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July 27, 2021

British Columbia Utilities Commission
Suite 410, 900 Howe Street
Vancouver, B.C.
V6Z 2N3

Attention: Mr. Patrick Wruck, Commission Secretary

Dear Mr. Wruck:

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 British Columbia Utilities Commission (BCUC) Information Request (IR) No. 1

On February 11, 2021, FEI filed the Application referenced above. In accordance with BCUC Order G-149-21 setting out the Regulatory Timetable for the review of the Application, FEI respectfully submits the attached response to BCUC IR No. 1.

If further information is required, please contact the undersigned.

Sincerely,

FORTISBC ENERGY INC.

Original signed:

Diane Roy

Attachments

cc (email only): Registered Parties

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A. PROJECT NEED

1.0 Reference: PROJECT NEED AND JUSTIFICATION

Exhibit B-1 (Application), Section 3.4, p. 30

FEI Transmission Pipelines and JANA's Reports

On page 30 of the Application, FEI states that it retained JANA Consulting Inc. (JANA) to conduct two reports to assess the risk of cracking threats to its transmission systems. JANA's reports are attached to the Application as Confidential Appendices B-1 and B-2.

Footnote 13 on page 30 of the Application states:

> JANA has adopted the term "mainline" in Appendices B-1 and B-2 to describe pipelines within the scope of their studies. Mainline refers to FEI's transmission pipelines that are not laterals, and includes FEI's larger diameter pipelines that are in-line inspected.

1.1 Please provide the total number of FEI transmission pipelines (including laterals) that are not included in JANA's reports.

Response:

There are 106 FEI transmission pipelines (including laterals) that are not included in the two reports prepared by JANA. Lines within the scope of the TIMC project are pipelines of NPS 10 and greater, due to the availability of commercialized EMAT tools for pipelines of these sizes.

1.2 Please provide a general description of each FEI transmission pipeline that is not within the scope of JANA's studies, including the name, dimensions, material characteristics of the pipe, age, type of coating, leak history and location of the pipeline, as related to population density and whether the pipeline is equipped for in-line inspection (ILI). Please provide the results in a table form, by pipeline.

Response:

The tables below provide a general description of each of FEI's transmission pipelines that is not within the scope of JANA's studies:

Pipeline Name	Line Length (kilometres)	Steel Grade (MPa)	Wall Thickness (mm)	Year Installed	Age	Pipe Coating Type	Joint Coating Type	% in Class 3 Location	In-line Inspection Capable?	Number of Recorded Failures
Mackenzie Lateral 168	28.6	241/290	4.8	1996	23	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	1	No	0
Mackenzie Loop 168	14.2	290	4.8	1972	47	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
BC Forest Products Lateral 168	0.5	290	4.8	1996	23	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Prince George 3 Lateral 219	5.3	317	4.8	1970	49	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Northwood Pulp Lateral 168	6.0	290	4.8	1965	54	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	0	No	0
Northwood Pulp Loop 219	5.8	359	4.8	1995	24	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Prince George 1 Lateral 168	4.7	241	4.8	1957	62	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	0	No	1
Prince George Pulp Lateral 168	1.0	241/290	4.8	1964	55	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	0	No	0
Husky Oil Lateral 168	1.1	290	4.8	1965	54	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	0	No	0
Prince George 2 Lateral 168	8.6	241	4.8	1972	47	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Cariboo Pulp Lateral 168	1.3	241	4.8	1993	26	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Williams Lake Loop 1/Loop 2 168	5.9	241/359	4.8	1993	26	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Kamloops 1 Lateral/Loop 168	6.7	290	4.8	1965/1979	40/54	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	27/31	No	0
Salmon Arm Loop 168	44.9	290	4.8	1976	43	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	12	No	1
Salmon Arm 3 Lateral 168	0.8	290	4.8	1981	38	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0

Pipeline Name	Line Length (kilometres)	Steel Grade (MPa)	Wall Thickness (mm)	Year Installed	Age	Pipe Coating Type	Joint Coating Type	% in Class 3 Location	In-line Inspection Capable?	Number of Recorded Failures
Coldstream Lateral 219	1.8	290	4.8	1998	21	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	49	No	0
Coldstream Loop 168	3.8	290	4.8	1989	30	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	16	No	0
Kelowna 1 Loop 219	2.1	317	4.8	1976	43	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	33	No	0
Celgar Lateral 168	5.8	241	4.8	1960	59	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	4	No	0
Castlegar Nelson 168	37.4	241/290	4.8	1957	62	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	21	No	3
Trail Lateral 168	4.2	241	4.8	1957	62	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	0	No	1
Fording Lateral 219/168	79.6	241/290	4.8	1971	48	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	6	No	3
Elkview Lateral 168	1.6	290	4.8	1970	49	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	19	No	0
Cranbrook Lateral 168	34.0	290	4.8	1990	29	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	9	No	0
Cranbrook Loop 219	34.0	290	4.0	1968	51	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	9	No	0
Cranbrook Kimberley Loop 219	4.0	290	4.8	1992	27	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	0	No	0
Cranbrook Kimberley Loop 273	9.4	359	4.8	1992	27	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	21	No	0
Kimberley Lateral 168	20.6	241/290	4.8	1962	57	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	2	No	0
Skookumchuck Lateral 219	35.9	290	4.0	1968	51	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	0	No	0

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Pipeline Name	Line Length (kilometres)	Steel Grade (MPa)	Wall Thickness (mm)	Year Installed	Age	Pipe Coating Type	Joint Coating Type	% in Class 3 Location	In-line Inspection Capable?	Number of Recorded Failures Caused by Other than External Corrosion
Campbell River Lateral 219	49.5	414	5.5	1990	29	Extruded Polyethylene	Heat Shrink Sleeves	0	Yes	0
Crofton Lateral 168	5.1	359	7.0	1990	29	Extruded Polyethylene	Heat Shrink Sleeves	0	Yes	0
Harmac Lateral 168	9.7	360	7.0	1990	29	Extruded Polyethylene	Heat Shrink Sleeves	37	Yes	0
Mt Hayes Lateral 273	5.4	483	8.4	2010	9	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	Yes	0
Port Alberni Lateral 168	21.7	240	4.9	1990	29	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	15	Yes	0
108 Mile Lateral 60	0.1	240	3.9	1998	21	Unknown	Unknown	0	No	0
150 Mile House 60	0.1	240	3.9	1995	24	Unknown	Unknown	0	No	0
Afton Mines Lateral 114	0.7	240	4.0	1976	43	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Armstrong Lateral 114	0.4	240	4.8	1957	62	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	100	No	0
Ashcroft Lateral 60/88/168	9.1	240	3.9	1993	26	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	2	No	0
Bear Lake Lateral 60	1.2	205	3.9	1964	55	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Byron Creek Lateral 114	11.6	240	3.2	1985	34	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Cache Creek Lateral 60	1.4	240	4.0	1971	48	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Chase Lateral 88	30.3	290	3.2	1985	34	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	1
Chute Lake Lateral 88	0.1	240	5.5	2002	17	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	100	No	0
Clinton Lateral 60	21.7	240	3.2	1969	50	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0

Pipeline Name	Line Length (kilometres)	Steel Grade (MPa)	Wall Thickness (mm)	Year Installed	Age	Pipe Coating Type	Joint Coating Type	% in Class 3 Location	In-line Inspection Capable?	Number of Recorded Failures Caused by Other than External Corrosion
Coldstream Lateral 114	4.1	240	4.8	1969	50	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	11	No	0
Cominco Lateral 114	1.0	240	4.8	1958	61	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	0	No	0
Creston Lateral 114	6.9	240	3.2	1962	57	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	14	No	0
Dallas Lateral 60	0.1	240	3.9	1972	47	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	100	No	0
Deadman Creek Lateral 26	0.1	205	2.9	1990	29	Unknown	Unknown	0	No	0
Dunkley Mills Loop 114	4.2	240	3.2	2004	15	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Dunkley Mills Lateral 60	5.7	240	3.2	1980	39	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Elko Lateral 88	0.9	240	4.0	1969	50	Unknown	Unknown	0	No	1
Enderby Lateral 114	0.2	240	4.8	1957	62	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	100	No	0
Fernie Lateral South Loop 114	7.9	290	4.8	1998	21	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Fernie Lateral North Loop 88	12.0	290	4.0	1991	28	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Fernie Lateral 88.9/168	23.1	240	3.2	1962	57	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	5
Finlay Forest Industries Loop 114	4.2	205	3.9	1981	38	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Finlay Forest Industries Lateral 60	4.3	205	3.9	1966	53	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0

Pipeline Name	Line Length (kilometres)	Steel Grade (MPa)	Wall Thickness (mm)	Year Installed	Age	Pipe Coating Type	Joint Coating Type	% in Class 3 Location	In-line Inspection Capable?	Number of Recorded Failures Caused by Other than External Corrosion
Fort Nelson Loop 114	0.7	240	4.0	1985	34	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Galloway Lateral 60	9.6	240	3.2	1981	38	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	1
Gibralter Mines Lateral 60	10.2	240	3.9	1971	48	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Grand Forks Lateral 114	0.9	240	4.8	1957	62	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	0	No	0
Green Lake Lateral 33	0.0	240	4.5	1993	26	Unknown	Unknown	0	No	0
High Country Estates Lateral 60	0.6	240	3.2	1975	44	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Hudson Hope Lateral 60	10.0	205	3.9	1965	54	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Highmont Mine Lateral 60	2.9	290	3.2	1979	40	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	1
Horse Lake Lateral 60	0.0	240	5.5	1993	26	Unknown	Unknown	100	No	0
Highland Valley Lateral 114	16.3	240	3.9	1971	48	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Kamloops 2 Lateral 114	1.1	240	4.8	1957	62	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	68	No	0
Kimberley Lateral 114	2.2	240	3.2	1962	57	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	24	No	0
Kelowna 1 Lateral 114	2.1	240	4.8	1957	62	Polyethylene Tape	Coal Tar, Heat Shrink Sleeve, or Cold Applied Polymer Tape	31	No	0
Knutsford Lateral 60	4.2	290	3.2	1984	35	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0

Pipeline Name	Line Length (kilometres)	Steel Grade (MPa)	Wall Thickness (mm)	Year Installed	Age	Pipe Coating Type	Joint Coating Type	% in Class 3 Location	In-line Inspection Capable?	Number of Recorded Failures Caused by Other than External Corrosion
Lac La Hache Lateral 60	0.2	240	3.9	2002	17	Unknown	Unknown	0	No	0
Ladysmith Lateral 114	1.0	360	4.9	2008	11	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	44	No	0
Lafarge Cement Lateral 114	3.3	240	4.8	1969	50	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Logan Lake Lateral 60	0.7	205	3.9	1971	48	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Line Creek Lateral 114	2.8	240	4.0	1981	38	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Louisiana Pacific Lateral 114	9.4	205	4.0	1995	24	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Marysville Lateral 60	0.9	240	3.9	1962	57	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	100	No	0
Merritt Lateral 114	4.9	240	3.9	1957	62	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	13	No	0
Moan Road Lateral 60	0.7	240	3.9	1995	24	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Mt Hayes Lateral 114	5.4	360	4.5	2010	9	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
North West Energy Lateral 114	6.4	240	3.9	1993	26	Fusion Bond Epoxy	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Oliver Lateral 114	2.0	240	4.8	1957	62	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	87	No	0
Osoyoos Lateral 114	20.9	240	4.8	1957	62	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	3	No	0
Port Mellon Lateral 114	0.7	359	4.0	1990	29	Extruded Polyethylene	Heat Shrink Sleeves	0	No	0

Pipeline Name	Line Length (kilometres)	Steel Grade (MPa)	Wall Thickness (mm)	Year Installed	Age	Pipe Coating Type	Joint Coating Type	% in Class 3 Location	In-line Inspection Capable?	Number of Recorded Failures Caused by Other than External Corrosion
Princeton Lateral 88	67.0	240	4.8	1968	51	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Powell River 114	1.1	360	5.5	1991	28	Extruded Polyethylene	Heat Shrink Sleeves	90	No	0
Quesnel 2 Lateral 114	2.8	290	4.0	1982	37	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Rossland Lateral 114	1.1	290	4.8	1957	62	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	45	No	0
Salmon Arm Lateral 114	44.3	240	4.8	1957	62	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	14	No	2
Savona Lateral 60	1.5	240	3.9	1958	61	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	58	No	0
Shoreacres Lateral 114	0.3	290	4.8	1993	26	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Silver Creek Lateral 60	6.7	290	3.2	1985	34	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Sorrento Lateral 114	24.7	290	3.2	1985	34	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	7	No	0
Spallumcheen Lateral 114	3.4	240	4.8	1995	24	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Sparwood Lateral 114	8.8	240	4.8	1969	50	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Summerland Lateral 114	16.0	240	4.8	1957	62	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	45	No	1
Swan Lake Lateral 60	1.6	240	3.9	1967	52	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Fort Nelson Tackama Forest Lateral 60	1.6	240	3.9	1975	44	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	0	No	0

Pipeline Name	Line Length (kilometres)	Steel Grade (MPa)	Wall Thickness (mm)	Year Installed	Age	Pipe Coating Type	Joint Coating Type	% in Class 3 Location	In-line Inspection Capable?	Number of Recorded Failures Caused by Other than External Corrosion
Tilbury Lng Plant 168	1.7	205	4.8	1971	48	Extruded Polyethylene	Heat Shrink Sleeves	100	No	0
Vernon 1 Lateral 114	0.6	240	4.8	1957	62	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	100	No	0
Westar Timber Lateral 60	1.0	290	3.2	1988	31	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0
Williams Lake Lateral 114	10.0	240	4.0	1957	62	Asphalt Enamel	Asphalt Enamel, Coal Tar, or Cold Applied Polymer Tape	0	No	0
Wildwood Lateral 60	0.5	290	3.2	1982	37	Extruded Polyethylene	Heat Shrink Sleeve, or Cold Applied Polymer Tape	0	No	0

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1.3 Please explain why JANA's assessment only includes FEI transmission pipelines that are not laterals.

Response:

For the TIMC project, FEI optimized the scope of work of its QRA by including transmission pipelines of NPS 10 or larger for which EMAT ILI tools are commercially available. As EMAT ILI tools are not yet generally commercially available for the smaller pipe diameters typical of FEI's laterals, smaller pipe diameters were generally excluded from JANA's assessment.

1.4 Please identify all FEI transmission pipelines that are not included in the JANA studies and are operating at pressures at or above 30 percent Specified Minimum Yield Strength (SMYS) of the pipe.

Response:

FEI defines transmission pipelines as pipelines operating at or above 30 percent of specified minimum yield strength (SMYS) of the pipe.[1] Please refer to the response to BCUC IR1 1.2 for a listing of all transmission pipelines that are not included in the JANA studies and are operating at pressures at or above 30 percent of SMYS.

1.5 Please discuss whether FEI assessed the risk of cracking threats to its remaining transmission pipelines which were not studied by JANA. Please explain why or why not.

1.5.1 If so, please provide FEI's risk assessment on those transmission pipelines and discuss the risk assessment method and any assumptions.

1.5.2 If so, please explain how FEI is managing the risk of cracking threats on those transmission pipelines.

1.5.3 If not, please explain whether FEI intends to assess the risk on the remaining transmission pipelines and, if so, when.

[1] Refer to Section 3.5.3.1 of the Application.

Response:

FEI did not undertake a QRA and did not assess the risk of cracking threats to its remaining transmission pipelines which were not studied by JANA. The baseline QRA was required for the CTS TIMC Project and the scope was optimized for this purpose. Please also refer to the response to BCUC IR1 1.3.

The QRA submitted as part of the CTS TIMC Application is the first iteration of FEI's QRA. FEI currently envisions that its second and future QRA iterations will be undertaken using internal resources as part of a sustainable, ongoing process for risk management of its transmission pipelines. While FEI is unable to confirm the timing of future iterations, FEI is developing a risk assessment process that will be applicable to all of FEI's BCOGC-regulated pipeline assets, and will, in time, be implemented for all of these assets.

As discussed in Section 3.2.5 of the Application, FEI manages the risk of cracking threats on its remaining transmission pipelines which were not studied by JANA by inspecting for cracking during "opportunity digs" when the pipeline is exposed because of other condition assessments. If significant cracking is discovered, a line specific mitigation plan will be developed. For transmission lines of diameter less than NPS 10 that are susceptible to cracking threats that can lead to failure by rupture, FEI will continue to monitor technologies as they become available and may determine that EMAT ILI is prudent in the future.

2.0 Reference: PROJECT NEED AND JUSTIFICATION

Exhibit B-1, Section 3.4.3.3, p. 41

Stress Corrosion Cracking (SCC) Crack Growth Rate Analysis

On page 41 of the Application, FEI provides the following description of the analysis performed on SCC crack growth rates:

> This analysis was conducted in conjunction with Dr. Chen of the University of Alberta, a recognized SCC expert researcher. Software developed by Dr. Chen, called Pipe-Online, was used for the analysis of SCC crack growth behaviour and to predict the remaining lifespan of a pipeline prior to cracks growing to failure. The analysis utilized pressure data from 54 pipeline locations in the CTS [Coastal Transmission System] and ITS [Interior Transmission System], 8 FEI detailed field inspection reports from integrity digs, and a summary of SCC findings from 14 dig excavations. The analysis considered a range of crack depths and lengths, which are reasonable approximations of what could be anticipated to be present in the FEI system. The analysis also considered a range of fracture toughness values consistent with typical industry values. The analysis used these inputs, FEI's operating conditions, and the Pipe-Online software to project the time to failure of SCC cracks.

Footnote 18 on page 41 of the Application states:

> SCC crack growth analysis was applied to SCC crack features derived from a sample of FEI dig reports, actual FEI operating data and pipe material properties characteristic of the FEI system.

2.1 Please provide the summary of SCC findings from the 14 dig excavations used in the SCC crack growth rate analysis referenced in the preamble.

Response:

JANA provides the following response:

For the Dr. Chen analysis, a total of 296 dig reports from the 2013 to 2017 time period were analyzed (dig reports for 14 pipelines, referenced as "14 dig excavations" in the Application). All eight dig reports where SCC was identified were provided to Dr. Chen (with a total of 16 SCC colonies identified in those eight dig reports).

2.2 Please describe FEI's methodology for deciding which sample of FEI dig reports to use in the SCC crack growth rate analysis.

Response:

JANA provides the following response:

The eight dig reports were the most recent dig reports with identified SCC at the time of analysis. These were provided so that Dr. Chen could characterize the most recent SCC found on the FEI system to use in his analysis.

2.3 Please explain why FEI believes that the range of crack depths and lengths considered in the analysis are a reasonable approximation of what could be anticipated to be present in the FEI system.

Response:

FEI's statement was based on JANA's analysis and therefore FEI requested JANA to provide the response to this question.

JANA provides the following response:

The range of crack lengths and depths is considered a reasonable approximation of what could be anticipated to be present in the FEI system as the ranges are in alignment with the cracking found to date on the FEI system. Please refer to Figures 3 and 4 in Confidential Appendix B-1, Analysis of Cracking Threats in FEI Mainline Pipelines. The ranges were selected in conjunction with Dr. Chen based on his experience with SCC cracking.

2.4 Please discuss whether FEI has made any additional SCC findings on its transmission system since Dr. Chen's analysis on SCC crack growth rates was performed.

2.4.1 If so, please provide the results of any new SCC finding.

Response:

FEI's SCC findings made after Dr. Chen's analysis are included in the response to BCUC IR1 11.1. These findings have not been used to update Dr. Chen's analysis on SCC crack growth rates, and as such, there are no results to provide. FEI's SCC findings made after Dr. Chen's analysis have been consistent with FEI's past findings of SCC, and therefore FEI does not expect that Dr. Chen's analysis would be significantly changed by incorporating these results.

2.5 Please discuss any additional integrity digs FEI completed, or could complete, to improve its understanding of cracking occurrence and size variation on its system.

Response:

JANA provides the following response:

Additional integrity digs would not materially improve FEI's understanding of cracking occurrence and size and variation. Due to the nature of SCC, where highly localized factors combine to drive the mechanism of failure, cracking can vary meter by meter along the length of the pipeline. For a pipeline of many kilometers, an integrity dig, which exposes a very limited length of pipe (typically on the order of 10 meters), only provides information for the limited section exposed.

2.6 Please describe, in detail, Dr. Chen's method for calculating SCC crack growth behavior, the accuracy of the results and any potential sensitivities or limitations in the results.

Response:

JANA provides the following response:

In addition to the analysis of industry SCC failures under operating conditions like those of the FEI system, the purpose of the Dr. Chen analysis was to assess if it is possible for the cracking observed to date on the FEI system to grow to failure. As there is not a complete characterization of the cracking on the FEI system, such as would be obtained by EMAT ILI analysis, Dr. Chen ran his crack growth models considering a range of practical input values in terms of the possible crack sizes, pipeline properties and operating conditions. The range of input parameters resulted in a range of calculated times to failures and represents the greatest limitation in the analysis. The purpose of the assessment, however, was not to develop explicit lifetime estimates, but to assess if the cracking could in fact grow to failure to further support the analysis of industry failures that confirmed that SCC failures have been observed under FEI operating conditions (in terms of % SMYS (Specified Minimum Yield Strength).

Dr. Chen's analysis methodology was developed and refined over several years through PRCI (Pipeline Research Council International) projects and research in his laboratory in conjunction with pipeline operators.

From extensive research, it has been determined by Dr. Chen's research group that crack growth in near-neutral pH SCC is driven by mechanisms consistent with corrosion fatigue. Based on long-term and extensive laboratory crack growth simulations, it was found that the crack growth rate (*da*/*dN*) could be correlated to a combined factor that incorporates both the mechanical and the environmental driving forces as expressed in the following equation:

$$\frac{da}{dN} = A\left(\frac{\Delta K^{\alpha} K_{max}{}^{\beta}}{f^{\gamma}}\right)^{n} + h \qquad (1)$$

In equation (1), *A*, *n*, α, β, and γ are all constants, $\alpha + \beta = 1$, and *h* is the contribution of stress corrosion cracking, which was found to be about one order of magnitude lower than the first term in Stage II crack growth. $(\Delta K^{\alpha} K_{max}{}^{\beta})/f^{\gamma}$ is termed as the combined factor, *ΔK* is the change in stress intensity at the crack tip due to cyclic loading, K_{max} is the maximum stress intensity at the crack tip, and γ is a factor representing the influence of the corrosion environment on the crack growth rate. *ΔK* and K_{max} are strongly dependent on the geometry of the specimen. Equation (1) has been validated by crack growth rate data obtained from full scale tests.

Equation (1) has also been revised to incorporate the effect of variable pressure loading conditions during field operation on crack growth rates. Dr. Chen has received positive feedback from several pipeline operators on the accuracy of the results of the model when compared to field studies.

The primary limitation of the Dr. Chen analysis is the uncertainty around the cracking that could be present in the FEI system (i.e., the actual range of crack sizes that could be present in the FEI system). Therefore, a range of input values was used to assess the potential for a crack to grow to failure on the FEI system given the cracking observed to date and the specific operating conditions.

Details on Dr. Chen's calculation of SCC crack growth have been published in *Metallurgical and Materials Transaction A: Physical Metallurgy and Materials Science*, which a peer-reviewed publication, as detailed in the references to Confidential Appendix B1.

2.7 Please describe any other studies FEI has performed to determine SCC crack growth behavior on its transmission pipeline system. Please provide the results of any such studies.

Response:

FEI has not performed any other studies to determine SCC crack growth behaviour on its transmission pipeline system.

2.8 Considering the scope and timeline of the CTS TIMC Project, please discuss any temporary risk mitigation actions that FEI has taken, or could take, such as reducing operating pressures, to reduce the likelihood of a leak or rupture until the CTS TIMC Project is complete.

Response:

FEI is not aware of any temporary risk mitigations that FEI can take to meaningfully reduce the likelihood of a leak or rupture before the CTS TIMC Project is complete without impairing the ability of FEI to meet the gas demand of customers supplied by the CTS.

While FEI recognizes that a pressure reduction could reduce the likelihood and/or consequences of a leak or rupture, FEI has not implemented such measures on the basis that:

- FEI requires the CTS to be at full operating pressure to maintain the capacity to serve its customers reliably throughout the year, and to respond to changes in load/demand; and
- FEI has no certainty in the degree of risk mitigation that may be achieved in the absence of specific crack data that will be obtained through the use of EMAT ILI technology on the CTS.

FEI has proposed the CTS TIMC Project scope that meaningfully mitigates the risk of cracking threats, and a Project timeline that mitigates the risk over an appropriate timeline. As discussed in the response to BCUC IR1 4.3, prioritizing the work on CTS pipelines as set out in the Application enables FEI to mitigate a larger proportion of system risk in a shorter time period.

2.9 Please describe the methodology and assumptions FEI used to forecast pipeline operating pressures for the crack growth rate analysis.

Response:

JANA provides the following response:

The crack growth analysis used hourly pressure measurements over a two-year operating period. The analysis assumed that future operation would be characterized by the pressure cycles observed over the measurement history.

2.9.1 Please discuss whether transporting methane with hydrogen in FEI's transmission system would impact SCC crack growth behavior on its pipelines. If yes, please describe the methodology and assumptions FEI used to determine the appropriate gas composition for the crack growth rate analysis.

Response:

FEI provides the following response:

FEI is still evaluating the impact of an increasing concentration of hydrogen in FEI's natural gas system on the risks posed by stress corrosion cracking, including SCC crack growth behaviour, and is unable to provide discussion at this time.

JANA provides the following response:

The analysis considered gas only with methane. More detailed characterization would be required to assess the impact of hydrogen transported within the gas stream on SCC.

3.0 Reference: PROJECT NEED AND JUSTIFICATION

Exhibit B-1, Section 3.4.1, p. 30; Section 3.4.4.2, p. 43

FEI Inland Gas Upgrades CPCN proceeding (IGU Project), Exhibit B-10, BCUC IR 36.2

Prioritization of CTS

On page 30 of the Application, FEI states:

> Based on its assessments, JANA concluded that the pipelines on FEI's CTS and ITS are susceptible to cracking threats which can lead to failure by rupture. The QRA identified that, at the system level, the safety risk is highest on the CTS and that cracking threats are the largest contributor to that risk. Based on the results of these assessments, FEI has prioritized work on the CTS in this Application and is developing a further TIMC project for work on the ITS.

On page 43 of the Application, FEI provides a safety risk comparison between its three transmission systems: CTS, ITS and Vancouver Island Transmission System (VITS). FEI states that based on the JANA assessments, "the CTS has the highest risk, driven primarily by its proximity to populated areas, followed by the ITS system. The VITS system has the lowest risk as it is a newer system in largely unpopulated areas."

In response to BCUC Information Request (IR) 36.2 in the IGU Project, FEI stated:

> FEI scheduled the order of execution based on the duration required to complete the laterals due to scope, length, operational limitations, and approval requirements. FEI has developed the schedule of the IGU Project based on optimizing the use of resources and to gain efficiencies in execution. FEI does not believe there would be any material impact from a safety perspective by prioritizing the laterals differently.

3.1 Please explain how pipeline proximity to populated areas is evaluated and explain how it was applied in JANA's safety risk assessment to identify CTS as the highest priority.

Response:

JANA provides the following response:

Pipeline proximity to populated areas was evaluated using industry standard approaches and geospatial analysis. This proximity was used in combination with a potential impact radius to assess the safety consequence in the safety risk assessment. The potential impact radius in this assessment was determined using the same method outlined in ASME B31.8S for natural gas pipelines. When combined with the frequency of failure assessments for each pipeline segment, a risk result was generated (risk = frequency of failure x potential consequences). These risk results were aggregated for each pipeline to arrive at overall on risk scores on a pipeline-by-

pipeline basis. The total risk of all pipelines in each of the three systems (CTS, ITS and VITS) was then aggregated to arrive at a total risk for each system. Based on this analysis, the CTS was shown to have the highest risk of the three systems. As cracking threats were also the highest contributor to risk in the CTS, this system was identified as highest priority.

3.2 Please discuss whether there are different regulatory or technical requirements for gas transmission pipelines in areas of higher population density.

3.2.1 If so, please provide details of the different requirements.

3.2.2 If so, please explain whether the different requirements factored in FEI's decision to prioritize CTS.

Response:

The CSA Z662:19 standard uses the term "Class Location" to classify the geographical area surrounding a pipeline according to its approximate population density and/or the potential for people to congregate. The potential class location designations range from Class 1 (least populated areas) to Class 4 (most populated areas).

CSA Z662:19 includes some prescriptive requirements with respect to the design and construction of pipelines in varying population densities. While various design and construction parameters can vary by class location, the primary parameters by class location are as follows:

- pipeline operating stress (in general locations[2]):
  - Class 1: maximum operating stress is 80 percent of specified minimum yield strength (SMYS)
  - Class 2: maximum operating stress is 72 percent of SMYS
  - Class 3: maximum operating stress is 56 percent of SMYS
  - Class 4: maximum operating stress is 44 percent of SMYS
- minimum pressure for a post-construction hydrostatic test:
  - Class 1 and Class 2: minimum test pressure is 125 percent of intended maximum operating pressure
  - Class 3 and Class 4: minimum test pressure is 140 percent of intended maximum operating pressure

[2] In some specific locations (e.g., road crossings) the maximum operating stresses may be lower.

The responses to increased population densities during the operation and maintenance of pipeline systems are less defined by the CSA standard. Examples are as follows:

- A guidance note to CSA Z662:19 Clause 9.9.6 suggests that population density, among other things, should be reviewed when considering inspection techniques (e.g., ILI) to monitor the effectiveness of a pipeline system's corrosion control program. This clause has existed in the CSA Z662 standard since 2003 or before, at a time when in-line inspection was not at an equivalent level of adoption by the pipeline industry as it is today. FEI, in alignment with its peers, is using in-line inspection techniques to monitor the condition of its transmission pipelines in areas of both high population density and low population density.

- CSA Z662:19 Clause 10.5.3.2 requires that pipeline signage be placed with consideration to, among other things, population density.

- CSA Z662:19 Clause 10.6.1.2 requires that the frequency of pipeline patrols be determined with consideration to, among other things, population density.

- CSA Z662:19 Clauses 10.10.2.5.1 and 10.11.2.3.1 require that the acceptance and repair of external metal loss imperfections be subject to a safety factor based on a pipeline's class location.

- CSA Z662-15 Clause 12.10.3.3 requires that the frequency of leak survey program for distribution pipeline systems be determined with consideration to, among other things, population density.

As explained in Section 3.4.5 of the Application, FEI's prioritization of the CTS has been informed by the baseline QRA that estimates that the CTS pipelines present a higher risk at the system level when compared to the ITS pipelines, and that cracking threats are the top driver of that risk. FEI did not explicitly consider any specific regulatory or technical requirements for gas transmission pipelines in areas of higher population density in its decision to prioritize the CTS TIMC Project.

3.3 Please explain why FEI prioritizes work in the CTS TIMC Project based on higher risk but prioritizes work in the IGU Project based on optimizing the use of resources and to gain efficiencies in execution.

Response:

As explained in the response to BCUC IR1 3.1 in the IGU Project (provided as Attachment 3.3), FEI's assessment (which was also supported by its external consultant, JANA) of the 29 Transmission Laterals was that there was no material difference in the integrity risk level of the

laterals. As such, FEI did not consider it necessary to prioritize work based on risk for the IGU Project and, instead, optimized the work based on the use of resources and to gain efficiencies in execution. For example, the work in the IGU Project is being performed on isolated or groups of laterals that are supplying population centres around the Province separated by hundreds of kilometers. As such, FEI pursued the optimization of resources and ability to gain execution efficiencies and to bring tangible benefits to the IGU Project in terms of cost and scheduling.

In contrast, the QRA performed by JANA for the TIMC project showed that there are differences in the integrity risk level between the CTS and ITS and the individual pipelines within these two systems. Further, CTS TIMC Project factors, such as the scheduling of work within a single construction season and the relative geographic proximity of construction, provided little opportunity for meaningful execution efficiencies through the reprioritization of work activities. As such, FEI prioritized work related to the CTS TIMC Project based on risk rather than the use of resources.

3.4 Please explain whether prioritizing work in the CTS TIMC Project based on optimizing the use of resources and to gain efficiencies in execution would result in cost savings. If so, please estimate the amount of these potential savings.

Response:

The execution of the CTS TIMC Project, the scope of which is provided in Section 5 of the Application, has been optimized based on resourcing and maximizing efficiencies. The work cannot be further optimized, and therefore no potential savings are expected.

3.5 Please describe any assessments to prioritize the 13 pipelines in order of risk level and provide the results of these assessments. Please explain whether risk level affects the order in which pipeline modifications are completed within the CTS TIMC Project.

Response:

FEI utilized the QRA prepared by JANA (filed confidentially as Appendix B-2) to prioritize the 13 CTS pipelines in order of risk level. Please refer to the material in Confidential Appendix B-2 for the assessments performed and the corresponding results.

1 The risk level does not affect the order in which pipeline modifications are completed within the
2 CTS TIMC Project. All work is scheduled to be completed within the same year (2024) as shown
3 in Table 5-9 of the Application.

4

4.0 Reference: PROJECT NEED AND JUSTIFICATION

Exhibit B-1, Section 1.3.1, p. 4

FEI IGU Project, Exhibit B-10, BCUC IR 36.2

Prioritization of CTS

On page 4 of the Application, FEI states:

> JANA's assessment shows that 11 pipelines on the CTS, and nine on the ITS, are susceptible to cracking. Further, the QRA has shown that, at the system level, the safety risk is greatest on the CTS and that cracking is the greatest contribution to this risk. FEI has therefore prioritized work on the 11 CTS pipelines that are susceptible to cracking through the CTS TIMC Project.

In response to BCUC IR 36.2 in the IGU Project, FEI stated:

> The QRA will provide a comprehensive understanding of system risk which will identify priority lines for mitigation of stress corrosion cracking and other crack-like imperfections. For this purpose, the QRA is assessing approximately 70,000 individual pipeline segments, and providing over 4 million risk estimate outputs. This will inform the TIMC project as follows:
>
> - The QRA will inform FEI's determination of the TIMC project scope of work. When planning system improvements to enable crack management, FEI will also be evaluating opportunities to improve system resiliency where the incremental investment can be justified from a risk reduction perspective.
> - The QRA will also inform FEI's determination of the TIMC project implementation and prioritization. FEI anticipates that resource and schedule optimization for CPCN development and project implementation will play a role in its determination of which project(s) will comprise its first TIMC CPCN application. It is possible that a project to address a higher risk pipeline, if more complex and requiring more time for CPCN development, may be applied for later than a project to address a lower risk pipeline.

4.1 Please discuss the role that resource and schedule optimization for CPCN development played in FEI's determination of which projects to include in its first Transmission Integrity Management Capabilities (TIMC) CPCN application.

Response:

As described in responses to BCUC IR1 3.4 and 3.5, FEI has prioritized its pipelines by risk and included the majority of higher risk pipelines as part of the CTS TIMC Project. As described in

Section 3.4.5 of the Application, ITS pipelines will be included in a forthcoming CPCN application.

Only three shorter CTS pipelines (TIL LNG 323, TIL BEN 323, and TIL FRA 508) were assessed by JANA as having a lower relative risk than ITS pipelines. Resource and schedule optimization brought these pipelines within the scope of this Application because of their proximity to the other higher risk pipelines and the shared footprint of the Tilbury Valve Assembly with the higher risk ROE TIL 914 pipeline.

4.2 Please discuss whether resource or schedule limitations were factors in FEI's decision-making when determining which projects to include in its first TIMC CPCN application.

Response:

As explained in the response to BCUC IR1 4.1, with three exceptions, the pipelines on the CTS were assessed by JANA as having a higher safety risk than the ITS. In determining which projects to include in its first TIMC Application, FEI considered the availability of resources and schedule limitations that would meaningfully impact Project execution. However, these considerations were ultimately secondary to the relative risk of each pipeline assessed and the need to address system level risk expeditiously and without undue delay.

4.3 Please discuss any potential challenges which FEI may face regarding: (i) resources; (ii) project timeline; (iii) CPCN development; or (iv) other challenges if its first TIMC CPCN application were to include higher risk pipelines in the ITS.

Response:

As described in Section 3.2.4 of the Application, cracking threats are time-dependent meaning that their potential to impact the pipeline increases over time. The decision to only include CTS pipelines in this Application enables FEI to mitigate a larger proportion of system risk in a shorter time period. As discussed below, the proposed Project schedule would not have been achievable had higher risk ITS pipelines been included in the Project scope.

FEI identified the following potential challenges resulting from the inclusion of higher risk pipelines in the ITS that would extend the Project schedule such that potential cracking threats have more time to grow:

- **CPCN Development:** The inclusion of higher risk pipelines in the ITS would have delayed CPCN development and submission due to an overall larger Project scope with the inclusion of additional pipelines. Further, FEI's ITS TIMC CPCN development activities have confirmed that the ITS pipelines are capacity constrained if required to operate at a reduced pressure. Therefore, as described in Section 5.5.4 of the Application, pressure reductions may be required after the EMAT ILI run. FEI does not face the same challenges with the CTS pipelines and thus, FEI has had to spend significantly more time determining ways to manage the capacity constraints on the ITS pipelines post-EMAT. Given this significant scope distinction, filing separate applications for the CTS and ITS TIMC projects is appropriate and allowed FEI to file the CTS TIMC Application sooner than a combined application, and thus is able to mitigate the risk posed by cracking threats to the CTS system earlier.
- **Resources:** The inclusion of higher risk pipelines in the ITS would necessitate the deployment of resources in two different geographic locations. FEI would require additional operations, Indigenous and community relations, and environmental management resources to deal with the different requirements associated with working in the Lower Mainland (for the CTS) and the Interior region (for the ITS). The effort and timelines associated with coordinating the appropriate resources would contribute to the delays described above.
- **Project Timeline:** As a result of the delays in CPCN development that would occur should higher risk ITS pipelines have been included in this Application, the Project timeline would also have been delayed for the CTS TIMC pipelines.
- **Other Challenges:** The inclusion of select higher risk ITS pipelines in the CTS TIMC Application would result in the need to consult and engage with some external stakeholders and Indigenous groups as part of two separate applications. When possible, it is FEI's preference to coordinate consultation and engagement activities to maintain transparency of current and potential future associated impacts of the proposed Project, and to maximize internal and external capacity.

4.4 Please discuss whether any project(s) to address a higher risk pipeline in the ITS has been deferred by prioritizing work on the CTS.

4.4.1 If so, please describe the deferred project's scope, cost, and anticipated schedule

4.4.2 Please discuss the risk trade-offs involved in the decision.

Response:

No high risk pipelines on the ITS have been deferred by prioritizing work on the CTS, but rather, as explained further below, some risks cannot be addressed until the capacity improvements outside the scope the ITS TIMC Project are completed.

The majority of CTS pipelines included in the Project have a higher safety risk than the ITS pipelines. In particular, only 3 of the 11 CTS pipelines included in this Application pose a lower risk than the ITS pipeline assessed by JANA as having the highest risk.

In order to address the cracking threats on the highest risk ITS pipeline, the Okanagan Capacity Upgrade (OCU) Project, for which a CPCN Application was filed with the BCUC on November 16, 2020, must be in service to ensure that FEI is able to meet customer demand in the event that the SCC-susceptible pipeline in the ITS is required to operate at a 20 percent pressure reduction for an extended period.

4.5 Please discuss whether FEI considered grouping the CTS transmission pipelines into smaller CPCN applications due to resource and schedule risks/complexities.

4.5.1 If yes, please explain the grouping options considered and why FEI determined that it would not be more reasonable to apply for separate CPCNs for some of the CTS pipelines.

4.5.2 If no, please explain why not, including any potential drawbacks to this approach.

Response:

FEI did not consider grouping the CTS pipelines into smaller applications. The CTS is an interconnected system in a relatively small geographic area and grouping all 11 CTS pipelines into a single application ensures efficiency, cost savings, and ultimately, mitigates risk to FEI's system in a timely manner.

An approach whereby the CTS pipelines were grouped into smaller CPCN applications would: (1) result in higher overall costs (due to repeated regulatory approval processes); (2) require additional time to obtain all of the necessary approvals,; and (3) lead to a protracted risk mitigation process on the CTS. In practice, additional applications would not decrease the time it would take to mitigate risk on the highest risk CTS pipelines, but would delay risk mitigation on the lower ranked CTS pipelines.

4.6 If the BCUC did not grant this CPCN for the entire scope of the Project (i.e. all 11 CTS pipelines), please explain the implications for the CTS TIMC Project (e.g. cost, timing, scope) and how FEI would adjust its approach to the projects.

Response:

If the BCUC did not grant this CPCN for the entire scope of the Project, FEI would need to consider the BCUC's reasons and assess its options at that time. As cracking threats are time-dependent and must be mitigated, FEI would need to address whatever concerns the BCUC identified in its Decision (including making any necessary scope alterations) and seek the appropriate approvals to move forward with the Project.

4.7 Please discuss any opportunities that FEI considered to improve system resiliency in the CTS TIMC Project and provide the associated cost benefit analysis.

Response:

The nature of the system alterations required to support running EMAT ILI tools did not present any opportunities to increase system resiliency. These alterations primarily consist of modifications of ILI tool launchers and receivers at existing gate stations to accommodate EMAT ILI tools, and the removal of heavy wall pipe segments in existing pipelines that could impair data collection by the EMAT ILI tool. These modifications do not affect the overall configuration or operation of the CTS, and hence do not directly impact system resiliency.

5.0 Reference: PROJECT NEED AND JUSTIFICATION

Exhibit B-1, Appendix C

BC Oil and Gas Commission Support for Project

Appendix C to the Application, the BC Oil and Gas Commission (BCOGC) states: "The Commission is supportive of FEI taking action to address its known integrity concerns and to ensure that it meets its requirements as a permit holder under the Oil and Gas Activities Act."

5.1 Please explain whether FEI currently meets all of its requirements as a permit holder under the *Oil and Gas Activities Act* related to integrity management on the CTS system.

Response:

FEI currently meets all of its requirements and obligations as a permit holder under the *Oil and Gas Activities Act* (OGAA) related to integrity management on the CTS.

The TIMC project is necessary for FEI to maintain compliance with its regulatory obligations and reflects FEI's assessment of relevant hazards to its pipeline system, FEI's understanding of industry practice, as well as FEI's knowledge of evolving technology available for assessing and managing pipeline condition.

The BCOGC has previously directed FEI to conduct a segment-by-segment risk assessment of its pipelines, and has expressed its support for the CTC TIMC Project, as included in Appendix C of the Application. While FEI does not interpret support from the BCOGC as a requirement that the Project be undertaken, if FEI were not taking steps to meet its legal and regulatory obligations, it is possible that the BCOGC would issue a direction to FEI requiring the activities enabled by the CTS TIMC Project.

5.2 Please explain whether the CTS TIMC CPCN Project was required by the BCOGC.

Response:

Please refer to the response to BCUC IR1 5.1.

B. PROJECT ALTERNATIVES

6.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES
Exhibit B-1, Section 1.3.3, p.6; Section 4.1, p. 56
Introduction and Overview

On page 6 of the Application, FEI states:

> As described in Section 5, the Project consists of the work required to modify pipelines within FEI's existing rights of way and associated facilities to ready the CTS for EMAT ILI tools. This work includes the replacement of 13 heavy wall segments on six CTS pipelines, to enable the EMAT ILI tools to travel within its optimal velocity range. The work also includes alterations to 13 CTS facilities, consisting of modifications to pig barrels and station piping, and the addition of pressure, flow and backflow regulating capability, as needed to run the EMAT ILI tools.

On page 56 of the Application, FEI states:

> This section describes FEI's evaluation of alternatives to complete the CTS TIMC Project. Based on the Project need and justification set out in Section, the objective of the Project is to enhance FEI's integrity management capabilities to mitigate cracking threats to the 11 CTS transmission pipelines (Project Objective).
>
> There are six alternatives currently available to achieve the Project Objective which FEI evaluated using non-financial and financial criteria.

6.1 Please explain whether FEI explored a project alternative involving a mix of alternatives, for example EMAT ILI on some pipelines and hydrostatic testing for other pipelines. Please explain any benefits or drawbacks to this approach.

Response:

FEI did not explore a project alternative involving a mix of alternatives. Due to the interconnected nature of the system, FEI evaluated alternatives at the system level, meaning the alternatives were considered for all 11 CTS pipelines and took into account their interactions and dependencies.

However, the conclusions reached by FEI due to the infeasibility of alternatives remain unchanged even if subsets of the system are considered. As outlined in Section 4.4 of the Application, three of the six alternatives evaluated are not feasible. The challenges associated with each of these alternatives applies to the entire system or sub-parts of the system.

- **SCCDA**

  As described in Section 4.4.1 of the Application, SCCDA cannot be used to reliably identify cracking that is most likely to result in pipeline failure. As such, SCCDA is not an effective method for mitigating cracking threats on any pipeline.

- **PRS**

  Reducing any of the pipelines to an operating stress below 30 percent of SMYS will result in a significant reduction in capacity available on that pipeline. As such, the capability to serve customers that FEI currently has would be reduced and system upgrades would be required either immediately or in the future to re-establish the capacity already present today.

  The ability to utilize PRS on the NOO BUR 508 segment of the CPH BUR 508 pipeline is unique due to the permanent reduction in demand on that line as the result of the Burrard Thermal facility being decommissioned and the location of the pipeline at the terminus of the system.

- **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.

In light of the considerable difference in costs among the remaining feasible alternatives (PLR and PLE) and EMAT ILI, FEI determined that these alternatives were not financially viable on a system-level or individual pipeline basis.

The approach that FEI has taken is appropriate and demonstrates that the outcome of evaluating a mix of alternatives would have resulted in the selection of EMAT ILI as the preferred alternative.

6.2 Please explain whether FEI explored a project alternative to perform above-ground facility modifications and delay replacement of the 13 heavy wall segments after the first run of the EMAT ILI tools. Please discuss any benefits or drawbacks to this approach.

Response:

FEI did not explore a Project alternative to perform above-ground facility modifications and delay replacement of the 13 heavy wall segments after the first run of the EMT ILI tools for the following reasons:

- Running an EMAT ILI tool through the pipeline without replacing the identified heavy wall pipe segments would result in speed excursions. It is known that these speed excursions will compromise the quality of data collected by the tool and/or compromise the ability of the tool to collect any data at all. This would result in sections of pipe where FEI will have compromised and/or no data to assess the integrity of the pipe, thereby necessitating alternative means of evaluating the pipe (i.e. exposing, inspecting, and recoating the pipe). This alternative process is onerous and would ultimately be more expensive. For example, one location on the HUN NIC 762 pipeline requires the replacement of approximately 20 metres of heavy wall pipe located within FEI's existing facility. This facility has caused previous ILI tool runs to experience downstream speed excursions over an approximate 900 metre distance, leaving a segment of pipe with degraded or no data.
- In several situations, the pipeline and facility modifications are located within the boundaries of an existing station. For example, at the Coquitlam Gate Station, the scope of Project work involves both facilities alterations and a pipeline alteration. Facilities alterations include extending a pig barrel, installation of a PRS, and modifications to above- and below-grade piping. The pipeline alteration includes replacing a 25 metre length of heavy wall pipe on the CPH BUR 508 pipeline. FEI intends to complete all of the modifications at this station at the same time, rather than splitting the work into stages, which would increase costs and cause operational disruptions.

7.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1, Section 1.3.2, pp. 5-6

Alternative 2: Pressure Regulating Station

On pages 5 and 6 of the Application, FEI states:

> An exception to the above evaluation is the Noon's Creek to Burrard 508 segment of the Cape Horn to Burrard 508 transmission pipeline, which does not have the gas flow conditions required to move an ILI tool through the pipeline. As such, FEI selected the pressure regulating station (PRS) alternative to manage and mitigate cracking threats on this segment.

7.1 Please confirm the cost of Alternative 2 PRS for the Noon's Creek to Burrard 508 segment and confirm that this cost is included in the CTS TIMC Project total cost estimate of $137.8 million. As part of the response, please indicate in which applicable Financial Schedule in Appendix G the cost can be found.

Response:

Confirmed. The costs of Alternative 2 PRS for the Noon's Creek to Burrard 508 segment is included in the $137.8 million total Project cost estimate. The costs of this PRS are included in the total capital expenditures of the Project shown in Schedule 6 of Confidential Appendix G-2. FEI clarifies that Schedule 6 of Confidential Appendix G-2 contains the total capital expenditures of the Project summarized by asset classes; however, the costs specifically related to the PRS, as well as other individual components of the Project, are not shown separately in the financial schedule.

FEI also confirms that the cost for the PRS at the Noons Creek to Burrard 508 segment was included in the $72.4 million on Line 1 of Table 5-14 of the Application (page 128) that made up the total project cost estimate of $137.8 million, which is provided below for ease of reference. As discussed in the response to BCUC Confidential IR1 5.1, the PRS at the Noons Creek to Burrard 508 segment was scoped and estimated separately by FEI from the report by Stantec because it is the only segment that will use the PRS alternative. Therefore, the cost was not included in the Stantec estimate (Appendix D-4 of the Application).

Line	Item	Amount
1	Construction Cost Estimate (Contractor)	$ 72.4
2	Owners Costs (FEI)	$ 15.2
3	**Sub-Total Construction Base Cost Estimate ($2020)**	**$ 87.6**
5	Pre-Construction Development Costs	$ 30.7
6	Contingency	$ 14.7
7	**Sub-Total Cost Estimate ($2020)**	**$ 133.0**
8	Cost Escalation Estimate	$ 7.8
9	**Sub-Total Cost Estimate (As-Spent)**	**$ 140.8**
10	AFUDC	$ 6.1
11	Tax Offset	$ (9.1)
12	**Total Project Cost Estimate (As-Spent)**	**$ 137.8**

7.1.1 If the cost is not included in the total cost estimate, please explain how FEI will address funding required for Alternative 2 PRS.

Response:

Please refer to the response to BCUC IR1 7.1 which confirms that costs related to Noons Creek to Burrard 508 transmission pipeline are included in the total cost estimate of $137.8 million.

7.2 Please explain whether the pressure regulating station for Alternative 2 PRS for the Noon's Creek to Burrard 508 segment of the Cape 27 Horn to Burrard 508 transmission pipeline will require replacement during the 70-year CTS TIMC Project analysis period.

7.2.1 If yes, please explain the necessary costs to replace the pressure regulating station. As part of the response, please discuss if these replacement costs are included in the CTS TIMC Project cost estimate of $137.8 million and analysis.

Response:

The majority of the components forming the PRS for the Noons Creek to Burrard 508 segment of the Cape 27 Horn to Burrard 508 transmission pipeline are not expected to need replacement during the 65-year post-project analysis period (70-year analysis period includes 5 years of construction period). However, minor components of the PRS such as telemetry, measuring and regulating equipment may require replacement as the life of these minor components is expected to be less than 65 years. FEI notes the future replacement costs for the telemetry, measuring, and regulating equipment of the PRS at the Noons Creek to Burrard 508 segment

are not part of the $137.8 million project capital costs. Rather, they are included in the sustainment capital of $84.983 million shown in Table 6-4 of the Application. The sustainment capital for these future replacements is based on today's capital estimate for the telemetry, measuring and regulating equipment of the PRS, escalated at 2 percent inflation annually.

8.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1, Section 4.2.3, p. 59; Section 4.4.3, pp. 69, 73, 79-80

Alternative 3 - Hydrostatic Testing

On page 59 of the Application, FEI states:

> Hydrostatic testing can be used to confirm the integrity of pipelines that may have time-dependent threats such as corrosion and cracking, construction damage, and/or manufacturing defects. Hydrostatic testing has been proven effective at safely removing near-critical axial flaws, such as SCC. By removing flaws that are approaching critical dimensions, a hydrostatic test helps prove the integrity of the pipeline, providing a margin of safety against an in-service failure for a period of time.

On page 69 of the Application, FEI states:

> HSTP is rated as an "acceptable choice" as it is an effective method for removing critical cracking threats by failing them out. However, HSTP does not provide the capability of identifying and locating sub-critical cracks. Therefore, the HSTP alternative does not give FEI as much visibility of cracking on its system as other on-going active monitoring methods.

On page 73 of the Application, FEI states: "The urban environment surrounding the CTS pipeline system amplifies the challenges associated with running a hydrostatic testing program, as the number of occupied residences and businesses in close proximity to the pipeline need to be considered."

Table 4-5 on pages 79-80 of the Application summarizes the preferred alternatives for each pipeline segment. Table 4-5 is reproduced below:

Table 4-5: Preferred Alternatives for Each Pipeline Segment

#	CTS Pipeline/Segment Name		Approximate Length	Preferred Solution
1	HUN NIC 1066	Huntingdon – Nichol 42"	55 km	EMAT ILI
2	HUN NIC 762	Huntingdon – Nichol 30"	56 km	EMAT ILI
3	LIV COQ 323	Livingston – Coquitlam 12"	35 km	EMAT ILI
4	LIV PAT 457	Livingston – Pattullo 18"	30 km	EMAT ILI
5	NIC PMA 610	Nichol – Port Mann 24"	5 km	EMAT ILI
6[1]	CPH NOO 508	Cape Horn – Noon's Creek 20"	9 km	EMAT ILI
	NOO BUR 508	Noon's Creek - Burrard 20"	8 km	PRS
7	ROE TIL 914	Roebuck – Tilbury 36"	13 km	EMAT ILI
8	TIL BEN 323	Tilbury – Benson 12"	6 km	EMAT ILI
9	TIL FRA 508	Tilbury – Fraser 20"	10 km	EMAT ILI
10	NIC FRA 610	Nichol – Fraser 24"	24 km	EMAT ILI
11	TIL LNG 323	Tilbury – LNG Plant 12"	2 km	EMAT ILI
Total Length of CTS TIMC Pipelines			**254 km**	

8.1 Please confirm that the feasibility of the HSTP alternative was assessed separately for each pipeline in the CTS.

Response:

Not confirmed. As explained in the response to BCUC IR1 6.1, FEI did not assess the feasibility of the HSTP alternative separately for each pipeline in the CTS, but rather evaluated all alternatives at the system level for all 11 CTS pipelines.

8.2 Please provide FEI's analysis of the feasibility of the HSTP alternative for shorter CTS pipelines, CTS pipelines in less urban areas or CTS pipelines which have fewer numbers of customers (including NIC PMA 610, NOO BUR 508, TIL BEN 323, TIL FRA 508, TIL LNG 323). For each of these pipelines, please provide:

- the advantages and disadvantages of selecting HSTP;
- a capital cost comparison between HSTP and EMAT ILI; and
- an operational cost comparison between HSTP and EMAT ILI.

Response:

Please refer to the response to BCUC IR1 6.1 that explains why FEI did not assess the feasibility of the HSTP alternative separately for each pipeline in the CTS. The challenges outlined in Section 4.4.3 of the Application with respect to identification and exacerbation of sub-critical cracks remain relevant to shorter, less urban CTS pipelines which serve fewer customers.

FEI has not prepared capital or operational cost comparisons between HSTP and EMAT ILI as the HSTP alternative was not feasible.

9.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1, Section 4.2.4, pp. 61,63

Alternative 4 – EMAT ILI Program

On page 61 of the Application, FEI states:

> Pipeline alterations: required to address locations where speed excursions may occur and where the ILI tool may not be able to pass through the pipeline. Pipeline alterations generally consist of cutting out the heavy wall features (e.g., fittings, pipe, etc.) causing speed excursions and replacing with higher grade pipe with a wall thickness that matches the rest of the pipeline.

9.1 Please clarify whether any of the pipeline alterations proposed in the Application are required to address a location "where the ILI tool may not be able to pass through the pipeline".

Response:

FEI reviewed the need for pipeline alterations to address locations where the ILI tool may not be able to pass through the pipeline and determined that there were no locations on any of the 11 CTS pipelines where the ILI tool would not be able to pass. As such, all of the proposed pipeline alterations in the Application are required to address locations where speed excursions are likely to occur.

On page 63 of the Application, FEI states:

> Facility alterations: EMAT ILI tools are generally longer than CMFL and MFL tools. Therefore, launchers and receivers located within existing FEI facilities must be modified to facilitate insertion and retrieval of the tool from the pipeline.

9.2 Please clarify whether the facility alterations proposed by FEI to facilitate insertion and retrieval of ILI tools are temporary or permanent alterations.

9.2.1 If permanent, please explain whether FEI assessed the use of temporary or vendor-supplied launchers and receivers, and the benefits and drawbacks of this approach compared to permanent facility alterations.

Response:

The proposed facility alterations to allow for the insertion and retrieval of ILI tools are permanent alterations. FEI did not assess the use of temporary or vendor-supplied launchers and receivers as there are already permanent launchers and receivers installed on the 11 CTS

1 pipelines. For clarity, FEI is proposing to modify existing permanent launchers and receivers so
2 that longer EMAT ILI tools can be inserted and retrieved.

3

10.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1, Section 3.3.2, p. 27; CEPA SCC Report, p. 138; FEI IGU Project, Exhibit B-1, Appendix E, pp. 2-3

Alternative 4 – EMAT ILI Program: Other ILI Technologies

On page 27 of the Application, FEI states:

> Senior members of FEI's System Integrity department actively participate in formal CEPA [Canadian Energy Pipeline Association] Community of Practice groups, including Pipeline Integrity, Inline Inspection, Corrosion Control, and Geohazard Management. Participation in these groups includes conducting research, developing industry recommended practice and guidance documents such as the CEPA Recommended Practice for Managing Near-neutral pH Stress Corrosion Cracking, conducting benchmarking exercises, and sharing of integrity related experiences. [Emphasis added]

Page 138 of the CEPA Recommended Practice for Managing Near-neutral pH Stress Corrosion Cracking document (CEPA SCC Report)[3] states:

> For some time, one ILI vendor has been developing an ILI crack detection tool based on self-excited eddy current (SEEC) technology. The technology shows promise for detection of SCC in both natural gas and liquid pipelines and does not require a liquid couplant to perform the inspection. Theoretically, this technology is not as sensitive to pipeline product speed and can collect optimum data at higher speeds, thereby reducing the operational and economic impacts of an SCC inspection run. As of August 2014, this technology is not yet commercially available.

On pages 2-3 of Appendix E of FEI's IGU CPCN Application, FEI stated:

> FEI has also been monitoring the evolution of new ILI tools. Robotic ILI tools (i.e. self-propelled) are emerging in the marketplace as a possible and cost-effective tool for shorter pipeline segments. Potential feasible and cost effective applications for Robotic ILI are:
>
> • Lower pressure pipelines or pipelines with insufficient flow to adequately propel a traditional ILI tool;
>
> • Inspection of pipelines or pipeline segments where access is difficult or where the line could not be retrofitted to allow for ILI (e.g. below a water crossing or below an immovable structure); and
>
> • Inspection of short pipeline segments where it may be more cost effective to run a Robotic ILI tool versus a traditional ILI tool.

[3] https://www.cepa.com/wp-content/uploads/2016/11/Stress-Corrosion-Cracking_3rdEdition_CEPA_FINAL.pdf.

Robotic ILI tool technology is still under development and is not considered by FEI proven and fully commercialized. As such, FEI has not accepted this alternative into its suite of adopted ILI tools at this time.

10.1 Please provide an update on SEEC technology, including whether this technology is now commercially available.

10.1.1 Please explain to what extent FEI has evaluated the use of SEEC technology for this Project.

10.1.2 Please clarify whether FEI has consulted with any ILI vendors about the use of SEEC technology.

10.1.3 Please explain whether the use of SEEC technology would reduce the number of pipe modifications required to reduce the occurrence of speed excursions.

Response:

The information provided by FEI in the Application regarding SEEC technology remains accurate. FEI is not aware of any commercially available ILI crack detection tools using SEEC technology. Therefore, FEI has not further considered the use of SEEC technology.

10.2 Please provide an update on FEI's assessment of Robotic ILI tool technologies.

10.2.1 Please explain to what extent FEI has evaluated the use of Robotic ILI tool technologies for this Project.

Response:

The following is FEI's current assessment of Robotic EMAT ILI tool technologies:

1. The use of Robotic EMAT ILI tools for inspection would require the pipeline to be taken out of service. This would be challenging for cases where the pipeline being inspected is not looped (i.e., does not have a redundant parallel path) and therefore downstream customers would require an alternate source of natural gas (e.g., compressed natural gas) to maintain supply while the pipeline is out of service for inspection.
2. Robotic EMAT ILI tools require the inside surface of a pipeline to be impeccably clean for its sensors to function properly. This is very difficult to achieve for pipelines that have been in service for many decades.
3. The technology utilized on Robotic EMAT ILI tools does not allow it to detect SCC within the long seam of a pipe, 30 mm on either side of the long seam, or within 100 mm on either side of a girth weld.

4. Robotic EMAT ILI tools have very low productivity rates when compared to conventional EMAT ILI tools. For example, according to one vendor of Robotic EMAT ILI tools, with their best efforts, the most pipe able to be inspected in one day ranges from only 45 to 90 metres.
5. Robotic EMAT ILI tools need to be inserted into the pipeline through cut-outs at a minimum of every 550 metres. This would require a significant number of excavations depending on the length of the pipeline and involve purging and re-gasifying the pipeline during subsequent re-inspections (i.e., on 5 to 7 year intervals).

Given the constraints identified above, FEI has determined that Robotic ILI tool technology would not achieve the integrity management objectives of the Project.

10.3 Is FEI aware of any Canadian natural gas utilities using Robotic ILI tool technologies?

10.3.1 If yes, please provide examples of the usage of these tools (e.g. pipeline design and operating characteristics).

Response:

FEI is not aware of any other Canadian natural gas utilities using Robotic ILI tool technologies.

10.4 Please explain whether the use of Robotic ILI tool technology could reduce the number of required pipeline modifications proposed in this Application.

Response:

Please refer to the response to BCUC IR1 10.2 that provides FEI's assessment of Robotic ILI tool technology and why the use of this technology will not achieve the integrity management objectives of the TIMC project.

11.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1, Section 3.3.3, p. 29; Section 4.7, p. 77

CPH BUR 508 Transmission Pipeline – Alternative analysis

On page 29 of the Application, FEI states:

> As part of FEI's project development work, FEI is completing a pilot of EMAT ILI evaluations on two CTS pipelines. This pilot is in progress, and as such, FEI is in the process of validating potential cracking detected by the EMAT tool. These instances of potential cracking on FEI's pipelines were not previously detected through opportunistic digs.
>
> The two pipelines chosen for the pilot, CPH BUR 508 and LIV PAT 457, had instances of cracking that FEI discovered during integrity dig activities, unrelated to investigating cracking. FEI determined that these pipelines could be modified to run EMAT ILI tools on a timeline suitable for informing the TIMC CPCN Project.

11.1 Please provide an update on the status of the pilot project and the work performed on the CHP BUR 508 and LIV PAT 457 lines with regards to the pilot project.

Response:

To date, FEI has performed the following work on the LIV PAT 457 and CPH BUR 508 pipelines as part of the pilot project:

1. All alterations to enable the ILI tool run and facilitate post-ILI run responses, as described in Sections 5.3.3.1 and 5.3.3.2 of the Application;
2. EMAT ILI tool runs on the LIV PAT 457 (2019) and CPH BUR 508 (2020) pipelines;
3. Ten integrity digs on the LIV PAT 457 pipeline; and
4. One integrity dig on the CPH BUR 508 pipeline.

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:

- All six reported seam weld features were inspected and removed from service for further advanced non-destructive and destructive testing. Five segments of pipe were cut-out and replaced, with one segment addressing two of the seam weld features.
- Two of the eight features in the pipe were inspected and were not required to be removed from service.
- The crack group feature was inspected and removed from service for further advanced non-destructive and destructive testing. One segment of pipe was cut-out and replaced.

FEI is planning to inspect one of the outstanding crack features in the pipe later this year and the 5 remaining reported crack features in 2022.

2. **CPH BUR 508 pipeline**
   The features that have been identified on the CPH BUR 508 pipeline to date remain the same as identified in the Application and are:
   - Four reported linear indications.
   - One reported crack group.

   One integrity dig has been performed to-date and has resulted in the finding described below:
   - One linear indication was inspected and was not required to be removed from service.

   FEI is planning to inspect the remaining features later this year.

11.1.1 Of the work completed to date, please explain whether the costs have been attributed to the deferral account or to the Project.

Response:

FEI clarifies that all preliminary stage development costs, which consists of QRA costs and EMAT ILI pilot project costs, are recorded in the TIMC Development Cost deferral account[4], and are part of the total Project cost estimate of $137.843 million (as shown in Table 6-2 of the Application). With reference to the work listed in the response to BCUC IR1 11.1 related to the EMAT ILI Pilot Project, a total of $7.4 million has been recorded to the deferral account to date for the following:

1. Alterations to enable the ILI tool run and facilitate post-ILI run responses;

[4] As approved under Order G-237-18.

2. EMAT ILI tool runs; and

3. Long lead repair materials for the LIV PAT 457 and CPH BUR 508 pipelines.

As discussed in Section 6.2 of the Application, FEI is proposing that some of these costs remain in the deferral account to be recovered from FEI ratepayers through amortization over three years. These consist of costs accumulated up to October 31, 2019 plus any related costs for the repair materials. The remainder would be capitalized and transferred to FEI's plant-in-service the January 1 following receipt of BCUC approval.

The table below provides a breakdown between deferral and capital amounts for the pilot project:

Component	Amount	
Deferral	$ 3.2 million	Subset of line 16 in Table 6-3
Capital	$ 4.2 million	Subset of line 12 in Table 6-3
Total	$ 7.4 million	

The EMAT ILI pipeline modifications as part of the pilot project are substantially complete with nominal costs remaining associated with project closeout and the finalization of alteration documentation. Any remaining costs associated with the work will be attributed to the Project.

The costs associated with the integrity digs performed on the LIV PAT 457 and CPH BUR 508 pipelines are part of FEI's forecast O&M between 2020 and 2024, as costs related to integrity digs are approved as flow-through items through BCUC Order G-165-20 as part of FEI's 2020-2024 MRP Decision.

FEI notes that future EMAT ILI runs will not be attributed to the deferral account or to the Project. The costs for the future EMAT ILI tools runs will be part of FEI's sustainment capital funding for integrity inspection reviewed through future rate applications.

11.1.2 Of the remaining work to complete the EMAT ILI pipeline modifications, please explain whether costs will be attributed to the Project or to the deferral account.

Response:

Please refer to the response to BCUC IR1 11.1.1.

11.2 Please explain whether modifications are complete on the CPH BUR 508 and LIV PAT 457 lines to run the EMAT ILI tool. If not, please explain the remaining scope of work.

Response:

All modifications to the LIV PAT 457 line and modifications to the CPH BUR 508 line between Coquitlam Station and Noons Creek Valve Assembly that were essential for the Pilot EMAT ILI run are complete.

However, as discussed in Section 5.4.2 of the Application, there are additional modifications required on the CPH BUR 508 line, the majority of which are on the section of the pipeline between and at the Cape Horn Valve Assembly and Coquitlam Station. Please also refer to Tables 5-5, 5-6, 5-7, and 5-8 of the Application for further details on the necessary modifications.

On page 77 of the Application, FEI states:

An EMAT ILI tool is required to travel within a certain velocity range in order to collect reliable ILI data. For the tail end of the Cape Horn to Burrard 508 transmission pipeline, there is insufficient gas demand to generate the required flow to propel the ILI tool through the pipeline. As a result, for this segment of pipeline, FEI considers that PRS is the most cost effective way to meet the Project Objective.

11.3 Please explain the gas demand required to propel an ILI tool through the tail end of the CPH BUR 508 line.

Response:

In order to propel the ILI tool through the pipeline at the required 1.5 metres per second, the gas demand at the tail end of the CPH BUR 508 line, from Noons Creek to Burrard, would need to be approximately 42 MMSCFD. As stated in the response to BCUC IR1 11.4, the average volumetric flow in the Noons Creek to Burrard segment of the CPH BUR 508 pipeline is approximately 0.6 MMSCFD at the current operating pressure.

11.4 Please provide the current operating characteristics of the CPH BUR 508 transmission line. Parameters to include are: maximum operating pressure, current average operating pressure, current hoop stress as a percentage of SMYS, and average volumetric flow at the inlet to the transmission line in million standard cubic feet per day (MMSCFD) or in thousand cubic meters (E3m3).

11.4.1 Please provide the future operating characteristics (listed in IR 11.4 above) of the CPH BUR 508 transmission line once the pressure regulating station is installed.

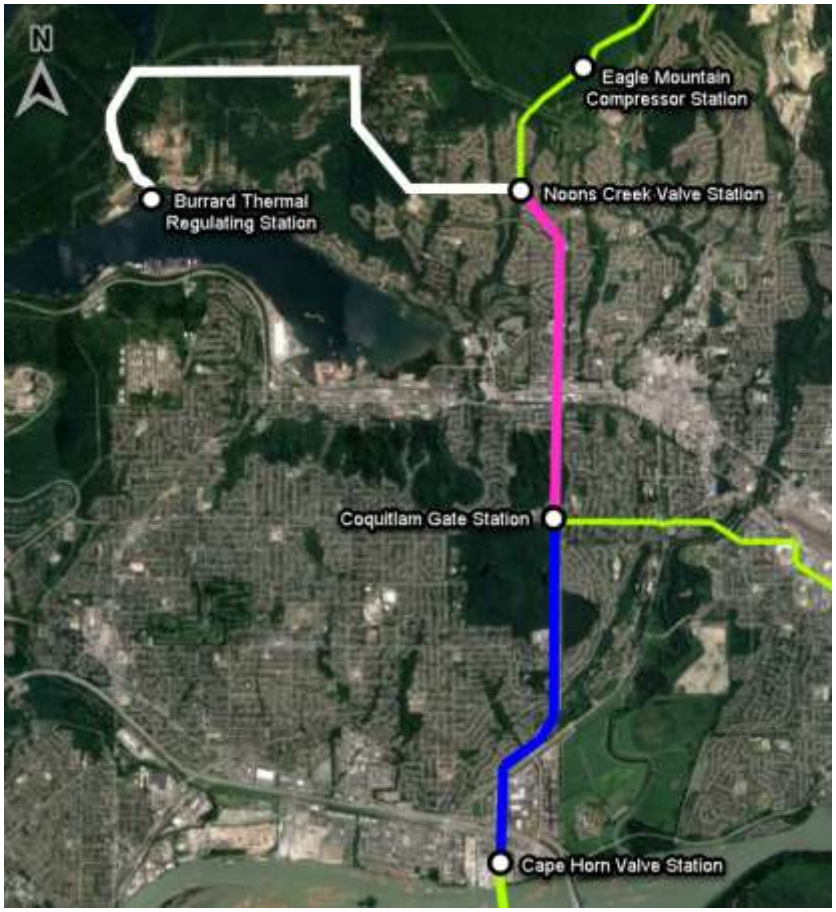
Response:

The current operating characteristics of the Cape Horn to Burrard 508 transmission line are provided in Table 1 below. While this transmission line shares common characteristics including diameter, hoop stress, and operating pressure, there are three distinct segments of the pipeline (see Figure 1) where flow rates differ. FEI does not have direct flow measurement on each of the segments, so the flow rates provided in Table 1 are estimated based on average flow rates observed at Coquitlam Gate Station and Eagle Mountain Compressor Station, the two major delivery points along the CPH BUR 508 transmission line.

Table 1: Current Operating Characteristics of CPH BUR 508

CPH BUR 508	
Maximum operating pressure	4,020 kPa
Average operating pressure	3,620 kPa
Maximum hoop stress	49.3% of SMYS
Average volumetric flow – Cape Horn to Coquitlam (blue line in Figure 1)	19.8 MMSCFD
Average volumetric flow – Coquitlam to Noons Creek (pink line in Figure 1)	54.7 MMSCFD
Average volumetric flow – Noons Creek to Burrard (white line in Figure 1)	0.6 MMSCFD

Figure 1: Segments of the Cape Horn to Burrard 508 Transmission Pipeline



FEI proposes to locate the pressure regulating station at the Noons Creek Valve Station, which is approximately midway along the pipeline. The upstream half of the pipeline will run from Cape Horn to Noons Creek and will maintain the same characteristics as presented in Table 1. The downstream half of the pipeline will run with the same volumetric flow as in Table 1 from Noons Creek to Burrard but with pressure at or below 2,413 kPa, resulting in a hoop stress of less than 30 percent of SMYS.

The future operating characteristics of the Noons Creek to Burrard segment are provided in Table 2 below.

Table 2: Future Operating Characteristics of NOO BUR 508

NOO BUR 508	
Maximum operating pressure	2,413 kPa
Average operating pressure (est.)	2,390 kPa
Maximum hoop stress	29.6% of SMYS

12.0 Reference: DESCRIPTION AND EVALUATION OF ALTERNATIVES

Exhibit B-1, Section 4.1, p. 56

Project Cost

On page 56 of the Application, FEI states:

> Based on a financial assessment, two of the remaining three alternatives were screened out because they were not financially feasible due to high-level cost estimates approaching $2 billion, approximately six times the costs of the EMAT ILI alternative.

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.

12.2 Please discuss the impact on rates if the project cost for the EMAT ILI alternative is i) 10% over the budgeted cost estimate and ii) 20% over the budgeted cost estimate.

Response:

Increasing the estimated total project cost by either 10 or 20 percent would result in a small increase in the estimated incremental year-over-year delivery rate impact. The following table shows the incremental year-over-year delivery rate impact for the project associated with the capital costs as filed and for the above scenarios where the estimated project costs are increased as requested.

Incremental % Delivery Rate Impact (Year-over-Year)	2022	2023	2024	2025	2026
Capital Costs as filed	1.22%	0.03%	-0.04%	0.09%	0.01%
10% increase in Capital Costs	1.27%	0.04%	-0.04%	0.13%	0.02%
20% increase in Capital Costs	1.32%	0.04%	-0.04%	0.18%	0.02%

C. PROJECT DESCRIPTION

13.0 Reference: PROJECT DESCRIPTION

Exhibit B-1, Section 5.3.3.3, p. 90

Pilot Project Informed Project Development

On page 90 of the Application, FEI states:

> The EMAT ILI data collected during the pilot run also confirmed that EMAT ILI tools with speed control return back to their optimal velocity range quickly as compared to MFL-C tools. This information allowed FEI to conservatively refine the scope of the remainder of the pipelines within the scope of the CTS TIMC Project and defer removal or alteration of pipeline components with a minor or moderate affect on the speed until after the baseline EMAT ILI runs. This resulted in a reduced Project scope, and therefore a reduced Project cost.

13.1 Please summarize the scope of the pipeline component alterations that have been deferred, and provide an estimate of the avoided costs, because of lessons learned from the EMAT ILI tool pilot project.

Response:

Based on observations of EMAT ILI tool behavior during the pilot project, FEI was able to refine the evaluation criteria used to analyze historical MFL tool data to anticipate EMAT tool behaviour. This allowed FEI to identity and select heavy wall segments with a high probability of causing EMAT tool speed excursions and include them in the Project, while also deferring the replacement of other heavy wall segments until after reviewing data collected during the first run.

The table below lists the number of instances where previous MFL ILI tool runs by FEI exhibited speed excursions, the length of heavy wall pipe that caused them, and the length of pipe where the quality of data was affected as a result of the speed excursions, organized by pipeline. The 13 speed excursion events driving the 13 pipeline alterations that are part of the Project scope are not included in the table below.

Pipeline ID	Length (km)	Number of speed excursion events	Approximate length of heavy wall piping causing speed excursions (m)	Approximate length of pipe affected by speed excursions (m)
TIL BEN 323	5.9	1	682	198
CPH BUR 508	17	12	232	990
LIV COQ 323	34.9	10	1,693	990
TIL FRA 508	9.6	6	1,739	1,235
HUN NIC 762	56.4	3	58	181
HUN ROE 1067	55.7	1	16	63

Pipeline ID	Length (km)	Number of speed excursion events	Approximate length of heavy wall piping causing speed excursions (m)	Approximate length of pipe affected by speed excursions (m)
NIC FRA 610	24.3	8	1,782	1,012
TIL LNG 323	1.7	1	48	10
ROE TIL 914	12.8	6	1,771	527
NIC PMA 610	4.9	2	77	130
LIV PAT 457	29.8	11	474	2,801

Given the extent of speed excursions exhibited by the MFL tools listed in the table above, FEI expects that the EMAT tool could perform better when compared to the MFL tools and therefore collect viable data. However, the magnitude of these speed excursions cannot be determined until the first tool run is complete and as such, to ensure a prudent use of funds and avoid doing work unnecessarily, FEI did not include them in the scope of the Project. If the EMAT tool exhibits a speed excursion during the baseline run at one of these locations, FEI may replace the heavy wall piping causing the speed excursion to avoid a repeat of the same scenario for future runs or it may choose to address the integrity of the affected segment of pipe through the use of pipeline replacement or pipeline exposure and recoat alternatives. FEI will evaluate the method that will be applied to mitigate SCC on a case-by-case basis to determine the most cost effective solution.

14.0 Reference: PROJECT DESCRIPTION

Exhibit B-1, Section 5.4.2, pp. 91-92

Speed Excursions

On page 91 of the Application, FEI states: "pipeline alterations are required to replace 13 heavy wall segments on six pipelines to ensure that the ILI tool can travel within its optimal velocity range, which is critical for the collection of full resolution ILI data."

On page 92 of the Application, FEI states:

> ILI tools are sensitive to speed as speed affects their capability to collect quality data. EMAT ILI tools are more sensitive to speeds than the ILI tools currently in use by FEI. For example, the maximum velocity beyond which data quality is compromised for EMAT tools is 2m/s while its 5m/s for the MFL tools.
>
> One phenomenon that affects the tools' data collection capabilities is known as "speed excursion". Speed excursions are localized increases in tool velocity where the tool travels beyond the maximum allowable velocity at which it can collect quality data. The effect of speed excursion ranges from degradation of data quality to a complete inability for the tool to collect data, resulting in blind spots.

14.1 Please clarify whether the 2 m/s maximum velocity limit for EMAT tools is common to all ILI vendors.

14.1.1 If not, please provide the range of maximum velocity limits for EMAT tools for various ILI vendors with whom FEI has consulted.

Response:

FEI understands that the 2 metre per second maximum velocity limit for EMAT tools is common to all ILI vendors.

14.2 Please provide the length of each proposed pipeline alteration on each of the six identified pipelines.

Response:

Please refer to the table below for the lengths of the replacement pipe required at each proposed pipeline alteration location.

Pipeline	Event ID	Type of heavy-wall feature	Approximate length of the replacement (metres)
TIL BEN 323	3	Forged elbow	6
TIL BEN 323	5	Forged elbow	6
CPH BUR 508	1	Station pipe	20
CPH BUR 508	4/5	Crossing pipe	304
CPH BUR 508	9	Forged elbow	10
CPH BUR 508	14	Station pipe	30
CPH BUR 508	20	Crossing pipe and station pipe	150
LIV COQ 323	9	Crossing pipe	65
TIL FRA 508	1	Station pipe and crossing pipe	95
TIL FRA 508	6	Station pipe	30
HUN NIC 762	36	Station pipe	30
HUN NIC 762	41	Station pipe	20
HUN ROE 1067	12	Station pipe	15

14.3 Please provide the expected EMAT ILI tool velocity at each of the 13 identified heavy wall segments proposed to be altered as part of this Project.

Response:

The ILI tool behavior is compromised downstream of the heavy wall segments, not within the heavy wall segments themselves.

ILI tools move through a pipeline due to the pressure differential that exists across the tool such that the pressure in front of the tool has to be lower than the pressure behind the tool for it to move. In order for an ILI tool to move through a pipeline, it has to fit tightly against the inside surface of the pipeline otherwise the gas would bypass around the tool and the tool would not move. The sensors, magnets and other components that are part of an ILI tool also require a tight fit to function properly. This tight fit creates friction and magnetic drag forces which needs to be overcome for the tool to move. Once the necessary pressure differential required to overcome the friction and magnetic drag forces is created across the tool, it starts to move.

When the tool meets a restriction in the form of heavy wall pipe (which translates to a reduced internal diameter), increased force is required in order to squeeze the tool through the restriction. This causes the tool to slow down, and an increased pressure differential is required to overcome the additional magnetic drag and friction forces. In some cases, the ILI tool comes to a complete stop and stays stationary until a pressure differential large enough is built up to dislodge the tool. When the ILI tool transitions from the heavy wall pipe back to the thinner wall

pipe (i.e. from small internal diameter to a larger internal diameter), the pressure differential built up while moving through the heavy wall pipe is more than what is required for passage in the thinner wall pipe, causing the tool to rapidly pick up speed and travel at elevated speeds resulting in a speed excursion. These speed excursions compromise the quality of data being gathered by the ILI tool in the thinner wall pipe that is located immediately downstream of the heavy wall pipe. This process is repeated every time the tool meets a restriction where it passes through heavy wall piping.

Without alteration, FEI expects the EMAT ILI tool to travel at velocities greater than 2 metres per second (m/s) downstream of each of the 13 identified heavy wall segments. This assessment is based on previous ILI runs using MFL tools which exhibited speed excursions in the same locations resulting in sections of pipe where the quality of data collected by the tool was compromised. The relationship between the behavior of the MFL and EMAT ILI tools was supported by the EMAT Pilot project completed on the LIV PAT 457 and CPH BUR 508 pipelines. The table below provides information on the historical MFL tool speeds downstream of the 13 locations identified for alteration in the CTS TIMC Project.

Pipeline ID	Pipeline Length (km)	Event #	Average tool velocity (m/s)	Length of speed excursion (m) / % of total pipeline length
TIL BEN 323	5.9	3	7.2	170 / 2.9%
		5 (Note 1)	N/A	N/A
LIV COQ 323	34.9	9	7.2	420 / 1.2%
CPH BUR 508	17	1	6.4	459 / 2.7%
		4/5	9.4	558 / 3.3%
		9	7.6	785 / 4.6%
		14	7.6	387 / 2.3%
		20	8.8	310 / 1.8%
TIL FRA 508	9.6	1	7.9	373 / 3.8%
		6	8.2	425 / 4.4%
HUN NIC 762	56.4	36	6.5	221 / 0.4%
		41	7.4	910 / 1.6%
HUN ROE 1067	55.7	12	7.9	80 / 0.14%

Note:

1. *A review of data collected at this location and based on its similarities with Event 3 indicated that there is a high probability that future ILI runs may experience blinding speed excursions at this location*

The table above identifies the locations where FEI expects the EMAT ILI tool will experience speed excursions as the result of passage through heavy wall pipe segments. However, as pipelines in the CTS are interconnected, it is difficult to predict where speed excursions may occur as a result of operational conditions on the day of the ILI tool run. Therefore, FEI cannot

with certainty provide a percentage for each pipeline where inspection data may be compromised for any reason.

14.4 Please elaborate on the extent of data quality degradation at each of the 13 identified heavy wall segments.

Response:

Data quality degradation resulting from speed excursions occurs in segments located immediately downstream of a heavy wall segment. There are no data quality issues anticipated at the heavy wall segments due to speed excursion because the ILI tool slows down when passing through heavy wall segments. Please refer to the response to BCUC IR1 14.3 for a further explanation.

As stated in the response to BCUC IR1 14.3, FEI expects the EMAT ILI tool to travel at velocities greater than 2 metres per second downstream of the heavy wall segments. The extent to which data is compromised depends on the actual tool velocities observed. If the EMAT ILI tool travels between 2 and 5 metres per second, data will be degraded. Degraded data carries some information and can provide some data to interpret the integrity of the pipeline, but as the speed of the tool increases, the minimum size of feature that the tool can detect also increases, meaning potentially injurious features may remain undetected and thus unmitigated. If the EMAT ILI tool travels above 5 metres per second, no viable data is collected, meaning that the integrity of the pipeline at these locations cannot be determined.

15.0 Reference: PROJECT DESCRIPTION

Exhibit B-1, Section 5.4.2.2, p. 93

Heavy-Wall Crossing Pipe

On page 93 of the Application, FEI states:

> Four locations have been identified where heavy-wall pipe was used to cross roads or other utilities that are associated with speed excursions. These heavy-wall pipe segments were either installed as part of original installation in the 1950s or installed in the 1980s when the infrastructure around the pipeline was upgraded. All such heavy-wall crossing pipe will be replaced with line pipe that matches the wall thickness of the adjacent pipe.

15.1 Please explain whether the replacement of heavy-wall crossing pipe with line pipe that matches the wall thickness of the adjacent pipe will require an increase to the pipeline depth of cover or will require a new pipeline alignment.

Response:

An increase to the depth of cover is not necessarily required where heavy-wall crossing pipe is replaced with line pipe that matches the wall thickness of the adjacent pipe. However, additional depth of cover may be required in some locations, depending on the installation technique undertaken. For example, the trenchless crossing of a road will generally be installed deeper than the existing crossing, providing additional cover. As part of assessing the pipeline depth of cover, FEI will ensure compliance with its internal requirements and Table 4.9 of CSA Z662:19.

Minor adjustments to the pipeline alignment will be required where a trenchless installation technique is used. In these circumstances, the heavy wall crossing pipe will be abandoned in place causing the new installation to be offset from the original alignment.

16.0 Reference: PROJECT DESCRIPTION

Exhibit B-1, Section 5.4.2.3, p. 94

Heavy-Wall Station Pipe

On page 94 of the Application, FEI states:

> Eight locations have been identified where heavy-wall pipe within a station boundary has caused speed excursions in the past. These segments of heavy-wall pipe are either downstream of pig-barrel isolation valves or are part of a heavy-wall valve assembly.

16.1 Please clarify whether the identified heavy-wall pipe locations within station boundaries are buried or above ground.

Response:

As shown in the table below, four of eight segments within station boundaries have pipe segments or valve assemblies comprising both buried and above ground piping. The four remaining segments comprise below ground piping only.

Pipeline	Facility	Segment Location
CPH BUR 508	Cape Horn Valve Station; City of Coquitlam	Mix of above and below ground
CPH BUR 508	Coquitlam Gate Station; City of Coquitlam	Mix of above and below ground
CPH BUR 508	Westwood Regulating Station; City of Coquitlam	Below ground only
HUN NIC 762	Fort Langley Valve Station; Township of Langley	Below ground only
HUN NIC 762	Latimer Gate Station; City of Surrey	Below ground only
HUN ROE 1067	King Road Valve Site; City of Abbotsford	Below ground only
TIL FRA 508	Tilbury Regulating Station; City of Delta	Mix of above and below ground
TIL FRA 508	Nelson Gate Station; City of Richmond	Mix of above and below ground

16.1.1 If the heavy-wall pipe locations within station boundaries are above ground, please explain whether other pipeline integrity inspection methods were considered other than in-line inspection.

Response:

Pipeline integrity inspection methods other than in-line inspection (ILI) were not considered for heavy-wall pipe locations within station boundaries as ILI tools collect adequate data through these heavy-wall segments.

Speed excursions are observed after heavy-wall pipe locations when the ILI tool passes through a wall thickness transition into thinner wall pipe. As such, the integrity of the heavy-wall pipe is well understood through the use of ILI tools, but the pipe downstream of the transition from heavy-wall locations may have degraded or insufficient data quality. The pipe downstream of heavy wall pipe locations is generally located below ground.

16.1.2 If the heavy-wall pipe locations within station boundaries are above ground, please explain whether the risk of stress corrosion cracking is different than for buried pipe.

Response:

Buried pipe is more likely to experience stress corrosion cracking than above ground pipe due to the corrosive environment from the surrounding soil.

Speed excursions are observed after heavy-wall pipe locations when the ILI tool passes through a wall thickness transition into thinner wall pipe regardless if the pipe is above ground or buried. As such, the pipe downstream of the transition from heavy-wall locations may have degraded or insufficient data quality. The pipe downstream of heavy wall pipe locations is generally located below ground where stress corrosion cracking is more likely.

17.0 Reference: PROJECT DESCRIPTION

Exhibit B-1, Section 5.5.1, pp. 95-96

FEI Lower Mainland Intermediate Pressure System Upgrades CPCN Proceeding

Exhibit B-1, Section 3.3.3.2.2, p. 51

CTS Transmission Facilities

On page 96 of the Application, FEI states:

> As part of Project development, FEI assessed the 17 transmission pressure facilities associated with the 11 CTS pipelines within the scope of the Project to determine the scope of alterations required to make the system ready for the introduction of EMAT ILI tools.

On pages 95-96, FEI submits Table 5-8: Facilities Part of Project Scope. A portion of this table is reproduced below:

Facilities	Associated Pipelines	Scope of Modifications
Cape Horn Valve Station	CPH BUR 508	Modification to pig barrel and station piping
Coquitlam Gate Station	CPH BUR 508 LIV COQ 323	Modification to pig barrels, station piping and addition of pressure regulating capability
Noons Creek Valve Station	CPH BUR 508	Modification to station piping and addition of pressure regulating capability
Anmore Regulating Station	CPH BUR 508	Upgrades to pressure regulating capability
Pattullo Regulating Station	LIV PAT 457	None required
Burrard Thermal Regulating Station	CPH BUR 508	None required
Belcara Regulating Station	CPH BUR 508	None required
Ioco Regulating Station	CPH BUR 508	None required

On page 51 of FEI's Lower Mainland IP System Upgrades CPCN Application (LMIPSU Project), FEI stated:

> As the NPS 30 Coquitlam Gate IP pipeline capacity will be greater (a combination of higher gas flow rate and MOP), the Coquitlam Gate station infrastructure will need to be upgraded accordingly. Upgrades to mechanical, civil and electrical and controls infrastructure will be required and will involve the installation of larger equipment and pipework.

17.1 Please clarify whether any components of the Coquitlam Gate Station constructed as part of the LMIPSU Project are proposed to be replaced or altered as part of the CTS TIMC Project.

Response:

There will be no components replaced or altered in the Coquitlam Gate Station as part of the Project. All activities for the Project will impact transmission assets upstream of the LMIPSU project scope.

18.0 Reference: PROJECT DESCRIPTION

Exhibit B-1, Section 5.5.3, p. 98

Gas Flow Control

On page 98 of the Application, FEI states:

> To ensure that the ILI tools are traveling as close as possible to their optimum travel velocity, a Flow Control Station (FCS) will be installed on the downstream end of the pipeline in order to control the gas flowrate in the pipeline subjected to EMAT inspection.

18.1 Please explain the capability of existing station facilities to control the flow of gas in CTS pipelines and how the proposed Flow Control Stations mentioned in the preamble are a necessary improvement on these existing flow control capabilities.

Response:

FEI does not currently have the ability to adjust gas flows on individual pipelines in the CTS. The addition of flow control station (FCS) facilities to the CTS will increase the likelihood of successful EMAT ILI runs by providing two major improvements to FEI's existing flow control capabilities:

1. It provides a means of direct control on the pipeline being inspected; and

2. It widens the seasonal window for ILI tools runs.

An FCS discharges gas at a fixed rate into a parallel pipeline to maintain the ILI tool velocity within the targeted range, thus providing a more precise and localized method of controlling flow in the pipeline. Any variation in demand can be supplied by the parallel pipeline while the velocity in the pipeline under inspection remains relatively constant. EMAT ILI tools are required to travel at slower velocities than other in-line inspection tools currently used by FEI. Without an FCS, opportunities to successfully run EMAT ILI on the CTS would be limited due to the narrow seasonal window.

The FCS widens the seasonal window for ILI tool runs in certain pipelines by managing the effects of higher seasonal system demand on gas flow using the parallel pipeline. This allows the flexibility to run ILI tools in a broader range of system demand conditions. This will aid FEI in mitigating scheduling issues for tool availability or operational support which may be imposed by a narrow run window.

19.0 Reference: PROJECT DESCRIPTION

Exhibit B-1, Section 5.5.4, p. 99

Pressure Regulation

On page 99 of the Application, FEI states:

> Once the EMAT ILI tool has completed its run, with the exception of the HUN ROE 1067 transmission pipeline, it is not known how many features will be found, and as such, it may not be possible to complete all repairs in the same calendar year. Should this be the case, the integrity risk of having unrepaired features on those pipelines can be mitigated by a 20 percent reduction in operating pressure until all repairs are complete.

19.1 Please clarify the basis for designing the pressure regulation equipment to be able to reduce the operating pressure by 20 percent to mitigate the risk posed by unrepaired features found during inspection.

Response:

The design of pressure regulation equipment, which would allow for the reduction of the operating pressure by 20 percent, is based on prudent engineering practice and is consistent with industry practice. In the event that an inspection identifies a feature that could credibly fail in the immediate future, and which could not be repaired in a timely manner (e.g., until the following year), FEI would be able to reduce the pipelines' operating pressure to mitigate the risk of rupture in the interim period prior to repair.

Reducing the operating pressure by 20 percent is effectively equivalent to having performed a hydrostatic pressure test (i.e., the test pressure was the pre-occurrence operating pressure) with a test factor of 1.25 (i.e., 100% / 80% = 1.25), where 100% represents the pre-occurrence operating pressure and 80% represents the reduced operating pressure). This new operating pressure could be relied upon for the intervening period until repairs can be completed.

20.0 Reference: PROJECT DESCRIPTION

Exhibit B-1, Section 5.5.4.3, p. 102

Pressure Regulating Station (PRS) at Noons Creek Station

On page 102 of the Application, FEI states:

> In light of the discussion in Section 4.7, FEI is proposing to permanently reduce the pressure in the second half of the pipeline from transmission pressure to intermediate pressure. This pressure reduction will result in an operating pressure producing a hoop stress lower than 30% SMYS. This will be accomplished by adding a PRS at Noons Creek Valve Station in Port Moody that will get its intake from the first half of the NPS20 pipeline and reduce the pressure before feeding it to the downstream half of the NPS20 pipeline. A heater will also be added to heat the gas in order to maintain the same gas volume resulting from the significant pressure drop which will precipitate a corresponding temperature drop.

20.1 Please provide the current operating characteristics of the upstream half and downstream half of NOO BUR 508 transmission line. Parameters to include are: maximum operating pressure, current average operating pressure, current hoop stress as a percentage of SMYS, and average volumetric flow at the inlet to the transmission line in million standard cubic feet per day (MMSCFD) or in thousand cubic meters (E3m3).

Response:

The NPS 20 pipeline referenced in the preamble refers to the Cape Horn to Burrard 508 transmission pipeline. The gas in this pipeline flows from Cape Horn towards Burrard. FEI proposes to locate the new pressure regulating station at the Noons Creek Valve Station, which is approximately midway along the pipeline. As such, the upstream half of the pipeline runs from Cape Horn to Noons Creek and the downstream half of the pipeline runs from Noons Creek to Burrard. Please refer to the response to BCUC IR1 11.4 for the current operating characteristics of both segments.

20.1.1 Please provide the future operating characteristics (listed in IR 20.1 above) of the NOO BUR 508 transmission line once the pressure regulating station is installed.

Response:

Please refer to the response to BCUC IR1 11.4.

20.1.2 Please provide the operating pressure that would produce a hoop stress of less than 30% SMYS on the NOO BUR 508 pipeline.

Response:

Please refer to the response to BCUC IR1 11.4.

20.2 Please explain whether it is typical practice for FEI to install heaters at stations which regulate between transmission and intermediate pressure pipelines.

Response:

FEI's practice is to install line heaters at all pressure regulating stations that regulate between transmission and intermediate pressure pipelines and have capacities greater than 300 cubic metres per hour. Line heaters are used to increase the gas temperature prior to pressure regulation to counteract the Joule-Thompson effect.[5] For pressure regulating stations with this amount of pressure drop and flow rates, gas heating is required to ensure there is no hydrate formation in the gas, to protect the mechanical integrity of downstream equipment from extremely cold temperatures, and to protect third-party assets (such as roadways and sidewalks) from damage caused by frost heaving resulting from the ground freezing.

[5] The Joule-Thomson effect describes the cooling of natural gas that occurs when it expands during passage from a high-pressure region to a low-pressure region, such as that which occurs in a pressure regulator.

21.0 Reference: PROJECT DESCRIPTION

Exhibit B-1, Section 5.8.8, p. 110

Excavation

FEI submits Table 5-13: Proposed trenchless installation locations on page 110 of the Application. Table 5-13 is reproduced below.

Table 5-13: Proposed trenchless installation locations

Pipeline	Event ID	Location	Length (m)	Technique
CPH BUR 508	4/5	Lougheed Highway; City of Coquitlam	280	Horizontal Directional Drill (HDD)
CPH BUR 508	20	David Avenue; City of Coquitlam	40	Auger boring
TIL FRA 508	1	River Road; City of Delta	40	Auger boring

21.1 Please provide an update on the current design of the Lougheed Highway horizontal directional drill (HDD) scope component listed in Table 5-13. Please include any recent assessments of the geotechnical feasibility of the HDD at this location.

Response:

The design of the Lougheed Highway HDD is currently at the front end engineering design (FEED) level. The geotechnical assessment comprised of a desktop analysis and field gathered information from 2015. The 2015 geotechnical information was collected as part of the installation of FEI's NPS 36 pipeline, which was constructed in 2017, and involved a trenchless crossing of the same highway in close proximity to the proposed NPS 20 HDD that is included in the scope of the CTS TIMC Project. The geotechnical memo that was completed in the FEED is attached as Appendix D-2 Feed Report Documents of the Application.

21.2 Please provide an update on any consultations FEI has undertaken with the City of Coquitlam and other stakeholders with respect to the HDD at the Lougheed Highway location. Please include a summary of feedback received during any consultations undertaken with relevant stakeholders.

Response:

Consultation related to the HDD at the Lougheed Highway location that was completed with the City of Coquitlam and other stakeholders was included as Appendix J-5 and J-2, respectively. During a March 23, 2021 meeting with FEI, the City of Coquitlam indicated that it had no requirements at this time and requested a further discussion with FEI once detailed design has progressed.

Consultation with other stakeholders about the HDD will be planned during the development of detailed engineering designs.

21.3 Please describe the risk of Project cost escalation or schedule delay associated with the HDD at the Lougheed Highway location and how FEI is mitigating these risks.

Response:

The risk of cost escalation associated with the HDD has been mitigated by estimating the HDD using current rates for HDD in the area and by conducting necessary pre-work (e.g., geotechnical investigations). The cost escalation risk from any other unknown conditions or event, such as a second HDD attempt at Lougheed Highway, will be managed through the Project contingency.

Schedule delay risk may occur if work cannot be begin on the Lougheed Highway crossing as planned. Should the commencement of work be delayed, the associated schedule risk will be managed by planning the work such that the HDD is not on the Project's critical path (so sufficient schedule float is available) and by rescheduling crews to other non-critical work. Should the HDD work become part of the Project's critical path, the delays will be managed using the Project's schedule contingency.

22.0 Reference: PROJECT DESCRIPTION

Exhibit B-1, Section 5.9.2.1, p. 110

Permits – the BC Oil and Gas Commission

On page 110 of the Application, FEI states:

> The construction and operation of the Project are governed by the Oil and Gas Activities Act and are expected to require minor pipeline amendment applications. All pipeline and stations fall under existing pipeline permits through the BCOGC. A Pipeline Amendment Application requires notification to directly impacted Land Owners, Right Holders and Indigenous Groups prior to submission.

22.1 Please clarify how many BC OGC permits FEI expects will be required as part of the CTS TIMC Project.

Response:

The CTS TIMC Project requires 11 BCOGC amendments and two Notice of Intent permits.

22.1.1 Please clarify the timing of submitting the necessary applications to the BC OGC for these permits.

Response:

FEI expects to apply for the 11 pipeline permit amendments from the BCOGC, referenced in the response to BCUC IR1 22.1, beginning in Q2 2022. The amendments are required for pipeline, station, and facility modifications which are outside of the conditions of existing permits. Review of any specific application can vary, and is dependent upon a project's size, scope, and associated consultation requirements. Based on applications of a similar in size and scope, FEI anticipates that the BCOGC's review process will be completed within two to four months from the time of submission.

22.2 Please provide an update on FEI's notification to directly impacted Land Owners, Right Holders and Indigenous Groups.

Response:

Please refer to the response to BCUC IR1 32.3 (Updated Appendix J-2) for engagement with directly impacted landowners, and the response to BCUC IR1 33.2 (Updated Appendix K-4) for engagement with Indigenous groups since the Application was filed with the BCUC on February 11, 2021.

FEI will consult with directly impacted Land Owners and Rights Holders and Indigenous groups as part of the British Columbia *Oil and Gas Activities Act* minor pipeline amendment at the time of the application and in accordance with the associated application requirements.

23.0 Reference: PROJECT DESCRIPTION

Exhibit B-1, Section 5.9.3, p. 111

Permits – Municipal

On page 111 of the Application, FEI provides a list of municipalities and regional districts in which CTS TIMC Project activities will occur. Further on page 111 of the Application, FEI states:

> FEI has operating agreements with most of the municipalities affected by the Project except the City of Richmond, Village of Anmore, and Metro Vancouver. Pipeline construction may require additional municipal permits to ensure construction and installation meets municipal bylaws and guidelines. FEI is currently in the process of identifying all required municipal permits and will determine requirements during detailed design. [Emphasis added]

23.1 Please provide an update on FEI's process of identifying all required municipal permits.

Response:

Once the Project detailed engineering designs have been advanced, FEI will conduct a review of Project works occurring in each municipality, and review applicable municipal bylaws and existing Operating Agreements to clarify permitting requirements.

On March 10, 2021, FEI consulted with Metro Vancouver and confirmed that based on preliminary workspace coordinates, a Burns Bog Ecological Conservancy Area (BBECA) Access Permit would not be required for Event ID 3 (Table 5-5: Bend Modification Scope). Metro Vancouver requested engagement with its Parks staff as well as the City of Delta to review detailed work plans and to confirm permitting requirements once FEI is at a further advanced stage of planning. As discussed in the response to BCUC IR1 22.1, the City of Coquitlam indicated that they had no requirements at this time and requested a further discussion once detailed design had progressed.

23.2 Please explain which municipal permit requirements will be determined during detailed design.

Response:

Please refer to the response to BCUC IR1 23.1.

23.2.1 Please discuss to what extent municipal permit requirements can be determined at the current Project stage rather than at the detailed design stage.

Response:

FEI has prepared a list of municipal permits that may be required based on a preliminary design for the Project; however, permitting requirements cannot be confirmed until construction workspace and design details are finalized.

23.2.2 Please discuss the risk that Project costs may escalate following the determination of municipal permit requirements and how FEI has mitigated this risk.

Response:

FEI considers the risk of cost escalation arising from municipal permit requirements to be negligible. The majority of the construction activities entail replacement or modification of existing infrastructure. As a result, FEI is anticipating that operating agreements will apply to most activities, and hence involve limited and standardized municipal permit requirements. The remaining work activities that include new infrastructure, or are not already covered by an existing operating agreement, are contained within FEI's existing rights-of-way and facility stations, thus minimizing anticipated permit requirements. FEI has prepared a preliminary list of municipal permit requirements associated with the proposed scope of work, and accounted for these in the CPCN cost estimate.

D. PROJECT COST AND RATE IMPACT

24.0 Reference: FINANCIAL

Exhibit B-1, Section 5.4.1, p. 91; Exhibit B-1, Section 6.4, p. 122

Project Service Life

On page 91 of the Application, FEI shows Table 5-4: Pipelines Part of Project Scope, which has been reproduced below:

Table 5-4: Pipelines Part of Project Scope

Pipeline	Length (km)	Number of alterations	Summary of alterations
HUN ROE 1067	55.7	1	Replacement of heavy wall valve assembly
HUN NIC 762	56.4	2	Replacement of heavy wall valve assemblies
LIV COQ 323	34.9	1	Replacement of heavy wall crossing pipe
CPH BUR 508	17	5	Replacement of heavy wall valve assembly, station pipe, crossing pipe and forged elbow
TIL FRA 508	9.6	2	Replacement of heavy wall valve assembly, station pipe and crossing pipe
TIL BEN 323	5.9	2	Replacement of heavy wall forged elbows
LIV PAT 457	29.8	None	Not applicable
NIC FRA 610	24.3	None	Not applicable
ROE TIL 914	12.8	None	Not applicable
NIC PMA 610	4.9	None	Not applicable
TIL LNG 323	1.7	None	Not applicable

On page 122 of the Application, FEI states:

> FEI has performed a financial evaluation of the Project based on the present value (PV) of the incremental revenue requirement and the levelized delivery rate impact to FEI's non-bypass customers over a 70-year analysis period. The 70-year analysis period is based on a 65-year post-project analysis period plus five prior years. The five prior years, 2021-2024, relate to the construction period, and the subsequent year, 2025, relates to the project close out period. All new assets will be in-service by January 1, 2026. The 65-year post-project analysis period is the average service life (ASL) of transmission mains pooled asset account 46500 as detailed in FEI's 2017 depreciation study approved with Order G-165-20 as part of FEI's 2020-2024 Multi Year Rate Plan (MRP) Application.

24.1 Please confirm the original service life and the current remaining service life of each of the CTS pipelines assets.

Response:

The average service life (ASL) of FEI's transmission mains, which includes each of the CTS pipelines, is 65 years as determined in FEI's most recent 2017 Depreciation Study[6]. However, the actual service life of a pipeline is dependent on a number of factors including the ongoing condition of the pipeline, the effectiveness of FEI's integrity management activities, and early retirements driven by third-party projects all of which can extend or shorten a pipeline's actual service life.

Well designed and constructed pipeline assets, if maintained appropriately and continually, can be used indefinitely. On this basis, FEI cannot define a remaining service life for assets of this kind. Instead, in the table below, FEI provides both the original in-service year for the pipeline, and the current remaining depreciable life which also takes into account amounts that have been capitalized to each of the CTS pipelines since their original construction. The remaining depreciable life is based on the net book value of each CTS pipeline as of December 31, 2020 (including all prior capital expenditures incurred on the individual pipelines), and the currently approved depreciation rates for transmission mains (as approved by FEI's MRP Decision) that are recorded under the group asset account.

The remaining depreciable life in the table below is the number of years until that specific asset would be fully depreciated, with no future capital expenditures being incurred, which is not a realistic scenario. However, FEI has provided the information to illustrate the ongoing nature of the integrity and sustainment work on its pipelines.

CTS PIPELINE	Original In-Service Year	Remaining Depreciable Life (Years)
HUN ROE 1067	1977	44
HUN NIC 762	1960	45
LIV COQ 323	1957	50
CPH BUR 508	1960	49
TIL FRA 508	1959	54
TIL BEN 323	1960	58
LIV PAT 457	1956	50
NIC FRA 610	1958	55
ROE TIL 914	1981	47
NIC PMA 610	1958	59
TIL LNG 323	1970	51

[6] As approved under Order G-165-20 as part of FEI's 2020-2024 MRP Decision.

24.2 Please discuss in detail how the **replacement** project increases the life of the pipeline assets to justify an additional 65-years of service life.

Response:

FEI did not state that there will be an increase in the life of its pipeline assets by an additional 65 years due to the pipeline replacement portion of the CTS TIMC Project. As noted in the preamble, FEI undertook a financial analysis that considers the financial life over which the pipeline assets included in this Project will be depreciated. The 65 years is the **existing** approved financial life for FEI's group assets of transmission mains.

As discussed in the preamble, the 65-year analysis period is chosen based on the average service life (ASL) of FEI's transmission mains as determined in FEI's most recent 2017 Depreciation Study[7]. Under group asset accounting, all capital costs incurred for the same asset class (i.e. transmission mains) will be depreciated at the approved depreciation rates, which is determined based on the ASL of the asset class[8].

FEI also notes that well designed and constructed pipeline assets, if maintained properly and continuously, can be used indefinitely. The need for retirements or replacement is primarily impacted by factors such as third-party relocation requests, system demand growth, system alterations for operating benefits and integrity concerns. In the absence of external influence or identified integrity concerns, the physical life of the asset such as the pipeline can be longer than the depreciable life of the individual assets.

[7] As approved under BCUC Order G-165-20 as part of FEI's 2020-2024 MRP Decision.

[8] Depreciation rates also depend on the accumulated gains/losses within the same asset class at the time of the depreciation study. The depreciation rates of each asset account are reviewed and updated periodically with new studies that are filed to BCUC for approval.

25.0 Reference: FINANCIAL

Exhibit B-1, Section 6.4, pp. 123-124

Sustainment Capital

On page 123 of the Application, FEI shows Table 6-4: Financial Analysis of the Project which has been reproduced below, including notes:

Table 6-4: Financial Analysis of the Project ($millions)

Line	Particular	Project [a]	Reference (Confidential Appendix Financial Schedules)
1	Total Charged to Gas Plant in Service ($ millions)	124.600	Schedule 6, Line 35, less Table 6-4 Line 4
2	Total Project Deferral Cost	13.243	Schedule 9, Line 2 + Line 7
3	**Total Project Cost - Excluding Sustainment Capital ($ millions)**	**137.843**	**Sum of Line 1 & Line 2**
4	Sustainment Capital [b]	84.983	Schedule 6, Sum of lines 12 & 13, 2026-2090
5	**Total Project Cost - Including Sustainment Capital ($ millions)**	**222.826**	**Sum of Line 3 & Line 4**
6	Incremental Rate Base in 2026 ($ millions)	107.257	Schedule 5 Line 19 (2026)
7	Incremental Revenue Requirement in 2026 ($ millions)	11.588	Schedule 1 Line 11, (2026)
8	**PV of Incremental Revenue Requirement 70 Years ($ millions)**	**147.460**	**Schedule 10, Line 25**
9	Net Cash Flow NPV 70 Years ($ millions)	(4.718)	Schedule 11, Line 17
10			
11	Delivery Rate Impact in 2026 (%)	1.32%	Schedule 10, Line 28 (2026)
12	**Levelized Delivery Rate Impact 70 years (%)**	**0.94%**	**Schedule 10, Line 32**
13	Levelized Delivery Rate Impact 70 years ($/GJ)	0.042	Schedule 10, Line 45

Notes:

[a] *Confidential Appendix G-2 – Financial Schedules*

[b] *Sustainment Capital allowance included to refresh end of life Telemetry and Measuring Equipment, original estimate inflated at 2 percent per annum every 11 years*

25.1 Please provide an explanation of the scope of work covered by Sustainment Capital.

Response:

Sustainment Capital includes the periodic refresh[9] of capital assets. In the context of Table 6-4, these Sustainment Capital assets are forecasted to be fully depreciated based on the average service life of those assets over the 70-year financial analysis period of the CTS TIMC Project.

The CTS TIMC Project includes $10.770 million of station construction costs related to the measuring and regulating equipment and telemetry ($5.385 million each on line 6 and 7, respectively on Table 6-3 of the Application). The currently approved depreciation rates for measuring and regulating equipment and telemetry equipment are 2.21 percent (approximately 47 years) and 8.97 percent (approximately 11 years), respectively. As part of the financial analysis, at the end of their depreciable life, FEI has retired the original fully-depreciated assets and included future replacement costs (called sustainment capital in Table 6-4 of the Application) based on the current cost estimate for those assets plus inflation at 2 percent per annum. The current approved depreciation rate for assets associated with the transmission

[9] In this context, FEI uses “refresh” to refer to future capital replacements or upgrades that occur as assets become obsolete, reach end-of-life, or are otherwise no longer suitable for their intended purpose.

mains (line 2 and 5 of Table 6-3 of the Application) is 1.46 percent (68 years), thus no future replacement cost is included for these assets.

25.1.1 Please provide a description of the "refresh end of life Telemetry and Measuring Equipment." As part of the response, please explain the importance of the refresh every 11 years to the CTS TIMC Project over the 65-year post-project period.

Response:

FEI clarifies that the note included in Table 6-4 should read:

"Sustainment Capital allowance included to refresh end of life Telemetry and Measuring Equipment, original estimate inflated at 2 percent per annum every 11 years and 47 years, respectively." [Emphasis added]

FEI inadvertently omitted the reference to 47 years which applies to measuring equipment that is also part of the Sustainment capital shown on Line 4 of Table 6-4 of the Application.

As discussed in the response to BCUC IR1 25.1, the CTS TIMC Project includes $5.385 million of measuring and regulating equipment and $5.385 million of telemetry equipment. As part of the financial analysis, FEI assumes the replacement happens at the end of the asset's depreciable life, which is 47 years for measuring and regulating equipment, and 11 years for telemetry equipment.

Telemetry equipment provides remote monitoring and control of station devices from FEI's Gas Control and is used to ensure safe and reliable operation of the gas system. Measurement equipment is used to record gas flows, pressures, and other parameters over a period of time and this information is critical for peak demand forecasting, asset management, and system operations. Much of this equipment uses electronic or computer technology that has a relatively short lifespan and, as noted above, will require periodic replacement.

25.1.2 Please discuss the delivery rate impact in the years where a refresh of the telemetry and measuring equipment is expected to occur.

Response:

The future delivery rate impacts due to the Sustainment Capital estimates related to telemetry and measuring equipment are small. The following table summarizes the future annual Sustainment Capital cost and the estimated delivery rate impacts for the years in which the costs are forecast to occur.

Sustainment Capital Estimated Delivery Rate Impact	2035	2045	2055	2065	2071	2075	2085	Total
Telemetry Sustainment Capital ($000s)	6,481	8,058	10,019	12,457	-	15,489	19,259	71,763
Measuring & Regulating Sustainment Capital ($000s)	-	-	-	-	13,220	-	-	13,220
Total Sustainment Capital	**6,481**	**8,058**	**10,019**	**12,457**	**13,220**	**15,489**	**19,259**	**84,983**
% Delivery Rate Impact	**0.01%**	**0.01%**	**0.01%**	**0.01%**	**0.01%**	**0.02%**	**0.02%**	

On page 124 of the Application, FEI shows Table 6-5: Summary of Rate Impact of the Project which has been reproduced below:

Table 6-5: Summary of Rate Impact of the Project

Project Rate Impacts	2022	2023	2024	2025	2026
Annual Delivery Margin, Incremental to 2021 Approved, Non-Bypass ($millions)	10.726	11.004	10.691	11.461	11.588
% Increase to 2021 Approved Delivery Margin, Non-Bypass	**1.22%**	**1.25%**	**1.22%**	**1.30%**	**1.32%**
Incremental % Delivery Rate Impact (Year-over-Year)	**1.22%**	**0.03%**	**-0.04%**	**0.09%**	**0.01%**
Average Annual % Delivery Rate Impact (5 years, 2022-2026)	0.26%				
Average Annual Delivery Rate Impact (5 years, 2022-2026), $/GJ	0.013				
Cumulative % Delivery Rate Impact (5 years, 2022-2026)	1.32%				
Cumulative Delivery Rate Impact (5 years, 2022-2026), $/GJ	0.066				

25.2 Please confirm if the average and cumulative delivery rate impacts shown in the bottom half of Table 6-5, on a percentage and $/GJ basis, include the cost of Sustainment Capital.

Response:

Not confirmed. Table 6-5 includes the initial rate impacts of the Project up until 2026 only. The initial rate impacts are related to the Project capital costs of $137.843 million shown on Line 3 of Table 6-4. Additions to Sustainment Capital are not expected to occur until 2035.

25.2.1 If not, please provide the estimated delivery rate impacts which include the Sustainment Capital. As part of the response, please provide the average bill for an FEI residential customer including the Sustainment Capital.

Response:

Table 6-5 was provided to show the expected cumulative delivery rate impact until 2026 when Project construction is expected to be complete and all assets have entered rate base.

Sustainment Capital is not expected until 2035, and as such, the estimates of this type of capital have no impact on the amounts reported in Table 6-5.

Table 6-4 of the Application summarizes the levelized rate impact over the 70-year analysis period which includes the impact due to Sustainment Capital. The levelized delivery rate impact for the 70-year analysis period is 0.94[10] percent. This equates to $0.042[11] per GJ and would result in a $3.78[12] bill impact for an average residential customer who consumes 90 GJs per year.

[10] Table 6-4, Line 12.
[11] Table 6-4, Line 13.
[12] $0.042 X 90 GJs = $3.78.

26.0 Reference: FINANCIAL

Exhibit B-1, Section 5.3.2, p. 86; Exhibit B-1, Section 6.2, p. 121

Development Costs and Deferral Account

On page 86 of the Application, FEI states:

> The total actual and projected development costs for the CTS TIMC project are $30.824 million to be incurred to the end of 2021, compared to the original estimated CPCN application development costs of $41.620 million for the entire TIMC project, as shown in Table 12-1 above. FEI notes, however, that the development costs for the future ITS TIMC CPCN application will continue to be collected in the deferral account until submission and a decision from the BCUC on that application.

26.1 For each of the CTS TIMC project, the ITS TIMC project, and total TIMC project, please confirm i) the original estimated development costs, ii) the total actual and projected development costs, iii) the current deferral account balance and iv) the carrying cost for each account.

Response:

When FEI requested the deferral account to develop the TIMC Project, the susceptibility and integrity risk to FEI's pipelines from cracking threats were unknown. As part of TIMC Project development, FEI undertook a QRA to inform its understanding of susceptibility and risk. FEI had no expectation of what systems would require mitigation at the time of requesting the deferral account estimated at $41.6 million, or that there would be a need for multiple projects. As such, FEI did not develop a split in the estimated costs between the CTS and ITS. Once the risk differences between the two systems were better understood, FEI identified CTS and ITS pipelines as requiring mitigation and proceeded to develop the CTS TIMC Application, based on it being higher risk than the ITS.

The following table provides the original estimated development costs for the combined CTS and ITS projects. The table also provides the actual spend as of December 31, 2020 for the CTS TIMC Project, and the projected remaining development costs for both projects.

Amounts in ($000s)	Original Estimate	Actual Spend	Projected Remaining Spend	Total Actual & Projected Costs
Direct Deferral Costs		14,401	6,117	20,518
Capitalized Development Costs		9,340	3,907	13,247
Total CTS Costs		**23,741**	**10,024**	**33,765**
Development Costs			6,050	6,050
Total ITS Costs		**-**	**6,050**	**6,050**
Combined CTS & ITS Costs (Before Carrying Costs)	**41,600**	**23,741**	**16,074**	**39,815**
CTS Carrying Costs		1,244	598	1,842
ITS Carrying Costs			351	351
Combined CTS & ITS Costs (After Carrying Costs)	**41,600**	**24,985**	**17,023**	**42,008**

On page 121 of the Application, FEI states:

> FEI proposes to recover the balance of costs in the deferral account associated with the development of the CTS TIMC Application estimated at $13.2 million by amortizing the December 31, 2021 actual balance of those costs over 3 years commencing in 2022. The capitalized development costs, also estimated at $13.2 million, will enter rate base at January 1, 2022.
>
> Note that FEI will continue to record costs associated with the future ITS TIMC application in the same deferral account, but these costs will be tracked and recorded separately from the CTS TIMC development costs and disposition will be requested as part of the ITS TIMC CPCN application.

26.2 Aside from consistency with FEI's previous CPCN applications, please provide the rationale for a three-year amortization period.

Response:

The following response also addresses BCUC IR1 26.3 and 26.4.

When preparing this response, FEI identified a need to amend the approvals sought to request 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.

As stated on page 3 of the Application, FEI is seeking approval to recover the portion of the balance in the deferral account related to the CTS TIMC Project by amortizing the December 31, 2021 deferral account balance related to the Project over 3 years commencing in 2022.

This request was based on an expectation that FEI would receive a decision on the CTS TIMC CPCN in 2021. As FEI currently does not anticipate receiving approval in 2021, FEI is now 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 refer to Attachment 26.2 in which FEI has provided a revised draft form of the final order sought reflecting this amendment.

FEI evaluated amortization periods of 1 though 5 years for the deferral account. FEI believes it is appropriate to amortize the deferral account for the CTS TIMC Project in under 5 years as the Project is forecasted to be undertaken over a 5-year period. With the exception of 1-year amortization period, FEI considered the differences between the annual delivery rate impact to

be immaterial. FEI ultimately selected an amortization period of three years, which is consistent with recent BCUC approvals for FEI's CPCN applications:

- BCUC Order C-2-21 for the Pattullo Gas Line Replacement Project approved a single Application and Preliminary Stage Development Costs deferral account with a three-year amortization period;
- BCUC Order G-12-20 for the Inland Gas Upgrades Project approved a single Application and Preliminary Stage Development Costs deferral account with a three-year amortization period;
- BCUC Order C-11-15 for the Lower Mainland Intermediate Pressure System Upgrade Project approved two separate deferral accounts for the Application and Project Development costs, both with three-year amortization periods; and
- BCUC Order C-2-14 for the Muskwa River Crossing Project for the Fort Nelson Service Area approved a single Application and Project Development Cost deferral account with a three-year amortization period.

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.

26.3 Please discuss whether any alternative amortization periods were considered by FEI.

26.3.1 If so, please discuss these alternatives including why they were not chosen.

26.3.2 If no alternatives were considered, please discuss why not.

Response:

Please refer to the response to BCUC IR1 26.2.

26.4 Please provide the delivery rate impact of the deferral account, as it relates to the CTS TIMC Project, if amortized over a one-year period and a two-year period, respectively.

Response:

Please refer to the response to BCUC IR1 26.2.

27.0 Reference: FINANCIAL

Exhibit B-1, Section 1.3, p. 4; Section 5.3.2, p. 86; Appendix C

QRA Costs

On page 4 of the Application, FEI states:

> … FEI contracted JANA Corporation (JANA), a QRA expert, to assess the susceptibility of FEI's transmission systems to cracking threats and to undertake a QRA of the safety risks to FEI's transmission systems. JANA's assessment shows that 11 pipelines on the CTS, and nine on the ITS, are susceptible to cracking.

On page 86 of the Application, FEI shows Table 5-3: Development Costs and Proposed Treatment, which has been reproduced in part below:

Table 5-3: Development Costs and Proposed Treatment

Item	Description	Phase	Proposed Treatment	Total Cost ($000s)
Initial QRA development	The costs for FEI's external consultant (JANA) to conduct a baseline system-level QRA. This work was required to meet previous commitments to the BCOGC to support the development of a segment-by-segment risk assessment process, as well as to confirm that SCC and cracking threats present a credible risk to FEI transmission pipelines.	Phase 1	Amortized expenses	10,552

27.1 Please explain the scope of work for the baseline system-level QRA and how that scope of work was determined.

Response:

The scope of work for the baseline system-level QRA that was submitted as Appendices B-1 and B-2 of the Application is as follows:

- Completion of an assessment of the susceptibility of FEI mainline transmission pipelines to cracking threats;
- Completion of an assessment of the potential for SCC growth to failure; and
- Completion of a baseline system-level quantitative risk assessment of FEI's mainline transmission pipelines, as documented in a report that conforms with CSA Z662:19 Annex B "Guidelines for risk assessment of pipeline systems"

Subject matter experts from both FEI and JANA determined this scope of work.

27.2 Please explain whether FEI intends to increase the scope of its baseline system-level QRA in the future. If so, please explain what would be included in the increased scope.

Response:

As explained in the response to BCUC IR1 1.5, FEI is planning for future iterations of QRAs, although their scope and timeline remain under development. FEI requires a sustainable and ongoing process to manage risk of its transmission pipelines, including by undertaking QRAs regularly. FEI is developing a risk assessment process that will be applicable to all of FEI's BCOGC-regulated pipeline assets, and will, in time, be implemented for all of these assets.

27.3 Please explain how FEI selected JANA to undertake the development of a QRA.

Response:

FEI selected JANA to undertake the development of its baseline system-level safety QRA through an internal evaluation process that considered technical and financial factors for a number of qualified consultancy firms. Technical assessment was completed by subject matter experts from FEI's System Integrity Programs department, with review by a representative of FEI's Asset Management team and the Director, Engineering Services.

27.4 Please explain why the costs for JANA to conduct the baseline system-level quantitative risk assessment (QRA) shown above are being included only as part of the CTS TIMC Project costs and not also as part of the expected ITS TIMC Project costs. As part of the response, please briefly explain the allocation of work on the report as it relates to the ITS and CTS projects.

27.4.1 Please confirm when FEI intends to submit the ITS TIMC CPCN application to the BCUC. As part of the response, please discuss when the ITS TIMC project is expected to be completed and if any of the costs for the QRA will be allocated to the ITS project.

Response:

This response addresses BCUC IR1 27.4 through 27.6.

FEI received BCUC approval with Order G-237-18 for the creation of the non-rate base TIMC Development Cost deferral account, with disposition to be proposed in a future application. In the proceeding that was the subject of that Order (FEI's Annual Review for 2019 Delivery

Rates), FEI explained that it was conducting a QRA in response to a direction from the BC Oil and Gas Commission to develop and implement a segment-by-segment risk assessment process , and FEI set out the types of costs it expected to record in the deferral account with respect to the QRA and the subsequent work that would be required.

As explained in Section 6.2 of the Application, costs captured in this deferral account include Preliminary Stage Development Costs (QRA and EMAT ILI pilot project costs), Pre-Construction Development Costs, and Application Costs. As FEI had approval to record the QRA costs in the TIMC Development Costs deferral account, it did not request approval to collect the costs in O&M or in rates until the filing of this Application.

With this Application, FEI has proposed that the costs of the QRA, the pilot project and the costs related to the CTS TIMC application be transferred to the CTS TIMC deferral account with recovery over a three year period.

In alignment with what was set out as the scope of the TIMC Development Costs deferral account, FEI will continue to record costs associated with the future ITS TIMC application (which is planned to be submitted in 2022, along with the timeline for completion of that project) in the TIMC Development Cost deferral account, but these costs will be tracked and recorded separately, and disposition will be requested as part of the ITS TIMC CPCN application.

The results of the baseline QRA provided a foundation for proceeding with the TIMC project in two separate applications : (1) this Application for the CTS TIMC Project; and (2) a forthcoming CPCN application for the pipelines forming the ITS. The QRA considered transmission pipelines on both the CTS and ITS and the results informed the overall priority and urgency of addressing cracking throughout FEI's system.

As such, with this Application, FEI recognizes that it could have requested the creation of two separate deferral accounts – one for the QRA and one for the CTS TIMC costs. If two accounts were requested, FEI would have requested amortization of both of these accounts over the same three year period. As such, FEI did not see the value in having two separate deferral accounts, but is open to this option if the BCUC would prefer to keep the QRA costs separate. FEI recognizes there may be some value to maintaining a separate deferral account for QRA costs on an ongoing basis because, as discussed in the response to BCUC IR1 27.2, FEI is planning for future iterations of QRAs, although the specific scope and timeline remain under development. FEI requires a sustainable and ongoing process to manage risk of its transmission pipelines, and is planning for future ongoing operations and maintenance expenditures. If the BCUC determines a separate deferral account is appropriate for this purpose and to record the costs related to the QRA that has already been undertaken, FEI requests that the account be a rate base account with an ongoing three year amortization period, and that future costs added to the account be subject to review in future revenue requirement proceedings.

27.5 Please explain why the costs for JANA to conduct the QRA is being included as part of the CTS TIMC Project costs which were "required to meet previous commitments" to the BCOGC. As part of the response, please explain why the cost was not included in FEI's operations and maintenance budget in a prior revenue requirements application.

Response:

Please refer to the response to BCUC IR1 27.4.

27.6 Please indicate the year(s) during which the QRA was conducted and whether FEI has previously requested for the costs to be collected in rates for the year(s) in question.

27.6.1 If not previously requested, please explain why not.

Response:

Please refer to the response to BCUC IR1 27.4.

28.0 Reference: FINANCIAL

Exhibit B-1, Section 5.12, p. 119

FEI CTS TIMC Project Workshop, Transcript Volume 1, p. 81

EMAT ILI Tool Run Costs

On page 119 of the Application, FEI states: "After the Project, FEI expects additional resource and material needs because of the EMAT findings following the completion of the Project."

28.1 Please provide a description of the costs FEI expects will be required to fund the "additional resource and material needs because of the EMAT findings." If available, please provide an estimate of the costs over the life of the CTS TIMC Project.

Response:

As described in Section 5.11 of the Application, FEI will require additional resources in the following departments:

- **Gas Control:** to provide additional support during in-line inspections using EMAT ILI tools. Gas Control resources monitor the flowrates and pressure in the system during inspections and are integral to successful tool runs. The narrower operating ranges of EMAT ILI tools when compared to FEI's existing ILI tools drives additional support over the current baseline.
- **System Integrity:** to analyze the EMAT ILI data, develop discrete projects to mitigate blind spots after the baseline runs, and perform on-going risk assessments using the information provided by the EMAT ILI program.
- **Operations:** to run the EMAT ILI tools and respond to findings by performing integrity digs and repairs.

To provide safe working zones for pipeline field crews, FEI will also require new double block and bleed tools[13] to isolate lines and perform repairs based on the EMAT ILI findings. The tools required are pipe size specific, meaning that they can only be used on a single pipeline diameter. FEI is currently one year into a 3-year lease agreement for an NPS 18 tool, and has recently entered into the same agreement for an NPS 20 tool. At the end of the 3-year period, FEI will fully own these tools. FEI will require new tools for CTS pipelines with diameters of NPS 12, NPS 24, and NPS 30.

FEI intends to stage the requests for resources and materials identified above such that as FEI becomes better informed on the level of effort required during the baseline EMAT ILI tool runs

[13] The API Specification 6D defines a double block and bleed valve as a "single valve with two seating surfaces that, in the closed position, provides a seal against pressure from both ends of the valve with a means of vending/bleeding the cavity between the seating surfaces."

there will be better information on which to base the requests. Consequently, FEI is unable to provide an estimate of costs at this time.

During the FEI CTS TIMC Project Workshop, FEI's team stated:

> Currently we use three different vendors for all of our inline inspection activities. And FEI maintains that ongoing relationship with those vendors, and that is to give us consistent results that are comparable from run to run. We can switch between those service providers if needed.

28.2 Please provide the estimated cost for performing an EMAT ILI on the CTS system and the estimated number of times FEI expects to perform an EMAT ILI over the 65-year post-project analysis period. Alternatively, please provide the average annual costs to perform EMAT ILI over the 65-year post-project analysis period. As part of the response, please confirm, or explain otherwise, that the costs for the EMAT ILI tool runs are included in the project cost and indicate the applicable Financial Schedule in Appendix G in which the costs can be found.

Response:

The cost to run EMAT ILI tools differs for each of the CTS pipelines because of their varying lengths and diameters. Based on current forecasts, an EMAT ILI tool run can range from $1.5 to $2.5 million (inclusive of both FEI and contractor costs). Assuming a seven-year re-inspection cycle, FEI expects to run an EMAT ILI tool eight to ten times per pipeline over the 65-year post-project analysis period. Actual re-inspection frequencies for each pipeline will be determined based on the findings after the initial tool run. These costs constitute a component of the Phase 2 Integrity Capital costs included in the NPV calculation provided for Alternative 4: EMAT ILI in Table 4-4 of the Application. Please refer to the response to CEC Confidential IR1 52.1 and 52.2 for details of the other components of the Phase 2 Integrity Capital costs.

Future costs for EMAT ILI runs are not included in the Project cost. FEI will request approval for an incremental increase in Sustainment Capital for the EMAT ILI tool runs through future rate application filings, depending on when the runs are scheduled. It is appropriate to request the funding through an incremental increase because of the cyclical and ongoing nature of running these tools. As the timing of the runs is contingent upon approval of the Application, they are not yet scheduled and costs have not been finalized.

28.3 Please discuss whether FEI intends to use one, two or all three of the vendors to conduct ILI activities on the CTS system and briefly explain why the selected vendor(s) were chosen.

Response:

Depending on the availability of vendors and the CTS TIMC Project schedule, FEI may choose to use one or two vendors to conduct EMAT ILI activities on the CTS. These vendors were short-listed because they have proven and commercially available EMAT ILI tools in the diameters of CTS pipelines.

28.3.1 Please provide the cost of each vendor to perform an ILI.

Response:

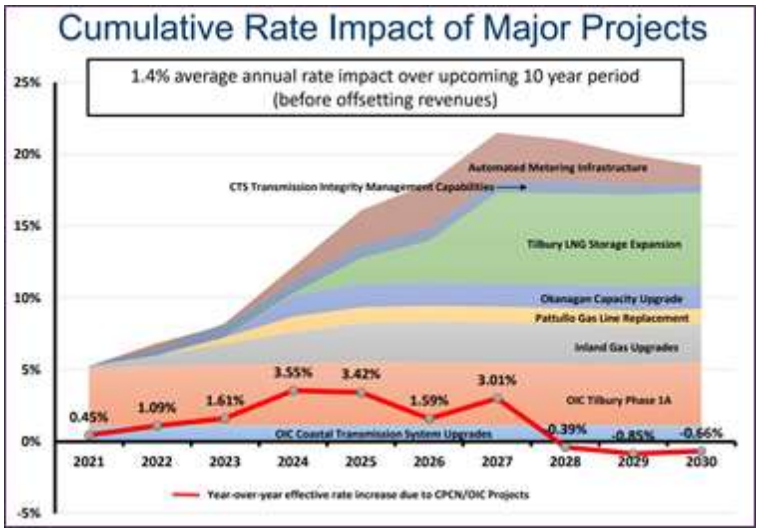
FEI has not yet scheduled the ILI runs or selected a specific vendor for each CTS pipeline and therefore does not have specific vendor costs at this time. Please refer to the response to BCUC IR1 28.2 for FEI's estimate for performing EMAT ILI.

29.0 Reference: FEI PROJECTS

Exhibit B-4, p. 5

Cumulative Rate Impact

On page 5 of FEI's CTS TIMC Project Workshop Presentation, FEI shows the cumulative rate impact of major projects of 1.4% average annual rate impact over the upcoming 10-year period, which has been reproduced below.



29.1 Please provide an updated chart to include the ITS TIMC CPCN, Woodfibre Gas Pipeline project and Tilbury Phase 1B project directed by Order in Council. As part of the response, please confirm the average annual rate impact over the upcoming 10-year period as a result of these projects and include the rate impact of each individual project.

Response:

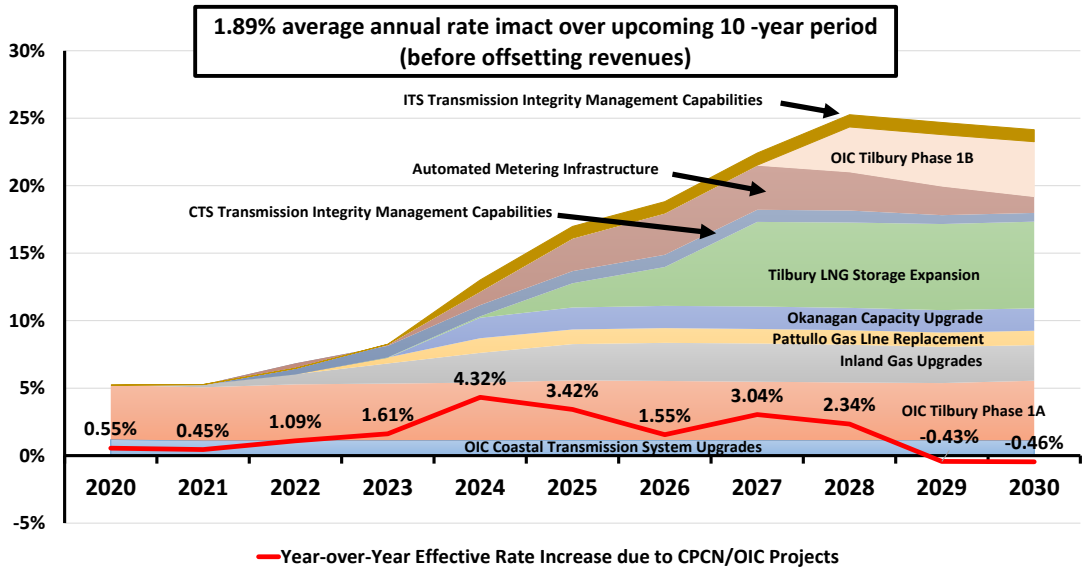
As discussed during the CTS TIMC Workshop,[14] FEI has not yet fully developed or committed to the Tilbury Phase 1B project and the Woodfibre Gas Pipeline project and therefore did not include them as part of the figure shown in the preamble. Similarly, FEI is in the process of developing the ITS TIMC project and does not yet have an estimate of the project's cost or timing.

However, in order to be responsive, please refer to the revised figure below in which FEI incorporates the estimated rate impact associated with these projects in the cumulative rate impact of the major projects identified in the Workshop. The estimated rate impacts of these projects are based on the following:

[14] CTS TIMC Workshop Transcript Volume 1, page 11 and 12.

- For Tilbury Phase 1B, Order in Council (OIC) 749 approved capital spending up to $400 million. This is similar to the $425 million approved for Tilbury Phase 1A. For this analysis, FEI has assumed the rate impact (before any offsetting revenues) due to Tilbury Phase 1B will be similar to Tilbury Phase 1A (as shown in the figure prepared for the Workshop), which averages to approximately 4.27 percent between 2021 and 2030. The timing of Tilbury Phase 1B is dependent on future developments in the LNG marine sectors, and as such, FEI is currently unable to confirm when Tilbury Phase 1B would enter FEI's rate base but, for the purpose of the cumulative rate impact figure provided below, FEI has assumed Tilbury Phase 1B will enter rate base in 2028.
- The Woodfibre Gas Pipeline would be subject to the demand toll under Rate Schedule (RS) 50 for large volume industrial transportation customers,[15] which is designed to recover the incremental cost of service required for the system upgrade. FEI is not expecting a rate impact to FEI's non-bypass customers, and therefore, has not included any rate impact related to the Woodfibre Gas Pipeline project in the figure below.
- As noted above, FEI has not developed a cost estimate for the ITS TIMC project. In the figure below, FEI has assumed the ITS TIMC project would have a similar rate impact as the CTS TIMC Project and that it would enter rate base in 2024.

As described in the Workshop, the figure below does not include any offsetting revenues stemming from increased capacity/demand or RS 46 revenues that would offset the rate impact of Tilbury Phase 1A. The same applies to the addition of Tilbury Phase 1B. FEI also notes the actual rate impact for FEI will not be dependent on these projects alone. There are various factors that will affect FEI's revenue requirement such as the demand forecast, taxes, O&M expenses, and other capital additions (beside these OIC and CPCN projects). As such, the figure below is illustrative only and does not represent FEI's estimated rate increase for the years shown.



[15] Approved by BCUC Order G-10-15.

29.2 Please discuss FEI's resource capabilities to execute all of the major projects identified over the upcoming 10-year period and the impact on rates.

Response:

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

29.3 Please identify the major projects which have construction in high density urban areas and that may experience unexpected underground conditions during construction. As part of the response, please briefly discuss FEI's resource capabilities to execute these projects in the event they go over budget and the overall impact on rates if each project is i) 10% over the budgeted cost estimate and ii) 20% over the budgeted cost estimate.

Response:

For the projects shown in the referenced figure, FEI considers only the Pattullo Gas Line Replacement (PGR) project to be in a medium- to high-density urban area. If the actual PGR project cost is 10 percent or 20 percent over the AACE Class 4 cost estimate as filed in the CPCN application, the levelized delivery rate impact would increase from 1.14 percent to 1.25 percent and 1.35 percent, respectively. This is equivalent to an increase in the annual bill impact by $0.45 and $0.90, respectively, for an average residential customer consuming 90 GJ per year. This cost increase would not be expected to impact FEI's resource capabilities to execute the project. Please refer to BCUC IR1 29.2 for a discussion of FEI's overall resource capabilities to execute major projects, including CPCNs.

E. ENVIRONMENT AND ARCHAEOLOGY

30.0 Reference: ENVIRONMENTAL REPORT

Exhibit B-1, Section 7.2.3, p. 131; Appendix H, p. vi

Required Environmental Permits

On page 131 of the Application, FEI states: "During the detailed engineering phase of this Project, FEI will undertake further environmental assessments to confirm permitting requirements and will apply for permits as required."

On page vi of Appendix H, Stantec states: "Regulatory requirements under the federal Fisheries Act are expected to be required for one event. Provincial permits under the Agricultural Land Commission Act, Wildlife Act, and Water Sustainability Act are anticipated to be required for five events and two facilities. Permits under municipal bylaws are anticipated to be required for two events and seven facilities."

30.1 Please explain whether these permits have been applied for or received, or when FEI expects to apply for or receive the permits.

Response:

FEI has not applied for the above listed environmental permits at this time. Given the current Project schedule, it is estimated that environmental permit applications will be submitted in approximately Q2 or Q3 2023.

30.2 Please explain whether FEI anticipates any issues with obtaining the required environmental permits. If so, please explain the potential impacts to the Project scope, schedule or budget.

Response:

FEI does not anticipate any issues with obtaining the required environmental permits. The above listed permits are typical of those required for FEI projects and there is sufficient time in the Project schedule to apply for and obtain the permits.

31.0 Reference: ARCHAEOLOGY

Exhibit B-1, Section 7.3, p. 125; pp. 132-133, 150; Appendix I, pp. vi, 8

High Archaeology Potential

On page 132 of the Application, FEI states: "The HUN ROE 1067 Event 12 and Huntington facility are within areas of modelled high archaeological potential, and will require AIA work."

On page 133 of the Application, FEI states:

> A permit will be required under Section 12.2 of the Heritage Conservation Act (HCA) in order to undertake AIA activities. FEI will obtain any Indigenous cultural heritage permits that are applicable at the time of the AOA and AIA. AIA work will be completed where Project components overlap with areas of moderate or high archaeological potential identified during the AOA. AIA work may begin during the detailed engineering phase and continue throughout construction, especially in areas of potentially deep buried cultural deposits.

31.1 Please explain whether the permits specified in the preamble have been applied for or received, or when FEI expects to apply for or receive the permits.

Response:

Indigenous cultural heritage permits were received from Katzie First Nation, Kwantlen First Nation, Musqueam Indian Band, Squamish Nation, Sto:lo Nation, and Tseil-Waututh Nation in March 2021 prior to the initiation of the AOA. No permit under the *Heritage Conservation Act* (HCA) was required for the AOA.

An HCA Section 12.2 permit and Indigenous cultural heritage permits will be required for the AIA. Based on the current Project schedule it is estimated that archaeological permit applications will be submitted in approximately mid to late 2022.

31.2 Please explain whether FEI anticipates any issues with obtaining the required Heritage Conservation Act permits or Indigenous cultural heritage permits. Please explain any potential impacts to the CTS TIMC Project scope, schedule or budget if the permitting process results in delays.

Response:

FEI does not anticipate any issues with obtaining the required archaeological permits. The above listed permits are typical of those required for FEI projects and there is sufficient time in the Project schedule to apply for and obtain the permits.

On page 125 of the Application, FEI states:

> As recommended by its archaeological consultant and to further assess the Project's potential archaeological impacts, in 2021 FEI will be conducting an Archaeological Overview Assessment (AOA) to determine archaeological potential, and an Archaeological Impact Assessment (AIA) for areas assessed as having elevated or high archaeological potential in the AOA. The AIA will provide a detailed assessment to allow for development of site-specific mitigation strategies to offset any potential impacts associated with the Project. If the results of the AIA determine that work is to take place in proximity to archaeological sites, monitoring during excavation works will be conducted, as per the recommendations of the archaeologist.

31.3 Please confirm that the AOA is completed. If yes, please provide the date of completion. If not, please state the anticipated date of completion.

Response:

The AOA work is currently being undertaken and a draft AOA is expected to be submitted to Indigenous groups for review in mid-Q3 2021. The completion date of the final AOA report will depend on the time it takes for Indigenous groups to complete their review, but FEI anticipates this process to be complete in Q4 2021.

31.4 Please provide a copy of any AIA completed to date. For any AIA not yet completed, please provide a list of anticipated assessments and expected completion date.

Response:

To date, no AIA work has been completed. Based on the current Project schedule, it is expected that AIA work will be conducted in 2023 once FEI obtains a permit under Section 12.2 of the *Heritage Conservation Act* and the necessary Indigenous cultural heritage permits.

On page vi of Appendix I, Stantec states:

> One of the Events (HUN ROE 1067 Event 12) and one of the facilities (Huntingdon) are within areas modelled as having high archaeological potential on the Province's Remote Access to Archaeological Data application. However, most of the Events and facilities are within areas of the Lower Mainland without any potential model coverage and the absence of modelled potential does not indicate the other areas have low potential. All of the Events and facilities other than Fraser Gate Station may have elevated archaeological potential and should be subject to further assessment through AOA and/or AIA with input from Indigenous groups.

On page 8 of Appendix I, Stantec states:

> However, there may also be sites that have cultural significance or sensitivity to Indigenous groups near the Project that are identified once consultation with those groups begins. In addition, this review does not include information or other input from Indigenous groups regarding their perspectives on archaeological potential or sensitivities that should be considered in future archaeological studies.

On page 150 of the Application, FEI states:

> FEI is committed to… Communicating and soliciting feedback regarding construction timelines, scope of work, and safety and mitigation plans. This includes, in particular, working with Indigenous groups in advance of completing an Archaeological Overview Assessment (AOA) and Archaeological Impact Assessment (AIA) by, for example, obtaining relevant Indigenous issued permits and sharing results for assessment review and comment.

31.5 Please explain whether all Indigenous Communities that may be affected by the potential for archaeological impact of the Project have been informed about this potential.

Response:

FEI sent two notification letters to all Indigenous groups that may be affected by the potential for archaeological impact of the Project to inform them of the Project and its potential for impacts. The Archaeology Constraints Report was sent to all Indigenous groups in November 2020.

FEI's archaeologist, Stantec, has also submitted permit applications to those Indigenous groups that have an existing Indigenous cultural heritage permitting system (Katzie First Nation,

Kwantlen First Nation, Musqueam Indian Band, Squamish Nation, Sto:lo Nation, and Tseil-Waututh Nation). These Indigenous groups will receive the draft AOA for review in mid Q3 2021 as a requirement of their respective permitting processes. All Indigenous groups that may be affected by the potential for archaeological impacts of the Project will be sent a copy of the AOA upon finalization.

31.5.1 Please summarize any issues or concerns raised by Indigenous Communities in this regard.

Response:

At this time, no issues or concerns have been raised by Indigenous groups through the Indigenous cultural heritage permitting process. As described in the response to BCUC IR1 31.5, the draft AOA will be provided to Indigenous groups with a cultural and heritage permitting system in July 2021, allowing them the opportunity to provide comment. All potentially impacted Indigenous groups will receive a copy of the final AOA report.

31.5.2 If not, please confirm that FEI intends to solicit input from Indigenous groups as part of its AOA and/or AIA process, in accordance with Stantec's recommendation.

31.5.2.1 If yes, please explain how FEI intends to solicit input from Indigenous groups as part of its AOA and AIA process.

Response:

The draft AOA will be provided to Indigenous groups with a cultural and heritage permitting system in mid Q3 2021, allowing them the opportunity to provide comment. All potentially impacted Indigenous groups will receive a copy of the final AOA report.

During the permit process contemplated under Section 12.2 of the *Heritage Conservation Act*, all potentially impacted Indigenous groups will have the opportunity to provide comments on the permit application and request participation in the associated AIA field work, or review of the AIA report. Prior to field work, the archaeologist retained for the Project will contact Indigenous groups to obtain applicable Indigenous permits and will also contact communities that have expressed an interest in participating in the AIA to assist with field work.

F. CONSULTATION AND ENGAGEMENT

32.0 Reference: PUBLIC CONSULTATION

Exhibit B-1, Section 8.2, p. 144; Appendix J-2

Issues Raised during Public Consultation

On page 144 of the Application, FEI summarizes its public consultation activities to date. In Appendix J-2 FEI recorded its public consultation activities to date.

In Table 8-2 on page 144 of the Application, FEI summarizes the two questions raised by residents using the dedicated project phone line.

32.1 Please provide any customer responses to FEI's answers. Please note whether the residents' concerns remain. Please explain any follow-up action required.

Response:

As outlined in Table 8-2 on page 144 of the Application, FEI addressed the two questions raised by residents using the dedicated Project phone line and is not aware of any outstanding concerns. FEI committed to communicating with these residents, and other residents along and near the Project rights of way prior to commencing construction activities and throughout the Project lifecycle.

32.2 Please provide a summary of any issues raised, in addition to that provided in Table 8-2 and Appendix J-2, during public consultation to date. Please provide a copy of FEI's responses to any issues raised and whether any follow-up action is required.

Response:

FEI provides the table below that summarizes the issues raised and FEI's response and follow-up.

Inquiry	Description of issue	FEI's response and required follow-up
Transmission work in the Kootenays	**February 13, 2021: Project Email** Question whether FEI is planning transmission upgrades in the East Kootenays.	FEI replied via email with informational links to the Inland Gas Upgrades Project in that region. No follow-up required.

Inquiry	Description of issue	FEI's response and required follow-up
Need for the Project and capital depreciation	**February 17, 2021: Project Email** Question whether Project is to increase capacity and whether FEI depreciates assets.	FEI replied via email and indicated the need for the Project is to improve the safety and reliability of the system, and clarified that it is not to increase capacity. FEI also clarified that capital assets are depreciated based on the estimated remaining period of time that they are expected to be useful. No follow-up required.
Rate impacts to customers	**February 28 and March 5, 2021: Project Email** Two customers questioned whether customers incur the costs of the Project (including one customer asking about customers in the Interior specifically) and where customers could express concerns about rate impacts.	FEI replied by indicating that there would be rate impacts to all of FEI's customers, including to FEI's customers in the Interior. FEI also noted the BCUC CPCN process and the opportunity to become involved in the regulatory process. No follow-up required.

32.3 Please provide an update of any public feedback received from the date of creation of Appendix J-2 to the date of the response to this IR.

Response:

Please refer to Attachment 32.3 for the Updated Appendix J-2, with updated entries beginning on February 9, 2021.

32.4 Please explain what future public consultation is contemplated subsequent to the submission of the CPCN Application, expanding on the information provided in Appendix J-1. Please provide a timeline for any planned activities.

Response:

FEI has continued to undertake public consultation activities since submitting the Application. In addition to the public consultation activities contained in Appendix J-2 of the Application, FEI sent a rate impact awareness bill insert to customers in February 2021. The table below provides a summary of the forthcoming public consultation that FEI anticipates.

Stakeholders	Deliverables	Timeline
FEI Customers	• Send notifications via FEI channels (e.g. email newsletters)	2022 to 2024
Stakeholder Engagement	• Monitor dedicated project email and phone line and respond to inquiries	2021 to 2024
	• Send notifications to Project website subscribers and other FEI channels including social media	2022 to 2024
	• Create and maintain communication materials (e.g. webpage and information cards) as Project advances and in preparation of construction activities	2022 to 2024
	• Send notification letters to residents and businesses (approximately two months) prior to construction starting	2024
	• Send notification letters during construction advising of impacts (e.g. traffic pattern changes, increase noise, limited access to multi-use pathways)	2024
Municipal Staff	• Review early engineering drawings with municipal staff	June 2022
	• Further discussions with municipal staff as required	2023 to 2024

32.5 Please explain how FEI's public consultation process has been successful engaging with those potentially affected by the Project.

Response:

FEI believes the consultation activities to date have been sufficient, appropriate, and reasonable. Throughout the consultation, FEI addressed questions and concerns, and is unaware of any outstanding concerns. FEI is also committed to continuing to consult with stakeholders and respond to feedback throughout the Project's lifecycle.

33.0 Reference: INDIGENOUS ENGAGEMENT

Exhibit B-1, Section 8.3, pp. 146, 148-149; Appendix J; Appendix K-4; Appendix K-3

Issues Raised during Indigenous Engagement

On pages 148-149 of the Application, FEI provides Table 8-5 summarizing questions, issues and concerns raised by Indigenous groups.

On page 146 of the Application, FEI states: "While the constitutional duty to consult with Indigenous groups rests with the Crown, FEI's Indigenous engagement activities will aid the appropriate Crown agencies in meeting that duty."

FEI may file its responses to these IRs confidentially, if required.

33.1 Please resubmit Table 8-5 with any updates since January 18, 2021.

Response:

Please refer to the Updated Table 8-5 which includes feedback from Indigenous groups obtained after filing the Application. This feedback is provided in bold.

Updated Table 8-5: Questions, Issues, and Concerns by Indigenous Groups

Indigenous Group	Summary of questions, issues or concerns	Next Steps/follow-up
Tsleil-Waututh Nation (TWN)	• **October 6, 2020:** TWN sent a copy of their Stewardship Policy and stated that they require a 45 days for review of documents or materials. • **December 17, 2020:** TWN sent a cost estimate for review of the Environmental Overview Assessment and Archaeological Constraints Report. • **January 19, 2021: TWN reviewed the Archaeological Constraints Report and requested FEI and its consultants apply for TWN archaeological permits for each work sites rather than one permit for the entire project. TWN notified that, due to internal capacity, they are delayed in reviewing the Environmental Overview Assessment.**	• **FEI has accepted the cost estimate for TWN to review materials. FEI has noted the request for multiple permits and will work with archaeological consultants to obtain the required permits. FEI is awaiting comments on the Environmental Overview Assessment and will continue to engage TWN to address any interests or concerns.**

Indigenous Group	Summary of questions, issues or concerns	Next Steps/follow-up
People of the River Referrals Office (PRRO)	• **October 8, 2020:** PRRO requested geospatial data. FEI provided KMZ file of worksites. • **November 30, 2020:** PRRO provided Technical Review on FEI's application, which indicated some worksites may potentially impact waterways, and cultural and heritage sites. • **December 3, 2020:** FEI hosted a virtual meeting with PRRO to discuss the Technical Review and PRRO's interests in the Project. • **January 18, 2021:** PRRO sent a final engagement report in which PRRO indicated approval with condition(s) for FEI's application. Conditions include a request for FEI to send reports related to watercourses and environmental impacts as they become available through the life of the Project. • **February 19, 2021: FEI met with the PRRO and Sto:lo Research and Resource on upcoming geotechnical program and the existing Archaeological Overview Assessment Sto:lo prepared for this area. They confirmed that there is high archaeological potential where geotech work is planned to occur. FEI will complete the geotech work with archaeological monitors on site.**	• FEI will continue to keep PRRO informed about the Project as it develops and share documents in advance of further archaeological and environmental assessments and construction activities as PRRO requested on January 18, 2021. • **Geotech work has been completed with archaeological monitors.**
Matsqui First Nation (MFN)	• **October 9, 2020:** MFN requested additional information about the Project. MFN indicated an interest in training opportunities and to have their own monitors present for project activities. • **October 14, 2020:** FEI hosted a telephone meeting to discuss the Project. • **November 19 and December 3, 2020:** FEI hosted a follow-up virtual meeting with MFN to review project details, the Environmental Overview Assessment and the Archaeological Constraints Report, further clarify the request for monitors and training, and respond to any further questions, concerns and interests.	• FEI is planning additional meetings with MFN to continue discussions about their interests in the Project.
Kwikwetlem First Nation (KFN)	• **October 27, 2020:** KFN indicated an interest in capacity funding to participate in engagement.	• FEI followed-up with KFN to discuss capacity funding. • **FEI provided a capacity funding agreement for KFN to review on May 18, 2021 which includes capacity funding for multiple FEI projects.**

Indigenous Group	Summary of questions, issues or concerns	Next Steps/follow-up
Musqueam Indian Band (MIB)	• **November 13, 2020:** Follow-up email to inform MIB about anticipated work in the Delta area.	• FEI will continue to update MIB about the Project as it develops and in advance of further archaeological and environmental assessments and construction activities.
Squamish Nation (SN)	• **November 10, 2020:** SN invited FEI to upload project materials to Squamish Connect referrals portal. • **November 24, 2020:** SN requested spatial data.	• FEI provided KMZ files through Squamish Connect.
Cowichan Tribes (CT)	• **December 11, 2020:** CT notified FEI of their review of the Environmental Overview Assessment and Archaeological Constraints Report. CT requested that they be engaged on future archaeological activities at Tilbury and Richmond worksites. • **January 18, 2021:** FEI hosted a virtual meeting with CT to discuss the Project and their interests in archaeological activities. CT re-iterated an interest in participating in archaeological activities at Tilbury and Richmond worksites.	• FEI will continue to send archaeological reports to CT for review and comment. FEI will continue to engage CT on archaeological interests.

33.2 Please provide any relevant, written documentation (confidentially, if required) regarding Indigenous engagement, such as notes or minutes of meetings or phone calls, or letters received from or sent to all Indigenous communities.

Response:

In Attachment 33.2, FEI has provided an updated Appendix K-4 Indigenous Groups Engagement Log.

33.3 Please Identify any specific issues or concerns raised by Indigenous communities.

33.3.1 Please describe how any specific issues or concerns raised by the Indigenous community were avoided, mitigated or otherwise accommodated, or explain why no further action is required to address an issue or concern.

Response:

Please refer to Attachment 33.2 provided in the response to BCUC IR1 33.2, which contains an Updated Appendix K-4 Indigenous Groups Engagement Log. Please also refer to the response to BCUC IR1 33.1, which provides an Updated Table 8-5 with questions, issues, and concerns raised after filing the Application.

Appendix K-4 details the Indigenous Groups Engagement Log.

33.4 Please provide an updated version of Appendix K-4 that documents any "next steps" or "follow up" activities that have been fulfilled and any further engagement activities or feedback received since the filing of the Application.

Response:

Please refer to the Attachment 33.2 provided in response to BCUC IR1 33.2.

33.4.1 Please summarize the main issues that FEI has presented to Indigenous communities in meetings to date.

Response:

To date, FEI has presented Indigenous groups with the known scope of the Project and potential associated impacts, including planned worksite locations. As part of this process, FEI has shared maps, spatial data (Google Earth KMZ file), an Environmental Overview Assessment, and the Archaeological Constraints Report.

A number of Indigenous groups have indicated an interest in engaging on future archaeological and environmental reports and plans as they become available and through the BCOGC permitting process, closer to Project construction.

Please also refer to updated Table 8-5 Questions, Issues, and Concerns by Indigenous groups provided in the response to BCUC IR1 33.1 and to the Updated Appendix K-4 Indigenous Groups Engagement Log in Attachment 33.2 in response to BCUC IR1 33.2 for a description of FEI's engagement activities in relation to the Project.

33.4.2 Please provide any evidence to indicate whether the Indigenous communities engaged with are satisfied with FEI's engagement to date and proposed next steps.

Response:

FEI has not received feedback to suggest Indigenous groups are satisfied or dissatisfied with engagement to date. Please refer to Attachment 33.2 provided in response to BCUC IR1 33.2 (Updated Appendix K-4 Indigenous Groups Engagement Log) for a record of engagement after the Application was filed with the BCUC in February 2021.

33.5 For the Indigenous communities identified in Appendix K-4 that have not provided a response to FEI's notification letter or have indicated that no further information/ engagement is required, please discuss whether FEI has undertaken, or plans to undertake any follow-up communication, including meetings, with these Indigenous communities. Please provide a summary of activities with dates as applicable.

Response:

FEI will communicate with all Indigenous groups throughout the lifecycle of the Project. Please refer to Attachment 33.2 provided in response to BCUC IR1 33.2 (Updated Appendix K-4 Indigenous Groups Engagement Log) for a summary of engagement with Indigenous groups following FEI's notification letter.

FEI will continue to share the results of environmental and archaeological reports with Indigenous groups, including those who have not responded to previous communications. FEI will also engage Indigenous groups on site-specific impacts through the BCOGC permitting process which includes soliciting feedback on environmental and archaeological reports and management plans in advance of construction. FEI will also engage Indigenous groups on employment and contracting opportunities through its Socio-Economic Impact Program.

These activities will occur leading up to contracting and construction, between 2022 and 2024.

33.5.1 Please provide an assessment of any potential risks or issues to be resolved with these communities as more detailed project information becomes available.

Response:

FEI anticipates responding to issues raised from Indigenous groups related to environmental and archaeological impacts, such as impacts to sensitive watercourses and areas with high archaeological potential, as more detailed Project information becomes available through the BCOGC permitting process. FEI will solicit input and feedback on environmental and archaeological reports or plans, and management plans, in advance of construction.

In Appendix K-3, FEI provides samples of letters and emails sent to Indigenous communities within the geographic area of the CTS TIMC Project.

33.6 Please discuss if the initial notification letters [Appendix K-3] were tailored to describe the nature of the specific potential impacts by site. If not, please explain.

33.6.1 Please explain whether FEI considers that all potentially affected Indigenous communities have been made sufficiently aware of the potential impacts of the CTS TIMC Project.

Response:

FEI's initial notification letter was part of early engagement and was not tailored to describe the nature of the specific potential impacts by site. This level of detail was not known at the time the notifications were sent. FEI plans to engage Indigenous groups regarding site-specific impacts as more detailed project information becomes available. FEI will also engage Indigenous groups on site-specific impacts through the BCOGC permitting process, which includes soliciting feedback on environmental and archaeological reports and management plans in advance of construction.

33.7 Please explain how FEI's approach to engagement with Indigenous communities has differed depending on whether a community is located near an event or facility with high impact potential or low impact potential.

Response:

Please refer to the response to BCUC IR1 33.6.

33.8 Please provide evidence that the Indigenous communities have been notified of the filing of the Application with the BCUC and have been informed on how to raise outstanding concerns with the BCUC.

Response:

On March 29, 2021, FEI notified Indigenous groups of the filing of the Application with the BCUC. FEI provided a link to the full Application on the BCUC website and direction on how Indigenous groups could formally participate in the Application review process. Please refer to Attachment 33.2 in response to BCUC IR1 33.2 (Updated Appendix K-4 Indigenous Groups Engagement Log) for a record of FEI notifying each group.

33.9 Please explain how FEI's early engagement activities have been successful in understanding the nature of interests of Indigenous communities in the area of each of the events and facilities affected by the CTS TIMC Project.

Response:

FEI's early engagement activities included sharing initial archaeological and environmental reports with all Indigenous groups identified in the Province's Consultative Areas Database. Through email correspondence and virtual meetings, FEI was able to address all questions and issues from Indigenous groups to date. FEI plans to engage with Indigenous groups on site-specific impacts as more detailed project information becomes available. FEI will also engage Indigenous groups on site-specific impacts through the BCOGC permitting process, which includes soliciting feedback on environmental and archaeological reports and plans and management plans in advance of construction.

FEI considers that its early engagement activities have been successful in understanding the level of interest and the nature of interests of Indigenous groups for the Project, reflecting this stage in the Project lifecycle.

33.10 Please provide further details of what future engagement with Indigenous communities is contemplated subsequent to the submission of the CPCN Application, expanding on the information in Appendix J-1. Please also provide a timeline showing planned future activities.

Response:

FEI will continue to share results of environmental and archaeological reports with Indigenous groups. FEI will also engage Indigenous groups on site-specific impacts through the BCOGC permitting process which includes soliciting feedback on environmental and archaeological reports and management plans in advance of construction. FEI will engage Indigenous groups on employment and contracting opportunities through its Socio-Economic Impact Program. These future engagement activities are listed in the table below.

Activity	Timing
Share results of AOA	July/August 2021
BCOGC Permitting	2022 to 2024
Employment and contracting	2022 to 2024

33.11 Please explain whether FEI has executed any capacity funding agreements. If yes, please describe the nature and number of the capacity funding agreements and the Indigenous groups who have entered into the capacity funding agreements.

Response:

FEI is in the process of developing a capacity funding agreement with Kwikwetlem First Nation. On January 21, 2021, FEI also paid an invoice from Tsleil-Waututh Nation to provide them with capacity funding to review the Project's Environmental Overview Assessment and Archaeological Constraints Report.

Attachment 3.3

3.0 Reference: PROJECT JUSTIFICATION

Exhibit B-1, Section 1.2.2, p. 5; Exhibit A2-1

Risk Analysis and Evaluation

On page 5 of the Application, FEI states:

> FEI has a comprehensive Integrity Management Program (IMP) as required by the BC Oil and Gas Commission (BC OGC)…
>
> …As corrosion is the leading cause of transmission pipeline failures in British Columbia, the Project is proposing several alternatives to the status quo that will provide for continued safe and reliable long-term operation of the 29 Transmission Laterals. The Project, completed proactively over a reasonable planning horizon and in consideration of the feasibility and benefits of alternative integrity management strategies, demonstrates FEI's commitment to continual improvement within its integrity management program, and is an appropriate response to the potential for rupture failure due to corrosion.

Section 1.5.4 of the BC OGC Compliance Assurance Protocol, provided as Exhibit A2-1, states:[2]

> The permit holder shall prioritize the pipelines/segments in order of risk level and shall implement an effective process for identifying and evaluating the available risk reduction options (CSA Z662 – Clause N.10) to prevent, manage, and mitigate risks where the chosen threshold of risk is exceeded.

3.1 Please describe any assessments to prioritize the 29 Transmission Laterals in order of risk level and provide the result of these assessments.

Response:

This response also addresses BCUC IRs 1.3.2, 1.3.3, 1.3.4, 1.3.6, 1.3.8 and 1.3.8.1, and CEC IR 1.2.1 and 1.3.1.

Based on FEI's existing methods and the information available on the 29 Transmission Laterals, FEI's assessment is that there is not a material difference in the integrity risk level of the laterals. All of the 29 Transmission Laterals 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 ability to prioritize amongst the 29 Transmission Laterals based on risk level is limited because the available condition information is comprised of limited quantities of integrity digs and failure records (rather than in-line inspection), and this information does not provide any indication of

[2] BC Oil & Gas Commission Compliance Assurance Protocol – Integrity Management Program for Pipelines, April 2018, Version 1.9.

systemic issues on any particular lateral. Given the information available, FEI's assessment is that it is appropriate to implement the proposed scope of the IGU Project for all 29 Transmission Laterals proactively over a reasonable planning horizon.

FEI's Integrity Management Program – Pipelines (IMP-P) currently follows a hazard management approach, as recognized by Clause N.8.3 (b) of the CSA Z662 standard:

> "Where hazards that might lead to failure or damage incidents are identified, the operating company shall…implement and document measures for monitoring conditions that could lead to an incident with significant consequences and eliminate or mitigate such conditions…."

Taking into account FEI's obligations under the above standard, the planned 5-year implementation timeline for the IGU Project is a reasonable period over which to achieve proactive mitigation of the potential for rupture of the 29 Transmission Laterals. Further, FEI does not have condition assessment or other information that would support the need to expedite or delay the project timeline. In FEI's judgement, taking into account all the information available to it, and its legal and regulatory obligations, 5 years is a reasonable time frame over which to execute the IGU Project.

FEI has developed the detailed schedule for the IGU Project based on factors such as the regional distribution of the Project, capacity limitations including industrial customers' requirements, scheduling constraints (such as windows of time where work can be undertaken on the laterals), cost efficiencies by managing as a single project, operational constraints (such as working on an in-service line), and contractor and resource limitations. As discussed above, FEI has no information that indicates that there would be improvement from a safety or reliability perspective by prioritizing the laterals differently than currently planned.

Please refer also to the response to BCUC IR 1.6.3 regarding FEI's capabilities to successfully implement the IGU Project within the proposed timeline.

FEI is currently responding to direction from the BC OGC to develop a method to conduct quantitative risk assessments, as discussed in response to BCUC IR 1.6.5. FEI is undertaking the first iteration of a quantitative risk assessment (QRA) of its transmission pipelines as part of Phase 1 of its Transmission Integrity Management Capabilities (TIMC) CPCN development. This QRA is required for the purposes of that project, as described in Section 12.4.1.1 of FEI's Annual Review of 2019 Rates application. However, this QRA is not required to justify the need for the IGU Project and, given FEI's limited condition assessment information on the 29 Transmission Laterals due to lack of ILI data, FEI's ability to prioritize amongst the laterals is expected to remain limited.

Attachment 26.2

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ORDER NUMBER
C-xx-xx

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

and

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

BEFORE:
[Panel Chair]
Commissioner
Commissioner

on Date

ORDER

WHEREAS:

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

B. The CTS TIMC Project includes the following:

    1. Required pipeline alterations including replacement of heavy wall segments and alterations to related facilities that are necessary to ready the 11 susceptible CTS pipelines for electro-magnetic acoustic transducer (EMAT) in-line inspection (ILI); and

    2. Installation of a pressure regulating station (PRS) on a single segment of one of the pipelines where EMAT ILI is not possible;

C. In the Application, FEI also requests approval, pursuant to sections 59 to 61 of the UCA, to recover the balance of costs in the TIMC Development Cost deferral account associated with the development of the Application, estimated at $13.2 million, by amortizing the December 31, 2021 actual balance of these costs over three years commencing in 2022;

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

E. By Order G-74-21 dated March 11, 2021, the BCUC establishing an initial regulatory timetable including intervener registration and a transcribed workshop hosted by FEI with participation by the BCUC, BCUC independent expert Dynamic Risk Assessment Inc. (Dynamic Risk) and registered interveners;

F. By Order G-149-21, the BCUC established a further regulatory timetable including an independent expert report by Dynamic Risk and round one information requests (IRs) to FEI and Dynamic Risk;

G. On July 27, 2021, FEI filed its responses to IRs No. 1 and amended the approvals sought related to the TIMC Development Cost deferral account;

H. to FEI proposes to transfer the balance in the deferral account to rate base on January 1 of the year following BCUC approval of the application and commence amortization over a three-year period thereafter; and

I. The BCUC has reviewed the evidence in the proceeding and finds that approval is warranted.

NOW THEREFORE pursuant to sections 45 to 46 and 59 to 61 of the *Utilities Commission Act* and for the reasons set out in the decision issued concurrently with this order, the British Columbia Utilities Commission orders as follows:

1. FEI is granted a CPCN for the CTS TIMC Project.

2. FEI is approved to transfer the balance in the TIMC Development Cost deferral account associated with the development of the CTS TIMC Project to rate base on January 1in the year following BCUC approval of the Application, and commence amortization of the balance, estimated at $13.2 million, by amortizing the December 31, 2022 actual balance of these costs over a three-year period commencing January 1, 2023.

3. FEI is directed to comply with all directives outlined in Section # of the Decision issued concurrently with this order.

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

BY ORDER

(X. X. last name)
Commissioner

Attachment (Yes? No?)

Attachment 32.3

TIMC Consultation Log

Date	Consultation Type	External Representative	Stakeholder	Consultation Summary
1-Oct-20	Emailed Project Information Letter	Scott Neuman, Engineering, City of Surrey	City of Surrey	Sent Project information letter. City of Surrey responded to the letter, directing FEI to another individual who manages third party utility permits. City of Surrey requested engineering drawings, and FEI committed to providing them when available.
1-Oct-20	Emailed Project Information Letter	Chad Braley, Engineering, City of City of Coquitlam	City of Coquitlam	Sent Project information letter. City of Coquitlam responded that they will be in touch if they have questions. None raised.
1-Oct-20	Emailed Project Information Letter	Rob Isaac, Engineering, City of Abbotsford	City of Abbotsford	Sent Project information letter.
1-Oct-20	Emailed Project Information Letter	Roeland Zwaag, Engineering, Township of Langley	Township of Langley	Sent Project information letter.
1-Oct-20	Emailed Project Information Letter	Steven Lan, Engineering, City of Delta	City of Delta	Sent Project information letter. City of Delta responded and requested follow-up meeting where FEI provides an overview of potential impacts.
1-Oct-20	Emailed Project Information Letter	Milton Chan, Engineering, City of Richmond	City of Richmond	Sent Project information letter.
1-Oct-20	Emailed Project Information Letter	Hamad Quazi, Engineering, City of Vancouver	City of Vancouver	Sent Project information letter. City of Vancouver responded asking if this was part of the 2021 gas line upgrade work on East Kent Avenue. City of Vancouver had no concerns.
6-Oct-20	Emailed Project Information Letter	Jeff Moi & Philip Chow, Engineering, City of Port Moody	City of Port Moody	Sent Project information letter. The City of Port Moody responded on Oct 24, requesting technical information and scope of work relating to the City of Port Moody. FEI responded that detailed engineering drawings and scope will be shared mid-late 2022. FEI will keep the City of Port Moody informed of progress including schedule and any potential disturbances such as noise impacts to the local community.
6-Oct-20	Emailed Project Information Letter	Juli Halliwell CAO/CFO, Village of Anmore	Village of Anmore	Sent Project information letter.
20-Oct-20	Project information letters	Neighboring residents, Fort Langley Station facility, Township of Langley	Township of Langley, Residents	10 Project information letters distributed by hand to those within close proximity of the FEI facility.
20-Oct-20	Project information letters	Neighboring residents, Livingston Station facility, Township of Langley	Township of Langley, Residents	30 Project information letters distributed by hand to those within close proximity of the FEI facility.
20-Oct-20	Mailed Project information letter	Neighbouring businesses close to worksites	City of Surrey, City of Delta, City of Richmond, Business Owners/Managers	Project information letter mailed to 20 businesses.
21-Oct-20	Emailed Project Information Letter	Steve Neilson, Costco Warehouse, 65 Ave.	Township of Langley, Business Manager	Sent Project information letter. Stakeholder responded requesting more information.
21-Oct-20	Mailed Project information letter	Pastor Cote, Cornerstone Seventh-Day Adventist Church, Panorama Drive (next to David Ave.)	City of Coquitlam, Seventh-Day Adventist Church	Sent Project information letter.
21-Oct-20	Emailed Project Information Letter	Jenette Chen, Dwell Property Management	City of Vancouver, Property Management Company	Sent Project information letter via email to Property Management company for distribution to 60 residents of Lighthouse Terrance Strata, East Kent Ave. Vancouver.

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Date	Consultation Type	External Representative	Stakeholder	Consultation Summary
21-Oct-20	Mailed Project information letter	Sunny Chohan, Chohan Capital Inc. 15760 110 Avenue, Surrey, BC V4N 4Z1	City of Coquitlam, Property Owner	Project information letter mailed to business at 88 Golden Dr, City of Coquitlam BC to introduce the Project.
21-Oct-20	Mailed Project information letter	0998967 BC Ltd. 80 Golden Dr. City of Coquitlam BC V3K 6T1	City of Coquitlam, Property Owner	Project information letter mailed to 84 Golden Dr, City of Coquitlam BC to introduce the Project.
21-Oct-20	Mailed Project information letter	Crescent View Apts Ltd C/O Cressey Dev Corp #200-555 8th Ave W Vancouver	City of Coquitlam, Property Management Company	Project information letter mailed to Property Owner as the Project impacts residents at 2665 Cape Horn Ave, City of Coquitlam BC.
21-Oct-20	Mailed Project information letter	Bruce May, Owner, Cranwest Farms Corp. Inc. No. BC1262551 6770 - 72 Avenue Delta, BC V4G 1M2	City of Delta, Business Owner	Project information letter mailed to impacted landowner at 6770 72 St, Delta BC.
21-Oct-20	Mailed Project information letter	Husky Gas Station, c/o Saffal Investments Inc. 1672 W 6 Ave Vancouver BC V6J 1R3	City of Delta, Business Owner	Project information letter mailed to impacted landowner, where FEI requires access through private property.
21-Oct-20	Mailed Project information letter	Nicholas Kleider 8036 232 Street Langley BC V1M 3R8	Township of Langley, Business Owner	Project information letter mailed to impacted landowner, where FEI requires access through private property.
21-Oct-20	Mailed Project information letter	Kenneth Charles Blankstein 301-6351 197th Street, Langley BC V2Y 1X8	Township of Langley, Business Owner	Project information letter mailed to impacted landowner, where FEI requires access through private property.
22-Oct-20	Phone call	Jeannie Willson, Engineering Liaison City of Coquitlam	City of Coquitlam	City of Coquitlam staff noted no concerns at this time, and requested a follow-up meeting in 2021 to review schedule and its interaction with other major construction Projects planned in the City over the next 3-4 years.
23-Oct-20	Mailed Project information letter	Landowner, Blue Acre Farms, 1357 Gladwin Road, Abbotsford	City of Abbotsford, Business Owner	Project information letter mailed to impacted landowner, where FEI requires access through private property.
26-Oct-20	Email	Juli Halliwell CAO/CFO, Village of Anmore	Village of Anmore	Sent follow-up email asking if the Village of Anmore had any more questions ahead of filing. On Oct 27, the Village of Anmore responded requesting meeting for FEI to provide Project overview.
28-Oct-20	Virtual Meeting	Evan Chrystal, Terry Chan, City of Delta	City of Delta	City of Delta requested engineering drawings as the Project progresses, a designated FEI point of contact, a record that landowners have been notified, and a check of permitting requirements. Overall no concerns raised.
29-Oct-20	Virtual Meeting	Juli Halliwell CAO/CFO, Village of Anmore	Village of Anmore	Met with CEO of Village of Anmore. No concerns raised; requested a map highlighting FEI pipelines within their jurisdiction.
30-Oct-20	Project information letters	Neighbouring residents close to work site on right of way at Cape Horn	City of Coquitlam, Residents	Project information letter delivered by hand to 10 residents within close proximity of work within right of way at Cape Horn.
30-Oct-20	Email	Sam Lau, Land Manager, City of Surrey	City of Surrey	Sent follow up email to the City of Surrey with an update of the Project scope. No concerns raised.
30-Oct-20	Email	Roeland Zwaag, Engineering, Township of Langley	Township of Langley	Sent follow up email to the Township of Langley with an update of the Project scope. No concerns raised.
30-Oct-20	Email	Steve Neilson, Costco Warehouse, 65 Ave., Langley BC	Township of Langley, Business Manager	Sent follow-up email with Project update information. No concerns raised.

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Date	Consultation Type	External Representative	Stakeholder	Consultation Summary
30-Oct-20	Phone call	Sunny Chohan, Chohan Capital Inc. 15760 110 Avenue, Surrey, BC V4N 4Z1	City of Coquitlam, Property Owner	Follow-up phone call. Resident requested the notification letter be resent via email.
30-Oct-20	Email	Mr. Song, 0998967 BC Ltd. 80 Golden Dr. City of Coquitlam BC V3K 6T1	City of Coquitlam, Property Owner	Follow-up phone call. Mr. Song will forward to the owners.
30-Oct-20	Email	Tom Johnson, Crescent View Apts Ltd C/O Cressey Dev Corp #200-555 8th Ave W Vancouver	City of Coquitlam Properties, 2665 Cape Horn Ave, Coquitlam	Follow-up email. Responded with a request to email another copy of the Project information letter.
30-Oct-20	Voicemail	Bruce May, Owner, Cranwest Farms Corp. Inc. No. BC1262551 6770 - 72 Avenue Delta, BC V4G 1M2	City of Delta, Business Owner	Left voicemail following up and confirming the Project Information letter was received.
30-Oct-20	Phone call	Husky Gas Station, c/o Saffal Investments Inc. 1672 W 6 Ave Vancouver BC V6J 1R3	City of Delta, Business Owner	Follow-up call. Husky Gas Station received the Project information letter and is forwarding to property owner today.
30-Oct-20	Phone call	Nicholas Kleider 8036 232 Street Langley BC V1M 3R8	Township of Langley, Business Owner	Follow-up phone call to property owner who is aware of the Project and will advise if they have further questions.
30-Oct-20	Phone call	Kenneth Charles Blankstein 301-6351 197th Street, Langley BC V2Y 1X8	Township of Langley, Business Owner	Property owner did not receive the mailed copy of the Project information letter. FEI emailed directly to property owner.
30-Oct-20	Email	Sehdev Seikhon, 32744 King Rd Abbotsford BC	City of Abbotsford, Business Owner	Project information letter mailed to impacted landowner, where FEI requires access through private property.
30-Oct-20	Project information letters	Neighbouring residents close to work planned at the Noons Creek facility	City of Port Moody, Residents	Project information letter delivered to 20 residents within close proximity of FEI facility.
30-Oct-20	Project information letters	Neighbouring residents close to work planned at City of Coquitlam Gate Station facility	City of Coquitlam, Residents	Project information letter delivered to 60 residents within close proximity of FEI facility.
30-Oct-20	Project information letters	Neighbouring residents close to work planned on right of way and facility on David Ave	City of Coquitlam, Residents	Project information letter delivered to 20 residents within close proximity of FEI facility.
30-Oct-20	Project information letters	Neighbouring residents close to work planned at the Nichol and Roebuck facilities	City of Surrey, Residents	Project information letter delivered to 40 residents within close proximity of FEI facility.
2-Nov-20	Email	Rob Isaac, Engineering, City of Abbotsford	City of Abbotsford	Sent follow-up email asking if the City of Abbotsford had any more questions ahead of filing. No concerns raised.
2-Nov-20	Email	Milton Chan, Engineering, City of Richmond	City of Richmond	Sent follow-up email asking if the City of Richmond had any questions ahead of CPCN filing. City of Richmond responded and requested a meeting on Nov 12 for FEI to provide Project overview.
2-Nov-20	Phone call to FEI Helpline	Neighbouring residents close to Coquitlam Gate Station facility	City of Coquitlam, Resident	Resident called regarding ongoing construction impacts in the neighbourhood and concerns about noise. FEI acknowledged awareness of recent impacts and reiterated a commitment to consult with residents and address concerns prior to construction. Notifications will be provided ahead of construction.

TIMC Consultation Log

Date	Consultation Type	External Representative	Stakeholder	Consultation Summary
3-Nov-20	Email	Chad Braley & Jeannie Willson, Engineering, City of Coquitlam	City of Coquitlam	Sent follow-up email asking if the City of Coquitlam had any questions ahead of CPCN filing. City of Coquitlam responded on Nov 10 and stated they don't have any questions at this time and would like to meet with FEI once preliminary drawings are available.
3-Nov-20	Email	Evan Chrystal, City of Delta	City of Delta	City of Delta provided supplementary specifications and drawings, and Burns Bog Specialist contact information.
5-Nov-20	Phone call to FEI Helpline	Neighbouring resident close to Noons Creek, Port Moody	City of Port Moody, Resident	Resident called and enquired if a new gas line was being constructed in the area. FEI informed them the work is within FEI's facility and doesn't include a new gas line in the area. FEI will update residents as the Project progresses. The resident was grateful for FEI's response and had no further concerns.
12-Nov-20	Virtual Meeting	Beata Ng, Eric Sparolin, City of Richmond	City of Richmond	City of Richmond noted no concerns and requested that FEI continue dialogue with Project progress updates.
13-Nov-20	Email	Beata Ng, Eric Sparolin, City of Richmond	City of Richmond	FEI emailed a recap of the Nov 12, meeting reiterating locations of FEI work sites, commitment to ongoing consultation, and links to the Project webpage.
2-Dec-20	Virtual Meeting	Trans Mountain: Varga Marton, Manbir Bhullar, Permitting Technicians	Third Party Stakeholder	FEI provided a project overview and included details explaining where FEI's work is within close proximity to the existing Trans Mountain Pipeline. Trans Mountain identified three locations where planned expansion work will take place close to FEI's planned work. Dialogue will continue between FEI and Trans Mountain permitting and pipeline inspectors.
15-Dec-20	Virtual Meeting	Ministry of Transportation and Infrastructure (MOTI): Roanna Cruz, Maziar Kazemi, Rupinder Prihar, Tyler Gaudry, Jordan Catton, Sally Case	Third Party Stakeholder	FEI provided an overview of FEI infrastructure and introduced the project scope and reviewed with MOTI the three locations where there are MOTI - TSU Project interactions. Communication protocols and contact information to be shared. FEI to submit drawings and Geotech logs.
18-Dec-20	Virtual Meeting	BC Hydro: Ronuk Bhayaabi, Bobby Malach	Third Party Stakeholder	FEI reviewed the project scope and project description with the time frame of construction. While it is anticipated that there will be interaction between FEI and BC Hydro infrastructure at 23 of the 26 locations within the TSU scope, the discussion focused on locations with a higher degree of interaction. FEI to submit to BC Hydro property services drawings showing proposal in relation to transmission lines/cables, as well as the civic address.
6-Jan-21	Virtual Meeting	Telus: Gupinder Saran, Alex Huang, Anu George, Ka Hung Cho, Catalin Dobre, Steve Reader, Valeriu Juverdeanu	Third Party Stakeholder	FEI provided an overview of the Transmission System Upgrades Project and identified eight locations where FEI interacts with or is within proximity of Telus infrastructure. Telus enquired about work with underground conflicts. FEI to provide summary of scope of work for each location, construction methodology, and how it interacts with Telus infrastructure. Communication protocols were identified.

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Date	Consultation Type	External Representative	Stakeholder	Consultation Summary
12-Jan-21	Virtual Meeting	Metro Vancouver: Ravi Grewal, Ron Nishimura, Cal Merry, David Tam, Darren Lee	Third Party Stakeholder	FEI provided an overview of the Transmission System Upgrades Project and identified five locations where there are interactions with Metro Vancouver and provided a high level general scope for each piece of work. FEI will provide drawings that identify work close to Metro Vancouver infrastructure and determine where there is overlap.
9-Feb-21	Email	Rob Isaac, Engineering, City of Abbotsford	City of Abbotsford	FEI Emailed City of Abbotsford staff to inform them of upcoming survey & geotech work, no public impacts anticipated.
13-Feb-21	Email (Talking Energy inbox)	General Public	Resident	Inquirer wanted to know whether FEI is planning transmission upgrades in the East Kootenays. FEI replied via email with informational links to the Inland Gas Upgrades Project in that region. No follow-up required.
17-Feb-21	Email (TSU inbox)	General Public	Resident	Inquirer wanted to know if the project was to increase capacity and does FEI depreciate assets. FEI replied via email and indicated the need for the Project is to improve the safety and reliability of the system, and clarified that it is not to increase capacity. FEI also clarified that capital assets are depreciated based on the estimated remaining period of time that they are expected to be useful. No follow-up required.
28-Feb-21	Email (TSU inbox)	General Public	Resident	Inquirer want to know whether customers incur the costs of the Project and where customers could express concerns about rate impacts. FEI replied by indicating that there would be rate impacts to all of FEI's customers. FEI also acknowledged the BCUC CPCN process and the opportunity to become involved in the regulatory process. No follow-up required.
5-Mar-21	Email (Talking Energy inbox)	General Public	Resident	Inquirer had a question about rate impacts of the project. FEI replied by indicating that there would be rate impacts to all of FEI's customers, including to FEI's customers in the interior. No follow-up required.
23-Mar-21	Email	Chad Braley, Engineering, City of City of Coquitlam	City of Coquitlam	FEI notified City of Coquitlam staff of CPCN Application filing. City staff responded they have no requirements and would like to meet once design is advanced.
23-Mar-21	Email	Rob Isaac, Engineering, City of Abbotsford	City of Abbotsford	Notified City of Abbotsford staff of CPCN Application filing. No concerns raised.
24-Mar-21	Email	Roeland Zwaag, Engineering, Township of Langley	Township of Langley	Notified city staff of CPCN Application filing. City requested link to the BCUC webpage where the filing could be found. No concerns raised.
24-Mar-21	Email	Beata Ng & Eric Sparolin, Engineering, City of Richmond	City of Richmond	Notified City of Richmond staff of CPCN Application filing. No concerns raised.
24-Mar-21	Email	Terry Cheng, Engineering, City of Delta	City of Delta	Notified City of Delta staff of CPCN Application filing. City requested an idea of feed drawings to see if any work is required by the city. Drawing for River Road sent. No concerns raised.

TIMC Consultation Log

Date	Consultation Type	External Representative	Stakeholder	Consultation Summary
24-Mar-21	Email	Hamad Quazi, Engineering, City of Vancouver	City of Vancouver	Notified city staff of CPCN Application filing. City requested a copy of the current feed drawings and advanced drawings once available. FEI provided drawing. No concerns raised.
24-Mar-21	Email	Philip Chow, Engineering, City of Port Moody	City of Port Moody	Notified City of Port Moody staff of CPCN Application filing. No concerns raised.
24-Mar-21	Email	Juli Halliwell CAO/CFO, Village of Anmore	Village of Anmore	Notified Village of Anmore staff of CPCN Application filing. No concerns raised.
24-Mar-21	Email	Sam Lau, Land Manager, City of Surrey	City of Surrey	Notified City of Surrey staff of CPCN Application filing. City staff responded they do not need to see anything. They understand the scope of work.

Attachment 33.2

TIMC - Indigenous Engagement Log				
Date	Engagement Type	External Representative	Indigenous Group	Summary
26-Jan-21	Email	Lauren Bell, Referrals; Kate Menzies, Referrals Analyst	Tsleil-Waututh Nation	TWN requesed more details about the "historical request from the Ministry for additional environmental investigation related to the [Tilbury] LNG Plant" in Table 11: Contaminants of Concern at Proposed CTS TIMC Project Events. (EOA, page 21). FEI clarified that that FortisBC initiated a building permit application at its Tilbury LNG facility. As part of this application, the BC Ministry of Environment requested a Contaminated Site Investigation for future developments. FortisBC is currently completing the requested investigation as part of the Tilbury LNG Expansion Project. TWN noted no further questions from TWN on this topic.
19-Feb-21	Email	Cara Brendzy, Sto:lo Research and Resource Management Centre; Carli Pierrot, People of the River Referrals, Referrals Lead	Sto:lo Nation	FEI engaged Sto:lo Nation on upcoming geotechnical program and the existing Archaeological Overview Assessment Sto:lo prepared for this area. Email sent on Feb 5 2021. On Feb 19 2021, FEI had a telephone meeting with Cara Brendzy, archaeologist with Sto:lo Research and Resource Management Centre. They confirmed that there is high archaeological potential in where geotech work is planned to occur. FEI will complete the geotech work with Archaeological monitors on site
29-Mar-21	Email	Ashley Doyle, Lands Manager	Kwantlen First Nation	Sent follow-up email re: BCUC formal participation process
29-Mar-21	Email	Referrals Administrator	Leq'á:mel First Nation	Sent follow-up email re: BCUC formal participation process
29-Mar-21	Email	Alice McKay, Chief	Matsqui First Nation	Sent follow-up email re: BCUC formal participation process
29-Mar-21	Email	Chris Raftis, Major Project Coordinator	Musqueam Indian Band	Sent follow-up email re: BCUC formal participation process
29-Mar-21	Email	Chief and Council	Peters First Nation	Sent follow-up email re: BCUC formal participation process
29-Mar-21	Email	Effie Ned, Referrals Clerk	Seabird Island Band	Sent follow-up email re: BCUC formal participation process
29-Mar-21	Email	Chief and Council	Semiahmoo First Nation	Sent follow-up email re: BCUC formal participation process

TIMC - Indigenous Engagement Log				
Date	Engagement Type	External Representative	Indigenous Group	Summary
29-Mar-21	Email	Referrals Administrator	Shxw??whámel First Nation	Sent follow-up email re: BCUC formal participation process
29-Mar-21	Email	Robin Buss	Tsawwassen First Nation	Sent follow-up email re: BCUC formal participation process
29-Mar-21	Email	Candace Charlie, Referrals Coorinator	Cowichan Tribes	Sent follow-up email re: BCUC formal participation process
29-Mar-21	Email	Chief and Council	Halalt First Nation	Sent follow-up email re: BCUC formal participation process
29-Mar-21	Email	Alli Di Giovanni, Referrals Coordinator	Katzie First Nation	Sent follow-up email re: BCUC formal participation process
29-Mar-21	Email	Referrals, Lands and Resources Department	Kwikwetlem First Nation	Sent follow-up email re: BCUC formal participation process
29-Mar-21	Email	Aaron Hamilton	Lake Cowichan First Nation	Sent follow-up email re: BCUC formal participation process
29-Mar-21	Email	Chief and Council	Lyackson First Nation	Sent follow-up email re: BCUC formal participation process
29-Mar-21	Email	Josh James, Economic Development Officer	Penelakut Tribe	Sent follow-up email re: BCUC formal participation process
29-Mar-21	Email	Chrystal Nahanee	Squamish Nation	Sent follow-up email re: BCUC formal participation process
29-Mar-21	Email	Referrals Office	Stz'uminus First Nation	Sent follow-up email re: BCUC formal participation process
29-Mar-21	Email	Kate Menzies, Consultation and Accomodation Manager	Tsleil-Waututh Nation	Sent follow-up email re: BCUC formal participation process
29-Mar-21	Email	Referrals Administrator, People of the River Referrals Office	Stó:l? Tribal Council	Sent follow-up email re: BCUC formal participation process
29-Mar-21	Email	Referrals Administrator, People of the River Referrals Office	Stó:l? Nation	Sent follow-up email re: BCUC formal participation process
29-Mar-21	Email	Referrals Administrator, People of the River Referrals Office	Soowahlie First Nation,	Sent follow-up email re: BCUC formal participation process
29-Mar-21	Email	Referrals Administrator, People of the River Referrals Office	Skawahlook First Nation	Sent follow-up email re: BCUC formal participation process
29-Mar-21	Email	Referrals Administrator, People of the River Referrals Office	Sumas First Nation	Sent follow-up email re: BCUC formal participation process
29-Mar-21	Email	Referrals Administrator, People of the River Referrals Office	People of the River Referrals Office	Sent follow-up email re: BCUC formal participation process
30-Mar-21	Email	Carly Spence, Referrals	Katzie First Nation	Updated contact information and requested maps showing project location
31-Mar-21	Email	Karyn Scott, Consulation Coordinator	Lyackson First Nation	Requested copies of EOA and ACR. FEI sent reports
31-Mar-21	Phone/email	Effie Ned, Referrals Clerk	Seabird Island Band	Requested copies of EOA and ACR