BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF THE *UTILITIES COMMISSION ACT*
RSBC 1996, CHAPTER 473

and

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

Vancouver, B.C.
May 13th, 2021

WEB-BASED WORKSHOP

BEFORE:

A.K. Fung, Q.C.,	**Panel Chair**
D.M. Morton,	**Commissioner**
C.M. Brewer,	**Commissioner**

VOLUME 1

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Chrisopher R. BYSTROM Niall RAND	Counsel for FortisBC Energy Inc. (FEI)
Christopher P. WEAFER Patrick WEAFER	Counsel for Commercial Energy Consumers Association of British Columbia (CEC)
Sam MASON Brady RYALL	Residential Consumer Intervenor Association (RCIA)
Leigha WORTH Irina MIS	Counsel for British Columbia Old Age Pensioners' Organization, Active Support Against Poverty, Disability Alliance of BC, Council of Senior Citizens' Organizations of BC and the Tenants Resource and Advisory Centre (BCOAPO)

PARTICIPANTS:

FEI PRESENTERS:
- Ilva Bevacqua
- Diane Roy
- Ferenc Patakil
- Andrew Doyle
- Ken Oliphant

FEI SUPPORT STAFF:
- Doyle Sam
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- David Craig
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BCUC Staff:
- Nicola Simon
- Avery Jones
- Lisa Dang
- David Grohs
- Ivan Lapczak
- Sean Richards
- Jim Coady

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VANCOUVER, B.C.

May 13th, 2021

(PROCEEDINGS COMMENCED AT 1:00 P.M.)

MS. BEVACQUA: It is 1 o'clock now, and I believe we have representatives from all the intervenors, if not each individual person that registered, so I think we can get started.

I will pass it over to the Commission panel.

THE CHAIRPERSON: Thank you very much, Ms. Bevacqua.

Good afternoon everyone. On behalf of the B.C. Utilities Commission, I welcome you to this web-based workshop, which is being led by FortisBC Energy Inc., in respect of this application for a certificate of public convenience and necessity for approval of the Coastal transmission system transmission integrity management capabilities project, rather mouthful, which was filed on February 11th, 2021.

Now, this workshop is part of the public hearing process that the BCUC has established by order G-74-21 to review this application.

My name is Anna Fung, and I'm the Deputy Chair of the BCUC, and the Chair of the panel that has been assigned to hear this matter. With me this afternoon are my two fellow panel members, Commissioners David Morton, whom I hope has finished

his lunch, and Carolann Brewer. As well as our BCUC legal counsel, Mr. Jim Coady from Boughton Law Corporation. Along with a number of BCUC staff, and three representatives from an independent expert Dynamic Risk Assessments Inc. or Risk Assessment Systems Inc. whom I will introduce later in my remarks.

The purpose of the workshop today is for FEI to provide the BCUC and interveners with a better understanding of the application, and for us to ask clarifying questions about FEI's presentation. I remind all of us that there will be opportunity for us to ask detailed or technical questions in the course of the IR process following the workshop.

By letter of workshop guidance filed as Exhibit A-4, the BCUC has requested that FEI's presentation today include a discussion of certain matters, and they are included in FEI's agenda for the workshop.

I would like to remind all of you now to mute your microphones, and keep them muted until you are called upon to speak, and appear via Teams Video. If you have a question, or a comment that you wish to make during the workshop, please raise your virtual hand to speak, so that we can call on you in order.

And as we're dealing with technology here,

1 I cannot promise everything will go smoothly without
2 any hitches. In a worst-case scenario though, if we
3 lose any parties, I will temporarily adjourn the
4 proceeding and try and regroup and sort out where to
5 go from here.
6 I'd like to remind everyone that this
7 proceeding is being transcribed, and also being
8 webcast to the public. Please note that no recordings
9 or rebroadcasts of this proceeding will be permitted,
10 beyond that required by our Hearing Officers, Mr. Hal
11 Bemister, and Ms. Roberta Stinson of Allwest Reporting
12 for transcription purposes. Transcripts of this
13 particular workshop will be posted to the BCUC website
14 as soon as they are available.
15 **Proceeding Time 1:03 p.m. T2**
16 Now, a couple words about confidentiality.
17 As you are aware, while this workshop is limited to
18 registered interveners who are appearing via the
19 Microsoft Teams web platform, we cannot guarantee
20 confidentiality since we do not know who may be
21 sitting in the same room with you or who may walk by
22 while we're each online within our homes or offices.
23 I do not anticipate the need for any filing
24 of exhibits today, including confidential exhibits, in
25 the course of the workshop. But if necessary we will
26 deal with that by asking that they be filed with the

1 Commission Secretary after the workshop in accordance
2 with Part 4 of the BCUC Rules of Practice and
3 Procedure.
4 **Proceeding Time 1:04 p.m. T3**
5 To assist with the transcription of the
6 workshop please remember to state your name before you
7 speak.
8 And I'd like to introduce to you now the
9 BCUC staff on this proceeding who will be present for
10 all or part of the workshop today. They are Nicola
11 Simon as project manager, Avery Jones as lead staff,
12 along with David Grohs, Ivan Lapczak, Lisa Dang and
13 Sean Richards.
14 Also attending the workshop today are three
15 representatives from the independent expert Dynamic
16 Risk Assessment Systems Inc. and they are Phillip
17 Nidd, Mike Westlund and Ammad Farooq.
18 Now I would like to call on Ms. Bevacqua
19 now from FEI who will be facilitating this workshop to
20 introduce her team who are present.
21 Ms. Bevacqua, over to you, please.
22 MS. BEVACQUA: Thank you, Madam Chair, and good afternoon
23 everyone. Today we have a presentation from FEI, as
24 well as FEI's expert JANA Consulting. We expect the
25 workshop will last most of the afternoon and we do
26 have a plan to have a break at some point but we'll

have to just see how we progress and we'll check in with the panel.

We do encourage participants to use the video cameras when speaking so we do have the benefit to see each other. While we do have a designated open question period at the conclusion of the presentation, if you have a clarifying question about the material being presented feel free to raise your virtual hand or type in the meeting chat and we will periodically pause to address those questions.

Before I go over the agenda for this afternoon I will just let you know the people from FEI or on behalf of FEI that we have participating with us today, some of whom will be presenting.

From FEI we have Doyle Sam, Executive Vice President, Operations and Engineering. Diane Roy, Vice President, Regulatory Affairs. Doug Slater, Vice President, External and Indigenous Relations. Paul Chernikhowsky, Director, Regulatory Projects and Resource Planning. Ferenc Pataki, Director of Transmission; and Andrew Doyle, Manager Gas System Assets for Engineering Services.

From JANA Corporation we have Dr. Ken Oliphant. He's the Executive Vice President and Chief Technology Officer for JANA.

Counsel for FEI from Fasken is Chris

1 Bystrom and his co-counsel Niall Rand.
2 In addition, we have a number of support
3 personnel from FEI participating in the meeting and to
4 the extent that they need to speak during the session
5 to answer questions they will introduce themselves for
6 the record at that time.
7 We'll now turn to the interveners today and
8 ask that when identified please have one
9 representative speak up to introduce your
10 participants.
11 So we'll start with the Residential
12 Consumers Intervener Association, or RCIA.
13 MR. MASON: Thank you, Ms. Bevacqua. Hello, my name is
14 Sam Mason. I'm here representing the RCIA. The RCIA
15 was formed this past January through an agreement
16 between my employer, Midgard Consulting, and the BCUC
17 with an mandate to represent residential ratepayers in
18 BCUC matters, in particular in relation to public
19 proceedings and hearings.
20 Also representing the RCIA today is Brady
21 Ryall or Ryall Engineering. Thank you.
22 MS. BEVACQUA: Thank you. Now the Commercial Energy
23 Consumers Association of B.C. or CEC.
24 MR. C. WEAFER: Thank you. Good afternoon. It's Chris
25 Weafer, W-E-A-F-E-R, appearing for the Commercial
26 Energy Consumers, and with me on the call is Patrick

1 Weafer, also of Owen Bird, Janet Rhodes and David
2 Craig. Thank you very much.
3 MS. BEVACQUA: Thank you. And our final intervener is
4 the British Columbia Old Age Pensioners Organization
5 et al, BCOAPO.
6 MS. WORTH: Good afternoon. Sorry, I'm having some
7 bandwidth issues so I may be able to turn on my camera
8 a little bit later on but right now I think it might
9 interfere with my reception.
10 This is Leigha Worth, W-O-R-T-H, here as
11 counsel for the residential ratepayer groups known as
12 BCOAPO *et al*. I'm here with Irina Mis, M-I-S, who is
13 my co-counsel on this matter and our expert consultant
14 Mr. Russ Bell, who is also on the line. His last name
15 is B-E-L-L. Thank you.
16 **Proceeding Time 1:09 p.m. T4**
17 MS. BEVACQUA: Thank you, I don't think I've missed
18 anyone, but raise your hand if I have?
19 So, our presentation today incorporates the
20 items identified by the panel in the workshop guidance
21 letter, and so we will start with Diane Roy, who will
22 speak to the cumulative rate impacts of major
23 projects. Next we'll have Ferenc Pataki who speaks to
24 the integrity management and in-line inspection tools.
25 Then we will hear from Andrew Doyle who will review
26 the CTS TIMC project need, and followed by Dr.

1 Oliphant from JANA who will go over the quantitative
2 risk assessment. And then finally, Andrew Doyle will
3 return to go over project alternatives, the
4 description, and the approvals sought.
5 So, depending on the number of clarifying
6 questions throughout the presentation will determine
7 the appropriate time for a break, and will determine
8 whether that's before the open question period or at
9 some other point.
10 I will now turn it over to Diane Roy to
11 start us off. Thank you.
12 **PRESENTATION BY MS. ROY:**
13 MS. ROY: Thank you, Ilva, and good afternoon to
14 everyone attending today. I am Diane Roy from
15 FortisBC and I just would clarify, Doug Slater, I
16 believe as Ilva mentioned, he was attending today, he
17 is not in attendance today. Just for the record
18 there.
19 We do have a fair bit of information to get
20 through in our limited time today, and I'm going to be
21 starting off with the first item that was listed in
22 the BCUC panel request, Exhibit A-4. If we could just
23 go to the next slide here.
24 You can see it here, this was the request,
25 and just to review what it said in the letter, the
26 panel asked for a discussion of the estimated

1 cumulative rate impact of the approved -- approval and
2 completion of all FEI recent and anticipated major
3 projects, and to separate that estimate according to
4 the regulatory oversight method, either into projects
5 requiring BCUC approval, and projects directed by
6 Order in Council. And then finally to explain whether
7 FEI has considered staggering or adjusting the timing
8 of any of these projects.
9 Next slide please.
10 What you see on the slide here is the
11 information requested by the panel, showing the
12 cumulative rate impact of these major projects, which
13 equals 21.5 percent at its peak in 2027. Which in
14 that year is an incremental 16.3 percent from 2021.
15 This graph starts with 2021, and it shows that there
16 is an average increase of 1.4 percent -- Janice, could
17 you -- thank you. 1.4 percent over the upcoming 10-
18 year period, shown here, excluding incremental
19 revenues. The annual rate changes over this same
20 period are shown with the red line. Now, there is a
21 lot of information on this slide, but I will keep it
22 up here while I'm talking, so you'll have some time to
23 orient yourself.
24 What it shows is that the major projects
25 that have been filed with the BCUC for approval, so
26 that is item 1 in Exhibit A-4, those are the top six

1 bars there, when compared to existing 2021 rates, the
2 cumulative rate impact for those six projects as shown
3 here, is 16.5 percent in 2027, when they are all in
4 service and before costs begin to decline.
5 And then the two major projects that were
6 approved by Order in Council, this consists of three
7 of the four segments of the Coastal transmission
8 system, and also the Tilbury Phase 1A project. Both
9 of these projects were fully in rate base by 2019, and
10 are shown as the two bottom shaded areas of the graph
11 in blue and in orange. And when compared to existing
12 2021 rates, the cumulative rate impact for those two
13 projects is about five percent.
14 Now, the first thing I've mentioned is that
15 this graph shows rate impacts against existing 2021
16 rates. The actual rate impact will depend on the
17 rates in existence at the time the project comes into
18 service. Also, what we have provided is the cost of
19 service only of the projects. We have not included
20 any offsetting revenues for the projects that support
21 increased capacity or demand, or for the Tilbury 1A
22 project, because those revenues cannot be easily
23 separated, and also because they would vary by year.
24 Further, for the AMI project, which is the
25 top bar shown there, there are large savings that
26 occur in later years that aren't shown here, because

1 of the limited time frame included.

2 **Proceeding Time 1:14 p.m. T5**

3 Now, what the panel may notice is missing
4 from the graph are the two projects approved by Order
5 in Council that are not yet fully developed or
6 committed to. And the first one of those is Tilbury
7 Phase 1B and along with that is the remaining related
8 segment of the CTS, or Coastal Transmission System
9 project, which is for the piping between the Tilbury
10 gate station and the Tilbury facility. And the second
11 is the Eagle Mountain Gas Pipeline to the Woodfibre
12 LNG site.

13 Now, for Tilbury 1B, the Order in Council
14 allows for spending up to $400 million, which on its
15 own would result in a rate increase of about 4
16 percent. But the projected cost, timing and revenues
17 for that project are not developed to the extent that
18 it could be included in the slide. The project
19 remains in development and the timing of project
20 execution is dependent on developments in the marine
21 sector, specifically increase market demand for LNG as
22 a low carbon fuel and the development of other
23 requisite infrastructure.

24 And then for the Eagle Mountain Gas
25 Pipeline project it's a similar story. The project is
26 contingent upon Woodfibre LNG proceeding with their

1 project. And the rates that we will charge Woodfibre
2 are designed to recover the incremental cost of
3 service. Now, we would expect both of those projects
4 to be rate neutral or to have the effect of reducing
5 rates over their lives.
6 Now, I'm just about to go on to the second
7 question asked by the panel around adjusting the
8 timing, but I notice Commissioner Morton has his hand
9 up. So I was wondering if I should pause and ask for
10 a question there?
11 COMMISSIONER MORTON: Yeah, is it all right or do you
12 want me to save questions for later? It's okay?
13 Yeah.
14 MS. ROY: I just have a little more so maybe I'll just
15 get through that and then if it's all right you could
16 have the question then?
17 COMMISSIONER MORTON: Yeah, it's on this slide. Yeah.
18 MS. ROY: Okay. So the second question asked by the
19 panel was around whether FEI had considered adjusting
20 the timing of any of the projects to mitigate the rate
21 impacts. Now, first I would note that two of the
22 projects are already fully in rates. The remaining
23 six projects total a rate increase of about 14 percent
24 over the upcoming 10 years.
25 Second, the projects are necessary
26 projects, albeit with somewhat different drivers,

which fall into the categories of safety, reliability and resiliency, growth, forced upgrades and enhancing capabilities.

The Inland Gas Upgrade project, which is under construction with 13 percent of the project cost already in rates in 2021, and the TIMC project, which is the CPCN that is before this panel now and has a rate increase of about 1 percent, are driven by safety and reliability of the system and to some extent are related to the age of the system as it comes up on 60 years.

The Pattullo Gas Line Replacement project is one we would have preferred not to undertake at this time but we were not in control of that project or its timing. The Okanagan Capacity Upgrade is a capacity driven project and cannot be delayed without risking our ability to meet peak demand in that region. The Tilbury LNG Storage Expansion project is driven by system resiliency needs that were highlighted after the October 2018 Enbridge incident.

The only project that we have some degree of control over the timing is the AMI project. But for that project there are important customer and operational benefits and savings that would not be realized with a delay to that project. And although there is a rate increase in the early years, the AMI

1 project is effectively rate neutral over the life of
2 the meters.
3 So each of these projects has been proposed
4 for a reason and has a need that either has been or
5 will need to be determined to be in the public
6 interest as each is brought before the BCUC. As part
7 of the public interest determination, the BCUC will
8 look at the rate impact of that project, the need for
9 benefits of that project and the timing of the
10 project. For all of these projects, our view is that
11 they cannot be delayed. For safety and reliability
12 projects, for instance, once they have been identified
13 we cannot push them off to the future unless there is
14 some way to otherwise mitigate the risks.
15 We recognize the rate pressure that results
16 as we go through this period of necessary system
17 investment and gave consideration to whether we could
18 delay any of them. But given the drivers, we
19 concluded that was not possible. If the projects
20 themselves can't be staggered, then our next option is
21 to look at rate smoothing or rate mitigation measures.
22 Where we look at these rate smoothing options is in
23 our annual reviews and revenue requirement
24 proceedings, as these are the avenues where we can
25 consider not only the cost of the projects at the time
26 they enter rate base, but also any increased demand or

1 cost reductions that can help offset those costs and
2 the timing of those.
3 So it's in the annual reviews and revenues
4 requirements that we can see all of the various
5 factors impacting rates in a year.
6 **Proceeding Time 1:19 p.m. T6**
7 And that's where we will propose any possible rate
8 mitigation measures once we see the forecast rate
9 increase for the relevant year.
10 So as an example, even though over 2017 to
11 2019 period we had an approximate 5 percent increase
12 due to the investments in the Coastal Transmission
13 system and the Tilbury 1A, our approved rate increase
14 over that period was limited to 0.7 percent. During
15 that time period we had increases in demand and also
16 cost decreases that helped to offset those costs and
17 bring those necessary projects in without a
18 significant rate impact.
19 What this demonstrates is that the timing
20 of when rate increases occur is not always directly
21 correlated with when the major projects enter rate
22 base. So we will be continuing to look for
23 opportunities to mitigate or smooth in rate increases
24 in the future and if any opportunities do arise we
25 will bring these forward for the BCUC's consideration
26 in future annual review or revenue requirement

1 applications.
2 And I will pause here to see if there are
3 questions on this material I just discussed before we
4 move on to the next section. And I guess I can start
5 with Commissioner Morton.
6 COMMISSIONER MORTON: Thank you. Thanks, Ms. Roy. I
7 think you may have answered these questions but I'll
8 just re-ask them anyway for clarity, at least for me.
9 So first of all, just to clarify, the percent increase
10 -- the rate increase is along the red line of the
11 graph. Those are only for these projects shown on
12 this chart? It does not include any other rate
13 increase that may occur that year?
14 For example, you know, because of increased
15 O&M or if there's upward pressure on rates due to, you
16 know, purchasing RNG or something like that, that
17 would be over and above these numbers, is that
18 correct?
19 MS. ROY: Yes, that's correct. This is only the rate
20 impact from these particular projects shown here. If
21 there is other cost pressures or if there's increases
22 in demand or revenue that offset these then they are
23 not included.
24 COMMISSIONER MORTON: Thank you. And second question is
25 that you've indicated that some of these projects are
26 revenue neutral and I wonder if we could just go over

1 them again. What I heard was that the two OIC
2 projects identified here are revenue neutral and the
3 AMI is revenue neutral. Did I hear that correctly?
4 MS. ROY: Yes, that's correct. The -- and not
5 necessarily at the time they will come into services
6 because the --
7 COMMISSIONER MORTON: Yes, and that was my next question.
8 MS. ROY: Yes.
9 COMMISSIONER MORTON: The revenue neutrality, that
10 doesn't mean that there wouldn't be a rate impact at
11 some point but presumably you'd get that back again
12 later on to, you know --
13 MS. ROY: Yes, that correct. Both the AMI project is
14 effectively rate neutral over the life of the meters
15 and the other two projects, the rates that are being
16 charged for Woodfibre, for example, are designed to
17 recover the cost over the life of that project as
18 well.
19 COMMISSIONER MORTON: Right.
20 MS. ROY: So you wouldn't necessarily see that through
21 the entire life. It would vary by year.
22 COMMISSIONER MORTON: Right. And presumably that's at
23 last some basis for your suggestion that a rate
24 smoothing account could, you know, could possibly deal
25 -- it certainly could deal with some of that -- some
26 of the unevenness caused by the revenue neutrality

1 timing issues. Is that what you're -- partly why
2 you're suggesting that?
3 MS. ROY: Yes, partly that, and one thing that could have
4 a significant mitigating effect is if we were
5 successful in securing, for example, some LNG, some
6 large LNG revenues and the timing when that might
7 occur would help to mitigate some rate impacts as
8 well.
9 COMMISSIONER MORTON: Thank you very much.
10 MS. ROY: You're welcome.
11 COMMISSIONER MORTON: Thank you.
12 MS. ROY: Is there any other questions before -- we will
13 have also a Q&A at the end for other questions that
14 people will think of as we go further.
15 I don't see any hands up, I don't think.
16 Okay, great.
17 So I'm going to turn this over now to
18 Ferenc Pataki and he's going to be discussing
19 integrity management.
20 **PRESENTATION BY MR. PATAKI:**
21 MR. PATAKI: Thank you, Ms. Roy. My name is Ferenc
22 Pataki, and I'm the Director of Transmission at FEI.
23 I'm going to cover two topics as part of today's
24 workshop.
25 First, FEI's integrity management program
26 and second, an overview of inline inspection tools,

including those currently used by FEI. These topics will provide some of the context for the application being considered by the panel.

The CTS TIMC project is a pipeline integrity project required for the Coastal Transmission System. So let me show it to you and make sure we all know where it is located and what areas it serves.

Proceeding Time 1:24 p.m. T7

This is a satellite map of the Lower Mainland. You can see Vancouver and Burnaby on the left, Surrey and Langley in the middle, and Abbotsford in the bottom right of the map.

The green lines are our Coastal transmission system. Gas enters our system at a location called Huntingdon, that is marked on the map with a red star in the bottom right corner. Gas flows from the bottom right of the map towards the top left of the map, providing gas to the various load centres in the Lower Mainland.

The CTS is about 300 kilometres long, and serves about 700,000 customers. It also feeds Vancouver Island at the top of the map as shown by the blue arrow. As you can see, the Coastal transmission system is an interconnected system which means that gas can flow through different pipeline sections to

1 get to the same location.
2 Next slide please.
3 As this project is rooted in FEI's
4 Integrity Management Program for Pipelines, let me
5 further explain integrity management for pipelines.
6 Integrity management refers to the cradle to grave
7 management of a pipeline's suitability for continued
8 safe, reliable and environmentally responsible
9 delivery of natural gas and renewable natural gas to
10 customers. Under the *Oil and Gas Activities Act*,
11 FEI's technical regulator, the B.C. Oil and Gas
12 Commission, requires that all transmission pressure
13 pipeline operators, including FEI, have an integrity
14 management program.
15 The requirements of this program are laid
16 out in CSA Z662, which is the Canadian national
17 standard for the design, construction, operation and
18 maintenance of oil and gas pipeline systems. These
19 integrity management requirements are reflected in
20 FEI's integrity management program for pipelines
21 through five hazard categories and 19 activities.
22 Let me show you FEI's integrity management
23 program, and in doing so, address the BCUC panel's
24 question regarding how FEI addresses other pipeline
25 risks.
26 The leftmost column of this table shows the

1 five hazard categories in FEI's integrity management
2 program, which are third party damage, natural
3 hazards, time-dependent threat management, material
4 defects and equipment failures and human factors. All
5 of these hazards have the potential to undermine the
6 integrity of a pipeline, and are controlled by
7 physical and operational barriers as shown by the
8 example activities in the rightmost column of the
9 table.
10 Let me illustrate how the hazard categories
11 and mitigation activities work together. For third
12 party damage hazards, shown in the top row of the
13 table, we undertake a mitigation activity called
14 "right-of-way management" to manage the threat of
15 someone hitting our pipelines. As part of right-of-
16 way management, we issue permits to the public who are
17 planning to undertake activities along the pipeline
18 and within the right-of-way. Furthermore, we clear
19 the vegetation along the right-of-way, in order to
20 make it easy for the public to identify our pipelines.
21 Finally, we patrol our pipelines on a regular basis to
22 identify and stop unauthorized activities.
23 The two highlighted hazard categories in
24 red show where the CTS TIMC project fits with our
25 integrity management program. In particular, the
26 project will allow us to undertake activities that

1 will enhance our ability to mitigate two types of
2 hazards: time-dependent threats, and material
3 defects.
4 Time-dependent threats, such as stress
5 corrosion cracking, are anomalies that can grow over
6 time and lead to a failure. Material defects, such as
7 seam weld cracks, are anomalies that are left over
8 from the manufacturing process.
9 We need to be able to monitor the condition
10 of the pipeline for these anomalies so that we can
11 determine their interaction with other anomalies like
12 corrosion, and repair or remove them before they lead
13 to a pipeline failure.
14 **Proceeding Time 1:29 p.m. T8**
15 As you can imagine, it is very challenging
16 to find time-dependent threats and material defects
17 that are located directly on the pipeline because the
18 pipeline itself is buried and has a coating applied to
19 it. Because we cannot see the pipeline and therefore
20 cannot easily assess its condition directly, we need
21 to turn to sophisticated tools, such as inline
22 inspection tools, ILI tools for short, to collect data
23 on the pipeline's condition.
24 So what are ILI tools? This is a picture
25 of an ILI tool. As you can see, it's a complex
26 assembly that contains sensor systems and travels

1 within the pipeline to collect location specific data
2 on the condition of a pipeline. The blue circles are
3 cups used to move the ILI tool within the pipeline
4 with the flow of gas. The greyish pieces between the
5 blue circles are the magnets and sensors.
6 Let's look at a short video that shows how
7 an inline inspection tool is run in an operating gas
8 pipeline such as the one operated by FEI. This video
9 is from ROSEN, who's an ILI vendor. For clarity, the
10 orange colour in the video is meant to represent the
11 flow of natural gas in the pipeline.
12 I think you've got to click on the centre
13 of the picture, Janice, to start the video.
14 MR. BYSTROM: On the arrow.
15 MR. PATAKI: On the arrow, yeah.
16 MS. ROY: As luck would have it, Janice is having a bit
17 of technical difficult, so we'll give her a second
18 here.
19 THE HEARING OFFICER: It's the hearing officer here.
20 The PDF that's on the web is a PDF, so there's no
21 video in it.
22 MS. JOLY: I'm going to try this one more time. One
23 moment, please.
24 MR. BYSTROM: It's a great video, we promise, so well
25 worth the wait.
26 MS. WORTH: I don't think anybody's in any danger of us

1 asking for our money back.
2 MR. PATAKI: There we go.
3 [*Video Playing*]
4 MR. PATAKI: To begin, the ILI tool is loaded into a
5 tray to prepare it to be inserted into the launching
6 barrel. The launcher barrel door is opened and the
7 tool is inserted all the way to the end of the barrel.
8 **Proceeding Time 1:34 p.m. T9**
9 Next, the barrel door is closed and the barrel is
10 pressurized with gas from the pipeline. The launch
11 valve is then opened and the gas flow in the pipeline
12 is diverted into the barrel being the ILI tool.
13 The gas flow in the pipeline propels the
14 ILI tool into and along the pipeline. Sensors on the
15 tool record signals used to locate, to identify and to
16 size pipeline anomalies. There are several types of
17 ILI tools and each type utilizes different sensors.
18 ILI tools are available for detecting metal
19 loss anomalies such as corrosion, cracking anomalies
20 such as stress corrosion cracking and geometric
21 anomalies such as dents.
22 ILI tools can be used to inspect pipelines
23 ranging in length from kilometres to hundreds of
24 kilometres. At the end of the pipeline the ILI tool
25 is removed from the pipeline in an assembly called the
26 receiving barrel. As the tool nears the end of the

pipeline the barrel valve is opened and the gas is diverted through the receiving barrel to bring the ILI tool into it. The barrel is then isolated from the pipeline, depressurized and purged of gas allowing the ILI tool to be removed from the pipeline.

The data gathered by the ILI tool is downloaded by the ILI vendor and sent to their analysis team. Once the vendor ILI analysis is complete the ILI vendor sends a report of the findings to FEI. Our system integrity group then conducts analysis using this information. Integrity digs are performed as required to repair or to remove near critical anomalies and to assess the performance of the ILI tool.

This table shows the various ILI tools that are currently commercially available, what tools FEI uses today and what tools FEI intends to use.

The top row of the table shows the type of ILI tools commonly used in gas pipelines. The four types are Geometry, MFL, MFLC [*sic*] and EMAT.

The left most column of the table shows the various anomalies and features that each tool can identify and collect data on. Each tool is able to find different anomalies and features on the pipeline as shown by the check marks in the table.

Information from multiple tools is often

1 overlaid to manage interaction threats such as dents
2 interacting with corrosion.
3 The yellow box around three of the ILI
4 tools show what tools FEI runs today to collect data
5 on the condition of its pipelines. The blue box
6 around EMAT shows the tool that FEI intends to run
7 under this project to locate, identify and size cracks
8 and crack-like features on the Coastal Transmission
9 System.
10 That brings me to the end of my
11 presentation. And now I will pause for any clarifying
12 questions.
13 MS. BEVACQUA: I don't see any hands raised at this
14 point. All right we can -- oh, I do see a hand raised
15 now. Mr. Bell, please go ahead.
16 MR. BELL: Just to confirm, you will still continue to
17 run the other tools as well? This will add to your
18 capabilities, is that correct?
19 MR. PATAKI: Thank you for the question, Mr. Bell. That
20 is correct.
21 MR. BELL: Okay, thank you.
22 MS. BEVACQUA: Ms. Rhodes?
23 THE CHAIRPERSON: I believe you're on mute, Ms. Rhodes.
24 MS. RHODES: Sorry. Thank you. Two questions. I was
25 wondering how fast the pig goes through say 50
26 kilometres, and secondly, are you linked in then to

1 the provider of the system or can that be changed down
2 the road?
3 MR. PATAKI: So let -- thank you for the question. The
4 answer to the first question is that the tool travels
5 at around 1.5 metres a second and I'm not sure what
6 that is in kilometres per hour, but the optimum speed
7 for the tool is 1.5 metres per second.
8 And I would appreciate it if you could
9 repeat or rephrase your second question just to make
10 sure I understand what you're asking.
11 **Proceeding Time 1:40 p.m. T10**
12 MS. RHODES: I noted that you said the information goes
13 back to the service provider as opposed to going to
14 you?
15 MR. PATAKI: That's correct.
16 MS. RHODES: So, I was just wondering if that means
17 that you are consequently linked in to that service
18 provider indefinitely? Or is that something that you
19 could ever change down the road and say send it to
20 somebody else for analysis?
21 MR. PATAKI: It is linked in with the service provider,
22 and we take -- we get the data from the service
23 provider, and then we do our own analysis with the
24 data as well.
25 MS. RHODES: Okay, thank you.
26 MR. PATAKI: You're welcome.

1 MS. BEVACQUA: Okay, I don't see any other hands
2 raised. Ferenc, if you want to pass it off?
3 MR. DOYLE: I can jump in there.
4 MS. BEVACQUA: All right, thanks Andrew.
5 **PRESENTATION BY MR. ANDREW DOYLE:**
6 MR. DOYLE: Absolutely. Thank you, Mr. Pataki. My
7 name is Andrew Doyle, and I'm the manager of gas
8 system assets here at Fortis. I'll be taking you
9 through the specifics of the CTS TIMC project,
10 including the project's need, the alternatives that
11 were evaluated, and a description of the project
12 itself. I'm going to start by going over what
13 cracking threats are, and why FEI needs to mitigate
14 them on its system.
15 So, the MFL, or magnetic flux leakage, and
16 MFLC [*sic*], or circumferential magnetic flux leakage
17 shown on the table that Mr. Pataki showed a couple
18 slides back there, they're currently run in our
19 system, and they are highly effective at detecting
20 volumetric or three-dimensional imperfections, like
21 corrosion. Unfortunately, they are unable to detect
22 two-dimensional or planar imperfections like cracks.
23 In most cases, these cracks are considered
24 time-dependent threats, or threats that get
25 progressively worse over time, either by themselves,
26 or in conjunction with something else.

The two images shown on slide 14 are examples of cracking that were found on FEI's pipelines. The top image shows a cross section of the wall of a pipeline. The outer surface is at the top, and the inner surface is on the bottom. The black line is a crack-like lack of fusion imperfection. These types of imperfections are typically introduced through manufacturing processes that were common in and before the 1970s. Generally, pipe is manufactured by taking a steel plate, rolling it into a cylindrical shape and welding the edges together into what is referred to as the seam weld.

In and before the 1970s, common weld procedures resulted in lack of fusion features on the inside of the pipeline like the one pictured above. The main risk of these features is how they interact with corrosion on the outer surface of a pipeline. Put simply, corrosion eats through the pipeline wall, reducing the thickness in the affected area. If this occurs where there is a lack of fusion crack, there is less steel remaining and a relatively shallow corrosion defect could result in the pipeline's failure.

The image at the bottom of this slide shows stress corrosion cracking, or SCC. These imperfections typically occur on the outer surface of

1 the pipeline. Once a pipeline is buried and in
2 operation, stress corrosion cracking can occur where
3 the pipe's coating is of poor quality, or has been
4 damaged.
5 I'll go through the mechanism of stress
6 corrosion cracking in more detail in the slides that
7 follows, as this is the threat that underlies the need
8 for the CTS TIMC project.
9 So, SCC is the cracking of a material
10 produced by the combined action of corrosion and
11 tensile stress. Three elements need to be present for
12 SCC to occur. The first is susceptible metallic
13 material. Any steel will be susceptible. The second
14 is the tensile stress. This is a stress that tries to
15 pull the material apart. Tensile stress has two
16 contributing components.
17 The first component is residual stress.
18 Stresses of this kind result from various activities
19 in the insulation process, or through the
20 manufacturing process. An example of this is that the
21 pipes started as a plate, and generally wants to
22 return to being a plate. To prevent this, the pipe is
23 held together by the seam weld.
24 The second component is applied stress. In
25 typical operation, these stresses are exerted on the
26 pipe by internal pressure of the service fluid

1 resulting in something called the hoop stress.
2 For FEI, internal pressure is exerted by
3 the pressurized gas running through the system. This
4 is shown in the diagram with P-internal resulting in
5 S-hoop. Applied stresses can also arise from external
6 pressure exerted on the pipeline, such as post
7 installation ground movement, or if the pipeline runs
8 under a road, vehicle loading.
9 The third and final element required for
10 SCC to be present, is a suitable environment.
11 Pipeline operators go to great lengths to mitigate
12 this element. For example, the main purpose of the
13 pipeline coating is to separate the steel from the
14 soil, a suitable environment. Separation of the steel
15 from the surrounding soil protects against SCC and
16 corrosion generally.
17 **Proceeding Time 1:45 p.m. T11**
18 Operators also apply cathodic protection to
19 pipelines in order to stop the corrosion reaction
20 where there are gaps or damage to a pipeline's
21 coating. Unfortunately in certain situations or with
22 certain types of older coatings, these mechanisms are
23 insufficient and SCC can still occur in unpredictable
24 locations.
25 Similar to corrosion, SCC results in a
26 decrease in the strength of the pipeline. The image

on the right side of slide 20 is an example of SCC found on FEI's transmission system, with all coating, corrosion and debris washed away to show the remaining clean steel. You will note the different in appearance between the normal steel and the pock-marked external corrosion. These pock marks show where the normal steel had been converted to rust, as depicted in black in the top-left diagram. This results in a decreased wall thickness.

The cracks act in a similar fashion, as shown in the bottom-left diagram. They too result in an effective thinning of the wall. If you'll recall our discussion on applied stresses, the internal pressure of the gas results in a hoop stress in the steel. This hoop stress needs to be contained by a combination of the grade of the steel and the wall thickness. As the wall is thinned due to corrosion or cracking, there is less steel to restrain the same hoop stress. At some point, if the corrosion and cracks are left to grow, the remaining steel is unable to contain the pressurized gas resulting in a loss of containment.

There are two possible outcomes where a loss of containment occurs: a leak or a rupture. A leak can occur on any pipeline and results in gas escaping through the crack. Think of your garden hose

leaking where it connects to the hose bib on your home. Water seeps out but does so in a slow and predictable fashion. FEI manages leaks on its system by focusing on reducing the probability of a leak through coatings and cathodic protection or by reducing the consequences of a failures through the additions of odorant and leak surveys.

In contrast, a rupture can occur on certain transmission pressure pipelines where gas escapes violently, splitting open the pipeline similar to a balloon popping. These are high-consequence failures that involve an explosion and possibly ignition. FEI manages potential ruptures by protecting where they could occur and performing preventative activities to make sure they do not happen. These include the use of ILI tools and dig programs for identifying and addressing corrosion.

Any pipeline can leak, but industry and standards accept that pipelines operating at or above a certain stress threshold of 30 percent of specified minimum yield stress, or SMYS, can fail by rupture. Given that cracks in certain pipelines can lead to ruptures, which are not acceptable to FEI, and understanding that FEI's current ILI tools are unable to detect these cracks, FEI needs to incrementally improve upon its existing integrity management plan

activities to address these threats.

The CTS TIMC project will therefore mitigate the threat of cracking to FEI's transmission pipelines.

As part of this workshop, the BCUC panel requested that we provide a summary of FEI's past experience with loss of containment due to SCC. I'd like to address this now. To date, FEI has not experienced any pipeline ruptures as a result of SCC. However, FEI has observed leaks as a result of crack-like imperfections in the seam welds of its pipes. And while FEI has not experienced any pipeline ruptures directly, ruptures resulting from a pipeline crack have occurred in the broader industry, including on pipelines of a similar vintage and operating in similar conditions as those operated by FEI.

For example, in 2018 Enbridge experienced a rupture failure on its Westcoast transmission system. The rupture occurred at a group of stress corrosion cracks resulting in an ignition of the gas running through the system. The image on the left side of slide 24 shows the size of the crater and the size of the burned area, while the right image shows the extent of the cracks on a removed -- or recovered segment of the failed pipe. This example demonstrates the severity of a rupture and highlights the

1 importance of preventing the underlying causes of
2 ruptures, including cracking.
3 As the previous discussion demonstrates, we
4 now know that cracking is a threat to pipeline
5 integrity. Per the governing code of pipelines in
6 B.C., as an operator FEI is required to monitor for
7 conditions that could lead to failures and to
8 eliminate or mitigate such conditions where they
9 exist.
10 **Proceeding Time 1:50 p.m. T12**
11 Cracks are one of these conditions and therefore FEI
12 has an obligation to address them.
13 We have laid out the risks of cracking, the
14 challenges FEI faces in detecting them and using
15 existing ILI tools and the regulatory requirement to
16 manage them. The natural next question is how does
17 FEI currently manage cracking threats?
18 To date, FEI has managed cracking by
19 inspecting transmission pipelines during opportunity
20 digs such as the one shown in the image on slide 26.
21 Opportunity digs are integrity digs
22 undertaken based on information gathered by existing
23 ILI tools. The corrosion and dent detecting tools are
24 able to find these features and, with the location
25 known, FEI undertakes integrity digs to inspect and
26 repair these defects.

With the pipeline exposed due to this non-cracking integrity issue FEI takes the opportunity to inspect the exposed surface for cracking threats, addressing them as required. Opportunity digs are therefore the primary mechanism through which FEI has in the past found and repaired cracking on its system.

Through opportunity digs FEI has found 26 instances of cracking. The table on the left of this slide show the FEI pipelines in the CTS system where cracks have been found. The image on the right is an example of a crack within a dent that FEI found on one of its transmission pipelines. The dig was initiated due to the dent found by the Geometry ILI tool, but once exposed FEI also found and repaired the crack.

So what are some of the limitations of managing cracking threats as part of FEI's existing opportunity dig program?

Well first, over 99 percent of the roughly 1900 kilometres of FEI's transmissions lines has not been excavated or exposed through opportunity digs. This means that FEI has direct crack information for less than 1 percent of its transmission system.

Secondly, the development of cracks is complex, requiring the three elements I discussed earlier and therefore is a highly localized and unpredictable phenomena. The extent that susceptible

1 material, tensile stress and suitable environment will
2 contribute to the formation of cracking will vary from
3 site to site. This means that while we know that
4 cracking is generally a problem on certain pipelines,
5 analysis from opportunity digs or existing ILI
6 information cannot be used to predict where
7 specifically cracking has or may occur. We are left
8 knowing that there is a problem but we do not have the
9 tools or information to say we have it fully
10 mitigated.
11 FEI is pursuing the TIMC project because
12 industry knowledge, including our own internal
13 understanding, has evolved such that we have a more
14 complete understanding of how SCC can lead to failures
15 in pipelines, including FEI's Coastal Transmission
16 System.
17 First, we have a better understanding of
18 pipeline characteristics that can lead to potentially
19 injurious SCC, that means SCC that could lead to a
20 loss of containment, and in particular how these
21 cracks occur on lower stress pipelines such as those
22 run by FEI in urban environments.
23 Second, other pipeline operators have also
24 found potentially injurious cracking on pipelines with
25 similar characteristics to FEI's.
26 And finally, gas specific crack detection

1 tools are now commercially available and regular use
2 of them is becoming industry standard.
3 Another questions raised by the BCUC panel
4 was regarding FEI's definition of acceptable level of
5 risk as prescribed by CAS Z662. There is currently no
6 direction in Z662 regarding a quantitative criteria
7 for risk acceptance.
8 FEI has determined that ruptures are
9 unacceptable and therefore they are outside of its
10 acceptable level of risk. Understanding that some of
11 our pipelines are susceptible to cracking, an
12 understanding that has been verified by JANA, an
13 independent risk consultant, and understanding that
14 the consequences of a failure could be significant,
15 FEI must do something to address crack threats on its
16 system.
17 The CTS TMIC Project is a cost-effective
18 solution to mitigate a known risk. So the question
19 then becomes where do we start?
20 In 2018 we engaged JANA to help answer this
21 question through a quantitative risk assessment which
22 was used to prioritize how we should approach the
23 potential for cracking on FEI's system.
24 **Proceeding Time 1:55 p.m. T13**
25 Dr. Oliphant from JANA will take you
26 through the results of their analysis as part of the

1 QRA after we pause to take any clarifying questions on
2 the material covered so far.
3 MS. BEVACQUA: Thank you, Andrew. We had Mr. Bell with
4 your hand up first.
5 MR. BELL: Just to make sure I understand, so I thought
6 I heard you say early in your presentation that this
7 cracking and corrosion problem is more prevalent in
8 pipes manufactured in the 1970s and earlier. Did I
9 hear that correctly?
10 MR. DOYLE: Thank you, Mr. Bell. So different types of
11 cracking threats are more prevalent in pipelines that
12 were manufactures prior to 1970. We have some details
13 in Section 3 of the application on why that is, and in
14 particular that lack of fusion feature in the seam
15 weld. When it comes to the stress corrosion cracking
16 itself, older pipes are generally more susceptible but
17 1970s isn’t necessarily a hard cut off, if that makes
18 sense.
19 MR. BELL: Okay. And so of the system we're talking
20 about now, is the vast majority of that in that
21 vintage then or all of it?
22 MR. DOYLE: There are segments that are of that
23 vintage. The next segment that Dr. Oliphant's going
24 to go through, it speaks a bit about which pipeline
25 are and are not of that. It kind of -- there are a
26 number of pipelines that are in that vintage.

1 MR. BELL: Okay, but not all. And we can explore that
2 in a written IR. I just wanted to make sure I
3 understood.
4 And finally, and again I'm sure we'll
5 explore this in written IR, do your new construction
6 standards incorporate the requirements for this kind
7 of inline inspection?
8 MR. DOYLE: So let me just touch back on that last
9 question first. All the pipelines that are being
10 proposed as a part of the CTS TIMC project are at risk
11 of these cracking threats. So whether they're pre-70s
12 or post-70s, we've gone through and assessment them
13 and found everything included in the application is.
14 And then as far as the construction standards, in
15 terms of making these pipelines pigable in going
16 forward, is that your question?
17 MR. BELL: Well, I presume they're pigable to some
18 degree now. As I read the application, and I haven't
19 gone through it in detail yet, this is to enhance --
20 to provide the ability to do what I'll call, for lack
21 of a better term, enhanced pigging.
22 MR. DOYLE: Yes.
23 MR. BELL: And so, I guess, what I'm asking is, when
24 you build a new pipeline now would it have the
25 capability to include all the levels of pigging that
26 you talked about in your -- or that was talked about

1 in the chart in the last section?
2 MR. DOYLE: Yes, yeah.
3 MR. BELL: Okay, thank you.
4 MR. DOYLE: Good.
5 MS. BEVACQUA: Madam Chair, would you like to go next
6 or would you like to go last?
7 THE CHAIRPERSON: Why don't I let Mr. Brady Ryall go
8 first and then I'm happy to clean up.
9 MS. BEVACQUA: Okay.
10 MR. RYALL: Okay, thank you. Earlier you mentioned, I
11 think, 26 instances of cracking found on FEI's
12 pipelines, is that correct?
13 MR. DOYLE: I'm sorry, could you repeat the question?
14 MR. RYALL: Yes. Earlier you said that you have found
15 26 instances of cracking on FEI's pipelines?
16 MR. DOYLE: That's correct, yes, due to these
17 opportunity digs, that's correct.
18 MR. RYALL: Okay. With -- how many or what proportion
19 of those would you consider to be stress corrosion
20 cracking?
21 MR. DOYLE: I believe there's a breakdown of that in
22 the application.
23 MR. RYALL: Okay.
24 MR. DOYLE: Yeah, as far as stress corrosion cracking
25 as opposed to the image we found of the dent that had
26 the crack within it, that's not necessarily stress

1 corrosion cracking but it is still a cracking threat,
2 right?
3 MR. RYALL: Yes.
4 MR. DOYLE: It needs to be mitigated.
5 MR. RYALL: Okay. Right. And so, but all of these 26
6 you said were found from opportunity digs. So would
7 it be fair to assume that they were found in
8 conjunction with another inline inspection finding of,
9 say, metal loss or denting?
10 MR. DOYLE: Sometimes they were. A typical integrity
11 dig will be looking at a feature that can be anywhere
12 from, you know, ten centimetres to whatever it is, it
13 may be 100 centimetres, sort of thing, in size. We
14 need to excavate a larger chuck of the pipe, though,
15 in order to get the required equipment in there.
16 So we'll take the opportunity to inspect
17 the five, ten metres around that piece as well. So,
18 when we found these instances of cracking it wasn't
19 necessarily on a different feature that could be found
20 by a different tool that may be in the vicinity, if
21 that makes sense.
22 **Proceeding Time 2:00 p.m. T14**
23 MR. BELL: Yeah, okay, thank you.
24 MR. DOYLE: Absolutely.
25 MS. BEVACQUA: Thank you, go ahead, Madam Chair.
26 THE CHAIRPERSON: Thank you, Ilva. Mr. Doyle, just a

1 couple of questions. You have indicated that FEI
2 actually have not experienced any rupture failures as
3 a result of stress corrosion, cracking, so I'm very
4 glad to hear that. However, it's observed some leaks,
5 and then you point to the fact that similar ruptures,
6 failures have resulted from cracking in industry, and
7 then you took us to the Enbridge example.
8 I'm just wondering, how does the Enbridge
9 pipeline compare with FEI's system, in particular the
10 CTS in terms of age, and then operating pressure?
11 MR. DOYLE: Absolutely, thank you for your question,
12 Commissioner Fung. The Enbridge pipeline is of a
13 similar age, and it is at a similar operating
14 condition to some of FEI's pipelines, but not the
15 pipelines in the Coastal transmission system. The
16 pipelines in the Coastal transmission system typically
17 run at a lower stress level than the Enbridge pipeline
18 that ruptured does, and so that would be a key
19 difference.
20 THE CHAIRPERSON: But they are of the same age, is that
21 correct? Approximately?
22 MR. DOYLE: That's correct, they are of roughly the
23 same age.
24 THE CHAIRPERSON: So, do I take it from your response
25 though, that operating pressure does have an influence
26 in terms of the likelihood of a rupture from stress

1 corrosion then? In other words, the higher the
2 operating pressure, the more stress, presumably, that
3 puts on the pipe? Is that correct?
4 MR. DOYLE: In general, yes. If we go back to the
5 slide where we were talking about the leak versus
6 rupture, and we had that kind of industry and standard
7 accepted number of 30 percent SMIS, that is kind of
8 the limiting factor. So, if you have a pipeline
9 operating at a lower stress level, it's more likely to
10 leak than to rupture. There is a point where it kind
11 of transitions.
12 As far as the ruptures, ruptures go, it all
13 depends on the severity of the cracking in terms of
14 whether the pipeline is going to, is going to rupture,
15 if that makes sense. If it has numerous shallow
16 cracks, it may not be a problem, but as the cracks get
17 deeper or more extensive, it will eventually get to a
18 point where there is a problem.
19 THE CHAIRPERSON: Okay, thank you very much. I will
20 move on from there. The other question I had for you
21 relates to slide number 27, which lists the 11
22 segments that are at issue on this current project.
23 And it shows you the cracking was found in 7 of the
24 11, as reviewed by the opportunity digs. Do I take it
25 on the other four you did not find any cracking based
26 on opportunity digs that were performed by FEI?

1 MR. DOYLE: That's correct. But again, to highlight
2 that we have exposed less than one percent of our
3 transmission system, so just because we haven't found
4 it, doesn't mean it's not there.
5 THE CHAIRPERSON: So, how then did you arrive at the
6 conclusion that these are the ones that are
7 susceptible as opposed to any other ones where you did
8 not do opportunity digs and found no cracking?
9 MR. DOYLE: Great question. So, first off, we have
10 done integrity digs on these pipelines, we just
11 haven't found cracking while looking for other things.
12 As far as whether we believe they are susceptible, it
13 has to do with their age, it has to do with the
14 manufacturing processes that were used in the building
15 of these pipelines, and it has to do with the coating
16 type. There are certain older coatings that are more
17 susceptible to this, and so these pipelines that are
18 listed, all 11 of them, have some combination of those
19 factors that put them at risk of SCC.
20 THE CHAIRPERSON: Okay, that's great, thank you very
21 much, that was helpful. Those are all of my
22 questions. Thank you, Ilva.
23 MR. DOYLE: Thank you, Chair.
24 MS. BEVACQUA: Thank you.
25 MR. DOYLE: I think I'll pass it off to Dr. Oliphant at
26 this point?

PRESENTATION BY MR. OLIPHANT:

MR. OLIPHANT: Thank you, Mr. Doyle. Can the Commission and everyone hear me clearly?

THE CHAIRPERSON: Yes, we can, thank you.

MR. OLIPHANT: Thank you. I'm Ken Oliphant, executive Vice president, CTO of JANA, and I oversaw the project teams that conducted the work that we'll be talking about this afternoon. Which are first an analysis of cracking threats, where we did a pipeline-by-pipeline assessment of the susceptibility to the transmission pipelines due the cracking threats that Mr. Doyle was just describing. And also, a quantitative risk assessment of the transmission pipelines to assess the relative importance of the cracking threats and to support the overall planning process.

Next slide please?

Before I get into my summary of those projects, I just wanted to briefly introduce JANA. JANA's a engineering and software company founded in 1999, that operates exclusively within the gas pipeline industry providing quantitative risk solutions for integrity management, through our 95 engineering, data, software and project management professionals. And we work with a broad range of local distribution companies in the gas pipeline industry with U.S. and Canada.

1 **Proceeding Time 2:06 p.m. T15**
2 That represents roughly 51 million homes or roughly 60
3 percent of the pipeline mileage for local gas
4 distribution companies in North America.
5 The analysis I'll be talking about was
6 conducted on all three of Fortis' transmission
7 pipeline systems. The CTS system, which is the focus
8 of our discussions this afternoon, the ITS or Interior
9 transmission system, and the Vancouver Island system.
10 Just to go through the scope of the
11 cracking threats analysis, for those three systems and
12 the mainline pipelines within those systems which
13 comprise 35 different pipelines, representing 1900
14 kilometres, roughly, in terms of mileage, we did a
15 pipeline-by-pipeline assessment of the susceptibility
16 of those liens to cracking threats. The assessment
17 involved looking at the susceptibility, which is do we
18 expect that we could potentially see cracking on those
19 pipelines. That was based on an analysis of the
20 pipelines properties and the operating conditions and
21 comparing that to where industry stress corrosion and
22 cracking has been observed. And it was further
23 supported and verified through an assessment of the
24 historical dig reports, the opportunity digs that Mr.
25 Doyle was speaking to, and through SME workshops,
26 subject matter expert workshops, with Fortis personnel

1 to describe the cracking that they have found to date
2 on the FEI system.
3 We also then looked at, just because a
4 pipeline is susceptible to cracking does not mean that
5 that cracking can grow to failure. We also then
6 looked at the potential for those cracks to grow to
7 failure under the Fortis operating conditions, which
8 involved an analysis of historical industry failures
9 and then crack growth modeling which was done in
10 conjunction with Dr. Chen, an expert in stress
11 corrosion cracking at the University of Alberta. We
12 also combined that with the outputs of the
13 quantitative risk assessment to look at the overall
14 contribution of the cracking threats to the frequency
15 of failure and risk based on that QRA analysis.
16 In terms of the findings from that work, we
17 did identify CTS and ITS pipeline with characteristics
18 that made them susceptible to cracking threats. For
19 example, the 11 CTS pipelines that we're speaking to
20 here today and also 9 pipelines on the ITS system. So
21 of the 35 pipelines analyzed, 25 of those were
22 identified as being susceptible to cracking threats
23 and 10 were not.
24 We also, as Mr. Doyle had identified
25 previously, found that there were stress corrosion
26 cracking and seam cracking identified in the integrity

1 digs conducted within the CTS and ITS pipeline
2 systems.
3 We've further identified that the stress
4 corrosion cracking could potentially grow to failure
5 under the Fortis operating conditions as industry
6 failures have been observed within the operating
7 stress ranges of the Fortis susceptible lines and
8 through the crack growth rate modeling that was
9 conducted in conjunction with Dr. Chen at the
10 University of Alberta. And I'll also show the
11 relative importance that the QRA identified in terms
12 of the cracking threats for the susceptible lines
13 we're speaking to here today.
14 So, in terms of the quantitative risk
15 assessment, we conducted a baseline quantitative risk
16 assessment at the system level, where a quantitative
17 risk assessment is a formal and systematic approach to
18 estimated risk in terms of the probability and
19 consequences of potentially hazardous events. The
20 system level assessments enables identification of
21 general system risks and the threats driving that risk
22 to identify where additional integrity management
23 activities may be warranted. Again, the analysis
24 involved all three of the mainline transmission
25 systems, looking at the 35 mainline transmission
26 pipelines, representing approximately 1900 kilometres.

1 **Proceeding Time 2:11 p.m. T16**
2 As part of the analysis dynamic
3 segmentation was applied to look at -- break down the
4 pipelines, to examine segments with common features
5 that would have common risk across those segments,
6 which resulted in roughly 75,000 pipeline segments
7 being analyzed and for each of those 53 data
8 parameters were used to feed into the quantitative
9 risk assessment, along with the MFL and CMFL ILI data
10 that was available and along with building type
11 structure data to conduct the risk assessment.
12 The overall approach was presented to the
13 BCOGC, Fortis' technical regulator.
14 This just shows the different threats that
15 were analyzed as part of the overall quantitative risk
16 assessment. So it analyzed a full set of pipeline
17 threats common to gas transmission pipelines in
18 addition to the stress corrosion cracking threat, so
19 that we could have a relative comparison of the stress
20 corrosion cracking threat importance relative to the
21 other threats to the pipeline system.
22 As part of the BCUC panel questions, one of
23 the questions was to provide a discussion of FEI's
24 experience with past integrity digs and how the number
25 of integrity digs impacts the safety risk calculation.
26 In terms of their use in the quantitative

1 risk assessment the corrosion threats, not stress
2 corrosion cracking but the general corrosion that Mr.
3 Doyle spoke to, the risk for those threats was based
4 on the MFL and CMFL identified corrosion features
5 through those ILI runs and that risk was reduced based
6 on the repairs that were conducted as evidenced by the
7 dig reports and FEI criteria, so that the features
8 that were identified by the ILI runs and removed
9 through integrity digs, the risk for those sections
10 was reduced due to those risks being mitigated and
11 taken out of the system.
12 As Mr. Doyle has mentioned, less than 1
13 percent of the overall line length had been accessed
14 or excavated through those integrity digs, so that it
15 did not have a material impact on the other threats or
16 risk calculations.
17 In terms of the results, it was identified
18 that the CTS system has the highest risk of the three
19 systems when we look at total risk and risk per
20 kilometre of pipeline. This is driven primarily by
21 the fact that the CTS system is in a very urban
22 environment with high potential consequences. The ITS
23 system had the next highest risk, with similar or
24 slightly higher potential probability of failures but
25 in a more rural settings for the most part. And the
26 Vancouver Island system, because it is a much newer

1 pipeline in largely rural areas have the lowest
2 overall system risk.
3 Within the CTS system cracking threats were
4 found to be the greatest contributor to risk in that
5 system. And if we look at that at the pipeline level,
6 for the 11 CTS pipelines that were identified as
7 susceptible to cracking threats, cracking threats were
8 the top driver of risk for 9 of those pipelines and
9 the second and fourth top line pipeline level threat
10 for the other two pipelines, though there were
11 specific sections within each of those pipelines where
12 cracking threats were the top driver of risk.
13 Overall therefore, based on our analysis we
14 concluded that there as specific pipelines within the
15 Fortis system that are verified as being susceptible
16 to cracking threats. The QRA verified that cracking
17 is a credible threat for those susceptible pipelines,
18 that the CTS system has the highest overall system
19 risk and that cracking threats are the dominant risk
20 for that CTS system.
21 Thank you, and with that I'd be happy to
22 answer any questions that you may have.
23 MS. BEVACQUA: Madam Chair?
24 THE CHAIRPERSON: Thank you, Ilva. Thank you very much,
25 Mr. Oliphant. I just have a question with respect to
26 the scope of analysis of cracking threats. You've

1 mentioned on slide 35 that you examined as part of
2 that analysis the CTS, ITS, as well as VITS Mainline
3 pipeline, and in total you examined 35 pipelines.
4 **Proceeding Time 2:16 p.m. T17**
5 I'm interested in knowing what was the
6 breakdown between the three areas? CTS, ITS, VITS for
7 those 35 if you recall? Just a rough -- I don't need
8 the exact --.
9 MR. OLIPHANT: In terms of the total number of
10 pipelines in each system?
11 THE CHAIRPERSON: Correct.
12 MR. OLIPHANT: All right, I have that explicit
13 information in my notes here, although Fortis would
14 probably be able to answer that more quickly.
15 THE CHAIRPERSON: You know what, why don't you just
16 leave that. If you wanted to provide it afterwards,
17 or we can ask a follow up in IR, that's fine.
18 Because, I assume that the sample size is going to
19 have a bit of influence as to how you came to your
20 conclusion with respect to where the greatest area of
21 risk lies? Depending on how many you examined in each
22 one of those areas?
23 MR. OLIPHANT: That's why we express the risk, both in
24 terms of total system risk, and in terms of risk per
25 kilometre. So that -- and, and the CTS system has the
26 highest risk on both of those attributes. So in terms

1 of total risk, which is a length and, you know,
2 adjusted -- it includes the total length of the
3 system, and then the risk per kilometre, and on both
4 of those measures the CTS system has the highest risk.
5 There were 13 CTS systems, and 12 -- or sorry, 13 CTS
6 pipelines, 12 ITS pipelines and 10 Vancouver Island
7 pipelines.
8 THE CHAIRPERSON: Thank you very much. Next question
9 for you is on your QRA, or the quantitative risk
10 assessment analysis, those 11 CTS pipelines that were
11 identified as being more susceptible to cracking
12 threats, were they amongst the 13 that you looked at
13 in terms of your initial analysis of cracking threats?
14 Or were these a subset afterwards in your QRA?
15 MR. OLIPHANT: So, for both the analysis of cracking
16 threats and the QRA, we looked at all 35 pipelines.
17 THE CHAIRPERSON: But I'm asking specific about the 11,
18 the ones that are at issue in this application? Were
19 all 11 within that sample of 13?
20 MR. OLIPHANT: Yes, so there were 13 -- it wasn't a
21 sample, it was all the mainline transmission
22 pipelines, for which MFL and CFMFL [*sic*] inspections
23 had been run, which was a total of 35 pipelines, 13 of
24 those in the CTS system, 12 in the ITS and 10 in the
25 Vancouver Island. So, all the mainline transmission
26 pipelines were analyzed, and 11 of the 13 were found

1 to be susceptible.
2 THE CHAIRPERSON: And what caused you to exclude the
3 other two then?
4 MR. OLIPHANT: They were based on the age of
5 construction and the coating type, primarily, were
6 pipelines that based on those features, they're
7 generally newer pipelines, with coating types that are
8 much less susceptible to the cracking threats, and
9 construction practices that make them much less
10 susceptible to the seam welds cracking.
11 THE CHAIRPERSON: Okay, so based on your analysis, you
12 only excluded 2 of the 13 from inclusion in this
13 particular project?
14 MR. OLIPHANT: Two of the 13 CTS systems were excluded,
15 all 10 of the Vancouver Island systems were excluded
16 because again they were newer pipelines with coating
17 types that are generally considered to be much less
18 susceptible to cracking threats, and three of the ITS
19 systems, again, based on their age and coating types
20 were excluded.
21 THE CHAIRPERSON: Okay, thank you very much. Those are
22 all my questions, and I see that Commissioner Morton
23 has his hand up, followed by Mr. Craig, and then Mr.
24 Ryall.
25 COMMISSIONER MORTON: Thank you. Mr. Oliphant, this
26 question is actually beyond the scope of your study,

1 or even this proceeding, so please choose not to
2 answer it if you don't want to, but it's just a
3 curiosity. Given what we've heard about the
4 transmission system, is the distribution pipe
5 potentially susceptible to the same things? Or is it
6 because of the lower pressure? It's -- it's not as
7 big a worry? Again, just, just a general curiosity
8 question. Not asking you about Fortis' distribution
9 system.
10 MR. OLIPHANT: Yes, generally the distribution systems
11 are operating at much lower pressures and stresses,
12 and are not considered generally susceptible to stress
13 corrosion cracking.
14 COMMISSIONER MORTON: Okay, thank you.
15 MS. BEVACQUA: And we'll go over to Mr. Craig?
16 MR. CRAIG: Thank you. Mr. Oliphant, you are measuring
17 risk on a per-kilometre basis, SRU per kilometer?
18 MR. OLIPHANT: Yes, I guess the risk was calculated at
19 a granular level, and for each pipeline segment on a
20 per kilometre basis.
21 **Proceeding Time 2:22 p.m. T18**
22 MR. CRAIG: And my question is to go to, is it a
23 quantitative measure system and could you explain a
24 little bit of how that measurement works?
25 MR. OLIPHANT: Thank you for the question, certainly.
26 So, the quantitative analysis looks at the threats

that we had identified in the previous slide. And for each of those threats looks at making an estimate of the probability of failure or gas release across the different types of release scenarios, ranging from a small pinhole leak, medium sized leak, large leaks and ruptures. And then for each of those looks at the consequence scenarios for that.

So it's a probability of failure expressed on a per kilometre basis, multiplied by the potential consequences of that failure. And the consequences themselves were calculated based on industry standard calculation approaches for looking at the potential consequences of gas pipeline releases.

MR. CRAIG: So this is a fully professional measurement system for risk?

MR. OLIPHANT: Yes.

MR. CRAIG: Appreciate it, thank you.

MS. BEVACQUA: And over to Mr. Ryall.

MR. RYALL: Okay, thank you. Mr. Oliphant, was your company contracted by Fortis to conduct a quantitative risk assessment on the entire -- I guess, on all the threats to the transmission system or was it to evaluate the risk of cracking in relation to the other -- in relation to other threats. And the distinction I'm trying to draw is, did you do your risk assessment looking at all the threats and then the cracking

1 threat is the one that fell out of your analysis as
2 the dominant risk?
3 MR. OLIPHANT: Thank you for the question. The risk
4 assessment was conducted on all the different threats
5 for the pipelines system and the cracking threats came
6 out as the highest threat. Just to be specific, just
7 within those 11 lines identified as susceptible to
8 cracking threats, it was the highest threat for two of
9 those -- or for nine of those 11 pipelines. For two
10 of them it was not the highest cracking threat. And
11 it was not an appreciable threat to the other
12 pipelines, for example the Vancouver Island pipeline
13 system and the other pipelines where cracking threats
14 were not identified -- or were not identified as being
15 susceptible to cracking threats.
16 Did that answer your question?
17 MR. RYALL: Yes it did, thank you.
18 MS. BEVACQUA: Thank you. And over to Mr. Weafer.
19 MR. C. WEAFER: Thank you. Mr. Oliphant, I just have a
20 clarification question on page 39 of your slide deck.
21 And then the -- it's the third bullet point, "Approach
22 presented to technical regulator (BC OGC)". Can I
23 just get an understanding, what was the result of
24 that? I take it this QRA was taken as an acceptable
25 step by the Oil and Gas Commission in terms of
26 analysis of the pipeline? Is that what happened? I

1 just don't know the background to this.
2 MR. OLIPHANT: Yes, and maybe Fortis can provide the
3 details of that in terms of the communications back
4 from the regulator to Fortis. But the review -- we
5 presented a workshop and review of the approach to the
6 technical regulator and I'll maybe pass it to Fortis
7 to speak to the specific response back from the BC
8 OGC.
9 MR. BALMER: Good afternoon, my name is Bryan Balmer.
10 I'm manager of system integrity programs at FortisBC
11 and thanks for your question, Mr. Weafer.
12 So, yes, FortisBC did present to the B.C.
13 Oil and Gas Commission on our progress to date on
14 quantitative risk assessment and they did -- I forget
15 the exact words that you used, Mr. Weafer, but it did
16 characterize that, yes, the BC OGC accepted our
17 progress to date as sufficient evidence to close a
18 corrective action monitoring that they had previously
19 established with FortisBC.
20 **Proceeding Time 2:27 p.m. T19**
21 MR. C. WEAFER: Okay, and thank you. And just -- and
22 we can pursue this in IRs and so you don't have to
23 answer this now, but Enbridge has been used as an
24 example as to what we need to be looking at. There
25 was a rupture on the Enbridge line. My understanding
26 is Enbridge was in effect sanctioned by the Canadian

1 Energy Regulator for -- and I won't phrase this
2 properly because I don't have it in front of me, but
3 with respect to their maintenance or ongoing upkeep of
4 the pipe. We're not in that situation with Fortis,
5 right now, is that fair to say?
6 MR. BALMER: That's correct. We're not under any order
7 from the B.C. Oil & Gas Commission with respect to our
8 operation of our pipelines.
9 MR. C. WEAFER: Okay, yeah and so the Enbridge example
10 was found to be they were not up to standard in terms
11 of that rupture, as I understood the result of that.
12 So that's not what we're looking at as we look at
13 Fortis now. What we're looking at is avoiding moving
14 into that situation. Is that a fair statement of the
15 objective?
16 MR. BALMER: Yeah, there's a few nuances, I believe,
17 there. So the first is, and I wouldn't necessarily
18 want to make the leap that Enbridge was not meeting
19 standards prior to that failure, but perhaps if I may
20 offer that it -- that in industry practice or in
21 regulatory practice that following an incident it can
22 happen that a regulator would ask an operator to
23 reduce their operating pressure and then take steps to
24 demonstrate the safety of their system prior to
25 resuming regular operations, and that's how I might
26 characterize what happened with Enbridge.

1 MR. C. WEAFER: Well, we can leave that. I don't want to
2 debate it. I think there was a finding after the fact
3 that there was a problem, that Enbridge was -- so we
4 don't need to -- what I'm trying to understand is --
5 and I think it's been conveyed, is Fortis is in
6 compliance, Fortis QRA was accepted by the technical
7 regulator and this is another step you wish you take
8 with this project, is that a fair summary?
9 MR. BALMER: Absolutely. This is a continuing
10 improvement to enhance our integrity management
11 practices in accordance with industry practice and
12 leveraging available technology and addressing a
13 hazard to our system. So yes, thanks.
14 MR. C. WEAFER: Okay, but we'll follow up with the IRs.
15 No, thank you for the responses and for the
16 presentation. It's very helpful.
17 MR. BALMER: Thank you.
18 MS. BEVACQUA: Thank you. I don't see any other hands up
19 at this point so we'll pass it back to Andrew Doyle to
20 wrap it up.
21 **PRESENTATION BY MR. ANDREW DOYLE:**
22 MR. DOYLE: Thank you. All right. So in this section of
23 today's workshop I will be going through how FEI
24 evaluated the possible project alternatives and
25 selected EMT ILI as the preferred solution to
26 identifying cracking threats on the CTS.

1 FEI considered six alternatives against a
2 number of criteria. These criteria consisted of the
3 method effectiveness, which considers how effective
4 the alternative was in enhancing FEI's ability to
5 mitigate in-service pipeline failures resulting from
6 cracking threats.
7 Second, was implementation complexity,
8 which considers how readily the alternative can be
9 implemented on FEI's system and the relative
10 complexity of performing the alternative.
11 Third was community and environmental
12 impacts, which considered the potential effects on the
13 aforementioned while performing the field activities
14 associate with each alternative and if deemed
15 feasible, a financial analysis was completed on the
16 net present value of total capital and O&M costs
17 associated with the alternative.
18 At a high level the six alternatives
19 considered consisted of stress corrosion cracking
20 direct assessment, which attempts to predict SCC by
21 inferring the pipe condition from the findings of a
22 limited number of opportunity digs. This alternative
23 was deemed non-feasible as it cannot reliably identify
24 all locations or the extent of cracking on the system.
25 The second alternative was the installation
26 of a pressure regulating station on the pipeline that

is capable of reducing the pressure of the pipeline such that it is no longer at risk of rupture. This alternative was deemed non-feasible as said pressure reduction results in a reduced volume of gas leaving FEI unable to supply its customers' energy needs.

Proceeding Time 2:32 p.m. T20

The third alternative was to implement a hydrostatic testing program. This consists of removing each pipeline from operation periodically, typically every four to five years, filling it with water, and raising the pressure of the water to a specified limit. Flaws in the pipeline would be found by causing them to fail in a controlled manner. Then the failures would be located and repaired, which would allow the operator to confidently operate the pipeline until the next test.

We have provided a detailed explanation of the challenges associated with this alternative in section 4 of the application. But in short, it was removed from consideration because of the impracticability of FEI taking these pipelines out of service on such a frequent basis, and the impacts to the community from undertaking the required activities.

The fourth alternative was to add electromagnetic acoustic transducer inline inspection

1 tools, or EMAT ILI, to our existing integrity
2 management ILI program, to collect cracking data that
3 would then me actioned and repaired under our existing
4 integrity dig program. This alternative was deemed
5 feasible.
6 The fifth option was a pipeline
7 replacement, replacing all susceptible pipelines with
8 new, non-susceptible ones. And the last option was a
9 major rehabilitation effort of pipeline exposure are
10 recoating. This would consist of excavating the
11 entire line, inspecting for and repairing cracks, then
12 recoating the pipes in place.
13 These last two options were rejected due to
14 high costs and community impacts associated with the
15 work. This left EMAT ILI as the sole feasible
16 alternative to mitigate cracking on the CTS. It is
17 highly effective at detecting cracks. It can be
18 implemented relatively easily as FEI is already
19 running ILI tools, and it limits impacts to the public
20 as the integrity digs would be undertaken to directly
21 address a known integrity threat. In addition, the
22 information gathered can be utilized in FEI's ongoing
23 QRA's to improve and inform integrity management
24 activities related to time dependent threats. This
25 alights with both our integrity management, and the
26 practices of the industry at large.

1 Another question raised by the BCUC panel
2 was to discuss other industry standard crack detection
3 tools, including tools other than EMAT ILI.
4 Part of the challenge of adopting crack
5 detection technology is a general lack of other tools.
6 There are tools that work on liquids lines, such as
7 ultrasonic crack detection, but this technology
8 requires a liquid carrier between the tool and the
9 wall of the pipeline. While it can be run in a dry
10 gas line, a liquid slug has to be introduced to carry
11 the tool, which leads to challenges with the
12 interconnected system FEI operates as it pertains to
13 getting the liquids out of the pipeline afterwards.
14 There are also robotic driven tools, but
15 these were designed to inspect short lengths of
16 facility pipelines, rather than the long transmission
17 lines such as the ones FEI is looking at.
18 The EMAT tool was specifically designed for
19 use in gas pipelines, and is the current industry
20 standard for crack detection. As FEI's pipelines
21 support ILI tools, the EMAT option is a feasible and
22 effective option for detecting cracking threats.
23 This video explains how the EMAT ILI tool
24 detects cracks and areas of disbanded coating, which
25 we will watch now.
26 MS. BEVACQUA: Seems to have the same technical issues,

1 so we're just going to refresh it. We could take the
2 question from Mr. Bell while we wait?
3 MR. BELL: Sorry, just a quick one. When you had your
4 slide evaluation alternatives, you're talking about
5 the EMAT system detects cracks very well. Are you
6 going to repair every crack you detect? Or will you
7 have standards to say when it reaches a certain size
8 you'll dig and repair?
9 MR. DOYLE: Great question, Mr. Bell. We'll take a
10 similar approach to our corrosion management program
11 right now, which is to get the results, to evaluate
12 the results as it pertains to the pipeline itself.
13 We're able to detect what size of defect, whether it
14 be a crack or corrosion would be necessary to really
15 be a threat to our pipeline, and we'll be able to
16 determine which, which findings need to be actioned
17 immediately, and which can be, can be just evaluated
18 -- or we can wait until we run the tool the next time.
19 So, we won't be digging up every indication.
20 MR. BELL: Thank you.
21 MS. BEVACQUA: Madam Chair, did you want to answer
22 [*SIC*] your question first?
23 THE CHAIRPERSON: It doesn't matter, if the video is
24 ready, I'm happy to watch it first.
25 MS. BEVACQUA: Okay.
26 MR. DOYLE: Just before we do the video, just to jump

1 back to that, Mr. Bell. The one other thing that, the
2 challenge we have, is the interaction of defects. So,
3 if you'll recall from the first part, we were talking
4 about the lack of fusion features and how they can
5 interact with corrosion defects. And so, when I
6 mention we can measure corrosion, indeed I can figure
7 out when we need to dig it up.
8 **Proceeding Time 2:37 p.m. T21**
9 If we don't know about that, the lack of
10 fusion, then obviously we may misrepresent how deep
11 the corrosion pocket can be. So that would be one
12 thing that we would have to be careful about is we'd
13 be overlaying these different data sets on top of each
14 other and figuring out which ones need to be actioned.
15 MR. BELL: Okay, thank you.
16 [*Video playing*]
17 MR. DOYLE: All right. So this video is also by ROSEN
18 and it starts out with us at the end of the process.
19 So it has the excavator and they're starting their
20 targeted integrity at this point to fix a problem that
21 was food by the tool. In this case the issue is a
22 disbonded coating area that was found, and that's
23 depicted in that lighter grey colour on the pipeline.
24 This is the target of the dig.
25 So as the video rewinds it shows the EMAT
26 ILI tool running through the pipeline. And it shows

how the sensor picks up and logs features on the pipeline. Please note the sensor log along the bottom of the video. This captures the location and the severity of any issues providing the data that the operator will use to scope and schedule the integrity digs.

This tool uses a different sensor than the other tools used by FEI, which allows for the detection of cracks. This diagram explains the operating principle behind the sensor. EMAT tools use electromagnets to induce an ultrasonic pulse within the steel walls of the pipeline. Sensors then detect changes in the pulse to identify areas of potential concerns, such as cracks.

This information, along with the location of the tool at the time that the crack was found or the defect was found, is stored and will be analyzed and actioned after the run. This allows FEI to know where the issues are and to respond appropriately.

I'll just let the video play out.

VOICE: That was a fast fix.

MR. DOYLE: If only they were all that fast, hey?

So, there are four requirements in order to successfully undertake an EMAT ILI run. First, the tool needs to be able to pass through the pipeline. This means that there can be nothing on the pipeline

that would obstruct the tool and that the launching and receiving barrels are compatible with the tools. The pipelines included in the CTS TIMC project have been running ILI tools for years, so there's nothing that will block the EMAT ILI tool. However, EMAT tools are longer than FEI's existing tools so most of the existing barrels will need to be extended.

Second, the tool needs to travel within its optimal velocity range for cracks to be properly detected. Due to the sensor technology, EMAT tools need to move slower than the tools FEI is currently using. FEI has some ability to manage velocities within its system but additional capabilities are required.

Third, the tool needs to move at a consistent speed as the optimal velocity range for EMAT is narrow. Should the tool travel too fast or too slow, sections of pipeline will have low-quality data. These changes in speed or speed excursions are typically due to sections of pipe with a thicker wall historically used in higher stress environments such as under roads.

Finally, FEI needs the ability to respond to any findings. This typically requires a pressure drop to ensure safe digging and inspection activities. Currently, the CTS has a single pressure control point

1 and any pressure drops affects the entire system. To
2 be successful in responding to these threats, FEI
3 needs a more granular way to drop the pressure in
4 specific pipelines.
5 I think we'll take a second to answer your
6 question, Commissioner Fung.
7 **Proceeding Time 2:42 p.m. T22**
8 THE CHAIRPERSON: Yes, thank you, Mr. Doyle. I just want
9 to go back to your slide 48 where you discuss the six
10 alternatives that were considered by FEI before
11 launching this particular program, and you indicated
12 that the pressure regulating station was not a
13 feasible option from a technical perspective.
14 However, as I understand it, in addition to
15 the 11 where the ILI is being proposed as a solution
16 there's at least one other pipeline where you are
17 actually implementing a pressure regulating station as
18 an option because ILI is just not possible.
19 So maybe you can just explain the reason
20 for that and why the discrepancy.
21 MR. DOYLE: Absolutely, Commissioner Fung, I'd be happy
22 to explain that. So we're looking at our general
23 options here. We're looking at a system-wide approach
24 to dealing with cracking and when we look at the
25 system as a whole for the Coastal Transmission System
26 we're unable to drop the pressure because we simply

1 don't have the capacity. It would require -- we'll
2 get into what it would require later.
3 That said, when we moved forward with the
4 EMAT option and we got to that particular leg of that
5 pipeline which runs from the Noons Creek facility down
6 to the old Cape Horn -- or sorry, the old Burrard
7 Thermal Plant run by BC Hydro, that was the only load
8 on that particular line and that facility was
9 deactivated a number of years ago, which means that we
10 don't actually have the flows in that section of pipe
11 to run EMAT ILI tool.
12 We did some analysis and found that without
13 that large industrial demand point at the end there
14 was no need for the pipe to be as large as it was and
15 found that the best way in that scenario to deal with
16 cracking threats was to reduce the pressure.
17 THE CHAIRPERSON: Thank you very much, Mr. Doyle. That
18 explains it for me, thanks.
19 I believe, Ilva, the last one is for the
20 pilot and lessons learned from it.
21 MR. DOYLE: Yes, if you go back to slide 52, please.
22 Thank you.
23 So based on our understanding of these
24 requirements and to improve our development activities
25 for the project, FEI decided to undertake a EMAT ILI
26 pilot project. In the next section I will go over

1 this pilot project, including an overview of its
2 scoping and the key lessons learned.
3 When we considered the possible scope of
4 the pilot project we wanted to find pipelines with a
5 history of SCC that were already able to pass the EMAT
6 tools. This would theoretically allow FEI to receive
7 the results prior to finalizing the development of the
8 CTS TIMC Project and so that the lessons learned could
9 be used to refine our approach on the project.
10 The two pipelines selected are highlighted
11 in blue on the map on slide 53. They required
12 relatively minor alterations limited to barrel
13 extensions to accommodate the longer tools and
14 pressure reduction stations to support FEI's response
15 to the information gathered. The barrels were altered
16 at the end points of the blue lines shown on the map
17 and a pressure reduction station was installed on each
18 to allow for response.
19 The BCUC panel has asked us to discuss what
20 we learned from the pilot project. Well first, the
21 tool runs were successful. They traveled through the
22 pipeline as planned. High quality data was collected
23 and FEI was able to find and action cracking threats.
24 Secondly, FEI had three key assumptions
25 that form the basis for the project that were
26 confirmed and validated by the results. First, they

1 confirmed FEI's understand that there were
2 unidentified cracking threats on our system that
3 require identification, management and mitigation.
4 This image is of a previously undetected seam weld
5 crack that was identified by the EMAT ILI tool during
6 the pilot project.
7 Second, then confirmed FEI's approach was
8 valid. It was assumed that they behavior of the MFLC
9 tool when it passed something causing a speed
10 excursion would predict the way that the EMAT tool
11 would behave when it passed the same component. In
12 other words, areas with high or low speeds on FEI's
13 MFLC data set indicated that the same speed variation
14 was likely in the EMAT tool data set.
15 Analysis of the results confirmed that
16 there was a reasonable correlation between the
17 behavior of the two tools. It also indicated that the
18 EMAT tool recovered from these changes in velocity
19 over a shorter distance than the MFLC tool, returning
20 to its optimal speed over a shorter distance.
21 **Proceeding Time 2:42 p.m. T23**
22 This allowed FEI to refine the scope of the project.
23 Third, the results confirmed that the post-
24 run response was appropriate. The additional pressure
25 reduction facilities installed allowed FEI to
26 successfully respond to the unpredictable findings in

1 a timely and effective manner.
2 In addition to these confirmations, the
3 pilot allowed us to refine the design and
4 implementation of some of our system alterations,
5 including how we approached barrel modifications and
6 pressure reduction stations.
7 With these lessons learned, FEI was able to
8 validate the scope of the modifications required to
9 the CTS to allow for a successful EMAT ILI program.
10 I will now discuss the modifications
11 required for the CTS TIMC project.
12 MS. BEVACQUA: Andrew, perhaps I'll stop you there,
13 just given the time. I think I will be in Madam
14 Chair's hands whether we should take a break now, as
15 with the questions we've gone longer than we expected
16 at this point?
17 THE CHAIRPERSON: I think we've been going close to two
18 hours now, and perhaps if you don't mind, Mr. Doyle,
19 and I hate to do this to you before you kind of finish
20 off, if we could just take a break, maybe even just
21 for ten minutes just to give everybody a chance to
22 stretch their legs, and use the facilities if needed.
23 MS. BEVACQUA: And in the interest of time, we are
24 happy if you want to take a longer break and then
25 we'll just roll right into the Q&A period after, it's
26 up to you.

1 THE CHAIRPERSON: Does anybody have a preference?
2 COMMISSIONER MORTON: I personally think that is a good
3 suggestion. I can live with just one break.
4 THE CHAIRPERSON: Let's then take maybe a 15-minute
5 break and have everybody come back. And I notice that
6 really the project description presentation is just a
7 summary essentially --
8 COMMISSIONER MORTON: Yeah.
9 THE CHAIRPERSON: -- of what the implementation of the
10 project would look like, and I don't want to do short
11 shift to Mr. Doyle because I know he spent time on
12 doing this, but perhaps you could just run through
13 that quickly and then we can reserve the rest of the
14 time for questions? All right?
15 MS. BEVACQUA: Excellent.
16 THE CHAIRPERSON: So, we will reconvene then at 5 after
17 3, and enjoy your break everyone. Thank you.
18 **(PROCEEDINGS ADJOURNED AT 2:49 P.M.)**
19 **(PROCEEDINGS RESUMED AT 3:06 P.M.) T24-26**
20 MS. BEVACQUA: All right, back to you, Andrew.
21 MR. DOYLE: Great. So pick up right on slide 56 with a
22 description of the project itself. So, to
23 successfully run these tools there are two major
24 components. There are 13 locations on the pipelines
25 that we need to modify them to ensure that they do not
26 negatively affect the consistency of the speed of the

EMAT ILI tool as it passes through the pipeline. All 13 locations are sections of heavy wall pipe. They are shown as red triangles on the map on slide 56. Each section will be replaced with a new pipe of appropriate wall thickness for the EMAT ILI tool to pass at a consistent speed.

Secondly, there are 13 facilities that require alterations within the Coastal transmission system, shown as blue triangles on the map on slide 57. These include modifications to existing tool launching and receiving barrels to accommodate the longer EMAT tools, as well as the addition of pressure and flow control equipment.

The image on slide 58 is from the pilot project. On the right-hand side you will see the barrel. The portion that is painted white was the legacy barrel and the brown section is the extension that was required to accommodate the longer EMAT tool. We also need to add flow control equipment to ensure required tool velocities can be maintained, facilitating high-quality data collection and pressure control equipment to provide the operational flexibility required to quickly and safely respond to anomalies found as a result of the EMAT ILI run. This is an image of one of the new pressure control stations that was added to the system as a part of the

1 pilot project.
2 The BCUC panel has asked how running EMAT
3 ILI tools will fit within FEI's broader SCC management
4 plan. Running the tools is just one step of a broader
5 management plan, as gathering the information is not
6 enough on its own to mitigate the threat. The CTS
7 TIMC project will prepare the system. Once complete,
8 FEI will run the tools and the tool vendor will
9 analyze the data. FEI will incorporate the analysis
10 into its integrity dig program, evaluating anomalies
11 and repairing cracks. The information gathered will
12 allow FEI to make informed integrity related decisions
13 about future work and risks to the line. This will
14 allow FEI to answer questions like, when will we next
15 run the tool? Is there missing data that needs to be
16 actioned sooner? And what is the appropriate response
17 and timeline for mitigation?
18 This mirrors the approach used by FEI after
19 its current ILI tool runs and ensures that the threats
20 are actively and sufficiently mitigated.
21 Therefore, FEI is requesting the following
22 approvals as laid out in Section 2 of the CTS TIMC
23 application. First, that the Commission grant a CPCN
24 for FEI to proceed with the project as described in
25 Section 5 of the application. And second, that the
26 Commission grant the requested treatment of

1 development costs as laid out in Section 6.2 of the
2 application.
3 And that concludes the material that has
4 been formally prepared for presentation today. Open
5 it up to questions.
6 MS. BEVACQUA: So for the question period we will have
7 Paul Chernikhowsky be the moderator for questions.
8 And then, Paul, perhaps you might want to check with
9 Mr. Ryall, as he had his hand up prior to the break.
10 MR. CHERNIKHOWSKY: Okay. Thank you very much. Yes,
11 so, Paul Chernikhowsky, I'm the director of regulatory
12 projects and resource planning at FortisBC. And I
13 will act as the moderator for the session.
14 So, yes, Mr. Ryall, if you would like to go
15 ahead and ask your question?
16 MR. RYALL: Yes, thank you. Perhaps we can go back, I
17 think it was slide 52, but I may be off by a slide
18 number. That's the one, thank you.
19 Can you explain a little bit more about the
20 ability or the requirement to reduce the pressure
21 after the ILI run in order to respond to integrity
22 findings?
23 **Proceeding Time 3:10 p.m. T27**
24 MR. DOYLE: Absolutely, thanks for the question, Mr.
25 Ryall. So once we -- any time that we expose our
26 pipe, we need to reduce the operating pressure. And

that's a safety activity that we undertake, just to make sure that as people are working around a line, that is typically covered with dirt and now is being exposed, and they have equipment around there, it's to make sure that it keeps our personnel safe.

So, historically our typical approach has been to drop the pressure, if you will, at Huntingdon. With respect to these crack-like features, they're treated differently in the code, such that when you find a crack-like feature, you need to do a different type of calculation to figure out what the kind of safe pressure is. And if we find cracking that is sufficiently bad, if you will, or deep, the immediate response to make it safe as soon as we find it is to reduce the pressure to as low as 80 percent of the current operating pressure. And that has the effect of giving us a safety factor on top of its proven strength, until we can get in and expose and repair the crack.

MR. RYALL: So it's to immediately, if necessary, drop the pressure in a line in advance of exposing it to do the repair?

MR. DOYLE: So it wouldn't be used in every situation, it'll be used in situations where the crack-like data, -- where the information from the tool indicates that there is a severe crack. A crack that we are worried

about the integrity today, not in a week, or in two weeks, or in a year, if that makes sense. So our immediate response at that point would be to reduce the pressure. To ensure that we have that factor of safety.

MR. RYALL: Yeah, where I was getting at is how would -- it sounded like you were going to have to reduce the pressure while doing the excavation and repair, and I was wondering how that was different than doing any repair to your line now that you would find from an existing ILI? I don't know, corrosion repair.

MR. DOYLE: Okay, I think I understand, I think I understand your question a little bit better now. The difference between our traditional corrosion repairs is that we've run these tools before, we know roughly what we have, and we know roughly what to expect. There are sometimes some surprises, but you don’t generally go from no corrosion to an extremely severe corrosion defect between runs, if that makes sense.

As we go to run these cracking tools, we're not sure what we're going to find, so we need to be prepared to find severe cracking, such that -- and have a response that will make it safe immediately.

MR. RYALL: Okay, thanks.

MR. DOYLE: Absolutely.

MR. CHERNIKHOWSKY: Okay, thank you, Mr. Ryall.

1 Just before we do go into the open question
2 and answer session, I would just like to clarify and
3 expand upon a response to a question from Mr. Rhodes
4 after Mr. Pataki's presentation.
5 And at that time, Ms. Rhodes asked whether
6 we were effectively locked in with our service
7 provider. And to add to the response that Mr. Pataki
8 provided, I just want to clarify that we do have some
9 flexibility in the providers that we use for inline
10 inspection. Currently we use three different vendors
11 for all of our inline inspection activities. And FEI
12 maintains that ongoing relationship with those
13 vendors, and that is to give us consistent results
14 that are comparable from run to run. We can switch
15 between those service providers if needed.
16 We can also use potentially other
17 providers, but the reality is there is very few to
18 choose from, at this point. It is very much a niche
19 industry.
20 And last, in terms of the raw data
21 collected from the tool, if that's what Ms. Rhodes was
22 referring to, that has to be analyzed by the tool
23 vendor as it's proprietary. But once they've analyzed
24 the data, then they provide that output to FEI and
25 then we're free to analyze it further.
26 So, I hope that's helpful, and it clarifies

1 that a bit further.
2 MS. BEVACQUA: Okay, --
3 MS. WORTH: Hello, sorry, this is Leigha Worth, I was
4 just wondering if I could ask a quick follow up on
5 that? I'm just wondering when you say that the data
6 is proprietary and that the provider, the specific
7 provider, whichever one it is for whichever form of
8 monitoring that you were engaged in that particular
9 moment, is it that they perform an analysis, and then
10 give you the final results? Or is it that they give
11 you the raw data and that is what -- you know, it's
12 sort of when they get the data back from the machine,
13 they look at, you know, the ones and zeros and do that
14 analysis?
15 **Proceeding Time 3:15 p.m. T28**
16 Or is it that they come back and say "These are your
17 vulnerable sections of your, of your system according
18 to our data, and this is the data that we have to
19 actually support it, although not necessarily in the
20 form of the raw figures?
21 So, I'm just wondering what level of
22 analysis they perform initially, and what you get to
23 perform a second analysis on?
24 MR. CHERNIKHOWSKY: Yes, no, thank you, that's an
25 excellent question about the process. And essentially
26 what happens is yes, so the vendor designs and

1 constructs the tool, and so they have the intimate
2 knowledge of how it collects the data itself. And so,
3 once the tool is run, they download that information,
4 and then they do process it, because as you say, it is
5 just raw ones and zeros. And they then filter out
6 anomalous data, and basically sanitize it, I guess is
7 probably the best way to put it.
8 They then provide us with that sanitized
9 version, and then our integrity management group then
10 further analyzes it and compares it to previous run
11 data, and makes their determinations of what work
12 needs to happen.
13 So hopefully that answers the question a
14 bit better. And if there is further questions, I can
15 always pass it over Bryan Balmer, he is one of our
16 specialists in that area, and can always add some
17 further colour.
18 Did that address your question, Ms. Worth?
19 MS. WORTH: Yes, but it actually sparked another.
20 Which is, if the provider is sanitizing the data,
21 isn't there a risk that they will know of certain
22 deficiencies in their equipment and that the
23 sanitization will actually mask that, so that the
24 information that Fortis is receiving is somehow
25 defective or not the best possible data that could be
26 provided with I guess equipment that is operating at

1 an optimal level?
2 MR. CHERNIKHOWSKY: So, I'll take a first level
3 response at that, and then perhaps I may pass it over
4 to Mr. Balmer again. But what I can say is that the
5 vendors that we use are industry recognized as
6 experts. They have well accepted industry track
7 record of producing very good data. Frankly, we
8 wouldn't use them if they weren't. And so we don't
9 really have any concerns about the quality of the data
10 that they pass on to us.
11 Now, that said, I will say that obviously
12 no tool is perfect, right? It would never guarantee
13 us 100 percent certainty; no engineer can ever do
14 that. But certainly the data that we do receive from
15 our vendors, we have very high confidence in.
16 MS. WORTH: Thank you.
17 MS. BEVACQUA: Okay, we're over to Mr. Mason?
18 MR. MASON: Yeah, thank you, I have a question about
19 slide 54, which is about the pilot project. There is
20 mention here that unidentified cracks were found in
21 the pilot project segments, and I'm wondering if FEI
22 undertook any type of exercise to extrapolate the
23 findings with, you know, some type of statistical
24 analysis from that pilot project to the entire TTS,
25 and if the findings of the pilot project are in line
26 with the expected number of cracks that your risk

1 analysis would have projected for the entire system?
2 MR. CHERNIKHOWSKY: Okay, thank you, Mr. Mason. That
3 is definitely an interesting question, and it touches
4 on a number of different individuals. Perhaps I may
5 start with Mr. Doyle in terms of could you address in
6 terms of what we were expecting to find? And then Mr.
7 Oliphant you may have some comments to add there in
8 terms of how it compared to what we found in industry
9 practice?
10 **Proceeding Time 3:20 p.m. T29**
11 MR. DOYLE: Absolutely. Thank you for the question, Mr.
12 Mason.
13 So as far was what we expected to find in
14 the pilot project we didn't have any prediction on the
15 number of cracks we would find, because as we covered
16 earlier in the presentation the occurrence of these
17 cracks, and stress corrosion cracking in particular,
18 they're highly localized. Because of that prediction
19 is nearly impossible.
20 What we did know and what was confirmed is
21 that there were cracks on those pipelines that we were
22 unaware of until we ran the tool. So the tool was
23 able to find cracks on the pipelines that were it not
24 for running the tool and doing the pilot project we
25 would have no indication of where they were or the
26 severity of those cracks.

1 Does that answer your question?
2 MR. MASON: Yeah, I think in part. I guess mostly what
3 I'm driving at is, you know, with the pilot project,
4 you know, did the pilot project's finding kind of
5 align with the level of risk that you were projecting
6 with your various risk analyses. But that does help,
7 thank you Mr. Doyle.
8 MR. DOYLE: Absolutely.
9 MR. CHERNIKHOWSKY: Yeah, I think I would just add there
10 that, you know, in terms of how it compare -- how our
11 finding compare to the actual risk analysis, I think
12 that's probably a question that's better left for an
13 information request so that we can more fully expand
14 upon on that in detail.
15 MR. MASON: Sure, understood.
16 MR. DOYLE: And one other thing I might add is just that
17 we really can't extrapolate from one pipeline to
18 another because of the highly localized nature of
19 these stress corrosion cracks. So saying we found X
20 on this pipeline and therefore we'll find -- it -- if
21 we go back to what we're required to do about threats
22 in terms of managing and mitigating and addressing
23 them, that approach wouldn't allow us to say that they
24 were managed, mitigated or addressed.
25 MR. MASON: Okay, thank you very much.
26 MR. DOYLE: Absolutely.

1 MS. BEVACQUA: Thank you. This point I don't see any
2 hands up or any questions in the chat. Maybe what we
3 can do is just go through interveners in order just to
4 double check there isn't any questions.
5 So we'll start with the RCIA.
6 MR. MASON: Well I just got one of mine out there. I
7 think Mr. Ryall and I have been asking questions as
8 they've come along. But, you know, Brady, please let
9 me know if I'm speaking out of turn on your behalf
10 there.
11 MR. RYALL: I can probably -- I'm jotting a few things
12 down, so. You're not planning on running the EMAT
13 tool in the -- what is it? The Noons Creek to
14 Burrard, segment, correct?
15 MR. DOYLE: That's correct.
16 MR. RYALL: And that's because you don't have sufficient
17 gas flow to propel the tool at the right velocity,
18 correct?
19 MR. DOYLE: That's correct.
20 MR. RYALL: Have you considered -- is it possible to take
21 the line out of service and use air and nitrogen to
22 propel the tool?
23 MR. DOYLE: So there are three communities that are
24 served through that pipeline. There are three gate
25 stations, they're relatively small loads but they do
26 need to be served.

1 We did look at other options for driving
2 tools, including artificial flow in terms of like
3 having a flare stack or something on the end or using
4 nitrogen or something, or even using robotics to crawl
5 through it. But none of them -- given the need of the
6 line and our future envisioning of what that line will
7 be used for, there was no reason to go ahead with any
8 of those options when the pressure reduction would
9 work effectively in that area.
10 MR. RYALL: But is the pressure reduction solution a more
11 expensive one than the other options?
12 **Proceeding Time 3:24 p.m. T30**
13 MR. DOYLE: Not in this case, no. It consists of the
14 installation of a pressure reducing station at that
15 Noons Creek facility that will just drop the pressure
16 in that line. So when you consider a regular EMAT ILI
17 program to run the tool on there over the -- every
18 five or seven years over the life of the pipe line as
19 compared to a single pressure reducing station,
20 financially it made sense in this situation to go with
21 pressure reduction.
22 MR. CHERNIKHOWSKY: Yeah, and perhaps I would just chime
23 in here actually and just say that a typical inline
24 inspection run can cost several hundred thousand
25 dollars, and so a single installation of that pressure
26 reducing equipment which may also only cost several

1 hundred thousand dollars pays itself off after that
2 first run.
3 MR. RYALL: Okay, thank you.
4 MS. BEVACQUA: Okay, so we'll --
5 MR. CHERNIKHOWSKY: And --
6 MS. BEVACQUA: Go ahead.
7 MR. RYALL: Do you want me to keep -- I've got a couple
8 more. Do you want me to keep going and get mine out
9 of the way or --
10 MS. BEVACQUA: Sure, because then we'll give everyone
11 around to have a chance.
12 MR. RYALL: Okay. You're going to be replacing some
13 heavy wall segments of the line. I assume then you
14 will not have heavy wall piping. Are you going to be
15 going with stronger, higher strength segment -- or
16 head joints to replace that? Is that the intention?
17 MR. DOYLE: That is the intention. There is a minimal
18 change in wall thickness that the tools can get
19 through, I think it's one or two millimetres
20 difference. And so we'll look at a combination of
21 that and a higher grade material in order to get the
22 consistent speeds we need.
23 MR. RYALL: Okay.
24 MR. DOYLE: Sorry, it was closer to one millimetre
25 difference in wall thickness, not one or two. So just
26 put that on record there.

1 MR. RYALL: Okay. And looking at it, it sounds like
2 there's only about 13 of these locations where you
3 need to replace a heavy wall segment with a more -- I
4 don't want to say thin wall segment, but just -- one
5 with a consistent internal diameter, but you also I
6 thought I heard you say that the tool recovers its
7 speed very quickly. So could you not forgo replacing
8 those segments and then just forgo quality data in a
9 very limited portion of the -- of these lines?
10 MR. DOYLE: That's a great question. We did in fact
11 look at that. So there are more than 13 locations in
12 the costal transmission system that have heavy wall or
13 changes in wall thickness that do cause some sort of
14 speed excursion. The 13 that we've located here are
15 the ones that are expected to cause the worst speed
16 excursions once we've controlled for our understanding
17 of how the EMAT tool operates and whatnot.
18 Using our modeling based off of the CFL --
19 or the CMFL, sorry, tool information, these are the
20 ones that really need to be addressed. If we have
21 speed excursions on the downstream side of some of the
22 other heavy wall pipe that we're leaving in there,
23 after we've run the tool we'll be in a better position
24 to understand what we're missing or what the issue
25 with the data is. It may only be, you know, a metre
26 or two or ten, in which case it can be pretty quick to

1 dig it up and inspect it as opposed to trying to guess
2 how long the speed excursion is going to be based off
3 of the MFLC data.
4 MR. RYALL: All right. Do all the EMAT tool vendors
5 have this same sensitivity to tool velocity or is it
6 just one selected as a specific requirement?
7 MR. DOYLE: So I don't think we've locked ourselves into
8 one vendor for all of the pipelines at this point.
9 There are a few options. And they have different
10 requirements, but they are quite similar. This is
11 probably something we could respond to in more detail
12 in the IR process, but they all operate on the same
13 principle in the sense of it's the EMAT sensor and
14 therefore they all have similar restrictions.
15 MR. RYALL: Okay.
16 MR. DOYLE: And we have scoped this out to make sure we
17 can use multiple vendors for the lines where there are
18 multiple vendors with tools, if that make sense.
19 We're not locking ourselves into one.
20 MR. RYALL: Okay, I think I'll pause there. I got a
21 few questions in, so I'll let somebody else have a
22 turn. Thanks.
23 MR. CHERNIKHOWSKY: Thank you.
24 MS. BEVACQUA: Thank you. So we'll move now to CEC.
25 MR. C. WEAFER: Thank you. We chatted in the break and
26 I just want to express appreciation to Fortis for the

very good helpful overview presentation today. And we'll reserve our questions for the IR process at this time. So thank you for your time today.

MR. DOYLE: Thanks.

MS. BEVACQUA: Thank you, Mr. Weafer.

BCOAPO. Oh? I'm hearing an echo.

MS. WORTH: Is that from me? My apologies.

MS. BEVACQUA: That's okay. Go ahead.

MS. WORTH: So I just had a couple of -- sorry, it is from me. I apologies, I don't know what's happening here.

I just had a couple of quick questions, and it may be that I just haven't delved deeply enough into the risk analysis piece to have the information.

Proceeding Time 3:30 p.m. T31

There was reference in the risk assessment to earth movement and I was wondering if that covers both, sort of, landslides where, you know, there'd be increased risk of either the, you know, the integrity being compromised due to moving or, you know, increased pressure from earth being dumped onto it, as well as the risk of, sort of, the big one. You know, the earthquake that we're apparently now overdue for. So I was just wondering if that was sort of built into the earth movement? Because that was where I saw probably the most likely consideration of those two

1 particular things.
2 MR. CHERNIKHOWSKY: Yes. So, thank you, Ms. Worth.
3 Perhaps, Dr. Oliphant, if you could discuss the
4 assumptions that you used for earth movement in the
5 QRA were used?
6 MR. OLIPHANT: Yes, thank you for the question. In
7 terms of the natural hazards in earth movements, it
8 did consider all those threats to the Fortis system,
9 and used the information that Fortis has developed in
10 conjunction with consultants that they used to assess
11 their geohazards threats within their system. So we
12 took all the information from those assessments and
13 incorporated that into the overall quantitative risk
14 assessment.
15 MS. WORTH: Okay, thank you. Those were my questions.
16 I'm not sure my co-counsel or Mr. Bell have any
17 questions of their own. I'll defer to them.
18 MS. MIS: Good afternoon, it's Irina Mis. I don't have
19 any additional questions. Thank you.
20 MR. BELL: Hi, it's Russ Bell. I don't have any more,
21 I will ask them in IRs.
22 MR. CHERNIKHOWSKY: Okay. How about any questions from
23 BCUC staff?
24 MS. SIMON: This is Nicola Simon. We don't have any
25 questions at this time. Our questions are better
26 suited to IRs. Thank you.

1 MR. CHERNIKHOWSKY: Thank you, Ms. Simon.
2 MS. BEVACQUA: So now it's over to the panel.
3 THE CHAIRPERSON: So, I'm going to invite my fellow
4 panel members to pose any questions that they may have
5 and then I do have one question after that. So,
6 Commission Morton?
7 COMMISSIONER MORTON: I would just echo what Mr. Weafer
8 just said. Thank you for an informative presentation,
9 much appreciated. I have no further questions, at
10 least that would be appropriate at this time. So, on
11 that note, I'll say thank you very much.
12 THE CHAIRPERSON: Thank you. And Commissioner Brewer?
13 COMMISSIONER BREWER: I actually do not have any
14 questions. I appreciate the presentation, it was very
15 good, and I'll look forward to asking some -- or
16 having input into some IRs probably at a later date.
17 THE CHAIRPERSON: Thank you very much, Commissioner
18 Brewer.
19 Now, I just have question and I don't know
20 who best to pose it to, maybe it's Ms. Roy or perhaps
21 Mr. Doyle. And it relates to a comment that was made
22 by Mr. Oliphant with respect to the relative risks
23 between the Coastal transmission system and the
24 Interior transmission system. And I think you
25 indicated that of the 12 pipelines that were looked at
26 or analyzed amongst the 35 in the Interior system,

1 nine of them actually shared the similar risks that
2 were found to exist in the Coastal Transmission
3 System, with the remaining three being excluded from
4 that list because of their relatively newer age and
5 the coating that was used in those pipelines.
6 **Proceeding Time 3:34 p.m. T32**
7 And I guess my question to you is that
8 based on what we've seen today and the assessment of
9 the total safety risk and the average safety risk for
10 these types of pipelines, are we to anticipate a
11 similar application coming down shortly or within the
12 next few years for the Interior Transmission System?
13 And if so, what might be the expected capital cost of
14 such a project, which obviously is not included
15 amongst the list of projects for which Ms. Roy
16 provided an overview of the overall rate impact?
17 MR. DOYLE: I can speak to the ITS TIMC project. It is
18 under development right now. We are looking -- there
19 are the -- we are looking at the pipeline stress
20 susceptible and we are developing plans as to what
21 needs to happen in terms of alterations to the system,
22 to similarly make them ready for EMAT ILI tools.
23 We're looking to have that application
24 submitted to yourselves in early 2022. And as for the
25 capital costs associated with that, we haven't
26 finished our cost estimating exercises yet but we

1 expect it to be a similar order of magnitude as the
2 CTS TIMC application.
3 THE CHAIRPERSON: And is there a reason why we decided to
4 do this in two tranches? In other words focusing on
5 the Coastal System first with the 13 and then
6 presumably the 9 to follow next year in the Interior?
7 MR. DOYLE: Absolutely. Mainly it was due to -- the CTS
8 had that higher level of risk and it was shown that
9 the risks to the CTS system were more focused on those
10 cracking threats. I think they were the first and the
11 third highest ranked, if I recall correctly from Dr.
12 Oliphant's presentation.
13 The ITS, it was less risk than the Coastal
14 Transmission System, so we decided to focus on the
15 Coastal first while working on the ITS. Yeah.
16 MR. CHERNIKHOWSKY: Yeah, I think I would just clarify a
17 little bit there. It wasn't so much that we --
18 decided implies that it was discretionary.
19 MR. DOYLE: Sorry.
20 MR. CHERNIKHOWSKY: What we were saying is that the
21 consequences are higher for the CTS pipelines. I
22 think we all recognize that in the Coastal
23 Transmission System area populations are higher,
24 there's more development around the pipelines and so
25 given that risk equals probability times consequences,
26 since the consequences are higher in the Lower

1 Mainland, that's what drove the need to pursue the CTS
2 work prior to the ITS work.
3 THE CHAIRPERSON: Okay, thank you very much. That is my
4 last question.
5 Okay, if I hear no other or see no other
6 hands up, I can safely adjourn this workshop. But
7 before I do that I just want to thank Ms. Roy as well
8 as the other presenters from FEI for spending your
9 afternoon, what is a beautiful afternoon, with us and
10 educating us about this very interesting CPCN
11 application. I've learned lots, so I really
12 appreciate your patience and your willingness to share
13 your knowledge with all of us and your willingness to
14 answer our many questions actually, throughout.
15 I want to thank Mr. Chernikhowsky for
16 fielding the question session at the end. Ilva for
17 facilitating the entire workshop and Ms. Joly for your
18 efforts and persistence with the two videos. You
19 deserve a lot of praise and you're obviously a very
20 patient person, more so than I am.
21 MS. JOLY: Thank you.
22 THE CHAIRPERSON: Just want to thank all of you, the rest
23 of us who attended this workshop and for your
24 indulgence and I just want to thank you for taking
25 time out to share in this workshop and I want to wish
26 you a great afternoon and just want to say thank you

to FEI. You're way ahead of schedule. It's only 3:38. So you get to have a back a couple of hours of your day to go out and enjoy the sunshine.

So take care everyone and thank you to Allwest Reporting for sticking with us to the end and I'm sure we'll be seeing each other, hopefully, in person soon. So take care. Have a wonderful afternoon.

(PROCEEDINGS ADJOURNED AT 3:39 P.M.)

I HEREBY CERTIFY THAT THE FORGOING is a true and accurate transcript of the proceedings herein, to the best of my skill and ability.

A.B. Lanigan, Court Reporter

May 13th, 2021