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September 4, 2019

Commercial Energy Consumers Association of British Columbia
c/o Owen Bird Law Corporation
P.O. Box 49130
Three Bentall Centre
2900 – 595 Burrard Street
Vancouver, BC
V7X 1J5

Attention: Mr. Christopher P. Weafer

Dear Mr. Weafer:

Re: FortisBC Energy Inc. (FEI)

Project No. 1598988

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

Response to the Commercial Energy Consumers Association of British Columbia (CEC) Information Request (IR) No. 3

On December 17, 2018, FEI filed the Application referenced above. In accordance with British Columbia Utilities Commission Order G-153-19 setting out a further Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to CEC IR No. 3.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Doug Slater

Attachments

cc (email only): Commission Secretary
Registered Parties

44. Reference: Transcript #1 page 46-47 and page 48

MR. CHERNIKHOWSKY: First of all, I don’t think we are saying that it is exactly the same. What we're saying is it can be exactly the same, and the corrosion mechanism is independent of the age of the pipeline, whether it's 60-year old construction, it's 60-year old steel, or 20-year old construction and 20-year old steel. The mechanism of corrosion is the same. Fundamentally the steel is not really any different over the years. Yes, the construction methods may have changed, but the steel that actually composes the pipeline wall hasn’t. And so it is still appropriate to use that same assumption regardless of the age of the pipeline.

MR. BALMER: I'd say type of coating is a factor that is considered by industry, but as we've presented is that there are factors other than coating that can impact the presence of corrosion, such as rocks. And so the uncertainty is such that it's not sufficient indicator for us to rely on for future performance. And that is consistent with industry practice.

44.1 Please discuss the changes in construction methods over time and how they would impact the corrosion of the various laterals.

Response:

Changes in construction methods have occurred since the time of FEI's original transmission pipeline installations beginning in the 1950s to the present day, with potential impacts on corrosion. These changes include the following:

- Backfill materials: In early pipeline construction, fill materials sourced locally from the site of the pipeline were primarily used for backfill regardless of the fill type and quality. Backfill materials included all types of soils, as well as large rocks, construction debris, and organic material, all of which can impact pipeline coatings (e.g. through physical damage) and the application of cathodic protection (e.g. through cathodic protection shielding) to prevent active corrosion. Today, backfill is engineered for lifecycle integrity of the pipeline system, which may necessitate the use of non-locally sourced fill materials;
- Pipe Handling: In early pipeline construction, handling of pipe during installation was not monitored with the same level of inspection that it is today. Today, full time inspectors are utilized such that pipeline or coating damage is identified and repaired prior to backfill; and
- Quality Control Inspection: Inspection of pipeline installation has evolved from no inspection to full time inspection. Today, full time inspectors monitor and observe all aspects of construction from pipe transportation, handling, welding, laying, coating and backfilling.

The selected alternatives for the 29 Transmission Laterals can be used to manage external corrosion over the long-term regardless of the construction methods used. In-line inspection data enables targeted replacements or repairs on specific locations along a pipeline that may be experiencing active corrosion. The PRS and PLR alternatives both provide effective mitigation of rupture due to external corrosion by operating the pipeline at less than 30 percent of SMYS.

44.2 Please discuss the various coatings used over time, and how these impact the corrosion of the various laterals.

Response:

Coatings used in the pipeline industry have evolved over time in terms of application, performance and failure mechanism:

- Coal tar or asphalt enamel coatings, both factory applied and field applied, were common in early pipeline construction up to the mid-1960s. Coal tar and asphalt enamel coatings have had mixed performance in their long-term capability to mitigate active corrosion, with field-applied coatings tending to have a greater number of issues. Factors affecting the performance of these field-applied coatings include surface preparation, pipe temperature, material temperature, application technique (pouring vs. mopping), use of primer, use of reinforcing fibre mats, and backfill. Cold applied asphalt adhesive tapes were also used for field application on girth welds in the 1950s;

- In the mid-1960s, two-layer polyethylene factory-applied coatings became more common in the industry. While this factory-applied coating has generally demonstrated reasonable long-term performance, issues with field-coated girth welds on pipelines of this vintage have not been uncommon. Cold applied tapes with bitumen adhesive as well as synthetic butyl rubber adhesive became more prevalent and exclusively used as field applied girth weld coatings on two-layer polyethylene factory applied coatings;
- In the 1970s, cold-applied butyl rubber adhesive polymer backed tapes were increasingly used. Application of these tapes tended not to be closely monitored and primers to aid with adhesion of the tapes were not always used. These tapes typically fail by losing adhesion. This causes voids where water (e.g. moisture found in soil) can contact the pipe wall resulting in corrosion, while at the same time shielding the cathodic protection current from reaching the pipe surface. In the mid to late 1970s, cold-applied tapes first evolved to hot-applied tapes, and then later to heat-shrinkable sleeves. These later products only marginally improved performance and are associated with coating failure mechanisms that can result in CP shielding;
- Starting in the early 1990s, quality control inspection of coating application became more common. Although this inspection reduced the failure rate of these products, consistency of application procedures and subsequent coating performance remained an issue in the pipeline industry; and
- More recently, from the mid 1990s, the pipeline industry has generally moved to products such as liquid-applied epoxies that have been assessed as “fail-safe” (i.e. they will not shield cathodic protection current from reaching the steel pipe surface in the event of future coating failure). Although epoxies can still fail, they are expected to fail in a manner where cathodic protection remains effective in providing corrosion protection to the steel pipeline.

FEI’s evidence from its in-line inspection-driven integrity digs is that cathodic protection shielding is an issue throughout its system, over a range of pipeline coating types and installation years. As such, FEI is obligated to adopt improved methods where available and consistent with industry practice for managing the hazard of external corrosion.

44.3 If available, please provide a list of laterals associating the differing construction methods and coatings.

Response:

FEI's historical records do not identify the specific construction methods employed for each of the 29 Transmission Laterals. Please refer to Table 4 from FEI's response to BCUC IR 1.8.2 for a list of the 29 Transmission Laterals with their year of installation, along with their predominant pipe and joint coating types.

As discussed in the responses to CEC IRs 3.44.1 and 3.44.2, both construction methods and coatings have evolved over time, each with potential impacts to external corrosion. In FEI's experience, the associated impacts of historical practices are not necessarily systemic, nor are correlations between construction timeframes or practices specifically identifiable; instead, they typically result in compromised performance of a single pipeline. For example, to date the only FEI example of a systemic (but still localized to a single pipeline) concern is the NPS 20 Coquitlam Gate IP gas line which was the subject of the Lower Mainland Intermediate Pressure System Upgrade Project. In that project, FEI received approval for replacement of the entire pipeline due to demonstrated coating issues at field-coated weld joints along its entire length, and the inability to further localize the resulting corrosion locations. It is much more common for corrosion to occur only at isolated locations along a pipeline.

45. Reference: Exhibit B-17, PDF page 3/150 and Transcript 1 pages 11-12

> Further to the update provided for Q1 2019, the following activities have been undertaken by FEI during Q2 2019:
>
> - October 2018 – present: FEI's contracts with JANA Corporation pertaining to integrity data improvements and Quantitative Risk Assessment are progressing. FEI's first iteration of a segment-by-segment risk assessment process will be demonstrated through this work. FEI has been, and will continue to work closely with JANA through completion of these contracts, which is expected by year-end 2019.
> - April 16, 2019: FEI and JANA delivered presentations to the BC Utilities Commission staff and Interveners on its planned Transmission Integrity Management Capabilities (TIMC) Project, which is anticipated to provide required upgrades for enabling in-line inspection with crack-detection (EMAT) tools or alternate crack-management strategies that may be deemed preferable through FEI's analysis. JANA's presentations comprised a general overview of quantitative risk assessments as well as updates on both the integrity data improvements and FEI's quantitative risk assessment. Copies of these presentations are attached.
>   - Preliminary documentation (e.g. methodology) has been made available by JANA for FEI review beginning in Q2 2019.
>   - Preliminary results have been presented by JANA to FEI in Q2 2019.
>
> Further technical workshops are being scheduled between FEI and JANA representatives for Q3 2019 to confirm technical defensibility and documentation of these results are in line with FEI's expectation. FEI expects to meet with the BC OGC to review the results of the first iteration Quantitative Risk Assessment in Q4 2019 or Q1 2020.
>
> FEI will submit its next update in Q4 2019 for the preceding quarter.

45.1 Please provide a summary of the preliminary results.

Response:

Please refer to the response to BCUC IR 3.66.3.

45.2 At what stage is the 'First Iteration' of the QRA at present?

Response:

The data collection and analysis portions of the first draft iteration QRA have been completed by JANA, and review of this draft submission will be undertaken by FEI over the coming months.

45.3 Has FEI scheduled the appointment with the BC OGC? If yes, please provide the date.

Response:

FEI has not yet scheduled the appointment with the BC OGC to review the first iteration of the Quantitative Risk Assessment.

45.4 What outcomes does FEI expect from its meeting with the BC OGC? Please explain.

Response:

FEI expects that it will be able to demonstrate to the BC OGC that FEI has developed and implemented a segment-by-segment risk assessment process to determine the risk associated with its pipeline assets in BC. Therefore, FEI expects that the outcome of the meeting will be that the BC OGC would advise FEI that no further submissions are required related to the BC OGC's risk assessment finding identified during the 2014 Integrity management program assessment.

45.5 Please comment, with quantification to the extent possible, on the likely increases in risks that could accrue if the Commission decision were to be deferred:

A) until after the FEI has met with BC OGC; and

B) for 1 year.

Response:

As explained in the response to CEC IR 2.40.1, FEI is exposed to increased risk due to any deferral of the IGU Project. Until the IGU 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.

45.6 Please comment, with quantification to the extent possible, on the likely savings in costs that could accrue if the Commission decision were to be deferred for 1, 2 or 3 years.

Response:

FEI is unable to identify any likely cost savings that could accrue if the Commission decision were to be deferred for 1, 2 or 3 years. Under the project scope as presented in the Application, deferring the Project for 1, 2 or 3 years would result in higher capital costs when taking into account inflation.

46. Reference: Transcript Volume 1 pages 11-12

> So here is a zoomed in, 3D view, and it shows a portion of a condominium complex in Kelowna, and these are the buildings in the bottom. It is an adult community with over 200 units in four residential buildings. Effectively we are seeing two of them here. And again, you can see the Kelowna 1 Loop pipeline corridor. These are the red lines.

> Now, when we talk of pipeline ruptures, one of the things we can calculate is the so-called potential impact radius, if an ignition occurs. And this is defined as, the radius of a circle within which the potential failure of a pipeline could have a significant impact on people or property. In other words, at the edge of the circle, there is a one percent chance of mortality, and that risk increases as one approaches the centre. It is a fairly simple calculation and it is based on the pipeline diameter and operating pressure, and it is explained in the Gas Research Institute Reference cited in the response to CEC IR 1.3.2.
>
> 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.

46.1 Has FEI conducted any assessments of the highest potential impacts from ruptures?

Response:

FEI has not conducted any explicit assessments of the highest potential impacts from ruptures at this time. The localized example used by Mr. Chernikhowsky during the Procedural Conference was for illustrative purposes only. Given that a rupture of a transmission pipeline operating over 30 percent SMYS can have significant safety, reliability, environmental and regulatory consequences, regardless of the failure location, there is no identified benefit from conducting such an assessment as part of the IGU Project.

46.1.1 If yes, please provide.

Response:

Please refer to the response to CEC IR 3.46.1.

46.1.2 If not, please explain why not?

Response:

Please refer to the response to CEC IR 3.46.1.

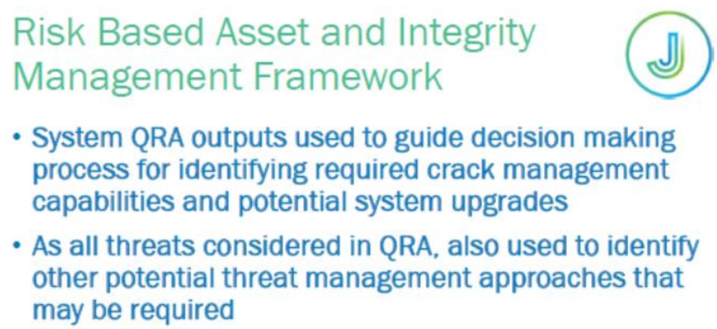
46.2 Please comment, with quantification if possible, on the potential for cost savings to accrue if FEI were able to prioritize transmission laterals according to overall risk, such that the project could be conducted over a period of time five years longer than is currently planned.

Response:

FEI is unable to identify any cost savings by conducting the Project over a period of time five years longer than is currently planned. The current Project schedule was developed based on regional distributions of the 29 Transmission Laterals, cost efficiency, and other constraints as discussed in the response to BCUC IR 1.3.1. Therefore, if the Project were to be completed over a longer period of time, FEI expects the project capital costs to be higher taking into account lost efficiencies and cost inflation. Since Project capital cost savings are not expected under this scenario, FEI did not develop a cost estimate or conduct a financial analysis to determine the actual change in the present value (PV) of incremental revenue requirements over the 66-year analysis period.

Further, as FEI discussed in the response to BCUC IR 1.3.1, it has limited ability to prioritize amongst the laterals based on risk level because the condition information on these laterals does not provide any indication of localized issues on any particular lateral. FEI's assessment is that there is no material difference in the overall integrity risk level of the laterals as they are subject to the same potential for rupture due to external corrosion that may go undetected by FEI's current integrity management techniques. FEI's integrity assessments do not provide information to suggest there would be material improvement from a safety or reliability perspective by prioritizing the laterals differently from currently planned.

47. Reference: Exhibit B-17, PDF page 61/150



47.1 Please discuss the 'other potential threat management approaches' that may be required.

Response:

JANA Corporation provides the following response:

In addition to running EMAT ILI to manage cracking threats, other threats could be identified for potential future mitigations that would be applied independently of EMAT ILI as FEI transitions to risk based Integrity Management, such as threats in the five hazard categories in FEI's IMP-P process:

- Third Party Damage:
  - Potential additional third-party damage mitigation (beyond current measures, e.g. increase in depth of cover, additional signage, etc.)
- Natural Hazards:
  - Potential additional mitigations for ground movement (beyond current measures, e.g. ground stabilization)
- Pipe Condition:
  - Corrosion threats currently managed using MFL ILI, crack threats to be addressed through EMAT ILI
- Material Defects & Equipment Failures
  - Potential additional preventative maintenance
- Human Factors
  - Potential additional mitigative actions (e.g., training, etc.)