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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)

Application for a Certificate of Public Convenience and Necessity (CPCN) for Approval of the Coastal Transmission System Transmission Integrity Management Capabilities Project (Application)

Response to the Commercial Energy Consumers Association of British Columbia (CEC) Information Request (IR) No. 2

On February 11, 2021, FEI filed the Application referenced above. FEI respectfully submits the attached response to CEC IR No. 2 in advance of the deadline established in British Columbia Utilities Commission Order G-285-21.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Commission Secretary
Registered Parties

53. Reference: Exhibit B-7, CEC 1.1

> 1.1 Please provide the sources with quantification of the 'offsetting revenues'.
>
> **Response:**
>
> The offsetting revenues referenced in the figure in the preamble refer to revenues from the projects that support increased capacity or demand and the potential revenue from LNG sales under FEI's Rate Schedule 46 which would offset the rate impact of the Tilbury Phase 1A project. As discussed during the CTS TIMC Workshop,[1] FEI has not prepared a forecast of these offsetting revenues as they would vary year by year and are difficult to forecast. Moreover, the timing of these offsetting revenues are not necessarily aligned with the timing of the rate impact resulting from these projects.

53.1 Please give examples of the types of projects that support the increased capacity or demand referenced in the response.

Response:

The following response references the graph provided by FEI in the response to BCUC IR1 29.1 which also included the impact of the OIC Tilbury Phase 1B and the Interior Transmission System - Transmission Integrity Management Capabilities (ITS TIMC) projects.

Of the projects referenced in the response to BCUC IR1 29.1, three support increased capacity: 1) the Okanagan Capacity Upgrade (OCU), 2) the OIC Coastal Transmission System (CTS) Upgrades, and 3) the Woodfibre Gas Pipeline. As explained in that response, the Woodfibre Gas Pipeline was not included in the graph because the incremental cost of service would be recovered by the demand toll under Rate Schedule 50 for large volume industrial transportation customers.

With respect to increasing demand, the OIC Tilbury Phase 1A and OIC Tilbury Phase 1B projects are being undertaken to support anticipated increases in LNG sales. FEI expects the anticipated growth in LNG demand will cover the costs of the Tilbury Phase 1A and 1B projects over the life of the assets.

The remaining projects listed in the graph are either reliability, resiliency, or integrity-driven projects.

53.2 Recognizing that FEI does not have forecasts for the figures, please provide an annual range estimate of the $ values that might be expected from each project, and from LNG sales.

Response:

As stated in the response to CEC IR1 1.1, FEI has not prepared a forecast of the offsetting revenues from the projects identified in CEC IR2 53.1 as they are difficult to forecast, would vary from year to year, and the timing of the revenue would not necessary align with the rate impacts from the Project. Further, the annual range estimate of the $ values that might be expected from these projects is not relevant to the CTS TIMC Project or this proceeding generally. FEI will be providing its load forecast over a twenty year planning period as part of its 2022 Long Term Gas Resource Plan.

54. Reference: Reference: Exhibit B-7, CEC 1.2.1 and Exhibit BCUC 1.26.2

> 2.1 If the CTS TIMC Project has not, or not yet, received CPCN approval by January 2022, would FEI expect to defer its recovery or would the recovery occur in any event?
>
> **Response:**
>
> If the proposed deferral account is approved, recovery of the CTS TIMC Project deferred project costs will occur January 1 the year following the BCUC decision. As FEI currently does not anticipate receiving approval by January 2022, FEI is amending its approvals sought to request the transfer of the non-rate base deferral account to rate base on January 1, 2023 with amortization over a three-year period commencing at that time. Please also refer to the response to BCUC IR1 26.2 for further detail.

> The following table summarizes the levelized annual delivery rate impact in $/GJ and the levelized annual bill impact for a residential customer with an average consumption of 90 GJs per year for each of the amortization periods evaluated.

	Amortization Period				
	1 Year	2 Years	3 Years	4 Years	5 Years
Levelized Annual Delivery Rate Impact ($/GJ)	0.096	0.049	0.034	0.026	0.021
Levelized Annual Bill Impact for Residential Customer, 90GJs ($)	**8.60**	**4.42**	**3.03**	**2.33**	**1.91**

> Ultimately, FEI considers that there is no basis on which to deviate from prior practice for this Project because the difference in terms of bill impact to FEI's ratepayers is immaterial for the various amortization intervals and a three-year period is consistent with previous applications.

54.1 Please provide the average Levelized Annual Delivery Rate Impact for Commercial rate classes, as shown in the Amortization Period table for residential customers.

Response:

FEI provides the table below which includes the levelized annual bill impact for small and large commercial customers. The impact is based on an average consumption of 340 GJ for small commercial customers under Rate Schedule 2, and 3,770 GJ for large commercial customers under Rate Schedule 3.

	Amortization Period				
	1 Year	2 Years	3 Years	4 Years	5 Years
Levelized Annual Delivery Rate Impact ($/GJ)	0.096	0.049	0.034	0.026	0.021
Levelized Annual Bill Impact for Residential Customer, 90GJs ($)	**8.60**	**4.42**	**3.03**	**2.33**	**1.91**
Levelized Annual Bill Impact for Small Commercial Customer, 340GJs ($)	**32.50**	**16.69**	**11.43**	**8.80**	**7.23**
Levelized Annual Bill Impact for Large Commercial Customer, 3,770GJs ($)	**360.33**	**185.09**	**126.73**	**97.60**	**80.15**

55. Reference: Exhibit B-7, CEC 1.3.1

Regulatory Requirement	Significance / Relevance to FEI's management of its transmission pipelines in a proactive and systematic way
Section 37 (1) (a) of the OGAA states, "A permit holder, an authorization holder and a person carrying out an oil and gas activity must prevent spillage"[4]. This requirement pertains to pipelines operating at or above a pressure of 700 kPa.	FEI's primary objective with its IMP-P 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 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.

55.1 FEI states that there is a preference given to a methodology such as ILI. Is this FEI's preference, or is there a preference or perceived preference for such methodologies under the OGAA? Please explain.

Response:

In the preamble, FEI is referring to its preference for methodologies that provide FEI with the capability to monitor and proactively respond to potential changes in asset condition that occur with time, as such methodologies provide FEI with the capability to meet its obligations under the OGAA and meet OGAA regulatory expectations. In the context of in-line inspection (ILI), FEI's preference is informed by its understanding that ILI is a cost-effective methodology enabling an operator to detect areas along a pipeline that may warrant site-specific mitigation, rather than replacing an entire pipeline. FEI's preference is also informed by the factors below (and others); namely, that compliance under the OGAA (including meeting regulatory expectations) has multiple considerations, including:

Regulations

- FEI interprets its obligation under the BC Pipeline Regulation to "prevent spillage" as warranting consideration of industry practice, availability of appropriate technology, and the degree of confidence that can be achieved with a particular condition monitoring methodology.

Standards

- FEI is obligated to consider the use of ILI in its transmission pipelines per CSA Z662:19 Clause N.1.12.4 which states:

  "Consideration shall be given to using in-line inspection equipment to detect
  - a) internal and external corrosion imperfections (see Annex D);
  - b) dents;

c) cracks; and
d) excessive pipe movement."

- FEI's consideration of the availability of appropriate technology is in accordance with informational notes to CSA Z662:19 Clause 9.9.6:

  "Techniques (e.g., the use of internal and external inspection equipment) to monitor the effectiveness of the corrosion control program shall be considered.

  Notes:

  1) Guidelines for in-line inspection of piping for corrosion imperfections are contained in Annex D.
  2) The factors to be reviewed when considering such inspection should include, but not be limited to, the following:
     a) the availability and capability of the equipment;
     b) the age, condition, and configuration of the piping;
     c) the service, leak, and corrosion mitigation history of the piping; and
     d) population density and environmental concerns."

Industry Practice

- For natural gas transmission pipelines in diameters for which ILI tools are proven and commercialized (and relevant to the hazard being assessed), ILI is the predominant assessment method.

Availability of proven and commercialized technology

- As part of its Inland Gas Upgrade project, FEI is adopting ILI tools for detecting corrosion, dents, and pipe movement in its transmission pipelines of NPS 6 and greater (constrained by technology availability and capability).
- As part of its CTS TIMC Project, FEI is adopting EMAT tools in transmission pipelines of NPS 10 and greater (constrained by technology availability and capability).

56. Reference: Exhibit B-7, CEC 1.8.1

> In its report "Best Available Technologies in Federally-Regulated Pipelines"[6], dated 30 September 2016, the National Energy Board (now the Canada Energy Regulator) stated:
>
> > Though an emerging technology, EMAT is more generally described as a controlled implementation. The principal challenge is that it tends to find defects that are not there (false positives). However, the technology has been under development for some 20 years, and has become more sensitive and reliable so that now EMAT can be considered BAT [Best Available Technologies] for ILI crack detection in gas pipelines.
>
> Although the above-referenced report was published nearly five years ago, it is indicative of the trend of EMAT ILI increasingly being adopted by industry (as described by FEI in Section 3.3.2 of the Application). As indicated by the report, EMAT has now been under development for approximately 25 years.
>
> While the maturity and capabilities of EMAT technology are continually evolving, another necessary consideration is the commercial availability of tools suitable for FEI's natural gas pipelines. Until recently, EMAT ILI tools were not commercially available for pipe diameters as small as NPS 10. As discussed in Section 3.2.2.3 of the Application, the issue of suitability includes that the ILI tools must be operable within the variable flow rates encountered on FEI's system. Please refer to the response to CEC IR1 7.1 which explains that EMAT ILI was sufficiently proven and commercialized for adoption in FEI's system since 2018.
>
> Please also refer to the responses to RCIA IR1 2.1 and CEC IR1 3.1 that describe the adoption and use of EMAT ILI in British Columbia, Canada, and worldwide.

56.1 Please provide any quantitative information that FEI has relating to the expected likelihood of false positives.

Response:

FEI has no quantitative information related to the expected likelihood of false positives. As discussed in the response to CEC IR2 64.1, FEI has not experienced any false positives in its EMAT ILI activities to date.

56.1.1 If no quantitative information is available, please provide FEI's best estimate of the likelihood of false positives arising.

Response:

FEI's assessment is that the likelihood of false positives occurring is low, given that industry is widely adopting EMAT ILI for crack detection. FEI anticipates that the likelihood of false positives arising will continue to decrease with time as the technology continues to improve.

Please also refer to the response to CEC IR2 64.1 which discusses FEI's experiences related to false positives from its pilot projects.

56.1.2 What costs arise as a result of false positives? Please identify and quantify where possible.

Response:

If false positives arise, FEI would incur the associated integrity dig costs; however, there is currently no method to quantify the number of false positives (if any) with certainty. Should FEI experience false positives, it is estimated that it could cost on average approximately $68 thousand per dig, which is consistent with FEI's forecasted 2022 average cost per dig in its Annual Review for 2022 Delivery Rates application (BCOAPO IR1 12.1, Table 1, Page 22 for ILI digs related to the running of new ILI tools). The cost of an individual integrity dig can vary significantly depending on factors including location and access constraints, surface and subsurface conditions, depth, proximity to geographic features (e.g. river crossings, environmental zones, and highways), season, the number of imperfections requiring assessment, and availability of operations resources such as tools and equipment.

57. Reference: Exhibit B-7, CEC 1.8.2

> 8.2 Is it possible that the suitable EMAT tools will be either further developed for superior performance, or come down in price over the next 5 years? Please explain.
>
> **Response:**
>
> Based on FEI's experience with other ILI technologies, FEI expects that the performance of EMAT tools will continue to evolve and improve over the next five years and beyond. However, FEI cannot predict whether the cost to run EMAT tools will increase or decrease in price over the next five years.
>
> For clarity, to FEI's awareness, pipeline operators (including FEI) do not purchase ILI tools. Instead, pipeline operators contract with ILI vendors who develop, test, and construct ILI tools for the industry and then offer pipeline inspection services to customers. Thus, the ILI tool related cost, development, and obsolescence risks are borne by the ILI vendors, not the pipeline operators.

57.1 Please confirm that although the ILI vendors own the majority of the ILI tools, FEI will nonetheless be purchasing elements of the ILI systems that could potentially become obsolete over time.

Response:

Not confirmed. FEI will not be purchasing any element of the ILI systems. All ILI systems are owned by the ILI tool vendors.

57.1.1 To the extent that the EMAT technology continues to improve over the course of time, can FEI guarantee that it will not be required to incur any additional costs in order to 'keep up' with the technology? Please explain.

Response:

Since FEI will not be purchasing any elements of ILI systems, there will be no additional cost in order to "keep up" with the technology as suggested by the preamble.

ILI vendors typically spread the cost of EMAT ILI tools, including costs to develop and advance the technology, among all pipeline operators who utilize the tools. FEI cannot predict whether there will be additional costs over time as EMAT technology continues to improve. Due to typical vendor pricing structures, FEI does not have information to assess whether fees paid by FEI to an ILI vendor are allocated to tool technology advancement or other areas of their business.

57.2 To the extent that the technology is not yet required, and still developing, could FEI safely and cost-effectively defer implementation for a year or more? Please explain.

Response:

As explained in the response to CEC IR1 8.1, EMAT technology has been under development for approximately 25 years, is no longer considered novel, and is sufficiently proven and commercialized for adoption in FEI's system as proposed in the Application.

The CTS 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. FEI has no basis on which to support a deferral of the proposed Project timeline for a year or more.

58. Reference: Exhibit B-7, CEC 1.11.1

> 11.1 If FEI had used pipeline manufactured using other processes, would FEI still likely experience similar or different imperfections? Please explain.
>
> **Response:**
>
> In addition to ERW and submerged arc welding (SAW and DSAW), FEI has used pipe manufactured using spiral welded process in limited locations of its transmission pipeline system. FEI has also used seamless pipe for some of its transmission station piping. Seamless pipe is manufactured by a hot extrusion process, and therefore it does not have a weld seam. These pipes are not susceptible to seam weld anomalies but are susceptible to several different types of imperfections.

58.1 Please identify the types of imperfections that pipe manufactured with spiral welded processes can potentially experience.

58.1.1 Will FEI's proposed project address these types of issues? Please explain why or why not.

58.1.2 If no, please explain how FEI addresses the types of issues that may arise in pipeline manufactured using spiral welded processes.

Response:

FEI's understanding is that spiral welded processes utilize submerged-arc-welding (SAW), and as such, are also subject to the types of imperfections applicable to SAW pipe discussed in Section 3.2.4.2 of the Application.

FEI's proposed project will address these types of issues to the extent that such features exist on FEI's pipelines and where such features are within the detection and sizing threshold of the EMAT tool.

58.2 Please identify the types of imperfections than the extruded pipe may have and FEI's approach to dealing with that type of pipe.

Response:

FEI understands that the seamless pipe manufacturing process can result in voids and/or non-metallic inclusions (i.e., air or other contaminants) in the base steel. These inclusions can result in a sloping lamination through the thickness of the pipe over a portion of the circumference, which in turn weakens the pressure-bearing capacity of the pipe. FEI has not identified any seamless pipe within the scope of the TIMC Project, and as such, FEI's approach to dealing with that pipe is to inspect for cracking during opportunity digs.

58.2.1 Please quantify the imperfections on this type of pipe which FEI has experienced and or provide industry data applicable to these issues.

Response:

FEI has records of opportunity digs of seamless pipe dating from 2003 at its Warfield and Kitchener Compressor Stations. The reports did not directly link any of the imperfections found to the manufacturing process, although it is possible that there was some relation. The imperfections noted in the reports were non-injurious to the pipeline steel.

FEI does not have access to recorded data applicable to these issues that may exist with respect to gas transmission pipelines owned and operated by its peer Canadian operators.

59. Reference: Exhibit B-7, CEC 1.11.1.1

> 11.1.1 If FEI might not have experienced imperfections using pipeline manufactured with other processes, please explain how the use of pipeline manufactured using other processes might have mitigated the current risks and quantify any potential cost savings.
>
> **Response:**
>
> If FEI had used pipe without a seam weld there would be no risk associated with seam weld failures; however, there is typically a 30 percent cost premium for seamless pipe versus welded pipe. Further, seamless pipes would not lead to inspection cost savings as EMAT ILI would still be required to manage SCC in the pipe body.

59.1 Please roughly estimate the proportion of issues requiring EMAT ILI likely to arise from seam weld failures, versus SCC occurring in the pipe body and requiring EMAT ILI.

Response:

Following receipt and analysis of EMAT ILI data on the CTS pipelines, FEI will be able to determine the proportion of issues that have arisen from seam weld issues versus SCC occurring in the pipe body. However, the QRA provides data for roughly estimating this proportion using risk as opposed to cause. As such, FEI requested JANA respond to this question.

JANA provides the following response:

The issues requiring EMAT ILI due to SCC are the dominant threat. In terms of risk for the CTS system, the QRA identified SCC threats as roughly three orders of magnitude higher than seam weld risks.

FEI adds the following:

On a risk basis, and utilizing the information provided by JANA above, the requested rough estimate is approximately 1000 (SCC related) to 1 (seam weld related).

60. Reference: Exhibit B-7, CEC 1.11.2

> 11.1.2 If FEI might not have experienced imperfections using pipeline manufactured with other processes, please explain why FEI selected pipeline manufactured using the ERW or SAW and DSAW processes.
>
> **Response:**
>
> Please refer to the response to CEC IR1 11.1. FEI selected pipeline manufactured using the ERW, SAW and DSAW processes because these were the most commonly used pipe in the industry at the time of construction. FEI determined that this pipe was technically acceptable, readily available, and cost effective at the time of selection.

60.1 Did FEI consider the installation of seamless pipe at the time of construction? Please explain why or why not.

Response:

FEI does not have records to confirm if it considered the installation of seamless pipe at the time of construction. As explained in the response to CEC IR1 11.1, FEI would have considered pipe that was technically acceptable, readily available, and cost effective at the time of selection.

61. Reference: Exhibit B-7, CEC 1.14.1

> **14. Reference: Exhibit B-1, page 28**
>
> JANA observes the following regarding the increasing knowledge of cracking threats:[11]
>
> > 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.
>
> 14.1 Does FEI use polyethylene tape?
>
> **Response:**
>
> FEI has historically used polyethylene tape as a field applied joint coating and as a repair coating. FEI has also used polyethylene tape as the pipe body coating on a limited number of segments of transmission pipeline. FEI does not currently use polyethylene tape.

61.1 What alternatives to polyethylene tape are and have been available to FEI?

Response:

Current alternatives to polyethylene tape as a field applied coating include liquid applied epoxies, petrolatum/wax tapes, visco-elastic tapes and polyethylene backed heat shrink sleeves.

With respect to factory applied coatings, current alternatives are fusion bond epoxy and extruded polyethylene, while coal tar or asphalt enamel coatings were common alternatives prior to the 1980s.

61.1.1 Why did FEI elect to use polyethylene tape? Please explain.

Response:

Similar to many other pipeline operators, FEI elected to use polyethylene tape as it was recognized and accepted industry practice at that time. Over time, pipeline coatings have evolved, and greater emphasis is now placed on the preparation and the quality of coating application. In addition, consistent with industry knowledge, coating failure mechanisms and their potential effects on cathodic protection shielding and SCC susceptibility were not well-understood at the time when FEI, and industry, used polyethylene tape coatings.

FEI notes that polyethylene tape is still utilized in industry today; however, application quality is carefully assessed during the coating application process in order to mitigate the risks associated with adhesion failure, which can result in SCC susceptibility.

61.1.2 Please explain the reasons FEI has switched to a different solution than polyethylene tape and if possible, provide quantitative analysis of the issues.

Response:

FEI reviews its protective coatings standards on an ongoing basis to ensure current practices align with industry practices and technology advancement. FEI switched from using polyethylene tape due to the understanding (both internally and in industry) that these materials tend to fail in adhesion causing the potential for cathodic protection shielding and SCC.

Appendix B-1 of the Application includes JANA's assessment of the susceptibility of pipelines to cracking threats and includes quantitative analysis that has considered coating type. This analysis has considered current known issues.

62. Reference: Exhibit B-7, CEC 1.14.2

> 14.2 Does FEI use asphalt-coated lines or coal-tar coated pipe? Please explain.
>
> **Response:**
>
> FEI installed asphalt-coated and coal-tar coated pipe up until the early 1980s. While these coatings have not been used in pipeline installations since that time, FEI still has approximately 1,000 kilometres of transmission pressure pipelines in service which use these coatings.

62.1 What alternatives to asphalt coated and coal-tar coated pipe were available when FEI was using this pipe in their installations? Please explain.

62.1.1 Why did FEI not make use of these alternatives at the time?

Response:

For larger pipe applications, alternatives to coal-tar or asphalt enamel coatings were limited to polyethylene tapes until the late 1970s, when fusion bond epoxies began to become available as a factory applied coating for the pipe body. Coal-tar and asphalt enamel coatings were commonly used by the industry for large diameter pipe construction prior to the 1980s. Consistent with industry practice at this time, all of these alternatives were used by FEI during various eras of pipeline construction.

For smaller diameter pipe (i.e., less than NPS 12) extruded polyethylene was available beginning in the late 1950s and was also used by FEI for some pipeline construction.

63. Reference: Exhibit B-7, CEC 1.15.1

> - **September 21, 2016**: FEI indicated it was assessing the need for and feasibility of adopting crack-detection capabilities within its in-line inspection program in the Annual Review for 2017 Rates, BCUC IR1 9.11.
> - **September 26, 2017:** FEI indicated that it was continuing its assessment in the Annual Review for 2018 Rates, BCUC IR1 1.9.
> - **August 3, 2018:** FEI applied for a new non-rate base deferral account to capture development costs for the TIMC Project in the Annual Review for 2019 Rates, as approved by Order G-237-18.
>
> FEI's TIMC project is comprised of two CPCN applications: one for the CTS TIMC, and another for the ITS TIMC. FEI confirms that it has no other projects currently planned to address cracking threats to its transmission pipelines.

63.1 How much additional pipeline does FEI have that could benefit from TIMC?

<u>Response:</u>

FEI has not identified any pipelines, other than those forming part of the CTS and ITS, that could benefit from inline inspection using EMAT ILI. Currently, EMAT ILI tools that are commercially available and proven are limited to pipelines NPS 10 and larger. FEI will continue to monitor EMAT technology developments for use on smaller diameter transmission pipelines as it becomes available and will continue to inspect pipelines for cracking during opportunity digs. Until such EMAT ILI tools become commercially available and proven, FEI does not have any other projects planned to address cracking on its transmission pipelines.

Additional projects may be required in the future, but FEI is unable to provide a timeframe due to the uncertainty regarding when or how technology may evolve.

63.2 Please explain why FEI does not have any other project planned to address cracking threats to its transmission pipelines.

<u>Response:</u>

Please refer to the response to CEC IR2 63.1.

63.2.1 Does FEI expect to have additional projects in the future? Please explain and provide a timeframe of when such projects might be developed.

<u>Response:</u>

Please refer to the response to CEC IR2 63.1.

63.2.2 Could FEI achieve cost savings by undertaking any additional TIMC projects either at this time or in the future? Please explain why or why not.

<u>Response:</u>

As discussed in the response to CEC IR2 63.1, FEI has not identified any additional TIMC projects and therefore there are no cost savings that could be achieved at this time.

Similarly, as the scope and timing of additional TIMC projects is unknown, FEI is also unable to assess whether any cost savings could be achieved in the future. FEI will continue to monitor EMAT ILI technology developments for use on smaller diameter transmission pipelines as it becomes available, and identify future TIMC projects if and when required.

64. Reference: Exhibit B-7, CEC 1.17.2/ BCUC 1.11.1 and CEC 1.8.1

> The results provided by the pilot project thus far are summarized below:
>
> 1. **LIV PAT 457 pipeline**
>   The features that have been identified on the LIV PAT 457 pipeline to date are:
>   - Six reported crack features in the seam weld.
>   - Eight reported crack features in the pipe.
>   - One crack group.
>
> Ten integrity digs have been performed to-date and have resulted in the findings described below:

> In its report "Best Available Technologies in Federally-Regulated Pipelines"[6], dated 30 September 2016, the National Energy Board (now the Canada Energy Regulator) stated:
>
> > Though an emerging technology, EMAT is more generally described as a controlled implementation. The principal challenge is that it tends to find defects that are not there (false positives). However, the technology has been under development for some 20 years, and has become more sensitive and reliable so that now EMAT can be considered BAT [Best Available Technologies] for ILI crack detection in gas pipelines.
>
> Although the above-referenced report was published nearly five years ago, it is indicative of the trend of EMAT ILI increasingly being adopted by industry (as described by FEI in Section 3.3.2 of the Application). As indicated by the report, EMAT has now been under development for approximately 25 years.

64.1 In BCUC 1.11.1, FEI provides an overview of various results from its pilot projects, including several instances of cracking evidence. Is there any possibility that the results have shown false positives? Please explain why or why not.

64.2 If yes, how will FEI determine whether or not the results were false positives?

<u>Response:</u>

FEI interprets the request for "false positives" as instances where an EMAT ILI tool run identifies a crack but instead there was clean pipe found in the field (i.e., no imperfections).

FEI clarifies that for all of the EMAT digs conducted to date, imperfections have been found in the field at the EMAT-reported locations. While not all imperfections have been found to be cracking, imperfections have been "crack-like" and thus were detected by the tool. In FEI's interpretation, these are not false positives as the ILI tool has detected the presence of a crack-like imperfection (e.g., imperfections with sharp edges which appear similar to cracks in EMAT ILI signatures).

Since not all validation digs have been completed, there is still a possibility that remaining digs may show false positives (as characterized above).

FEI will determine whether or not the EMAT ILI results were false positives through validation digs.

65. Reference: Exhibit B-7, CEC 1.24.2/Exhibit B-8, RCIA 1.14.2

> 24.2 Please describe how FEI will utilize the requested technology to inspect once it is installed. For example, will FEI conduct a transmission system overview sequentially reviewing its pipelines, or will it conduct simultaneous inspections of several or all transmission lines? Please explain.
>
> **Response:**
>
> Please refer to the response to RCIA IR1 14.2 for the proposed inspection schedule.

> **Response:**
>
> FEI anticipates EMAT ILI tool runs will be completed in four years starting from 2024 to 2027, with a preliminary schedule provided in the table below. Detailed EMAT ILI planning such as scheduling with tool vendors is not complete, so this schedule is subject to change based on factors such as resource and tool availability.

Year	Pipeline	Baseline Run
1	HUN ROE 1066	2024
2	HUN NIC 762	2025
	NIC PMA 610	2025
	NIC FRA 610	2025
3	ROE TIL 914	2026
	CPH NOO 508	2026
	LIV PAT 457	2026 (Rerun)
4	TIL BEN 323	2027
	TIL FRA 508	2027
	TIL LNG 323	2027
	LIV COQ 323	2027

65.1 How did FEI prioritize which lines would be examined first and last? Please explain.

Response:

FEI prioritized its pipelines for EMAT ILI primarily based on risk, with higher risk pipelines being inspected first and lower risk pipelines being inspected last. Where practical, FEI has also grouped pipelines by their diameter to optimize ILI tool mobilization costs. For instance, the same tool can be used to inspect the NIC PMA 610 and NIC FRA 610 pipelines in Year 2.

The exception to this prioritization methodology is the HUN ROE 1067 pipeline. While this is not the highest safety risk pipeline, it has been selected as the first line for inspection because of capacity constraints which could impact customer supply. As described in the response to BCUC

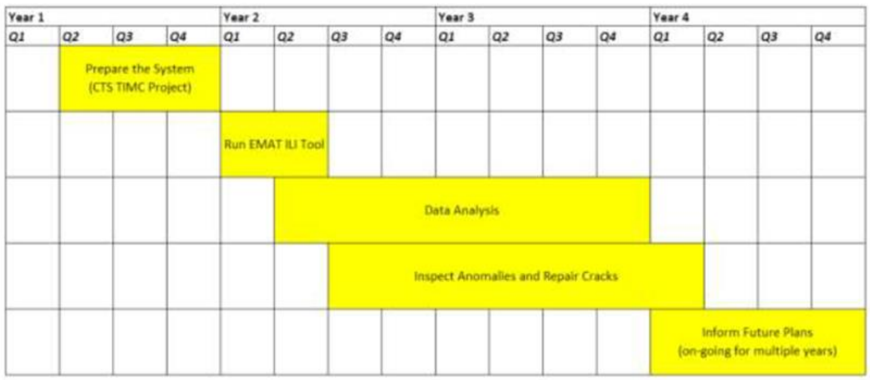
IR2 37.2, the CTS has insufficient capacity when operating the HUN ROE 1067 pipeline with a 20 percent pressure reduction through the winter. While FEI does not anticipate having to operate this pipeline at a reduced pressure for an extended period of time, FEI has prioritized the EMAT ILI run on this pipeline in an earlier year to ensure it has the ability to perform integrity digs and repairs prior to winter to avoid capacity shortfalls.

66. Reference: Exhibit B-7, CEC 1.33.1

33.1 Please provide timelines for each of the identified activities.

Response:

The typical timelines for each activity are provided in the Gantt chart below. The actual timelines may vary for each pipeline based on availability of tools and resources and pipeline operating conditions. A brief description of each activity is also provided.



1. **Prepare the System:** Includes performing pipeline and facility alterations required to ready the system for EMAT ILI tool runs and facilitate post-EMAT ILI run actions.

2. **Run EMAT ILI Tool:** Includes cleaning tool runs to prepare the pipeline for the EMAT ILI tool, and the EMAT ILI tool run.

- *Note:* EMAT ILI tool runs on the 11 CTS pipelines will be completed over the multiple years and thus, may not occur directly after CTS TIMC Project construction (preparing the system).

3. **Data Analysis:** An iterative process performed in conjunction with inspection and repairs. The EMAT ILI vendor assesses tool data and FEI reviews the findings and identifies whether any digs are required. Dig information is fed back to the EMAT ILI vendor to refine the data analysis.

4. **Inspect Anomalies and Repair Cracks**: An iterative process performed in conjunction with data analysis; includes inspection and repair of features identified through the data analysis process.

5. **Inform Future Plans:** Including blind spot repairs, determination of EMAT ILI re-inspection interval, and the assessment of pipeline integrity data to determine areas requiring broader mitigation efforts.

66.1 Please elaborate on the types of information from the 'dig' that would be fed back to the ILI vendor to refine analysis. What types of additional information might the vendor provide that is not provided by the dig, and how would this inform FEI's actions? Please explain.

Response:

Any information from the dig that can help refine ILI analysis is fed back to the ILI vendor. This includes the following:

- Field as-found feature information including:
  - location information such as axial and radial start and end of feature(s);
  - dimensions such as length, width, and depth; and
  - feature type.
- Girth weld coordinates for refining global positioning system (GPS) location accuracy; and
- Coating condition which can help inform the existence of certain types of features and feature severity.

Tool velocity is the primary additional information provided by the vendor that is not provided by the dig. The tool velocity information is used during the ILI data analysis phase as speed excursions negatively impact data quality.

Feature information, including that which is collected in the area of speed excursions, is fed back into the ILI analysis process and can result in actions such as:

- Inspecting additional anomalies;
- Inspecting similar anomalies in similar speed excursion areas; or
- Informing future inspection plans.

67. Reference: Exhibit B-7, CEC 1.25.2.

> 25.2 Once FEI has conducted a thorough inspection of its entire system, would FEI need to essentially recommence the same process immediately, such that there is continuous inspection or would FEI wait for particular period, i.e. the 7 years? Please explain.
>
> **Response:**
>
> The re-inspection cycle for each pipeline will be determined using the findings of the initial EMAT ILI run. As described in CEC IR1 25.1, FEI expects to complete the baseline EMAT ILI runs within a period of four years. FEI does not anticipate that it will need to recommence the same process immediately in the CTS; however, some pipelines may be re-inspected earlier than others depending on the findings of the initial EMAT ILI run.

67.1 What re-inspection intervals are standard in the industry? Please provide quantification with an explanation. What factors influence when re-inspection will be considered appropriate?

Response:

FEI confirms that its re-inspection intervals fall within range of standard practice in the industry. Canadian pipeline standards are generally not prescriptive in nature, so each operator determines appropriate re-inspection intervals for its relevant pipeline assets and inspection technologies.

The factors considered in establishing a re-inspection interval are both qualitative and quantitative, and are listed in the response to BCUC IR1 11.6.

FEI provides the following examples from publicly available sources that indicate a quantification of a re-inspection interval, with explanation of the relevance to FEI's re-inspection interval range:

Source	Excerpt	Relevance
Canadian Energy Pipeline Association (CEPA), Metal Loss Inline Inspection Tool Validation Guidance Document, 1st Edition, January 2016[1]	Section 6.2.2, page 34, "Furthermore, a lengthy interval (e.g. more than 5 years) between ILI inspections or the use of very different technologies can make matching difficult if not impossible."	This indicates a consensus among CEPA members that "more than 5 years" is a "lengthy interval" for a re-inspection with an ILI tool and for matching defect information between ILI inspections.

[1] CEPA-Guidance-Document-Inline-Inspection-Tool-Validation-FINAL-DRAFT-FOR-EXTERNAL-PUBLICATIONJan-20-2016.pdf.

Source	Excerpt	Relevance
Transportation Safety Board of Canada, Pipeline Transportation Safety Investigation Report P18H0088, Pipeline rupture and fire, Westcoast Energy Inc., Prince George, British Columbia, 09 October 2018[2]	4.1 Safety action taken From 4.1.2 Westcoast Energy Inc. "The maximum re-inspection interval for EMAT in-line inspections for all L2 pipeline segments was set to 6 years. Further, Westcoast has implemented a more conservative approach in responding to pipeline inspection data that may identify areas requiring closer monitoring or earlier maintenance work."	FEI's re-inspection interval range is consistent with this quantification of a re-inspection interval from Westcoast Energy Inc.
US Code of Federal Regulations Part 192 – Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards[3]	§192.937 "What is a continual process of evaluation and assessment to maintain a pipeline's integrity? […] An operator must reassess a covered segment on which a baseline assessment is conducted […] by no later than seven years after the baseline assessment of that covered segment unless the evaluation under paragraph (b) of this section indicates earlier reassessment." §192.939 "What are the required reassessment intervals? […] The maximum reassessment interval by an allowable reassessment method is seven years."	Part 192 contains federally regulated requirements for US gas transmission pipelines. FEI's assessment of industry practice in Canada, while not similarly prescribed in a Canadian standard or regulation, does align with this prescriptive US pipeline regulation. This provides an indication that FEI's range of re-inspection frequency is common. FEI notes that there are provisions in the US standard that allow for an extension of the maximum re-inspection interval up to 10 years for transmission pipelines inspected with ILI tools, although this requires the performance of supplemental inspections.

FEI's re-runs of geometry and standard magnetic flux leakage tools are currently planned on a maximum 7-year interval. As discussed in the response to BCUC IR2 48.1, FEI used a re-inspection interval of 7 years to estimate its EMAT costs throughout the 65-year post-project analysis period in the CTS TIMC Application.

67.2 What is the duration of the contract with the ILI provider? Is FEI able to complete its contract at the end of the cycle? Please explain.

[2] https://www.tsb.gc.ca/eng/rapports-reports/pipeline/2018/p18h0088/p18h0088.html.
[3] https://www.ecfr.gov/current/title-49/subtitle-B/chapter-I/subchapter-D/part-192.

Response:

The duration of a contract with an ILI provider can vary, but is typically on the order of one year.

FEI confirms it is able to complete (i.e., terminate) its contract at the end of the cycle.

FEI's contracts with ILI providers consists of both an umbrella agreement and specific purchase orders issued under that agreement, which can have different durations. FEI issues purchase orders to ILI providers based on quotations for work that typically cover an annual work cycle. It is possible that FEI may accept a quotation for work covering a longer period if sufficient business benefits are identified. Contract terms and conditions provide FEI with the ability to terminate a contract during or following the completion of contracted work in a purchase order.

68. Reference: Exhibit B-7, CEC 1.25.2.1

> 25.2.1 Please provide a discussion relating the time frame it takes for a crack to develop and the expected inspection frequency.
>
> **Response:**
>
> Cracks can develop and grow over any time frame and, hence, crack analysis to establish integrity digs and re-inspection frequencies employs appropriate conservatism and line-specific inputs to ensure timely intervention such that potential cracks are found and repaired prior to growing to failure.
>
> FEI will use a range of crack growth rates, informed by industry practice and the *CEPA Recommended Practice for Managing Near-neutral pH Stress Corrosion Cracking*, to assess the features found through EMAT ILI and to determine a re-inspection frequency for subsequent EMAT ILI. FEI typically inspects its pipelines on a 7-year cycle, unless the growth assessment or other line-specific considerations (such as an observed localized external stress) indicates earlier re-inspection is required.

68.1 Will the improved inspection and pipeline integrity knowledge acquired as a result of running ILI mean that FEI can extend its inspection period? Please explain why or why not.

68.1.1 If yes, what term of inspection period would FEI expect to undertake following the initial complete runs of the ILI tools, analysis, and completed repairs? Please explain.

Response:

Although FEI's ILI re-inspections are currently set at a maximum 7-year interval, FEI is committed to continual improvement in all of its integrity management practices. FEI is open to identifying possible extension(s) to its inspection periods as a result of improved inspection, pipeline integrity knowledge, or other factors. However, at this time, FEI does not anticipate significant changes to its re-inspection intervals as they currently fall within the range of industry standards.

Please also refer to the response to BCUC IR1 11.6 for the factors currently considered by FEI in the determination of its re-inspection intervals.

69. Reference: Exhibit B-7, CEC 1.26.1 and Exhibit B-1, page 76 and Exhibit B-7, CEC 1.29.1.3

- **Alternative 3:** A hydrostatic testing program would have similar elements as an EMAT ILI program, in that testing would be required to be completed on a recurring interval. However, FEI would also need to consider alternate ways to supply customers serviced by lines that do not have a parallel pipeline to maintain gas supply during testing. This would likely involve looping some pipelines and would make up a majority of the cost of the alternative. As such, if 25 percent of the system required looping, then the magnitude of costs would be in the hundreds of millions of dollars (assuming 25 percent of the cost of Alternative 5).

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

29.1.3 Please explain why additional looping is not feasible.

Response:

Pipeline looping was considered not feasible to allow operating the CTS at a reduced pressure because of the challenges associated with the extensive looping that would be required.

First, as discussed in the response to CEC IR1 29.1, operating pressures that would reduce pipeline stress to below 30 percent of SMYS creates capacity limitations for large portions of the year. This is based on current customer demand and does not consider future growth in

69.1 Would the looping requirements referenced in CEC 1.26.1 be the same as those referenced in CEC 1.29.1.3?

69.2 If it is not the same looping requirements referenced in CEC 1.29.1.3, is FEI able to readily identify what percentage of the system would require looping for the hydrostatic testing option?

69.2.1 If no, please explain why not.

69.2.2 If yes, please provide the % of the system that would require looping.

Response:

The looping requirements referenced in CEC IR1 26.1 and 29.1.3 are not the same. The extent of looping required to support the PRS alternative referenced in CEC IR1 29.1.3 is more significant than for the HSTP alternative.

In the HSTP alternative, FEI would perform hydrostatic testing on a segment-by-segment basis until the entire pipeline has been tested. If a failure occurs during a test, FEI would locate the failure, repair and then re-test the segment of pipeline. Due to the long lengths of some CTS pipelines and the uncertainty in the quantity of repairs that could be required, FEI may not be able to complete testing of the entire pipeline prior to the winter when it is required to be back in service. In the event that there are untested segments of pipeline <u>and</u> a failure occurred in a previous test, it would be consistent with industry practice for FEI to implement a 20 percent pressure reduction when the pipeline is put back into service to establish a factor of safety on any integrity features that may remain in the untested segments of the pipeline (please also refer to the response to BCUC IR2 34.3). The current configuration of the CTS only allows for a system-wide pressure reduction using the Huntingdon Control Station. As such, pipeline looping would be required to ensure sufficient system capacity was available during the 20 percent pressure reduction scenario.

In the PRS alternative, the capacity limitations would be more significant than in the HSTP alternative because a pressure reduction of approximately 40 percent would be required to achieve hoop stresses below 30 percent of SMYS on the CTS pipelines. As such, more pipeline looping would be required to ensure sufficient capacity was available when the system is permanently operated with a 40 percent pressure reduction.

FEI is unable to identify what percentage of the system would require looping for the HSTP alternative without further and extensive analysis. The HSTP and PRS alternatives were dismissed for the reasons described in Section 4.4 of the Application. As such, FEI did not further investigate the alternatives to define any capacity management requirements.

70. Reference: CEC 1.26.2 and Exhibit B-5, BCUC 1.6.1

- **HSTP**

As described in Section 4.4.3 of the Application, 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. 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.

70.1 Would the additional looping required for the hydrostatic testing option serve to provide additional redundancy for the transmission system, mitigate the risk of cracking, or meet future requirements, potentially resulting in an overall additional benefit to customers? Please explain why or why not

Response:

The looping of existing un-looped segments could provide some benefits with respect to increased capacity, resilience, and redundancy, where those opportunities may exist. However, for the reasons discussed in Section 4.4.3 of the Application and further explained in the response to BCUC IR1 6.1, the HSTP alternative has significant challenges and shortcomings that would include leaving unidentified sub-critical cracks present in operating pipelines. FEI does not consider an HSTP solution, even with some incremental and localized capacity and resiliency benefits, as providing a greater overall benefit to customers than FEI's proposed solution.

71. Reference: Exhibit B-7, CEC 1.30.1/ Exhibit B-5, BCUC 1.12.1, and Exhibit B-7, CEC 1.3.2

> 12.1 Please discuss at what cost FEI would no longer consider the EMAT ILI alternative financially feasible.
>
> **Response:**
>
> As set out in Table 4-4 and further explained in Section 4.5 of the Application, FEI considers a Project alternative with an NPV of $1.8 billion or more to be cost prohibitive. FEI considers an alternative with a NPV of $307 million to be a reasonable level of expenditure to mitigate the risk posed by cracking threats on the CTS.
>
> FEI has not identified a threshold between these two points where an EMAT ILI alternative would be considered financially non-feasible. Ultimately, numerous factors contribute to FEI's determination of feasibility, including the amount of risk reduction, the capital cost of improvements versus the rate base value of the installed assets, the technical feasibility, environmental and archaeological impacts and impacts to the public and Indigenous groups.

> 3.2 To what extent are EMAT ILI tools already in use in other jurisdictions? Please provide the names of the jurisdictions in Canada and the US and the total length of pipelines using EMAT ILI to date.
>
> **Response:**
>
> FEI is aware of EMAT ILI tools being used throughout the world to manage cracking in transmission pipelines, and that their adoption is increasing throughout Canada and the US. FEI does not have access to the total length of pipelines using EMAT ILI to date in Canada and the US.
>
> Please also refer to the response to RCIA IR1 2.1 which documents FEI's awareness through public sources that all major operators of natural gas transmission pipelines in British Columbia, namely FEI, Westcoast, and Pacific Northern Gas have adopted EMAT ILI tools, and FEI's further awareness of EMAT ILI adoption by all Canadian Energy Pipeline Association members who are natural gas pipeline operators.

71.1 Please provide a total estimated cost per km of pipeline for the CTS TIMC project.

Response:

The total estimated cost per km of pipeline is $542 thousand in as-spent dollars.

This calculation uses the total CTS TIMC Project capital cost estimate of $137.8 million in as-spent dollars (as provided in Table 5-14 of the Application) divided by the total length of pipeline that will be inspected using EMAT ILI tools which is approximately 254 kilometres.

71.2 FEI intends to add the ITS TIMC project in the future. Please provide an estimated cost per km of pipeline for the ITS TIMC project.

Response:

FEI is currently developing cost estimates for the ITS TIMC Project. As such, FEI is unable to provide a cost per km of pipeline at this time.

71.3 Please provide any known $ per km of pipeline costs incurred in other jurisdictions for EMAT ILI.

Response:

FEI is not aware of publicly available sources for $ per km of pipeline costs in other jurisdictions for EMAT ILI. For clarity, the $ per km costs referenced in the responses to CEC IR2 71.1 and 71.2 are only with respect to the costs of the system modifications necessary to allow the use of EMAT ILI tools and therefore do not include the cost of the inspections themselves or any repair costs. As every operator's system has unique attributes (i.e., the system configuration required to deliver gas to their particular service territory and the design/construction attributes influenced by the year of construction or company-specific material selection) there is no reason to expect that the cost of modifications for one operator would be representative of the modification costs for another operator in a different jurisdiction.

72. Reference: Exhibit B-7, CEC 1.41.2.1 and 1.41.2.2

> 41.2.1 If the party such as a Husky Station would normally be required to remediate their own site, does FEI intend to recover costs from these landowners? Please explain why or why not.
>
> **Response:**
>
> If the site is not considered high risk under the EMA or the CSR, then there is no regulatory requirement for Husky or any other responsible person to remediate their site. FEI will remove contaminated soil from the rights-of-way, if encountered, to facilitate the Project because the EMA/CSR does not allow re-use of contaminated soil.
>
> 41.2.2 Has FEI contacted the landowners with contaminated sites? Please explain.
>
> 41.2.2.1 If yes, please briefly describe the communications between the parties.
>
> 41.2.2.2 If no, please explain why not.
>
> **Response:**
>
> The two Areas of Potential Environmental Concern (APECs) that are listed on the contaminated sites registry are the Husky fuel station and the Tilbury LNG plant. The other three APECs are not listed on the site registry, and are only considered to be areas that could potentially be contaminated due to present or historic land use. To date, FEI has not communicated with any of the landowners with regard to potential contamination. FEI plans to undertake sampling on its

72.1 Please confirm that, to the extent that any other parties have a legal obligation to remediate contamination that FEI encounters, FEI will undertake to recover the costs that it incurs from those parties.

Response:

FEI will assess on a case by case basis whether it is economical to pursue the recovery of remediation costs from responsible parties through litigation.