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August 8, 2019

Sent via email/eFile

FEI CPCN FOR INLAND GAS UPGRADE PROJECT
EXHIBIT A-14

Mr. Doug Slater
Director, Regulatory Affairs
FortisBC Energy Inc.
16705 Fraser Highway
Surrey, BC V4N 0E8
doug.slater@fortisbc.com.
gas.regulatory.affairs@fortisbc.com

Re: FortisBC Energy Inc. – Certificate of Public Convenience and Necessity Application for the Inland Gas Upgrade Project – Project No. 1598988 – Information Request No. 3

Dear Mr. Slater:

Further to your December 17, 2018 application of the above noted matter, enclosed please find British Columbia Utilities Commission Information Request No. 3. Please file your responses by **Wednesday, September 4, 2019.**

Sincerely,

Original signed by:

Patrick Wruck
Commission Secretary

/aci
Enclosure

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

INFORMATION REQUEST NO. 3 TO FORTISBC ENERGY INC.

A. PROJECT NEED AND JUSTIFICATION

63.0 **Reference: PROJECT NEED AND JUSTIFICATION**
Exhibit B-2, British Columbia Utilities Commission (BCUC) 8.1.4, p. 75;
Exhibit B-1 (Application), Appendix E
Pipeline Rupture and Corrosion Imperfections

In response to BCUC 8.1.4, FortisBC Energy Inc (FEI) states:

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

Appendix E in the Application provides a description of FEI's in-line inspection (ILI) process. Data analysis performed by FEI on the ILI data include, among other things, "clustering of potentially interacting metal loss imperfections" and "estimation of a failure mode (i.e. leak or rupture) and failure pressure, if applicable, for reported imperfections."

63.1 Please provide the range of corrosion depths and defect lengths identified on FEI's system.

63.2 Please discuss FEI's method to determine the effective defect length of a clustering of potentially interacting metal loss imperfections.

63.3 Please discuss the relationship between failure pressure, failure mode (leak or rupture) and defect length and depth.

63.3.1 If possible, please provide graphs showing the relationship of failure pressure, the leak-rupture transition to defect length and depth. Please ensure the graphs cover the range of defect lengths and depths identified on FEI's system.

63.4 Please discuss FEI's method, including factors, assumptions and calculations to determine failure mode (leak or rupture) and failure pressure of a corroded pipeline.

63.5 Please provide details of any FEI assessment that required immediate pressure reduction to reduce the risk to personnel, the public and the environment.

63.5.1 Please confirm, otherwise explain, whether pressure was reduced to or below 30 percent specified minimum yield strength (SMYS).

64.0 **Reference: PROJECT JUSTIFICATION**
Transcript Volume 1 (V-1), Workshop/Procedural Conference, pp. 38–39
Risk Assessment

On page 38 of the Workshop/Procedural Conference transcript, Mr. Chernikhowsky states:

> So again, some form of risk assessment is always needed to determine the drivers for a project. And historically we've typically described those as being qualitative in nature. Based, again, on judgement. We don't necessarily numerically define probability or consequences. But we determine whether they're -- if you want to use the terminology low, medium, high, of that nature. And so, it's that type of determination that we use to whether the IGU project is necessarily (sic) or not. The need to conduct a quantitative risk assessment in a very fine grained manner, prioritize how quickly or where the work needs to happen, that was not necessary in the case of the IGU project.

64.1 Please provide the risk assessment (high, medium, low), if any, for each of the 29 laterals that FEI used to determine whether the Inland Gas Upgrade (IGU) project is necessary. If no such risk assessment was done, please explain why not and please reconcile this response with the above extract from the transcript.

65.0 **Reference: PROJECT JUSTIFICATION**
Transcript V-1, Workshop/Procedural Conference, pp. 11–13
Consequence of Pipeline Rupture

On pages 11 of the Procedural Conference Transcript V-1, Mr. Chernikhowsky states:

> In the case of the Kelowna 1 Loop, that PIR, potential impact radius, works out to about 140 feet, and would encompass much of one of the buildings in that complex. As mentioned, individuals within this radius would expect serious injuries or worse. …

Further, on page 13 of the transcript, Mr. Chernikhowsky states:

> …we are proposing a small, pressure reducing station upstream of the pipeline, and this will effectively mitigate the risk of a rupture by reducing the operating pressure below the point where a rupture could occur.

65.1 Please provide the potential impact radius at 30 percent SMYS and explain whether it would encompass any part of the building complex.

65.2 Please confirm, otherwise explain, that it is possible for rupture to occur at or below 30 percent SMYS.

66.0 **Reference: PROJECT JUSTIFICATION**
Exhibit B-17, Clarification of Procedural Conference Transcript, pp. 1–3
Quantitative Risk Assessment (QRA)

On page 1 of Exhibit B-17, FEI states:

> FEI wishes to confirm that it is developing and implementing a segment-by-segment risk assessment process to determine the risk associated with all of FEI's BC OGC-regulated pipeline assets, including the 18 laterals that FEI proposes to install pressure regulating stations or replace such that they operate below 30 percent SMYS. In this regard, FEI is attaching FEI's latest quarterly report to the BC OGC on FEI's risk assessment process implementation.

On page 3 of the same exhibit, FEI provides a letter written to the BC Oil and Gas Commission (OGC) dated July 12, 2019. The second paragraph of that letter reads:

> …FEI's first iteration of the Quantitative Risk Assessment will apply to lines with in-line inspection data. This first iterations [sic] will assist in establishing the priority and urgency of upgrades to FEI's transmission mainlines for enabling in-line inspection with crack-detection (EMAT) tools. FEI will use its experience with the first iteration of the Quantitative Risk Assessment to identify and evaluate process improvements prior to undertaking further iterations that will be expanded to include FEI's other pipeline assets (i.e. BC OGC-regulated pipelines not currently subject to in-line inspection). Preliminary results have been presented by JANA to FEI in Q2 2019.

66.1 Please confirm, otherwise explain, that the statement in the preamble means that all laterals in the IGU Project will be included in the QRA being prepared by JANA Corporation.

66.2 Please state when the "first iteration" of the QRA will be complete, and when the "second iteration" of the QRA will be complete.

66.2.1 Please clarify which of the 29 laterals in the IGU Project will be included in the first iteration of the QRA, and which of the 29 laterals will be included in the second iteration of the QRA.

66.3 Please provide the "preliminary results" of the QRA that JANA provided to FEI in Q2 2019.

66.4 Please confirm, otherwise explain, that FEI intends to file the completed QRA with the BCUC.

66.5 Would a QRA potentially direct a different rupture mitigation action than what is currently being proposed for any of the 14 Transmission Laterals where Pressure Regulating Station (PRS) is proposed?

67.0 **Reference: PROJECT JUSTIFICATION**
Transcript V-1, Workshop/Procedural Conference, p. 79
BC OGC Written Confirmation

On page 79 of the Procedural Conference Transcript V-1:

> THE CHAIRPERSON: Has FEI obtained any kind of confirmation from the B.C. Oil and Gas Commission that this is an appropriate way to deal with the 18 [laterals]? And that they are happy with what you are proposing?
> MR. CHERNIKHOWSKY: Yes, so I can confirm that I met with the B.C. Oil and Gas Commission and presented to them June 20 – subject to check.
> THE CHAIRPERSON: A week ago perhaps.
> MR. CHERNIKHOWSKY: Several weeks ago, and presented to the Oil and Gas Commission the proposed IGU project. Described to them the drivers for the project, and the proposed solutions, and they were supportive of it.

67.1 Please provide written confirmation from the BC OGC in support of the IGU Project.

68.0 **Reference: PROJECT JUSTIFICATION**
Transcript V-1, Workshop/Procedural Conference, p. 59
Modified External Corrosion Direct Assessment (ECDA) Integrity Digs

On page 59 of the Procedural Conference Transcript V-1:

> MS. SIMON: Thank you. You indicated that you've completed ECDA for the 29 laterals, is that correct?

MR. BALMER: So we either have or we're in the process of implementing ECDA, so that our methodology. We've conducted above ground surveys. We have not performed digs on all the lines. I don't know if that's clear on not.
MS. SIMON: Yeah, that's helpful. So then my follow on question, in the presentation you provided a picture of corrosion found on one of the laterals.
MR. BALMER: That's correct.
MS. SIMON: That's correct? Okay. Have – the above ground part of the ECDA, have you identified other areas of external corrosion and have you investigated those?
MR. BALMER: So we've identified a number of areas where the coating and cathodic protection surveys indicate corrosion. We also have other areas that are planned to be inspected with digs that have not been completed. So we're in – it's an ongoing integrity process and it's at various stages of completion for various pipelines.

68.1 Please provide the results of any ECDA-driven digs performed this year and whether any of those digs relate to the 29 laterals in the IGU Project.

68.2 Please provide the timeline for the implementation of any planned ECDA-driven digs that have not been completed, and whether any of those planned digs relate to the 29 laterals in the IGU Project.

69.0 **Reference:** **PROJECT JUSTIFICATION**
Transcript V-1, Workshop/Procedural Conference, p. 61, 77.
Exhibit B-4, Section 2.1, p.12; FEI-City of Kelowna Operating Agreement, p. 2,3.
Distribution Pipeline definition

On page 61 of the Procedural Conference Transcript V-1:

MR. BALMER: Right. Exactly. So – and so we adopted – the Z662 is the standard that governs pipeline design and operation in Canada and that standard has a threshold between a gas distribution system, our pipelines that are operating at less than 30 percent SMYS or in this case we're reducing to below 30, 29.9 or lower, and it is based on studies. We did submit some references towards that. But really that's the – an industry accepted threshold for the likelihood to fall, I'll say to a level that warrants operation as a gas distribution system versus a transmission pipeline. So different levels of risk mitigation.

Further, on page 77 of the Procedural Conference Transcript V-1:

MR. BALMER: So when I used that term "gas distribution system", that's a term that's used in the Canadian Standards Association, Z662 standard. And the definition for that is a pipeline operating below 30 percent SMYS. So it's a term that's used in that standard for a pipeline that has lower risk and that will fail by leak instead of rupture.

In its response to BCOAPO IR 1.2.1, FEI provides the Canadian Standards Association (CSA) Z662-15 definition of "a 'Distribution system, gas' as 'the main and service lines, and their associated control devices, through which gas is conveyed from transmission lines or from local sources of supply to the termination of the operating company installation…' "

Further in the same IR, FEI provides the CSA Z662-15 definition of "a 'Line, transmission' as 'a pipeline in a gas transmission system that conveys gas from a gathering line, treatment plant, storage facility, or field collection point in a gas field to a distribution line, service line, storage facility, or another transmission line' ". FEI states that that definition is relevant to this application since "This Application comprises laterals considered as part of FEI's transmission pipeline system."

Regarding Clause 12 Gas Distribution Systems, CSA Z662-19 provides a commentary that the application of Clause 12 should consider pipe dimension, pipe grade and intended operating pressure.

Within the terms of FEI Operating Agreements with interior municipalities (for example, FEI-City of Kelowna Operating Agreement approved by BCUC order G-99-19), a Distribution Pipeline "means pipelines operating at a pressure less than 2071 kilopascals (300 psi)" and a Transmission Pipeline "means a pipeline of FortisBC having an operating pressure in excess of 2071 kilopascals (300 psi)."

69.1 Please clarify how FEI determines whether an asset shall be considered a "Transmission Line" or a "Distribution Line".

69.1.1 How does this determination impact the suitability of various integrity management strategies?

69.1.2 How will FEI's application of the CSA Z662-19 standard change after the implementation of PRS?

69.1.3 Are the definitions within the FEI Operating Agreement terms applicable to the FEI IGU Project or do some other definitions apply? If the latter, please specify.

70.0 **Reference: PROJECT JUSTIFICATION**
Exhibit B-16, p. 8; Transcript V-1, Workshop/Procedural Conference, pp. 13, 14, 15; Exhibit B-10, Section 37.1, p. 22.
Suitability of PRS rupture mitigation option

On page 8 of Exhibit B-16, FEI states:

> The Quantitative Risk Assessment (QRA) under development is not necessary to justify the IGU Project. Compliance with industry standard practise, and codes and regulation are sufficient to support the need for the IGU project.

On page 13 of the Procedural Conference Transcript V-1, Mr. Chernikhowsky states:

> Now, to reiterate, we have no reliable way to detect where corrosion is occurring. In this case, we could dig up and expose the pipeline, all two kilometers of it, it would be very impactful to landowners in the area, and instead, we are proposing a small, pressure reducing station upstream of the pipeline, and this will effectively mitigate the risk of a rupture by reducing the operating pressure below the point where a rupture could occur.

Further, on page 14 of the same transcript, Mr. Chernikhowsky states:

> So, where does a QRA fit into this picture? So, fundamentally a QRA is used for two purposes; to prioritize complex work, and activities that could not otherwise be addressed all at the same time, or to identify otherwise unknown risk, which we call "interacting threats" that we might not otherwise have been aware of due to their complexity.

Further, on page 15 of the same transcript, Mr. Chernikhowsky states:

> And to put it another way, the BC OGC has directed FEI to conduct a segment-by-segment risk assessment to assure that we have not missed anything, not to allow us to defer addressing known risks.

In its response to BCUC IR 37.1, FEI states that "In very rare cases of selective seam weld corrosion in low-frequency electrical resistance welded seam welds or instances involving

outside forces, pipelines operating at less than 30 percent of SMYS may result in rupture failure."

70.1 With respect to the PRS mitigation option, is FEI aware of any additional applicable hazards which when compounded with potential corrosion make reduction to below 30 percent SMYS an ineffective mitigation action?

70.2 With respect to any pipe laterals installed prior to 1970, does operating at 30 percent SMYS or below reduce the risk to the same level regardless of pipe manufacturing standards at the time of installation or pipe welding standards at the time of installation?

70.3 Is FEI aware of any ruptures on any North American situated pipelines that were operating at or below 30 percent SMYS? If so, please specify.

B. DESCRIPTION AND EVALUATION OF ALTERNATIVES

71.0 **Reference: PROJECT ALTERNATIVES**
Exhibit B-1, Section 4.5.4, Table 4-10; Exhibit B-2, BCUC IR 8.2, Table 4
Table Consolidation

In Table 4-10, page 47 of the Application, FEI provides a present value of each of the three project alternatives.

In its response to BCUC IR 8.2, FEI provides Table 4, a summary of each lateral, including coating type, age and the percentage of Class 3 sections, and other information.

71.1 Please consolidate these two tables into a single table, with a row for each lateral, by completing the table below:

Lateral	ILI present value	PLR present value	PRS present value	Preferred Alternative	% Class 3	Year Installed	Pipe Coating Type	Line length

72.0 **Reference: PROJECT ALTERNATIVES**
Exhibit B-1, Section 5.1, Table 5-1; Exhibit B-2, BCUC IR 8.2, Table 4
PRS Alternative

In Table 5-1 of the Application, FEI provides the preferred alternative for each of the 29 laterals.

In its response to BCUC IR 8.2, FEI provides Table 4, listing the percentage of Class 3 sections of each of the 29 laterals.

To summarize, the laterals with Class 3 sections that are proposed for the PRS alternative are:

- Coldstream Lateral 219, 49 percent Class 3
- Coldstream Loop 168, 16 percent Class 3
- Kelowna 1 Loop 219, 33 percent Class 3
- Celgar Lateral 168, 4 percent Class 3
- Castlegar Nelson 168, 21 percent Class 3
- Elkview Lateral 168, 19 percent Class 3

72.1 Please explain, in detail, how FEI proposes to perform integrity management on the laterals chosen for PRS.

72.1.1 Please explain how FEI will monitor and assess the pipeline wall condition of the laterals chosen for PRS. In your answer, please include monitoring and assessment of corrosion.

72.2 Please explain how FEI considered the potential impact of a rupture to the public for each lateral when choosing its preferred alternative.

72.3 Please explain whether the consequences of a leak or rupture are increased in Class 3 areas.

73.0 **Reference: EVALUATION OF ALTERNATIVES**
Exhibit B-2, BCUC IR 24.1; Exhibit B-1-2, Evidentiary Update, Table 4-10, p. 47
PRS Alternative

In Table 4-10 on page 47 of the Evidentiary Update to the Application, FEI provides the following present value of incremental requirements analysis for each lateral and identifies the preferred alternative for each lateral:

Lateral	Length (kilometres)	ILI Present Value ($ millions)	PLR Present Value ($ millions)	PRS Present Value ($ millions)	Preferred Alternatives
Mackenzie Lateral 168	28.7	44.7	-	-	ILI
Mackenzie Loop 168	14.2	25.2	-	-	ILI
BC Forest Products Lateral 168	0.5	12.6	3.5	7.0	PLR
Prince George 3 Lateral 219	5.3	14.3	-	2.2	PRS
Northwood Pulp Lateral 168	6.0	15.4	-	2.2	PRS
Northwood Pulp Loop 219	5.8	14.1	-	2.2	PRS
Prince George #1 Ltl 168	4.7	14.4	-	-	ILI
Prince George Pulp Lateral 168	1.0	14.3	7.7	3.6	PRS
Husky Oil Lateral 168	1.1	16.4	5.6	3.6	PRS
Prince George #2 Lateral 219	8.7	15.8	-	6.3	PRS
Cariboo Pulp Lateral 168	1.3	10.5	5.5	6.5	PLR
Williams Lake Loop 168	5.9	15.7	-	6.0	PRS
Kamloops 1 Lateral & Loop 168	6.6	32.1	15.8	-	PLR
Salmon Arm Loop 168	44.9	32.6	-	-	ILI
Salmon Arm 3 Lateral	0.9	10.5	4.2	6.6	PLR
Coldstream Lat 219	1.8	13.2	9.3	5.9	PRS
Coldstream Loop 168	3.8	14.2	-	6.0	PRS
Kelowna 1 Loop 219	2.1	14.0	-	6.9	PRS
Celgar Lateral 168	5.8	11.7	-	5.9	PRS
Castlegar Nelson 168	37.4	54.2	-	9.0	PRS
Trail Lateral 168	4.2	19.0	-	5.9	PRS
Fording Lateral 219/168	79.7	102.8	-	-	ILI
Elkview Lateral 168	1.6	10.1	5.9	5.9	PRS
Cranbrook Lateral 168	34.0	21.2	-	-	ILI
Cranbrook Loop 219	34.0	20.8	-	-	ILI
Cranbrook Kimberley Loop 219	4.0	9.4	-	-	ILI
Cranbrook Kimberley Loop 273	9.4	10.9	-	-	ILI
Kimberly Lateral 168	20.6	23.5	-	-	ILI
Skookumchuck Lateral 219	35.9	14.0	-	-	ILI

In response to BCUC IR 24.1, FEI provided a project risk ranking of the 29 Transmission Laterals and a detailed explanation for each ranking based on various risk areas. With regard to the Transmission Laterals where PRS is the chosen alternative, the risk was ranked as either moderate or low.

73.1 Please provide a revised response to BCUC IR 24.1 for each of the 29 Transmission Laterals, where the proposed alternative is PRS but under a hypothetical scenario where FEI instead selected the second alternative for each of those laterals (i.e. either ILI or PLR). Please provide both the revised tabular risk rankings and a detailed explanation for each revised ranking based on the risk areas identified in BCUC IR 24.1.

73.1.1 If FEI does not consider either the ILI or PLR alternatives feasible for any of the Transmission Laterals where PRS is the chosen alternative, please explain why in detail.

73.1.1.1 If PLR and ILI are not considered feasible, please explain how FEI would propose to address the risk of rupture failure due to corrosion on these laterals in the absence of PRS as an alternative.

74.0 **Reference: PROJECT ALTERNATIVES**
Exhibit B-1, Section 4.2.5, p. 31
ILI Alternative

In Section 4.2.5, on page 31 of the Application, FEI discusses ILI:

> ILI is highly regarded by operators as the data enables rehabilitation efforts to be focused on specific locations. ILI also enables proactive asset management by providing pipeline wall condition data (including changes over time) that can inform long-term asset planning.

74.1 Following conversion of laterals to ILI ready, please explain when FEI proposes to run ILI tools to determine pipeline condition and areas of corrosion.