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British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, BC V6Z 2N3

Attention: Mr. Patrick Wruck, Commission Secretary

Dear Sirs/Mesdames:

Re: FortisBC Energy Inc. ("FEI") Application for a Certificate of Public Convenience and Necessity for the Coastal Transmission System Transmission Integrity Management Capabilities Project - Final Submission

In accordance with the regulatory timetable in the above proceeding, we enclose for filing the Final Argument of FortisBC Energy Inc., dated October 26, 2021.

Yours truly,

FASKEN MARTINEAU DuMOULIN LLP

[Original signed by]

Christopher Bystrom*
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CRB/NR
Encl.

BRITISH COLUMBIA UTILITIES COMMISSION

FORTISBC ENERGY INC.

CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY FOR THE COASTAL TRANSMISSION SYSTEM TRANSMISSION INTEGRITY MANAGEMENT CAPABILITIES PROJECT

BCUC PROJECT NO. 1598988

FINAL ARGUMENT

OF

FORTISBC ENERGY INC.

OCTOBER 26, 2021

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PART ONE: INTRODUCTION

A. Overview of Application and Proceeding

1. FEI filed its Application to the British Columbia Utilities Commission (BCUC) for a Certificate of Public Convenience and Necessity (CPCN) for the Coastal Transmission System Transmission Integrity Management Capabilities Project (Project or CTS TIMC Project) on February 11, 2021 (Application).[1] FEI is seeking a CPCN for the CTS TIMC Project pursuant to sections 45 and 46 of the *Utilities Commission Act* (UCA). FEI also seeks approval to transfer the balance in the TIMC Development Cost deferral account associated with the development of the CTS TIMC Project to a new rate base CTS TIMC deferral account on January 1 of 2023, and to commence amortization of the balance of these costs, estimated at $13.2 million, over a three-year period commencing at that time.[2]

2. FEI has demonstrated in this proceeding that the CTS TIMC Project is in the public interest as it is necessary to ready 11 of its coastal transmission system (CTS) pipelines for in-line-inspection (ILI) tools capable of detecting cracking threats, such as stress corrosion cracking (SCC), which can lead to failure by rupture.[3] Through a baseline system-level quantitative risk assessment (QRA) undertaken by Jana Corporation (JANA), a QRA expert,[4] these cracking threats were assessed as the highest contributor to the safety risk of FEI's CTS.[5] Electro-magnetic acoustic transducer (EMAT) ILI tools are increasingly becoming the standard industry practice for mitigating cracking threats on pipelines and are the only technically and financially feasible alternative to mitigate such threats. FEI must adopt EMAT ILI for the 11 of its CTS pipelines to keep pace with evolving industry practice and regulatory expectations for managing the safety risk posed by cracking threats, and to meet its obligations to ensure the safety and security of its pipeline operations.[6]

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1 Exhibit B-1, Application and Confidential Exhibits B-1-1 and B-1-1-1.

2 Exhibit B-5, BCUC IR1 26.2 and 27.4.1. FEI notes that its explanation that it was seeking the creation of a new rate base deferral account was not as clear as it could have been. FEI has included a clarified Order Sought as an attachment to this Final Submission.

3 Exhibit B-1, Application, Section 3.

4 The C.V.s of the lead authors of the JANA reports, Ken Oliphant, Ph.D., P.Eng. and James DuQuesnay, M.A.Sc., are included in Exhibit B-1-1, Confidential Appendices B-1 and B-2.

5 Exhibit B-1, Application, Table 3-12; Exhibit B-1-1; Confidential Appendix B-2, pp. 14-15. FEI is in the process of developing a separate project to address the risk to nine of FEI's Interior Transmission System (ITS) pipelines which are also considered susceptible to cracking, although generally assessed as having a lower safety risk than the CTS.

6 Exhibit B-1, Application, pp. 1, 5 and Section 3.

3. The CTS TIMC Project consists of the replacement of 13 heavy wall segments on six CTS pipelines and alterations to 13 facilities that are necessary to implement EMAT ILI on the 11 CTS pipelines, as well as the installation of a pressure regulating station (PRS) on a single segment of one of the CTS pipelines where EMAT ILI is not possible. The Project is confined to existing rights of way and facilities and has an estimated total cost in as-spent dollars of $137.8 million, which includes an Allowance for Funds Used During Construction (AFUDC).[7]

4. The public process to review the Application has included the following process steps:

(a) On May 13, 2013, FEI led a workshop that provided the BCUC and interveners with a better understanding of the Application and provided an opportunity to ask clarifying questions;[8]

(b) On June 15, 2021, the BCUC filed the Independent Report on the FortisBC Energy Inc. Application for Approval of a Certificate of Public Convenience and Necessity for the Coastal Transmission System Transmission Integrity Management Capabilities Project (Independent Report), by Dynamic Risk Assessment Systems Inc. (Dynamic Risk), an pipeline integrity expert;[9]

(c) In July 2021, FEI and Dynamic Risk responded to a first round of information requests from the BCUC and interveners;[10] and

(d) In October 2021, FEI and Dynamic Risk responded to a second round of information requests from the BCUC and interveners.[11]

5. 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 implement EMAT ILI in order to mitigate the threat of cracking to the safe operation of the 11 CTS pipelines. EMAT ILI is the industry standard approach and will enhance FEI's ability to locate, assess, and address cracking threats on these pipelines.[12] The BC

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7 Exhibit B-1, Application, pp. 2, 114.

8 Exhibits B-2 and B-4.

9 Exhibit A2-1; see also Exhibit A2-8, BCOAPO-Dynamic Risk IR2 4.1.

10 Exhibit B-5, BCUC IR1; Exhibit B-5-1, Confidential BCUC IR1; Exhibit B-6, BCOAPO IR1; Exhibit B-6-1, Confidential BCOAPO IR1; Exhibit B-7, CEC IR1; Exhibit B-7-1, Confidential CEC IR1; Exhibit B-8, RCIA IR1; Exhibit B-8-1, Confidential RCIA IR1; Exhibit A2-2, BCUC-Dynamic Risk IR1; Exhibit A2-3, RCIA-Dynamic Risk IR1; Exhibit A2-4, CEC-Dynamic Risk IR1; Exhibit A2-5, BCOAPO-Dynamic Risk IR1.

11 Exhibit B-11, BCUC IR2; Exhibit B-12, Confidential BCUC IR2; Exhibit B-13, CEC IR2; Exhibit B-14, Confidential CEC IR2; Exhibit B-15, RCIA IR2; Exhibit B-16, BCOAPO IR2; Exhibit B-17, Confidential BCOAPO IR2; Exhibit A2-6, RCIA-Dynamic Risk IR2; Exhibit A2-7, CEC-Dynamic Risk IR2; Exhibit A2-8, BCOAPO-Dynamic Risk IR2.

12 Exhibit B-1, Application, p. 49.

Oil and Gas Commission (BCOGC) has indicated its support for FEI taking action to address its known integrity concerns in alignment with its regulatory and legal responsibilities as a BCOGC permit holder.[13]

6. Therefore, FEI submits that the BCUC should issue the order sought in the Application:

- Granting a CPCN for the Project as described in the Application pursuant to sections 45 and 46 of the UCA; and
- Granting approval to transfer the balance in the TIMC Development Cost deferral account associated with the development of the CTS TIMC Project to a new rate base CTS TIMC deferral account on January 1, 2023 and commence amortization of the December 31, 2022 actual balance of these costs, estimated at $13.2 million, over a three-year period commencing on that date.

7. An updated draft order is included as an appendix to this Final Submission.

B. <u>Organization of this Submission</u>

8. The remainder of this submission is organized as follows:

- Part Two discusses how the Project is necessary and justified, including FEI's comprehensive justification in Section 3 of the Application, Dynamic Risk's unqualified support for the Project, and the fact that the IRs raised no material issues with respect to the need for the Project.
- Part Three discusses how FEI identified the available alternatives and correctly concluded that EMAT ILI is the only feasible and preferred alternative.
- Part Four describes the evidence filed on the scope and cost estimate for the Project, including FEI's AACE International (AACE) Class 3 cost estimate and that FEI has appropriately included cost contingency and management reserve in the Project cost estimate.
- Part Five describes how the environmental and archaeological assessments assess the Project as having a low to moderate environmental impact which can be appropriately mitigated.
- Part Six describes how FEI's public consultation and early engagement with Indigenous groups has been sufficient and reasonable to date and will continue throughout the life of the Project.
- Part Eight concludes this Final Submission.

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13 Exhibit B-1, Application, Appendix C.

PART TWO: THE PROJECT IS NECESSARY AND JUSTIFIED

9. This Part discusses how the Project is necessary and justified, and is organized around the following key points:

(a) FEI's Application provides a detailed and comprehensive justification of the need for the Project.

(b) Dynamic Risk's Independent Report commissioned by the BCUC provides unqualified support for the Project need.

(c) The IRs to FEI and Dynamic Risk raised no material issues with respect to the need for the Project.

(d) It would not be prudent to delay the Project.

10. FEI submits that the BCUC should determine that the CTS TIMC Project is needed.

A. <u>FEI's Application Provides a Detailed and Comprehensive Justification of the Project</u>

11. Section 3 of FEI's Application sets out the need and justification for the Project in a detailed and comprehensive manner. In FEI's submission, the need articulated in the Application is compelling and has not been subject to material challenge through the evidentiary phase of this proceeding. The following subsections summarize the main points of Section 3 of the Application.

(a) FEI's Existing Integrity Management Practices Only Allow a Small Portion of Pipelines To Be Assessed for Cracking

12. The need for the Project stems from the fact that FEI's current integrity management practices cannot identify all cracking threats on its pipelines.

13. Cracking threats are simply cracks or "planar imperfections"[14] in the pipe that effectively reduce the wall thickness of the pipeline, thereby affecting the strength of the pipeline. The two main types of cracking threats to FEI's system are stress corrosion cracking (SCC) and crack-like imperfections in the seam weld of a pipeline. SCC and crack-like imperfections can also interact with other time-dependent integrity threats, such as external corrosion, resulting in compounded integrity issues on a pipeline.[15]

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[14] Cracks have a measurable length and depth, but are sufficiently narrow that they do not typically have a measurable width associated with their dimensions.

[15] Exhibit B-1, Application, p. 23. See Section 3.2.4 of the Application for further discussion of the nature of cracking threats.

14. The cracks that are a threat to pipelines are too narrow (i.e., lack volume) to be detected by FEI's current ILI tools.[16] Further, it is not possible to pinpoint the exact locations where cracking will occur by assessing the factors that cause it.[17] The development of cracking requires the presence of three factors: (1) a susceptible metallic material (e.g., all pipeline steels, albeit to varying degrees); (2) a tensile stress; and (3) a suitable environment. Due to variability in these factors, the formation and growth of cracks is a complex, highly localized, and often unpredictable process.[18]

15. FEI currently relies on "opportunity digs" to manage cracking. Opportunity digs are integrity digs that expose a portion of a pipeline to undertake other pipe condition assessments, which presents an "opportunity" to assess cracking. As part of a given dig, FEI completes a visual anomaly assessment of corrosion, dents or gouges, and performs a magnetic particle inspection[19] to assess microscopic imperfections along the exposed surface of the steel pipe which may be indicative of cracking.[20] FEI is aware of the existence of cracking threats on its system through these opportunity digs, and to date, has addressed any identified cracking through pipeline repairs or replacement, as necessary.[21]

16. However, opportunity digs only provide the capability to asses a small portion of FEI's pipelines for cracking threats.[22] A typical dig on a pipeline will only expose in the order of 10 metres of the pipeline that is many kilometres long.[23] Further, the results of an opportunity dig are only applicable to the limited section exposed and not the entire length of the pipeline.[24] As cracking is highly localized and often unpredictable, the lack of cracking in one narrow length of pipe cannot be relied upon to assess other locations. FEI estimates that the total amount of pipeline exposed to date and assessed for cracking is less than one percent of the total length of pipe in FEI's transmission system, leaving approximately 99 percent of FEI's system unassessed for cracking.

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16 Exhibit B-1, Application, p. 23. See Section 3.2.4 of the Application for further discussion of the nature of cracking threats.

17 Exhibit B-1, Application, p. 27.

18 Exhibit B-1, Application, Section 3.2.4.

19 MPI is an industry-standard, non-destructive evaluation methodology: Exhibit B-1, Application, p. 26.

20 FEI schedules "opportunity digs" to primarily assess metal loss (e.g., corrosion) and mechanical damage (e.g., dents, gouges) anomalies and those sites identified through above-ground surveys without ILI capability: Exhibit B-1, Application, p. 26.

21 Exhibit B-1, Application, p. 26.

22 Exhibit B-1, Application, p. 27.

23 Exhibit B-5, BCUC IR1 2.5.

24 Exhibit B-1, Application, p. 27.

(b) Industry Knowledge of Cracking Threats and Means to Mitigate Them Are Improving

17. A primary driver for the Project is the evolution of industry knowledge about cracking threats and industry practice on how to manage those threats.[25] In short, industry has learned that cracking poses a greater threat to pipeline integrity than previously believed. JANA observes:[26]

> Historically, the majority of significant SCC has been associated with [polyethylene] tape. However, as companies have expanded monitoring, significant SCC has been found on asphalt-coated lines and on coal-tar coated pipe (previously considered to have a low susceptibility to SCC). This is consistent with the overall trend of SCC being found more and more in pipelines previously thought to be less susceptible, as the time dependent mechanisms at play continue to manifest themselves.

18. Through its industry involvement, FEI is aware that SCC that could lead to failure has been found on pipelines similar to those operated by FEI (i.e., pipelines with similar coatings, age, diameters, and operating stress level).[27]

19. Industry has also evolved in how it responds to these cracking threats. Specifically, EMAT ILI has developed and is rapidly becoming the industry standard for managing cracking threats on transmission pipelines that are large enough to accommodate the tools.[28] As explained by Dynamic Risk in its Independent Report, EMAT ILI has evolved and expanded in prevalence within the industry in its management of cracking threats:[29]

> For natural gas pipelines, the management of SCC has benefited from the introduction and evolution of ILI technologies, specifically EMAT technology, that can reliably detect, identify, and size cracking anomalies. Since it's introduction in the early 2000's, the performance of EMAT technology has been evaluated and documented through many industry research projects and published articles that describe operational experience.

20. Dynamic Risk added in response to BCUC IR1 5.1:[30]

> EMAT technology has been widely used by various operators in Canada and North America. As an example, one of the major ILI Vendors, Rosen, has worked with many operators worldwide and to date has inspected more than 80,000 km of pipelines with EMAT tools varying in diameter from NPS 10 to NPS 48.

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25 Exhibit B-1, Application, Section 3.3. Exhibit B-8, RCIA IR1 2.2.

26 Exhibit B-1-1, Appendix B-1, p. 5.

27 Exhibit B-1, Application, p. 28; Exhibit B-1-1, Confidential Appendix B-1, p. 5.

28 Exhibit B-1, Application, p. 28; Exhibit B-7, CEC IR1 3.2; Exhibit B-8, RCIA IR1 2.1.

29 Exhibit A-2-1, Independent Report, p. 18.

30 Exhibit A-2-2, BCUC-Dynamic Risk IR1 5.1.

21. Given the advancement in knowledge of the threat of cracking and the availability of EMAT ILI tools, FEI has undertaken an EMAT ILI pilot project to assess cracking on two CTS pipelines,[31] and further inform the development of the CTS TIMC Project. The two pipelines were selected for the pilot project after cracking was discovered during opportunity digs, and FEI determined that the required modifications to run EMAT ILI tools could be completed on a timeline to inform the Project. Importantly, the tool runs detected instances of potential cracking that FEI had not previously detected through integrity digs.[32] This result demonstrates that EMAT ILI can detect cracking on FEI's pipelines that have so far gone undetected. However, as cracking is highly localized and often unpredictable, FEI cannot extrapolate the findings from the pilot project to determine where cracking may be occurring on other segments of pipeline not yet assessed using EMAT ILI.[33] Rather, EMAT ILI inspection of each individual line is required to collect the necessary information to determine if cracking is present.

(c) FEI Has Correctly Identified and Prioritized the Need to Mitigate the Threat of Cracking on 11 Pipelines in the CTS

22. The need for the Project is supported by third-party risk assessments of the threat of cracking to FEI's larger diameter pipelines operating at transmission pressure for which EMAT ILI tools are available. Specifically, JANA conducted two related assessments in order to assess the susceptibility to cracking threats of FEI's transmission pipelines in the three transmission systems that FEI operates – the CTS, Interior Transmission System (ITS) and Vancouver Island Transmission System (VITS).[34] These assessments, as summarized below, demonstrate that FEI has correctly brought forward the Application to address the cracking threats to 11 of its CTS pipelines.

23. JANA's first report, titled *Analysis of Cracking Threats in FEI Mainline Transmission Pipelines* and attached as Confidential Appendix B-1 to the Application,[35] assesses the susceptibility of FEI's transmission system pipelines to cracking.[36] The assessment comprised a line-by-line assessment of: (1) "susceptibility"[37] to cracking threats for each system based on pipeline properties and operating conditions compared with those where historical failures have been observed in industry; (2) historical

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31 The pipelines selected are CPH BUR 508 and LIV PAT 457.

32 Exhibit B-1, Application, pp. 29-30.

33 Exhibit B-8, RCIA IR1 8.1.

34 See Exhibit B-1, Application, pp. 31-32 for a description of each system.

35 Exhibit B-1-1.

36 See Exhibit B-1, Application, Section 3.4.3.

37 The term "susceptible" is used by JANA to indicate the potential for SCC or pipe seam cracking to initiate on the lines, based on the specific characteristics of the lines and their operating conditions: Exhibit B-1, Application, p. 33.

cracking found on FEI pipelines; (3) industry historical failures and crack growth modelling to determine the potential for cracks to grow to failure; and (4) the estimated contribution of cracking threats to overall frequency of failure and risk based on the QRA.[38] By applying susceptibility ratings to each of the assessed pipelines, JANA considered criteria such as coating type and manufacturing process that are typically found to be associated with the formation of stress corrosion and seam weld cracking.[39] JANA concluded that 11 of the 13 CTS, 9 of the 12 ITS, and none of the VITS mainline transmission pipelines were susceptible to cracking threats.

24. JANA's conclusions regarding the susceptibility of FEI's transmission pipeline is supported by cracking already found on FEI's system through opportunity digs. These occurrences are summarized in Tables 3-6 and 3-7 of the Application and demonstrate that the conditions for cracking exists within both the CTS and ITS.[40] Further, Table 1 of JANA's first report correlates the properties of FEI's CTS pipelines with conditions shown in the industry to correlate with SCC.[41]

25. JANA's assessment of industry failures at a range of operating stresses,[42] and the analysis completed in conjunction with Dr. Weixing Chen of the University of Alberta,[43] show that cracks can grow to failure under FEI operating conditions. First, as demonstrated by industry failure reporting, failures have been observed in the industry throughout the operating stress range of the pipelines in the CTS.[44] Second, based on Dr. Chen's analysis, cracks grow to failure within certain timeframes – necessitating active mitigation.[45] There is no one timeline for cracks to grow to failure and the purpose of the analysis was not to define explicit times to failure; rather, the purpose was to determine whether there was the <u>potential</u> for cracks to grow to failure.[46] FEI's systems were estimated as having a range of potential time for cracks to grow to failure from 5 to 85 years. While the lower bound timeframe of five years is considered highly unlikely (reflecting a combination of the longest, deepest crack with the lowest toughness pipeline), the

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38 Exhibit B-1, Application, p. 32; Exhibit B-1-1, Confidential Appendix B-1, p. 4.

39 Exhibit B-1, Application, p. 34.

40 Exhibit B-1, Application, pp. 38-39.

41 Exhibit B-8, RCIA IR1 6.2; Exhibit B-1-1, Appendix B-1, p. 6.

42 According to Pipeline and Hazardous Materials Safety Administration (PHMSA) reporting, incidents through 2002-2016 occurred at 60 percent of SMYS or lower: Exhibit B-1, Application, p. 40; Exhibit B-1-1, Appendix B-1, p. 12.

43 Exhibit B-1-1, Appendix B-1-1, p. 22.

44 Exhibit B-8, RCIA IR1 6.2.

45 Exhibit B-1, Application, p. 41; see also Exhibit B-5, BCUC IR1 2.6 for JANA's detailed description of Dr. Chen's method for calculating crack growth behavior, the accuracy of the results and any potential sensitivities or limitations in the results.

46 Exhibit B-7, CEC IR1 18.2.

analysis indicates that cracking is a credible integrity threat that needs to be managed in a timely manner.[47]

26. JANA's second report, titled *Quantitative Safety Risk Assessment of FEI Mainline Transmission Pipelines* and attached as Confidential Appendix B-2 to the Application, provides the results of a baseline, system-level, safety QRA of FEI's transmissions systems quantifying the safety risk posed by cracking threats in comparison to other threats and hazards.[48] A QRA is a systematic approach to estimating the probability and consequences of hazardous events, and expresses the results quantitatively as risk to people, the environment, and/or the business.[49] The purpose of a system-level QRA is to assess the overall threats to the pipeline system at a level that enables identification of general system risk and the threats driving that risk, and to identify where additional integrity management activities may be warranted.[50] A QRA is an accepted method for transmission operators to comply with the CSA Z662 standard.[51]

27. FEI's decision to prioritize work on the CTS through this Application is justified by the results of the QRA. As shown in Figure 3-12 of the Application, the CTS was assessed as having the highest risk, driven primarily by its proximity to populated areas, followed by the ITS and then the VITS.[52] Further, as shown in Figure 3-13 of the Application, cracking threats (SCC and pipe seam) are the top driver of risk for the CTS at the system level.[53]

(d) FEI Must Mitigate Cracking Threats on the 11 CTS Pipelines To Maintain Compliance With Regulations and Standards, Align With Evolving Industry Practice, and Meet its Duty to Maintain the Safety of its CTS Pipelines

28. FEI must proceed with the CTS TIMC Project to comply with various laws, regulations, or standards regarding the safe and reliable operation of its gas system assets. For example, FEI must remain compliant with the CSA Z662 standard, which is prescribed by the *Pipeline Regulation* under the *Oil and Gas Activities Act* (OGAA). Section 10.3.1 of the *Pipeline Regulation* requires that FEI's pipeline system integrity management program "include procedures to monitor for conditions that can lead to failures, to eliminate

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47 Exhibit B-1, Application, p. 41.

48 See Exhibit B-1, Application, Section 3.4.4.

49 See Exhibit B-1, Application, Section 3.4.4.1.

50 Exhibit B-1.

51 The CSA Z662 standard requires operators to develop, implement, and continually improve a risk management process for their pipeline systems that identifies, assesses, and manages the hazards and associated risks over their life cycle: Exhibit B-1, Application, p. 42.

52 The VITS has the lowest risk as it is a newer system in largely unpopulated areas.

53 Exhibit B-1-1, Appendix B-2, p. 15.

or mitigate such conditions".[54] Similarly, section 37 (1) (a) of the OGAA requires FEI, as a BCOGC permit holder, to "prevent spillage" associated with the operation of pipelines operating at or above 700 kPa. As FEI explained:[55]

> FEI's primary objective with its IMP-P [Integrity Management Program for Pipelines] is to prevent failure incidents that could result in significant safety, environmental, and/or reliability consequences. FEI has obligations as a "Permit Holder" under the OGAA to prevent all release of product from its BC OGC regulated pipeline system. This obligation also influences FEI's selection of asset management strategies over the lifecycle of a pipeline, with preference given to a methodology (such as ILI) that provides FEI with the capability to monitor and proactively respond to potential changes to asset condition that occur with time.

29. As in the above example, regulations related to the integrity of FEI's system are typically goal-oriented and not prescriptive, meaning requirements are expressed as outcomes. While FEI is not required to undertake specific actions (i.e., how to achieve the outcomes associated with a safe and reliable system), these obligations directly correlate with FEI's efforts to take additional measures to mitigate the risk of failure on the 11 CTS pipelines due to cracking threats.[56] FEI has identified cracking threats as a condition that can lead to failure on the CTS and there are known approaches (i.e., EMAT ILI) that can eliminate or mitigate these threats. Therefore, in order to maintain compliance with regulations and standards, FEI must align with evolving industry practice to enhance its integrity management capabilities to locate, assess and address cracking threats on the CTS.[57]

30. The BCOGC is supportive of FEI taking action to address its known integrity concerns, which is in alignment with FEI's regulatory and legal responsibilities as a BCOGC "permit holder".[58] Similarly, the BCUC has recently recognized FEI's obligations to ensure the safety and security of its pipeline operations. In the case of FEI's Application for a CPCN for the Inland Gas Upgrade (IGU) Project, the BCUC noted in its Decision (at p. 7) that "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 BCUC went on to state (at p. 7):

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54 Exhibit B-1, Application, p. 48.

55 Exhibit B-7, CEC IR1 3.1.

56 Exhibit B-7, CEC IR1 3.1.

57 Exhibit B-1, Application, p. 49.

58 Exhibit B-1, Application, Appendix C.

"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."[59]

31. This Project is driven by the potential safety consequences of a rupture caused by cracking threats. It is generally accepted by FEI and the Canadian pipeline industry that a pipeline operating at or above 30 percent of SMYS has a potential to fail by rupture, whereas a pipeline operating below 30 percent of SMYS would have a potential to leak.[60] FEI's CTS pipelines operate at above 30 percent of SMYS and therefore are susceptible to rupture. An ignited release can result in potential harm due to any ensuing fire and resulting thermal effects on people and property.[61] As much of the CTS is located in highly urban areas, including much of the residential, commercial and industrial areas of the Lower Mainland, the potential consequences of a failure are significant.[62]

32. Other consequences of a rupture include:[63]

(a) **Reliability Consequences:** A pipeline rupture, in the absence of a redundant gas supply source, would result in loss of supply to end-use customers with economic consequences for residential, commercial, and industrial customers.

(b) **Environmental Consequences:** A pipeline rupture could result in damage to the natural environment, potentially impacting aquatic and terrestrial resources, in addition to degraded air quality and greenhouse gas emissions. The environmental consequences associated with a pipeline rupture or a sudden and uncontrolled release of natural gas would be classified as a Level 2 Major or Level 3 Serious reportable incident by the BCOGC. In addition, the release of gas by rupture would be considered a reportable incident under the *Environmental Management Act Spill Reporting Regulation* for transmission pipelines.

(c) **Regulatory Consequences:** In alignment with the Canadian transmission pipeline industry, FEI and the BCOGC consider that a failure by rupture of FEI's natural gas pipelines to be a significant incident and not acceptable performance within FEI's IMP-P.

33. FEI has provided a number of examples of natural gas pipeline ruptures illustrating their potential consequences including, in particular, the Enbridge (Westcoast) NPS 36 natural gas transmission pipeline which occurred in October 9, 2018.[64]

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59 Decision and Order G-12-20, FortisBC Energy Inc. Application for a Certificate of Public Convenience and Necessity for the Inland Gas Upgrade Project. Online: https://docs.bcuc.com/Documents/Proceedings/2020/DOC_56891_2020-01-21-G-12-20-FEI-CPCN-IGU-Project-Decision.pdf.

60 Exhibit B-1, Application, p. 50.

61 Exhibit B-1, Application, p. 50

62 Exhibit B-1, Application, pp. 53-55.

63 Exhibit B-1, Application, pp. 50-51.

64 Exhibit B-1, Application, pp. 51-53.

34. As stated by the BCUC in its Decision approving the IGU Project, FEI has obligations to ensure the safety and security of its pipeline operations.[65] Therefore, in order to remain compliant with its regulatory obligations, align with industry best practices and meet its duty to maintain the safe operation of the CTS, FEI submits that it is in the public interest for FEI to proceed with the CTS TIMC Project.

B. <u>Dynamic Risk Confirms the Need and Justification for the Project</u>

35. Dynamic Risk's expert report provides unqualified independent third-party support for FEI's analysis for the need and justification for the Project.

36. Dynamic Risk endorses the results of FEI's QRA results:[66]

> The QRA performed on the three (3) transmission systems is in alignment and follows the approach defined in the CSA Z662-19 with hazard identification, frequency and consequence analysis, and risk estimation. The results show the CTS to have the highest risk as compared to the other systems (ITS and VITS). The top risk driver is SCC for nine (9) of the eleven (11) segments that are susceptible to SCC Within [sic] the CTS. For the remaining two (2) susceptible segments, SCC is the second and fourth risk driver.
>
> The results of the QRA are as expected due to the CTS segments proximity to populated areas and the lack of crack ILI data to be incorporated into the risk model. In the absence of EMAT ILI data, the risk model for SCC relies on an analysis of industry historical failure data and the susceptibility factors for SCC. Based on the results of the QRA, FEI has appropriately determined that performing an EMAT ILI on the eleven (11) pipeline segments in the CTS is required to reduce the risk on the CTS.

37. Further, Dynamic Risk finds that "SCC has been found on the CTS pipelines and is a credible threat that could potentially lead to failure".[67] Dynamic Risk states:[68]

> FEI has determined the eleven (11) CTS segments are susceptible to SCC based on an evaluation of coating type, age of pipeline and long seam type, which is in alignment with the SCC susceptibility guidelines provided by CEPA and ASME noted above.
>
> The coating type of the eleven (11) susceptible pipeline segments is coal tar enamel or shrink sleeves on girth welds and the coating type of the two (2) lines that are deemed "low" susceptibility are coated with fusion bonded epoxy (FBE). This is in alignment with the industry experience as SCC has been found beneath coal tar and girth weld shrink sleeves, no SCC has been documented for FBE coated pipelines.

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65 Decision and Order G-12-20, p. 7.

66 Exhibit A2-1, Independent Report, p. 7.

67 Exhibit A2-1, Independent Report, p. 9.

68 Exhibit A2-1, Independent Report, pp. 8-9.

> The CTS system was also evaluated based on pipeline age as pipeline coating damage is more likely to occur with increasing age. The age criteria within ASME B31.8S is pipelines older than 10 years are susceptible to SCC due to coating degradation. CEPA notes that pipelines constructed prior to 1980 are considered more susceptible. This is based on SCC failures for eight major North American gas pipeline operators. Ten (10) of the eleven (11) pipelines in the CTS system that are deemed susceptible have construction dates of prior to 1977. One (1) of the segments deemed susceptible is constructed in 1981 however, is still considered susceptible to SCC based on the primary factor of the coating type (coal tar enamel). The two (2) CTS line segments that are deemed "low" susceptibility are coated with FBE and were constructed after 1991.
>
> FEI has also evaluated the CTS pipeline segments for susceptibility to seam weld cracking and have considered pipelines manufactured prior to 1970 as susceptible to seam weld cracking. Pipelines installed prior to 1970 are generally considered vintage pipelines and may contain a variety of manufacturing related flaws associated with the seam weld such as lack of fusion, selective seam corrosion and hook cracks. Seam weld manufacturing improvements and the requirement to hydrotest following pipeline construction was implemented in 1970. The two (2) CTS pipeline segments that are considered "low" susceptibility for SCC are constructed after 1970, coated with FBE and therefore considered to have "low" susceptibility to seam weld cracking.
>
> The susceptibility of the CTS pipeline segments to SCC is further confirmed by the discovery and presence of SCC on the system, which has been found during previous integrity excavations performed. SCC has been found on six (6) of the eleven (11) CTS pipeline segments that are considered susceptible within thirty-three (33) previous integrity excavations that contained cracks. These features would be reported by the EMAT ILI if they are above the minimum detection thresholds of the tool.
>
> It should be noted that the susceptibility criteria within the ASME B31.8S standard states that pipelines operating at greater than 60% of the SMYS are susceptible to SCC. It is also noted in the FEI application that the majority of the pipeline segments in the CTS operate at hoop stress levels between 45% to 50% of SMYS. Although the CTS pipeline segments operate at less than 60% SMYS, SCC has been found on the CTS pipelines and is a credible threat that could potentially lead to failure. Industry data shows that susceptibility to SCC increases with stress level pipelines that are operated at stress levels above 60 % of SMYS appear to be most susceptible, and pipeline failures due to SCC have occurred in pipelines that operate at less than 50% SMYS.

38. Overall, Dynamic Risk concludes that FEI has appropriately identified the need for the Project:[69]

> SCC is a form of environmentally assisted cracking; wherein small surface cracks can form and grow over time. Cracks that continue to grow will frequently overlap and/or coalesce to become the equivalent of a large single crack in terms of their effect on the pressure carrying capacity of the pipe. Eventually such overlapping and coalescence can create a crack of sufficient size to cause the pipeline to leak or rupture. It is the independent

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[69] Exhibit A2-1, Independent Report, p. 30.

> pipeline integrity expert panel's view that SCC is a credible threat for FEI that if left unmitigated, could lead to pipeline failure.
>
> FEI operates eleven (11) pipe segments within the CTS considered as susceptible to SCC, which has been validated through results of opportunistic excavations, where pipe examinations have confirmed the presence of SCC. Currently, there is a gap in the existing FEI integrity management practices to address the threat of SCC, as opportunistic excavations alone are not sufficient to fully characterize, detect and manage the threat. The results of the quantitative risk assessment (QRA) demonstrate the risk of SCC to be highest on the CTS pipeline segments and it is the independent pipeline integrity expert panel's view that EMAT ILI is the most appropriate response and mitigation action to reduce risk and strengthen the overall integrity management program.

39. FEI submits that Dynamic Risk provides an unqualified endorsement of the Project's need, which should be given significant weight by the BCUC.

C. It Would Not be Prudent to Delay the Project

40. The CTS TIMC Project should proceed on FEI's planned Project schedule and scope, including the replacement of 13 heavy wall segments on six CTS pipelines and the alterations to 13 CTS facilities. A delay to the implementation of the Project would prevent FEI from identifying cracking on its CTS pipelines, which could have significant consequences. In particular, and as recognized by Dynamic Risk, the location of the CTS in a populated area means that there is a "high societal risk and high consequence of rupture" and any extended delay will increase the likelihood for pipeline failure to occur.[70]

41. Cracking is a time-dependent threat, meaning that its potential to impact the pipeline increases over time.[71] JANA's baseline system-level QRA has identified the higher safety risk of the CTS due to cracking threats. As explained by FEI, "[t]he TIMC project, if completed over a reasonable planning horizon as FEI has proposed, reflects an appropriate operator response to available information regarding the potential threat posed by pipeline cracking.[72] As noted by Dynamic Risk with respect to the timing and urgency of the Project, "the eleven (11) lines selected to be inspected have been prioritized to be addressed within an optimized and acceptable time frame."[73] As also stated by Dynamic Risk, "the EMAT ILIs should commence immediately following the pipeline modifications in 2025".[74]

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70 Exhibit A2-2, BCUC-Dynamic Risk IR1 4.3.

71 See also Exhibit B-1, Application, Section 3.2.4.

72 Exhibit B-8, RCIA IR1 2.3.

73 Exhibit A2-2, BCUC-Dynamic Risk IR1 4.1 and 4.2.

74 Exhibit A2-3, RCIA-Dynamic Risk IR1 3.3.

42. Ultimately, over two rounds of IRs to FEI and Dynamic Risk, FEI submits that no material concern emerged with respect to the need for the Project. FEI submits that the evidence overwhelmingly supports FEI proceeding with the Project as planned.

PART THREE: ALTERNATIVES ANALYSIS CORRECTLY IDENTIFIED THE PREFERRED ALTERNATIVE

43. FEI correctly identified EMAT ILI as the preferred, and only feasible, alternative to achieve the Project objective of enhancing FEI's integrity management capabilities to mitigate cracking threats to the 11 CTS transmission pipelines. FEI evaluated six available alternatives using non-financial and financial criteria, as summarized in Table 4-1 of Application, reproduced below. As shown in the table, EMAT ILI is the only alternative that is both technically and financially feasible and is therefore the preferred alternative for the CTS TIMC Project.

Table 4-1: Summary of Alternatives Evaluation

	Non-Financial Assessment	Technical Feasibility	Financial Assessment	Financial Feasibility
Alternative 1: SCCDA		Not Feasible		
Alternative 2: PRS		Not Feasible		
Alternative 3: HSTP		Not Feasible		
Alternative 4: EMAT ILI		**Feasible**		**Feasible**
Alternative 5: PLR		Potentially Feasible		Not Feasible
Alternative 6: PLE		Potentially Feasible		Not Feasible

44. As discussed further in Part Three, Section E of this Submission, the Noons Creek to Burrard segment of the Cape Horn to Burrard 508 transmission pipeline (NOO BUR 508) no longer has sufficient gas flows to move an ILI tool through the pipeline,[75] and therefore, EMAT ILI is not feasible. FEI has instead selected Alternative 2: Pressure Regulating Station (PRS) to manage and mitigate cracking threats on this segment.

45. This Part is organized around the following key points:

(a) FEI conducted a careful and detailed analysis of all identified alternatives using a comprehensive decision-making framework.

(b) FEI correctly screened out alternatives that are not technically feasible.

[75] Gas flows in this pipeline decreased as result of the decommissioning of the BC Hydro Burrard Thermal plant: Exhibit B-1, Application, p. 78 and footnotes 2 and 35.

(c) FEI correctly screened out alternatives that are not financially feasible.

(d) EMAT ILI is the only feasible alternative to meet the project objective.

(e) PRS is needed for the NOO BUR 508 segment of the Cape Horn to Burrard 508 transmission pipeline.

(f) FEI has addressed other topics explored in IRs.

A. FEI Analyzed All Identified Alternatives Using a Comprehensive Framework

46. In Section 4.2 of the Application, FEI describes each of the six currently available alternatives it identified to mitigate cracking threats on the 11 CTS pipelines that have been identified as susceptible to this threat.[76] FEI evaluated the alternatives against three non-financial criteria and one financial criterion using a "Good-Acceptable-Poor Choice" rating system.[77] FEI first assessed all of the alternatives against the non-financial criteria to determine their technical feasibility, and then assessed the three remaining alternatives using the financial criterion to assess their financial feasibility.[78] The results are summarized below.

B. Alternatives Screened Out as Not Technically Feasible

(a) Alternative 1: SCCDA Cannot Reliability Identify Cracking Threats

47. The SCCDA alternatives involves inferring the integrity of pipeline sections that are not identified and exposed during a five-step assessment process.[79] SCCDA cannot be counted on to reliably identify the most significant, and therefore most likely to fail, cracking threats. This is because cracking can be highly randomized and unpredictable along a susceptible pipelines and existing assessment approaches (e.g., soil models) have limited value in pin-pointing the location of the deepest cracks.[80] SCCDA was not developed to manage crack-like imperfections in seam welds and is not viewed by FEI's peers as effective in comparison to the other alternatives.[81] Dynamic Risk similarly concludes: "While SCCDA is a suitable method for determine a pipeline's potential susceptibility to SCC, this method will not reliably identify or size the cracking on the CTS pipelines and should therefore not be considered as an alternative to EMAT

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76 Exhibit B-1, Application, pp. 57-65.

77 See Exhibit B-1, Application, Section 4.3.

78 Exhibit B-1, Application, p. 68.

79 Exhibit B-1, Application, p. 58.

80 Exhibit B-1, Application, p. 71.

81 Exhibit B-1, Application, pp. 71-72.

ILI."[82] On its own,[83] SCCDA is not considered an effective approach to SCC integrity management. While SCCDA can be used to assess lines to determine if cracking is a potentially significant threat, FEI has already identified that cracking is a credible threat on CTS pipelines.[84]

(b) Alternative 2: PRS Leads to System Capacity Limitations

48. The PRS alternative involves permanently lowering the maximum operating pressure of a pipeline such that the resultant hoop stresses are reduced to below 30 percent of SMYS. PRS can reduce the likelihood for SCC to cause an in-service pipeline rupture, as these SCC threats would instead be expected to result in leaks.[85] However, with the exception of the Noon's Creek to Burrard 508 segment (NOO BUR 508), implementation of PRS on the 11 CTS pipelines would result in FEI being unable to maintain reliable service to its customers. Pressure reduction would create significant operational challenges when applied to FEI's CTS. PRS is not feasible when applied to the pipeline system because the maximum operating pressure of the CTS would need to be reduced by approximately 40 percent to achieve the desired stress levels. This would lead to a significant reduction in the capacity available to customers in the Lower Mainland and Vancouver Island. At these reduced operating pressures, the capacity requirements of the system under current peak day demand cannot be met and extensive system looping would be required to meet current and future gas supply needs.[86]

49. Specifically, to achieve an operating stress less than 30 percent of SYMS, the system would need to operate at a pressure of 2390 kPa. The capacity of the system under this condition is exceeded when the average daily temperature is between 9 degrees Celsius or cooler, which could occur any time in the period of September through May.[87] The system capacity issues would occur at multiple locations across the CTS and would occur for large portions of the year, including the spring, fall and winter seasons.[88]

50. It would not be feasible to increase the system's capacity as this would require extensive pipeline looping. FEI would be required to install new, large-diameter transmission lines from the Huntingdon Control Station in Abbotsford to near the Coquitlam Gate Station and another similar station location in

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82 Exhibit A2-1, Independent Report, p. 13; see also Exhibit A2-6, RCIA-Dynamic Risk IR2 9.2.

83 The NACE, which developed this approach, states that SCCDA should be complementary to other inspection methods such as ILI or hydrostatic testing: Exhibit B-1, Application, p. 71; see also Exhibit A2-6, RCIA-BCUC IR2 9.3.

84 Exhibit B-1, Application, pp. 71-72.

85 Exhibit B-1, Application, p. 72.

86 Exhibit B-1, Application, p. 72.

87 Exhibit B-7, CEC IR1 29.1.1.

88 Exhibit B-7, CEC IR1 29.1.2 and 29.1.2.1.

Delta. These modifications are not desirable due to their cost, implementation complexity, and community, Indigenous, and environmental impacts. Furthermore, the CTS pipelines are located in highly urbanized areas and some statutory rights of ways (SRWs) are already occupied by multiple transmission pipelines. The installation of another transmission pipeline would be difficult and it may not even be possible while maintaining adequate clearance between existing pipelines in the SRW. Therefore, expansion of existing SRWs or acquisition of new land rights would likely be required.[89]

51. Dynamic Risk similarly concludes:[90]

> The installation of a pressure regulating station (PRS) would effectively manage the threat of SCC by reducing the operating pressure below 30% of the SMYS and reduce the potential for rupture. This alternative causes capacity limitations in the pipeline and as noted by FEI, would lead to a significant reduction in the capacity available to customers.
>
> To meet the demand while operating at reduced pressure the pipeline would require system looping. Utilizing the EMAT ILI tool and having a robust validation program, as outlined in Section E.7, has allowed gas pipeline operators to successfully manage the threat of SCC while operating the pipelines without system wide pressure reduction.

52. A pressure reduction is also not a feasible temporary risk mitigation measure to meaningfully reduce the likelihood of a leak or rupture before the CTS TIMC Project is complete.[91] First, as described above, a pressure reduction would impair FEI's ability to serve the gas demand of customers supplied by the CTS reliably throughout the year.[92] Between 2021 and 2030 the forecast system peak hour demand exceeds the available system capacity during a pressure reduction in all years.[93] Second, a pressure reduction would reduce line pack and associated system resiliency, decreasing FEI's ability to respond to rapid weather-related changes in demand.[94]

53. Ultimately, without specific crack data that will be obtained through the use of EMAT ILI technology on the CTS, FEI lacks certainty respecting the degree of risk mitigation that may be achieved through a pressure reduction.[95] If FEI cannot be certain that the pressure reduction is actively mitigating an integrity risk, it would not be reasonable to expose customers to the risks of significant load curtailment

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[89] Exhibit B-7, CEC IR1 29.1.3.

[90] Exhibit A2-1, Independent Report, p. 13.

[91] Exhibit B-5, BCUC IR1 2.8.

[92] Exhibit B-5, BCUC IR1 2.8.

[93] Exhibit B-11, BCUC IR2 36.1 and 36.3.

[94] Exhibit B-11, BCUC IR2 36.3.

[95] Exhibit B-5, BCUC IR1 2.8.

and associated social and economic impacts of supply interruptions during extreme cold winter conditions.[96] As such, PRS is not technically feasible for system wide application to all 11 interconnected CTS TIMC pipelines.[97]

(c) Alternative 3: HSTP has Significant Operational Challenges in an Urban Environment

54. The implementation of a hydrostatic testing program (HSTP) to verify the integrity of a transmission pipeline over its lifecycle is a complex process that involves periodically taking the pipeline out of service at recurring intervals and subjecting it to a hydrostatic test.[98] HSTP is not effective as a method for managing cracking threats on operating gas lines as hydrostatic testing does not provide information on cracks that do not fail during the test and there is also the potential to exacerbate sub-critical cracks which FEI cannot monitor. While a pipeline may not fail testing, it may nonetheless have cracking that will grow over time. Additionally, in shorter or less interconnected parts of the system, the pipelines are typically the only transmission supply to customers and thus, removing them from service for hydrotesting would require alternative means of supplying customers during the test.[99]

55. Dynamic Risk similarly concludes that HSTP is not a preferred alternative:[100]

> A hydrostatic testing program (HSTP) involves taking the pipeline out of service, introducing water into the pipeline and pressurizing the line to confirm the integrity. As noted by FEI in the application, hydrotesting is a complex process that involves significant operational, community and environmental challenges in an urban environment. This method is effective to manage the threat of SCC, however, only significant features that are close to leak or rupture (near critical) will be detected and repaired. The hydrotest confirms the integrity of the pipeline but offers no information on the cracks that survived the hydrotest, which can continue to grow under normal operations following the test. The EMAT ILI tool is significantly less disruptive to the operations of the pipeline and provides location and sizing information on both the near critical flaws and sub critical flaws. This allows the operator to repair any near critical features, perform an assessment on the sub critical flaws to plan future excavations and re-inspection intervals.

56. Finally, large portions of the CTS are also located within the urban environment, making the implementation of such testing challenging for a number of reasons (as set out in the Application).[101]

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[96] Exhibit B-5, BCUC IR1 2.8.

[97] Exhibit B-1, Application, p. 72.

[98] Exhibit B-1, Application, pp. 59-60.

[99] Exhibit B-5, BCUC IR1 6.1; Exhibit B-1, Application, p. 72.

[100] Exhibit A2-1, Independent Report, p. 13.

[101] Exhibit B-1, Application, p. 74.

These operational, community and environmental challenges render this alternative unsuitable for general use.[102] As such, HSTP is not technically feasible for system wide application to the 11 CTS pipelines.

C. Alternatives 5 and 6: Screened Out as Not Financially Feasible

57. Alternatives 5 (PLR) and 6 (PLE) contemplate the replacement or exposure and recoating of the 11 CTS pipelines in their entirety. FEI calculated and compared the NPV of the total cost for Alternatives 5 and 6, in addition to the preferred Alternative 4. Table 4-4 of the Application, reproduced below, shows the results of the financial cost comparison. A high-level financial analysis for each alternative cost can also be found in Confidential Appendix G-1.[103]

Table 4-4: NPV Cost Comparison of Three Remaining Alternatives (2020$)

	Alternative 4: EMAT ILI ($ millions)	Alternative 5: PLR ($ millions)	Alternative 6: PLE ($ millions)
NPV of Capital Cost	$225	$1,818	$1,909
NPV of O&M Costs (Savings)	$82	$(7)	$(7)
NPV of Total Capital and O&M Costs	$307	$1,811	$1,902

58. Given the extensive scope of the work that would be required, Alternatives 5 and 6 have very high costs (approaching $2 billion), and therefore, are cost prohibitive compared to Alternative 4. On this basis, FEI assessed both as being not financially feasible.

D. Alternative 4: EMAT ILI Is the Only Feasible Alternative to Achieve the Project Objective

59. EMAT ILI (Alternative 4) is the sole alternative that is both technically and financially feasible and is therefore the preferred alternative to achieve the Project objective of enhancing FEI's integrity management capabilities to mitigate cracking threats to the 11 CTS transmission pipelines.

60. FEI's proposed EMAT ILI program involves periodically running[104] an ILI tool which uses varying magnetic fields to generate and detect sound waves in the steel pipe. EMAT ILI provides insight into anomalies and defects that would not fail a hydrostatic pressure test, for both SCC and sub-critical long seam weld features, by identifying when the resulting sound waves are interrupted.[105] Cracking threats

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[102] Exhibit B-1, Application, p. 73.

[103] Exhibit B-1-1; see also Exhibit B-1, Application, pp. 75-76.

[104] These runs are undertaken based on a pipeline-by-pipeline analysis.

[105] Exhibit B-1, Application, p. 61.

are then analyzed, integrity digs performed to remove defects, and the EMAT tool data validated through the integrity dig findings.[106]

61. EMAT ILI is highly effective for managing cracking threats as it is capable of identifying, locating, and sizing cracking anomalies or defects.[107] There is extensive evidence on the record that EMAT ILI is the best available technology for mitigating cracking threats on natural gas pipelines.[108] For example, the National Energy Board (now the Canada Energy Regulator) considers EMAT to be the best available technology for ILI crack detection in gas pipelines.[109] Similarly, Dynamic Risk described EMAT ILI as "a reliable technology that can detect the cracking features previously found through opportunistic excavations" and that, when used together with a robust validation program, EMAT is "appropriate to manage the threat of SCC on the CTS".[110] These conclusions are also supported by FEI's peer operators, who are enhancing their approaches to crack management with the adoption of EMAT ILI.[111] As a result, the use of EMAT crack detection ILI is rapidly becoming the industry standard for managing cracking threats on transmission pipelines which have the potential for significant consequences should failure occur.[112]

62. With EMAT ILI, FEI will be able to actively and more cost-effectively monitor and manage cracking threats because ILI data will be available on an ongoing basis, allowing for the prioritization of mitigation for cracks posing significant threats. This will result in benefits for FEI's overall IMP-P as the data collected through an EMAT ILI program can also be utilized in FEI's future QRAs.[113] EMAT ILI was also found to have less impact on the community and environment as compared to other alternatives.[114] This alternative is also financially feasible.[115]

63. FEI submits that EMAT ILI is clearly the preferred alternative to address the identified cracking threats to the CTS.

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106 Exhibit B-1, Application, p. 61

107 Exhibit B-1, Application, p. 76.

108 Exhibit B-1, Application, pp. 28-29 and 76-77; Exhibit B-8, RCIA IR1 2.1; Exhibit B-7, CEC IR1 3.1, 7.1 and 8.1; Exhibit A2-1, Independent Report, pp. 12-30; Exhibit A-2-7, CEC-Dynamic Risk IR2 8.1, 9.2.

109 Exhibit B-7, CEC IR1 8.1.

110 Exhibit A2-1, Independent Report, p. 31.

111 Exhibit A2-1, Independent Report, p. 31.

112 Exhibit B-1, Application, p. 77.

113 Exhibit B-1, Application, p. 76.

114 Exhibit B-1, Application, Table 4-3.

115 Exhibit B-1, Application, Table 4-4.

E. Insufficient Gas Demand for EMAT ILI in a Segment of the Cape Horn to Burrard 508 Transmission Pipeline

64. FEI has correctly identified the use of PRS as the appropriate option for the tail end of the Cape Horn to Burrard 508 transmission pipeline, from Noons Creek to Burrard (NOO BUR 508), where there is insufficient gas demand to generate the required flow to propel the EMAT ILI tool through the pipeline.[116] In order to propel the ILI tool through the pipeline at the required 1.5 metres per second, the gas demand in the NOO BUR 508 segment would need to be approximately 42 MMSCFD. The average volumetric flow in this segment of the pipeline is approximately 0.6 MMSCFD at the current operating pressure.[117] As a result, for this segment of pipeline only, PRS is the most cost-effective way to mitigate cracking threats through enhanced integrity management capabilities.

65. As described above, when PRS (Alternative 2) was considered for system-wide application to all 11 CTS pipelines, FEI identified significant impacts to the capacity, reliability and resiliency of the system that would negatively impact customers. However, a review of the capacity on the NOO BUR 508 segment of the Cape Horn to Burrard 508 pipeline indicates that it would still have sufficient capacity at a lower maximum operating pressure to meet the load demands of customers supplied by this pipeline. An individual application of the PRS alternative to the NOO BUR 508 segment is viable due to its location at the tail-end of the CTS and its current operational requirements. At its reduced pressure, the NOO BUR 508 segment will no longer be considered a transmission pipeline and data regarding cracking is not required.[118]

66. FEI proposes to locate the pressure regulating station at the Noons Creek Valve Station, which is approximately midway along the pipeline.[119]

67. In summary, PRS is feasible and appropriate in light of the above-noted flow deficiencies, and remains consistent with the objective of the CTS TIMC Project.

F. Other Topics Explored in IRs Were Addressed

68. The IRs to FEI and Dynamic Risk were largely in the nature of seeking further information or confirmation of FEI's evidence. For example, IRs explored whether EMAT ILI is a mature technology, which

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116 Exhibit B-1, Application, p. 77.

117 Exhibit B-5, BCUC IR1 11.4.

118 Exhibit B-1, Application, p. 79.

119 Exhibit B-5, BCUC IR1 11.4.

FEI's evidence definitively affirms.[120] FEI has identified few substantive topics, beyond confirming FEI's evidence, regarding FEI's assessment of alternatives. These topics are organized around the following points:

(a) FEI's analysis of alternatives applies equally to subsets of the system.

(b) Robotic ILI is not a feasible alternative.

(c) Random integrity digs are not a feasible alternative.

(a) Alternatives Analysis Applies Equally to Subsets of the System

69. FEI's alternatives analysis is equally applicable to the entire system and sub-parts of the system (with the exception of the NOO BUR 508 segment, as discussed above).[121] FEI evaluated alternatives at the system level to account for the interaction and dependencies as between the 11 CTS pipelines, reflecting the interconnected nature of the system. However, even if subsets of the system are considered, EMAT ILI remains the only feasible alternative because the SCCDA (Alternative 1), PRS (Alternative 2), and HSTP (Alternative) alternatives are not feasible based on non-financial criteria and PLR (Alternative 5) and PLE (Alternative 6) are extremely costly. The ability to utilize PRS on the NOO BUR 508 segment of the Cape Horn to Burrard 508 pipeline is unique due to the permanent reduction in demand on that line as the result of the BC Hydro Burrard Thermal facility being decommissioned and the location of the pipeline at the terminus of the system.[122]

(b) Robotic ILI is Not a Feasible Alternative

70. Robotic ILI would not achieve the integrity management objectives of the Project. Unlike EMAT ILI, Robotic ILI tools are self-propelled. Based on FEI's discussions with the only vendor of Robotic ILI tools technologies, there a number of technical and implementation constraints with this technology both generally and in the context of FEI's system. In particular, Robotic ILI tool technologies:

- Require a given pipeline to be taken out of service, necessitating the need for redundancies to maintain supply to FEI's customers. [These redundancies do not currently exist for the 11 CTS pipelines].[123]

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120 Exhibit A2-2, BCUC-Dynamic Risk, IR1 5.1, 5.2; Exhibit A2-4, CEC-Dynamic Risk IR1 5.2, 5.3; Exhibit B-7, CEC IR1 3.2, 8.10; Exhibit B-8, RCIA IR1 2.1.

121 Exhibit B-5, BCUC IR1 6.1

122 Exhibit B-5, BCUC IR1 6.1

123 Exhibit B-5, BCUC IR1 10.2.

- Have stringent pipeline inside surface cleanliness requirements. There is not such a specific and stringent constraint specified for EMAT ILI tools and would be practically difficult to implement on pipelines that have been in service for many decades.[124]

- Cannot identify SCC to the same extent as EMAT ILI. FEI assumes that the specification is due to a combination of constraints with the current technology and limitations that may have been identified/confirmed during tool testing.[125]

- Are less productive than conventional EMAT ILI tools (i.e., are capable of inspecting less pipe in the same timeframe). This is because require the rolls frequent battery re-charging and only travel inside the pipeline at a typical speed of approximately 0.1 metres per second.[126]

- Finally, unlike EMAT ILI, Robotic ILI tools need to be inserted into the pipeline through cut-outs in the pipe, requiring a significant number of excavations (a minimum of every 550 metres). The pipeline must also be purged and re-gasified with each inspection interval.[127]

71. FEI is not aware of any other Canadian natural gas utilities using Robotic ILI tool technologies,[128] and FEI has confirmed that its existing ILI tool vendors do not offer Robotic EMAT ILI.[129] Therefore, Robotic ILI tools technologies are not a feasible alternative for this Project.

(c) Undertaking Random Integrity Digs is Not a Feasible Alternative

72. Undertaking a random integrity dig program conducted for the express purpose of identifying cracking would not improve FEI's ability to manage such threats. As described in Part Two of this Submission and Section 3.2.5 of the Application, cracking is a highly localized and unpredictable phenomenon. As such, cracking can vary significantly meter to meter along the pipeline. Without full inspection of the pipeline, either through ILI or exposing the entire pipeline for external inspection, the risk associated with cracking could not be effectively mitigated. As noted by JANA, "[g]iven a typical integrity dig is on the order of 10 to 20 meters it is not practical to inspect enough of the pipeline to identify with certainty the most significant SCC on the pipeline", and as such, this approach is not viable.[130]

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124 Exhibit B-5, BCUC IR1 10.2; Exhibit B-11, BCUC IR2 41.1 and 41.2.

125 Exhibit B-5, BCUC IR1 10.2; Exhibit B-11, BCUC IR2 41.1 and 41.3.

126 Exhibit B-5, BCUC IR1 10.2; Exhibit B-11, BCUC IR2 41.1 and 41.4.

127 Exhibit B-5, BCUC IR1 10.2.

128 Exhibit B-5, BCUC IR1 10.3.

129 Exhibit B-11, BCUC IR2 41.1.

130 Exhibit B-7, CEC IR1 12.2.

PART FOUR: PROJECT DESCRIPTION, COSTS, ACCOUNTING TREATMENT AND RATE IMPACT

73. This Part of this Final Submission addresses the Project description, costs, accounting treatment and rate impacts, including FEI's request for approval regarding transferring the balance in the TIMC Development Cost deferral account associated with the development of the CTS TIMC Project to a new rate base CTS TIMC deferral account.[131]

74. As described in Section 5 of the Application, the CTS TIMC Project consists of the work required to modify pipelines within FEI's existing rights of way and associated facilities to ready the CTS for EMAT ILI tools. This work includes the replacement of 13 heavy wall segments on six CTS pipelines, which are required to enable the EMAT ILI tools to travel within their optimal velocity range downstream of the heavy wall segments. The work also includes alterations to 13 CTS facilities, consisting of modifications to pig barrels and station piping, and the addition of pressure, flow and backflow regulating capability, as needed to run the EMAT ILI tools.[132] In 2022, upon receiving BCUC approval, FEI plans to initiate the detailed design and procurement activities. FEI will commence construction in Q1 2024 with Project completion and close-out activities to be completed by end of 2025. [133]

75. The total capital cost estimate for the Project is $137.8 million (as-spent), which includes AFUDC. The Project will result in an estimated cumulative delivery rate impact of 1.32 percent by 2026 when all construction is completed and all capital costs have entered FEI's rate base. The average annual delivery rate impact over the five years from 2022 to 2026 is estimated to be 0.26 percent annually or $0.013 per GJ annually. For a typical FEI residential customer consuming 90 GJ per year, this would equate to an average bill increase of approximately $1.19 per year over the five years, or $5.96 cumulatively by 2026.[134]

76. The evidence supporting the Project scope, cost estimate, schedule and rate impacts analysis is detailed and complete, and demonstrates that FEI has prudently and carefully scoped, planned, and estimated the costs for the Project. In Section 5 of the Application, FEI provided detailed information on the Project, including:

(a) an overview of the Project and the rationale for performing alterations to the pipelines and their associated facilities in preparation for EMAT ILI runs;

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131 Exhibit B-5, BCUC IR1 26.2 and 27.4.1.

132 Exhibit B-1, Application, p. 6.

133 Exhibit B-1, Application, p. 6.

134 Exhibit B-1, Application, p. 6.

(b) a history of the Project development activities, including the pilot project activities;

(c) a description of the modifications to the pipelines that are necessary for the collection of full resolution ILI data;

(d) a description of the modifications required to the facilities associated with the 11 pipelines that are necessary to run EMAT ILI tools and to respond to any anomalies found as a result of the in-line inspections;

(e) a description of the schedule, project resource requirements and management;

(f) the basis of the cost estimate, and the processes undertaken to validate the estimate including risk assessment and contingency determination.

(g) a description of the post-Project work following the completion of alterations described.

77. In Section 6 of the Application, FEI describes the actual and forecast costs in the TIMC Development Cost deferral account, provides a breakdown of the Project costs, summarizes the financial analysis, and details the accounting treatment of capital costs and rate impact of the Project.

78. Sections 5 and 6 of the Application are supported by extensive reports, including: Stantec's Front-End Engineering Design (FEED) reports and documents, the Basis of Schedule and Schedule Report, and the Basis of Estimate and Estimate Report (in Confidential Appendix D);[135] the Project QRA Report, Project Risk Register, Validation Estimating Contingency Report and Validation Estimating Escalation Report (in Confidential Appendix E);[136] the Project schedule (in Appendix F); and the financial analysis (in Confidential Appendix G).[137]

79. The following sections discuss the topics explored in the proceeding, making the following points:

(a) FEI has correctly scoped and planned the Project.

(b) FEI's cost estimate is robust and meets the BCUC's CPCN Guidelines.

(c) FEI's proposed treatment of the balance of the TIMC Development Cost deferral account balance is just and reasonable.

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135 Exhibit B-1-1.

136 Exhibit B-1-1.

137 Exhibit B-1-1-1.

A. FEI's Has Correctly Scoped and Planned the Project

80. The CTS TIMC Project scope will prepare the CTS for EMAT ILI tool runs through the replacement of 13 heavy wall segments and the alteration of 13 facilities. These modifications are described in detail in Sections 5.4, 5.5, and Appendix D-2 (Final FEED Report (M-0002-PMT-REP-0021)) of the Application and will enable the system to launch and receive the longer EMAT ILI tools, install the capability to alter flowrates and pressures, and prevent backflow in the pipelines. FEI has been running geometry, MFL-A, and MFL-C tools in the CTS pipelines for many years, but EMAT ILI tools have a different set of system readiness criteria, as provided in Confidential Appendix D-1, necessitating the proposed modifications to the CTS.[138] FEI will continue to use MFL technology to identify corrosion on its system.[139]

81. In order to inform the development and planning of the Project, FEI conducted an EMAT ILI pilot project on two pipeline segments on the CTS (LIV PAT 457 and CPH BUR 508). These two pipelines were selected because they had previously been found to experience cracking, had a low likelihood of data loss due to speed excursions, and could be configured to operate at lower pressures to conduct EMAT ILI runs with relatively minor upgrades. In Sections 5.3.3.1 and 5.3.3.2 of the Application, FEI describes the results of the baseline inspections, including the features that had not been identified by FEI's current integrity management practices.[140] There have not been any reports of urgent crack related integrity threats on the pipeline sections included in the pilot project. Validation digs on CPH BUR 508 have now been completed and FEI has scheduled the remaining digs on LIV PAT 457 in 2022.[141] The pilot remains in progress, and as such, FEI is in the process of validating potential cracking detected by the EMAT tool. FEI's ILI vendor will generate a final report after FEI shares the validation dig results.[142]

82. The Project scope includes:

(a) **The replacement of 13 segments of pipe along the six pipelines:**[143] These pipeline segments need to be replaced in order to ensure the EMAT ILI tool travels within its optimal velocity range, thereby preventing speed excursions. Analysis of ILI velocity data from previous inspection runs, coupled with a review of EMAT ILI tool specifications and

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138 Exhibit B-1, Application, pp. 81-82; Exhibit B-1-1, Confidential Appendix D-1.

139 Exhibit A2-7, CEC-Dynamic Risk IR2 9.2.

140 For example, on LIV PAT 457, 5 crack features located in the seam weld, 7 crack features located in the pipe, and 1 crack group were found: Exhibit B-1, Application, p. 87.

141 Exhibit B-15, RCIA IR2 23.2.

142 Exhibit B-8, RCIA IR1 4.1; Exhibit B-15, RCIA IR2 23.1.

143 Exhibit B-1, Application, Figure 5-4 and p. 92.

discussions with ILI tool vendors, revealed that speed excursions frequently happen downstream of heavy-wall portions of pipe;[144] and

(b) **The alteration of 13 facilities to enable the introduction of EMAT ILI tools:**[145] These modifications include: (i) pig barrel modifications;[146] (ii) the installation of flow control capability;[147] (iii) the installation of pressure regulation capability;[148] and (iv) the installation of backflow prevention capability.[149]

83. Delaying or not implementing these pipeline or facilities modifications would not be prudent, would be inconsistent with the need for the Project, and would hinder the implementation of EMAT ILI on the CTS.

84. With respect to delaying the replacement of the 13 heavy wall segments, running EMAT ILI tools prior to replacing the identified heavy wall segments (including those outside of existing stations) would result in sections of pipe where FEI would expect to collect compromised data or no data at all. This is because the heavy wall segments will result in speed exclusions downstream of these segments as significant speed excursions have already been observed at these locations with its existing MFL-C ILI tools.[150] Where data is compromised or non-existent, FEI will be required to undertake alternative means of evaluating the pipe, which requires exposing, inspecting and recoating the pipe – a laborious, costly and inefficient process.[151] Dynamic Risk agrees that delaying these pipeline modifications would slow implementation of the Project:[152]

> Based on this SCC growth assessment, and in alignment with the SCC risk model, the eleven (11) lines selected to be inspected have been prioritized to be addressed within an optimized and acceptable time frame. Foregoing the pipeline modifications, while providing for an enhanced EMAT inspection program schedule (depending on EMAT tool availability and other variables) may however, result in program completion delays due to degraded data, leading to the need for additional data analysis and extensive pipeline excavations and pipe examinations to reduce data uncertainties.

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144 Exhibit B-1, Application, pp. 91-92.

145 Exhibit B-1, Application, Table 5-8.

146 Exhibit B-1, Application, pp. 97-98.

147 Exhibit B-1, Application, pp. 98-99. The four facilities requiring permanent piping and foundations are: Nichol Valve Station, Port Mann Valve Station, Tilbury Regulating Station, and Fraser Gate Station.

148 Exhibit B-1, Application, pp. 99-100.

149 Exhibit B-1, Application, pp. 103-104.

150 Exhibit B-5, BCUC IR1 6.2; Exhibit B-11, BCUC IR2 40.1.1.

151 Exhibit B-11, BCUC IR2 40.1.1; Exhibit A2-6, RCIA-Dynamic Risk IR2 6.4.

152 Exhibit A2-2, BCUC-Dynamic Risk IR1 1.1.2. Also see: Exhibit A2-2, BCUC-Dynamic Risk IR1 1.1.1; Exhibit A2-3, RCIA-Dynamic Risk IR1 6.4; Exhibit A2-7, RCIA-Dynamic Risk IR2 9.1; Exhibit B-5, BCUC IR1 6.2.

85. Similarly, there are no benefits associated with delaying the proposed facilities modifications (as set out in Table 5-8 of the Application).[153] All of the facility modifications, including the Huntingdon, Nichol, Coquitlam, Roebuck, and Livingstone Station facility modifications, are required to meet the Project objective and will support both the initial EMAT ILI run response and future EMAT ILI run responses.[154] In some cases, efficiencies with associated pipe modifications will also be realized.[155] Further, it would not be prudent to run the tools without an appropriate plan to respond to any associated findings. If FEI is unable to complete the required activities in the time remaining, there would be an increased risk that cracking grows to failure. As FEI will be undertaking initial EMAT ILI runs, the uncertainty around finding a number of features, such that modifications are required, presents a higher risk and therefore makes delaying these modifications imprudent.

86. While outside the scope of the Project, FEI has also provided detailed description of the post-Project work, including timing of EMAT ILI tool runs, and a summary of its proposed approach to the approval of incremental increases in O&M or Sustainment Capital to manage the additional work associated with FEI's expanded integrity management activities. FEI cannot confirm the extent of post-Project work required until the EMAT ILI tool has been run on each pipeline, integrity digs have been performed, and the results have been interpreted.[156]

87. The proposed scope of the Project was the subject of several IRs through which FEI supported and explained its decision-making in this regard. The topics covered are addressed below, and are organized around the following points:

(a) The ITS pipelines are appropriately excluded from the Project scope.

(b) FEI's 106 smaller-diameter pipelines are appropriately excluded from the Project scope.

(c) The inclusion of pressure reduction capabilities are needed and provide a reasonable and industry-accepted level of risk mitigation.

(d) FEI has optimized execution of Project work and has the resources to complete the Project as proposed.

(e) FEI will be able to reduce operating pressure without any supply shortfalls on the CTS after the EMAT ILI runs.

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[153] Exhibit B-1.

[154] Exhibit B-15, RCIA IR2 18 series.

[155] For example, at the Coquitlam Gate Station: Exhibit B-5, BCUC IR1 6.2.

[156] Exhibit B-1, Application, Section 5.11.

(a) ITS Pipelines Appropriately Excluded from Scope of the Application

88. FEI correctly prioritized work on the CTS pipelines in this Application. As described in Section 3.4.4.2 of the Application, the results of the QRA clearly demonstrate that the CTS pipelines pose the highest overall safety risk at the system level due to cracking threats. Limiting the scope of the Application to only the CTS pipelines was appropriate and allowed FEI to address the highest safety risk pipelines in the CTS in a timely manner.

89. While there were two higher risk pipelines identified as part of the QRA,[157] their inclusion would have delayed development and submission of this CPCN Application due to an overall larger Project scope with the inclusion of additional pipelines from a different system.[158] The challenges that would have resulted from their inclusion include:[159]

- Delays to the submission of this Application due to an overall larger and more complicated Project scope with the inclusion of additional pipelines and associated intestacies of the ITS that are not present in the CTS.[160]
- The deployment of resources in the Lower Mainland (for the CTS) and the Interior region (for the ITS) would require additional operations, Indigenous and community relations, and environmental management resources as part of two separate applications.
- In order to address the cracking threats on the highest risk ITS pipeline, the Okanagan Capacity Upgrade (OCU) Project, for which a CPCN Application was filed with the BCUC on November 16, 2020, must be in service to ensure that FEI is able to meet customer demand in the event that an ITS pipeline is required to operate at a 20 percent pressure reduction for an extended period.[161]

90. Even if the BCUC were to disagree with FEI's decision on how to scope the CTS TIMC Project, this should not have any impact on approval of this Application. Delaying the work on the CTS to include some or all ITS pipelines would not be reasonable or in the public interest given the identified risk and availability of EMAT ILI to mitigate that risk. FEI has acted reasonably in addressing the highest risk to its transmission system without undue delay. Further, FEI has been developing the ITS TIMC Project in parallel with the

157 The Savona Vernon 323 and Vernon Penticton 323 pipelines.

158 Exhibit B-5, BCUC IR1 4.3.

159 Exhibit B-5, BCUC IR1 4.3.

160 Exhibit B-5, BCUC IR1 4.3; Exhibit B-11, BCUC IR2 34.4.

161 Exhibit B-5, BCUC IR1 4.4.

CTS TIMC Project to address the risk cracking threats pose to the ITS pipelines.[162] FEI anticipates filing its ITS TIMC CPCN Application in 2022 following the receipt of a decision on the CTS TIMC Application.[163]

(b) Smaller Diameter Pipelines Were Appropriately Excluded from Scope

91. FEI also correctly limited the scope of its QRA and this Application to larger diameter pipelines for which EMAT ILI tools are commercially available. As EMAT ILI tools are not yet commercially available for the smaller pipe diameters typical of FEI's laterals, FEI optimized the QRA scope to include only transmission pipelines of NPS 10 or larger for which EMAT ILI tools are commercially available.[164] As a result, 106 smaller diameter pipelines were excluded from the QRA scope.

92. Despite the lack of commercial availability of EMAT ILI tools, FEI assesses and manages risk qualitatively on the 106 pipelines through its IMP-P, including identifying relevant hazards, considering potential consequences, and selecting and implementing appropriate mitigation.[165] FEI will continue to inspect for cracking during opportunity digs when the pipeline is exposed because of other condition assessments,[166] and will develop a line specific mitigation plan in the event significant cracking is discovered.[167] FEI will continue to monitor technologies as they become available for transmission lines of diameter less than NPS 10.[168] As observed by Dynamic Risk, "operators investing in the current EMAT technology by performing inspections utilizing the services of ILI vendors provide necessary support to further the development and improve the capabilities of EMAT technology."[169] FEI will also be conducting further iterations of its QRA which will over time include the 106 pipelines as FEI acquires the data capability to run meaningful QRAs on these assets.[170]

(c) Pressure Reduction Capabilities Are Needed and Provide A Reasonable and Industry-Accepted Level of Risk Mitigation

93. FEI is currently unable to reduce the operating pressure in individual pipelines with the exception of the LIV PAT 457 and CPH BUR 508 pipelines. These two pipelines were inspected under the EMAT Pilot

162 Exhibit B-11, BCUC IR2 34.3.
163 Exhibit B-11, BCUC IR2 34.4.
164 Exhibit B-5, BCUC IR1 1.3.
165 Exhibit B-11, BCUC IR2 38.4.
166 Exhibit B-1, Application, Section 3.2.5.
167 Exhibit B-5, BCUC IR1 1.5.
168 Exhibit B-11, BCUC IR2 38.4.1.
169 Exhibit A2-7, CEC-Dynamic Risk IR2 9.3.
170 Exhibit B-11, BCUC IR2 38.1 and BCUC IR2 38.2

Project in 2019 and 2020, respectively. As described in Sections 5.3.3.1 and 5.3.3.2 of the Application, FEI installed a pressure regulating station at the upstream end of each pipeline to allow for localized pressure reductions following EMAT ILI tool runs. For all other CTS pipelines, FEI must apply a pressure reduction at Huntingdon Control Station which results in a system-wide pressure reduction and negatively impacts system capacity. To mitigate impacts to the capacity of the CTS when a pressure reduction is required, FEI needs the ability to reduce the operating pressure of individual pipelines. As such, FEI is proposing to construct new pressure regulating stations as described in Section 5.5.4 of the Application.[171]

94. These pressure control capabilities to be added at strategic locations across the CTS will allow FEI to reduce pressure by 20 per percent, which is accepted industry standard safety factor.[172] At a 20 percent pressure reduction, the pipeline, operating at its new restricted pressure, would effectively have the same safety factor as a pipeline subject to a hydrostatic pressure test with a test factor of 1.25. This is the minimum safety factor adopted in CSA Z662, when verifying the pressure-containing capacity of a pipeline by hydrostatic testing, and has become the industry standard safety factor for integrity decision-making.[173] The adoption of the 20 percent reduction in operating pressure is illustrated by the response to the October 2018 cracking-related failure of a transmission pipeline in the Prince George area and other gas transmission pipeline incident reports published by the Transportation Safety Board of Canada.[174]

(d) Execution of Work Has Been Optimized and FEI Has the Resources to Complete the Project

95. The execution of the CTS TIMC Project has been optimized based on resourcing and maximizing efficiencies.[175] FEI has the internal resources to manage and execute each of the projects identified over the upcoming 10-year period. For those projects that are in the planning stage, FEI establishes a project management team to develop the project and adds resources as the project progresses to the execution stage. These resources are supplemented by subject matter experts from FEI’s other disciplines (e.g., engineering, environmental, external relations, and archaeological) and from external consulting firms and/or industry experts that provide discrete services during the planning and execution phases of the Project. Each project will be constructed by a contractor and there are multiple contractors that provide the construction services required for each project.[176]

171 Exhibit B-15, RCIA IR2 20.

172 Exhibit B-11, BCUC IR2 34.3 and 37.1.

173 Exhibit B-11, BCUC IR2 34.3.

174 Exhibit B-11, BCUC IR2 34.3.

175 Exhibit B-5, BCUC IR1 3.4.

176 Exhibit B-5, BCUC IR1 29.2.

(e) No Supply Shortfalls Post-EMAT Runs

96. FEI does not anticipate any supply shortfalls on the CTS after the EMAT ILI runs. All CTS pipelines, with exception of the HUN ROE 1067 pipeline, will be able to have their operating pressure reduced by 20 percent year-round without any supply shortfalls once the proposed PRS facilities are installed and the modifications to Huntingdon Control Station are completed as part of the CTS TIMC Project.

97. As described in the response to BCUC IR2 36.1, the CTS has insufficient capacity when operating the HUN ROE 1067 pipeline with a 20 percent pressure reduction through the winter. This is because the HUN ROE 1067 serves as the backbone of the CTS, supplying a majority of gas to the other transmission pipelines in the CTS. Thus, a pressure reduction on the HUN ROE 1067 pipeline effectively results in a pressure reduction for the entire CTS. As a result, FEI will avoid implementing a pressure reduction on the HUN ROE 1067. Instead, FEI will prioritize the EMAT ILI run on the HUN ROE 1067 pipeline, work with the ILI vendor to accelerate data reporting, and ensure sufficient resources are available to perform all repairs on the HUN ROE 1067 pipeline to avoid the need for a pressure reduction.[177]

B. FEI Cost Estimate for the Project is Robust and Meets the BCUC's CPCN Guidelines

98. Consistent with the BCUC's CPCN Guidelines, FEI and Stantec developed an AACE Class 3 estimate for the Project using AACE Recommended Practices Nos. 18R-97 and 97R-18 as guides.[178] The current scope of work definition is close to 100 percent known, while the percentage of overall Project scope definition is approximately 30 percent.[179] The Class 3 Cost Estimate and Basis of Estimate are provided in Confidential Appendix D-4. The accuracy range for the current Project cost estimate is +16 to -14 percent at an 80 percent confidence level, as stated on page 12 of Confidential Appendix E-3 - Validation Estimating Contingency Report.[180]

99. FEI used a risk analysis to establish a contingency percentage of 10 percent that aligns with the P50 confidence level, based on the current understanding of the Project's risk profile, discrete project risks, and to account for possible scope changes. FEI engaged Yohannes Project Consulting Inc. (YPCI), a company specializing in risk management, to conduct a qualitative risk analysis to identify all of the risks associated with the Project. YPCI conducted multiple workshops with impacted stakeholders to develop

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177 Exhibit B-11, BCUC IR2. 37.2.

178 Exhibit B-1, Application, p. 112.

179 Exhibit B-11, BCUC IR2 45.1.

180 Exhibit B-11, BCUC IR2 45.2

a risk register for the Project (Appendix E-2) to identify risks that could likely occur. As the engineering advanced on the Project, the probability or the consequence of several risks which were initially identified were either mitigated entirely or reduced to a lesser extent. All of the remaining risks associated with the Project are contained within the Risk Report and included in Confidential Appendix E-1.

100. FEI also retained Validation Estimating LLC, USA (Validation Estimating, John Hollmann), a company that provides services in estimate validation, risk analysis and contingency estimation, to complete an escalation estimate and a quantitative analysis using an integrated parametric and expected value methodology. This analysis is described in the report titled “Capital Cost and Schedule Risk Analysis and Contingency Estimate,” dated November 15, 2020 and provided in Confidential Appendix E-3. Validation Estimating facilitated a series of risk workshops to evaluate the systemic and project-specific risks with the extended project team. Following the acquisition of these required risk inputs, this independent expert quantified the contingency to adequately address Project risks over a multi-year execution timeframe. This risk quantification applies a hybrid approach that combines a parametric model analysis for systemic risks based on empirical knowledge, and an expected value analysis for project specific risks, which assesses probability of occurrence and integrates anticipated cost and schedule impacts. The hybrid approach is in accordance with AACE Recommended Practices and is documented in the report titled “Capital Cost and Schedule Risk Analysis and Contingency Estimate”, dated November 15, 2020 and provided in Confidential Appendix E-3 and is based upon:

(a) 40R-08 *Contingency Estimating – General Principles*;

(b) 42R-08 *Risk Analysis and Contingency Determination Using Parametric Estimating*; and

(c) 65R-11 *Integrated Cost and Schedule Risk Analysis and Contingency Determination Using Expected Value*.

101. All cost estimates, including material supply and construction contracts, were developed based on 2020 market prices. In accordance with AACE Recommended Practice 68R-11, a probabilistic assessment of escalation was completed by Validation Estimating. The report, provided in Confidential Appendix E-4, establishes the escalation at $7.9 million (5.4 percent of the total base cost plus contingency) that aligns with the P50 confidence level.[181]

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[181] Exhibit B-1, Application, p. 115.

102. FEI has included a management reserve based on the contingency analysis and recommendation from Validation Estimating, as set out in Confidential Appendix E-3.[182] Specifically, the management reserve is set based on the project-specific risk of a frac-out, as identified in Confidential Appendix E-3. FEI has explained how the management reserve would be accessed if required.[183]

103. The cost estimate has been subject to quality assurance and validation through:[184]

(a) Internal Stantec reviews that included peer reviews, document quality checks, and independent review;

(b) Validation reviews involving both Stantec and FEI team members throughout the estimate development process to confirm that the estimate assumptions were valid;

(c) External independent review to verify that the estimate criteria and requirements were met and a documented, reasonable estimate was developed; and

(d) Independent external reviews of the Class 3 cost estimate was done by Universal Pegasus International (UPI).

104. The nature of the Project work is significantly different from FEI's most recent major urban pipeline project, the Lower Mainland Intermediate Pressure System Upgrade (LMIPSU) Project. The LMIPSU Project involved the installation of 20 km of continuous NPS 30 pipeline across three densely populated urban municipalities, and modifications to two large gate stations. In contrast, the CTS TIMC Project involves relatively small modifications of facilities in existing stations, and the pipeline alterations will occur within existing rights of way in non-urban areas. In addition, the LMIPSU Project was executed over a relatively small geographical area whereas the distance between the sites for the CTS TIMC Project spans a wide geographic area.

105. Further, due to the nature of the CTS TIMC Project, the risk of cost escalation arising from municipal permit requirements is negligible. The majority of the construction activities for the CTS TIMC Project entail replacement or modification of existing infrastructure. As a result, FEI is anticipating that its operating agreements with municipalities will apply to most activities, and hence involve limited and standardized municipal permit requirements. The remaining work activities that include new infrastructure, or are not already covered by an existing operating agreement, are contained within FEI's existing rights-of-way and facility stations, thus minimizing anticipated permit requirements. FEI has

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182 Exhibit B-12, Confidential BCUC IR2 12.1 and 12.2.

183 Exhibit B-12, Confidential BCUC IR2 12 series.

184 Exhibit B-1, Application, pp. 114-115.

prepared a preliminary list of municipal permit requirements associated with the proposed scope of work, and accounted for these in the CPCN cost estimate.[185]

106. FEI has responded to detailed inquiries regarding permitting requirements and its cost estimate:

(a) There is only one land acquisition required and the land is already encumbered by a statutory right of way; the cost to acquire the land in fee simple is included in the Project cost estimate.[186]

(b) FEI is proactively engaging with stakeholders and taking other steps, such as incorporating learnings from past projects, to mitigate and minimize the potential for unexpected changes in permitting that could result in cost escalation.[187] Even so, the risk of permitting delays is included in the Project cost estimate.[188]

(c) The minor cost of municipal permitting requirements is included in the Project cost estimate.[189]

(d) The cost of approvals from Ministry of Transportation and Infrastructure, BC Hydro and other third parties are included in the Project cost estimate.[190]

107. FEI submits that its cost estimate for the Project meets the BCUC CPCN Guidelines and is both reasonable and robust.

C. Proposed Treatment of TIMC Development Cost Deferral Account Balance is Just and Reasonable

108. FEI is seeking approval to transfer the balance in the TIMC Development Cost deferral account associated with the development of the CTS TIMC Project to a new rate base CTS TIMC deferral account on January 1 of 2023, and commence amortization of the December 31, 2022 actual balance of these costs, estimated at $13.2 million, over a three-year period commencing at that time.[191]

109. Consistent with BCUC Order G-237-18, FEI will continue to record the ITS TIMC development costs associated with the future ITS TIMC CPCN Application in the existing TIMC Development Cost deferral account. These costs will be tracked and recorded separately, and disposition will be requested as part of

185 Exhibit B-5, BCUC IR1 23.3.3.
186 Exhibit B-11, BCUC IR2 43.1.
187 Exhibit B-11, BCUC IR2 44.1
188 Exhibit B-11, BCUC IR2 44.1.2.
189 Exhibit B-11, BCUC IR2 44.2 and 44.3 series.
190 Exhibit B-11, BCUC IR2 44.4, 44.5 and 44.6 series.
191 Exhibit B-5, BCUC IR1 26.2 and 27.4.1.

the ITS TIMC CPCN Application. FEI will seek approval to begin amortization of these ITS TIMC development costs as part of its ITS TIMC CPCN Application.[192]

110. The following subsections are organized around the following points:

(a) The Project development activities were necessary and consistent the original cost estimate.

(b) Development Costs eligible for capitalization will be transferred to capital assets.

(c) Remaining development costs are appropriately amortized over three years.

(d) FEI is amenable to the creation of a separate account for QRA costs.

(a) Project Development Activities Were Necessary and Consistent with Original Cost Estimate

111. In Decision and Order G-237-18, the BCUC approved FEI's request to establish the non-rate base TIMC Development Cost deferral account, attracting a WACC return, for the development costs related to the TIMC project. As described in Section 5.3 of the Application, all of FEI's Preliminary Stage Development Costs, Pre-Construction Development Costs, and Application Costs have been prudently incurred and are necessary expenditures to ensure the CPCN Application has been developed to the degree required by the BCUC's CPCN Guidelines, as well as to support the pipeline failure risk mitigation addressed by the Project. On this basis, these costs are recoverable from ratepayers.[193]

112. The total actual and projected development costs for the CTS TIMC Project are $30.824 million to be incurred to the end of 2021, compared to the original estimated CPCN application development costs of $41.620 million for the entire TIMC project. The development costs for the future ITS TIMC CPCN Application will continue to be collected in the TIMC Development Cost deferral account.[194] The projected balance for the TIMC Development Cost deferral account, including the ITS TIMC CPCN Application, is consistent with the original estimate of $41.620.[195]

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[192] Exhibit B-1, Application, p. 121; Exhibit B-5, BCUC IR1 27.4; Exhibit B-11, BCUC IR2 47.3. Future EMAT ILI runs will not be attributed to the deferral account or to the Project. The costs for the future EMAT ILI tools runs will be part of FEI's sustainment capital funding for integrity inspection reviewed through future rate applications (Exhibit B-5, BCUC IR1 11.1).

[193] Exhibit B-5, BCUC IR1 9.1.

[194] Exhibit B-1, Application, p. 86.

[195] Exhibit B-11, BCUC IR2 47.3.

(b) Development Costs Eligible for Capitalization Will be Transferred to Capital Assets

113. As explained in the Application, FEI will capitalize $13.2 million of development costs related to the base line QRA, QRA sustainment, and EMAT inspections. FEI assessed the development costs under US GAAP, and identified these costs as eligible for capitalization.[196] Therefore, it is appropriate that these costs be capitalized and transferred to FEI's plant-in-service on January 1 in the year following BCUC approval of the Application.[197]

(c) Remaining Development Costs to Be Transferred to a Rate Base Account and Amortized over Three-Year Amortization Period For Remaining Costs is Appropriate

114. The remaining balance in the account representing the non-capitalizable portion of the CTS TIMC Application development costs is proposed to be a transferred to a new rate base CTS TIMC deferral account and amortized over three years.[198]

115. The existing TIMC Development Cost deferral account is a non-rate base account, attracting FEI's WACC return, so that the costs incurred would be held outside of FEI's rate base as well as FEI's delivery rates until BCUC approval of the CTS TIMC CPCN. Once the CPCN is approved, FEI will transfer the deferral account to a new rate base deferral account on January 1, 2023. Transferring from non-rate base to rate base upon BCUC approval is consistent with past CPCN applications approved by the BCUC, reflecting that assets in service are included in FEI's rate base.[199]

116. FEI's proposed three-year amortization period is reasonable and consistent with past practice. It is appropriate to amortize the deferral account for the CTS TIMC Project in under 5 years as the Project is forecasted to be undertaken over a 5-year period. The differences in the annual delivery rate impact from amortization periods from 2 to 5 years is immaterial.[200] Therefore, FEI selected an amortization period of three years to be consistent with recent BCUC approvals for FEI's CPCN applications, including under BCUC Orders C-2-21 for the Pattullo Gas Line Replacement Project, Order G-12-20 for the IGU Project, Order C-11-15 for the LMIPSU Project, and Order C-2-14 for the Muskwa River Crossing Project.[201]

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196 Exhibit B-5, BCUC IR1 12.2.

197 Exhibit B-1, Application, p. 121; BCUC IR1 11.1.

198 Exhibit B-5, BCUC IR1 26.2 and 27.4.1.

199 Exhibit B-11, BCUC IR2 47.2.

200 Exhibit B-5, BCUC IR1 26.2 and 27.4.1.; Exhibit B-13, CEC IR2 54.1.

201 Exhibit B-5, BCUC IR1 26.2 and 27.4.1.

(d) FEI Is Open to the Creation of a Separate Account for QRA Costs

117. As the baseline QRA informed the present CTS TIMC Application and its forthcoming ITS TIMC Application, FEI recognizes that it could have requested the creation of two separate deferral accounts – one for the QRA and one for the CTS TIMC costs.[202] While FEI considers that both accounts should be amortized over a three-year period, FEI is open to the option of a separate account for QRA costs if the BCUC would prefer to keep the QRA costs separate. There would also be value to maintaining a separate deferral account for QRA costs on an ongoing basis as FEI is planning for future iterations of QRAs which will require future ongoing operations and maintenance expenditures, which could be recorded in the new account.[203]

118. As the existing TIMC Development Cost deferral account had a specific scope and estimate associated with its creation (including the initial QRA, but not ongoing QRAs), FEI does not consider it appropriate to attribute costs for future QRA iterations to this deferral account. Therefore, FEI does not intend to attribute costs related to future iterations of QRAs to the existing TIMC Development Cost deferral account.[204]

119. If the BCUC determines a separate deferral account is appropriate to record the costs related to the QRA that has already been undertaken and incremental costs related to future QRAs, FEI requests that the account be a rate base account with an ongoing three year amortization period, and that future costs added to the account be subject to review in future revenue requirement proceedings.[205] FEI submits that it should be a rate base account because the QRA costs are not the subject of a separate CPCN proceeding, but will be reviewed in FEI's ongoing revenue requirement/annual review proceedings. Rate base treatment is simpler and more transparent and is FEI's general approach to deferral account requests. FEI only requests non rate base treatment if there is a specific reason for the treatment.[206]

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202 Exhibit B-5, BCUC IR1 27.4.

203 Exhibit B-5, BCUC IR1 27.4.

204 Exhibit B-11, BCUC IR2 47.1.

205 Exhibit B-5, BCUC IR1 27.4.

206 Exhibit B-11, BCUC IR2 47.2.

PART FIVE: FEI WILL MITIGATE ENVIRONMENTAL AND ARCHAEOLOGICAL IMPACTS

120. The Project is expected to have low to moderate environmental and archaeological impacts based on the environmental and archaeological assessments undertaken, which can be appropriately mitigated.[207]

121. The Environmental Overview Assessment (EOA) of the Project was completed by Stantec Consulting Ltd., which is included as Appendix H of the Application, and concludes that the overall environmental risk of the Project is low to moderate, reflecting varied impacts between locations. The assessment also concludes that potential impacts can be mitigated through the implementation of standard best management practices, which FEI will follow during construction.[208] These best management practices and mitigation measures, as described in Section 5 of the EOA report, will form part of the Project's Environmental Management Plans prior to commencement of construction.[209] Detailed environmental specifications will also be prepared as part of the Project's tendering process to ensure that contractors are aware of the Project's environmental requirements under those permits.[210]

122. FEI will also be able to minimize impacts to construction timelines and costs as a result of encountering species at risk, fish habitat, or contaminated soil or groundwater through additional pre-construction investigations.[211] Environmental constraints and potential environmental effects related to the Project will be further assessed and documented during the detailed engineering phase of the Project. Given the current Project schedule, FEI has not yet submitted environmental permit applications, but does not anticipate any issues with the timelines to apply for and obtain such permits by the start of construction in 2024.[212] Additional environmental studies are planned during the Project's detailed design phase to verify if all the permits identified in the preliminary EOA will ultimately be required.[213]

123. Once construction begins, FEI will undertake environmental monitoring to oversee construction activities and identify any adverse effects. Monitoring of this kind will ensure that areas impacted by the

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207 Exhibit B-1, Application, Section 7.

208 Exhibit B-1, Application, p. 131.

209 Exhibit B-1, Application, p. 126.

210 Exhibit B-1, Application, p. 131.

211 Exhibit B-1, Application, pp. 128-130, Appendix O.

212 Exhibit B-1, Application, p. 131 and Appendix H, p. vi; Exhibit B-5, BCUC IR1 30.1, 30.2; Exhibit B-11, BCUC IR2 49.1.

213 Exhibit B-6, BCOAPO IR1 10.1.

Project are returned to pre-construction conditions. FEI will be conducting post-construction inspections to determine the success of restoration efforts and mitigation measures.[214]

124. FEI completed an Archeological Constraints Report (ACR) for the Project, included as Appendix I of the Application. The ACR concluded the Project's 13 events and 13 facilities may have elevated archaeological potential, with the exception of Fraser Gate Station which has low archaeological potential, an no registered archaeological sites or registered historic heritage sites were identified overlapping the Project study area.[215] As recommended by its archaeological consultant (Stantec Consulting Ltd.), in order to further assess the Project's potential archaeological impacts, FEI is undertaking an Archaeological Overview Assessment (AOA) for the events and facilities that do not have any modelled archaeological potential. FEI obtained all required Indigenous cultural permits prior to commencing the AOA,[216] and is in the process of identifying areas assessed as having elevated or high archaeological potential, and therefore, where an Archaeological Impact Assessment (AIA) will be recommended.[217] The AIA will provide a detailed assessment to develop site specific mitigation strategies to offset any potential impacts associated with the Project. A small portion of the HUN ROE 1067 pipeline and Huntington facility are within areas of modelled high archaeological potential and will require AIA work.[218]

125. FEI requires a permit under Section 12.2 of the *Heritage Conservation Act* to undertake detailed AIA activities, which FEI will obtain during the detailed engineering phase of the Project. This is the only government archaeology permit required for the Project.[219] FEI's archaeological consultant (Stantec) has also applied for all necessary heritage permits issued through Indigenous permitting processes, including the Kwantlen First Nation, Musqueam Indian Band, Squamish Nation, Tsleil-Waututh Nation, and the Stó:lō Nation. FEI has obtained all but one heritage permit,[220] which it expects to obtain in Q4 2021.[221] All potentially impacted Indigenous groups will also have the opportunity to provide comments on the permit application and request participation in the associated AIA field work, or review of the AIA report.[222] In

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214 Exhibit B-1, Application, pp. 131-132.

215 Exhibit B-1, Application, p. 132.

216 Exhibit B-5, BCUC IR1 31.1.

217 Exhibit B-1, Application, p. 125.

218 Exhibit B-1, Application, pp. 132-133.

219 Exhibit B-1, Application, p. 131; Exhibit B-11, BCUC IR2 50.2: As no events or facilities are located within known archaeology sites, a HCA Section 12.4 Site Alteration Permit is not required unless there is a chance find during the AIA.

220 FEI's consultant remains in contact with the Indigenous group regarding the outstanding permit, which is being delayed due to capacity constraints of the community, not due to concerns with the permit itself: Exhibit B-11, BCUC IR2 50.4.

221 Exhibit B-11, BCUC IR2 50.4.

222 Exhibit B-5, BCUC IR1 35.5.2.

early Q4 2021, Stantec has shared a draft AOA report with Indigenous groups from whom it received Indigenous-issued permits for review and feedback and will share the final AOA with all affected Indigenous groups in late Q4 2021.[223]

126. In summary, based on the assessments undertaken for the CTS TIMC Project outlined above, the Project is expected to have low to moderate environmental and archaeological impacts.

PART SIX: FEI'S ENGAGEMENT ACTIVITIES WILL CONTINUE TO BE SUFFICIENT

127. This Part of this Final Submission discusses how FEI's public consultation and engagement with Indigenous groups has been sufficient, and that there have not been any significant issues or concerns raised with respect to the Project. FEI's approach to consultation and engagement is guided by a Consultation and Engagement Plan, included in Appendix J-1 of the Application, which ensures the public and Indigenous groups have a meaningful opportunity to learn about and provide input into the Project.[224] FEI initiated consultation and engagement for the Project in October 2020 and will be continuing to consult with the public and engage with Indigenous groups throughout the life of the Project. FEI continues to adapt its consultation methods to ensure adequate opportunities are available in light to the COVID-19 pandemic.

A. Public Consultation Has Been Sufficient and Does Not Indicate Significant Concerns

128. As stated in the Application, FEI identified and adopted a number of objectives to guide public consultation which are consistent with industry best practices:[225]

- Ensure balanced and objective information is provided to all affected and interested stakeholders;
- Communicate the benefits of the Project (e.g., reliability and integrity of FEI's system), and potential positive socio-economic impacts to communities during construction;
- Provide opportunities for stakeholders to give feedback and to understand their concerns through an ongoing dialogue; and
- Consider and, where possible, incorporate stakeholder feedback.

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223 Exhibit B-11, BCUC IR2 50.4.1.

224 Exhibit B-1, Application, Section 8.

225 Exhibit B-1, Application, pp. 137-138.

129. FEI considers these objectives appropriately allow it to solicit community feedback throughout the Project. As part of its Consultation and Engagement Plan, FEI identified a number of stakeholders, including: nine municipalities, FEI customers, permitting authorities, and residents and businesses along and nearby the Project rights of ways and worksites.[226] Community, social and environmental considerations informed this plan, and as set out in Table 8-1 of the Application, enabled FEI to identify potential impacts to the public and an associated approach to consultation and mitigation.

130. In order to support its consultation activities, FEI developed the following communication materials:[227]

- **Project Webpage:** The webpage on FEI's "Talking Energy" website platform provides transparent, clear, accurate and easily accessible project information to support consultation efforts and solicit feedback, including a high-level map showing all Project sites and detailed maps of two municipalities where there is a concentration of work. FEI will continue to update the Project webpage (Appendix J-3).

- **Mail Notifications:** Project information letters were distributed beginning in October 20, 2020 to provide information about the proposed work, including a link to the above-noted webpage, phone number and email address details. These notifications enable residents or businesses to learn more, ask questions or provide feedback about the Project. FEI also contacted residents and businesses along the rights of way by phone to confirm receipt of project information letters and in order to address any concerns.[228]

- **Email and Phone Line:** A Project email address and project-specific phone line has been activated to help better direct inquiries FEI receives about the Project. Both of the channels went live in October 25, 2020 and will continue to be closely monitored throughout the Project. As discussed below, FEI received two questions from residents using the phone line, which have both been responded to.[229]

- **Newsletter and Social Media:** FEI's Talking Energy newsletter and its various social media channels provide an additional avenue to communicate with affected stakeholders. On October 29, 2020, FEI sent a Talking Energy newsletter providing information regarding the Project to 3,866 subscribers (Appendix J-4).

- **Customer Notifications:** Information regarding the Project and its associated rate impacts has been shared with all gas customers using a number of communication methods including bill inserts, the Accounts Online payment portal and as part of e-bill emails, FEI's website, and/or the Project webpage. In the February and March 2021 billing cycles, FEI

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226 Exhibit B-1, Application, p. 138.

227 Exhibit B-1, Application, pp. 138-140.

228 Exhibit B-1, Application, p. 143.

229 See Exhibit B-1, Application, p. 144.

distributed a bill insert to all FEI gas customers, including the estimated Project costs and associated rate impacts.[230]

131. As described in detail in Section 8.2.5 of the Application, FEI's consultation methods are tailored to each group, including potentially impacted residents, businesses, and municipalities, through a variety of methods. For example, FEI contacted all of the impacted municipalities following the distribution of the project information letter in order to confirm whether any questions or concerns arose and to offer a virtual presentation clarifying the Project's scope.[231] Of the three municipalities that accepted FEI's offer to attend a virtual presentation, no concerns or issues were expressed.[232] Follow-up meetings and communication will continue with municipalities as the Project progresses.[233]

132. FEI has tracked issues or concerns raised regarding the Project and is committed to work with customers and stakeholders to address any outstanding matters. To date, FEI has only received the following concerns which relate to: (i) noise and construction impacts;[234] (ii) whether a new gas line formed part of the Project scope;[235] (iii) the need for the Project and FEI's approach to asset depreciation;[236] and (iv) the rate impacts of the Project to customers. [237] Each of these concerns was responded to and has been resolved.

133. FEI submits that its Consultation and Engagement Plan and associated public consultation activities have been sufficient, appropriate, and reasonable to meet the requirements of the CPCN Guidelines. Throughout the consultation process to date, FEI has addressed questions and concerns, and is unaware of any outstanding concerns.[238] FEI has provided a summary of forthcoming public consultation activities that it expects to undertake in advance of consultation.[239] FEI will continue to consult with stakeholders regarding construction timelines, scope of work, safety, and mitigation plans.[240] FEI anticipates resuming public consultation activities in 2022 as the Project continues to develop.[241]

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230 Exhibit B-7, CEC IR1 43.1.

231 Exhibit B-1, Application, p. 142.

232 See Exhibit B-1, Application, Appendix J-2 for summaries of these meetings.

233 Exhibit B-1, Application, p. 142.

234 Exhibit B-1, Application, Table 8-2.

235 Exhibit B-1, Application, Table 8-2.

236 Exhibit B-5, BCUC IR1 32.2.

237 Exhibit B-5, BCUC IR1 32.2.

238 Exhibit B-5, BCUC IR1 32.5.

239 Exhibit B-5, BCUC IR1 32.4.

240 Exhibit B-1, Application, p. 144.

241 Exhibit B-11, BCUC IR2 51.1

134. Ultimately, FEI is dedicated to maintaining open dialogue and good relationships with its customers, residents and businesses, municipalities and permitting agencies throughout the various stages of construction and will work with them to minimize the impacts of the Project.[242] FEI is not aware of any outstanding concerns and is committed to responding to the feedback received from stakeholders as the Project continues to develop.

B. Engagement with Indigenous Groups Has Groups Has Been Thorough, Timely and Meaningful

135. As outlined in Section 8.3 of the Application, FEI has engaged with all Indigenous groups with asserted interests in the Project area.[243] FEI initiated early engagement activities with 25 Indigenous groups that may potentially be affected by the Project to: (1) provide information about the Project; (2) describe any potential impacts; (3) understand the interests in the area; and (4) provide an opportunity for these groups to identify additional impacts and to give input on the Project. Through this early engagement process, FEI has established key points of contact with Indigenous groups potentially affected by the Project, their preferred methods of communication, and an early understanding of their interests and concerns.[244] FEI has been able to address all questions and issues from Indigenous groups to date[245] and considers that its early engagement activities have been successful in understanding the level of interest and the nature of interests of Indigenous groups for the Project, reflecting this stage in the Project lifecycle.

136. Engagement was initiated through a Project information letter, as well as preliminary maps and reports, and has progressed through virtual meetings when requested by Indigenous groups, including meetings with the Matsqui First Nation, People of the River Referrals Office and the Cowichan Tribes.[246] As described in response to BCUC IR1 33.4.1, FEI has presented Indigenous groups with the known scope of the Project and potential associated impacts, including planned worksite locations.[247] Through this process, a number of Indigenous groups have indicated an interest in engaging on future archaeological and environmental reports and plans as they become available and through the BCOGC permitting

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242 Exhibit B-1, Application, pp. 144-145.

243 Exhibit B-1, Application, Table 8-3.

244 Exhibit B-1, Application, p. 150.

245 Exhibit B-5, BCUC IR1 33.9.

246 Exhibit B-1, Application, p. 147.

247 Exhibit B-5.

process, closer to Project construction.[248] FEI has also provided any requested information to groups as available.[249]

137. An updated Table 8-5 summarizing FEI's consultation with Indigenous groups to date was provided in the second round of IRs.[250]

138. As the Project progresses into later stages, FEI will continue to work with Indigenous groups to keep them apprised of new developments, including all follow up commitments. In particular, FEI will engage Indigenous groups during the permitting process and will communicate and solicit feedback regarding construction timelines, scope of work, and safety and mitigation plans.[251] This includes engagement regarding site-specific impacts through the BCOGC permitting process, which includes soliciting feedback on environmental and archaeological reports and management plans in advance of construction.[252]

139. FEI's approach ensues that Indigenous groups can obtain relevant information regarding the Project and its potential impact to their interests (e.g., the above-noted results of environmental and archaeological reports) as it becomes available. FEI intends to consider, and where appropriate, incorporate feedback from Indigenous groups throughout the Project lifecycle, including Project planning, construction and restoration. This approach is consistent with its Statement of Indigenous Principles, which as been provided in Appendix K-1 of the Application,[253] and FEI will continue to include those groups who have not responded to previous communications.[254] FEI has taken the same approach in relation to previous projects, thus ensuring an open dialogue and long-term relationships with Indigenous groups.

140. FEI continues to support Indigenous engagement activities through capacity funding. As of September 2021, FEI has confirmed capacity funding for a Project Coordinator for Kwikwetlem First Nation to support engagement with FEI with respect to the CTS TIMC Project.[255] FEI has not received any further requests for capacity funding from Indigenous groups, or indication that such requests will be

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[248] Exhibit B-5, BCUC IR1 33.4.1.
[249] Exhibit B-1, Application, Table 8-5.
[250] Exhibit B-11, BCUC IR2 52.1.
[251] Exhibit B-1, Application, p. 150.
[252] Exhibit B-5, BCUC IR1 33.6.
[253] Exhibit B-1.
[254] Exhibit B-5, BCUC IR1 33.5.
[255] Exhibit B-1, Application, p. 150; Exhibit B-11, BCUC IR2 52.1.

forthcoming, but will continue to offer capacity funding to Indigenous groups throughout the Project lifecycle in order to ensure they can assess the Project's impacts on their interests.[256] FEI will also engage Indigenous groups on employment and contracting opportunities through its Socio-Economic Impact Program.[257] These activities will occur between 2022 and 2024 in the lead up to contracting and construction for the Project.[258]

141. Given the stage of the Project, FEI submits that its engagement activities with Indigenous groups to date have been sufficient, appropriate, and reasonable, and are consistent with the BCUC's CPCN Guidelines.[259] In particular, FEI has notified each identified Indigenous community about the Project, and FEI has met with and provided information back to these communities as requested. Where requests were made for more detail than is currently available, FEI has committed to ongoing engagement through follow-up meetings to share information as it becomes available. FEI has also provided letters to each Indigenous community advising of the filing of the Application and how to get involved in the process to review the Application.[260] During the BCOGC permitting and consultation process, more detailed Project information will be provided to the Indigenous communities for review and comment. FEI anticipates responding to issues raised from Indigenous groups related to environmental and archaeological impacts, such as impacts to sensitive watercourses and areas with high archaeological potential, as more detailed Project information becomes available.[261]

PART SEVEN: CONCLUSION

142. FEI's evidence in this proceeding is comprehensive, responding to all issues raised, and conclusively demonstrates that the CTS TIMC Project is in the public interest. The need and justification for the Project is clear and FEI's alternatives analysis demonstrates that EMAT ILI is the only feasible and most cost-effective alternative to meet the Project need. 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 archeological impacts, and FEI's public consultation and early engagement with Indigenous communities has not indicated any significant concerns.

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[256] Exhibit B-11, BCUC IR2 52.5.

[257] Exhibit B-5, BCUC IR1 33.10.

[258] Exhibit B-5, BCUC IR1 33.5.

[259] Exhibit B-1, Application, p. 150.

[260] Exhibit B-5, BCUC IR1 33.8.

[261] Exhibit B-5, BCUC IR1 33.5.1.

143. FEI submits that the BCUC should grant a CPCN for the Project and approve FEI's proposed deferral account to capture the costs of preparing the Application and evaluating the feasibility of and preliminary stage development of the Project.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

Dated: October 26, 2021

[original signed by Chris Bystrom]
Chris Bystrom
Counsel for FortisBC Energy Inc.

[original signed by Niall Rand]
Niall Rand
Counsel for FortisBC Energy Inc.

Appendix A

DRAFT ORDER

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ORDER NUMBER
C-xx-xx

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

and

FortisBC Energy Inc.
Application for Approval of a Certificate of Public Convenience and Necessity for the Coastal Transmission System Transmission Integrity Management and Capabilities Project

BEFORE:
A. K. Fung, QC, Panel Chair
D. M. Morton, Commissioner
C. Brewer, Commissioner

on Date

ORDER

WHEREAS:

A. On February 11, 2021, FortisBC Energy Inc. (FEI) filed an application (Application) with the British Columbia Utilities Commission (BCUC) for a Certificate of Public Convenience and Necessity (CPCN) pursuant to section 45 and 46 of the *Utilities Commission Act* (UCA) for FEI's Coastal Transmission System (CTS) Transmission Integrity Management Capabilities (TIMC) Project (CTS TIMC Project);

B. In the Application, FEI also seeks approval, pursuant to sections 59 to 61 of the UCA, to transfer the balance of costs in the TIMC Development Cost deferral account associated with the development of the CTS TIMC Project to a new rate base CTS TIMC deferral account on January 1, 2023 and commence amortization of the December 31, 2022 actual balance of these costs, estimated at $13.2 million, over a three-year period commencing on that date.

C. FEI states the CTS TIMC Project is needed to enhance FEI's integrity management capabilities to mitigate cracking threats on 11 CTS pipelines where such cracking has the potential to lead to failure;

D. FEI explains that the CTS TIMC Project consists of the work necessary to ready 11 pipelines on the CTS for electro-magnetic acoustic transducer (EMAT) in-line inspection (ILI) tools capable of detecting cracking on its pipelines. The components of the Project include:

   1. Replacing 13 heavy wall pipeline segments in six of the CTS pipelines to enable the EMAT ILI tools to travel within its optimal velocity range; and

   2. Modifying 13 transmission pressure facilities on the CTS, to enable FEI to introduce the EMAT ILI tools and install the capability to regulate flow, pressure, and backflow in their associated pipelines;

E. FEI requests that Appendices B, D, E, and G to the Application relating to engineering, cost estimates, and risk assessments be treated as confidential due to their private and commercially sensitive nature and to maintain the safety and security of FEI's assets; and

F. By Order G-74-21 dated March 11, 2021, the BCUC established a regulatory timetable for the review of the Application which consisted of intervener registration, workshop, and one round of information requests (IRs); and

G. The BCUC has reviewed the evidence in the proceeding and finds that approval is 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 CTS TIMC Project as described in the Application.
2. FEI is approved to to transfer the balance of costs in the TIMC Development Cost deferral account associated with the development of the CTS TIMC Project to a new rate base CTS TIMC deferral account on January 1, 2023 and commence amortization of the December 31, 2022 actual balance of these costs, estimated at $13.2 million, over a three-year period commencing on that date.
3. FEI is directed to comply with all directives outlined in Section # of the decision issued concurrently with this order.

DATED at the City of Vancouver, in the Province of British Columbia, this (XX) day of (Month Year).

BY ORDER

(X. X. last name)
Commissioner