u>

- To facilitate normal unrestricted operation of the Hanna Creek FT (10280), a 100 m^3 per day CNG tanker with maximum flowrate of 5.5 m^3/hr will be required on 8DD or warmer days.

- [redacted]

[redacted]

<u>CRANBROOK LOOP 219</u>

- Two small TP service customers at separate locations would require temporary service transfer to the adjacent in-service TP loop or local supplementation could be sustained with a small local CNG supply.

- Pipeline is looped – Other than the above TP services, this segment requires no LNG/CNG supplementation if the Skookumchuck large industrial customer is held at firm contractual load or testing is coordinated with plant shut down.
- To facilitate normal unrestricted operation of the Skookumchuck large industrial customer, up to 4 isotainers/day (14,250 gal ea.) and LNG vapourization capacity of at least 5,500 std m³/hr will be required to supplement the 4,560 std m³/hr being supplied by the laterals 168mm loop to sustain the estimated daily load of this customer.

<u>CRANBROOK KIMBERLEY LOOP 273</u>

- If the Skookumchuck large industrial customer is held at firm contractual load up to [redacted] isotainers/day (14,250 gal ea.) and LNG vapourization capacity of at least [redacted] std m³/hr will be required to sustain the estimated daily load of this customer.
- To facilitate normal unrestricted operation of the Skookumchuck large industrial customer, up to [redacted] isotainers/day (14,250 gal ea.) and LNG vapourization capacity of at least [redacted] std m³/hr will be required to sustain the estimated daily load of this customer.
- To facilitate normal unrestricted operation of the eight TP services, a 100 m³ per day CNG tanker with maximum flowrate of 5.5 m³/hr will be required at each of these site on a 8DD or warmer days.
- To facilitate normal unrestricted operation of the seven Stations below, the LNG requirements at each site on a 8DD or warmer day are listed below:

Station Name	LNG Required (gallons/day)	LNG Vapourization Capacity (std m³/hr)
Mission Wycliffe Road Station (20058)	430	60
Ta Ta Creek Station (20059)	100	15
Porteous Station (20057)	50	10
4627 Farstad Way (20108)	90	15
Marysville (20014)	1,970	255
Six Mile Road (20033)	900	115
Kimberley (20013)	9,330	1,190

SKOOKUMCHUCK LATERAL 219

- If the Skookumchuck large industrial customer is held at firm contractual load, up to [redacted] isotainers/day (14,250 gal ea.) and LNG vapourization capacity of at least [redacted] std m³/hr will be required to sustain the estimated daily load of this customer.

- To facilitate normal unrestricted operation of the Skookumchuck large industrial customer, up to [redacted] isotainers/day (14,250 gal ea.) and LNG vapourization capacity of at least [redacted] std m³/hr will be required to sustain the estimated daily load of this customer.

- To facilitate normal unrestricted operation of the four TP services, a 100 m³ per day CNG tanker with maximum flowrate of 5.5 m³/hr will be required at each of these sites on 8DD or warmer days.

- To facilitate normal unrestricted operation of the two stations below, the LNG requirements at each site on a 8DD or warmer day are listed below:

Station Name	LNG Required (gallons/day)	LNG Vapourization Capacity (std m³/hr)
Ta Ta Creek Station (20059)	100	15
4627 Farstad Way (20108)	90	15

15.3 Please discuss whether FEI has any experience with CNG transport by road (virtual pipeline).

Response:

FEI recently gained experience in using a virtual pipeline transporting CNG by road following the Westcoast Energy Inc. (Enbridge) pipeline rupture north of Prince George in October 2018. Starting on December 5, 2018, FEI contracted Certarus Ltd. (Certarus), a Houston TX based company with operations in Alberta, to move gas from Princeton, in the BC Interior, to Aldergrove, in the Lower Mainland. Certarus' scope included supplying, filling and transporting a fleet of CNG trailers with each unit capable of delivering approximately 350-380 GJ of gas. At the compression site (a transmission tap on FEI's Kingsvale-Oliver transmission pipeline at Princeton, BC) gas was compressed using Certarus's equipment into the CNG trailers at approximately 3600 psig and transported via truck to the Aldergrove de-compression site. At the de-compression site, 2 portable regulating stations (supplied by Certarus) were brought in to regulate the pressure from the CNG trailers and was discharged into a local FEI Intermediate

Pressure distribution system supplying gas at 275 psig to local district regulating stations in the Aldergrove area.

For two months 20 to 24 trucks per day were cycling between the two locations and delivered a total of approximately 462,000 GJ. Based on this, FEI concludes that with 20 trucks delivering the maximum 380 GJ each, a sustained average hourly gas flow of approximately 9,900 m3/hr could be delivered in a scenario with similar characteristics (e.g., distance and complexity) as the Princeton to Aldergrove virtual pipeline.

15.3.1 If so, please provide an assessment of the results.

Response:

Please refer to the response to BCUC IR 1.15.3.

15.4 Please discuss whether CNG is a cost-effective option of supporting customers during line shut-down due to hydrostatic testing.

Response:

As discussed in the Application, hydrostatic testing was ruled out for reasons of cost, significant operational complexity, and higher risk of outages extending into colder weather with associated increasing supply requirements should testing result in pipeline failure. Although CNG may be a somewhat more cost-effective option compared to LNG, dependent on the volume of gas required to support customers during a line shut-down, FEI still considers this option to be impractical and not cost-effective due to the logistical challenges associated with frequent and ongoing CNG transport. Without additional practical and operational experience in medium to large-scale ongoing CNG deliveries, FEI is unable to determine if the option could be reliable, practical and cost effective for some circumstances.

15.4.1 If not, why not.

Response:

Please refer to the response to BCUC IR 1.15.4.

15.5 Please discuss whether hydrostatic testing reduces the risk of pipeline failure.

Response:

A Hydrostatic test can demonstrate the fitness of a pipeline for continued service and reduce the potential for pipeline failure by rupture during operation. A successful hydrostatic test would very likely screen out any defects that might threaten the pipeline's ability to sustain its intended operating pressure, or show that none exists.

The test pressure is high enough to allow confirmation that any defects on the pipeline at the time of testing would most likely not cause rupture under the intended operating pressure and hence demonstrate the reduction in risk of pipeline failure by rupture. The remaining defects, however, may eventually fail through time-dependent mechanisms and the timing of a recurring hydrostatic test needs to be determined from the previous test pressure, operating pressure history, estimated defect size after the previous test, pipe material properties including toughness, and an estimated corrosion rate. In addition, although a hydrostatic test can screen out the largest defects in the pipeline, the distribution and exact location of the remaining defects along the pipeline would still be unknown after the test.

15.5.1 If so, would the risk be reduced to an acceptable level?

Response:

Yes. Please refer to the responses to BCUC IRs 1.15.1 and 1.15.5.

16.0 Reference: ALTERNATIVES EVALUATION METHODOLOGY

Exhibit B-1, Sections 4.1, 4.5.4, pp. 28, 46-47, Table 4-10

In-line Inspection (ILI) Alternative

On page 28 of the Application, FEI states: "Where PRS was not viable, ILI was selected for longer laterals due to a lower cost and rate impact, and better proactive asset management capability. For longer laterals, PLR had a much higher capital Project cost and resulted in a higher rate impact when compared to ILI for the same lateral."

Table 4-10 on page 47 of the Application shows that ILI was selected as the preferred alternative for 11 of the Transmission Laterals.

16.1 Please confirm, or explain otherwise, that all of the Transmission Laterals where ILI is selected as the preferred alternative will reach the end of their useful life before the end of the 66-year analysis period.

Response:

While the transmission laterals will be fully depreciated before the end of the 66-year analysis period, please refer to the response to BCUC IR 1.1.1 for a discussion of how a pipeline can be safely operated well beyond its expected life from an accounting perspective.

16.2 Please explain if each of the 11 Transmission Laterals selected for the ILI alternative will require replacement during the 66-year analysis period.

Response:

FEI is not forecasting replacement of these 11 transmission laterals over the 66-year analysis period. The selection of the ILI alternative for these 11 transmission laterals means that once upgrades are complete, FEI will be able to inspect the pipeline using ILI technology. Until the ILI is completed there will remain some level of uncertainty regarding the condition of the pipeline. However, once ILI is completed, FEI does not expect that these pipelines would require replacement during the 66-year analysis period because ILI would allow FEI to monitor the pipeline condition on an ongoing basis and locate any pipe imperfections that could require localized repair. A full replacement of the lateral for integrity reasons would only be contemplated if significant integrity concerns were identified during ILI, such that replacement becomes necessary to enable continued safe and reliable operation.

16.2.1 If yes, please explain why the cost to replace the pipeline has not been included in the PV of incremental revenue requirement financial analysis for each of the laterals.

Response:

Please refer to the response to BCUC IR 1.16.2.

16.2.2 If no, please explain why replacement will not be necessary.

Response:

Please refer to the response to BCUC IR 1.16.2.

16.3 If the replacement cost of the pipeline at the end of the 11 Transmission Laterals' useful life was factored into the financial analysis, would ILI still be the preferred alternative for each of the applicable laterals? Please explain and provide all supporting calculations and assumptions.

Response:

As discussed in the response to BCUC IR 1.16.2, there is no evidence to suggest that a replacement would be required for the 11 laterals with ILI as the preferred alternatives. ILI allows FEI to monitor the pipeline on an ongoing basis and locate any pipe imperfections that require localized repair. For this reason, ILI can potentially defer the need to replace the pipeline indefinitely unless systemic integrity concerns are identified for which replacement is determined to be the best and most cost effective alternative.

Notwithstanding this, in order to be responsive, for the 11 transmission laterals with ILI as the preferred alternative, the following table compares the PV of incremental revenue requirements over a 66-year analysis period between ILI and PLR for the hypothetical scenario[13]. The following assumptions were used in the comparison:

- The capital costs to replace the 11 transmission laterals are based on the high level capital cost for PLR in 2018 dollars plus inflation as shown in Table 4-9 of the Application; and
- Replacement of the 11 transmission laterals is assumed to occur when each pipeline reaches the end of its financial life of 65 years.

Line / Loop No.	Lateral	PLR Present Value ($000s)	ILI (with future PLR) Present Value ($000s)	Number of years until future PLR	Original ILI (No future PLR) Present Value ($000s)
1	Mackenzie Lateral 168	103,454	111,024	13	44,750
2	Mackenzie Loop 168	51,318	46,934	23	25,188
7	Prince George 1 Lateral 168	24,998	36,510	3	14,401
14	Salmon Arm Loop 168	143,681	81,589	29	32,564
22	Fording Lateral 219/168	264,428	237,300	19	102,818
24	Cranbrook Lateral 168	113,513	48,555	36	21,151
25	Cranbrook Loop 219	113,940	74,579	21	20,752
26	Cranbrook Kimberley Loop 219	22,010	14,219	38	9,387
27	Cranbrook Kimberley Loop 273	38,888	19,456	38	10,942
28	Kimberly Lateral 168	66,341	72,243	8	23,542
29	Skookumchuck Lateral 219	110,980	79,767	14	14,001

The above hypothetical analysis showed that three out of the 11 transmission laterals will be less expensive in terms of PV of incremental revenue requirement to replace the pipeline today (i.e., PLR today) than completing ILI today with pipeline replacement at the end of the financial life.

It is important to note that, to be conservative, FEI assumed that the future pipeline replacement would occur immediately after the pipeline reaches the end of its financial life at 65 years. However, as discussed in response to BCUC IR 1.1.1, the physical life of a transmission pipeline is not the same as the financial life and a pipeline can have a longer physical life than its financial life, especially when ILI integrity inspections are performed periodically. If the replacement of the pipeline is deferred beyond the end of the financial life, the ILI alternative will become less expensive in terms of the PV of the revenue requirement. As a result, ILI would likely still be selected under this hypothetical scenario because it is the most cost effective solution today for these 11 transmission laterals to achieve the IGU Project's objective.

13 PRS is not feasible for these laterals thus not included in this hypothetical comparison.

17.0 Reference: ALTERNATIVES EVALUATION METHODOLOGY

Exhibit B-1, Section 4.2.5, pp. 30-31

PLR Alternative

On page 31 of the Application, FEI states: "ILI data collection occurs on a recurring cycle (typically 5 to 7 years). For the purposes of this application, including lifecycle cost estimates, FEI has estimated a seven-year re-inspection cycle."

With regard to the PLR alternative, FEI states on page 31 of the Application: "This alternative involves replacing the existing pipeline with a new pipeline constructed to current standards of design (including accommodations for future ILI capability with limited retrofits, e.g., installation of launcher and receiver barrels), material selection, and construction."

17.1 Please confirm, or explain otherwise, that FEI intends to perform ILI data collection on a recurring 5-7 year cycle on the four laterals which have been selected for PLR (once the PLR is completed).

Response:

FEI does not intend to perform ILI on a recurring 5 to 7 year cycle on the four laterals which have been selected for PLR (once the PLR is completed). As the pipelines proposed for PRS and PLR alternatives will operate at less than 30 percent SMYS, the risk to these pipelines due to corrosion is the occurrence of leaks, rather than rupture of the pipeline. As discussed in response to BCUC IR 1.9.1, FEI interprets CSA Z662-15, Clause 12.10.3.3 (d) as recognizing that an operator may wait for an occurrence of leaks on its system prior to implementing a significant condition monitoring program (such as a regular in-line inspection program) or mitigation (replacement, reconditioning, or abandonment). FEI therefore has no reason to include the future sustainment cost of performing ILI integrity runs and digs over the 66-year financial analysis period for PLR. Rather, with the operating stress reduced, these laterals will be subject to pipe condition management activities suitable to the reduced corrosion-related rupture potential (e.g., CP monitoring, leak survey, etc.).

17.1.1 If confirmed, please explain if the costs associated with performing ILI data collection are included in the PV of incremental revenue requirement financial analysis for these laterals.

Response:

Please refer to the response to BCUC IR 1.17.1.

17.1.1.1 If the costs of performing ILI data collection every 7 years are not included in the financial analysis for the four laterals selected for PLR, please explain why not and, if applicable, please provide the revised PV of incremental revenue requirements with the ILI costs included.

Response:

FEI did not add the future sustainment cost of ILI integrity runs and digs to the four transmission laterals with PLR as the preferred alternative since FEI does not expect to incur these costs as discussed in the response to BCUC IR 1.17.1.

17.1.1.2 If FEI factored in the costs of recurring ILI data collection into the financial analysis of the PLR alternative, would PLR continue to be FEI's preferred alternative for the four applicable laterals? Please discuss.

Response:

As discussed in the response to BCUC IR 1.17.1, there is no requirement for, or benefit from, implementing a significant condition monitoring program (such as a regular in-line inspection program) for the PLR alternative, as the new pipeline would be operated below 30 percent SMYS. Therefore, FEI would have no reason to include the cost of installation of launcher and receiver stations and the future cost of performing ILI integrity runs and digs over the 66-year financial analysis period for PLR.

Notwithstanding this, in order to be responsive, for the four transmission laterals with PLR as the preferred alternative, the following table compares the PV of incremental revenue requirements over a 66-year analysis period between ILI, PLR, and PRS for the hypothetical scenario[14]. The following assumptions were used in the comparison:

- The costs of installing the launcher and receiver stations are included as capital costs and are assumed to be constructed at the same time as the new pipeline under construction (previously only the provision for the potential of future installation of launcher and receiver stations was included); and
- ILI integrity runs begin immediately after construction is complete with a 7-year recurring cycle (same as laterals with ILI as the preferred alternative).

Line / Loop No.	Lateral	ILI Present Value ($000s)	PLR (with ILI included) Present Value ($000s)	PRS Present Value ($000s)
3	BC FOREST PRODUCTS LATERAL 168	12,598	8,809	6,955
11	CARIBOO PULP LATERAL 168	10,507	8,175	6,487
13	KAMLOOPS 1 LATERAL & Loop 168	32,104	26,890	-
15	SALMON ARM 3 LATERAL	10,493	9,510	6,589

The above analysis shows that PLR would continue to be less expensive than ILI in terms of PV of incremental revenue requirement when the costs of the launcher and receiver stations and recurring ILI runs are included. However, for the three laterals where PRS is feasible, PLR is no longer the least expensive alternative in terms of PV of incremental revenue requirement.

When also accounting for the technical and project execution and operation scores, as shown in the table below, only one lateral (Cariboo Pulp Lateral 168) would have slightly higher overall score for PRS than PLR.

Line / Loop No.	Lateral	ILI Overall Score	PLR Overall Score	PRS Overall Score
3	BC FOREST PRODUCTS LATERAL 168	3.6	4.0	3.8
11	CARIBOO PULP LATERAL 168	3.5	3.8	3.9
13	KAMLOOPS 1 LATERAL & Loop 168	4.3	4.6	1.8
15	SALMON ARM 3 LATERAL	3.4	3.8	3.7

It is important to note that, to be conservative, FEI assumed the launcher and receiver stations would be installed immediately following construction of the new lateral and integrity runs would begin immediately thereafter. Since FEI sees no reason to incur these costs immediately as discussed above, PLR will become less expensive in terms of PV of revenue requirement as these costs are deferred into the future. As a result, PLR would likely be selected under this

[14] PRS for Salmon Arm 3 Lateral is included as a result of FEI's response to BCUC IR 1.14.1. The evidentiary update to Confidential Appendix N-2 filed as part of the IR responses include the financial analysis of PRS as an alternative for Salmon Arm 3 Lateral.

hypothetical scenario because it is the most cost effective solution for these four transmission laterals to achieve the IGU Project's objective.

18.0 Reference: ALTERNATIVES EVALUATION METHODOLOGY

Exhibit B-1, Sections 4.3, 4.5.4, pp. 32-37, 47, Table 4-10; Appendix I

Evaluation Criteria and Weighting

FEI provides the weight it assigned to each evaluation criterion in Table 4-1, on page 36 of the Application.

18.1 Please further explain how FEI determined the specific percentage weightings for the three criteria (Integrity and Asset Management Capabilities; Project Execution & Lifecycle Operation; and Financial) and why.

Response:

This response also addresses BCUC IR 1.18.1.1.

The weights assigned reflect the relative importance of a criterion in comparison to another criterion. Specifically, FEI determined the weightings for the three criteria as follows.

- Integrity and Asset Management Capabilities were given the highest weighting of 45 percent because the alternative selected must be able to meet the Project's objectives. That is, Integrity and Asset Management Capabilities is the most important criterion to meet the Project's objective.
- Financial scoring was the second most important criteria and was assigned a 35 percent weighting so that the alternative selected minimizes the overall Project cost and thereby reduces the rate impact to customers.
- Project Execution & Lifecycle Operation was assigned a 20 percent weighting as it does not directly impact achieving the Project's objectives, but it is still an important criterion from a Project construction and operations perspective. That is, the alternative selected should, in general, have the lowest execution risks and the lifecycle cost must still be a factor in determining an alternative's feasibility.

18.1.1 As part of the above response, please explain why Project Execution & Lifecycle Operation was weighted the lowest at 20 percent.

Response:

Please refer to the response to BCUC IR 1.18.1.

FEI provides weightings for each category within the three evaluation criteria in Tables 4-2 through 4-4 on pages 36-37 of the Application.

18.2 For each of the three evaluation criteria, please explain how FEI developed the categories within each criteria and how it determined the appropriate weighting for each category.

Response:

FEI subject matter leads representing the applicable business areas used their collective experience on past projects to determine categories within each criterion and the appropriate weightings as described below.

With respect to the Integrity and Asset Management Capabilities:

- Prevention of Ruptures is key to achieving the Project's objectives and was therefore given the highest weighting of 45 percent.
- Proactive Asset Management has the second highest weighting at 25 percent because any alternative that could provide FEI with the ability to obtain asset condition information to plan, repair and replace the asset prior to failure occurring is better than a reactive asset management approach.
- Technical Certainty has the third highest weighting at 20 percent because the selection of an alternative should not result in changing to another alternative such as replacement in the future. The ability to plan proactively to address hazards before a failure occurs ranks higher because it minimized the need for replacement as a result of failure.
- Prevention of Leaks has the lowest weighting at 10 percent because the main objective of the Project is to address rupture failures. Although FEI implements asset management and maintenance activities such as leak survey and odourization to identify and manage leaks, FEI has an obligation to prevent spillage under the Oil and Gas Activities Act; therefore, this criterion is included.

With respect to the Project Execution and Lifecycle Operation:

- Operational Complexity has the highest weighting of 25 percent because this has the highest long term impact during the lifecycle of the asset. In addition, the more complex the operation, the more likely that the other criteria in the lifecycle operation would be affected, such as environmental, consultation and customer impacts.
- System Capacity and Customer Impacts has the second highest weighting of 20 percent because the ability of the different alternatives to maintain FEI's system capacity with minimal impact to customers is important. The weighting of 20 percent helped FEI select

an alternative that would be unlikely to have a significant impact on its customers and the capacity of its system.

- Environmental, Lands & ROW, Consultation and Engagement Complexity were all given equal weightings of 15 percent because they were equally important in the Project Execution and during the lifecycle of the asset. FEI weighted these equally after giving consideration to the Operational Complexity and Customer Impacts since all three of these factors are important to FEI.
- Project Execution Certainty has the lowest weighting, 10 percent, of all the criteria in the Project Execution and Lifecycle Operation. The project execution was considered to be a short term impact and FEI wanted to prioritize the lifecycle operation higher than the project execution.

With respect to the Financial criteria, the PV of the incremental annual revenue requirement was considered and given 100 percent weighting.

In Table 4-3 on pages 36-37 of the Application, FEI provides the categories within the criterion Project Execution & Lifecycle Operation and the weightings assigned to each category, as follows:

- Environmental – 15%
- Lands & ROW [Right of Way] – 15%
- Consultation and Engagement Complexity – 15%
- Operational Complexity – 25%
- System Capacity & Customer Impacts – 20%
- Project Execution Certainty – 10%

18.3 Please explain how the financial costs associated with each of the above categories in the Project Execution & Lifecycle Operation criterion were taken into account when evaluating each lateral. For instance, were these costs included in the Project Execution & Lifecycle Operation criterion or in the Financial criterion (or both) and why?

Response:

The costs associated with the Project Execution and Lifecycle Operation were included in the financial criterion rather than the Project Execution and Lifecycle operation criterion. The costs associated with the categories in the Project Execution and Lifecycle Operation were taken into account when developing the alternative costs for each lateral since each lateral has unique considerations.

Table 4-10 on page 47 of the Application shows the preferred alternative for Elkview Lateral 168 to be PRS, with a PV of incremental revenue requirements amount of $5.9 million compared to a PV of incremental revenue requirements for the second alternative PLR of $5.8 million.

On page 47 of the Application, FEI states that the PRS alternative was selected for the Elkview Lateral even though the PRS and PLR alternatives had comparable net present values. FEI further states that “due to higher capital costs and the larger construction impact associated with a PLR installation in an industrial environment as compared to the PRS, the PRS alternative was selected.”

Appendix I shows that the “1st Alternative” for the Elkview Lateral 168 is PLR and the “2nd Alternative” is PRS, with the PLR and PRS alternatives scoring 4.5 and 3.8, respectively.

18.4 Please elaborate on FEI’s rationale for selecting PRS as opposed to PLR for the Elkview Lateral.

Response:

Although the overall score of PLR and PRS for the Elkview Lateral 168 is 4.5 and 3.8 respectively, there was a very small difference of $46 thousand in the PV of revenue requirement over a 66-year analysis period between PLR and PRS ($5.831 million and $5.877 million, respectively[15]). Considering the small difference in the PV of revenue requirement for the two alternatives over a 66-year analysis period, FEI also considered the difference in the capital cost between PLR and PRS and lateral characteristics. The capital cost of the PLR alternative for Elkview Lateral 168 is $1.239 million more expensive than PRS ($6.588 million and $5.319 million, respectively) and has a higher immediate delivery rate customer impact than PRS (i.e., PRS has a slightly higher but comparable delivery rate impact over a 66-year period but a smaller immediate delivery rate impact in the early years due to a lower initial capital cost).

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[15] FEI notes that an errata to the financial analyses included in Appendix N-2 of the Application will be filed as a result of FEI’s response to BCUC Confidential IR 1.2.5 and BCUC IR 1.21.2. The PV of revenue requirement over a 66-year analysis period for PLR at the Elkview Lateral 168 is revised to $5.850 million from the originally $5.831 million. Although the decision to select PRS as the preferred alternative was based on the original financial analyses, the updated financial analyses do not impact this decision. It is also important to note that the difference in PV of revenue requirement between PLR and PRS is now reduced to $27 thousand over a 66-year analysis period.

Additionally, FEI also considered that the ground disturbance over the construction footprint for the PRS would be significantly less than would be required to replace a 1.5 kilometres lateral. The PRS option also requires less coordination over Teck Coal lands and will have less archaeological and environmental impacts.

As a result, FEI selected PRS as the preferred alternative for Elkview since it has a smaller immediate delivery rate impact, a comparable revenue requirement over the 66-year analysis period, less ground disturbance over a smaller construction footprint than PLR, and less archaeological and environmental impacts.

18.5 Please provide a detailed quantitative and qualitative explanation for how the ILI, PLR and PRS alternatives for the Elkview Lateral were evaluated using the three criteria.

Response:

This response also addresses BCUC IR 1.18.5.1.

A table summarizing the individual category rankings found in Appendix I for the Elkview Lateral are shown below:

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

All of the criteria in the table above were scored from 0-5.

For the Integrity and Asset Management Capabilities and Project Execution & Lifecycle Operation criteria, the scores are as follows:

5 = Good
4 = Above Average
3 = Average
2 = Below Average
1 = Poor
0 = Not Acceptable / Not Feasible

For the Financial criteria, the scores were determined as follows:

5 = Alternative with the Lowest PV or within 5% of the lowest PV
4 = Alternative is 5% to 20% higher than the lowest PV alternative
3 = Alternative is 20% to 50% higher than the lowest PV alternative
2 = Alternative is 50% to 100% higher than the lowest PV alternative
1 = Alternative is over 100% higher than the lowest PV alternative
0 = No cost estimate was prepared for this alternative

Integrity and Asset Management Capabilities

The Integrity and Asset Management Capabilities were determined based on the technical merits of the alternatives, and therefore were scored independent of the specifics for each lateral. For this reason, the Integrity and Asset Management Capabilities scores are identical across all laterals for their respective alternative.

Prevention of ruptures – all three alternatives scored a 5 for prevention of ruptures because each is capable of meeting the project objective.

Prevention of Leaks – ILI scored a 5 since the alternative is capable of preventing leaks with regular in-line inspection. PLR scored a 4 because, while the alternative involves installing a new pipe with modern coating, it does not account for an ongoing condition monitoring program and therefore was not rated a 5. PRS scored a 0 for leak prevention because ECDA is not effective at identifying areas of corrosion for pipes that might have CP shielding and therefore would not provide FEI the ability to prevent leaks. FEI would manage leaks as they occur and should a leak history develop, FEI would explore replacement or other integrity management options.

Proactive Asset Management – ILI scored a 5 since in-line inspection would provide pipe data enabling FEI to plan repair/replace decisions to address potential hazards. PLR scored a 4 because the alternative involves construction of a new pipeline with modern coating and to current construction standards and would therefore be expected to require very little, if any, asset management intervention over the 66-year analysis period. PRS scored a 0 since it does not provide FEI with the ability to plan proactively without regular inspection of the lateral.

Technical Certainty – ILI scored a 4 since in-line inspection could identify sections of pipe requiring replacement. Once the line has been inspected, FEI considers it unlikely that the results from the inspections would require FEI to replace the entire lateral. A benefit of ILI for operators is the ability to focus pipeline rehabilitation efforts to specific locations along a pipeline. PLR scored a 5 for technical certainty, because the alternative would include replacing the entire lateral with a new pipeline with modern coating and to current construction standards not susceptible to CP shielding. PRS scored a 3 for technical certainty because there is a possibility that there could be a need to replace the lateral or implement another integrity management solution (such as ILI) in the future if the lateral demonstrates a leak history.

Project Execution and Lifecycle Operation:

The Project Execution and Lifecycle Operation capabilities for each alternative were evaluated based on the alternatives but also the specifics for each lateral.

Environmental – ILI scored a 3 for the environmental category because there would be a fairly large amount of ground disturbance associated with the necessary pipeline modifications (bend removals, etc.) throughout the length of the lateral. PLR scored a 2 in the environmental category because there would be ground disturbance for the full length of the lateral leading to a larger environmental impact. PRS scored a 4 for the environmental category because the ground disturbance would be limited to the extent of the PRS facility at the start of the lateral.

Lands & ROW – ILI scored a 3 for this category because of the need to obtain additional ROW for the ILI launcher/receiver assemblies, and in particular, the receiver site which would be very close to the mine. PLR scored a 1 for this category because additional ROW would be required for the full length of the pipeline which could be difficult to obtain. PRS scored a 4 for this category, as the land requirement would be limited to the PRS facility at the start of the lateral.

Consultation and Engagement Complexity – ILI and PRS both scored a 3 for this category because of the consultation and engagement complexity with private landowners for the required property for the ILI launcher/receiver assemblies and the PRS. PLR scored a 2 for this category because the consultation and engagement would extend for the full length of the lateral which would be more onerous than the ILI and PRS alternatives.

Operational Complexity – ILI scored a 4 for this category because the ILI runs would only occur every few years and wouldn't require substantial operational activity outside of the ILI runs. PLR scored a 5 for this alternative because once the pipe is installed, there would be no activity required besides ECDA. PRS scored a 3 because there would be regular maintenance activities required on the PRS throughout the lifecycle of the asset.

System Capacity & Customer Impacts – ILI scored a 4 for this category because of potential, relatively minor impacts associated with managing the flow rates required to run the ILI tools. PRS and PLR were both scored a 5 for this category because neither of the alternatives will impact the ability to meet the customers demand requirements.

Project Execution Certainty – ILI and PLR scored a 3 for this category because the amount of ground disturbance required during the project execution could lead to timeline and schedule impacts given that there are sites with archaeological potential. The PRS alternative scored a 4 for this category, because the scope is limited to just the fenced station at the start of the lateral which should result in less complications in terms of scheduling and archaeological impacts.

Financial

Based on the PV shown in the table below from Appendix A, ILI scored a 2 for this category since the PV was 73 percent higher than the lowest PV alternative (PLR). PLR and PRS both scored a 5 for this category since the PV of PRS was 0.8 percent higher than PLR, the lowest PV alternative.

	ILI	PLR	PRS
AACE Estimate Class	Class 3	Class 3	Class 3
Total Project Capital Costs, As-Spent, incl. AFUDC & Removal ($000s)	8,213	6,588	5,319
PV of Post-Project Incremental Sustainment Capital - 66 years ($000s)	1,722	-	1,314
PV of Post-Project Incremental Sustainment O&M - 66 years ($000s)	659	-	18
PV of Incremental Revenue Requirement - 66 years ($000s)	10,072	5,831	5,877
Levelized Rate Impact - 66 years (%)	0.07%	0.04%	0.04%

Conclusion

Based on the financial and non-financial evaluation discussed above, the PRS alternative was selected for the Elkview Lateral.

18.5.1 As part of the above response, please provide the ranking of each category within each criterion and how the individual category rankings were then used to determine the overall ranking of each criterion. Please also explain why the ranking was assigned to each category.

Response:

Please refer to the response to BCUC IR 1.18.5.

18.6 Please further explain FEI's statements on page 47 of the Application regarding higher capital costs for the PLR alternative given the lower PV of incremental revenue requirements for the PLR alternative. As part of this response, please explain all assumptions and calculations.

Response:

As discussed in Section 4.3.1.3 of the Application, the financial analyses over a 66-year period for PRS included the replacement or sustainment costs for the measuring and regulating equipment, the building or enclosed structure for housing the measuring and regulating equipment, and the telemetry equipment when they reach the end of their expected life[16]. The financial analyses also included the incremental O&M expenditures for maintaining the new PRS stations, which is estimated to be $1,000 per year (2018 dollars) per station.

In comparison, for PLR, there is no incremental future capital for replacement and no incremental O&M expenditures (i.e., no increase in O&M costs compared to the O&M costs for the existing pipeline).

The table below is reproduced from Appendix A, Section 1.1.23 of the Application. It shows for the Elkview Lateral 168: the breakdown of the total cost (as-spent dollars), the PV of post-implementation incremental sustainment capital over a 66-year period, and the PV of post-implementation incremental sustainment O&M expenditures over a 66-year period for ILI, PLR and PRS. The combined effect of the total capital cost, future incremental sustainment capital as well as future incremental O&M expenditures resulted in PLR having an overall slightly lower PV of revenue requirement over a 66-year analysis period than PRS[17].

[16] The currently approved depreciation rate for transmission measuring and regulating equipment is 2.41 percent (41.5 years), for transmission measuring and regulating structure is 2.29 percent (43.7 years) and for transmission telemetering is 9.75 percent (10.3 years).

[17] FEI notes that an errata to the financial analyses included in Appendix N-2 of the Application will be filed as a result of FEI's response to BCUC Confidential IR 1.2.5 and BCUC IR 1.21.2. The PV of revenue requirement over a 66-year analysis period for PLR at the Elkview Lateral 168 is revised to $5.850 million from the originally $5.831 million. Although the decision to select PRS as the preferred alternative was based on the original financial analyses, the updated financial analyses do not impact this decision. It is also important to note that the difference in PV of revenue requirement between PLR and PRS is now reduced to $27 thousand over a 66-year analysis period.

	ILI	PLR	PRS
AACE Estimate Class	Class 3	Class 3	Class 3
Total Project Capital Costs, As-Spent, incl. AFUDC & Removal ($000s)	8,213	6,588	5,319
PV of Post-Project Incremental Sustainment Capital - 66 years ($000s)	1,722	-	1,314
PV of Post-Project Incremental Sustainment O&M - 66 years ($000s)	659	-	18
PV of Incremental Revenue Requirement - 66 years ($000s)	10,072	5,831	5,877
Levelized Rate Impact - 66 years (%)	0.07%	0.04%	0.04%

18.7 Please discuss whether, if FEI were to factor in the future replacement of the pipeline within the 66-year analysis period for the PRS alternative, the capital costs for the PLR alternative would become more favourable than the PRS alternative.

<u>Response:</u>

For the Elkview Lateral 168, if FEI were to factor in a replacement of the pipeline 16 years in the future for the PRS alternative (based on the remaining financial life of the lateral), the PV of the <u>capital cost</u> over 66 years would be $9.328 million compared to $5.097 million for the PLR alternative (or $10.333 million in PV of <u>revenue requirement</u> over 66 years for PRS compared to $5.850 million for PLR as shown in response to BCUC IR 1.13.3).

19.0 Reference: ALTERNATIVES EVALUATION METHODOLOGY

Exhibit B-1, Section 4.3.1.3, p. 35

Financial

On page 35 of the Application, FEI states that it considered the long term rate impact to FEI's non-bypass customers to financially compare the feasible alternatives.

19.1 Please discuss whether any of FEI's bypass customers will be impacted by the IGU Project.

Response:

This response also addresses BCUC IR 1.19.1.1.

FEI's bypass customers will not be impacted by the IGU Project.

Bypass contracts are service agreements included as tariff supplements to FEI's rate schedules. Bypass customers have negotiated with FEI for delivery rates that are based on the customer's estimated cost of constructing and operating its own hypothetical pipeline to bypass FEI's system. All bypass agreements and rates are contractual obligations and are approved by the BCUC. These rates cannot be changed outside the terms of the contract and are not subject to general rate changes that would be part of an annual review or revenue requirement application. However, the rates are generally subject to change to reflect costs that the bypass customers would have incurred as a result of an increase in the volume of gas to be transported, had it built its own pipeline. The proposed work on the 29 Transmission Laterals as proposed in the IGU project will not trigger a change to the rates in the agreements because the work is not initiated or requested by bypass customers to increase their contract demand.

19.1.1 As part of the above response, please explain if, based on FEI's bypass agreements with existing customers, the proposed work on any of the Transmission Laterals will impact these agreements or will trigger a change to the agreements. Additionally, please explain if potential impacts on FEI's bypass agreements were taken into consideration when determining the preferred alternative for the Transmission Laterals and if so, how such considerations impacted the selection of the preferred alternative.

Response:

Please refer to the response to BCUC IR 1.19.1.

20.0 Reference: ANALYSIS OF ALTERNATIVES

Exhibit B-1, Sections 4.4.5, 4.5.4, Tables 4-9, 4-10, pp. 44, 47; Appendix I

PLR vs PRS Alternative

Table 4-10 on page 47 of the Application provides the following financial comparisons for the Prince George Pulp Lateral 168, Husky Oil Lateral 168 and Cariboo Pulp Lateral 168:

- Prince George Pulp Lateral 168 – ILI = $14.3 million; PLR = $7.4 million; PRS = $3.6 million
- Husky Oil Lateral 168 – ILI = $16.4 million; PLR = $5.5 million; PRS = $3.6 million
- Cariboo Pulp Lateral 168 – PLR = $5.3 million; PRS = $6.5 million

Appendix I shows that the preferred alternative for the Prince George Pulp Lateral is PRS and the “2nd Alternative” is ILI, with the PRS, ILI and PLR alternatives scoring 3.8, 3.2 and 3.1, respectively.

20.1 Please explain why ILI was ranked as the second alternative for the Prince George Pulp Lateral over PLR given that the cost of ILI is almost double PLR, and the ILI and PLR have almost identical scores.

Response:

The score for an alternative is based on the weights assigned to three criteria: integrity and asset management capabilities at 45 percent, financial scoring at 35 percent, and project execution and lifecycle operation at 20 percent. Please refer to FEI’s response to BCUC IR 1.18.1 for an explanation of each criterion. The following table (also in Appendix A, Section 1.1.8 of the Application) shows the overall score for each alternative considered for the Prince George Pulp 168 Lateral (with higher being better):

	ILI	PLR	PRS
Integrity and Asset Management Capabilities	4.8	4.7	2.9
Project Execution & Lifecycle Operation	3.5	3.3	3.8
Financial	1.0	1.0	5.0
Overal Score	**3.2**	**3.1**	**3.8**

The reason why ILI was ranked as the second alternative over PLR given the cost[18] of ILI is almost double that of PLR ($14.331 million for ILI vs. $7.381 million for PLR) is because both the

[18] Cost in terms of PV of incremental revenue requirement over 66 years.

ILI and PLR received a financial score of 1. The financial scores were determined based on a relative scale as discussed in Section 4.3.2 of the Application and reproduced in the table below:

5 = Alternative with the Lowest PV or within 5% of the lowest PV
4 = Alternative is 5% to 20% higher than the lowest PV alternative
3 = Alternative is 20% to 50% higher than the lowest PV alternative
2 = Alternative is 50% to 100% higher than the lowest PV alternative
1 = Alternative is over 100% higher than the lowest PV alternative
0 = No cost estimate was prepared for this alternative

Even though ILI is almost twice as expensive as PLR in terms of PV of incremental revenue requirement over 66 years, both the ILI and PLR have a PV greater than 100 percent of the PRS, therefore each was assigned a score of 1.0 and PRS a score of 5.0. The table below summarizes the calculations.

	ILI	PLR	PRS
AACE Estimate Class	Class 3	Class 3	Class 3
Total Project Capital Costs, As-Spent, incl. AFUDC & Removal ($000s)	11,664	8,384	2,938
PV of Post-Project Incremental Sustainment Capital - 66 years ($000s)	1,836	-	769
PV of Post-Project Incremental Sustainment O&M - 66 years ($000s)	680	-	9
PV of Incremental Revenue Requirement - 66 years ($000s)	14,331	7,381	3,600
Levelized Rate Impact - 66 years (%)	0.10%	0.05%	0.03%

The financial scoring system was developed to compare the overall delivery rate impact to FEI's customers on a relative scale so that the differences in Present Values could be differentiated and each PV calculation compared as a relative numerical ranking.

The individual scores for each of the other two criteria are likewise determined on a relative ranking scale.

As a result, when combined with the financial score, the overall score for ILI is slightly higher than PLR (3.2 for ILI vs. 3.1 for PLR).

Appendix I shows that the preferred alternative for the Husky Oil Lateral is PRS and the "2nd Alternative" is PLR, with the PRS, PLR and ILI alternatives scoring 3.8, 3.5 and 3.2, respectively.

20.2 Please compare and contrast the Husky Oil Lateral and the Cariboo Pulp Lateral and explain why the PLR alternative is less costly than PRS for the Cariboo Pulp Lateral but not for the Husky Oil Lateral. Please explain all assumptions used when developing the financial analysis for the PLR and PRS alternatives for each lateral.

Response:

Although the Husky Oil Lateral 168 and the Cariboo Pulp Lateral 168 are similar in length (approximately 1.114 km and 1.331 km, respectively), the reason why PRS is less expensive than PLR for the Husky Oil Lateral, but not for the Cariboo Pulp Lateral, is because the PRS station for the Husky Oil Lateral is shared with the Prince George Pulp Lateral (i.e., one station for both Husky Oil Lateral and Prince George Pulp). This can be done because the Husky Oil Lateral continues from Canfor Pulp where the Prince George Pulp Lateral ends. All costs, including future sustainment expenditures for the PRS station is shared between the Husky Oil Lateral and the Prince George Pulp Lateral. If the Husky Oil Lateral could not share the PRS station with Prince George Pulp Lateral, then PLR would have been less expensive than PRS, similar to Cariboo Pulp Lateral.

For the Cariboo Pulp Lateral, the PRS station is not shared with any other laterals. Thus, when considering all costs, including capital costs and future sustainment expenditures, PLR is the least expensive alternative in terms of PV of incremental revenue requirement over 66 years.

21.0 Reference: ANALYSIS OF ALTERNATIVES

Exhibit B-1, Appendix K, Tables K-44, K-45, pp. 83-84

Kamloops 1 Lateral & Loop 168

On pages 83-84 of Appendix K to the Application, it states that PLR is the preferred alternative for the Kamloops Lateral & Loop.

Tables K-44 and K-45 in Appendix K provide the following information on the existing Kamloops Lateral/Loop segments:

Table K-44: Existing KA1 LTL 168 Segments

From KP	To KP	Diameter	Predominant Year of Construction
0+000	0+001	NPS 6 Valve Station	2012
0+001	3+044	NPS 6	1965
3+044	3+058	NPS 8 MLVA	2009
3+058	3+570	NPS 8	1971

Table K-45: Existing KA1 LOP 168 Segments

From KP	To KP	Diameter	Predominant Year of Construction
0+000	0+008	NPS 6 Valve Station	2012
0+008	3+045	NPS 6	1979
3+045	3+050	NPS 6 MLVA	2009

21.1 Please confirm, or explain otherwise, that based on the above tables, certain existing segments of the Kamloops 1 Lateral & Loop were constructed within the past 10 years.

<u>Response:</u>

Some of the existing segments were constructed within the past 10 years but these were limited to only the valve stations. Below is a breakdown of the year of construction of the different segments for each of the Kamloops 1 Lateral and Loop:

	Year of Construction	Length of Segment (m)
Kamloops 1 Lateral 168	1965	3032.6
	1971	512.0
	2009	14.4
	2012	11.4
Kamloops 1 Loop 168	1971	64.2
	1979	2973.1
	2009	5.7
	2012	7.7

As shown above, the predominant years of construction are 1965 for the Kamloops 1 Lateral and 1979 for the Kamloops 1 Loop. The valve stations shown in Tables K-44 and K-45 were constructed in 2009 and 2012.

21.1.1 Please discuss whether the relatively young age of these pipeline segments was taken into consideration when selecting PLR as the preferred alternative.

Response:

FEI clarifies that the pipeline segments of both the Kamloops 1 Lateral and Kamloops 1 Loop are not considered to have a relatively young age. As discussed in the response to BCUC IR 1.21.1, the predominant years of construction are 1965 for the Kamloops 1 Lateral and 1979 for the Kamloops 1 Loop. Only the pipeline segments associated with the valve stations and the Mainline Valve Assembly (MLVA) were installed in the years 2009 or 2012. However, combined, these represent less than one percent in length of both the Kamloops 1 Lateral 168 and Kamloops 1 Loop 168.

Please also refer to the response to BCUC IR 1.1.1.

21.2 Please explain how the undepreciated portions of the existing assets will be accounted for, with the supporting journal entries.

Response:

Prior to providing a response to this question, it is important to understand the group accounting method used by FEI and other utilities in Canada for retirement of plant. For this purpose, FEI has provided a summary below from its 2012-2013 Revenue Requirements Application (pages 289 to 290):

> Historically, the FEU have followed recognized regulatory group accounting procedures in accounting or their property plant and equipment. The FEU also adhere to the BCUC Uniform System of Accounts, unless modified by Commission order. Under both of these procedures, on retirement of depreciable gas plant, Accumulated Depreciation is charged with the ledger value of the gas plant retired and the cost of removal less amounts recovered for salvage and insurance. It is only in rare cases where the forces of retirement are outside of the forces that were contemplated in determining depreciation rates that gains and losses on depreciable plant would be recognized in income. Therefore, under historical practice, all normal course gains and losses on retirement of assets are included in accumulated depreciation.
>
> This treatment is appropriate since group depreciation rates are set to recover the asset values over the average service life of the asset group, so that we expect some assets to be retired before their net book value reaches zero; others would be retired after their net book value reaches zero; and overall the gain/loss amount included in accumulated depreciation will have an immaterial value, with any material amounts recovered through changes to future depreciation rates. When depreciation rates are not adjusted to reflect the shorter service lives of assets, or retirements occur in a different pattern than was expected in the last accepted depreciation study, then the loss amount can build in accumulated depreciation.

An excerpt from the BCUC Uniform System of Accounts explains this more fully:

> The group system contemplates that some part of the investment in a group of assets probably will be recovered through salvage realizations and that probably there will be variations in the service lives of the assets constituting the group, even among assets of the same class. The depreciation provision determined for the group is a weighted average of the various individual provisions reflecting the individual expectancies of life and salvage for the respective assets in the group. It is not the intention of this classification to require the company to keep records of the accumulated depreciation of each unit of plant. For purposes of analysis, however, each company shall maintain subsidiary records in which accumulated depreciation is subdivided according to the utility department to which applicable, or to each group of gas plant accounts. When the retirement or disposal of any

> individual asset in a group occurs under circumstances reasonably provided for through accumulated depreciation, it may be assumed such provision has been made. Thus, whether the period of service is less or greater than average, accumulated depreciation attributable to an asset at the time of retirement under such circumstances, is equal to the cost, except for that portion reasonably assumed recoverable through salvage realization.

At the time of retirement and in accordance with typical treatment as noted above, the accounting of the book asset value includes a credit to Gas Plant in Service with an equal debit entry to Accumulated Depreciation.

Using Kamloops 1 Lateral and Loop 168 as an example, below are the journal entries to record the retirement costs. The same journal entries will apply to the other laterals that have PLR as the preferred alternative. There are no retirements forecasted for laterals with ILI and PRS as the preferred alternative.

Kamloops 1 Lateral & Loop 168

Year	**Account**	**Debit ($000s)**	**Credit ($000s)**
2023	Accumulated Depreciation	476	
2023	Plant		476
This entry accounts for the portion of the Transmission Main to be retired from Asset Account 46500 in 2023			

Year	**Account**	**Debit ($000s)**	**Credit ($000s)**
2024	Accumulated Depreciation	53	
2024	Plant		53
This entry accounts for the portion of the Transmission Main to be retired from Asset Account 46500 in 2024			

The following table shows the continuity of Plant, Accumulated Depreciation, and Rate Base as included in the Financial Analysis (Using Kamloops 1 Lateral & Loop 168 as an example). It is to be noted that for Major Projects, capital expenditures are added to rate base on Jan 1 of the year following the actual in-service date as an opening balance adjustment. Similarly, for Major Projects, retirements are adjusted in rate base on Jan 1 of the year following the actual retirement date as opening balance adjustment.

Rate Base Continuity ($000s)

Line	Rate Base Continuity	Reference	Financial Schedule	2023	2024
1	Plant Opening Balance	Ending Balance of Previous Year		-	14,521
2	Opening Balance Adjustment - Project Cost			14,997	1,689
3	Opening Balance Adjustment - Retirements			(476)	(53)
4	Ending Plant Balance	Sum of Line 1 to 3	Financial Schedule 5, Line 3	14,521	16,157
5	Accumulated Depreciation - Beginning	Ending Balance of Previous Year		-	291
6	Opening Balance Adjustment - Retirements			476	53
7	Depreciation Expense			(185)	(206)
8	Accumulated Depreciation - Ending	Sum of Line 5 to 7	Financial Schedule 5, Line 6	291	138
9	Rate Base - Beginning	Sum of Line 1 to 3 and Sum of Line 5 to 6		14,997	16,501
10	Rate Base - Ending	Sum of Line 4 and 8		14,812	16,295
11	Mid Year Rate Base	(Sum of Line 9 and 10)/2	Financial Schedule 5, Line 14	14,904	16,398

While preparing this response, FEI noticed the Financial Analyses submitted for PLR in the Confidential Appendix N-2 of the Application included the retirement as a credit to the opening balance of the plant; however, FEI inadvertently omitted the debit of the same amount in retirement to the opening balance of accumulated depreciation. The above supporting journal entries show the correct entries for both plant and accumulated depreciation, using Kamloops 1 Lateral & Loop 168 as an example.

FEI is filing an Evidentiary Update which will correct the financial analyses in both Confidential Appendix N-1 and Confidential Appendix N-2. The revision to include the correct debit of retirement costs to accumulated depreciation does not change the alternative evaluation for any lateral and did not change the selection of the preferred alternative.

22.0 Reference: ANALYSIS OF ALTERNATIVES

Exhibit B-1, Sections 4.4.5, 4.5.5, Tables 4-9, 4-10, pp. 44, 47; Appendix I

Kelowna 1 Loop 219

Table 4-9 on page 44 of the Application shows a high level cost for the ILI alternative of $8.3 million and a high level cost for the PLR alternative of $8.2 million for the Kelowna 1 Loop 219.

Table 4-10 on page 47 of the Application shows that further financial analysis was performed on the ILI and PRS alternatives only for the Kelowna 1 Loop 219.

Appendix I to the Application shows that the preferred alternative for the Kelowna 1 Loop 219 is PRS and the "2nd Alternative" is PLR, with the PRS, PLR and ILR alternatives scoring 3.9, 3.8 and 3.1, respectively.

On page 29 of Appendix A to the Application, it states that the year of construction of the Kelowna 1 Loop is 1976.

22.1 Please explain why further financial analysis was not performed for the PLR alternative given the comparability of high level costs between ILI and PLR and the fact that PLR was ranked as the second alternative for the Kelowna 1 Loop 219.

Response:

The PLR cost estimate for Kelowna 1 Loop 219 would have been developed further if PRS was not considered to be a feasible alternative for this lateral. As described in Section 4.5.1 of the Application, where it was viable, PRS was chosen as the preferred alternative in all cases except for one because of the ability of PRS to meet the objectives of the Project at the lowest cost. As shown in Table 4-9, the PRS alternative was less than half the cost of either the ILI or PLR alternative for this lateral.

22.2 Please explain whether the age of the Kelowna Loop and the potential need for replacement in the medium term was taken into account when selecting the PRS alternative.

Response:

The age of the Kelowna 1 Loop 219 was not taken into account when selecting the PRS alternative. As discussed in the response to BCUC IR 1.13.2, FEI has no information or evidence to support the premise that the Kelowna 1 Loop, with PRS as the preferred alternative, will require replacement during the 66-year analysis period.

In the response to BCUC IR 1.13.3, FEI completed a financial analysis for the PRS laterals that accounted for incremental costs associated with ILI or PLR when the pipeline reaches the expected asset financial life of 65 years. In the case of the Kelowna 1 Loop, even when accounting for ILI starting in year 65, PRS is still the most cost effective alternative. FEI has proposed PRS as the most cost effective solution to achieve the IGU Project objective while potentially deferring a higher cost alternative such as ILI or PLR indefinitely.

D. PROJECT DESCRIPTION

23.0 Reference: PROJECT COST ESTIMATE DETAILS

Exhibit B-1, Section 5.3, pp. 68, 72

Contingency and Management Reserve

FEI states the following on page 68 of the Application:

> Ultimately, the risk analysis, as supplemented by the reports from Bramcon and Validation Estimating, were used to establish a contingency percentage at the P50 confidence level. FEI also set a management reserve of 11 percent based on the current understanding of the Project's risk profile and to account for possible scope changes or unknown future events which cannot be anticipated and which were not quantified in the risk register. The Project budget with the management reserve approximates a P70 confidence level.

23.1 Please provide examples of other projects where FEI included a management reserve in addition to the contingency. For each identified project, please describe the project and provide the management reserve and contingency applied to the project.

<u>Response:</u>

This response also addresses BCUC IR 1.23.1.1.

FEI has not previously included a management reserve in addition to contingency. However, FortisBC Inc. included a management reserve in the CPCN Application for the Replacement of the Corra Linn Dam Spillway Gates project. On February 7, 2017, the BCUC granted a CPCN for that project by Order C-1-17. The management reserve was included as part of the Project Contingency. The Project Contingency was estimated at approximately 15.2 percent of the sum of the Total Contractor Costs and Owner's Costs, with the management reserve amounting to approximately 11.6 percent and the contingency amounting to approximately 3.6 percent.

The Corra Linn project was the only project where a management reserve was applied. As it is still ongoing, total actual capital costs are not yet available.

23.1.1 For each of the identified projects provided in the above response, please provide the total actual capital cost of the project compared to the approved budget and explain the cause(s) of any projects which exceeded the approved capital budget (inclusive of contingency and management reserve).

Response:

Please refer to the response to BCUC IR 1.23.1.

FEI further states on page 72 of the Application:

> For a project that is executed over multiple years, however, there are certain risks that can occur but are relatively unknown and have a low likelihood of occurrence but the occurrence of which could have high consequences. To account for these risks, typically called system risks, and based on the analysis conducted by Validation Estimating, the addition of a management reserve of 11 percent (totalling 28 percent together with contingency) is considered prudent.

23.2 Please explain in detail how FEI developed the 11 percent management reserve, including the risks specific to FEI and the IGU Project, and the potential cost implications, which were considered when developing the management reserve.

Response:

FEI calculated its management reserve based on the output of the Monte Carlo Simulation conducted by Validation Estimating LLC, USA (Validation Estimating). As explained on page 70 of the Application, Validation Estimating conducted 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 the Project system risks and Project-specific risks (events and conditions). The details of the methodology are summarized in the Validation Estimating report included as Confidential Appendix L-3 in the Application. The 11 percent management reserve was chosen to arrive at the P70 confidence level cost estimate, as indicated by the results by Validation Estimating's Monte Carlo Simulation.

The potential cost implications of the 11 percent management reserve are equivalent to $29.567 million in As-Spent$ as detailed in Table 5-11.

24.0 Reference: PROJECT RISK

Exhibit B-1, Section 5.3, pp. 68-72

Ranking of Transmission Laterals

24.1 Please provide a table ranking the 29 Transmission Laterals from highest risk to lowest risk based on the following risk areas and provide a detailed explanation for the ranking assigned to each lateral within each risk area:

- Overall risk;
- Project cost;
- Project scope and timeline;
- Consultation requirements;
- Environmental impacts;
- ROW requirements;
- Permitting; and
- Other.

Response:

FEI has provided two tables below that rank the 29 Transmission Laterals based on the execution risk and other risk areas as mentioned in the preamble. The table below shows the approximate execution risk ranking for each lateral from high to moderate to low.

Lateral	Risk Ranking
22. FRD LTL 219/168	High
13. KA1 LTL/LOP 168	High
14. SAL LOP 168	High
1. MAC LTL 168	High
7. PG1 LTL 168	High
28. KBY LTL 168	Moderate
24. CRK LTL 168	Moderate
25. CRK LOP 219	Moderate
29. SSK LTL 219	Moderate
26. CRK LP2 219	Moderate
27. CRK LOP 273	Moderate
15. SA3 LTL 168	Moderate
2. MAC LOP 168	Moderate
18. KE1 LOP 219	Moderate
16. COL LTL 219	Moderate

Lateral	Risk Ranking
17. COL LOP 168	Moderate
8. PGP LTL 168	Moderate
11. CAR LTL 168	Moderate
23. ELK LTL 168	Low
3. BCF LTL 168	Low
10. PG2 219 168	Low
20. CAS NEL 168	Low
5. NWP LTL 168	Low
6. NWP LOP 219	Low
12. WIL LP1/LP2 168	Low
19. CEL LTL 168	Low
21. TRA LTL 168	Low
9. HUS LTL 168	Low
4. PG3 LTL 219	Low

<u>High Risk Laterals</u>

FRD LTL 219/168 – Considered high risk because the timeline of the lateral is over the full five year Project schedule. There is potential for the Project cost to change subject to the number of modifications required. There are also complex consultation requirements since there are multiple large industrial customers that can be impacted during the installation of ILI modifications given that the Fording Lateral is a single feed supply to these customers. Additionally, this is the longest lateral in the IGU project which will require more permitting due to the large number of sites affected.

KA1 LTL/LOP 168 – Considered high risk because of the existing narrow ROW, challenging construction terrain which can affect the Project cost and timeline, and complex consultation requirements because the Kamloops Lateral will cause disturbance to the municipal Kenna Cartwright Park. The area also has multiple environmental factors to address since it is a critical habitat for woodpecker, toad and snake.

SAL LOP 168 – Considered high risk because of the consultation requirements due to the large number of potentially affected land owners, many environmental factors including critical habitat for great basin spadefoot, and species at risk occurrences. There is a potential for Project cost to change subject to the number of modifications required as well as moderate to high archaeological potential. There are several sites in the ALR that could result in longer permitting approval time.

MAC LTL 168 – Considered high risk due to the HDD across the Mischinsinlika Creek which has potential to affect the Project cost and timeline if the HDD is unsuccessful. There is also potential for cost and timeline change if more modifications are encountered during construction. Because the sites are spread throughout the lateral, there is moderate to high archaeological potential.

PG1 LTL 168 – Considered high risk due to the single feed lateral supplying several industrial customers. There are also sites with moderate to high archaeological potential, registered contaminated sites and creek crossings. Additionally, the potential for more ILI modifications can affect the Project cost and timeline. There are also properties within the ALR that could result in longer permitting approval time.

<u>Moderate Risk Laterals</u>

Cranbrook System (CRK LTL 168, CRK LOP 219, CRK LP2 219, CRK LOP 273, KBY LTL 168, SSK LTL 219) - This system is considered moderate risk because of the potential for Project cost and timeline change. Initial investigations indicate few bend replacements will be required on these laterals so there is potential for cost and timeline change if more modifications are encountered during construction. There is also moderate to high archaeological potential throughout the Cranbrook system which could also affect the Project cost and timeline. All of these laterals have properties in the ALR that could result in longer permitting approval time.

SA3 LTL 168 – Considered moderate risk due to the location of the lateral being adjacent to the Canoe Creek golf course resulting in potential construction impacts to the golf course. The lateral is also in the ALR which could result in longer permitting approval time.

MAC LOP 168 – Considered moderate risk due to the Project cost and timeline changes if more modifications are encountered during construction. There is also moderate to high archaeological potential.

KE1 LOP 219 – Considered moderate risk due to the land acquisition required on high valued property. The Kelowna Loop PRS will require an expansion of the existing ROW in Walmart's parking lot. The permitting may be more challenging than the other laterals since the proposed construction footprint will be in a high traffic area of Kelowna, and may result in more complex consultation requirements.

COL LTL 219 – Considered moderate risk due to the proposed location of the PRS on private property, areas of high archaeological potential confirmed.

COL LOP 168 – Considered moderate risk due to the proposed location of the PRS with unexploded ordinances (UXO) along ROW, areas of high archaeological potential confirmed.

PGP LTL 168 – Considered moderate risk due to the CN rail crossing and lack of existing ROW at proposed PRS site. Overall the construction footprint of the PRS will be limited so FEI does not anticipate many complications on this lateral.

CAR LTL 168 – Considered moderate risk due to the replacement length (1.3 kilometres), the involvement of a road crossing, moderate to high archaeological potential and a registered contaminated site.

Low Risk Laterals

ELK LTL 168 – Considered low risk due to the limited ground disturbance required for the PRS installation. The land acquisition will require negotiation because the PRS will be located on private land.

BCF LTL 168 – Considered low risk because the lateral only has one landowner. Overall, the replacement length is short at 450 metres so FEI does not anticipate many complications on this lateral.

PG2 LTL 219 – Considered low risk due to the limited ground disturbance required for the PRS installation. The land acquisition will be slightly more complex because the PRS will be located on private land.

NWP LTL 168, NWP LOP 219 – Considered low risk due to the limited ground disturbance required for the PRS installation. The PRS will be located on crown land, and FEI anticipates minimal complications in acquiring ROW on crown land.

WIL LP1/LP2 168 - Considered low risk due to the limited ground disturbance required for the PRS installation. The PRS will be located on crown land, and FEI anticipates minimal complications in acquiring ROW on crown land.

CEL LTL 168 – Considered low risk due to the limited ground disturbance required for the PRS installation. The land acquisition will require negotiation because the PRS will be located on private land.

CAS NEL 168 - Considered low risk due to the limited ground disturbance required for the PRS installation. The land acquisition will require negotiation because the PRS will be located on private land.

TRA LTL 168 - Considered low risk due to the limited ground disturbance required for the PRS installation. The land acquisition will require negotiation because the PRS will be located on private land.

HUS LTL 168 – Considered low risk because the PRS will be installed on the Prince George Pulp Lateral so the Husky Oil lateral will not be impacted.

PG3 LTL 219 – Considered low risk because the PRS will be installed on the Northwood Pulp Lateral so the Prince George 3 Lateral will not be impacted.

Lateral	Overall Risk	Risk Ranking	Project Cost	Project Scope and Timeline	Consultation Requirements	Environmental Impacts	ROW Requirements	Permitting
22. FRD LTL 219	28	High	5	5	5	5	4	4
13.1. KA1 LTL/LOP 168	26	High	4	3	5	5	5	4
14. SAL LOP 168	22	High	4	4	5	3	2	4
1. MAC LTL 168	21	High	4	4	3	5	1	4
7. PG1 LTL 168	20	High	3	3	5	3	3	3
28. KBY LTL 168	18	Moderate	2	2	5	3	4	2
24. CRK LTL 168	17	Moderate	2	2	5	5	1	2
25. CRK LOP 219	17	Moderate	2	2	5	5	1	2
29. SSK LTL 219	16	Moderate	2	2	5	3	2	2
26. CRK LP2 219	16	Moderate	2	2	5	3	2	2
27. CRK LOP 273	16	Moderate	2	2	5	3	2	2
15. SA3 LTL 168	16	Moderate	2	1	3	3	5	2
2. MAC LOP 168	15	Moderate	3	2	3	3	1	3
18. KE1 LOP 219	15	Moderate	2	2	3	1	5	2
16. COL LTL 219	14	Moderate	2	1	3	3	3	2
17. COL LOP 168	14	Moderate	2	1	3	3	3	2
8. PGP LTL 168	13	Moderate	2	2	1	1	3	4
11. CAR LTL 168	13	Moderate	2	1	3	1	4	2
23. ELK LTL 168	10	Low	1	1	1	1	4	2
3. BCF LTL 168	10	Low	2	1	1	1	1	4
10. PG2 219 168	10	Low	1	2	1	1	3	2
20. CAS NEL 168	10	Low	2	1	1	1	3	2
5. NWP LTL 168	9	Low	2	1	1	1	3	1
6. NWP LOP 219	9	Low	2	1	1	1	3	1
12. WIL LP1/LP2 168	9	Low	1	1	1	1	3	2
19. CEL LTL 168	9	Low	1	1	1	1	3	2
21. TRA LTL 168	8	Low	1	1	1	1	2	2
9. HUS LTL 168	6	Low	1	1	1	1	1	1
4. PG3 LTL 219	6	Low	1	1	1	1	1	1

E. PROJECT COSTS, ACCOUNTING TREATMENT AND RATE IMPACT

25.0 Reference: ACCOUNTING TREATMENT

Exhibit B-1, Section 6.3.3, pp. 86-87

Application and Preliminary Stage Development Costs

On pages 86-87 of the Application, FEI seeks approval of deferral account treatment for the IGU Project's Application and Preliminary Stage Development costs and proposes to transfer the balance in this deferral account to rate base on January 1, 2020 and commence amortization over a three-year period.

Table 6-5 on page 87 of the Application shows the total before tax offset costs to be $1.348 million.

25.1 Please provide a breakdown and detailed description of the preliminary stage development costs (before tax offset) of $0.950 million.

Response:

The table below provides the breakdown of the preliminary stage development costs (before tax offset) of $0.950 million. The description of each line item is provided below the table.

	Preliminary stage development costs ($000s)
Archaeological & Environmental	34
Engineering	80
Engineering - External	695
Project Management	74
Project Operations Coordination	10
Property Services	38
Subtotal	931
WACC Return (AFUDC)	19
Total Before Tax Offset	950

- **Archaeological & Environmental:** Includes developing management plans, internal oversight and audits.
- **Engineering & Engineering - External:** Includes engineering and engineering support for pipeline, stations, electrical & instrumentation, civil, and geotechnical.
- **Project Management & Project Operations Coordination:** Includes project management, inspection services, and project support.

- **Property Services:** Includes work related to potential land and land rights acquisitions.

25.2 Please explain why FEI is requesting a three-year amortization period for the Application and Preliminary Stage Development Costs deferral account.

Response:

The proposed three-year amortization period for the Application and Preliminary Stage Development Costs deferral is primarily based on recent similar deferral accounts approved for recent CPCN applications. For example, BCUC Order C-2-14 for FEI's Muskwa River Crossing Project for the Fort Nelson Service Area approved a single Application and Project Development Cost deferral account with a three-year amortization period. As well, BCUC Order C-11-15 for FEI's Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) Projects approved two separate deferral accounts for the Application and Project Development costs, both with a three-year amortization period.

Given the size of the projected balance in the deferral account, FEI believes either a one or two-year amortization period would also be appropriate.

25.2.1 As part of the above response, please explain other alternative amortization periods considered by FEI and why these alternatives were considered less appropriate than the proposed three years.

Response:

Please refer to the response to BCUC IR 1.25.2.

F. ENVIRONMENT AND ARCHAEOLOGY

26.0 Reference: ENVIRONMENT AND ARCHAEOLOGY

Exhibit B-1, pp. 92-97

Consultation Strategies by Lateral's Impact Potential

On pages 91 to 92 of the Application, FEI states:

> Locations where there is a medium to high potential for encountering soil or groundwater contamination within the Project area may impact Project construction, cost, and timelines. These areas of potential are called Areas of Potential Environmental Concern (APECs) and are summarized in the Environmental Overview Assessment (Appendix O) and in Table 7-1. Forty seven medium or high risk APECs are present along 21 of the 29 Transmission Laterals.
>
> …
>
> FEI will undertake further assessment of medium and high risk APECs during the detailed engineering phase of the Project to minimize the risk of these APECs on the Project costs and timelines.

26.1 Please summarize the assumptions that FEI has made regarding risks to project costs and timelines, with respect to medium and high risk APECs.

Response:

Areas with potential for existing contaminants (APECs) are identified for each lateral in the Environmental Overview Assessment (EOA) based on the type of contamination expected. The risk of interaction with the Project is ranked as either low, medium or high. For those areas identified with medium and high risk APECs, the associated risks can be mitigated as described in the EOA and the cost is included as mitigation costs in the Project cost. Mitigation costs included pre-construction testing and implementation of standard practices for APECs. In addition, the schedule includes float to address the schedule impacts, if any.

On page 95 of the Application, with respect to terrestrial resources, FEI states:

> Best management practices and mitigation measures to minimize and avoid potential negative effects of the Project on terrestrial resources are described in Section 6 of the EOA [Environmental Overview Assessment] report, including:
>
> - Apply best practices for managing invasive plants;

- Adhere to general wildlife measures;
- Minimize vegetation removal; and
- Adhering to bird timing windows.

FEI will follow the best management practices and mitigation measures applicable to the Project Upgrades during construction.

Sections 7.2.1.5 and 7.2.1.6 of the Application summarize aquatic resources and species at risk, respectively.

26.2 Please confirm that for aquatic resources and species at risk, FEI will follow the best management practices and mitigation measures applicable to the IGU Project Upgrades during construction, as described in Section 6 of the EOA report.

Response:

FEI confirms that the best management practices and mitigation measures for aquatic resources and species at risk will be followed as applicable, as described in Section 6 of the EOA report.

26.3 Please discuss if FEI considers that the best management practices and mitigation measures described in Section 6 of the EOA report are sufficient to ensure that any concerns regarding terrestrial resources, aquatic resources and species at risk are sufficiently addressed.

Response:

Confirmed. The EOA identifies terrestrial and aquatic resource and species at risk sensitivities by lateral, and lateral-specific environmental management plans will be developed prior to construction. The tools outlined in the guiding documents, best management practices, and mitigations measures as described in Section 6 of the EOA will be integrated into the lateral-specific environmental management plans.

26.3.1 Please describe any other actions that may be required, and what assumptions FEI has made regarding costs and timelines for such actions.

Response:

FEI has not identified any action that will be required other than those identified in Section 6 of the EOA, which lists the guiding documents, best management practices, and mitigation measures that will be integrated into the lateral-specific management plans, where applicable. Environmental constraints and associated costs and timelines were considered early on to inform option prioritization. FEI considered surveys, environmental management plan development, permitting, implementation of environmental protection and mitigation measures, environmental monitoring, and restoration in the development of costs and timelines, which are reflected in the cost estimates and schedule for the IGU Project.

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

26.4 Please identify any permits where FEI considers there may be a particularly challenging approval process. Please explain what actions FEI plans to mitigate any potential issues.

Response:

This response also addresses BCUC IRs 1.26.5, 1.26.5.1, and 1.26.5.2.

FEI does not anticipate that any of the environmental permit approval processes will be particularly challenging, and does not anticipate that the extent or complexity of permits required for any of the 29 Transmission Laterals poses a potential risk to the expected timelines or project construction costs. However, FEI is aware that permits such as DFO authorizations and SARA permits could require longer than planned application times. To mitigate the risk associated with the longer than planned times to obtain permits, FEI has included some schedule float in the Project planning schedule.

Estimated environmental permits and approvals were based on the results of desktop studies, preliminary fieldwork programs, and professional experience. Permit application development and approval costs were included in the cost estimate including permits overseen by local, provincial and federal agencies. Expected permitting requirements and associated rationale is provided for each lateral in Section 5 of the EOA.

Environmental permitting is not expected to further affect the sequencing of the work and is not expected to be a primary driver of Project schedule due to other overlapping scheduling considerations. Environmental factors and permitting requirements will be developed further during detailed design.

26.5 Please discuss whether FEI considers that the extent or complexity of permits required for any of the 29 Transmission Laterals poses a potential risk to the expected timelines or project construction costs.

Response:

Please refer to the response to BCUC IR 1.26.4.

26.5.1 Please summarize the assumptions made by FEI in this regard.

Response:

Please refer to the response to BCUC IR 1.26.4.

26.5.2 Please discuss if FEI believes that time required for permitting will affect the sequencing of the works on the 29 Transmission Laterals.

Response:

Please refer to the response to BCUC IR 1.26.4.

G. CONSULTATION

27.0 Reference: CONSULTATION

Exhibit B-1, Table 8-1, pp. 105, 106

Consultation Strategies by Lateral's Impact Potential

On page 105 of the Application, Table 8-1 classifies each lateral into three tiers of "impact potential": high, moderate and low. On page 106, FEI describes the consultation strategies by tier.

27.1 Please provide specific examples of the additional actions that FEI has undertaken in its consultation activities to date with respect to the laterals classified as high impact potential, compared to laterals classified as moderate or low impact potential.

Response:

The difference between the consultation strategy for laterals with high impact potential as compared to low and moderate impact potential is the addition of an opportunity for community information sessions. Consultation activities to date with respect to laterals classified as having high impact potential include sending notification letters to directly impacted landowners and industrial customers, completing presentations at local government association conferences, and meeting with local government and regional districts as requested. At this time, only two local governments have requested public information sessions. Please refer to BCUC IR 1.27.3.

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

27.2 Please explain what actions FEI has taken or plans to take, in order to follow up with stakeholders and rights holders in the laterals with high impact potential where there was no initial response for FEI's notification letters. Please explain if this differs from the approach in the lower impact laterals.

Response:

Please refer to the response to BCUC IR 1.27.1.

27.3 For the laterals with high impact potential, please confirm if community information sessions are planned in each instance.

Response:

At this time, FEI has planned community information sessions in relation to two of the high impact potential laterals: KA1 LTL 168 (PLR) and KA1 LOP 168 (PLR). FEI will continue to be in contact with local governments regarding any future requests for community information sessions as the Project progresses. All high impact potential laterals will have an opportunity for community information sessions.

27.3.1 Please provide estimated timelines, as applicable.

Response:

To ensure customers and the public have the most up to date information, community session timing will be determined and arranged closer to the commencement of construction activities in collaboration with the respective local municipal government.

28.0 Reference: CONSULTATION

Exhibit B-1, pp. 76, 108

Landowners

On page 76 of the Application, FEI states:

> The Project will require fee-simple land acquisition, expanded ROW, temporary construction working space and access rights (Land Rights). FEI will develop a land management plan to assess the required properties and prioritize the acquisitions based on risk and impacts to the schedule. In order to reduce the potential uncertainty associated with securing Land Rights, FEI will enter into an early Option to Purchase Agreement with affected landowners beginning in March 2019 based on the land management plan. Upon granting of the CPCN, FEI will complete the acquisition of Land Rights with all affected landowners.

On page 108, FEI states:

> Notification letters were mailed to directly impacted landowners on June 15, 2018. A sample of the letter can be found in Appendix Q-3. The letters provided information about the Project, the regulatory process and how to contact FEI with any questions or concerns.
>
> …
>
> FEI also provided advanced notification to landowners along FEI's rights of way, informing them about upcoming preliminary Project environmental and survey work. The landowners were notified by phone call or letter, and no concerns were raised. FEI will continue to provide advanced notification of work throughout the duration of the Project.

28.1 Where fee simple purchases are expected, please confirm if all potentially affected landowners have provided response or feedback to FEI's initial consultation.

Response:

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

28.2 Please provide a summary of the risks or issues to be resolved with respect to fee-simple land acquisition.

Response:

Possible risks associated with the completion of fee simple land acquisition include:

- The landowner not wishing to sell the property; or
- The land owner having unreasonable expectations for compensation.

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

Should FEI need to proceed with expropriation in a particular situation, FEI would make an application under Section 6 of the *Gas Utility Act* or section 34(3) of the *Oil and Gas Activities Act* as appropriate for approval to expropriate the necessary land. Should FEI have to undertake expropriation, costs are not expected to vary beyond those in the estimate, with the exception of costs for legal fees.

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

28.2.1 Where applicable, please outline how FEI intends to address these issues with landowners.

Response:

Please refer to the response to BCUC IR 1.28.2.

29.0 Reference: CONSULTATION

Exhibit B-1, Appendix I

Expropriation

On page 2 of Appendix I, FEI makes reference to "potential for expropriation".

29.1 Under what circumstances, if any, does FEI consider there could be the potential for expropriation?

<u>Response:</u>

As discussed in response to BCUC IR 1.28.2, FEI will follow its standard practices with respect to the acquisition of fee-simple land or right of way as applicable to the circumstance and will seek to negotiate mutually acceptable agreements with landowners. While FEI's objective is to reach agreements with landowners, should an agreement not be reached in a particular case, and IGU Project construction could be delayed and no reasonable alternatives exist, FEI would take steps to expropriate the required land rights.

30.0 Reference: CONSULTATION

Exhibit B-1, p. 108

Shuswap National Golf Course

On page 108 of the Application, FEI states:

> FEI also engaged with the Shuswap National Golf Course, formally the Canoe Creek Golf Course, on July 25, 2018 to discuss the Project details and impacts. The general manager advised FEI that the golf course is awaiting budget approvals to build a new course entrance on a road, which runs parallel to the Project's projected construction route for the Salmon Arm Lateral (SA3 LTL 168), a 0.8 kilometre pipeline requiring replacement. The Shuswap National Golf Course management team is interested in completing construction of the new entrance and FEI pipeline replacement in the same timeframe. FEI is committed to keeping the management group at the golf course engaged with Project details and timelines as construction nears.

30.1 Please discuss if FEI identifies any risks or issues with respect to co-ordinating construction at the Shuswap National Golf Course and the FEI pipeline replacement.

Response:

FEI has not identified any risks and does not expect any issues with respect to coordinating construction at the Shuswap National Golf Course. FEI will maintain ongoing dialogue as more detailed construction timelines are finalized to ensure customer inconvenience is minimized. Please refer to the response to BCUC Confidential IR 1.8.3.1.

31.0 Reference: CONSULTATION

Exhibit B-1, pp. 27, 109; Appendix Q-2

Industrial Customer Consultation

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

On page 27 of the Application, FEI states:

> The installation of a PRS was not viable for some laterals due to capacity limitations, which would cause the PRS to impact existing firm customers or interruptible customer operations or prevent new additions of new customers to the lateral.

Appendix Q-2 contains the industrial customers' notification letter.

31.1 Please confirm, or explain otherwise, that the letters sent to industrial customers did not provide information regarding potential impacts such as minor traffic delays on construction routes and the restricted access to peak demand gas use.

<u>Response:</u>

The notification letters sent to industrial customers did not provide specific information regarding potential impacts. Instead, the letters indicated the potential for impacts. FEI received written responses from some industrial customers in regards to the letters and these written responses are included in the Application.

FEI also conducted one-on-one discussions with industrial customers that are served directly from the impacted transmission laterals. The discussions focussed on explaining the proposed work, the possible options and the preferred solution for the transmission lateral from which that customer is served. FEI discussed the proposed work and the potential impacts at a high level. However, FEI believes there should be limited impacts to industrial customers both during and as a result of the work, which was also discussed during the calls. FEI committed to further dialogue and effort to align work during periods of the customers' scheduled maintenance where possible. Customer feedback was supportive and customers had no concerns as the potential work should have minimal impacts to their businesses. The customers requested that FEI remain in communication with respect to schedules of the proposed work and any potential impacts to their daily operations.

31.1.1 If confirmed, please outline how industrial customers have been made aware of these potential impacts.

Response:

Please refer to the response to BCUC IR 1.31.1.

31.2 Please confirm if there are any potentially affected industrial customers that have not provided a response or feedback to FEI's initial consultation.

Response:

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

31.3 Please provide a summary of the feedback received by industrial customers to date.

Response:

Please refer to the response to BCUC IR 1.31.1.

31.4 Please discuss if FEI has, or plans to have, discussions with industrial customers regarding the potential for aligning works on the project with periods of industrial customers' scheduled maintenance.

Response:

Please refer to the response to BCUC IR 1.31.1.

32.0 Reference: CONSULTATION

Exhibit B-1, pp. 103, 104, 110-120

Municipal and Regional Government Consultation

On pages 103 and 104 of the Application, FEI lists the municipal and regional governments potentially affected by the Project.

In Table 8-2 of the Application (pages 110 to 119), FEI provides a summary of local government consultation.

32.1 For the municipalities or regions listed in pages 103 and 104 of the Application where there is no documented consultation in Table 8-2, please provide a summary of FEI's consultation to date, the level and nature of feedback received and future planned consultation activities.

Response:

This response also addresses BCUC IRs 1.32.1.1, 1.32.1.1.1 and 1.32.1.2.

Some communities were not listed in Table 8-2 because responses were not received from those communities. Consultation for all communities is consistent with the tier classification as set out in Section 8.2.2.5 of the Application and communications as described in Section 8.2.2.6 of the Application have been undertaken.

Consultation for Tier Two – Moderate Impact Potential, and Tier Three - Low Impact Potential included Project notification letters to landowners and industrial customers, local and/or regional stakeholder meetings if requested, presentations at the local government association conferences and CPCN filing notification letters.

Consultation for Tier One – High Impact Potential included the additional opportunity for community information sessions and/or presentations. FEI will continue consultation activities throughout the duration of the Project to appropriately inform stakeholders. Additional consultation activities have occurred since the filing of the Application and consultation activities with the City of Prince George are included within an updated Table 8-2 provided as part of the response to BCUC IR 1.32.2.

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

While FEI has not received a response from the communities noted above, FEI intends to continue to engage closely with these municipal and regional governments and will address risk should they arise.

32.1.1 For these municipalities or regions, please discuss whether any are potentially impacted by the "high impact" tier of laterals.

Response:

Please refer to the response to BCUC IR 1.32.1.

32.1.1.1 If yes, please explain why FEI has not documented any consultations.

Response:

Please refer to the response to BCUC IR 1.32.1.

32.1.2 Please discuss if FEI has identified any risks or potential issues to be resolved with respect to the interests of these municipal and regional governments.

Response:

Please refer to the response to BCUC IR 1.32.1.

32.2 Please provide an updated version of Table 8-2 that documents any "next steps" or "follow up" activities that have been fulfilled since the filing of the Application.

Response:

An updated Table 8-2 is provided below. It includes activities related to consultation with the Columbia Shuswap Regional District that occurred after the filing of the Application and also includes consultation activities with the City of Prince George that were inadvertently omitted from the original version.

1 **Table 8-2: Summary of Local Government Consultation**

Local Government	Discussion Summary and/or Issues Raised	Next Steps / Follow up	Actions since CPCN Application Filing
Regional District of Central Kootenay, Area E (Blewett)	**Communication Type:** Inbound email **Location:** n/a **Date**: April 25, 2018 **Email received from:** Ramona Faust, Director Area E, Regional District of Central Kootenay **Stakeholder Interests:** There is an interest in exploring natural gas services for residents of Blewett.	**Follow-up:** FEI replied in person to Director Faust that FEI will investigate if providing gas to the residents of Blewett during Project construction will be feasible. FEI has passed on this request to our Energy Solutions team for consideration	**Follow up:** Letter mailed, January 22, 2019 notifying that CPCN application has been submitted to the BCUC
City of Cranbrook	**Communication Type:** In-person Meeting **Location:** 40 10 Avenue S, Cranbrook, BC **Date**: June 13, 2018 **In Attendance from Cranbrook:** Rob Veg, Senior Planner Rob Price, Planner Tony Hetu, Deputy Director of Public Works Mike Matejka, Manager, Infrastructure Planning Chris Mummery, Construction Compliance Tech. **In Attendance from FEI:** David Seaby, Operations Manager Blair Weston, Community & Indigenous Relations Manager **Stakeholder Interests:** The city requested detailed information on all proposed dig sites, one year prior to the start of construction.	**Next Steps:** Follow-up communications will be ongoing with the City of Cranbrook closer to Project construction dates.	**Follow up:** Letter mailed, January 22, 2019 notifying that CPCN application has been submitted to the BCUC
District of Elkford	**Communication Type:** In-Person Meeting **Location:** 760 Copper Road, Invermere BC **Date**: April 27, 2018 **In Attendance from Invermere:** Curtis Helgesen, Chief Administrative Officer for the District of Elkford. **In Attendance from FEI:** Blair Weston, Community and Indigenous Relations Manager **Stakeholder Interests:** Mr. Helgesen requested detailed map of the proposed construction route for Elkview Lateral 168 (ELK LTL 168).	**Next Steps:** Follow-up meeting was scheduled and held on June 5, 2018 to review route maps and provide more Project details (see entry below).	**Follow up:** Letter mailed, January 22, 2019 notifying that CPCN application has been submitted to the BCUC

Local Government	Discussion Summary and/or Issues Raised	Next Steps / Follow up	Actions since CPCN Application Filing
	Communication Type: In-Person Meeting **Location:** 816A Michel Road, Elkford, BC **Date**: June 5, 2018 **In Attendance from Elkford:** Curtis Helgesen, Chief Administrative Officer for the District of Elkford. **In Attendance from FEI:** Blair Weston, Community and Indigenous Relations Manager **Stakeholder Interests:** Mr. Helgesen inquired about the ability to tie a new gas main extension to a new subdivision during FEI's Project construction in the area.	**Next Steps:** FEI will follow-up with the District when the Project is approximately a year away from construction about the potential main extension.	
Association of Kootenay Boundary Local Governments Conference	**Communication Type:** Presentation **Location:** 901 6 Avenue, Fernie, BC **Date**: April 19, 2018 **In Attendance:** Association of Kootenay Boundary Local Governments Conference, 200 representatives in attendance, including local government elected officials and staff. **In Attendance from FEI:** Blair Weston, Community and Indigenous Relations Manager Darin Wong, Community and Indigenous Relations Manager **Stakeholder Interests:** No concerns or interests were raised.	**Next Steps:** One-on-one meetings were held (detailed in next section of table) on April 19, 2018 with municipalities with highest potential impacts.	
	Communication Type: Follow-up, in-person Meeting **Location:** 901 6 Avenue, Fernie, BC **Date**: April 19, 2018 **In Attendance from Fernie:** Rob Gay, Director Area A, Regional District East Kootenay Mike Sosnowski, Director Area C, Regional District East Kootenay Andy Davidoff, Director Area I, Regional District East Kootenay **In Attendance from FEI:** Blair Weston, Community and Indigenous Relations Manager **Stakeholder Interests:** Attendees requested detailed maps of pipeline routes, inquired about rate impacts, and local procurement opportunities.	**Next Steps:** A follow-up meeting will be scheduled to address stakeholder interests as Project information becomes available. No date set at this time.	**Follow up:** Letter mailed, January 22, 2019 notifying that CPCN application has been submitted to the BCUC

Local Government	Discussion Summary and/or Issues Raised	Next Steps / Follow up	Actions since CPCN Application Filing
	Communication Type: Follow-up, in-person Meeting **Location:** Whistler, BC **Date**: September 12, 2018 **In Attendance from Regional District Kootenay Boundary:** Stewart Horn, Chief Administrative Officer **In Attendance from FEI:** Blair Weston, Community and Indigenous Relations Manager **Note:** Mr. Horn attended FEI's presentation held at the Association of Kootenay Boundary Local Governments Conference on April 19, 2018.	FEI provided Mr. Horn with an update on the Project, while attending the UBCM conference. No concerns were raised and no additional follow up is required at this time.	
Regional District of Kootenay Boundary	**Communication Type:** Follow-up, in-person Meeting **Location:** Whistler, BC **Date**: September 11, 2018 **In Attendance from Regional District Kootenay Boundary:** Mark Andison Chief Administrative Officer **In Attendance from FEI:** Blair Weston, Community and Indigenous Relations Manager **Note:** Mr. Andison attended FEI's presentation held at the Association of Kootenay Boundary Local Governments Conference on April 19, 2018.	FEI provided Mr. Andison with an update on the Project, while attending the UBCM conference. No concerns were raised and no additional follow up is required.	
Regional District of Central Kootenay	**Communication Type:** Inbound email. **Location:** n/a **Date**: May 31, 2018 **Email received from:** Andy Davidoff, Director Area I, Regional District of Central Kootenay **Stakeholder Interests:** FEI received an email requesting the maps of proposed dig sites for the Project on the Castlegar Nelson Lateral (CAS NEL LTL 168).	**Next Steps:** Digital copies were provided in confidence. No additional follow up is required at this time.	**Follow up:** Letter mailed, January 22, 2019 notifying that CPCN application has been submitted to the BCUC
	Communication Type: Inbound email **Location:** n/a **Date**: May 31st, 2018 **Email received from**: Andy Davidoff, Director Area I, Regional District of Kootenay **Stakeholder Interests:** Director Davidoff's email inquired if FEI planned any public information sessions in the Regional District of Kootenay and if FEI is aware of the private water line crossings that cross FEI's right of way in the area. Asked to ensure FEI contacts water license holders, which have water pipes crossing FEI rights of way prior to construction.	**Follow-Up** FEI informed Director Davidoff about FEI's notification letters that were sent to affected landowners. Discussed with Director Davidoff that FEI was going to wait to see if there were any responses to the notification letters before deciding on the need for an open house. FEI also informed Director Davidoff of the BC OGC process and the need for more consultation closer to start of Project construction. FEI suggested that this was a better time for an open house for the residents and Director Davidoff agreed. No further follow up is required at this time.	

Local Government	Discussion Summary and/or Issues Raised	Next Steps / Follow up	Actions since CPCN Application Filing
	Communication Type: outbound phone call **Location:** n/a **Date**: August 14, 2018 **Phone call to**: Andy Davidoff, Director Area I, Regional District of Kootenay	Provided Director Davidoff with an update on the Project.	
City of Kamloops	**Communication Type**: In Person Meeting **Location**: 7 Victoria Street W, Kamloops, BC **Date:** May 30, 2018 **In Attendance from Kamloops:** Jen Fretz, Public Works and Utilities Director Wendy Heshka, Communications Manager Jeff Putnam, Parks and Civic Facilities Manager Kirsten Wourms, Crew Leader - Natural Resources Michael Doll, Parks Ops & Planning Supervisor **In attendance from FEI:** Tony Pham, Project Manager Matt Mason, Community and Indigenous Relations Manager **Stakeholder Interests:** The scope of the Project was discussed. The City does not have any objections to the Project, but the City's primary interests and concerns are related to the Kenna Cartwright Park. The Kenna Cartwright Park ground has recently gone through a BC Hydro power line upgrade project, and construction for the Trans Mountain pipeline project is scheduled roughly around the same time as the Project (estimated in 2020). The City wants FEI to inform and engage with the public regarding impacts to the park. The City has requested that FEI hold public information sessions. The City would like to be involved in the restoration plan once Project construction is complete. The City is interested in Project legacy commitments, such as park benches and a gazebo.	**Next Steps**: FEI will send details on restoration plan, Project schedule, public information session planning and communication planning to stakeholders.	**Follow up:** Letter mailed, January 22, 2019 notifying that CPCN application has been submitted to the BCUC

Local Government	Discussion Summary and/or Issues Raised	Next Steps / Follow up	Actions since CPCN Application Filing
	Communication Type: Follow-Up, In-Person Meeting **Location:** 7 Victoria Street W, Kamloops, BC **Date:** June 27, 2018 **In Attendance from Kamloops:** Jen Fretz, Public Works and Utilities Director Wendy Heshka, Communications Manager Jeff Putnam, Parks & Civic Facilities Manager Kirsten Wourms, Crew Leader, Natural Resources Michael Doll, Parks Operations & Planning Sup. **In Attendance from FEI:** Matt Mason, Community and Indigenous Relations Manager **Stakeholder Interests:** Discussed location for public information session (*determined to host at the park entrance*) and which community groups to involve. Discussed City involvement with restoration planning, ROW width increase requirements, mayor and council communication, and City leadership (Directors) presentation.	**Follow-Up:** FEI will schedule a follow-up meeting to discuss venues for the information session and council presentation format.	
	Communication Type: Follow-Up, In-Person Meeting **Location:** 7 Victoria Street W, Kamloops, BC **Date**: July 9, 2018 **In Attendance from Kamloops:** Ken Christian, Mayor of Kamloops Marvin Kwiatkowski, Director of Development and Engineering Services Wendy Heshka, Communications Manager **In Attendance from FEI:** Kevin Gerow, Regional Manager, Interior North Matt Mason, Community and Indigenous Relations Manager **Stakeholder Interests:** The City requested an in-camera meeting held in August to discuss the additional ROW widening needed. This will require City Council approval for additional land requirement. FEI briefly spoke about the public information session scheduled for August 28, 2018. This was to confirm if there were any outstanding concerns or requests from the City. No concerns were raised from the City about the public information session at this time.	**Follow-Up:** Follow-up requirements include: ongoing Project updates to City Council and staff as the Project progresses.	

Local Government	Discussion Summary and/or Issues Raised	Next Steps / Follow up	Actions since CPCN Application Filing
	Communication Type: Follow-Up, Phone Call **Location:** N/A **Date**: July 25, 2018 **In Attendance from Kamloops:** Jen Fretz, Public Works and Utilities Director Wendy Heshka, Communications Manager Jeff Putnam, Parks and Civic Facilities Manager Kirsten Wourms, Crew Leader - Natural Resources Michael Doll, Parks Ops & Planning Supervisor **In Attendance from FEI:** Matt Mason, Community and Indigenous Relations Manager **Stakeholder Interests:** City staff expressed reservations regarding the timing of the public information session scheduled for August 28, 2018. The City felt strongly that the information session was premature, and that it would be would be more beneficial to postpone the public information session until more detailed Project information was available to share with the public.	**Follow-Up:** FEI has postponed the planned public information session, and is seeking to reschedule the session for some time in the Fall 2018. FEI will continue to engage and communicate with City staff regarding Project details as they become available.	
City of Kimberley	**Communication Type:** In-person Meeting **Location:** 340 Spokane Street, Kimberley, BC **Date**: June 6, 2018 **In Attendance from Kimberley:** Scott Summerville, Chief Administrative Office, City of Kimberley **In Attendance from FEI:** Blair Weston, Community and Indigenous Relations Manager **Stakeholder Interests:** The District would like to ensure that when/if the Project impacts the *Rails to Trails* natural trail between Cranbrook and Kimberley, that ample notification to the public is given, and there is always an accessible path around the worksite.	**Next Steps:** Before the Project begins, FEI will review impacts to the *Rail to Trail* nature trail and discuss plans to mitigate impacts with the District of Kimberley.	**Follow up:** Letter mailed, January 22, 2019 notifying that CPCN application has been submitted to the BCUC
Rocky Mountain and Kootenay Local Government Association.	**Communication Type:** Presentation **Location:** 760 Copper Road, Invermere, BC **Date**: April 27, 2018 **In Attendance:** 150 representatives from local area governments were in attendance. **In Attendance from FEI:** Blair Weston, Community and Indigenous Relations Manager **Stakeholder Interests:** A high-level presentation of the Project was provided to attendees. No issues or concerns were raised.	**Next Steps:** Follow-up one-on-one meetings were held on April 27, 2018 with municipalities with highest impacts (detailed in other sections of the table).	**Follow up:** Letter mailed, January 22, 2019 notifying that CPCN application has been submitted to the BCUC

Local Government	Discussion Summary and/or Issues Raised	Next Steps / Follow up	Actions since CPCN Application Filing
Southern Interior Local Governments Conference	**Communication Type:** Presentation **Location:** 600 Campbell Avenue, Revelstoke, BC **Date**: April 25, 2018 **In Attendance:** 150 representatives were in attendance. **In Attendance from FEI:** Blair Weston, Community and Indigenous Relations Manager **Stakeholder Interests:** Attendees asked general Project questions about timelines and routes. Requested more information as the Project moves forward.	**Next Steps:** Follow-up meetings will be scheduled once the Project has been approved and construction schedules are finalized.	
District of Sparwood	**Communication Type:** In-person Meeting **Location:** 136 Spruce Avenue, Sparwood, BC **Date**: June 5, 2018 **In Attendance from Sparwood:** Terry Mercer, Chief Administrative Office, District of Sparwood **In Attendance from FEI:** Blair Weston, Community and Indigenous Relations Manager **Stakeholder Interests:** The District requested Archeological and Environmental reports that were completed in the District. The District has requested shape files of the Project for their respective region.	**Next Steps:** FEI provided maps of the Project and will send shape files of the Project a year before the construction date. FEI will also follow up with the environmental and archeological reports once they are complete.	**Follow up:** Letter mailed, January 22, 2019 notifying that CPCN application has been submitted to the BCUC

Local Government	Discussion Summary and/or Issues Raised	Next Steps / Follow up	Actions since CPCN Application Filing
Mackenzie Prince George Quesnel Williams Lake Kamloops Salmon Arm Enderby Armstrong Spallumcheen Coldstream Kelowna Trail Castlegar Nelson Cranbrook Kimberley Sparwood Elkford Fraser Fort George RD Cariboo RD Thompson-Nicola RD Columbia-Shuswap RD North Okanagan RD Central Okanagan RD Kootenay Boundary RD RD Central Kootenay	**Communication Type:** Notification Letter mailed **Location:** various **Date**: January 22, 2019		**Follow up:** Letter mailed, January 22, 2019 notifying that CPCN application has been submitted to the BCUC
City of Prince George	**Communication Type: In-person Meeting** **Location: Prince George, BC** **Date: October 31, 2018** **In Attendance from Prince George:** Mayor Lyn Hall Kathleen Soltis, City Manager **In Attendance from FEI:** Mike Leclair, VP Major Projects Kevin Gerow, Regional Manager Matt Mason, Community and Indigenous Relations Manager	**Next Steps:** Follow-up meetings will be scheduled once the Project has been approved and construction schedules are finalized.	

Local Government	Discussion Summary and/or Issues Raised	Next Steps / Follow up	Actions since CPCN Application Filing
Columbia Shuswap Regional District	**Communication Type:** In-bound email **Location:** n/a **Date**: January 30, 2019 **Email received from**: Jan Thingsted, Planner, Development Services, Columbia Shuswap Regional District **Stakeholder Interests:** Jan Thingsted's email inquired as to whether this upgrade would affect Ranchero, south of Salmon Arm and if the City of Salmon Arm and Ministry of Transportation have been notified. Requested that FEI provide CSRD notice of any public information meetings. Requested maps and shape files of project areas.	**Next Steps:** FEI provided maps of the laterals in CSRD area and will send shape files.	**Follow up:** Send shape files and provide updates on project scope and potential information sessions prior to construction

FEI states the following on page 120 of the Application:

> During FEI's initial consultation with the City of Kamloops had raised concerns about the pipeline replacement for KA1 LTL 168 that traverses Kenna Cartwright Park, a regularly used Municipal park in Kamloops. Requests by the City of Kamloops include:
>
> - **Public Consultation:** The City of Kamloops has requested public engagement and awareness about the Project.
>   - FEI is committed to transparent public consultation.
>   - In addition to notification letters, stakeholder meetings and paid advertisements, FEI proposed an open house session for Kamloops residents prior to submission of the CPCN Application. Through engagement with the municipality, the City of Kamloops determined that it would be more effective to hold a public consultation session once more detailed information about the construction plans and schedule were known. FEI committed to follow up with the City of Kamloops to collaborate on rescheduling the session.
> - **Legacies:** The City of Kamloops requests proper restoration efforts with the addition of park benches and a gazebo. The City of Kamloops also wishes to be actively involved during the restoration phase.
>   - FEI's objective is to create these legacies as a part of the restoration commitment, and maintain open communication with the City of Kamloops during the restoration phase.

On page 117 of the Application, FEI states the following:

> The City requested an in-camera meeting held in August to discuss the additional ROW widening needed. This will require City Council approval for additional land requirement. FEI briefly spoke about the public information session scheduled for August 28, 2018. This was to confirm if there were any outstanding concerns or requests from the City. No concerns were raised from the City about the public information session at this time.

32.3 Please confirm, or explain otherwise, that the Kamloops public information session has now taken place.

Response:

Not confirmed. The information session was deferred until closer to construction at the request of City of Kamloops's Director of Parks and staff. As indicated on page 108 of the Application, it was determined by the municipality that the public information session should be rescheduled when Project plans, such as construction timelines and impacts have been finalized, in order to meaningfully engage with the public.

32.3.1 If confirmed, please provide a summary of the feedback from the session, and next steps.

Response:

Please refer to the response to BCUC IR 1.32.3.

32.4 Please describe whether the City of Kamloops has formally or informally set out any "conditions" that it will require being met, for example with respect to FEI's restoration efforts, in order to grant approval for FEI's additional land requirement.

Response:

The City of Kamloops has informally asked FEI to be included in restoration discussions and efforts, but has not made this a conditional requirement to FEI receiving approval for its additional land requirements.

32.4.1 Please discuss if FEI identifies any issues to be resolved in order to receive approval for FEI's additional land requirement with the City of Kamloops.

Response:

In FEI's early discussions with the City of Kamloops, the City recognized the need for the gas line upgrade and that FEI has rights and obligations according to the existing ROW agreement. However, the City identified issues with the ROW widening request from 6m to 18m as per current FEI standards. The City has indicated that the widening of the ROW is subject to the approval of the City Council and the request for the 18m width could be denied due to public concerns.

FEI will continue negotiating with the City for the ROW widening, temporary workspace, and access routes planning in more detail. FEI will submit additional information for review and approval by the City of Kamloops at the detailed engineering design phase.

On page 120 of the Application, FEI states:

> The City of Kimberley also expressed concern regarding the North Star Rails to Trails corridor, a 25-kilometre nature trail that connects the City of Kimberley to the City of Cranbrook. The City requested that the trail remain open during construction. FEI is aware of the concern, and will continue to work with the City of Kimberley through future meetings closer to the construction period.

32.5 Please discuss if FEI's expectation is that the North Star Rails to Trails will be able to remain open during construction.

Response:

It is FEI's preference that the trail remain open during construction. As the Project gets closer to commencing, and detailed design is completed, FEI will have a better understanding of impacts to the trail and will work proactively with the City of Kimberley to minimize any disruptions.

32.5.1 Please discuss any issues that may affect the trail remaining open during construction.

Response:

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

33.0 Reference: CONSULTATION

Exhibit B-1, pp. 98, 122, 123, 127, 129

Consultation with Indigenous Communities

On pages 122 to 123, FEI states:

> FEI has been engaging early with Indigenous communities that may potentially be affected by the Project to:
>
> - Provide information about the Project;
> - Describe any potential impacts from the Project;
> - Understand the interests of Indigenous communities in the area and how they may be affected by the proposed work; and
> - Provide opportunities to give input on the Project.
>
> Engagement was initiated by notification letters followed by face-to-face meetings as requested by the respective community… One purpose of FEI's early engagement is to better understand the nature of interests of Indigenous communities in the area of each of the 29 Transmission Laterals. The impacts of the Project vary by site depending on the proposed work on each lateral.

Table 8-3 on page 123 of the Application provides a list of potentially affected Indigenous Community by lateral.

Table 8-4 on page 127 of the Application provides a summary of FEI's consultation with Indigenous Communities.

33.1 Please provide an updated version of Table 8-4 that documents any "next steps" or "follow up" activities that have been fulfilled since the filing of the Application.

Response:

An updated Table 8-4 is provided below. It includes activities related to engagement with Indigenous communities that occurred after the filing of the Application.

1 **Table 8-4: Summary of Consultation with Indigenous Communities**

Indigenous Community	Summary of Discussion and/or Issues Raised	Next Steps / Follow up	Action since CPCN Application Filing
Splats'in First Nation	In person meeting May 2, 2018 with Director, Title & Rights to discuss Inland Gas Upgrades Project and lateral locations within Splats'in area of interest. Director confirmed they would like to be kept informed about work on SAL LTL and SAL LOP as there is potential for impact to known traditional land use areas and unrecorded archaeological areas; also discussed potential for procurement through Splats'in development corporation business Yucwmenlúcwu, a cultural and natural resource management company.	FEI will continue to provide updates as the Project moves forward, construction timelines are confirmed and procurement opportunities are identified. FEI will continue to meet with the Splats'in First Nation as needed.	**Follow up:** Letter mailed, January 21, 2019 notifying that CPCN application has been submitted to the BCUC
	Follow up meeting held on July 17, 2018 with Yucwmenlúcwu of Splats'in Indian Band. Discussed Project scope, areas of interest to the community and procurement/training opportunities.	FEI will continue to meet with Yucwmenlucwu to provide updates on construction timelines and procurement opportunities.	
Westbank First Nation	FEI had an in-person meeting on May 31, 2018 with Westbank First Nation Intergovernmental Affairs, Rights & Title and Referrals Coordinator regarding KEL 1 LOP. FEI advised that proposed work is for pressure regulating stations and additional land around the existing station will be required.	FEI to follow up with Westbank First Nation Archaeology to discuss any concerns regarding land requirements.	**Follow up:** Letter mailed, January 21, 2019 notifying that CPCN application has been submitted to the BCUC
Stk'emlupsemc te Secwepemc Nation (SSN)	FEI received an email request on May 10, 2018 from Referral Manager for additional maps. FEI requested an in-person meeting to share more information. The meeting was rescheduled twice by Referrals Manager.	FEI spoke with the Director of Operations (Otis Jasper) in an informal meeting about the Project and he did not seem concerned due to the construction being 3 years out. Detailed meeting on the Project will be called in the future and maps will be shared at that time.	**Follow up:** Letter mailed, January 21, 2019 notifying that CPCN application has been submitted to the BCUC
Bonaparte Indian Band	On June 4, 2018, FEI received an email response to notification letter from the Director of Natural Resources, requesting clarification regarding the area of the proposed pipeline.	FEI responded that the proposed work is in the area of Kamloops, outside the area of interest for Bonaparte Indian Band.	**Follow up:** Letter mailed, January 21, 2019 notifying that CPCN application has been submitted to the BCUC

Indigenous Community	Summary of Discussion and/or Issues Raised	Next Steps / Follow up	Action since CPCN Application Filing
Southern Dakelh Nation Alliance	On May 8, 2018, FEI received an email response to the notification letter from the Land and Resource Officer directing FEI to engage with alliance member bands directly.		**Follow up:** Letter mailed, January 21, 2019 notifying that CPCN application has been submitted to the BCUC
Lheidli T'enneh	On May 9, 2018, FEI received a response to the notification letter regarding the consultation process the band prefers.	FEI followed up with Referrals Officer to determine what other information is required and sent the requested information to the Referrals Officer. FEI is committed to meeting with the Lheidli T'enneh again once more information on the Project is available to share.	**Follow up:** Letter mailed, January 21, 2019 notifying that CPCN application has been submitted to the BCUC
	On November 22, 2018, FEI met with Chief Dominique and Band Manager Joe.	FEI provided them with an update on the Project, no concerns raised and no additional follow up is required at this time.	
Ktunaxa Nation Council	FEI had an in-person meeting at the Ktunaxa Nation Council Office on June 8, 2018. Five representatives of the Lands Sector of the Ktunaxa Nation attended. A follow up meeting was held at the Ktunaxa Nation Council Office on June 28th with the Economic Sector of the Ktunaxa Nation. Attendees discussed ways in which the Ktunaxa Nation and community-owned businesses could participate in the Project. FEI assured the Ktunaxa Nation that there would be ongoing engagement on economic opportunities.	The Ktunaxa Nation has provided FEI a letter (Appendix R-3) outlining details they would like to see included in the Environmental and Archaeological plan for the Project. The letter also outlines their position on how to engage, and provide economic and employment opportunities during the length of the Project.	**Follow up:** Letter mailed, January 21, 2019 notifying that CPCN application has been submitted to the BCUC
	FEI had an in-person meeting at the Ktunaxa Nation Council Office on August 29, 2018. Two representatives of the Economic Development attended. FEI provided them with an update on the Project.	FEI will continue to keep the Ktunaxa Nation Council informed as the Project progresses.	

Indigenous Community	Summary of Discussion and/or Issues Raised	Next Steps / Follow up	Action since CPCN Application Filing
Neskonlith Indian Band	FEI had an in-person meeting with the Tmicw Department on June 19, 2018 to discuss the Project. The Neskonlith Indian Band Chief joined the discussion by phone. Tmicw requested more detailed information regarding each lateral, and expressed interest in procurement opportunities during the archaeological work and construction.	FEI sent shape files for each lateral location and additional detailed Project information on June 26, 2018.	**Follow up:** Letter mailed, January 21, 2019 notifying that CPCN application has been submitted to the BCUC
	Follow up meeting with Executive Director was held on July 23, 2018. The discussion focused on potential procurement and training opportunities	FEI will have ongoing meetings as the Project progresses to keep community up to date on developments.	
Osoyoos Indian Band	FEI had an in-person meeting on July 4, 2018 with Referrals Coordinator to discuss the Project. Request to see the environmental plan once complete and review dig locations for culturally sensitive areas, not just archeological sites	FEI provided digital shape files for the laterals in Osoyoos Indian Band traditional territory, and copy of the archeological and environmental assessments currently underway.	**Follow up:** Letter mailed, January 21, 2019 notifying that CPCN application has been submitted to the BCUC
Coldwater, Cook's Ferry and Siska Band	FEI received an email on July 6, 2018 acknowledging receipt of notification letter from FEI.	FEI responded and offered to meet and discuss the Project.	**Follow up:** Letter mailed, January 21, 2019 notifying that CPCN application has been submitted to the BCUC
Okanagan Indian Band	FEI received confirmation of receipt of notification letter on May 9, 2018.	FEI responded and offered to set up a meeting to review the Project in more detail.	**Follow up:** Letter mailed, January 21, 2019 notifying that CPCN application has been submitted to the BCUC

33.1.1 Please summarize the main issues that FEI has presented to Indigenous communities in meetings to date.

<u>Response:</u>

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

- potential for archaeological sites;
- stream crossings; and
- sensitive environmental areas.

33.1.2 Please provide any evidence to indicate whether the Indigenous communities consulted with are satisfied with FEI's consultation to date and proposed next steps.

Response:

FEI has not received any evidence to indicate Indigenous communities are dissatisfied with engagement to date. The responses received are shown in Table 8-4 included in the Application. FEI has committed to ongoing engagement with Indigenous Communities as more project details become available, as discussed in Section 8.3.1 of the Application.

33.2 Please discuss if the initial notification letters [Appendix R-2] were tailored to describe the nature of the specific potential impacts by site. If not, please explain.

Response:

FEI sent the notification letter identified in Appendix R-2 to potentially impacted Indigenous communities identified in Section 8.3.2 of the Application. This initial letter included a general overview of the Project, but did not describe details of the specific impacts by site, as Project details were still being developed at the time of notification. However, maps showing the lateral locations within each Indigenous communities' traditional territory were included. FEI will provide updated site specific Project details to impacted communities, as they become available.

33.2.1 Please explain whether FEI considers that all potentially affected Indigenous communities have been made sufficiently aware of the potential impacts of the IGU Project.

Response:

FEI considers that its engagement activities with Indigenous communities to date have been sufficient, appropriate and reasonable. FEI has notified each identified Indigenous community about the IGU Project. FEI has met with and provided information back to these communities as requested. Where requests were made for more detail than is currently available, FEI has committed to ongoing engagement through follow-up meetings to share information as it becomes available. FEI has also provided letters to each Indigenous community advising of the filing of the Application and how to get involved in the process to review the Application. During the OGC permitting and consultation process that will occur prior to construction, more detailed Project information will be provided to the Indigenous communities for review and comment.

33.3 Please explain how FEI's approach to consultation with Indigenous Communities has differed depending on whether a community is located near a lateral with high impact potential or low impact potential.

Response:

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

33.4 For the Indigenous Communities identified in Table 8-3 that are not listed in Table 8-4, please summarize, whether these communities have: a) provided a response to FEI's notification letter indicating no further information/ consultation is required; b) not responded to FEI's notification letter; or c) other. Please provide any relevant supporting details.

Response:

Please refer to the following table.

Lateral	Indigenous Community	Response
Castlegar CEL LTL 168 CAS NEL 168	Adam Lake	did not respond to FEI's notification letter
	Neskonlith Indian Band	responded, as shown on Table 8-4
	Penticton Indian Band	did not respond to FEI's notification letter
	Upper Nicola Indian Band	did not respond to FEI's notification letter
	Okanagan Nation Alliance	did not respond to FEI's notification letter
	Lower Similkameen Indian Band	did not respond to FEI's notification letter
	Okanagan Indian Band	responded, as shown on Table 8-4
	Splats'in First Nation	responded, as shown on Table 8-4
	Osoyoos Indian Band	responded, as shown on Table 8-4
	Shuswap Indian Band	did not respond to FEI's notification letter
Coldstream COL LTL 219 COL LOP 168	Neskonlith Indian Band	Responded, as shown on Table 8-4
	Penticton Indian Band	did not respond to FEI's notification letter
	Upper Nicola Indian Band	did not respond to FEI's notification letter
	Okanagan Nation Alliance	did not respond to FEI's notification letter
	Okanagan Indian Band	responded, as shown on Table 8-4
	Lower Similkameen Indian Band	did not respond to FEI's notification letter
	Splats'in First Nation	responded, as shown on Table 8-4
Kelowna KE1 LOP 219	Westbank First Nation	responded, as shown on Table 8-4
	Esh-kn-am Cultural Resources Management Services	did not respond to FEI's notification letter
	Nooaitch Indian Band	did not respond to FEI's notification letter
	Okanagan Nation Alliance	did not respond to FEI's notification letter
	Penticton Indian Band	did not respond to FEI's notification letter
	Upper Nicola Indian Band	did not respond to FEI's notification letter
	Lower Similkameen Indian Band	did not respond to FEI's notification letter
	Okanagan Indian Band	responded, as shown on Table 8-4
Cranbrook – Kimberley – Skookumchuck CRK LTL 168 CRK LOP 219 CRK LP2 219 CRK LOP 273 KBY LTL 168 SSK LTL 219	Shuswap Indian Band	did not respond to FEI's notification letter
	Ktunaxa Nation Council*	responded, as shown on Table 8-4
Elkford – Sparwood FRD LTL 219 168 ELK LTL 168	Shuswap Indian Band	did not respond to FEI's notification letter
	Ktunaxa Nation Council*	responded, as shown on Table 8-4

Lateral	Indigenous Community	Response
	Adams Lake Indian Band	did not respond to FEI's notification letter
	Ashcroft Indian Band	did not respond to FEI's notification letter
	Little Shuswap Lake Indian Band	did not respond to FEI's notification letter
	Bonaparte Indian Band	responded, as shown on Table 8-4
	Whispering Pines/ Clinton Band	did not respond to FEI's notification letter
	Neskonlith Indian Band	responded, as shown on Table 8-4
	Nooaitch Indian Band	did not respond to FEI's notification letter
	Esh-kn-am Cultural Resources	responded, as shown on Table 8-4
	Boothroyd Indian Band	did not respond to FEI's notification letter
Kamloops	Spuzzum First Nation	did not respond to FEI's notification letter
	Skuppah Indian Band	did not respond to FEI's notification letter
KA1 LTL 168	Nlaka'pamux Nation Tribal Council	did not respond to FEI's notification letter
KA1 LOP 168	Nicola Tribal Association	did not respond to FEI's notification letter
	Lower Nicola Indian Band	did not respond to FEI's notification letter
	Lytton First Nation	did not respond to FEI's notification letter
	Siska Indian Band	responded, as shown on Table 8-4
	Cook's Ferry Indian Band	responded, as shown on Table 8-4
	Coldwater Indian Band	responded, as shown on Table 8-4
	Oregon Jack Creek Indian Band	did not respond to FEI's notification letter
	Skeetchestn Indian Band	did not respond to FEI's notification letter
	Tk'emlups Band	did not respond to FEI's notification letter
	Stk'emlupsemc te Secwepemc Nation (SSN)	responded, as shown on Table 8-4
Mackenzie	Blueberry River First Nation	did not respond to FEI's notification letter
	West Moberly First Nation	did not respond to FEI's notification letter
MAC LTL 168	Halfway River First Nation	did not respond to FEI's notification letter
MAC LOP 168	Doig River First Nation	did not respond to FEI's notification letter
BCF LTL 168	MacLeod Lake Indian Band	did not respond to FEI's notification letter
Prince George	Nak'azdli Whut'en'	did not respond to FEI's notification letter
	Nazko First Nation	did not respond to FEI's notification letter
PG2 219 168	Carrier Chilcotin Tribal council	did not respond to FEI's notification letter
PG3 LTL 219	Lheidli – T'enneh Band	responded, as shown on Table 8-4
PG1 LTL 168		
NWP LTL 168		
NWP LOP 219		
PGP LTL 168		
HUS LTL 168		
Quesnel	Tsihlqot'in National Government	did not respond to FEI's notification letter
	Carrier Chilcotin Tribal Council	did not respond to FEI's notification letter
CAR LTL 168	Lhtako Dene Nation	did not respond to FEI's notification letter
	Lhoosk'uz Dene Nation	did not respond to FEI's notification letter
	Ulkatcho First Nation	did not respond to FEI's notification letter

Lateral	Indigenous Community	Response
Trail TRA LTL 168	Neskonlith Indian Band Penticton Indian Band Upper Nicola Indian Band Okanagan Nation Alliance Lower Similkameen Indian Band Okanagan Indian Band Splats'in First Nation Osoyoos Indian Band Shuswap Indian Band Ktunaxa Nation Council*	responded, as shown on Table 8-4 did not respond to FEI's notification letter did not respond to FEI's notification letter did not respond to FEI's notification letter did not respond to FEI's notification letter responded, as shown on Table 8-4 responded, as shown on Table 8-4 responded, as shown on Table 8-4 did not respond to FEI's notification letter responded, as shown on Table 8-4
Salmon Arm SAL LTL SAL LOP	Neskonlith Indian Band Okanagan Nation Alliance Penticton Indian Band Upper Nicola Indian Band Lower Similkameen Indian Band Okanagan Indian Band Adams Lake Indian Band Little Shuswap Lake Indian Band Splats'in First Nation	responded, as shown on Table 8-4 did not respond to FEI's notification letter did not respond to FEI's notification letter did not respond to FEI's notification letter did not respond to FEI's notification letter responded, as shown on Table 8-4 did not respond to FEI's notification letter did not respond to FEI's notification letter responded, as shown on Table 8-4
Williams Lake WIL LP1/LP2 168	Xats'ull First Nation Northern Secwepemc Tribal Council Canim Lake Band Neskonlith Indian Band Tsihlqot'in National Government Williams Lake Indian Band	responded, as shown on Table 8-4 (Southern Dakelh Nation Alliance)

** Akisqnuk First Nation, Lower Kootenay Band, St. Mary's Indian Band, Tobacco Plains Indian Band are collectively notified through Ktunaxa Nation Council.*

33.4.1 Please discuss whether FEI has undertaken, or plans to undertake any follow-up communication, including meetings, with these Indigenous Communities. Please provide a summary of activities with dates as applicable.

<u>Response:</u>

As the Project progresses, FEI will continue to work with Indigenous communities as identified in Section 8.3.2 of the Application to keep them apprised of new developments and offer opportunities to comment on Project-specific impacts. Please refer to the response to BCUC IR 1.33.1 for updated Indigenous engagement activities post application filing.

While FEI has not received responses from all Indigenous communities, it will strive to maintain engagement and dialogue with communities during the application phase as per its Statement of Indigenous Principles. Should FEI receive any concerns from Indigenous communities during this phase, it will work to mitigate those concerns in a respectful manner.

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

33.4.2 Please provide an assessment of any potential risks or issues to be resolved with these Communities as more detailed project information becomes available.

<u>Response:</u>

FEI cannot determine a particular risk by community at this stage but it expects primary issues will include environmental impacts, minimizing impacts to archaeological and culturally sensitive areas, and creating employment and procurement opportunities. FEI will continue to engage with Indigenous communities as identified in Section 8.3.2 of the Application as the Project progresses, to ensure opportunities are available to provide input and feedback on potential impacts.

33.5 Please provide FEI's position on whether its early consultation activities have been successful in understanding the nature of interests of Indigenous communities in the area of each of the 29 Transmission Laterals.

<u>Response:</u>

Early engagement with Indigenous communities in the area for each of the 29 Transmission Laterals has been productive in outlining the nature of initial interests of communities that responded. FEI will continue to engage with all Indigenous communities identified in Section

8.3.2 of the Application to ensure they receive opportunities throughout Project development to provide input into the Project.

On page 98 of the Application, FEI states

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

On page 99, FEI states:

> Notifications letters were sent out to Indigenous communities prior to the onset of the AOA preliminary field reconnaissance program. Notification letters outlined the intended fieldwork, included a request for participation in the field program, and opportunities to provide information or comments. Archaeological field crews consisted of one qualified archaeologist and at least one indigenous community member.

On page 129 of the Application, FEI states:

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

33.6 Please describe the level of response to the notification letters regarding the AOA preliminary field reconnaissance program.

<u>Response:</u>

FEI notified Indigenous communities about the IGU Project, outlined the intended field work, and requested participation to provide information and comment. Indigenous communities were then contacted by the Project's Archaeological consultants and provided with an opportunity to participate in the AOA preliminary field reconnaissance (PFR) program. Ten communities participated in the AOA PFR program as noted in Section 7.3.3 of the Application.

33.6.1 Please summarize any comments received with respect to the program.

Response:

No comments were received by FEI with respect to the Project; however, FEI received interest in opportunities for involvement which were brought forward during regular meetings between FEI and Indigenous groups.

33.6.2 Please discuss whether there was any follow-up communication where no response to the letter was received.

Response:

Indigenous communities were contacted by the Project's archaeological consultants and provided with an opportunity to participate in the AOA PFR program. Ten communities participated in the AOA PFR program as noted in Section 7.3.3 of the Application. The project's archaeological consultants contacted communities irrespective of whether they responded to the initial FEI letter notification.

33.7 Please explain whether all Indigenous Communities that may be affected by the potential for deeply buried cultural deposits have been informed about this potential.

Response:

FEI has not had discussions with Indigenous communities specific to deeply buried cultural deposits to date. The Archaeological Overview Assessment (AOA) reports, as filed in Appendix P, identify areas with potential for deeply buried cultural deposits along the existing laterals. The AOA is based on preliminary engineering design; however, further design is required to identify if areas with potential for deeply buried deposits are within the expected Project footprint. FEI will be conducting Archaeological Impact Assessment (AIA) activities closer to construction along with consultation on applicable permits. As more details from the AIA are made available, FEI commits to communicating with affected Indigenous communities about areas with potential for deeply buried cultural deposits.

33.7.1 Please summarize any issues or concerns raised by Indigenous Communities in this regard.

Response:

Please refer to the response to BCUC IR 1.33.7.

33.8 Please provide an estimate of when site specific information related to sensitive areas is likely to be available.

Response:

The collection of sensitive area information will occur during the design phase for each lateral. FEI estimates that much of this site-specific design work will be done in 2020, with some design work related to acquiring long lead materials commencing in 2019.

33.9 Please discuss whether FEI considers that there are any notable risks or issues that will require resolution with respect to sensitive areas as the project develops.

Response:

Based on the AOA information and discussions with Indigenous groups to date, FEI has not identified any notable risks or issues related to sensitive areas that will require resolution. FEI will continue reviewing site-specific information and engage Indigenous communities during Project planning, detailed design, and implementation to manage concerns that may arise related to sensitive areas.

33.9.1 Please clarify if FEI will provide information pertaining to sensitive areas (when available) to all potentially affected communities, regardless of whether further information has been explicitly requested at this stage.

Response:

Confirmed. FEI is committed to ongoing engagement with potentially affected communities and will share information as it becomes available through follow-up meetings, regardless of whether it has been requested.

H. PROVINCIAL GOVERNMENT ENERGY OBJECTIVES AND LONG TERM RESOURCE PLAN

34.0 Reference: PROVINCIAL GOVERNMENT ENERGY OBJECTIVES

Exhibit B-1, p. 131

BC Energy Objectives

On page 131 of the Application, FEI states:

> the Project will support the following British Columbia energy objective found in section 2(k) of the CEA:
>
> > to encourage economic development and the creation and retention of jobs

34.1 Please discuss if FEI considers the Project to be in conflict with any of BC's energy objectives.

Response:

The Project does not conflict with any of BC's energy objectives. The IGU Project is an integrity driven project that will support continued safe and reliable natural gas service to British Columbians.

34.1.1 Please describe any actions that FEI has taken or intends to take to mitigate any such issues.

Response:

Please refer to the response to BCUC IR 1.34.1.

Attachment 6.5

BC Oil & Gas COMMISSION

November 16, 2017

Paul Chernikhowsky
Director, Engineering Services
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, B.C. V4N 0E8

RE: Corrective Action Plan (CAP) Review by BCOGC

On August 3, a meeting was held between BCOGC (the Commission) and FortisBC to review the corrective actions completed and proposed action for the risk assessment finding identified during the 2014 Integrity management program assessment by the Commission. The purpose of the meeting was to clarify BCOGC's expectations and current requirements, and to discuss a moving forward strategy. In response to the meeting, FortisBC had put forward a submission on August 11, 2017 to outline initiatives undertaken to address their risk assessments. This letter is a response to the submission received by the Commission.

Based on the discussion during the meeting, and the assessment of submissions received to date, the following are the Commission's review of FortisBC's corrective action plan:

- The Commission has approved FortisBC's MOC process and proposed corrective actions. (**No further submission required**)
- The Commission has approved FortisBC's Training and Competency assessment process. (**No further submission required**)
- The Commissions requires FortisBC to take further actions for the risk assessment finding as explained below:
  The risk assessment finding required FortisBC to develop and implement a segment-by-segment risk assessment process to determine the risk associated with its pipeline assets in BC.
  From the review of records, documents, and existing procedures and practices, the Commission has determined that FortisBC has only a hazard assessment process that includes *what can go wrong*; determination of controls and management of such controls, as per CSA Z662-15 Annex N Cl. N.8.3 (a) & (b). Since 2014, FortisBC refined its existing approach of hazard identification and control by identifying thresholds for various integrity activities, which can trigger risk assessment requirements/engineering assessment for particular pipelines and segments when those thresholds are reached.

The risk associated with gas pipelines owned and operated by FortisBC can vary according to location, material type, pressure, current condition, and age.
FortisBC has shown no systematic process to determine risk (i.e., the likelihood of failure resulting from hazards and severity of such events or failures) and no process to analyse the hazards, their potential interactions, and overall impact on risk.

The Commission notes that recently FortisBC has made progress with respect to determining risk for capital projects to enable better decision making. These initiatives for capital risk assessments are steps in the right direction. However, the Commission requires FortisBC to commit, develop and implement a risk management process for operating pipelines. This must be carried out to fully meet the requirements of the risk assessment non compliance and meet CSA Z662-15 Clause 3.4.

Z662-15 Clause 3.4 Risk management
There is a commentary available for this Clause.
The operational control required by Clause 3.1.2 f) i) shall be in the form of a risk management process that identifies, assesses, and manages the hazards and associated risks for the life cycle of the pipeline system. The risk management process shall include the following:
a) risk acceptance criteria;
b) risk assessment, including hazard identification, risk analysis, and risk evaluation;
c) risk control;
d) risk monitoring and review;
e) communication; and
f) documentation.
Notes:
1) CAN/CSA-ISO 31000 sets out principles and guidelines for risk management.
2) Annex B provides guidance on performing pipeline system risk assessments.

Commentary on 3.4 from Z662-15
3.4 Risk management
This is a commentary on Clause 3.4.
Risk management is a process whereby operating companies can identify and assess risk throughout the pipeline life cycle and manage it as part of their decision-making process to control the impact of undesirable consequences.
The safety and loss management system includes a requirement for operational controls for risk management. This Clause sets out the objective for the risk management process, as well as the mandatory elements of the process.

FortisBC shall move forward with suitable actions in a timely manner to meet the above requirement. For further guidance, refer to our Compliance Assurance Protocol for Integrity Management Program for Pipeline Systems.

The Commission requires a quarterly update in the progress toward completing this corrective action until completed and an estimated completion date. If you have any questions, please feel free to contact the undersigned.

Sincerely,

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