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

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

Dear Sirs/Mesdames:

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

In accordance with the Regulatory Timetable set out for this proceeding by Order G-219-19, we enclose for filing FEI's Reply Submission.

Yours truly,

FASKEN MARTINEAU DuMOULIN LLP

[Original signed by Christopher Bystrom]

Christopher Bystrom

Encl.

British Columbia Utilities Commission

FortisBC Energy Inc.

Certificate of Public Convenience and Necessity Application for the Inland Upgrades Project

BCUC Project No. 1598988

Reply Submission

of

FortisBC Energy Inc.

October 24, 2019

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PART ONE: INTRODUCTION

1. FEI submits that the evidence in this proceeding demonstrates that the Inland Gas Upgrades Project (the "Project") is in the public interest and that FEI's Application for a Certificate of Public Convenience and Necessity for the Project (the "Application")[1] should be approved as filed. In their intervener final arguments, the Commercial Energy Consumers Association of British Columbia ("CEC") agrees that the Project is in the public interest and recommends approval by the BCUC, while the BC Old Age Pensioners' Organization et al ("BCOAPO") does not oppose the Project. In this Reply Submission, FEI responds to the BCOAPO's comments and the CEC's other recommendations. FEI submits that the BCUC should approve the Project as proposed in the Application so that FEI can commence work to reduce the identified risk of rupture of the 29 transmission laterals as soon as practicable.

PART TWO: REPLY TO BCOAPO

2. BCOAPO states that it does not oppose the Project, and states:[2]

> Our client groups fully accept the need for utilities to remain compliant with applicable standards (like those set by the OGAA, BCOGC, and CSA), both regulatory and legal, consistent with accepted or industry best practices. BCOAPO does not disagree with the Utility's evidence that it cannot reliably determine the extent of external corrosion on the 29 subject pipelines and that such external corrosion (in addition to other possible contributing factors) may lead to a pipeline rupture if undiagnosed and/or unattended. It goes without saying that the damage, danger, and service disruption associated with pipeline ruptures is not something our clients wish to risk. In addition, our clients accept that, given the very serious risk to public safety that such a rupture represents and the material consequences in terms of service impacts of a rupture, it is important that the risks be mitigated in a timely fashion.

3. BCOAPO nonetheless makes some additional comments to which FEI replies below. In summary:

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[1] Exhibits B-1 and B-1-1, as updated and amended by Exhibit B-1-2 and B-1-2-1.

[2] BCOAPO Final Argument, pp. 4-5.

(a) In reply to BCOAPO's description of the legal framework,[3] section 45(8) of the UCA relates to a "privilege concession or franchise granted to a public utility by a municipality or other public authority" and is not relevant to this proceeding.

(b) In reply to BCOAPO's suggestion that there is disagreement regarding the applicability of the 30 percent of specified minimum yield strength ("SMYS") threshold,[4] there is no evidence of any such disagreement on the record.

(c) In reply to BCOAPO comments on the timing of the Project,[5] FEI has reasonably proceeded with the Project in response to advancements in technology and industry standard practice.

(d) In reply to BCOAPO's suggestion that FEI could have undertaken integrity digs to improve condition information to prioritize work on the Project,[6] information from an integrity dig at one location cannot be used to predict the occurrence of corrosion at any other location.[7] Further, as FEI already plans to proceed with the work as quickly as reasonably possible over a five-year period, any prioritization of the work would not make any material improvement to safety or reliability.[8]

A. Legal Framework for CPCNs

4. As noted by BCOAPO on page 3 of its submission, the requirement for a CPCN is found in section 45(1) of the UCA. However, BCOAPO goes on to cite section 45(8) of the UCA, which is not applicable to this proceeding.[9] Section 45 of the UCA is divided into two parts. Sections 45(1) to (6) relate to the need for a CPCN for the construction and operation a public utility plant or system, or an extension of either. Sections 45(6) to (9), on the other hand, are related to the approval of a "privilege concession or franchise granted to a public utility by a municipality or other public authority". Thus, BCOAPO's reference to section 45(8) is out of place. BCOAPO correctly cites section 46(3.1) of the UCA for the list of items that must be considered by the BCUC when granting a CPCN for a public utility other than BC Hydro. FEI addressed these items in section 9 of the Application.

3 BCOAPO Final Argument, p.3.

4 BCOAPO Final Argument, p. 4.

5 BCOAPO Final Argument, pp. 7-9.

6 BCOAPO Final Argument, pp. 13-14.

7 Evidence of Mr. Chernikhowsky, Transcript, pp. 34; Evidence of Mr. Wayne Bryce, Transcript, pp. 51-54; Exhibit B-10, BCUC IR 2.36.1.

8 Exhibit B-2, BCUC IR 1.3.1.

9 BCOAPO Final Argument, p. 3.

B. Threshold of 30 Percent of SMYS Reflects CSA Z662 and Industry Practice

5. Contrary to the BCOAPO's statements on page 4 of its submission, there is no "expert disagreement as to whether the use of less than 30 percent of SMYS is adequate mitigation to protect against rupture."[10] FEI's responses to BCUC IR 2.37.1 through 2.37.4, as cited by the BCOAPO, confirm that it is generally accepted in the industry that the rupture threat associated with external corrosion is appropriately mitigated if a pipeline is operating below 30 percent of SMYS and that FEI's adoption of this threshold is consistent with CSA Z662.[11] FEI addressed this matter in detail on pages 10-12 and 33-34 of its Final Submission.

C. The Timing of the Project Reflects Continual Improvement of Technology and Industry Practice

6. BCOAPO's submission that FEI should have undertaken the Project sooner[12] is without merit, and overlooks the impact of advancements in technology and industry practice. As explained by Mr. Chernikhowsky at the workshop, the Project is a good example of continual improvement that results from the evolution in integrity management practices in the industry.[13] FEI's integrity management practices for different sizes of pipelines has evolved with improvements in technology and industry standard practice.[14] Thus, while the phenomena of external corrosion and of CP shielding were known many years ago, technology and industry practice has evolved such that in-line inspection has become available for FEI's smaller diameter transmission pressure lines, and industry standard practice to mitigate the hazard of external corrosion on these sizes of pipe has also evolved accordingly. Technology and practices improve over time, such that what at first may be considered novel can become standard practice and the expectation of regulators. As such, FEI reasonably identified the need for the Project to mitigate the potential for rupture failure of the 29 transmission laterals

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[10] BCOAPO Final Argument, p. 4.

[11] Exhibit B-10, BCUC IR 2.37.1.

[12] BCOAPO Intervener Final Argument, pp. 7-9.

[13] Transcript, pp. 16-17.

[14] Transcript, pp. 16-17.

due to corrosion in August 2015.[15] Having identified the need, FEI has proceeded with the planning of the Project and has proposed to complete the Project over five years, by 2024.[16]

D. Further Integrity Digs Would not Aid with Risk Prioritization of the Work

7. BCOAPO's suggestion that FEI could have undertaken random integrity digs to prioritize work on the Project[17] is incorrect. Information from an integrity dig at one location cannot be used to predict the occurrence or pinpoint the location of corrosion at any other location.[18] Because external corrosion and CP shielding can occur randomly anywhere on a pipeline,[19] there is no sufficiently large sample size of integrity digs that would give assurance that corrosion is not occurring in places that have not been dug up and visually inspected. As Mr. Chernikhowsky explained, FEI would have to dig up the entire pipeline and visually inspect it in order to assess the level of corrosion on a pipeline as a whole.[20] The cost of digging up all of the 29 transmission laterals would cost more than the Project itself.

8. Further, FEI plans to proceed with the work as quickly as reasonably possible over a five-year period. Given the timeframe over which FEI already plans to implement the Project, there is no opportunity for improvement from a safety or reliability perspective by prioritizing the laterals differently than currently planned.[21] To the contrary, delaying the Project to conduct further integrity digs or prioritization work would only serve to increase safety and reliability risks by delaying the benefits of the Project.

PART THREE: REPLY TO CEC

9. The CEC recommends that the BCUC approve the Project, but suggests that the BCUC consider a conditional approval and suggests there may be benefit in examining a "staged

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[15] Exhibit B-19, BCOAPO IR 1.1.1; Exhibit B-5, CEC IR 1.3.6.

[16] Exhibit B-1, pp. 73-74.

[17] BCOAPO Intervener Final Argument, pp. 13-14.

[18] Evidence of Mr. Chernikhowsky, Transcript, pp. 34; Evidence of Mr. Bryce, Transcript, pp. 51-54; Exhibit B-10, BCUC IR 2.36.1.

[19] Evidence of Mr. Chernikhowsky, Transcript p. 13; Evidence of Mr. Balmer, Transcript, p. 48; Evidence of Mr. Bryce, Transcript p. 51.

[20] Transcript p. 13.

[21] Exhibit B-2, BCUC IR 1.3.1.

option."[22] A conditional approval or a staged option would only serve to delay the benefits of the Project, leaving the identified risk of rupture unaddressed, which is contrary to FEI's obligations under CSA Z662 and standard practice in the industry. FEI responds in detail to the CEC's arguments below.[23]

A. Risk and Urgency of the Project is Manifest and Compelling

10. FEI has provided extensive evidence demonstrating that the Project is needed to proactively mitigate the risk of rupture of the 29 transmission laterals. The CEC agrees, stating:

> The CEC is of the view that FEI's proposal to upgrade the 29 transmission laterals to necessary safety standards is in the public interest, and recommends approval by the Commission.[24]
>
> The CEC acknowledges that FEI has provided significant qualitative evidence as to the need for remedial measures with regard to the issue of corrosion and potential for rupture[25]
>
> The CEC accepts that the IGU Project, or some version thereof, is necessary to maintain compliance with legal and regulatory obligations.[26]
>
> The CEC notes the OGC's support of FEI taking action to address its known integrity concerns.[27]
>
> The CEC also accepts that a QRA would likely not have made any change to the overall need for a Project to mitigate the risks of rupture and to be compliant with regulations and industry best practices.[28]
>
> The CEC would not support a project deferral that could unreasonably increase the risk of significant negative consequences which jeopardize the safety or well-being of any community or individual, create irreversible harm to the environment, or result in customer service disruptions or widespread outages.[29]

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[22] CEC Final Submissions, p. 1.

[23] In response to paragraph 47 of the CEC's Final Submission, corrosion (generally) is the leading cause of pipeline failure. See Exhibit B-1, p. 18.

[24] CEC Final Submissions, p. 1.

[25] CEC Final Submissions, p. 1.

[26] CEC Final Submissions, p. 33.

[27] CEC Final Submissions, p. 10.

[28] CEC Final Submissions, p. 10.

[29] CEC Final Submissions, p. 2.

> The CEC would also not support a deferral which resulted in FEI failing to meet regulatory standards and best practices in a timely manner.[30]

11. Given the statements above, the CEC should support FEI's plan to address the identified risk of rupture in a timely manner over a five-year period. Indeed, the CEC states: "CEC submits that there is not sufficient evidence in the proceeding to suggest that FEI has unacceptably brought forward a Project that could be safely deferred, or even staged".[31] FEI understands the CEC to be saying that there is sufficient evidence to conclude that FEI has brought forward a project that cannot be safely deferred or even staged.

12. In apparent contradiction to the above, however, the CEC also asserts that it "does not find the documentation of risk and urgency of the Project to be compelling",[32] saying that it has not identified evidence as to when the 29 transmission laterals "may become unsafe".[33] The binary distinction between "safe" and "unsafe" is not helpful in this context. While FEI employs integrity management practices today to manage external corrosion on the 29 transmission laterals, FEI has identified the risk of rupture due to external corrosion that cannot be detected due to CP shielding. As a prudent operator, FEI's must proactively address the identified risk as soon as practicable in accordance with regulatory requirements and industry standard practice.[34] Therefore, CEC's recommendations to delay the Project should be rejected.

B. Additional Work to Quantify Risk and Prioritize Activities would Increase Costs with No Benefits

13. The CEC's apparent position is that additional work to quantify risk and prioritize activities could potentially "ensure that the project is undertaken in the most cost-effective manner possible".[35] There is, however, no reasonable basis to conclude that further work could increase the cost-effectiveness of the Project. FEI responds to the various comments of the CEC on this matter below.

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[30] CEC Final Submissions, p. 33.

[31] CEC Final Submissions, p. 19.

[32] CEC Final Submissions, p. 10.

[33] CEC Final Submissions, p. 2.

[34] FEI Final Submissions, Part Two.

[35] CEC Final Submissions, p. 33.

(a) A Quantitative Risk Assessment Identifies Risks, Not Cost Savings

14. The CEC's suggestions that a quantitative risk assessment could reduce the construction costs of the Project[36] or "reduce uncertainty and potentially reduce cost impacts to ratepayers"[37] misunderstands the purpose and use of a quantitative risk assessment. A quantitative risk assessment can help prioritize complex work that could not otherwise be addressed at the same time or identify otherwise unknown risk, but cannot relieve FEI of the need to mitigate known risks or comply with regulations and industry standard practice.[38] As explained by JANA, "QRA outputs provide insight into further opportunities for risk reduction".[39] Furthermore, a quantitative risk assessment would take resources and time, which would add costs to the Project.[40] Therefore, a quantitative risk assessment could only increase costs of the Project.

15. The CEC incorrectly implies that the uncertainty in the condition data on the pipelines leads to greater uncertainty and therefore more contingency and cost. In the context of its argument on contingency, the CEC attributes the following to FEI:[41]

> FEI states that the low-quality, less-granular data available for the 29 laterals results in assumptions being made during the risk estimation, which is reflected in larger uncertainty or error bounds around the estimated failure rates.

16. The CEC takes this from page 20, paragraph 55 of FEI's Final Submission, which is a discussion of why a quantitative risk assessment is not required for the Project. FEI was referring here to the low quality of data for a quantitative risk assessment, which means that the outputs of the quantitative risk assessment would have large uncertainty bounds. This discussion is unrelated to the cost estimate of the Project and has no bearing on the contingency.

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36 CEC Final Submissions, p. 5.

37 CEC Final Submissions, p. 12.

38 Evidence of Mr. Chernikhowsky, Transcript pp. 13-16.

39 Exhibit B-10, Attachment 36.1, *Integrating QRA Outputs into Pipeline Integrity Management Decision-Making,* p. 3.

40 Exhibit B-10, BCUC IR 2.36.4.

41 CEC Final Submissions, p. 14.

17. Based on the above confusion, CEC claims that

> improving the quality of data available as to the condition of some laterals may be representative of the condition of the remainder of the 29 laterals. This information could reduce risk and reduce the amount required for contingency.[42]

18. This is incorrect. First, as noted above, corrosion and CP shielding can occur randomly over the length of a pipeline, and it is not possible to infer the condition of one lateral from the condition of another.[43] Second, the project contingency was influenced primarily by the number of restrictive bends that might be encountered,[44] not the condition of the laterals. The number of restrictive bends can only be discovered by inspecting the inside of the pipelines, and therefore further condition information cannot be used to reduce uncertainty. Third, reducing uncertainty and contingency can at most improve the accuracy of the estimate, not reduce actual project costs. For example, knowing the number of restrictive bends would increase certainty of the estimated costs to retrofit the pipelines to be capable of in-line inspection, but would not change the actual costs to retrofit those pipelines.

(b) Alleged Benefits of Information in Early Years of Project are Purely Speculative

19. CEC submits that the alternatives analysis was "potentially lacking" in that it focused "only on the technological response to the issue rather than potentially examining all options available, such as deferrals or a stage approach."[45] FEI's alternatives analysis in fact examined all the options available; no alternative was identified during the proceeding that FEI did not consider. Deferrals and staged approaches are not alternatives for the Project, but ways of implementing (or delaying) a particular alternative. FEI is proposing to implement the Project over 5 years, which reasonably stages the work on the 29 transmission laterals. There is no reasonable basis for deferring the Project or implementing a more staged approach than what FEI has already planned.

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42 CEC Final Submissions, p. 14.

43 Evidence of Mr. Chernikhowsky, Transcript p. 13; Evidence of Mr. Balmer, Transcript, p. 48; Evidence of Mr. Bryce, Transcript p. 51.

44 Exhibit B-1, p. 69.

45 CEC Final Submissions, p. 15.

20. The CEC claims that information gathered on laterals completed in year 1 "may possibly be extrapolated to provide the basis for a quantitative risk assessment of the remainder of the laterals."[46] This is not possible. Mr. Chernikhowsky explained at length at the workshop why information from the in-line inspection on other pipelines cannot be used to infer where corrosion is occurring on the 29 transmission laterals.[47] As stated by Mr. Chernikhowsky, "corrosion caused by CP shielding on one pipe tells us nothing about where it could be occurring in another pipeline."[48]

21. The CEC also speculates "that an understanding of the corrosion patterns could assist in providing comfort as to the appropriateness of treating all laterals as being equally risky."[49] There is no evidence that corrosion occurs in "patterns", let alone that such patterns could be used to assess the risks to the laterals. To the contrary, FEI's engineering team and external experts have provided evidence that, due to the many factors at play, corrosion can occur randomly anywhere on a pipeline, and corrosion on one pipeline cannot be used to predict where corrosion may be occurring on another pipeline.[50]

22. The CEC's suggestion that information from year one or two of the Project could be used to "evaluate the need for the rest of the Project to proceed" is also incorrect.[51] The CEC appears to be operating under the mistaken assumption that information on pipelines in the early years can be used to evaluate the conditions of the other pipelines, or somehow lead FEI to a revaluation of the risk. This is not the case. The need for the Project is based on the identified risk of rupture due to external corrosion where there is CP shielding, which cannot be detected by FEI's current management of these pipeline. This risk cannot change based on any condition assessment of the laterals. Therefore, FEI should proceed with the Project as soon as practicable to mitigate the identified risk.

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46 CEC Final Submissions, p. 13.

47 Transcript, p. 33 and 34, as quoted on page 9 of FEI's Final Submission

48 Transcript, p. 33 and 34.

49 CEC Final Submissions, p. 19.

50 Evidence of Mr. Chernikhowsky, Transcript p. 13; Evidence of Mr. Balmer, Transcript, p. 48; Evidence of Mr. Bryce, Transcript p. 51.

51 CEC Final Submissions, p. 14.

(c) It is not Reasonable to Conduct a QRA to Provide "Additional Comfort"

23. The CEC states that a quantitative risk assessment prior to the implementation of the Project "could have been worthwhile and potentially offered quantitative support for a decision to proceed in a different manner" and "additional comfort to the Commission for Project justification".[52] FEI has explained at length why a quantitative risk assessment would not change the need for the Project. The CEC has accepted this evidence, stating:

> The CEC also accepts that a QRA would likely not have made any change to the overall need for a Project to mitigate the risks of rupture and to be compliant with regulations and industry best practices.[53]

24. Therefore, incurring the cost and time of a quantitative risk assessment to provide "quantitative support" or "additional comfort" is not necessary, and would only delay the benefits of the Project.

(d) Further Quantification Would Not Change Timing or Scheduling of Work

25. In reply to comments of the CEC regarding prioritization of the work, FEI has planned and scheduled the Project in a cost effective manner. FEI developed the detailed schedule for the Project based on factors such as the regional distribution of the Project, capacity limitations including industrial customers' requirements, scheduling constraints (such as windows of time where work can be undertaken on the laterals), cost efficiencies by managing as a single project, operational constraints (such as working on an in-service line), and contractor and resource limitations.[54] FEI has been clear that there could be no improvement from a safety or reliability perspective by prioritizing the laterals differently than currently planned.[55]

26. JANA has confirmed that a quantitative risk assessment could not materially change the timing or scheduling of the Project.[56] A quantitative risk assessment cannot take away the risk that FEI has identified, or relieve FEI of its obligations under CSA Z662 or the need as a prudent

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52 CEC Final Submissions, p. 10.

53 CEC Final Submission, p. 10.

54 Exhibit B-10, BCUC IR 1.3.1.

55 Exhibit B-10, BCUC IR 1.3.1.

56 Exhibit B-10, BCUC IR 2.36.1.

operator to maintain industry standard practices.[57] Further, a quantitative risk assessment is only as good as the data on which it is based. Without data from in-line inspection, a quantitative risk assessment of the 29 transmission laterals would not provide granular enough results to change the prioritization of the work. Both FEI's team and independent third-party experts in quantitative risk assessment have confirmed this.[58] The CEC offers no evidence or line of reasoning to refute the expert opinions offered by FEI and JANA.

(e) Delaying the Project for Development of Robotic Technologies is Not Reasonable

27. The CEC speculates, without evidentiary support, that robotic technologies may potentially become proven and commercialized over the next few years.[59] FEI cannot prudently delay a project that is needed to mitigate an identified risk of rupture in the hopes that future technology may become proven and commercialized. FEI stated that if it identified a commercially feasible and industry accepted alternative during implementation of the Project, then it would evaluate the alternative and advise the BCUC of the results of any change.[60] The CEC agrees this approach is reasonable, saying: "FEI's approach to monitoring the status of robotic tools during the implementation of the Project is reasonable to the extent that the Project is approved and commences as planned in the Application."[61] Therefore, there is no need for any conditional approval or staged approach to wait for robotic technology to mature. Indeed, FEI submits that delaying the Project to wait for a technological development that may or may not occur would be imprudent.

C. Conditional Approval or Staged Approach Would Result in an Unacceptable Delay to the Project

28. Any conditional approval or staged approach to the Project would result in unacceptable delay to the Project, as it would delay FEI's timely action to comply with its regulatory obligations and adopt industry standard practices.

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57 Exhibit B-10, BCUC IR 2.36.1.

58 Exhibit B-10, BCUC IR 2.36.1.

59 CEC Final Submissions, p. 14.

60 Exhibit B-5, CEC IR 1.21.1.5.

61 CEC Final Submissions, p. 30.

(a) There is no safe period over which the Project can be Delayed

29. The CEC states that the Project is necessary due to safety standards, and states that it would not support a project deferral "that could unreasonably increase the risk of significant negative consequences…"[62] FEI has proposed the Project to proactively address the potential for rupture of the 29 transmission laterals which can have significant consequences. FEI's customers, employees and the public would be exposed to increased risk due to any deferral of the Project. Until the Project is completed, there will continue to be the potential for significant regulatory, safety, reliability and environmental consequences in the event of a pipeline rupture due to external corrosion.[63] As the Project cannot be safely deferred, the CEC's suggested conditional approval is unacceptable and should be rejected.

(b) Delay would Prevent FEI from Complying with Regulation and Adopting Industry Standard Practice in a Timely Manner

30. The CEC accepts that the Project, or some version thereof, is necessary to maintain compliance with legal and regulatory obligations, and states that it would "not support a deferral which resulted in FEI failing to meet regulatory standards and best practices in a timely manner."[64] Again, based on the CEC's own submissions, any delay to the Project is unacceptable. Taking into account FEI's obligations under CSA Z662, FEI's planned 5-year implementation timeline for the Project is a reasonable period over which to proactively mitigate the potential for rupture of the 29 transmission laterals. Taking into account all the information available, and its legal and regulatory obligations, 5 years is a reasonable time-frame over which to execute the Project.[65] The Project is necessary to maintain compliance with FEI's legal and regulatory obligations and, as such, the Project cannot be safely deferred.[66]

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62 CEC Final Submissions, p. 33.

63 Exhibit B-20, CEC IR 3.45.5.

64 CEC Final Submission, p. 33.

65 Exhibit B-2, BCUC IR 1.3.1.

66 Exhibit B-13, CEC IR 2.40.1.

D. Using Pressure Regulating Stations Where it Would Reduce Service to Customers is Unreasonable

31. FEI has fully analyzed the feasibility of undertaking a pressure regulating station ("PRS") for each lateral. As explained in the Application, PRS was not viable for some laterals due to capacity limitations of some systems.[67] By reducing the operating pressure of the pipeline, the capacity available to customers will change. For some laterals, the PRS would cause a reduction in capacity and would result in a year-round requirement for more frequent curtailment of customer loads, such that FEI not would not be providing a reasonable level of reliable service. In some instances, a PRS would mean FEI could not meet supply needs for forecasted growth in the region served by those laterals. In those instances, PRS could not be undertaken without also requiring a pipeline expansion to restore capacity on that lateral as it could no longer handle expected customer loads.[68]

32. FEI provided a detailed discussion of its methodology and calculations for determining the impacts of PRS for each of the laterals,[69] and analysis of potential days of curtailment of customers.[70] Two systems, the Salmon Arm system and the Cranbrook Lateral 168 and Loop 219 in the Cranbrook Kimberly system, could not meet the current and forecasted firm demand on the system if a PRS was installed. Consequently, a PRS installation would not allow FEI to meet its firm demand obligations within the forecast period.[71] The impacts to interruptible customers on the remaining systems are discussed in detail in the response to CEC IR 2.37.6.2. FEI summarized the impacts to interruptible customers on the four systems where PRS is not feasible as follows.

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67 Exhibit B-1, p. 39.

68 Exhibit B-5, CEC IR 1.23.3.

69 Exhibit B-2, BCUC IR 1.14.1, 14.2 and 14.3.

70 Exhibit B-13, CEC IR 2.37.6.2.

71 Exhibit B-13, CEC IR 2.37.6.

Customer Impacts on Systems Where PRS is not Feasible[72]

Lateral System	Line/loop Fill Name	Customers Impacted	Impacts
MacKenzie System	Mackenzie Lateral 168 Mackenzie Loop 168	2 Large Industrial Interruptible Customers	With PRS on the Mackenzie System, two large industrial operations on the system could be required to manage to less than half of their combined maximum observed consumption regardless of the pressure available at the lateral tap. A PRS would require these customers to significantly adjust the way they use natural gas currently in their business practices. They would move from periodic winter time curtailment to regular year round load management.
Prince George 1 System	Prince George 1 Lateral 168	5 Large Industrial Interruptible Customers	With PRS on the Prince George 1 System at the start of the Prince George 1 Lateral 168, five large industrial operations in the system would be required to manage to less than 17% of their combined maximum observed consumption regardless of the pressure available at the lateral tap. While these customers currently require some degree of load management, a PRS would remove access to a large amount of capacity currently available that these customers regularly consume. A PRS would require these customers to significantly adjust the way they use natural gas currently in their business practices. They would move from periodic curtailment when tap pressures provided lower capacity than their combined requirements to significant regular year round load management below their typical current combined consumption.
Kamloops 1 System	Kamloops 1 Lateral 168 Kamloops 1 Loop 168	2 Large Industrial Interruptible Customers	With PRS on the Kamloops 1 System, two large industrial operations in the system could be required to manage to less than their current maximum observed consumption regardless of the pressure available at the lateral tap. A PRS would require these customers to adjust the way they use natural gas currently in their business practices. A PRS would limit the ability to attract other new Interruptible customers to the Kamloops system.
Fording System	Fording Lateral 219 Fording Lateral 168	4 Large Industrial Interruptible Customers	With PRS on the Fording System at the start of the Fording Lateral 219, four large industrial mining facilities in the system would be required to manage to less than 17% of their current maximum capacity limits regardless of the pressure available at the lateral tap. While these customers currently require some degree of load management, a PRS would remove access to a large amount of capacity currently available that these customers regularly consume. A PRS would require these customers

[72] Exhibit B-5, CEC IR 1.23.1.

Lateral System	Line/loop Fill Name	Customers Impacted	Impacts
	Cranbrook Loop 219		to significantly adjust the way they use natural gas currently in their business practices. They would move from periodic curtailment when tap pressures provided lower capacity than their combined requirements to significant regular year round load management below their typical current combined consumption.
Cranbrook Kimberley System	Cranbrook Kimberley Loop 273	1 Large Industrial Interruptible Customer	With a PRS on the Cranbrook Kimberly System at the tap location of the Cranbrook Kimberley Loop 273 one large industrial customer at the tail end of the lateral system could be required to manage to less than 70% of their current maximum observed consumption regardless of the supply pressure available at the TransCanada tap serving the lateral system. A PRS would require this customer to adjust the way they use natural gas currently in their business practices.
Cranbrook Kimberley System	Cranbrook Kimberley Loop 219 Kimberley Lateral 168	1 Large Industrial Interruptible Customer	With a PRS on the Cranbrook Kimberly System at the start of the Kimberley Lateral 168 and the Cranbrook Kimberley Loop 219, one large industrial customer at the tail end of the lateral system could be required to manage to less than 57% of their current maximum observed consumption regardless of the supply pressure available at the Transcanada tap serving the lateral system. A PRS would require this customer to adjust the way they use natural gas currently in their business practices.
Cranbrook Kimberley System	Skookumchuck Lateral 219	1 Large Industrial Interruptible Customer	With a PRS on the Cranbrook Kimberly System at the tap location of the Skookumchuck lateral, one large industrial customer at the tail end of the lateral system could be required to manage to less than 90% of their current maximum observed consumption regardless of the supply pressure available at the Transcanada tap serving the lateral system. A PRS would require this customer to adjust the way they use natural gas currently in their business practices.

33. The CEC's suggestion that FEI use a PRS where it would prevent a reasonable level of service to customers is short-sighted and a case of cutting off your nose to spite your face. The purpose of these laterals is to serve customers, and integrity management is about ensuring that this service to customers continues to be safe and reliable. Choosing integrity management solutions that prevent FEI from serving its customers undermines the purpose of the pipelines, and denies customers the benefits of natural gas to serve their needs. Furthermore, if FEI installs a PRS such that it cannot provide interruptible customers with

reasonable service, the customers can elect firm service, triggering more expensive upgrades to serve their needs as FEI would not be able to interrupt their service at all. Alternatively, the interruptible customers could cease to be customers, reducing revenue to the detriment of all customers and making the investment in the existing lateral and integrity management solution less economical.[73] Finally, installing a PRS in these cases would prevent FEI from adding further customers without further upgrades to the system, potentially denying the benefits of natural gas service to others and reducing the potential benefits of increased revenue and consequently lower rates for all customers. In short, choosing PRS for laterals where it would prevent FEI from serving its customers is not a reasonable solution as it would undermine the purpose of the laterals and could trigger even greater costs. The CEC's suggestion must be rejected.

PART FOUR: CONCLUSION

34. The need for FEI to proceed with the Project as planned is clear and compelling. FEI has identified a risk of rupture of the 29 transmission laterals due to external corrosion which is undetectable where there is CP shielding. FEI must proceed in a timely manner to comply with its regulatory obligations to mitigate this hazard and, as a prudent operator, must adopt industry standard approaches to managing the risk. Therefore, 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 24, 2019

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

73 Exhibit B-5, CEC IR 1.23.3.