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FortisBC Energy Inc.

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

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Decision
and Order G-12-20

January 21, 2020

Before:
A. K. Fung, QC, Panel Chair
E. B. Lockhart, Commissioner
T. A. Loski, Commissioner
R. D. Revel, Commissioner

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Executive Summary

FortisBC Energy Inc. (FEI) has 29 transmission laterals in its pipeline inventory that it proposes to upgrade for regulatory, safety and environmental reasons (Project). The laterals are at risk of rupture due to external corrosion, and FEI has determined that this Project is required to mitigate this risk. The Project's cost estimate is approximately $360 million. The Project will take approximately five years to complete.

FEI filed an application (Application) on December 17, 2018 with the British Columbia Utilities Commission (BCUC) seeking a Certificate of Public Convenience and Necessity (CPCN) pursuant to sections 45 and 46 of the *Utilities Commission Act* (UCA). FEI also requests BCUC approval of the establishment of a deferral account, pursuant to sections 59 to 61 of the UCA, to amortize the regulatory costs of the Application and preliminary Project development over three years (Deferral Account).

FEI presented evidence of the need for the Project, explaining why it must address the rupture risk now rather than later, why it should combine the work on 29 laterals into one Project and why the three solutions it has selected to remediate the laterals are the best options. The BC Oil and Gas Commission (BC OGC) supports FEI addressing the identified pipeline integrity concerns. The Project will enable FEI to meet its regulatory obligations set out in the *Oil and Gas Activities Act.*

Although the Project involves 29 transmission laterals, FEI explains that there are several reasons to combine the various upgrades into one Project. FEI can achieve cost and regulatory efficiencies and benefit from scheduling flexibility, by managing the upgrades as one Project. Further, none of the laterals is capable of in-line inspection and all are currently operating at a hoop stress that has the potential for pipeline rupture due to corrosion. Therefore, the need to mitigate the potential for rupture and reduce the consequences of the associated risks is the same for each lateral.

FEI describes its communication plan and consultation activities and indicates that it will continue consultation prior to and throughout construction to help inform local government and residents about construction activities in their area. The Panel is satisfied that FEI's consultation with First Nations to date is adequate. FEI states that it will engage in more extensive consultation to satisfy the BC OGC permitting requirements as the Project unfolds.

Based on the evidence adduced in this proceeding, the Panel approves FEI's Application for a CPCN for the Project and also approves the establishment of the Deferral Account for amortization over three years. In addition, the Panel directs FEI to provide detailed reporting to the BCUC throughout the term of the Project as set out in Section 9 of this Decision.

1.0 Introduction

1.1 Background

On December 17, 2018, FortisBC Energy Inc. (FEI) filed an application with the British Columbia Utilities Commission (BCUC) for a Certificate of Public Convenience and Necessity (CPCN) pursuant to sections 45 and 46 of the *Utilities Commission Act* (UCA)[1] for the Inland Gas Upgrade (IGU) Project (Project) (Application).[2]
FEI is a wholly-owned subsidiary of FortisBC Holdings Inc., a wholly-owned subsidiary of Fortis Inc. FEI is incorporated under the laws of the Province of British Columbia. As the largest natural gas distribution utility in the province, FEI provides residential, commercial and industrial customers with sales and transportation services in more than 100 communities in BC.[3] The utility operates more than 49,000 km of natural gas transmission and distribution mains and service lines serving more than one million customers throughout the province.[4]

FEI's service lines include "transmission laterals" or "lateral pipelines" which deliver natural gas to or from the mainline and are typically between 6 and 16 inches in diameter. In particular, this Application pertains to 29 transmission laterals which FEI owns and operates. These laterals serve customers in the interior of British Columbia including the Northern Region, the Thompson Region, the Okanagan and the Kootenays.[5] These laterals are described in depth in Section 2.1.

The objective of the IGU Project is to mitigate the potential for pipeline rupture on the 29 transmission laterals due to corrosion which is undetectable using currently available pipeline integrity methods[6]. Rupture of a transmission pipeline could have significant safety, reliability, environmental and regulatory consequences. The Project is scheduled to conclude in 2024 and the total Project cost, including the capital costs as well as the Application and preliminary stage development costs, is estimated to be $361.184 million.[7]

1.2 Approvals Sought

In its Application, FEI seeks approval of a CPCN for its IGU Project, pursuant to sections 45 and 46 of UCA.

FEI also seeks approval of a deferral account pursuant to sections 59 to 61 of the UCA to capture the regulatory costs of this Application and the costs expended for the purpose of evaluating the feasibility and preliminary development of the Project.[8]

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[1] *Utilities Commission Act*, R.S.B.C. 1996, c. 473.
[2] Exhibit B-1, Section 1.1, p. 1.
[3] Exhibit B-1, Section 2.1, p. 13.
[4] Exhibit B-1, Section 2.3, p. 13.
[5] Exhibit B-1, Section 1.2.1, p. 4-5.
[6] Exhibit B-1, Section 1.1.1, p. 1.
[7] Exhibit B-1-2, Section 1.1, p.1.
[8] Exhibit B-1, Section 1.1.2, p.2.

1.3 Regulatory Process

By Order G-11-19 dated January 17, 2019, the BCUC established a regulatory timetable for the review of the Application which consisted of intervener registration and one round of information requests (IRs).

By Order G-79-19 dated April 12, 2019, the BCUC amended the regulatory timetable to allow for a second round of IRs, followed by a workshop/procedural conference on July 10, 2019.

By Order G-153-19, dated July 11, 2019, the BCUC further amended the regulatory timetable to allow for a third round of IRs, dates for final and reply arguments and a placeholder for a Streamlined Review Process (SRP).

By Order G-219-19, dated September 11, 2019, the BCUC further amended the regulatory timetable to cancel the SRP and establish dates for final and reply argument.

Five interveners registered in the proceeding: City of Kamloops (Kamloops), City of Kelowna (Kelowna), British Columbia Old Age Pensioners' Organization *et al.* (BCOAPO), the Commercial Energy Consumers Association of British Columbia (CEC), and the Stk'Emlupsemc Te Secwepemc Nation (SSN). BCOAPO and the CEC actively participated in this proceeding. The remaining three interveners did not. Four interested parties registered: City of Prince George, District of Elkford, Tk'Emups Te Wecwepemc, and the BC Oil and Gas Commission (BC OGC). No letters of comment were received.

1.4 Legal and Regulatory Framework

Section 45(1) of the UCA stipulates that a person must not begin the construction or operation of a public utility plant or system, or an extension of either, without first obtaining from the BCUC a certificate that public convenience and necessity require, or will require, the construction or operation of the plant or system.

Section 46(3) states that the BCUC may issue or refuse to issue a CPCN or may issue a CPCN for the construction or operation of only a part of the proposed facility, line, plant, system or extension, and may attach terms and conditions to the CPCN. Section 46 (3.1) and (3.2) require the BCUC to consider:

a) the applicable of British Columbia's energy objectives,[9]

b) the most recent long-term resource plan filed by the public utility under section 44.1, if any, and

c) the extent to which the application for the certificate is consistent with the applicable requirements under sections 6 and 19 of the *Clean Energy Act* (CEA).[10]

The BCUC has jurisdiction to approve the establishment of deferral accounts, pursuant to sections 59 to 61 of the UCA.

[9] BC's energy objectives are defined in section 2 of the *Clean Energy Act*.

[10] Sections 6 and 19 of the CEA do not apply to FEI.

The BCUC's CPCN Guidelines[11] provide general guidance regarding the information that should be included in a CPCN application and the flexibility for an application to reflect the specific circumstances of the applicant, the size and nature of the Project and the issues raised by the application.[12]

Recognizing that it would be onerous, inefficient and not in the public interest to require a CPCN for every utility capital expenditure, the BCUC sets CPCN financial thresholds for FEI. BCUC Order G-120-15 sets the CPCN materiality threshold for FEI at $15 million currently. For capital projects costing more than $15 million, Order G-120-15 directs FEI to demonstrate to the BCUC that the project applied for is not the result of combining smaller projects and that the actual costs exceed the CPCN materiality threshold. The Order also states that the BCUC may require a CPCN review for projects below this threshold if it finds under section 45 of the UCA that it is in the public interest to do so.

FEI is currently under a Performance Based Ratemaking (PBR) Plan which expires at the end of 2019. The $15 million threshold for FEI CPCNs has also been used during FEI's current PBR plan. The proceeding into FEI's Multi-Year Rates Plan for 2020–2024 has not yet concluded. A new materiality threshold may be established as a result of that proceeding.

1.5 *Oil and Gas Activities Act*

The BC OGC is mandated under the *Oil and Gas Activities Act*[13] (OGAA) to regulate natural gas pipelines in the province that operate at pressures greater than 700 kilopascals, which includes the 29 laterals in question. The acceptable standard for the design, construction, operation and maintenance of a gas pipeline is CSA Z662, Oil and Gas Pipeline Systems, developed by the Canadian Standards Association (CSA). The Pipeline Regulation[14] under the OGAA requires natural gas pipeline permit holders to comply with CSA Z662.

1.6 Decision Framework

The structure of this Decision largely follows that of the Application and the BCUC's CPCN Guidelines. Relevant evidence submitted by the applicant and interveners is summarized in each section.

Section 2 addresses the Project need and its justification. Section 2 also focuses on integrity management, the risk of rupture due to external corrosion and the risk assessment methodology.

Section 3 outlines FEI's proposed pipeline integrity management solution, namely, the pipeline modification and replacement projects that it submits are technically and financially feasible methods of mitigating the risk of pipeline rupture. The section also discusses Project execution, construction scheduling and permitting.

Section 4 discusses the alternative technical solutions that FEI considered were capable of meeting the overall Project objectives. This section also describes the Project evaluation criteria and methodology.

Section 5 outlines Project costing, accounting treatment, rate impact and FEI's requested deferral account.

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[11] BCUC Order G-20-15, 2015 Certificate of Public Convenience and Necessity Application Guidelines https://www.bcuc.com/Documents/Guidelines/2015/DOC_25326_G-20-15_BCUC-2015-CPCN-Guidelines.pdf.
[12] BCUC CPCN Guidelines, p. 1.
[13] S.B.C. 2008, c. 36.
[14] B.C. Reg. 281/2010.

The final sections of the Decision address environmental permitting, stakeholder and First Nations consultation, as well as alignment with provincial energy objectives and FEI's internal long-term resource planning.

Panel determinations are provided in Section 9 of the Decision along with BCUC directives relating to detailed reporting requirements and recommendations in Section 10 for FEI's future CPCN applications. Section 11 summarizes the Panel's approvals and directives.

2.0 Project Need and Justification

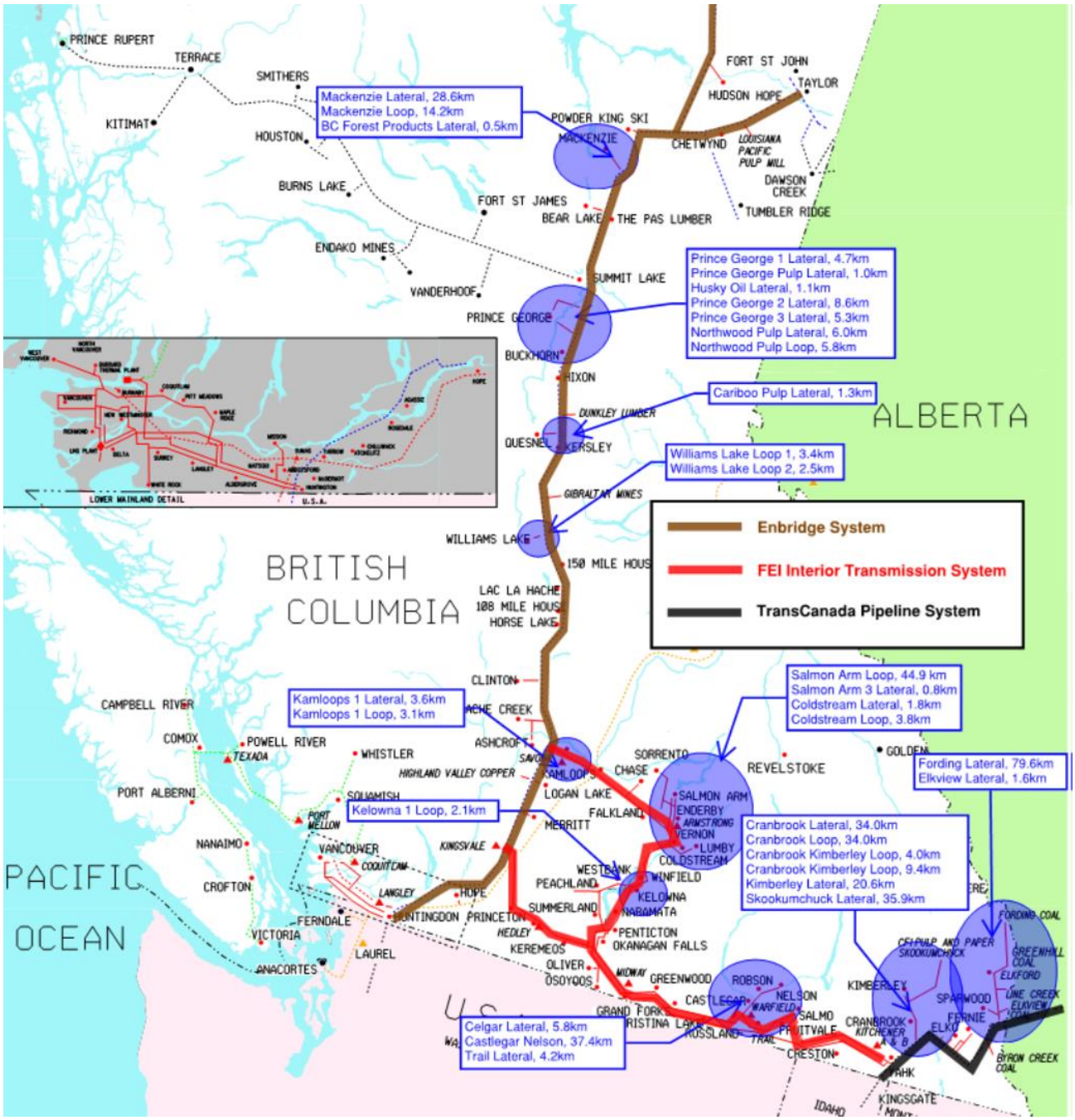
As previously stated, the objective of the IGU Project is to mitigate the likelihood of rupture due to corrosion on the 29 laterals.[15] All of these laterals operate at a hoop stress[16] of 30 percent or more of the specified minimum yield strength (SMYS) of the pipe, and are not capable of in-line inspection. As a result, the laterals are subject to potential rupture due to external corrosion, which is undetectable using current pipeline integrity methods.[17] FEI states that rupture of a transmission lateral could have "significant, safety, reliability, environmental and regulatory consequences and such an occurrence would be unacceptable to FEI, the public and its regulators."[18] According to FEI, the IGU Project is an appropriate, proactive response to FEI's obligations under the OGAA, with consideration to cost effectiveness in addition to a solution's ability to prevent ruptures, prevent leaks, and provide data for proactive lifecycle asset management decisions.[19]

2.1 Potential Failure by Rupture of the 29 Transmission Laterals

The 29 laterals that FEI proposes to address in the IGU Project are dispersed throughout the BC Interior and serve large industrial customers, commercial customers and downstream district stations which supply gas to many municipalities. The laterals serve about 167,000 FEI customers in the Northern Region, the Thompson Region, the Okanagan and the Kootenays.[20] Figure 1 identifies the name, location and length of the 29 laterals as well as the distribution network throughout the BC Interior.

[15] Exhibit B-1, Section 3.1, p.15.
[16] Hoop stress is the circumferential stress in a pipe wall.
[17] Exhibit B-1, Section 3.5, p. 26.
[18] Exhibit B-1, Section 3.5, p.26.
[19] Exhibit B-1, Section 3.4.3, p. 22.
[20] Exhibit B-1, Section 1.2.1, p. 5.

Figure 1: Overview of the Transmission System in Interior British Columbia[21]



The 29 laterals were installed between 1957 and 1998 and constructed using various pipe coating materials.[22] FEI acknowledges that the risk associated with its pipelines can differ according to location, material type, pressure, current condition and age.[23] However, FEI has not conducted a segment-by-segment assessment of the likelihood of failure resulting from external corrosion for the 29 laterals nor the location-specific consequences of potential rupture.[24] Risk assessment is addressed in Section 2.2.

[21] Exhibit B-1, Section 1.2.1, p. 4.

[22] Exhibit B-2, BCUC IR 8.2.

[23] Exhibit B-10, BCUC IR 35.1.

[24] Exhibit B-10, BCUC IR 35.7.

A rupture is an instantaneous and uncontrolled release of gas that could extend beyond the immediate area surrounding the pipeline, and if ignited, could potentially affect public safety, environment and property.[25] In contrast, a leak is characterized as a failure resulting in a limited loss of containment and does not constitute a significant safety hazard.[26] The IGU Project addresses the risk of rupture and not leaks.

FEI's operating history shows there has been no recorded rupture caused by corrosion on the 29 laterals.[27] Corrosion did cause one leak in 1996, however, on the Fording lateral.[28]

FEI states that a pipeline's potential to fail by rupture from corrosion can be determined by comparing the pipeline's operating hoop stress to the SMYS of the pipe. FEI explains the Canadian pipeline industry generally accepts that a pipeline operating at a hoop stress at or above 30 percent of SMYS has a potential to fail by rupture, whereas a pipeline operating at a hoop stress below 30 percent of SMYS has a potential to leak.[29] The 29 laterals are all operating at a hoop stress of 30 percent or more of SMYS.[30]

FEI explains that proactive external corrosion management of buried steel pipelines is achieved primarily through external coatings in conjunction with cathodic protection (CP). CP is the application of an electrical current to the pipeline to minimize the natural corrosion tendency of buried steel. CP provides a secondary defense where imperfections in the pipeline coating may exist. Industry and FEI's experience recognize that, although CP is being applied to a pipeline, corrosion can still occur due to a process called CP shielding. CP shielding is where the CP current is prevented from reaching the pipeline, due to situations such as the presence of disbonded pipe coatings or large rocks.[31]

FEI presently mitigates the potential for failure (leak or rupture) from corrosion on the 29 laterals using a modified External Corrosion Direct Assessment (Modified ECDA) method. The ECDA method is an industry standard practice using above ground surveillance of the cathodic protection (CP) system and direct pipeline examination to identify potential coating imperfections and CP issues.[32]

FEI has found evidence of corrosion on sections of its pipeline system (not including the 29 laterals), due to CP shielding, which cannot be detected using ECDA.[33] Consequently, FEI believes that if it were to continue only with Modified ECDA on the 29 laterals, CP shielding will result in "corrosion sites remaining unidentified and therefore unmitigated."[34]

FEI states that given the limitations of the ECDA method on pipelines with CP shielding, it needs to implement other integrity management measures that will mitigate the potential for rupture due to corrosion. FEI submits that it is obliged to undertake these measures pursuant to the OGAA requirement to prevent all releases of

[25] Exhibit B-1, Section 3.3.4, p.20.
[26] Exhibit B-1, Section 3.3, p.18.
[27] Exhibit B-2, BCUC IR 8.2 and Exhibit B-5, CEC IR 30.2.
[28] Exhibit B-10, BCUC IR 39.3.
[29] Exhibit B-1, Section 3.3.3, p.19.
[30] Exhibit B-1, Section 1.2.1, p. 3.
[31] Exhibit B-1, Section 3.3.2, p. 18.
[32] Exhibit B-1, Section 3.1, p.15.
[33] Exhibit B-1, Section 3.1, p.15.
[34] Exhibit B-1, Section 3.4.2, p.21.

product from operating pipelines.[35] Further, FEI suggests that industry standard practice has evolved with the development of smaller diameter in-line inspection technology such that pipelines the size of the 29 laterals and operating at a hoop stress above 30 percent of SMYS should now be in-line inspected to prevent failure by rupture.[36]

Positions of the Parties

Neither BCOAPO nor the CEC disputes the need to address rupture risk due to corrosion on the 29 laterals.

BCOAPO indicates that its client groups fully accept the need for utilities to remain compliant with applicable regulations, consistent with accepted or industry best practices. Further, BCOAPO agrees with FEI's evidence that it cannot reliably determine the extent of external corrosion on the 29 pipelines and that such external corrosion (in addition to other possible contributing factors) may lead to a pipeline rupture if undiagnosed and/or unattended.[37]

BCOAPO concludes that "It goes without saying that the damage, danger, and service disruption associated with pipeline ruptures is not something our clients wish to risk. In addition, our clients accept that, given the very serious risk to public safety that such a rupture represents and the material consequences in terms of service impacts of a rupture, it is important that the risks be mitigated in a timely fashion."[38]

The CEC supports FEI's proposal to upgrade the 29 transmission laterals to necessary safety standards as being in the public interest and recommends BCUC approval.[39]

FEI's position is that as a prudent operator, it must carry out the IGU Project to meet its regulatory requirements under the OGAA and bring its integrity management of the 29 laterals in line with industry practice.[40]

Panel Discussion

The primary justification for the IGU Project relates to safety, specifically, safety of supply and the continued provision of natural gas without interruption to customers, as well as the physical safety of residents and others along and near the laterals.

The Panel is persuaded by the evidence and arguments provided by FEI and the interveners that the risk of pipeline rupture must be mitigated. In the Panel's view, FEI has a duty to ensure the safety and security of individuals who may be injured due to an explosion emanating from a pipeline rupture and subsequent ignition. The Panel further considers that the Project is essential to reduce the risk of a pipeline rupture on the laterals and the attendant interruption of services with its consequential social, environmental and economic disruption and upheaval.

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[35] Exhibit B-1, Section 3.4.3, p.22 - 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".
[36] FEI Final Argument, paragraph 3.
[37] BCOAPO, Final Argument, p.4.
[38] BCOAPO, Final Argument, pp.4-5.
[39] CEC Final Argument. paragraph 4.
[40] FEI Final Argument, paragraph 4.

2.2 Risk Assessment - Urgency and Prioritization of the IGU Project

Every pipeline operator within BC must have an integrity management program (IMP) that complies with CSA Z662.[41] IMPs provide a systematic approach for assuring pipeline integrity throughout the entire pipeline life cycle including planning, design, construction, operation, maintenance and abandonment. IMPs have been a regulatory requirement in BC since they were introduced in the 1999 edition of CSA Z662.[42]

An IMP must include a risk assessment and management process, as described in Section 1.5 of the BC OGC's Compliance Assurance Protocol.

> The permit holder shall apply an ongoing risk assessment process that identifies hazards and quantifies risk, and analyses and implements appropriate risk reduction measures/controls to prevent, manage and mitigate identified hazards and risks. The permit holder shall ensure that the pipeline inventory data are gathered and integrated to support Risk Assessment. The permit holders must document and maintain an ongoing process for the identification and analysis of all possible hazards throughout the entire life cycle. The permit holder shall establish and implement a process for evaluating the risks associated with identified hazards (that is represented by probability/likelihood of occurrence of hazard and severity of resulting consequence). The permit holder shall prioritize the pipelines/segments in order of risk level and be able to evaluate and implement risk reduction measures, where the chosen threshold of risk is exceeded.[43]

FEI states that it has a comprehensive IMP.[44] Nevertheless, in a 2017 IMP compliance audit, the BC OGC found that FEI had no systematic process to determine risk and no process to analyse the hazards, their potential interactions and overall impact on risk. Consequently, the BC OGC directed FEI to develop and implement a segment-by-segment risk assessment process to determine the risk associated with its pipeline assets in BC, and to "move forward with suitable actions in a timely manner" to meet the OGC's requirements.[45] FEI is currently responding to the BC OGC's direction.[46] The BC OGC supports FEI taking action to address its known integrity concerns and to ensure that it meets its requirements as a pipeline operator under the OGAA.[47]

FEI submits that a segment-by-segment risk assessment is not required to justify the need for the IGU Project.[48] FEI states that its ability to prioritize the 29 laterals based on risk level is limited because the available condition information comprises limited quantities of integrity digs and failure records (rather than in-line inspection).[49]

In addition, FEI confirms that it did not consider any additional integrity assessment actions that could refine or validate the condition of the 29 laterals.[50] FEI explains that further condition assessments such as integrity digs and speciality in-line inspection tools are not required to prioritize its work on the 29 laterals. FEI also submits

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[41] B.C. Reg. 281/2010, s. 7.
[42] Exhibit A2-1, BC Oil & Gas Commission Compliance Assurance Protocol – Integrity Management Program for Pipelines, p.4,5.
[43] Exhibit A2-1, p. 11.
[44] Exhibit B-1, Section 1.2.2, p.5.
[45] Exhibit B-2, BCUC IR 6.5 and Attachment 6.5.
[46] Exhibit B-2, BCUC IR 3.1.
[47] Exhibit B-18, Attachment to BCUC IR 67.1.
[48] Exhibit B-2, BCUC IR 3.1.
[49] Exhibit B-10, BCUC IR 35.10.
[50] Exhibit B-10, BCUC IR 35.10.

that it would be imprudent and technically unnecessary to undertake further condition assessment activities on these laterals prior to undertaking the IGU Project. FEI stresses that undertaking additional assessments would not provide value, irrespective of the scope, scale, or potential impacts of the IGU Project, and would instead result in unnecessary delays to the safety and reliability improvements afforded by the Project.[51]

Positions of the Parties

Both the CEC and BCOAPO state that they did not receive adequate risk analysis information to assess the urgency and prioritization of the IGU projects. They suggest additional work should be done to assess the risk level of each lateral.

The CEC submits:

> It is difficult for interveners and the BCUC to assess the urgency of the Project or the value of conducting even portions of the Project over a longer period of time given the lack of analysis provided as to the actual risk levels from each lateral over time, and the benefits of any deferral that might accrue from prioritizing risky sites over less risky sites.[52]

Further, the CEC suggests that:

> It might be possible that FEI could refine its assessment of where corrosion is taking place through increased integrity digs and control digs enabling the utility to address the key concerns while addressing the lower risked laterals more slowly.[53]

The CEC recommends that it may be appropriate for the BCUC to condition its approval on having FEI conduct additional work quantifying risk and prioritization activities and providing reporting to the BCUC such that the BCUC can ensure that the Project is undertaken in the most cost-effective manner possible.[54]

Likewise, BCOAPO notes:

> While FEI asserts that action is required, the Utility was not only unable to assign any probabilistic estimate to a catastrophic rupture event associated with any of the subject pipelines, FEI was unable to even order and hence prioritize the pipelines in terms of the risk they posed to public safety and the environment.[55]

BCOAPO continues:

> While FEI submits that it does not have sufficient information to ordinally rank the subject pipelines in terms of risk, it did little to try to acquire more information that might aid in this process prior to this application.[56]

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[51] Exhibit B-10, BCUC IR 35.10.
[52] CEC Final Argument, paragraph 144.
[53] CEC Final Argument, paragraph 147.
[54] CEC Final Argument, paragraph 5.
[55] BCOAPO Final Argument, p.11.
[56] BCOAPO Final Argument, p.14.

BCOAPO concludes that its inability to go on the record supporting the IGU Project is rooted in part in the difficulty it sees in how FEI has proceeded, by failing to do the work necessary to prioritize work amongst the laterals before applying for a CPCN. Therefore, BCOAPO supports any FEI attempts to not only order the risks but also quantify them in the future.[57]

In Reply Argument, FEI states:

> Given the timeframe over which FEI already plans to implement the Project, there is no opportunity for improvement from a safety or reliability perspective by prioritizing the laterals differently than currently planned. To the contrary, delaying the Project to conduct further integrity digs or prioritization work would only serve to increase safety and reliability risks by delaying the benefits of the Project.[58]

FEI asserts that "any conditional approval or staged approach to the Project would result in an unacceptable delay to the Project, as it would delay FEI's timely action to comply with its regulatory obligations and adopt industry standard practice."[59]

Panel Discussion

The Panel is sympathetic to the concerns raised by both the CEC and BCOAPO related to the lack of segment-by-segment risk assessment on the laterals, which could lead to a better understanding of risk level, urgency and prioritization of the IGU Project. The Panel recognises that had such an assessment been done the task of considering the merits of the Application would have been simpler. However, the Panel acknowledges FEI's position that such a prioritization would at best be limited and of marginal use in guiding the overall Project. The Panel is persuaded by FEI's position that the Project is essential, that FEI has limited ability to conduct a thorough prioritization of the 29 laterals, and that it has adequately demonstrated the need for the Project in the absence of a segment-by-segment risk assessment. The Panel finds further assurance in the fact that the BC OGC supports FEI taking action to address known pipeline integrity concerns.[60]

2.3 One IGU Project *versus* 29 Separate Projects

The Panel has considered whether the upgrades to the 29 laterals should be combined into one project or whether they should be treated as 29 separate projects.

FEI's rationale for combining the 29 laterals into a single CPCN for the IGU Project is "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 that the work will be executed as one program to obtain efficiencies and flexibility in scheduling. FEI states that "[g]iven 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."[61]

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[57] BCOAPO Final Argument, p.15.
[58] FEI Reply Argument, paragraph 8.
[59] FEI Reply Argument, paragraph 28.
[60] Exhibit B-18, Attachment 67.1
[61] Exhibit B-2, BCUC IR 2.1 – 2.2.

FEI notes that considered as individual capital projects, the majority of the 29 laterals would fall below FEI's current CPCN materiality threshold of $15 million.[62] However, if the 29 laterals were considered as one overall Project, the cost would exceed that threshold (hence requiring BCUC approval of a CPCN) and would also be excluded from the capital expenditure formula within FEI's current PBR plan.

BCOAPO submits that regulated utilities have an incentive to group different activities into a single "project" in order to exceed a materiality threshold and then recover all associated costs, when individual components of the project might not have qualified for additional cost recovery from ratepayers.[63]

Panel Discussion

The evidence demonstrates that FEI has combined the 29 pipeline upgrades into one Project for a number of legitimate reasons, including achieving efficiencies and flexibility in scheduling, Project management and procurement, the shared justification for the upgrades, the alternatives analysis and the Project execution strategy.[64] Further, FEI has demonstrated the need for this Project from a safety perspective. The Panel notes that the IGU Project will not be completed prior to the end of the current PBR term, and FEI's Multi-Year Rates Plan for 2020-2024 Application, including the determination of the appropriate capital spending envelope and CPCN materiality thresholds during that period, is ongoing. The Panel is satisfied that in the specific circumstances of this case, FEI has appropriately treated the upgrades on the 29 laterals as one capital project, rather than 29 separate capital projects.

3.0 Project Description

3.1 Introduction

FEI proposes three engineering solutions that are financially and technically feasible and would adequately mitigate the identified risk of rupture. These solutions are described below, along with summaries of the Project Execution Risk Assessment and Construction Schedule. The rupture risk mitigation alternatives that FEI considered but did not select are described in Section 4.

In-line inspection

The in-line inspection (ILI) alternative requires the retrofitting of the existing pipelines to accommodate the operation of a data collection device or ILI tool (industry refers to this tool as a 'smart pig'). The retrofit includes the construction of ILI tool launching and receiving pipe work and the removal of obstructions that may impede the tool (e.g. reduced-port valves, low radius bends, unbarred tees and wall thickness variations).[65] ILI data collected on a recurring cycle (typically five to seven years) would inform FEI of pipeline wall imperfections and enable proactive asset management.[66]

[62] Exhibit B-1 Section 6.2, Table 6-2, p. 84.
[63] BCOAPO Final Argument, p. 9.
[64] Exhibit B-2, BCUC IR 2.1.
[65] Exhibit B-1, Section 4.2.5, p. 31.
[66] Exhibit B-1, Section 4.2.5, p. 31.

Pressure regulating station

This alternative involves the installation of a pressure regulating station (PRS) on the pipeline in order to reduce the operating stress to below 30 percent of the pipeline SMYS. At this reduced operating stress level, FEI indicates that pipeline failure due to corrosion has the potential to leak rather than rupture.[67] FEI submits that once operating at this reduced stress level, the pipelines would be subject to pipe condition management activities suitable to the reduced corrosion-related rupture potential (e.g. CP monitoring, leak survey, etc.).[68] Finally, FEI notes that it must consider the forecasted demand of current and future customers when evaluating the feasibility of PRS, because operating at a reduced stress level reduces the capacity of a pipeline.[69]

Pipeline replacement

This alternative mitigates the potential for corrosion-related rupture by replacing the existing pipeline with a new pipeline designed to current standards, one of which is to operate at a stress level below 30 percent of SMYS.[70]

FEI evaluated and determined the preferred alternative for each of the 29 transmission laterals. ILI is the preferred alternative for 11 laterals, PRS is the preferred alternative for 14 laterals and pipeline replacement (PLR) is the preferred alternative for four laterals.[71]

FEI submits that based on its legal and regulatory obligations, assessment of relevant hazards to its pipeline system, understanding of industry practice, and 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.[72]

The design, construction and operation of FEI natural gas pipelines and stations are in accordance with the BC OGC's regulations and CSA Z662. FEI states that it will develop each of the PRS, ILI and PLR options chosen in accordance with all applicable statutory codes and standards, including FEI's internal standards.[73]

3.2 Basis of Design and Engineering for the Three Preferred Alternatives

3.2.1 In-Line Inspection

As noted above, FEI proposes in-line inspection (ILI) for 11 laterals.[74] Refer to Table 1 in Section 4.2.2.

Retrofitting the 11 laterals selected for ILI will enable FEI to conduct comprehensive in-line inspection to detect external corrosion in these pipelines and take proactive steps to manage the potential for rupture due to external corrosion.[75] For pipelines where commercially available ILI tools are available, in-line inspection is the standard to determine pipeline condition and safety.

[67] Exhibit B-1, Section 4.2.4, p. 30.
[68] Exhibit B-1, Section 3.4.4.2, pp. 24-25.
[69] Exhibit B-1, Section 4.2.4, p.30.
[70] Exhibit B-1, Section 4.2.6, p. 31.
[71] Exhibit B-1, Section 5.1, Table 5-1, p. 48-49.
[72] Exhibit B-2, BCUC IR 3.5.
[73] Exhibit B-1, Section 5.2.1.1, p. 49, Section 5.2.2.1, p. 57, Section 5.2.3.1, p. 59.
[74] Exhibit B-1, Section 5.2.1.11, p. 56.
[75] Exhibit B-2, BCUC IR 3.5.

Retrofitting the laterals for ILI capability involves installing pig barrels at each end of the pipeline to allow ILI tools (up to six metres long) to be launched and retrieved, and removing all obstructions in the pipeline that may prevent successful tool runs, including restrictive bends and elbow fittings, and pipe size or wall thickness changes.[76] The restrictive bends and elbow fittings must be replaced to allow the ILI tool to pass through the pipeline with minimal interference.[77] FEI states that it is difficult to predict the number and location of bends that will require replacement because data is limited due to the vintage of the affected laterals.[78] In order to safely complete the pipeline modifications necessary to enable ILI, FEI will install control valve assemblies (CVA) consisting of a gas filter and a pneumatically actuated valve assembly with two control valves.[79]
New right of way (ROW) and temporary work space land requirements have been calculated for the ILI upgrades. Total costs for land requirements for the IGU Project are shown in the Project Cost Estimate in Section 4.3.

Once the launcher and receiver assemblies are added, and known obstructions in the pipeline are removed, FEI will conduct verification runs to confirm that there are no remaining obstructions that can cause an unsuccessful ILI run.[80] FEI acknowledges that until the inaugural ILI tool run is completed, some level of uncertainty regarding the condition of the pipeline will remain.[81]

Post-construction, FEI will implement ILI monitoring: the first year post-construction will consist of pipeline cleaning, the second year will be an in-line inspection with geometry and metal-loss tools and subsequent years will feature integrity digs and associated pipeline repairs, if needed.[82] Future ILI integrity management tool runs for maintenance purposes will be scheduled on a maximum seven-year interval.[83]

3.2.2 Pressure Regulation Station

FEI proposes PRS for 14 laterals.[84] Refer to Table 1 in Section 4.2.2.

The scope of work for the pressure regulating station (PRS) alternative includes installing a facility on each lateral to regulate the maximum operating pressure. The facility will be placed near the transmission tie-in location and will include redundant pressure regulating assemblies.[85] FEI estimates that each PRS requires a land footprint of 20 metres x 15 metres.[86] The PRS will be located on fee simple land adjacent to the ROW[87] to maintain control of the site and access for regular maintenance.[88]

[76] Exhibit B-1, Section 5.2.1.1, p. 49.
[77] Exhibit B-1, Section 5.2.1.5, p. 52.
[78] Exhibit B-1, Section 5.2.1.5, p. 53.
[79] Exhibit B-1, Section 5.2.1.2, p. 50.
[80] Exhibit B-1, Section 5.2.1.10, p. 56.
[81] Exhibit B-2, BCUC IR 16.2.
[82] Exhibit B-13, BCUC IR 74.1.
[83] Exhibit B-2, BCUC IR 11.6.
[84] Exhibit B-1, Section 5.2.2.8, p. 58-59.
[85] Exhibit B-1, Section 5.2.2, p.57.
[86] Exhibit B-1, Section 5.2.2.5, p. 58.
[87] Exhibit B-1, Section 5.2.2.5, p. 57.
[88] Exhibit B-1, Section 5.2.2.5, p. 58.

Each PRS assembly will be in a building enclosure, with electrical modules in a separate telemetry building. The pressure regulating assembly consists of a gas filter, main and monitor control valves, pressure controller, backup power generator, pressure indicators, isolation valves, vent valves, and bleed valves.[89]

Once constructed, the PRS will undergo a comprehensive commissioning plan to check, inspect, test and validate the successful implementation of all control and safety modules, subsystems and systems.[90] Future maintenance for PRS pipeline laterals will consist of recurring operational activities, such as CP surveillance and leak detection, in compliance with Clause 12, CSA Z662 for pipelines operating below 30 percent of SMYS.[91]

3.2.3 Pipeline Replacement

FEI proposes pipeline replacement (PLR) for four laterals.[92] Refer to Table 1 in Section 4.2.2.

PLR involves installing a new pipeline parallel to the existing pipeline. The new pipeline will be designed to operate below 30 percent of SMYS which will mitigate the potential for rupture.[93] Replacing a lateral with a new gas line that operates below 30 percent of SMYS will meet the Project objective because 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.[94]

In addition to the new pipeline within the existing ROW, the scope of work includes installing the necessary valve assembly and tie-ins to the mainline pipeline, and abandoning in place the existing pipeline once the new line is operational.[95] FEI explains that it cannot abandon or remove the existing pipeline prior to installing and commissioning the new pipeline in its entirety, because it must maintain supply to all customers.[96] The new PLR laterals will have ILI capability, provided launcher and receiver assemblies are added in the future.[97]

FEI will design the new pipelines to include industry accepted corrosion protection measures, such as external coatings and cathodic protection. External coatings provide the first level of defence against external corrosion of buried steel piping.[98]

The replacement pipelines will require an additional 8-metre wide ROW adjacent to the existing 10-metre wide ROW to form a total width of 18 metres. A typical pipeline installation will require also a 5-metre wide temporary work space, while a bored crossing will require and an additional 10-metre wide temporary work space.[99]

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[89] Exhibit B-1, Section 5.2.2.2, p. 57.
[90] Exhibit B-1, Section 5.2.2.7, p. 58.
[91] Exhibit B-2, BCUC IR 9.1.
[92] Exhibit B-1, Section 5.2.3.10, p. 63.
[93] Exhibit B-1, Section 5.2.3, p. 59.
[94] Exhibit B-2, BCUC IR 3.5.
[95] Exhibit B-1, Section 5.2.3, p. 59.
[96] Exhibit B-1, Section 5.2.3.9, p. 63.
[97] Exhibit B-1, Section 5.2.3.6, p. 62.
[98] Exhibit B-1, Section 5.2.3.5.1, p. 62.
[99] Exhibit B-1. Section 5.2.3.7, p. 62.

Once the PLR is completed, FEI will conduct a comprehensive pre-commissioning and commissioning plan to check, inspect, test and validate the successful implementation of all control and safety modules, subsystems, and systems.[100]

Future maintenance for PLR pipeline laterals will consist of recurring operational activities, such as CP surveillance and leak detection, in compliance with Clause 12, CSA Z662 for pipelines operating below 30 percent of SMYS.[101]

3.2.4 Project Execution Risk Assessment

FEI's consultant, Stantec Consulting (Stantec), conducted a risk analysis (Risk Report) to identify the technical and non-technical risks associated with the Project. FEI supplemented the Risk Report with input from two independent experts: Bramcon Project Consultants Ltd. and Validation Estimating, LLC.[102] Bramcon estimated the contingency for the budget by conducting a simulation for the ILI component of the Project to establish the most likely number of restrictive bends;[103] any restrictive bend on a lateral becomes part of the Project scope and must be replaced. Using Bramcon's analysis FEI determined a project contingency of 18 percent to achieve a P50 level of confidence.[104]

The risk identification process identified several risks and a qualitative analysis prioritized those risks. Stantec completed a quantitative analysis using Monte Carlo simulation to determine a distribution of possible cost outcomes associated with the existing scope of the Project at different levels of confidence. The Stantec analysis derived a risk adjusted P50 cost of $279 million representing a contingency of approximately 14.4 percent.[105] Validation Estimating conducted a benchmarking analysis, indicating that a contingency of approximately 17 percent is required to achieve a P50 confidence level.[106]

FEI explains that contingency is used as an allocation for risks that are known with a relatively high level of certainty and likely to be encountered during project execution. For a project that is executed over multiple years, however, there are certain risks that 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, FEI considered it prudent to add a management reserve of 11 percent. A management reserve of 11 percent of the total base capital plus a contingency of 17 percent of the total base capital equals 28 percent and approximates a P70 confidence level.[107] The dollar impact of the contingency and management reserve on the capital costs is described in Section 5.1.

FEI has successfully completed similar pipeline integrity management capital projects in the past. In the early 2000s, FEI conducted a five-year program, the Transmission Pipeline Integrity Program (TPIP), to retrofit its Coastal Transmission System mainline pipelines for ILI.[108] In response to IRs, FEI provided details of actual versus

[100] Exhibit B-1, Section 5.2.3.8, p. 63.
[101] Exhibit B-2, BCUC IR 9.1.
[102] Exhibit B-1, Section 5.3.4, p. 68.
[103] Exhibit B-1, Section 5.3.4.3, p. 69.
[104] Exhibit B-1, Section 5.3.4.3, p. 70.
[105] Exhibit B-1, Section 5.3.4.3, p. 69.
[106] Exhibit B-1, Section 5.3.4.3, pp. 70-71.
[107] Exhibit B-1, Section 5.3.4, p. 68.
[108] Exhibit B-1, Section 3.4.4.2, p. 23.

planned expenditures for each BCUC order that approved the TPIP.[109] There were no material cost overruns or significant delays in the TPIP project schedule.[110] FEI explained some of the lessons learned on the TPIP, and how it applied those learnings to the designs and plans for the IGU Project.[111] In particular, FEI notes that the "degree of project risk understanding and mitigation plan is more developed for the IGU Project compared to what is indicated in the TPIP Application."[112]

FEI includes a contingency of 17 percent as well as a management reserve of 11 percent on the IGU Project based on its 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.[113] FEI states that it has not previously included a management reserve in any of its capital projects, although FortisBC Inc. (FBC) did include such a reserve as part of the project contingency on the Corra Linn Dam Spillway Gates project.[114] For that project, the contingency was estimated at 15.2 percent of the sum of the Total Contractor Costs and Owners Costs, comprising 11.6 percent for the management reserve and 3.6 percent for the contingency.[115]

FEI indicates that including both a management reserve and contingency is consistent with the Association for the Advancement of Cost Engineering (AACE) recommended practices, the BCUC's CPCN Guidelines, and practices used by other utilities in Canada such as BC Hydro and Manitoba Hydro. FEI explains that should the need arise to access the management reserve during project execution, it will submit a request for additional funds for executive approval and, upon approval, it will increase the Project's baseline cost accordingly. FEI states that if either the contingency or management reserve is accessed during the Project, it will identify the amount spent in the Project updates provided to the BCUC.[116]

Positions of the Parties

The CEC points out that the contingency and management allowance of 28 percent represents approximately $100 million.[117] It submits that this represents a potential source of cost savings which might benefit from more information, in particular, the quality of data as to the condition of some laterals could reduce the amount required for contingency. FEI, on the other hand, disagrees for two reasons: (1) corrosion and CP shielding can occur randomly over the length of a pipeline, and it is not possible to infer the condition of one lateral from the condition of another and (2) the Project's contingency was influenced primarily by the number of restrictive bends that might be encountered, not the condition of the laterals."[118]

Panel Discussion

The Panel has reviewed both the proposed 17 percent contingency and the management reserve of 11 percent and acknowledges the rigour with which FEI calculated the Project's contingency. The Panel considers 17 percent to be a reasonable contingency for this Project and that FEI has adequately justified the need for the

[109] Exhibit B-2, BCUC IR 11.1.
[110] Exhibit B-2, BCUC IR 11.2.
[111] Exhibit B-2, BCUC IRs 11.3 and 11.4.
[112] Exhibit B-10, BCUC IR 38.1.
[113] Exhibit B-1, Section 5.3.2, p. 66.
[114] Exhibit B-2, BCUC IR 23.1.
[115] Exhibit B-2, BCUC IR 23.1.
[116] Exhibit B-10, BCUC IR 49.1.
[117] CEC Final Argument, paragraph 109.
[118] FEI Reply Argument, paragraph 15.

11 percent management reserve. FEI also indicates that it will report to the BCUC if it does access either the contingency or the management reserve.

3.3 Construction Schedule and Milestones

FEI developed the schedule for the IGU Project based on the assumption of receiving BCUC Approval by October 2019 and a construction start of Q2 2020.[119] The schedule considers performance of site work between the months of April and October. The Project's activities are subdivided into six main groups: Contractor evaluation, selection and contract award; Permitting; Engineering detailed design; Procurement/manufacturing; Mobilization to site; and Fabrication and Site installation. Table 5-13 of the Application sets out the full Project schedule.[120] Permitting schedules vary between laterals due to differing construction schedules, but FEI will seek approvals and permits at least six months prior to construction. All laterals are scheduled for completion of construction between October 2022 and October 2024, with demobilization and restoration completed by November 2024.

4.0 Description and Evaluation of Alternatives

FEI identified a total of seven alternatives that could, in theory, have met the Project's objective of mitigating the potential for pipeline rupture due to external corrosion:

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

A description of the evaluation methodology which led to the selection of PRS, ILI and PLR as the preferred alternatives is provided below.

4.1 Description of Alternatives

Alternative 1 – Status Quo: Modified External Corrosion Direct Assessment

This alternative involves the continued implementation of Modified ECDA as directed within FEI's Integrity Management Program – Pipelines. The standard ECDA process is defined by ANSI/NACE Standards[121] and involves four steps:

1. Pre-assessment – Collection and consideration of pipeline information;
2. Indirect Inspection – Surveys of the buried pipeline from the ground surface;
3. Direct Examination – Pipeline exposed at selected dig locations;
4. Post Assessment – Data analyzed, and further investigation established as required.

[119] Exhibit B-1, Section 5.4, p. 72.
[120] Exhibit B-1, Section 5.4, Table 5-13, pp. 73-74.
[121] Exhibit B-1, Appendix G. ANSI/NACE is the National Association of Corrosion Engineers.

FEI has modified the ANSI/NACE Standard ECDA process with respect to the determination of the number of digs. FEI submits that its use of Modified ECDA complies with the applicable legislation and standards and with Canadian industry practice.[122] The Modified ECDA process allows FEI to identify potential coating imperfections and CP system issues, and to mitigate the potential for external corrosion. The technical limitations of the Modified ECDA process prevent the detection of corrosion in areas of CP shielding.[123]

Alternative 2 – Pipeline exposure and re-coat)

This alternative involves exposing the entire length of pipeline so that a detailed inspection and any necessary repairs can be completed, and the entire pipe surface can be recoated. FEI states that large-scale in-ditch recoating of pipelines is a complex undertaking, and is not typically performed due to high costs relative to other available solutions.[124]

Alternative 3 – Hydrostatic testing program

This alternative involves periodically verifying the integrity of the pipe by filling the pipeline with water and subjecting it to a pressure above the expected maximum operating pressure (i.e. hydrostatic test). FEI states that the length of pipe undergoing hydrostatic test would be out of service for a period of at least a week on an estimated recurring frequency of between five to ten years.[125] FEI further states that this alternative would typically only be considered for pipelines that are looped or that could be temporarily supplied by alternate energy sources.[126]

Alternative 4 – Robotic Inspection

The ROB alternative is similar to the ILI alternative in that a data collection device is inserted into the pipeline to assess pipe wall condition, however the robotic inspection tool is self-propelled (i.e. does not require gas flow) and it can be inserted through stopple fittings. The ROB tool relies on rechargeable batteries which require recharging approximately every 450 metres.[127] FEI does not consider robotic ILI tools to be proven and commercialized.[128]

Refer to Section 3.1 for descriptions of the preferred alternatives 5, 6 and 7.

4.2 Project Alternatives Evaluation

FEI used a multi-step evaluation process to determine the most appropriate alternative for each of the 29 laterals. The first step was a preliminary technical review of each alternative, and FEI screened out those that would not mitigate the potential for rupture due to corrosion.[129] The second step was a technical and high-level

[122] Exhibit B-2, BCUC IR 12.3.
[123] Exhibit B-1, Section 4.2.1, p. 29.
[124] Exhibit B-1, Section 4.2.3, p. 30.
[125] Exhibit B-1, Section 4.2.3, p. 30.
[126] Exhibit B-1, Section 4.2.3, p. 30.
[127] Exhibit B-1, Section 4.2.7, p. 32.
[128] Exhibit B-1, Section 4.4.2, p. 39.
[129] Exhibit B-1, Section 4.4, p. 38.

financial evaluation of the remaining alternatives.[130] The third step was a detailed evaluation of each of the remaining three feasible alternatives for each of the 29 laterals,[131] as described below.

4.2.1 Detailed Evaluation of PRS, ILI and PLR Alternatives

FEI applied a weighted-scoring methodology based on three sets of evaluation criteria. 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 described below:[132]

1. Integrity and Asset Management Capacity (Evaluation weighting = 45 percent)
2. Project Execution & Lifecycle Operation (Evaluation weighting = 20 percent)
3. Financial (Evaluation weighting = 35 percent)

The Integrity and Asset Management Capacity category provided FEI with a means to select an alternative that met the technical objectives of the Project and therefore was assigned the highest weighting.[133] The Project Execution and/or Lifecycle Operation category allowed FEI to assess the alternatives on key factors that supported efficient and effective project execution and life cycle operation.[134] The Financial category considered the long term rate impact to FEI's non-bypass customers.[135]

Evaluation of the Pressure Regulating Station Alternative

FEI states that the PRS alternative achieves the technical objectives of the Project and had the highest rating with respect to project execution and lifecycle operation. PRS was also generally the lowest cost alternative. As a result, FEI selected the PRS alternative for 14 laterals. On three laterals, the PRS alternative was considered technically viable. However, it was not selected because the PLR alternative had a higher overall rating and was supported by FEI's internal subject matter experts.

FEI acknowledges, through evidence submitted by its expert witness JANA Corp., that "the rupture of a pipeline operating under 30 percent of SMYS is a rare occurrence in the industry, and, where it has occurred, it has not been due to external corrosion."[136] FEI states further that "while the residual risk that remains with pipelines that are operated below 30 percent of SMYS can never be zero, operation of a pipeline below 30 percent of SMYS addresses the primary hazard of external corrosion, and other hazards."[137]

Evaluation of In-line Inspection Alternative

FEI's evaluation found the ILI alternative to be comparable to PLR in achieving the Project's objective of preventing ruptures. However, ILI rated highly in the Integrity and Asset Management Capability category,

[130] Exhibit B-1, Section 4.4.5, p. 42.
[131] Exhibit B-1, Section 4.5, p. 45.
[132] Exhibit B-2, BCUC IR 18.2.
[133] Exhibit B-1, Section 4.3.1.1, p. 33.
[134] Exhibit B-1, Section 4.3.1.2, p. 34.
[135] Exhibit B-1, Section 4.3.1.3, p. 35.
[136] FEI Final Argument, Paragraph 95.
[137] FEI Final Argument, Paragraph 96.

specifically for the proactive asset management[138] criterion within this category.[139] FEI states that the ILI alternative had a lower rate impact than PLR, especially for longer laterals. The ILI alternative was selected for 11 laterals, ranging in length from 4.7 km to 79.7 km.[140]

The financial evaluation of the ILI alternative did not account for any replacement costs at the end of the useful life of the selected 11 laterals because FEI does not expect that these laterals will require replacement during their financial life.[141]

Evaluation of Pipeline Replacement Alternative

The PLR alternative was selected as the preferred alternative for four laterals following the technical and financial evaluation. These four laterals are generally shorter in length, ranging from 0.5 km to 6.6 km.[142]

4.2.2 Selection of Preferred Alternative for Each 29 Laterals

Application of the weighted-scoring methodology resulted in the selection of a preferred alternative for each of the 29 laterals, as listed in the table below. PRS was typically the lowest cost alternative and was selected for any lateral that would not encounter capacity limitations as a result of a reduction of pipeline pressure.[143] ILI and PLR were considered for the remaining laterals, and the ILI alternative was selected whenever more cost effective than PLR. In terms of financial evaluation, the difference between ILI and PLR for each lateral depended mostly on the length of the lateral, and thus ILI was generally the preferred alternative for longer laterals.[144]

[138] Proactive asset management is a measure of the ability of an alternative to enable proactive repair/replace decisions based on asset condition over the lifecycle of the asset, and to provide data for other asset management processes (e.g. ground movement, centreline mapping, validation of records). The ability to proactively manage assets allows potential hazards to be addressed before failures occur. (Exhibit B-1, Section 4.3.1.1, p. 33)

[139] Exhibit B-1, Section 4.5.2, pp. 45-46.

[140] Exhibit B-1-2, Section 4.5.2, p. 47.

[141] Exhibit B-2, BCUC IR 16.3.

[142] Exhibit B-1-2, Section 4.5.2, p. 47.

[143] Exhibit B-1, Section 4.4.3, p. 39.

[144] Exhibit B-1, Section 4.5.2, p. 46.

Table 1: Preferred Alternative for Each Lateral

Line/ Loop ID No.	Line/Loop Full Name	Line Length (km)	Preferred Alternative
1	Mackenzie Lateral 168	28.6	In-line Inspection
2	Mackenzie Loop 168	14.2	In-line Inspection
3	BC Forest Products Lateral 168	0.5	Pipeline Replacement
4	Prince George 3 Lateral 219	5.3	Pressure Regulating Station
5	Northwood Pulp Lateral 168	6.0	Pressure Regulating Station
6	Northwood Pulp Loop 219	5.8	Pressure Regulating Station
7	Prince George 1 Lateral 168	4.7	In-line Inspection
8	Prince George Pulp Lateral 168	1.0	Pressure Regulating Station
9	Husky Oil Lateral 168	1.1	Pressure Regulating Station
10	Prince George 2 Lateral 219	8.6	Pressure Regulating Station
11	Cariboo Pulp Lateral 168	1.3	Pipeline Replacement
12.1	Williams Lake Loop 1 168	3.4	Pressure Regulating Station
12.2	Williams Lake Loop 2 168	2.5	Pressure Regulating Station
13.1	Kamloops 1 Lateral 168	3.6	Pipeline Replacement
13.2	Kamloops 1 Loop 168	3.1	Pipeline Replacement
14	Salmon Arm Loop 168	44.9	In-line Inspection
15	Salmon Arm 3 Lateral 168	0.8	Pipeline Replacement
16	Coldstream Lateral 219	1.8	Pressure Regulating Station
17	Coldstream Loop 168	3.8	Pressure Regulating Station
18	Kelowna 1 Loop 219	2.1	Pressure Regulating Station
19	Celgar Lateral 168	5.8	Pressure Regulating Station
20	Castlegar Nelson 168	37.4	Pressure Regulating Station
21	Trail Lateral 168	4.2	Pressure Regulating Station
22.1	Fording Lateral 219	34.5	In-line Inspection
22.2	Fording Lateral 168	45.1	In-line Inspection
23	Elkview Lateral 168	1.6	Pressure Regulating Station
24	Cranbrook Lateral 168	34.0	In-line Inspection
25	Cranbrook Loop 219	34.0	In-line Inspection
26	Cranbrook Kimberley Loop 219	4.0	In-line Inspection
27	Cranbrook Kimberley Loop 273	9.4	In-line Inspection
28	Kimberley Lateral 168	20.6	In-line Inspection
29	Skookumchuck Lateral 219	35.9	In-line Inspection

Positions of the Parties

BCOAPO notes in its final submission that FEI listed seven possible alternatives it had examined to address the risk of pipeline rupture. Of those seven, BCOAPO notes, FEI determined that only three were feasible: PRS, ILI, and PLR. With regards to many of the technical aspects of the Project, BCOAPO explains that it does not have sufficient expertise to fairly evaluate such matters and has chosen instead to focus on areas that do engage its

expertise.[145] BCOAPO does, however, note that "…there appears to be expert disagreement as to whether use of the <30 percent SMYS rule of thumb is adequate mitigation to protect against rupture protection due to corrosion."[146]

BCOAPO concludes by noting it does not take any position on the weighting methodology given that the evidence indicates that the criteria chosen resulted in the election to propose the lowest cost alternative that would meet code in all but one instance.[147]

The CEC notes that it has reviewed the evidence regarding the alternative evaluation methodology and agrees with FEI's analysis and weightings. It is satisfied with FEI's decision to not implement the *status quo* (Modified ECDA),[148] PLE or HSTP alternatives. The CEC also accepts that ILI is desirable where feasible and cost effective because it will allow for ongoing monitoring.[149] Similarly, the CEC submits that FEI's approach to monitoring the status of robotic tools is reasonable, although it would support the BCUC including in its approval a condition that FEI implement robotic inspection technology once it is deemed cost-effective.[150] The CEC does, however, submit that FEI could have included as an option in its alternatives assessment a deferred or staged approach, rather than only focusing on the proposed seven technological responses.[151]

With respect to the PRS approach, the CEC notes that this alternative is very cost effective and submits that many of the laterals that FEI has chosen for ILI should be reconsidered for PRS instead to reduce project costs. The CEC states that FEI should consider natural gas service curtailment to certain customers so as to allow for the reduction of pressure to below 30 percent of SMYS. The CEC discusses in detail the evidence presented regarding curtailment on five lateral systems (MacKenzie, Prince George, Kamloops 1, Cranbrook Kimberley and Fording) and submits that "there are cases where the customer impacts may not be significant."[152]

The CEC states, for example, that had PRS been in place on the Mackenzie System[153] over the five-year period of 2014-2018, customers would have experienced 35 more days of potential curtailment – an approximate six percent increase.[154] The CEC submits that for the Mackenzie Lateral alone, costs of $27 million for ILI are significant and it could be worthwhile to consider a PRS option and then alternative means of addressing customer curtailment issues.[155] With respect to the Kamloops System, the CEC submits "that there is limited evidence of likely curtailment and a PRS alternative could potentially be reasonably reconsidered."[156] In its discussion regarding the merits of the PRS option for the Cranbrook Kimberley system, the CEC "agrees that there is likely no benefit to reviewing a PRS option where firm customers cannot be served."[157]

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[145] BCOAPO Final Argument, p. 4.
[146] Ibid.
[147] BCOAPO Final Argument, p. 5.
[148] CEC Final Argument, paragraph 170.
[149] CEC Final Argument, paragraph 180.
[150] CEC Final Argument, paragraph 235.
[151] CEC Final Argument, paragraph 123.
[152] CEC Final Argument, paragraph 200.
[153] Some of the 29 individual laterals under discussion in this application are connected and operate as a system; for example, Mackenzie Lateral 168 and Mackenzie Loop 168 operate as a single system (Exhibit B-1, Appendix A, p. 2). Exhibit B-1, p. 37: "In some cases…the laterals and their corresponding loops are physically joined with crossover connections and are operated as a system"
[154] CEC Final Argument, paragraph 201.
[155] CEC Final Argument, paragraph 205.
[156] CEC Final Argument, Paragraph 211.
[157] CEC Final Argument, Paragraph 221.

FEI Reply Argument

In reply to BCOAPO's suggestion that there is disagreement regarding the applicability of the <30 percent of SMYS threshold, FEI responds that "…there is no evidence of any such disagreement on the record."[158]

FEI rejects the CEC's statement that its assessment of alternatives was potentially lacking because FEI did not consider a deferred or staged approach as an alternative: "no alternative was identified during the proceeding that FEI did not consider" and that "deferrals and staged approaches are not alternatives for the Project, but ways of implementing (or delaying) a particular alternative."[159]

In response to the CEC's suggestion that a condition be imposed on FEI requiring it to monitor the status of robotic tools during the implementation of the Project, FEI indicates that there is no need for any conditional approval or staged approach to wait for robotic technology to mature because FEI already intends to monitor robotics for possible benefits.[160] The CEC and FEI agree with this approach to continue monitoring the possibility of implementing robotic technology.

FEI finds the CEC's suggestion unreasonable, that FEI use pressure regulating stations on laterals where such use would reduce the service to FEI's customers. FEI states that "choosing integrity management solutions that prevent FEI from serving its customers undermines the purpose of the pipelines, and denies customers the benefits of natural gas to serve their needs."[161] FEI describes the adjustments or significant adjustments customers would be required to make to the way they currently use natural gas in their business practices.[162] FEI submits that if reasonable service could not be provided as a result of implementing PRS, customers could elect for firm service or cease use of natural gas. For these reasons, and due to the risk of not being able to serve future additional customers, FEI states "choosing PRS for laterals where it would prevent FEI from serving its customers is not a reasonable solution as it would undermine the purpose of the laterals and could trigger even greater costs."[163]

Panel Discussion

The Panel notes BCOAPO's concern that there is conflicting evidence regarding the effectiveness of the PRS alternative. The Panel agrees with FEI, however, that the evidence gathered throughout this proceeding supports the conclusion that this alternative is an industry accepted rupture risk mitigation strategy.

The Panel also notes the CEC's objections concerning FEI's decision not to consider the PRS alternative for specific laterals with limited supply capabilities for the FEI customers. The Panel has reviewed the CEC's suggestion that PRS could be potentially reasonably pursued on these specific laterals and FEI's Reply. The Panel is satisfied with FEI's approach to not pursue PRS for laterals where that alternative would create capacity limitations. The Panel supports FEI prioritizing existing and future customer service levels in the evaluation and choice of integrity management alternatives.

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[158] FEI Reply Argument, paragraphs 3 and 5.
[159] FEI Reply Argument, paragraph 19.
[160] FEI Reply Argument, paragraph 27.
[161] FEI Reply Argument, paragraph 33.
[162] FEI Reply Argument, paragraph 32.
[163] FEI Reply Argument, paragraph 33.

5.0 Project Costs, Accounting Treatment and Rate Impact

FEI states the total anticipated cost of the IGU Project is $361.184 million in as spent dollars which includes $360.193 million of capital costs and $0.991 million of project deferral costs.[164] FEI submits that the Project's cost estimate meets the requirements of the BCUC's CPCN Guidelines and is robust and reasonable.[165]

5.1 Project Cost Estimate

FEI developed an AACE 18R-97 Class 3 cost estimate in conjunction with Stantec.[166] In its Application, FEI provides information based on estimates in Confidential Appendices J-2, J-3, and J-4 for ILI, PRS, and PLR alternatives. The cost estimates developed by Stantec for each of the selected alternatives were provided in Confidential Appendix J-1. [167]

Stantec completed designs and material take-offs, [168]estimated quantities from the designs and MTOs, and then used the quantities as the basis to develop direct and indirect costs, which include:[169]

- Pipeline and stations direct construction costs including land acquisition;
- Pipeline and stations indirect construction costs;
- Construction sub-contracts; and
- Engineering services.

FEI supplied information regarding owner's costs, which include:[170]

- Project management and engineering;
- Permits and approvals;
- Consultation;
- Environmental and archaeological monitoring; and
- Inspection and operations coordination.

The IGU Project's capital cost estimate is forecast to be $320.853 million in 2018 dollars or $360.193 million in as-spent dollars (including AFUDC [Allowance for Funds Used During Construction] of $15.327 million).[171] FEI prepared Table 2, reproduced below, summarizing the IGU Project's capital budget.

[164] Exhibit B-1-2, Section 6.1, p. 83.
[165] FEI Final Argument, p. 43.
[166] Exhibit B-1, Section 5.3, p. 64.
[167] Exhibits C4-2 and C4-4.
[168] Material Take-Off (MTO) is an itemized list of all the components required to complete a construction project.
[169]Exhibit B-1, Section 5.3, p. 64.
[170] Exhibit B-1, Section 5.3, p. 64.
[171] Exhibit B-1-2, Section 5.3.2, p. 66.

Table 2: Summary Project Capital Budget ($ millions)[172]

	2018 $	As-Spent $
Construction		
Materal [*sic*] & Unit Price Items	49.140	52.853
Construction - Direct and Indirect	136.768	146.999
Removal/Abandonment	0.226	0.243
Property and Right of Way	12.067	12.962
Contingency – Construction	33.694	36.220
Subtotal – Construction	231.895	249.277
Engineering and Development	14.845	15.715
FEI Project Management	38.368	41.403
Contingency	8.465	9.129
Management Reserve	27.279	29.343
Subtotal (incl. Construction)	320.853	344.866
AFUDC	-	15.327
TOTAL Project Capital Budget	***320.853***	***360.193***

FEI states that the cost estimates were developed based on 2018 market prices and use a 2.0 percent per annum inflation escalation rate based on the current forecast of BC Consumer Price Index (CPI) (July 2018) for both the as-spent capital cost estimates and the 60-year financial analysis. FEI also states that the cost estimate excludes GST but includes seven percent PST on materials. FEI, as a GST registrant, is entitled to recover the GST it pays on its taxable purchases. As such, GST does not represent a net cost to FEI.[173]

Quality assurance on the cost estimate and validation were completed by internal and Stantec reviews, external independent review, and periodic validation review by Stantec and FEI throughout the estimate development process.[174]

FEI prepared the following table summarizing the forecast capital costs by the selected option, which includes a breakdown of the deferred costs for the IGU Project. The treatment of the deferred costs is discussed in Section 5.3.

Table 3: Total Project Cost: Summary of Forecast Capital and Deferred Costs ($millions)[175]

	2018 $	As Spent $	AFUDC	Tax Offset	TOTAL
Type of Preferred Option					
In-line Inspection (ILI) - 11 Laterals	240.227	257.065	10.864	-	267.929
Pipeline Replacement (PLR) - 4 Laterals	26.948	28.855	1.252	-	30.107
Pressure Regulating Station (PRS) - 14 Laterals	53.388	58.635	3.197	-	61.831
Total Addition to Plant - Total 29 Laterals	320.563	344.555	15.313	-	359.868
Abandonment/Demolition Cost	0.290	0.311	0.014	-	0.325

[172] Exhibit B-1-2, Section 5.3.2, Table 5-11, p. 67.
[173] Exhibit B-1, Section 5.3.2.2, p. 67.
[174] Exhibit B-1, Section 5.3.3, p. 67.
[175] Exhibit B-1-2, Section 6.2, Table 6-1, p. 83.

Subtotal - Project Capital Budget	*320.853*	*344.866*	*15.327*	*-*	*360.193*
IGU Project Application Cost	0.390	0.390	0.008	(0.105)	0.293
IGU Project Preliminary Stage Development Cost	0.931	0.931	0.019	(0.251)	0.698
Subtotal - Project Deferral Cost	*1.321*	*1.321*	*0.027*	*(0.357)*	*0.991*
TOTAL Project Cost	***322.174***	***346.187***	***15.354***	***(0.357)***	***361.184***

In addition to the forecast total project costs presented above, the laterals will incur costs for sustainment activities and/or routine operations and maintenance. As each alternative involves slightly different integrity management activities, these costs will vary depending on the alternative selected.[176,]

Positions of the Parties

The CEC is largely satisfied with the cost estimate. It notes, however, that the IGU Project is a large capital expenditure and due to potential uncertainty includes a substantial contingency and management allowance.[177] BCOAPO did not comment on the cost estimate.

FEI submits the cost estimate for the IGU Project is reasonable and meets the requirements of the BCUC's CPCN Guidelines.[178] Further, it claims the contingency and management reserve are in accordance with AACE recommended practices, and appropriately reflect the potential uncertainty and risks associated with the Project.[179]

Panel Discussion

The Panel agrees with FEI that the cost estimate for the IGU Project satisfies the BCUC's CPCN Guidelines. The Panel has reviewed both the proposed contingency and management reserve and is satisfied they are reasonable. The Panel used the AACE Class 3 cost estimate evidence to gain satisfaction over the costs forecast for the IGU Project and notes that no party challenged the validity of this evidence. The Panel acknowledges the IGU Project is a large capital expenditure. However, the Panel is satisfied that the AACE Class 3 cost estimate combined with the BCUC directives as set out in Section 9 provide reasonable assurance with respect to the forecasted costs.

5.2 Accounting Treatment

Consistent with FEI's treatment of previous CPCNs, the capital costs of the IGU Project will be held in a Work in Progress account, attracting AFUDC at a rate equivalent to the after-tax weighted average cost of capital (WACC) until entering rate base.[180]

The IGU Project is scheduled to be completed in multiple phases between now and 2024. FEI will place the specific assets into service when they are commissioned. At the time assets are placed into service FEI will transfer the associated capital costs from the Work in Progress account to the specific asset accounts for inclusion in FEI's rate base on January 1 of the following year. Depreciation of the assets included in FEI's rate

[176] Exhibit B-5, CEC IR 4.11, CEC IR 31.2.
[177] CEC Final Argument, paragraphs 96 and 97.
[178] FEI Final Argument, paragraph 116.
[179] FEI Final Argument, paragraph 115.
[180] Exhibit B-1, Section 6.3.1, p. 85.

base will begin at the start of that year[181] and will be depreciated based on the approved depreciation rate for that asset account. Considering the majority of the capital expenditures, especially for ILI and PLR, are tracked under the transmission main pipeline asset, these additions will depreciate at a rate of 1.47 percent (or 68 years).[182]

Abandonment/demolition costs related to existing laterals will be charged to FEI's existing Net Salvage Deferral Account pursuant to Order G-44-12.[183] The abandonment/demolition costs for the IGU Project are forecast to be $0.325 million in as spent dollars (including $0.014 million in AFUDC).[184]

Costs will be recorded in accordance with generally accepted accounting principles (GAAP) and the BCUC Uniform System of Accounts for Gas Companies.[185]

Positions of the Parties

FEI submits that its accounting treatment for the IGU Project costs is reasonable and appropriate.[186] Interveners did not take a position on the proposed accounting treatment for the IGU Project.

Panel Discussion

The Panel is satisfied that the proposed accounting treatment of the capital costs is in accordance with GAAP and the Uniform System of Accounts for Gas Companies, and notes that no party took issue with it.

5.3 Deferral Account

FEI proposes to establish a deferral account to capture the costs of preparing the Application and evaluating the feasibility of the preliminary stage development of the IGU Project (IGU Deferral Account).[187] The Application filing and preparation costs include expenses for legal review, BCUC costs including approved intervener funding, and forecast costs to support a written hearing process. The preliminary stage development costs include expenses incurred by FEI internally as well as third-party consultants for assessing the feasibility of the IGU Project, and developing and evaluating preliminary design alternatives.[188]

FEI proposes that the IGU Deferral Account will be a non-rate base deferral account, with costs captured on a net-of-tax basis attracting AFUDC at a WACC return until December 31, 2019 and will be transferred to rate base on January 1, 2020 and amortized over three years. As at December 31, 2019 net-of-tax balance for the Application costs and the preliminary stage development costs are forecast to be $0.293 million and $0.698 million respectively. The following table summarizes FEI's forecast deferral account balances.[189]

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[181] Exhibit B-1, Section 6.3.1, p. 85.
[182] Exhibit B-1, Section 6.3.1, p. 85.
[183] BCUC Order G-44-12 Application by the FortisBC Energy Utilities for Approval of 2012 and 2013 Natural Gas Rates.
[184] Exhibit B-1, Section 6.3.2, p. 86.
[185] Exhibit B-2, BCUC IR 21.2.
[186] FEI Final Argument, Paragraph 126.
[187] Exhibit B-1, Section 1, p. 1.
[188] Exhibit B-1, Section 1.1, p. 1; Section 6.3.3, p. 86.
[189] Exhibit B-1-2, Section 6.3.3, pp. 86-87.

Table 4: Forecast Deferred Regulatory Application Costs and Preliminary Stage Project Development Costs ($ millions)[190]

Particulars	Application	As-Spent ($ millions) Preliminary Stage Development	TOTAL
Costs	0.390	0.931	1.321
WACC Return	0.008	0.019	0.027
Total Before Tax Offset	***0.398***	***0.950***	***1.348***
Tax Offset	(0.105)	(0.251)	(0.357)
Total	***0.293***	***0.698***	***0.991***
Annual Amortization for 3 years	(0.098)	(0.233)	(0.330)

FEI submits that the three-year amortization period is primarily based on similar deferral accounts approved for recent FEI CPCN applications, including the Muskwa River Crossing Project (approved by Order C-2-14) and the Lower Mainland Intermediate Pressure System Upgrade Project (approved by Order C-11-15), and reasonably spreads the projected balance of the account.[191] Given the size of the projected balance in the IGU Deferral Account, FEI believes either a one or two-year amortization period would also be appropriate.[192]

Positions of the Parties

The CEC supports FEI's proposal to use the IGU Deferral Account to capture the costs of preparing the Application and the costs of preliminary stage development of the IGU Project. The CEC notes that the deferral of the Application and preliminary stage development costs is consistent with recent CPCN applications. The CEC also notes that, combined with the Project delivery costs, the deferral will have a minimal effect on rates.[193] BCOAPO does not comment on the IGU Deferral Account.

Panel Determination

The Panel is satisfied with the proposed accounting treatment of the IGU Deferral Account and recognizes the account will attract interest at the WACC until entering rate base. The Panel considers the forecast costs to be accumulated in the IGU Deferral Account to be reasonable.

The Panel notes that the deferral treatment of these costs and the three-year amortization period are consistent with FEI's past practice for similar applications, which have been previously accepted and approved by the BCUC. In addition, the three-year amortization period offers the benefits of rate smoothing and matching, while avoiding an exceedingly long amortization period. The Panel notes that interveners did not oppose the establishment of the IGU Deferral Account nor the requested three-year amortization period.

The Panel approves the establishment of the IGU Deferral Account pursuant to sections 59 to 61 of the UCA to capture the costs of preparing the Application and evaluating the feasibility of the preliminary stage development of the Project for amortization over three years commencing January 1, 2020.

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[190] Exhibit B-1-2, Section 6.3.3, p. 87.

[191] Exhibit B-1-2, Section 6.3.1, p. 85; FEI Final Argument, paragraph 126.

[192] Exhibit B-2, BCUC IR 25.2.

[193] CEC Final Argument, paragraphs 255 - 257.

5.4 Financial Analysis

FEI presented a financial evaluation of the IGU Project in the Application (reproduced below.) FEI considered an analysis period of 66 years which included six years during the execution of the IGU Project (from 2019 to 2024) and 60 years post-IGU Project lifecycle operation. The 60-year post-IGU Project period is based on currently approved depreciation rate of the Transmission Main pipeline (68 years) adjusted down to 60 years for simplicity and considering that analysis period covered approximately 90 percent of the depreciation life of a Transmission Main pipeline.[194]

Table 5: Financial Analysis of the Project[195]

	ILI	PLR	PRS	TOTAL
Number of Laterals per Type of Preferred Option	11	4	14	***29***
Total Charged to Gas Plant in Service ($ millions)	267.929	30.107	61.831	***359.868***
Abandonment / Demolition Costs ($ millions)	0.058	0.268	-	***0.325***
Total Project Deferral Cost	0.376	0.137	0.478	***0.991***
Total Project Cost ($ millions)	***268.363***	***30.511***	***62.310***	***361.184***
Rate Impact in 2025, when all assets enter Rate Base (%)	3.30%	0.29%	0.71%	***4.30%***
Levelized Delivery Rate Impact 66 years (%)	2.32%	0.21%	0.52%	***3.05%***
Levelized Delivery Rate Impact 66 years ($/GJ)	0.094	0.009	0.021	***0.123***
PV of Incremental Revenue Requirement 66 years ($ million)	319.497	29.042	71.615	***420.154***
Net Cash Flow NPV 66 years ($ million)	(1.63)	(0.46)	(1.48)	***(3.58)***

FEI determined the present value of the net cash flow of the IGU Project represents (0.85 percent) of the present value of the incremental revenue requirement over 66 years.[196]

Interveners did not comment on the financial analysis.

5.5 Indicative Rate Impacts

According to the construction schedule the IGU Project will impact customer delivery rates starting 2020 and customers will continue to experience incremental rate increases through to 2025. The following table prepared by FEI presents the annual delivery rate percentage increase (year over year between 2020 and 2025) from FEI's 2018 non-bypass revenue requirement approved by BCUC Order G-196-17.[197]

Table 6: Summary of Rate Impact for the Inland Gas Upgrades Project[198]

	2020	2021	2022	2023	2024	2025
Annual Revenue Requirement, Incremental to 2018 Approved, Non-Bypass ($ millions)	(0.156)	2.823	9.828	19.189	28.298	34.172
% Increase to 2018 Approved Revenue Requirement, Non-Bypass (G-196-17)	***(0.02%)***	***0.36%***	***1.24%***	***2.41%***	***3.56%***	***4.30%***
Incremental % Rate Impact (Year-over-Year)	***(0.02%)***	***0.37%***	***0.88%***	***1.16%***	***1.12%***	***0.71%***
Average Annual % Delivery Rate Impact (6 years, 2020-2025)	0.70%					
Average Annual Delivery Rate Impact (6 years, 2020-2025), $/GJ	0.029					
Cumulative % Delivery Rate Impact (6 years, 2020-2025)	4.30%					
Cumulative Delivery Rate Impact (6 years, 2020-2025), $/GJ	0.174					

[194] Exhibit B-1, Section 4.3.1.2, p. 34.
[195] Exhibit B-1-2, Section 6.2, Table 6-3, p. 85.
[196] Exhibit B-1-2, Section 6.2, p. 85.
[197] Exhibit B-1-2, Section 6.4, p. 87.
[198] Exhibit B-1-2, Section 6.4, Table 6-6, p. 87.

When construction is completed, and all assets are placed in service in 2024, FEI determines the IGU Project will result in an estimated cumulative delivery rate impact of 4.3 percent in 2025. The average annual delivery rate impact over the six years during construction is estimated to be 0.7 percent or $0.029 per GJ annually. For a residential customer, this approximates an annual increase of $2.61 over the Project construction period.[199]

Positions of Interveners

BCOAPO did not comment on the rate impact. However, it does not oppose the IGU Project.[200] While the CEC supports the IGU Project, it submits the forecast rate increases represent a significant impact.[201]

Panel Discussion

The Panel's review of the evidence did not reveal any reason to question the accuracy of FEI's rate impact analysis. The Panel notes that although the CEC submits there is a significant rate impact, the CEC supports the Project, and does not take issue with the cost evidence apart from recognizing the Project is a large capital expenditure. The Panel considers the indicative rate impacts to be reasonable in light of the Project size and scope and the need for the Project.

6.0 Environment and Archaeology

As detailed in Section 5.7 of the Application, the Project will require extensive federal, provincial and municipal permitting and approvals due to the construction work on the 29 Laterals.[202] The construction and operation of the Project are governed by the OGAA. The Project will require pipeline applications for all 29 laterals which FEI plans to file in 2020 with the BC OGC. Each component of the Project must receive approval from the BC OGC prior to the start of construction. The Project timetable assumes a six-month approval period from the time of filing of each pipeline application.

Hemmera Envirochem Inc. (Hemmera) conducted an Environmental Overview Assessment of the Project, indicating that the overall environmental risk is low.[203] Hemmera also concludes that where environmental risks have been identified, potential impacts can be mitigated through the implementation of standard best management practices. As for impacts to construction timelines and costs resulting from encountering species at risk, fish habitat, or contaminated soil or groundwater, additional pre-construction investigations would minimize any impacts. The Project's Environmental Management Plans will incorporate these best management practices and mitigation measures.[204] FEI illustrates that there will be a number of environmental permits likely required at the provincial level under the *Environmental Management Act* and the *Water Sustainability Act*, and potentially federal permitting/authorization under the *Fisheries Act* and the *Species at Risk Act*.[205] However, FEI

[199] Exhibit B-1-2, Section 6.4, pp. 87-88.
[200] BCAOPO Final Argument, p. 15.
[201] CEC Final Argument, paragraphs 93 and 258.
[202] Exhibit B-1, Section 5.7, pp.79-82.
[203] Exhibit B-1, Appendix O
[204] Exhibit B-10, BCUC IR 50.1
[205] Exhibit B-1, Section 7.2.2, pp. 96 – 97.

does not anticipate that the extent or complexity of the permits required poses a potential risk to the expected timelines or project construction costs.[206]

As for the Project's archaeological impacts, Stantec completed an Archaeological Overview Assessment (Stantec Report) identifying areas of low, moderate or high potential impact areas.[207] Stantec contacted all affected Indigenous communities before FEI filed the Application and provided them with an opportunity to participate in the Archaeological Overview Assessment preliminary field reconnaissance.[208] The Stantec Report concluded that the majority of the expected Project's footprint would have low archaeological potential impact due to the amount of previous disturbance. It went on to recommend an Archaeological Impact Assessment for ground disturbance activities in areas identified as moderate or high potential impact which would help in developing site specific mitigation strategies to offset any potential impacts.[209] Under the *Heritage Conservation Act*, FEI requires permits to undertake detailed Archaeological Impact Assessment activities, which FEI indicates it will obtain during the Project's detailed engineering phase.[210] Indigenous concerns can be addressed as part of the *Heritage Conservation Act's* permitting process. FEI also confirms that detailed archaeological specifications will be prepared as part of the Project's tendering process to ensure that contractors are aware of the archaeological requirements under the permits.[211]

Positions of the Parties

FEI states that based on the environmental and archaeological assessments undertaken, the Project is expected to have minimal environmental and archeological impact.[212] FEI further states that environmental risks can be mitigated as described in the Environmental Overview Assessment, and that it does not anticipate other activities or major environmental assessments will be required. Overall, FEI does not anticipate that the permit approval process will present challenges or be a primary driver of project schedule.

BCOAPO observes that while no concerns have appeared with respect to possible negative impacts on vulnerable plant and wildlife populations, FEI should "remain open to feedback and modifications of its plans to address any such concerns as they arise."[213]

The CEC submits that there are no significant environmental and archaeological concerns that should jeopardize the Project's plan. Accordingly, it recommends the acceptance of the Project's plan related to environmental and archaeological impact activities as FEI proposes.[214]

Panel Discussion

The Panel is satisfied, based on the evidence, that FEI has provided adequate information to describe the environmental and archaeological work undertaken to date as well as the risks, mitigation measures and next steps required.

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[206] Exhibit B-2, BCUC IR 26.4
[207] Exhibit B-1, Appendix P.
[208] Exhibit B-10, BCUC IR 51.2
[209] Exhibit B-1, Section 7.3, p. 98.
[210] FEI Final Argument, paragraph 129.
[211] FEI Final Argument, paragraph 129.
[212] FEI Final Argument, paragraph 127.
[213] BCOAPO Final Argument, p. 6.
[214] CEC Final Argument, paragraphs 240-241.

7.0 Consultation

Section 3 of the BCUC's CPCN Guidelines outlines the information expected from an applicant regarding consultation with First Nations and the public, which includes: a description of consultation activities; issues and concerns raised; the applicant's assessment of the sufficiency of the consultation process; and a statement of planned future consultation.

FEI submits that its main goals for public consultation are to:

> …create a dialogue with interested parties, explain the need for the Project, present FEI's preferred alternatives for the Project, demonstrate the detailed assessment of alternatives, and inform interested parties of the factors that FEI must consider, including environmental impacts, constructability, and rate Impacts resulting from the Project.[215]

The consultation process starts with the development of a Communication and Consultation Plan which "outlines potential issues, lists stakeholders and sets out the general approach to consultation with respect to the work on the 29 Transmission Laterals."[216] Potential key issues, risks and impacts are then ranked as high, moderate or low. Based on those rankings, FEI establishes tailored consultation methods to address each risk, including notifications through letters, a project webpage on FEI's Talking Energy website platform, bill inserts, advertisements, phone calls, meetings with government authorities and responses to requests for further information.[217]

The following subsections provide an overview of FEI's consultation activities with First Nations communities and stakeholders such as local governments, landowners and customers.

7.1 Consultation with First Nations

Section 3 of the BCUC's CPCN Guidelines specifically requires with respect to First Nations consultation that project proponents identify those First Nations potentially affected by the application, including the feasible project alternatives and the information considered to identify these First Nations, and provide a summary of the consultation to date for each potentially affected First Nation.[218]

FEI's Position

Prior to filing the Application, FEI sent a notification letter to all 49 First Nations in the vicinity of the 29 Laterals describing the Project at a high level (without site specific details) and potential impacts.[219] FEI then followed up with a notification of the filing of the Application. Although the majority of the First Nations did not respond (37 out of 49 contacted), FEI followed up with meetings and/or further information for those 12 First Nations that did express interest.[220] The purpose of FEI's early engagement was to provide First Nations an opportunity to identify additional impacts and to give input on the Project and for FEI to get a better understanding of their

[215] FEI Final Argument, paragraph 132.
[216] FEI Final Argument, paragraph 133.
[217] FEI Final Argument, paragraphs 133-135.
[218] CPCN Guidelines, Section 3.
[219] Exhibit B-2, BCUC IR 33.2.
[220] Exhibit B-2, BCUC IR 33.4.

interests.[221] FEI explains that based on its previous projects it has undertaken the appropriate level of engagement with First Nations.[222] In terms of the feedback received, some First Nations expressed interest in environmental and archaeological assessments and procurement or employment opportunities when the Project is constructed.[223] FEI incorporated this feedback into the Project and procurement plans for the affected laterals, such as modifying the proposed archeological and environmental activities. In response to IRs, FEI provided an updated table summarizing its consultation with First Nations as of March 2019 and pledges to do a similar range of engagement, and inclusion of their feedback, for the remaining laterals as site-specific details become available.[224]

FEI submits that although it has not sent the completed Environmental or Archaeological Overview Assessments to potentially affected First Nations or had discussions with them regarding deeply buried cultural deposits, it intends to do so when more defined Project information (such as dig location data) becomes available.[225] FEI submits that for some First Nations the information compiled in the Environment and Archaeological Overview Assessments would be common knowledge because it was obtained from publicly available data sources. However, FEI acknowledges that some information in those reports could be considered new and potentially useful to the communities as it was obtained from preliminary site visits.[226]

In response to BCUC IRs, FEI provided a more detailed review of its completed and planned consultation activities, which it submits involves a "multi-stage, multi-year Indigenous engagement plan by lateral." These consultations rely on the BC OGC's Indigenous Engagement process.[227] In support of the adequacy of its approach to engagement with First Nations, FEI refers to the BCUC decision in the Lower Mainland Intermediate Pressure Station Upgrade (LMIPSU) Application where the BCUC notes the responsibility for reciprocity from First Nations. FEI points out that in order to receive its permit(s) from the BC OGC, FEI is tasked by the BC OGC to engage with First Nations, but it has not been delegated the duty to consult.[228] FEI submits that the extent and cost of FEI's future First Nations engagement efforts will depend on the level of potential impact. However, it believes that there is a high likelihood that the funds it has allocated towards those efforts will be adequate.[229]

FEI confirms that based on its early engagement with First Nations, it is not aware of any material objection to the Project or any issues of law or jurisdiction that could impact the Project or its timing.[230] FEI further submits that its engagement activities with First Nations to date have been "sufficient, appropriate and reasonable" and "has not indicated any significant concerns."[231]Furthermore, FEI reassures parties that during the BC OGC's permitting and consultation process which will occur prior to construction, more detailed Project information will be provided to the First Nations for review and comment. At that time, the identified First Nations will have

[221] Exhibit B-1, Section 8.3.1, pp. 122-123.
[222] FEI Final Argument, paragraph 148
[223] FEI Final Argument. paragraph 142.
[224] Exhibit B-2, BCUC IR 1.33.1, FEI Final Argument, Paragraphs 144-145.
[225] Exhibit B-2, BCUC IR 33.7
[226] Exhibit B-10, BCUC IR 61.3.1
[227] FEI Final Argument, paragraph 146.
[228] Order C-11-15, FEI Final Argument, paragraphs 147-148.
[229] Exhibit B-11, BCUC Confidential IR 14.2.
[230] FEI Final Argument, paragraph 143.
[231] FEI Final Argument, paragraphs 149 and 151.

additional opportunities to comment on the Project's specific impacts including during that permitting process.[232]

Panel Discussion and Determination

Although FEI is not a Crown corporation, the BCUC remains tasked with the obligation to assess the adequacy of consultation with First Nations up to the point of its decision on matters before it.[233] Further, FEI states that the BC OGC has not delegated any aspects of its consultation duty to FEI[234] although it has tasked FEI to engage with First Nations on the Project.[235] Notwithstanding FEI's early engagement and outreach efforts towards First Nations that might be affected by this Project, the Panel has some concern regarding those First Nations that have not engaged to any degree with FEI on this Project.

Given the number of non-respondents (37 out of 49) to the initial notification and the lack of evidence that FEI provided any follow up with the non-respondents, the Panel is reluctant to assume that a lack of response to FEI's notification indicates that there are no concerns regarding the Project, or that these First Nations are satisfied with FEIs level of engagement to date. The Panel notes that for those First Nations that did not respond to FEI's early consultation, it is unclear whether there are potential issues that have yet to emerge that may compromise the timing or budget of the Project, and which may be more costly to address at a later date.

The Panel further notes that it is uncertain how, and if, the recent passage of the *Declaration on the Rights of Indigenous Peoples Act*[236] may affect further First Nations consultation on this Project.

With respect to the BCUC's determination in the LMIPSU Decision, the Panel observes that each project is different and the approach to First Nations consultation may in turn require adaptation. For example, for the LMIPSU project, FEI identified seven potentially affected First Nations concentrated within a similar geographic location. By comparison, for the IGU Project, the scale of the Project means that the number of potentially affected First Nations is significant and the issues may be more diverse and complex. The Panel acknowledges that there is a reciprocal responsibility on First Nations to engage with proponents, as stated in the LMIPSU Decision,[237] but this does not preclude the proponent from seeking opportunities to encourage more meaningful levels of early engagement. In this regard, pending a decision on this Application the Panel observes that FEI has undertaken a "do minimum" approach in its early engagement with the majority of potentially affected First Nations.

The Panel recognizes, however, that FEI plans to engage in more extensive consultation activities to satisfy the BC OGC permitting requirements. While the BCUC does not have the legal duty to consult on behalf of the Province (which legal duty has been delegated by the Province to the BC OGC, not the BCUC, in respect of the individual pipeline permitting process) the Panel is nonetheless obliged to consider the adequacy of First Nations consultation up to the point of its decision on this Application. In the present case, the Crown (specifically, the BC OGC) continues to have the duty to consult and, if necessary, accommodate potentially impacted First Nations.

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[232] FEI Final Argument, paragraphs 149-150.

[233] *Rio Tinto Alcan Inc. v. Carrier Sekani Tribal Council*, 2010 SCC 43 at para. 72-74

[234] Exhibit B-10, BCUC IR 62.1.

[235] Exhibit B-10, BCUC IR 60.1.

[236] S.B.C. 2019, c. 44.

[237] *Mikisew Cree First Nation v. Canada (Minister of Canadian Heritage)*, 2005 SCC 69 at paragraph. 65

Notwithstanding the Panel's concerns expressed above, on the basis of the evidence adduced, the Panel is satisfied and finds that FEI's early consultation activities with First Nations to be adequate up to the point of this Decision. The Panel considers that FEI has appropriately identified and notified First Nations potentially affected by the Project to date. The Panel is satisfied that for those First Nations that have expressed interest or concerns with the Project, FEI has responded or has provided a plan of how those interests and concerns will be more appropriately addressed in future engagement and consultation activities on this Project. The First Nations engagement and consultation process will continue as the Project further unfolds. Furthermore, given the BCUC directives in Section 9 relating to detailed regular reporting requirements for the term of the Project, the BCUC will have the opportunity to monitor the effect of issues raised by First Nations on the Project's schedule and costs.

7.2 Public Consultation

Positions of the Parties

The remainder of FEI's consultation activities ahead of filing the Application has targeted municipalities and regional districts, landowners and customers potentially affected by the Project. FEI states that the first phase of public consultation begins with sharing preliminary information with these key stakeholders.[238]

In terms of engagement with affected municipalities and local governments, FEI has provided further information or follow up meetings where requested.[239] FEI also intends to offer community information sessions in communities within proximity of laterals with "high impact potential" but does not intend to hold these until more detailed information is available closer to construction.[240] FEI identifies five municipalities/regional districts classified as "high impact potential" that have not responded to FEI's initial notification letter, all of which are in proximity to Salmon Arm Loop 168.[241] FEI acknowledges that while there may be public concerns about the potential impacts in those communities, it does not anticipate any concerns that would present a risk to project timeline or budget. It also believes that the Project contingency would be sufficient to cover off any risks.[242]

The three major concerns that FEI has identified as a result of its public consultation to date are summarized below along with FEI's responses:[243]

(a) Public Consultation re: Kenna Cartwright Park: The City of Kamloops raised concerns over the pipeline replacement for KA1 LTL 168 that traverses Kenna Cartwright Park in Kamloops. Initially, FEI proposed an open house for residents, but through discussions with the municipality, determined to defer a public consultation session until more details about the construction plans and schedule were known.

(b) Legacies re: Kenna Cartwright Park: Kamloops requested proper restoration efforts, including the addition of park benches and a gazebo. FEI agreed to provide these and to communicate with Kamloops during the restoration phase.

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[238] Exhibit B-1, Section 8, Appendix Q.
[239] Exhibit B-1, Section 8.2.4.3, Table 8-2, pp. 109-119.
[240] Exhibit B-10, BCUC IR 54.1.
[241] Exhibit B-2, BCUC IR 32.1.
[242] Exhibit B-10, BCUC IRs 54.2, 54.2.1.
[243] FEI Final Argument, paragraph 136.

(c) North Star Rails to Trails: Kimberley expressed concerns about this corridor, a 25-kilometre nature trail connecting Kimberley to Cranbrook. Kimberley requested that the trail remain open during construction. FEI agreed to review the impacts to the trail and discuss mitigating strategies with Kimberley. FEI states its preference is to keep the trail open but as the Project gets closer to commencing and detailed design is completed, it will have a better understanding of the impacts to the trail and will work with Kimberley to minimize any disruptions.

With respect to engagement with potentially affected private landowners, FEI sent notification letters, but no landowners have responded.[244] FEI believes that, while early discussions with landowners are important, the lack of response does not increase the risk of landowners not wishing to sell or having unreasonable expectations.[245] FEI intends to contact landowners prior to conducting engineering and geotechnical studies.[246] FEI notes that while it intends to negotiate mutually acceptable agreements with landowners, if that is not feasible, it would take steps to expropriate the necessary land rights.[247] The Project's cost estimate does not include any legal fees associated with exercising its expropriation rights should expropriation become necessary.[248]

As for engagement with its industrial customers, FEI notified the affected customers by letter and phone calls and undertook follow up meetings with customers that are served directly by the laterals.[249] Although some customers did not respond to FEI's initial notification letter, FEI submits that the potential impacts to industrial customers are limited, particularly in light of its choice of project alternatives to avoid service interruptions to such customers. FEI plans to send affected customers a further notification upon Project approval as well as comply with any applicable BC OGC consultation requirements.[250]

FEI submits that its communication plan and the public consultation activities to the time of filing the Application have been sufficient, appropriate and reasonable to meet the requirements of the BCUC CPCN Guidelines.[251]

As is the case with the Environment Overview Assessment process, BCOAPO acknowledges that while no issues have arisen to date with consultations with First Nations or landowner or industrial stakeholders, it is premature to assume that issues will not arise once site specific details are known. Indeed, it would be prudent to assume that issues will arise.[252]

The CEC indicates that it is satisfied with the depth and breadth of FEI's public consultation efforts and recommends that the BCUC find the public consultation to be adequate.[253]

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[244] Exhibit B-2, BCUC IR 28.1.
[245] Exhibit B-10, BCUC IR 52.1.1.
[246] Exhibit B-10, BCUC IR 52.1.2.
[247] Exhibit B-2, BCUC IR 28.2.
[248] Exhibit B-11, BCUC Confidential IR 16.18.
[249] Exhibit B-1, Section 8.2.4.2, p. 109.
[250] Exhibit B-10, BCUC IR 53.1.
[251] FEI Final Argument, paragraph 140.
[252] BCOAPO Final Argument, p.6.
[253] CEC Final Argument, paragraphs.246-247.

Panel Discussion

With respect to public consultation other than First Nations consultation, the BCUC is not required to make any determination as to the adequacy of FEI's public consultation efforts. Nonetheless, based on the evidence and given the stage of the Project, the information available at this time and the additional consultation yet to occur, the Panel is satisfied that FEI's consultation with affected stakeholders to date has been adequate and sufficient to inform them as to the risks of the Project and the impact on them. The Panel anticipates that as and when the Project proceeds, FEI will undertake more public consultation. Further issues may arise which may entail adjustments to the timeline and budget for the Project, which are to be expected for capital projects of this size and duration. Accordingly, to assist in keeping the Project on track, the Panel will direct in Section 9 detailed reporting requirements from FEI for the duration of the Project.

8.0 Provincial Government Energy Objectives and the Long-Term Resource Plan

As stated earlier, section 46(3.1) of the UCA requires the BCUC to consider "the applicable of British Columbia's energy objectives" and the extent to which the Application is consistent with the requirements of the *Clean Energy Act* (CEA).[254]

As part of the Project's overall impact and risk assessment, FEI completed a socio-economic assessment. FEI submits that the assessment shows:[255]

> The Project will result in an overall positive impact to residents and businesses through the creation of additional employment within the Project scope, and the procurement of local materials and the use of local services, such as local lodging and dining. The Project will limit the potential for a loss or a disruption of gas supply and will improve the reliability of the natural gas system.

Based on that assessment, FEI submits that the Project supports the following BC energy objective found in Section 2(k) of the CEA:[256]

> To encourage economic development and the creation and retention of jobs

FEI's most recent long-term resource plan is the 2017 Long-Term Resource Plan filed on December 14, 2017. FEI submits that the Project was described in that plan as the "Transmission System Laterals In-Line Inspection Capability Project" which contemplated that in-line inspection would be the primary means to mitigate the potential for rupture associated with corrosion. Since the filing of that plan, FEI has reviewed other more cost-effective alternatives which has resulted in the current Project. FEI submits that the current Project nonetheless remains consistent with the plan as filed.[257]

Panel Discussion

The Panel notes that no intervener has raised any issues regarding FEI's characterization of the Project's alignment with the Provincial Government's energy objectives and its consistency with FEI's most recently filed

[254] UCA, sections 46(3.1)(a) & (c).
[255] Exhibit B-1, Section 5.6.2, p. 78.
[256] Exhibit B-1, Section 9.2, p. 131.
[257] Exhibit B-1, Section 9.3, p. 131.

long-term resource plan. The Panel accepts FEI's explanation that to the extent that the plan originally contemplated in-line inspection as the preferred means of mitigating the risk of corrosion, that solution is now one of three alternatives included within the Project depending on the feasibility, practicality and cost of the chosen alternative for each of the laterals. As for the energy objective of promoting "economic development and the creation and retention of jobs" set out in section 2(k) of the CEA, the Panel accepts that the Project will result in employment and procurement opportunities for the duration of the Project. The Panel has considered the applicable Provincial Government's energy objectives set out in section 2 of the CEA, and is satisfied that the IGU Project is consistent with FEI's 2017 Long-Term Resource Plan accepted by the BCUC under section 44.1 of the UCA**.**

9.0 CPCN and Deferral Account Determinations

Section 45(1) of the UCA[258] stipulates that a person must not begin the construction or operation of a public utility plant or system, without first obtaining from the BCUC a certificate that public convenience and necessity require, or will require, the construction or operation of the plant or system.

Sections 46(1) and (3) of the UCA state that:[259]

> An applicant for a certificate of public convenience and necessity must file with the commission information, material, evidence and documents that the commission prescribes.
>
> …
>
> (3) … the commission may, by order, issue or refuse to issue the certificate… and may attach to the exercise of the right or privilege granted by the certificate, terms, including conditions about the duration of the right or privilege under this Act as, in its judgment, the public convenience or necessity may require.

Position of the Parties

FEI

In support of its Application for the granting of a CPCN for the Project, FEI submits that:

> …the evidence in this proceeding is compelling and demonstrates that the Project is in the public interest. FEI must carry out the Project to mitigate the potential for the 29 Transmission Laterals to fail by rupture due to external corrosion, consistent with its regulatory obligations set out in CSA Z662 and industry standard practice. FEI has consulted with the British Columbia Oil and Gas Commission ("BC OGC") regarding the Project, and the BC OGC has stated that it "is supportive of FEI taking action to address its known integrity concerns and to ensure that it meets its requirements as a permit holder under the Oil and Gas Activities Act."[260]

In urging the BCUC to approve the Project, FEI states:

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[258] *Utilities Commission Act*, RSBC 1996, c. 473.

[259] UCA, s.46(3)

[260] FEI Final Argument, paragraph 8.

> FEI's evidence in this proceeding is comprehensive, responding to all issues raised, and conclusively demonstrates that the Project is in the public interest. The need and justification for the Project is clear and FEI's alternatives analysis has been designed to ensure that the most cost-effective feasible alternative has been chosen for each of the 29 Transmission Laterals. FEI's cost estimate is reasonable and robust, appropriately including contingency and management reserve reflecting the attributes and risk of the Project. The Project is expected to have minimal environmental and archaeological impacts, and FEI's public consultation and early engagement with Indigenous communities has not indicated any significant concerns.[261]

The CEC

The CEC recommends that the BCUC approve the Project on the basis that the proposal to upgrade the 29 Transmission Laterals to necessary safety standards is in the public interest.[262] Furthermore, it would not support a "project deferral that could unreasonably increase the risk of significant negative consequences which jeopardize the safety or well-being of any community or individual, create irreversible harm to the environment, or result in customer service disruptions or widespread outages."[263] However, the CEC suggests that the BCUC should consider approving the Project on the condition that FEI carry out more work quantifying risk and prioritization activities and report to the BCUC to ensure that the Project is undertaken in the most cost-effective manner possible.[264] The CEC further suggests that FEI consider a staged option for the Project, whereby FEI would do quantitative ongoing analysis to determine the condition of the laterals and establish priorities, examine the potential for deferral of certain upgrades based on timing or enable alternative technologies to become commercially viable, and further examine whether PRS could be reasonably provided at greater cost-effectiveness in some cases.[265] Notwithstanding these suggestions, the CEC accepts that the Project, or some version thereof, is necessary to maintain compliance with legal and regulatory obligations.[266]

BCOAPO

BCOAPO is equivocal as to whether the BCUC should approve or deny this Application, stating that it is unable to support this Project although it does not oppose it. It cites the following three reasons for this position:[267]

1. FEI has failed to address the issue of cathodic protection shielding on the Transmission Laterals in a more timely fashion despite having identified this problem 13 years ago;
2. FEI has failed to spend any shareholder monies on this issue to date; and
3. FEI has failed to do further integrity digs to prioritize the 29 Laterals before applying for a CPCN.

BCOAPO submits that these issues should be addressed before the BCUC approves or denies this Application.

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[261] FEI Final Argument, paragraph 151.
[262] CEC Final Argument, paragraph 258.
[263] CEC Final Argument, paragraph 261.
[264] CEC Final Argument, paragraph 259.
[265] CEC Final Argument, paragraph 260.
[266] Exhibit B-5, CEC 18.2; CEC Final Argument, Paragraph 263.
[267] BCOAPO, Final Argument, pp. 7 & 15.

FEI Reply Argument

In response to BCOAPO's concerns, FEI submits that while the problem of external corrosion and CP shielding was known many years ago, evolving technology and industry practice have made in-line inspection available for smaller diameter transmission pipelines such that it has become standard practice and reflective of a regulator's expectations. As such, FEI reasonably identified the need for the Project to mitigate the potential for rupture failure of the laterals due to corrosion in August 2015, following which it began planning the Project for completion by 2024.[268] As for the suggestion that more integrity digs ought to be done to prioritize work on the Project, FEI submits that it would have to dig up the entire pipeline and visually inspect it in order to assess the level of corrosion on a pipeline as a whole. FEI submits: "The cost of digging up all of the 29 transmission laterals would cost more than the Project itself."[269] Furthermore, FEI submits that delaying the Project to conduct further integrity digs or prioritization works would only serve to increase safety and reliability risks and delay the Project's benefits.[270]

As for the CEC's suggestions for a conditional approval or a staged option for the Project, FEI argues that it would only serve to delay the Project's benefits, leaving the identified rupture risk unaddressed.[271] FEI points out that as a prudent operator, it must proactively address the identified risk as soon as practicable in accordance with regulatory requirements and standard industry practice.[272] As for the suggestion that a quantitative risk assessment could reduce Project construction costs or cost uncertainty or ratepayer impacts, FEI contends that such an assessment would entail resources and time, which would add (not reduce) costs to the Project and would only delay the Project's benefits.[273]

FEI further rejects the CEC's proposal for delaying the Project in anticipation of robotic technologies on the basis that it cannot prudently delay a project that is needed to mitigate an identified rupture risk in the hopes that future technology may become proven and commercialized.[274] Furthermore, FEI states that if it identifies a commercially feasible and industry accepted alternative during Project implementation, it would evaluate the alternative and advise the BCUC of any change.[275] FEI notes that the CEC agrees with this approach.[276] Accordingly, there is no need for any conditional approval or staged option to wait for robotic technology to mature.

FEI goes on to caution that the Project cannot be safely deferred. It states that "Until the Project is completed, there will continue to be potential for significant regulatory, safety, reliability and environmental consequences in the event of a pipeline rupture due to external corrosion."[277]

As for the CEC's suggestion that consideration be given to using PRS as the preferred option for cost reasons, FEI rejects this suggestion on the basis that PRS is not viable due to capacity limitations of some systems. Using PRS

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[268] FEI Reply Argument, pp.3-4, paragraph 6.
[269] FEI Reply Argument, paragraph 7.
[270] FEI Reply Argument, paragraph 8.
[271] FEI Reply Argument, paragraph 9.
[272] FEI Reply Argument, paragraph 12.
[273] FEI Reply Argument, paragraphs 14-23.
[274] FEI Reply Argument, paragraph 27.
[275] Exhibit B-5, CEC IR 21.1.5.
[276] CEC Final Argument, paragraph 234.
[277] FEI Reply Argument, paragraph 29.

for those laterals would entail a reduction in capacity and would result in a "year-round requirement for more frequent curtailment of customer loads" and a deterioration in reasonably reliable service for the affected customers. In some cases, a PRS would result in FEI failing to meet supply needs for forecast growth in the laterals' regions and require a pipeline expansion to restore capacity on those laterals in order to handle expected customer loads.[278] FEI also advises that choosing PRS as the preferred option in some cases can be counterproductive in terms of costs:

> If FEI installs a PRS such that it cannot provide interruptible customers with reasonable service, the customers can elect firm service, triggering more expensive upgrades to serve their needs as FEI would not be able to interrupt their service at all. Alternatively, the interruptible customers could cease to be customers, reducing revenue to the detriment of all customers and making the investment in the existing lateral and integrity management solution less economic. Finally, installing a PRS in these cases would prevent FEI from adding further customers without further upgrades to the system, potentially denying the benefits of natural gas service to others and reducing the potential benefits of increased revenue and consequently lower rates for all customers.[279]

Panel Determination

As noted earlier, on the basis of the evidence in this proceeding, the Panel is satisfied that FEI has demonstrated that there is a need for the Project in order to address the identified risk of pipeline rupture on the laterals due to external corrosion and that the three technical alternatives FEI has put forward to address that risk are appropriate. While we share some of the interveners' reservations about the extent of thoroughness and rigour of FEI's current risk assessment methodology and approach in reviewing the need for the Project, FEI has managed nonetheless to persuade us, in the words of FEI, that the need to proceed with this Project to proactively manage the identified rupture risk is "clear and compelling." The Panel is satisfied that from a safety perspective, the Project is an appropriate and timely response to address FEI's regulatory obligations to mitigate the identified hazard of rupture due to undetectable pipeline corrosion on the laterals. As for BCOAPO's suggestion that shareholder monies ought to be spent on mitigating the pipeline rupture risk, the Panel rejects that on the basis that there is no regulatory requirement for FEI's shareholder to fund pipeline integrity management initiatives.

Accordingly, the Panel approves:

1. **FEI's Application for a CPCN for the IGU Project pursuant to sections 45 and 46 of the UCA; and**
2. **The establishment of the IGU Deferral Account, pursuant to sections 59 to 61 of the UCA, to capture the costs of preparing the Application and evaluating the feasibility of the preliminary stage development of the Project, forecast at $0.991 million, and to amortize those costs over three years commencing January 1, 2020.**

However, given the magnitude of the Project and the extended timeline for its implementation, the Panel also finds it appropriate to direct FEI to provide regular reporting to the BCUC for the duration of the Project, as detailed below.

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[278] FEI Reply Argument, paragraph 31.

[279] FEI Reply Argument, paragraph 33.

The Panel directs FEI to file the following reports:

1. **Semi-annual Progress Reports on each of the 29 Laterals**

   Each report is required to detail:

   - **Actual costs incurred to date compared to the CPCN estimate highlighting variances with an explanation and justification of significant variances;**
   - **Updated forecast of costs, highlighting the reasons for significant changes in Project costs anticipated to be incurred; and**
   - **The status of Project risks, highlighting the status of identified risks, changes in and additions to risks, the options available to address the risks, the actions that FEI is taking to deal with the risks and the likely impact on the Project's schedule and cost.**

   FEI must file semi-annual progress reports within 30 days of the end of each semi-annual reporting period, with the first report covering the period ending June 30th, 2020. Each report must provide the information set out in Appendix A to this Decision.

2. **Material Change Reports on each of the 29 Laterals**

   A material change is a change in FEI's plan for an individual lateral that would reasonably be expected to have a significant effect on the schedule, cost or scope of that particular plan, such that:

   - **there is a schedule delay of greater than six months compared to the CPCN construction schedule for the lateral;**
   - **there is a cost variance of greater than 10 percent of the CPCN capital estimate for the lateral; or**
   - **there is a change to the integrity management alternative selected.**

   In the event of a material change, FEI must file a material change report with the BCUC, explaining the reasons for the material change, FEI's consideration of the Project risk and the options available and actions FEI is taking to address the material change. FEI must file the material change report as soon as practicable and in any event within 30 days of the date on which the material change occurs. If the material change occurs within 30 days of the date for filing a semi-annual progress report, FEI may include the material change information in the progress report.

3. **Final Report**

   The Final Report must include a breakdown of the final costs of the Project compared to the cost estimates included in Table 6-2 in the Exhibit B-1-2 and provide an explanation and justification of any material cost variances of 10 percent or more.

   The Final Report must be filed within six months of substantial completion or the in-service date of the Project, whichever is earlier.

10.0 Future CPCN Applications

Perhaps not surprising given the magnitude and complexity of the Project, review of this Application has taken more than a year to complete. The review process has entailed three rounds of IRs as well as a procedural conference/workshop to address our concerns relating to the need and timing for the Project. While the evidence and information gained through that process have been helpful to us in reaching our decision in the end, it would have been even more helpful had that information, particularly with respect to FEI's risk management methodology and approach (including the distinction between qualitative and quantitative risk assessments) been included amongst the materials filed initially in support of the Application.

We urge FEI in similar CPCN applications of this nature to consider providing a more comprehensive discussion of its risk assessment methodology that takes into account the likelihood of a specific risk occurring as well as the severity of the consequences that are site specific, so that the BCUC can more readily determine the appropriateness and sufficiency of the proposed solution for addressing the identified risk. We recommend, for example, that FEI consider providing a documented risk assessment which complies with the relevant mandatory sections of CSA Z662 Clause 3 (Safety and Loss Management System) and which follows the guidance given in Annex B of the Standard (Guidelines for Risk Assessment for Pipeline Systems). We believe that such information would lead to a more efficient and timely process for reviewing and determining similar applications from FEI in the future.

11.0 Summary of Approvals and Directives

This summary is provided for the convenience of readers. In the event of any difference between the approvals and directives set out in this summary and those in the body of the Decision, the wording in the Decision shall prevail.

	Approvals and Directives	**Page**
1.	The Panel approves the granting of a Certificate of Public Convenience and Necessity for FEI's Inland Gas Upgrades Project pursuant to Sections 45 and 46 of the UCA.	41
2.	The Panel approves the establishment of the IGU Deferral Account pursuant to Sections 59 to 61 of the UCA to capture the costs of preparing the Application and evaluating the feasibility and the preliminary stage development of the Project, forecast at $0.991 million, for amortization over three years commencing January 1, 2020.	41
3.	The Panel directs FEI to file the following reports for the duration of the Project: 1. Semi-annual Progress Reports on each of the 29 Laterals Each report is required to detail: • Actual costs incurred to date compared to the CPCN estimate highlighting variances with an explanation and justification of significant variances; • Updated forecast of costs, highlighting the reasons for significant changes in Project costs anticipated to be incurred; and	41–42 and Appendix A to the Decision

	• The status of Project risks, highlighting the status of identified risks, changes in and additions to risks, the options available to address the risks, the actions that FEI is taking to deal with the risks and the likely impact on the Project's schedule and cost. FEI must file semi-annual progress reports within 30 days of the end of each semi-annual reporting period, with the first report covering the period ending June 30th, 2020. Each report must provide the information set out in Appendix A to this Decision. 2. Material Change Reports on each of the 29 Laterals A material change is a change in FEI's plan for an individual lateral that would reasonably be expected to have a significant effect on the schedule, cost or scope of that particular plan, such that: • there is a schedule delay of greater than six months compared to the CPCN construction schedule for the lateral; • there is a cost variance of greater than 10 percent of the CPCN capital estimate for the lateral; or • there is a change to the integrity management alternative selected. In the event of a material change, FEI must file a material change report with the BCUC, explaining the reasons for the material change, FEI's consideration of the Project risk and the options available and actions FEI is taking to address the material change. FEI must file the material change report as soon as practicable and in any event within 30 days of the date on which the material change occurs. If the material change occurs within 30 days of the date for filing a semi-annual progress report, FEI may include the material change information in the progress report. 3. Final Report The Final Report must include a breakdown of the final costs of the Project compared to the cost estimates included in Table 6-2 in the Exhibit B-1-2 and provide an explanation and justification of any material cost variances of 10 percent or more. The Final Report must be filed within six months of substantial completion or the in-service date of the Project, whichever is earlier.	

DATED at the City of Vancouver, in the Province of British Columbia, this 21st day of January 2020.

Original signed by:

A. K. Fung, QC
Panel Chair

Original signed by:

E.B. Lockhart
Commissioner

Original signed by:

_____

T. A. Loski
Commissioner

Original signed by:

_____

R. D. Revel
Commissioner

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ORDER NUMBER
G-12-20

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc.
Application for a Certificate of Public Convenience and Necessity
for the Inland Gas Upgrades Project

BEFORE:
A. K. Fung, QC, Panel Chair
E. B. Lockhart, Commissioner
T. A. Loski, Commissioner
R. D. Revel, Commissioner

on January 21, 2020

ORDER

WHEREAS:

A. On December 17, 2018, FortisBC Energy Inc. (FEI) submitted an application to the British Columbia Utilities Commission (BCUC) pursuant to sections 45 and 46 of the *Utilities Commission Act* (UCA), seeking approval of a Certificate of Public Convenience and Necessity (CPCN) for the Inland Gas Upgrades (IGU) Project (Application);

B. FEI also seeks approval of a deferral account, pursuant to sections 59 to 61 of the UCA, to capture the regulatory costs of this Application and the costs expended for the purpose of evaluating the feasibility of and preliminary development of the Project;

C. By Order G-11-19 dated January 17, 2019, the BCUC established a regulatory timetable for the review of the Application which consisted of intervener registration and one round of information requests (IR);

D. By Order G-79-19 dated April 12, 2019, the BCUC amended the regulatory timetable to allow for a second round of IRs, followed by a workshop/procedural conference on July 10, 2019;

E. By Order G-153-19 dated July 11, 2019, the BCUC further amended the regulatory timetable to allow for a third round of IRs, submission dates for final and reply arguments and a placeholder for a Streamlined Review Process (SRP);

F. By Order G-219-19 dated September 11, 2019, the BCUC subsequently amended the regulatory timetable to cancel the SRP and establish dates for final and reply argument; and

G. The BCUC has reviewed the evidence in this proceeding and finds that certain approvals are warranted.

NOW THEREFORE pursuant to sections 45 to 46 and 59 to 61 of the *Utilities Commission Act* and for the reasons set out in the decision issued concurrently with this order, the British Columbia Utilities Commission orders as follows:

1. A CPCN is granted to FEI for the IGU Project.
2. FEI is approved to establish the IGU Project Application and Preliminary Stage Development Costs deferral account to record the Application and preliminary stage development costs to be amortized over three years commencing January 1, 2020.
3. FEI is directed to comply with all the directives outlined in Section 9 of the decision issued concurrently with this order.

DATED at the City of Vancouver, in the Province of British Columbia, this 21st day of January 2020.

BY ORDER

Original signed by:

A. K. Fung, QC
Commissioner

FortisBC Energy Inc.
Application for a Certificate of Public Convenience and Necessity
for the Inland Gas Upgrades Project

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     - 2.1.3 Schedule Difficulties and Variances
   - 2.2 Design Scope Change Summary with Description of Request, Explanation for Request, Request Amount, Approved Amount.
   - 2.3 Construction Scope Change Summary with Description of Request, Explanation for Request, Request Amount, Approved Amount.

3. Project Costs
   - 3.1 Project Cost Summary including explanation of variances relative to the cost estimate in the Application and the updated control budget. The report should show: “amount in CPCN Application”, amount in control budget”, “spent to date”, “estimate to complete”, “forecast total to complete”, and “variances”.
   - 3.2 Financial Summary including explanation of variances for the total project costs.

4. Project Risks
   - 4.1 Significant Project Risks
   - 4.2 Impacts to Project Schedule or Costs
   - 4.3 Plans to Mitigate Risks

5. Public and First Nations Consultation
   - 5.1 An ongoing report on the status of consultation efforts including description of issues raised and addressed.

IN THE MATTER OF
the *Utilities Commission Act*, RSBC 1996, Chapter 473

and

FortisBC Energy Inc.
Certificate of Public Convenience and Necessity Application for
the Inland Gas Upgrade Project

EXHIBIT LIST

Exhibit No.	**Description**
COMMISSION DOCUMENTS	
A-1	Letter dated January 10, 2019 - Appointing the Panel for the review of FortisBC Energy Inc. Certificate of Public Convenience and Necessity (CPCN) Application for the Inland Gas Upgrade (IGU) Project
A-2	Letter dated January 17, 2019 – Order G-11-19 establishing the regulatory timetable
A-3	Letter dated February 15, 2019 – Notice to Parties
A-4	Letter dated February 21, 2019 – BCUC Information Request No. 1 to FEI
A-5	**CONFIDENTIAL** - Letter dated February 21, 2019 – BCUC Confidential Information Request No. 1 to FEI
A-6	Letter dated March 7, 2019 – Update on Notice to Parties
A-7	Letter dated March 29, 2019 – BCUC Submission Request on Further Process
A-8	Letter dated April 12, 2019 – Order G-79-19 establishing a further regulatory timetable
A-9	Letter dated May 7, 2019 – BCUC Information Request No. 2 to FEI
A-10	**CONFIDENTIAL** - Letter dated May 7, 2019 – BCUC Confidential Information Request No. 2 to FEI
A-11	Letter dated June 27, 2019 – BCUC confirming Procedural Conference

A-12 Letter dated July 5, 2019 – BCUC responding to the Procedural Conference Request

A-13 Letter dated July 11, 2019 – Order G-153-19 establishing a further regulatory timetable

A-14 Letter dated August 8, 2019 – BCUC Information Request No. 3 to FEI

A-15 Letter dated September 6, 2019 – BCUC submission request on FEI's extension request

A-16 Letter dated September 11, 2019 – Order G-219-19 establishing a further regulatory timetable

COMMISSION STAFF DOCUMENTS

A2-1 **Letter dated February 21, 2019 – BCUC staff submitting BC Oil & Gas Commission Compliance Assurance Protocol – Integrity Management Program for Pipelines**

APPLICANT DOCUMENTS

B-1 **FORTISBC ENERGY INC. (FEI)** Letter dated December 17, 2018 - Certificate of Public Convenience and Necessity (CPCN) Application for the Inland Gas Upgrade Project (IGU) Project

B-1-1 **CONFIDENTIAL** – Appendices to the application – Filed confidentially Appendix J-Stantec FEED Report Documents, Appendix L-Risk Analysis and Appendix N-Financial Schedules

B-1-2 Letter dated April 5, 2019 – FEI Submitting Evidentiary Update and Errata to the Application

B-1-2-1 **CONFIDENTIAL** – Errata to the Appendices to the Application – Filed confidentially Appendix J-Stantec FEED Report Documents, Appendix L-Risk Analysis and Appendix N-Financial Schedules

B-2 Letter dated March 28, 2019 – FEI Responses to BCUC Information Request No. 1

B-2-1 **CONFIDENTIAL** - Letter dated March 28, 2019 – FEI Confidential Responses to BCUC Information Request No. 1.14.3 and 1.15.2

B-3 **CONFIDENTIAL** - Letter dated March 28, 2019 – FEI Confidential Responses to Confidential BCUC Information Request No. 1

B-4 Letter dated March 28, 2019 – FEI Responses to BCOAPO Information Request No. 1

B-5 Letter dated March 28, 2019 – FEI Responses to CEC Information Request No. 1

B-6	**CONFIDENTIAL** - Letter dated March 28, 2019 – FEI Confidential Responses to CEC Confidential Information Request No. 1
B-7	Letter dated March 28, 2019 – FEI Submitting Notice of Evidentiary Update
B-8	Letter dated April 4, 2019 – FEI Submitting Comment on Further Process
B-9	Letter dated April 8, 2019 – FEI Submitting Reply Submission on Further Process
B-10	Letter dated June 7, 2019 – FEI Responses to BCUC Information Request No. 2
B-11	**CONFIDENTIAL** - Letter dated June 7, 2019 – FEI Confidential Responses to BCUC Confidential Information Request No. 2
B-12	Letter dated June 7, 2019 – FEI Responses to BCOAPO Information Request No. 2
B-13	Letter dated June 7, 2019 – FEI Responses to CEC Information Request No. 2
B-14	**CONFIDENTIAL** - Letter dated June 7, 2019 – FEI Confidential Responses to CEC Confidential Information Request No. 2
B-15	Letter dated July 3, 2019 – FEI Submitting Procedural Conference Request
B-16	Letter dated July 10, 2019 – FEI Submitting Procedural Conference Presentation
B-17	Letter dated July 16, 2019 – FEI Submitting upon review of Procedural Conference Transcript clarification to FEI's evidence
B-18	Letter dated September 4, 2019 – FEI Responses to BCUC Information Request No. 3
B-19	Letter dated September 4, 2019 – FEI Responses to BCOAPO Information Request No. 3
B-20	Letter dated September 4, 2019 – FEI Responses to CEC Information Request No. 3

INTERVENER DOCUMENTS

C1-1	**CITY OF KAMLOOPS (COK) –** Letter dated February 12, 2019 – Request for Intervener Status by Emily Lomas
C2-1	**CITY OF KELOWNA (KELOWNA) –** Letter dated February 13, 2019 – Request for Intervener Status by James Kay

C3-1	**BRITISH COLUMBIA OLD AGE PENSIONERS' ORGANIZATION, DISABILITY ALLIANCE BC, COUNCIL OF SENIOR CITIZENS' ORGANIZATIONS OF BC, AND THE TENANT RESOURCE AND ADVISORY CENTRE (BCOAPO) –** Letter dated February 13, 2019 – Request for Intervener Status by Leigha Worth and Irina Mis
C3-2	Letter dated February 28, 2019 – BCOAPO submitting Information Request No. 1 to FEI
C3-3	Letter dated March 20, 2019 – BCOAPO Submitting notice of co-counsel Ms. Irina Mis and expert consultant Mr. James Wightman
C3-4	Letter dated April 4, 2019 – BCOAPO Submitting Comment on Further Process
C3-5	Letter dated May 7, 2019 – BCOAPO Submitting Information Request No. 2 to FEI
C3-6	Letter dated August 22, 2019 – BCOAPO Submitting Information Request No. 3 to FEI
C4-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC)** - Letter dated February 14, 2019 – Request for Intervener by David Craig and Christopher Weafer
C4-2	Letter dated February 20, 2019 – CEC submitting Confidentiality Declaration and Undertaking Form for Janet L. Rhodes and David W. Craig
C4-3	Letter dated February 15, 2019 – CEC submitting response regarding Exhibit A-3
C4-4	Letter dated February 21, 2019 – CEC submitting Confidentiality Declaration and Undertaking Form for Christopher Weafer
C4-5	Letter dated February 28, 2019 – CEC submitting Information Request No. 1 to FEI
C4-6	**CONFIDENTIAL** - Letter dated February 28, 2019 – CEC submitting confidential Information Request No. 1 to FEI
C4-7	Letter dated April 4, 2019 – CEC Submitting Comment on Further Process
C4-8	Letter dated May 7, 2019 – CEC Submitting Information Request No. 2 to FEI
C4-9	**CONFIDENTIAL** - Letter dated May 7, 2019 – CEC Submitting Confidential Information Request No. 2 to FEI
C4-10	Letter dated August 15, 2019 – CEC Submitting Information Request No. 3 to FEI
C4-11	Letter dated September 10, 2019 – CEC Submitting no objection to FEI Extension Request
C5-1	**STK'EMLUPSEMC TE SECWEPEMC NATION (SSN) –** Letter dated February 14, 2019 – Request for Intervener Status by Robert Simon

INTERESTED PARTY DOCUMENTS

D-1 **CITY OF PRINCE GEORGE** – Letter dated January 30, 2019 - Request for Interested Party Status by Kathleen Soltis

D-2 **DISTRICT OF ELKFORD** – Letter dated February 8, 2019 - Request for Interested Party Status by Curtis

D-3 **TK'EMLUPS TE SECWEPEMC** – Letter dated February 14, 2019 - Request for Interested Party Status by Jordan Dickie

D-4 **BC OIL & GAS COMMISSION -** Letter dated July 2, 2019 - Request for Interested Party Status by Dorothy McDaid