UNITED STATES OF AMERICA

NATIONAL TRANSPORTATION SAFETY BOARD

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Investigation of: *

ENBRIDGE - LINE 6B RUPTURE IN MARSHALL, MICHIGAN * Docket No.: DCA-10-MP-007

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Interview of: TOM ZIMMERMAN

Enbridge Headquarters
Edmonton, Alberta
Canada

Monday,
December 5, 2011

The above-captioned matter convened, pursuant to notice.

BEFORE: MATTHEW NICHOLSON
Investigator-in-Charge

APPEARANCES:

MATTHEW NICHOLSON, Investigator-in-Charge
Office of Railroad, Pipeline, and
Hazardous Materials Investigations
National Transportation Safety Board
[redacted]

RAVINDRA CHHATRE, Chair
Integrity Management Group
National Transportation Safety Board
[redacted]

MATTHEW FOX
Materials Lab
National Transportation Safety Board
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BRIAN PIERZINA, Accident Investigator
Pipeline and Hazardous Materials Safety
Administration (PHMSA)
[redacted]

JAY JOHNSON, Supervisor
Audits and Inspections
Enbridge Pipelines
[redacted]

# I N D E X

I N T E R V I E W

MR. NICHOLSON: This is NTSB Pipeline Case No. DCA-10-MP-007, Enbridge Energy July 2010 crude oil release in Marshall, Michigan. These are the Integrity Management Group interviews being conducted at the Enbridge Headquarters in Edmonton, Alberta, Canada.

Today is Monday, December 5th, 2011. This interview is being recorded for transcription at a later date. Copies of the transcripts will be provided to the parties and the witness for review once completed.

For the record, Tom, please state your name, full name, with spelling, employer name, and job title.

MR. ZIMMERMAN: Name is Tom Zimmerman, Z-i-m-m-e-r-m-a-n; my employer, Enbridge Pipelines, Incorporated; and my job title is director of operation services.

MR. NICHOLSON: And can you give us your title at the time of the accident, July 2010?

MR. ZIMMERMAN: In July 2010, my title was program manager, system integrity.

MR. NICHOLSON: Okay. Thank you. For the record, please provide a contact phone number and e-mail address that you can be reached at.

MR. ZIMMERMAN: Phone number [redacted] e-mail [redacted]

MR. NICHOLSON: Tom, you're allowed to have one other person of your choice present during this interview. This other person may be an attorney, friend, family member, co-worker, or nobody at all. If you would, please indicate whom you have chosen to be present with you during this interview.

MR. ZIMMERMAN: I didn't choose anybody, but Jay will do.

MR. NICHOLSON: We'll now go around the room and have each person introduce themselves for the record. Include your name, with spelling, your employer's name, and contact phone number and e-mail address.

I will start. Matthew Nicholson, M-a-t-t-h-e-w, N-i-c-h-o-l-s-o-n. I am the NTSB IIC on this investigation. My phone number is [redacted] I can be e-mailed at [redacted]

MR. FOX: Matt Fox, M-a-t-t, F-o-x, NTSB Materials Lab, [redacted]

MR. JOHNSON: Jay Johnson, Enbridge Pipelines, [redacted]

MR. PIERZINA: Brian Pierzina, B-r-i-a-n, P-i-e-r-z-i-n-a, [redacted], and my e-mail is [redacted]

MR. CHHATRE: Ravi Chhatre. I am Integrity Management Group chair, assisting IIC Nicholson. I'm with NTSB. My telephone is [redacted] E-mail: [redacted]

INTERVIEW OF TOM ZIMMERMAN

BY MR. NICHOLSON:

Q. Okay, Tom, to begin with, just so we get a better idea of what it was you were involved with, could you go back and just give us a little bit of history, what your background is, positions you've held within Enbridge, educational background, that sort of thing?

A. Sure. I've got a bachelor of science degree from the University of Alberta in civil engineering and a master's degree from the same place, also in civil engineering, and a Ph.D. from the same place, also in civil engineering.

Prior to Enbridge, I worked for almost 21 years for a engineering research company named C-FER Technologies that's in Edmonton. They do work primarily for the energy industry, and pipelines was a big part of what they did, and I was involved in pipeline work then.

I joined Enbridge in March of 2006 as an integrity engineering specialist. In February of 2007, I became supervisor of the materials technology group. In August of '08, I became manager of the Line 3 project. In August of '09, I became manager of pipeline integrity programs and technical services. And in June of 2010, I became the program manager for system integrity, which is the position I held at the time of the Marshall incident.

Q. Go back. You said you were on a -- 2008 you were on a Line 3 project?

A. Yup, the --

Q. Can you expand on that? What was that?

A. Sure. Line 3 is tape-coated line that runs from here to Superior. It has more than its share of corrosion issues because of the tape coating on that line. And there are -- we were looking ahead as to what kind of work would need to be done on that line in terms of repairs and replacement, and we were considering various different options. So, my role as the Line 3 project manager was to determine what the -- well, to establish some options for how we might want to treat that line in terms of maintaining operating pressures on the line and predicting how many repairs there might be in the years 10 -- 5, 10, 20 years going forward, to try and develop a strategy that made sense for how we would -- what we might like to do with that line in terms of repair, replacement, that kind of thing.

Q. You say it's a tape-coated line. So what kind of -- what issues was Line 3 having? Was it SCC or --

A. I don't know what -- I don't think there was any SCC on Line 3. Actually, I can't remember that. I'd have to look that one up. It wasn't one of the bigger problems. The two issues that have plagued Line 3 over the years have been, because of the tape coating, corrosion, selective seam corrosion, where the tape coating tents, and also cracking issues. Line 3 has cycled fairly heavily from time to time, and that can promote fatigue crack growth. Those are the two biggest issues that we needed to

address on Line 3.
Q. Okay. And to manage those threats, what kind of programs were in place?
A. The usual programs that we run are running ILI tools. To manage the external corrosion and cracking problems, run ILI tools, find the defects, conduct digs, and repair the pipe, usually with sleeves, or if the damage is found not to be that severe, then just a recoating job.
Q. Which ILI tools were you using on 3?
A. The whole suite, so magnetic tools for corrosion and ultrasonic tools for corrosion and ultrasonic tools for crack detection; principally GE's tools, so the GE USCD and the GE whatever they call the rest of them. I sort of forget the names of them now, their magnetic tool and their ultrasonic tool for corrosion. And we've run other people's tools in that line as well, but I'd have to actually look and see which ones and when and whatnot.
Q. Okay. And why is Line 3 so problematic? You mentioned the coating. Is it soil conditions, any other kind of contributing factors?
A. No. That's primarily -- it's a tape-coated line, so Line 3 does, you know, suffer from breakdowns in coating and -- which is why we have a fairly aggressive ILI program on that line.
Q. Okay. And then you said 2009 you were in the pipeline integrity services group; did I get that right?

A. I was the manager in pipeline integrity of programs and technical services. So those are two quite different groups. The programs part of that is the group that at that time looked after the digs, so looked after taking the ILI data that came in and developing dig packages to be issued to another part of the programs group. And that part of the programs group would then coordinate the digs that were actually going to take place in the region. At the time, we were also transitioning that work, that programs work to the engineering group, and that's where it resides right now.

The other part of the group, the technical services group, had a variety of jobs. Pipeline integrity frequently gets asked to help other parts of the company to look at integrity issues. And so as not to take time away from the core people who are looking at ILI data and making decisions on taking action on the lines at interest, that technical services group would help those other parts of the company. For instance, looking at new acquisitions, you want to buy somebody else's pipeline, and they want to come and let you have a look at the data they've got and ask questions and give some advice on what shape it's in, and that kind of thing. So those are the activities that the technical services group undertook.

Q. Now, we were talking to Steve Irving, I thought, and he mentioned that you had done some -- you were brought in, I thought, for failure analysis?

A. Yup. Actually, the technical services group, one of their -- one of the things they provided people for was failure analysis. When we would have an issue, the staff would come from that group, and that was -- that's probably a good part of what I've done since coming here. And in all of the roles I undertook, I would be involved usually in some capacity on many of the investigations we were undertaking.

Q. Okay. So as someone that's been involved with the failure analysis on other lines, have you seen anything similar to Marshall that would have been an SCC or corrosion fatigue-type failure on a different line, or even Line 6B?

A. No. I actually hadn't seen an SCC failure. As I say, I think in our history, there have been some in the past that were maybe perhaps called that. I remember one NEB failure on Line 3, actually, I think, that was referred to as SCC, but there was some dispute. We had two different consultants. One said it was; one said it wasn't. And I think in one of the NEB documents it's listed as an SCC failure, but in other documents, it's not. So it was never quite clear what the -- it wasn't the same, quite the same mechanism as this. It was much deeper corrosion, with maybe some cracking at the bottom of the corrosion feature.

Q. And I've looked through some of the Transportation Safety Board Canadian reports, and it seemed like there were actually a lot on Line 3 that were considered to be maybe SCC initiated and corrosion fatigue propagated. Are you familiar with any of those reports?

A. I don't know that there are a lot that are SCC initiated.

Q. Okay.

A. There are certainly a lot that are corrosion initiated.

Q. Okay.

A. So there were some -- there were a number of failures on Line 3 where slight corrosion at the weld toe seemed to be a bit of a trigger for cracking taking place, not stress corrosion cracking but fatigue cracking.

Q. Okay. So in 2010, then, you became program manager for system integrity?

A. Yup.

Q. Okay. Can you talk a little bit about that?

A. Yup. That was a new position created, again to unburden the regular group that was looking after -- evaluating our ILI data and making decisions on all of our lines. And the idea was that that position would focus more on some of the bigger projects we had like Line 6B and like Line 3, where there was the potential for a lot of work and the potential for perhaps taking a different approach to it rather than simply finding and fixing; trying to decide if it made some sense to reduce pressures and lower throughputs, and whether that was compatible with the throughput forecast we were seeing and the way we wanted to ship products on our lines. And so it was really to -- a position that would do more talking to other parts of the company to be sure we were bringing an understanding of what we needed to do with our lines into the integrity world and make decisions accordingly.

So I started that in June of 2010. Marshall happened at the end of July in 2010. So I didn't get very far into that position before I was pretty much full time on Marshall for the rest of that year anyway.

Q. So you had only been involved in the Line 6B replacement project since June; is that correct?

A. Correct.

Q. Okay. So can you talk about the Line 6B replacement project, how far -- I mean what the --

A. Yup.

Q. What were the ideas, where were they going with that --

A. So when I got there, there -- you know, we understood there were a lot of corrosion features on Line 6B and there would be a lot of work coming up in the future. The main area of concern was between Stockbridge and Sarnia, where the corrosion density was actually more severe than elsewhere on the line. And there was a proposal put forward -- there had been some analysis done and a proposal put forward to replace, I think, about 19 sections of that line between Stockbridge and Sarnia.

So I inherited that when I got there. And my role was to look over that analysis and just kick the tires on it and see if it still made sense and see if we could refine it at all, with the strategy being if there were a lot of features that currently existed in a segment and we were predicting into the future 5, 10 years and -- you know, for given corrosion growth rates and whatnot, if we thought there would be so many more digs in that section, the cost would be so much to repair that, and it might make more sense to replace that section than just keep doing all the digs.

So we were -- we played a lot with that analysis to try and make some sense of that, and also thinking about did you really want to have, you know, five short replacement segments and a short length or do you just want to go in and replace the whole length. So those were the kind of options we were toying with. But as I say, our focus was mostly downstream of Stockbridge because that's where the higher density of features was.

Q. Yeah, nothing at Marshall would have prompted this sort of analysis?

A. Well, I mean, on the upstream side of Stockbridge there are, you know, there are corrosion features as well. It's not that there were none there. But on that side of Stockbridge, it was felt that we could handle the volume of working simply by running the tools, finding the defects and doing the repairs.

Q. Okay. And those 19 sections, those were primarily corrosion defects?

A. They were.

Q. Okay.

A. They were all, actually, corrosion defects. Again, not to say there weren't some cracking defects that were located. We were running those tools. And in certain parts, there actually were higher densities of cracking as well, and we thought about that in terms of which sections we wanted to replace. But the real driver in the economic analysis we were doing was the corrosion, understanding what we were doing was not deciding what we needed to fix now but deciding what we might need to fix 5, 10, 15 years out, which requires a predictive model to so that. And we weren't so much trying to decide if that feature there would grow through wall, but how many features there might be in a given length.

So we had played with actual features using corrosion growth rates that we knew were sort of averages. Some would grow faster, some would grow less fast, but that would give us an estimate of the numbers we'd need to repair. So we weren't predicting which one we'd have to repair, but just how many we'd have to repair. And then as we ran the tools over time, we'd find out which ones we actually had to repair. So that's what that analysis was about, really, predicting into the future the volume of working and trying to decide if it made sense to do some replacement instead of repair.

Q. Okay.

A. And the driver there was corrosion because of the numbers of corrosion features we were seeing that would be coming up.

Q. So you weren't involved with the other work, the ILIs -- the 2004 ILI and the 2007 and the reissues and any of the drivers?

A. Well, I'd have been -- I was the supervisor of materials technology from February of '07 to August of '08. And the materials group is the group that analyzes the cracking issues. I don't particularly remember then whether -- you know, 6B is something we'd have run some tools on. I don't remember it being more of a concern than anything else, and it would have run through our -- the normal process with our -- with a supervisor who looked after that part of it and with other part of the company that would be organizing the tool runs and whatnot. So I wasn't completely divorced from it before that, but it wasn't -- it didn't have any higher priority than any of the other work we were doing.

Q. That was 2007 that you were the supervisor?

A. Yes.

Q. Okay. So you wouldn't have seen the 2004 --

A. Not necessarily.

Q. -- baseline?

A. Yeah.

Q. But you would have been involved in the reissues on the 2007 MFL run?

A. Well, I was the supervisor of that group at the time, right?

Q. Okay.

A. I would have seen them somehow or another.

Q. And can you talk a little bit about those reissues and what was driving it? I think we heard from someone else that the first was maybe a data overload?

A. Actually, I can't. I'd have to go and look up. I don't recall.

Q. Okay.

MR. PIERZINA: Real quick. You said you were responsible for the materials?

MR. ZIMMERMAN: Yes.

MR. PIERZINA: Is that cracking and corrosion or just cracking?

MR. ZIMMERMAN: No. That's just cracking.

MR. PIERZINA: Okay.

MR. ZIMMERMAN: It's cracking and welding and -- they always had two group -- it was a kind of funny name, right? One group was the corrosion group, which made sense. The other was materials group, which looked after cracking and some other stuff, so --

MR. NICHOLSON: Ravi, you want to go ahead?

MR. CHHATRE: Yeah.

MR. JOHNSON: Brian, do you have any questions? Oh --

MR. CHHATRE: I'll remember that. (Indiscernible) get you for that.

BY MR. CHHATRE:

Q. Question. On these -- the final decision, who made that on this project as to repair or replacement?

A. Which project are you talking about, 6B?

Q. Talking about 6B.

A. Well, we hadn't actually got to doing the replacements, so we were still talking about what it is we wanted to do. I would have made a -- probably did make a recommendation about what I thought made sense in terms of replace versus repair. And that would have been a recommendation that would have gone to my boss at the time and then, ultimately, to his boss, and that's how a decision would have gotten made.

MR. JOHNSON: Who would that have been at the time, do you remember?

MR. ZIMMERMAN: My boss was Steve Irving and his boss was John Gerez.

BY MR. CHHATRE:

Q. So I guess I'm trying to find out where in the hierarchy somebody will make a final decision and say, okay, either do it or don't do it; how far up it has to go beyond you?

A. I guess John Gerez would ultimately have given his approval for that.

Q. And that -- what would be his title?

A. He was the vice president of engineering and integrity. I think that was his title at the time.

MR. JOHNSON: I believe you're correct.

MR. NICHOLSON: Can you spell his name? I'm not hearing the last name.

MR. ZIMMERMAN: J-e-r-e-z [sic].

Understanding how those decisions get made, right? People were doing analysis that I was looking at and providing some comments, and then I was doing some more analysis and making some recommendations. And you know, my boss and his boss would ask questions about what we'd done, and they didn't dig into the analysis in detail because that was our job, right, but they certainly would ask us questions about whether or not the recommendations we were making made sense.

BY MR. CHHATRE:

Q. Your decision will be based on what factor? Is it commercial factor or was it --

A. Sorry?

Q. The repair or replacement decision, is it based on economic decision or is it technical decision, or how did that work?

A. Well, it's both, right? We -- I mean, to decide -- the predictive model that says how many defects we think we're going to have to fix is a technical model. So it would take existing corrosion defects. It would grow them at a certain rate, certain average rate, again, understanding we're not trying to decide when any individual defect's going to be repaired, but we want to know numbers in a certain area.

So the technical model would predict growth rates. It would use a -- it would have embedded in it a model that would calculate failure pressures. We'd look at maximum operating pressures and use the technical -- the criteria we had to decide when in time a repair might need to be fixed, and that's how we'd add the numbers up.

You then took that, those numbers of defects, and used an average dig cost -- and dig costs can be all over the map. Some are $5 million if you've got a lot of wet work, and some are $50,000, right? But we'd use an average dig cost, again, that we had over time. And we'd decide, well, if there's 200 digs in a given section and the average cost is $200,000 a dig, then that's so much money. And if we actually replace that section, a part of that section, that would get rid of this many digs, which means instead of spending money over 15 years on those digs, we'd be spending money up front on a replacement. And then there's some -- you know, the cost-benefit that goes along with that. So ultimately, it's an economic decision based on a number of different valid technical options.

Q. Those technical options are given to you by who?

A. I guess the technical options would be options that I would agree with based on discussions with others. I mean, there's only so many things you can do, right? You know you can replace. You know you can conduct digs and repair. So really those are the two main options.

Q. I guess you just mentioned that you are not looking into future as to within 5 years, does the pipe -- the crack will run or will not run. I guess my question is you were told that a certain number of locations you may have to dig. And my question is who was providing that information to you before you start your economic analysis?

A. Well, so we would get date from an ILI run, right, or from several runs, so --

Q. We, meaning your group or, we, meaning Enbridge?

A. I'm meaning Enbridge, the pipeline integrity group, right?

Q. Okay.

A. Would get the ILI data.

Q. Okay.

A. And through our normal process of analyzing that data and deciding what needed to be dug right now or this coming year, right, there's a lot of data in there that would say, well, here's a whole bunch of features that we know are there, but they're not big enough, they don't -- their RPR values are above 1, so they don't need to be dug right now, but if you grow those features, you know they might need to be done in the future -- dug in the future. You'd never make a decision now to actually dig that feature in the future because you don't really know what the growth rate is.

Q. I understand.

A. Right.

Q. Who was making that projection or the decision that this feature may require future --

A. Well, the model we were using was making the projection. I was involved in helping develop that model. And we were -- I was working with people in the integrity group to establish what we thought were reasonable corrosion growth rates based on some analysis of past data, and whatnot. And we grew -- the model actually grew two different things: It grew the depth of the feature, and it also grew the RPR of the feature, because those things can be quite different and they're two different triggers. A defect can be very short, in which case it won't lead to a rupture, but it could still lead to a leak. So some defects you'd -- some defects would exceed that criteria in time if you grew them, and others would exceed the rupture criteria in time if you grew them just because of their size, and whatnot.

So I was fully aware of the models that they were using that were in that and, you know, agreed with those models. But they're models that Enbridge has used -- Enbridge's pipeline group has used for years.

Q. We, meaning ILI group --

A. Yeah.

Q. -- came and told you that there are so many digs we project in 3 years, so many digs we project in 5 years?

A. Well, actually, Ravi, I had my own little spreadsheet, too, that did that. There were other people also doing the same kind of work. I often used my own little spreadsheet just so -- to kind of double check what was coming back from them to be sure I understood it, because I knew exactly what went into mine, and that's just the way I do things, but -- so I was fully familiar with the models that were in there and what they were doing --

Q. So and those numbers kind of matched --

A. Yup, yup, they did, yup. And if they didn't, we'd try and find out why and sort of that normal process.

Q. Change the subject little bit, going back to Line 3. You said there are a lot of corrosion concerns with Line 3 that you're the project manager of. Can you tell me what the pressure ranges were for Line 3 and the age of the pipeline?

A. I don't know. Line 3 is '50s vintage. I'm not exactly sure -- or I guess a lot of it's '60s.

MR. JOHNSON: Sixties.

MR. ZIMMERMAN: Well, some of it's actually '67 as well, now that I think of it. Line -- so, yeah, Line 5 is '50s vintage. Line 3 is in the '60s -- '67, '69, not sure about '70s.

But anyway that -- and that's the vintage -- that's -- those are the years when they were actually tape coating pipes, right? That's why that's a tape-coated pipe.

BY MR. CHHATRE:

Q. Did they come from the same manufacturer or -- like Line

6B or their manufacturer was different?

A. 6B has got lots of different manufacturers on it. We could hand you a document that would tell you exactly how many different mills are used on that line --

MR. JOHNSON: I think we have given them --

MR. ZIMMERMAN: Some of it's long seam, some of it -- I don't think any of it's spiral.

MR. NICHOLSON: I thought it was just two: A.O. Smith and Mattel Sauder (ph.), or whoever --

MR. JOHNSON: I don't remember. I just knew the line had --

MR. ZIMMERMAN: No, I --

MR. JOHNSON: That's information we've provided, so you do have that.

MR. CHHATRE: Okay. All right.

MR. ZIMMERMAN: Yeah. I recall some maps in Canada, maybe some more different mills than in the U.S. In the U.S., it might have been a couple of primary mills. I sort of forget. But we've got some maps that show exactly where all the pipe types are.

BY MR. CHHATRE:

Q. That's okay. I got the information, we can go back and look --

A. Yup.

Q. Now, with Line 3B -- or Line 3, were there ruptures, leakers or --

A. Oh, both.

Q. And what kind of ruptures you had? Were like what I consider total shear-type rupture, total rupture or a fishmount (ph.) or they are leaks?

A. Well, the -- well, again, both. We've had leaks on Line 3.

Q. Okay.

A. We've had ruptures on Line 3. The ruptures I can think of tend to look much like 6B, not in terms of -- I mean, 6B was surprising to me when I first looked at it because of the rupture being a little bit away from the girth weld. When I crawled into that ditch, I assumed it would be -- not the girth weld, sorry, the long seam weld. I assumed it would be on the long seam weld just because I knew the long seam weld was close to where that rupture was. And my own experience at Enbridge, which isn't vast, recall I started in 2006 -- but I had had an opportunity to go back and look at some of the old failure reports. That's just something we did. When we had an issue on Line 3, we'd go back and look at previous failures on Line 3. And the primary cause of ruptures on Line 3 was actually fatigue, and that usually happens at the long seam, whether it's an ERW long seam or at the toe of the weld or the -- of a double submerged arc-welded long seam. Those tended to be the ruptures, not exclusively.

The leakers tended to be some fatigue-initiated leaks as well, where you'd get a small crack that would go through wall but not extend, and some corrosion leaks as well, and then some mixed, like you mentioned before. There were some where -- I recall one, and I don't remember which, you know, milepost, but where there was quite aggressive narrow corrosion at the weld toe that then cracked in the bottom of it. But I think it was, you know, 60/70 percent through-wall corrosion.

There were others where you couldn't see the corrosion unless you used the magnifying -- you know, unless you used -- cut a cross-section and looked at it very closely. And so really the corrosion didn't have a lot to do with it; it was primarily a crack being driven by fatigue and by the environment, obviously, as well, because the adverse environment that -- the breakdown of the coating line also can accelerate the crack growth just because of that being present.

Q. And was a study done at that time to replace portions of Line 3 instead of repairing it or was that study done -- like, being done --

A. We were doing that study, and we actually hadn't decided to replace any sections of Line 3 at the time. It was being talked about, for sure, but Line 3 also at the time was in mixed heavy/light service. And when -- in deciding -- looking into the future, it was decided we could likely switch that line into all light service. And in doing that, we could also maintain adequate throughput volumes by dropping pressures on the line. And as soon as you drop pressures on the line, then that changes your, you know, what fails your dig -- changes what you need to repair, or at least it delays it in time because suddenly a feature that might fail your RPR criteria, if the operating pressure is lower, it doesn't fail it now, and it might fail it down the road at some point if it keeps getting worse, but that can change that equation as well --

Q. I'm going to go back to the dig package. What did the package contain actually?

A. Oh, the dig packages contained ILI information. It shows a map of the sections to be repaired. It shows what features are on the -- that were found on the line now and in past inspections. What else does it contain? Location data, you know, the milepost and measurements from various surface features they might be able to find to help them locate it, and whatnot.

MR. JOHNSON: We'll be able to show you one of those.

MR. ZIMMERMAN: Yeah --

MR. CHHATRE: Okay. Yeah.

MR. JOHNSON: Some of the other people --

MR. ZIMMERMAN: Fairly standard.

MR. CHHATRE: Some of these, yeah.

MR. ZIMMERMAN: Some of them are quite big documents, you know, just depending on what information is there that's required.

BY MR. CHHATRE:

Q. Do you guys have any interaction with the risk management or integrity management group when you prepare the dig packages or making -- selecting these locations?

A. The risk management group --

Q. I mean procedure-wise. You might have informal, but I mean, was there a procedure in place that you guys would be consulting with them on these issues?

A. No. The risk management group didn't have anything to say about which digs we were actually going to repair or which features were found with ILI that we were going to repair. That was a deterministic calculation based on what we found and what the assumed properties were of the pipe like, again, based on its known yield strength and wall thickness --

Q. So that was your group's decision alone as to where to dig?

A. As to where to dig? Yeah. We -- that group would decide -- the materials group and the integrity group would make decisions on which features actually required repair.

Q. And how did that interaction take place procedure-wise? I mean --

A. Well, when the ILI data comes in, the programs group has people who spend some time checking to be sure that the data looks reasonable and that the -- they've met certain criteria with respect to what should be in the report that comes from the ILI vendor. And from time to time, they get sent back because they realize they've mucked up the milepost numbers or something like that; there's some issue there. So things can get sent back. And so there's a check there.

Once we -- once the data is in good enough shape that we know it's -- or that we believe it to be accurate, then it goes to another group of analysts who would -- usually using, you know, programs, Excel spreadsheets, and whatnot, would go through and --

Q. When you say we, we meaning the materials group or we meaning --

A. Yeah, materials group.

Q. Okay.

A. And so the materials group would -- has analysts who would go through that data and do calculations to determine for a crack what the failure pressure is for corrosion, what the failure pressure is, and also look at the criteria for depth of corrosion. And out of that analysis, you flag the features that are required to be repaired based on their failure -- predicted failure capacity based on the models you have.

And anything that fails that repair criteria is subject to being dug. Or I mean, there's a few loops in there, because we start by doing -- for cracking, for instance, we start by assuming that the maximum depth is the -- holds for the entire length of a crack, and so that'll fail a lot of features. You can then ask the vendor to give you profiles of those cracks. And when you look at the profiles, that's a little less conservative, gives you a more realistic, hopefully, estimate of what the failure pressure is so you can actually loop through. It might flunk one check, and if you come back and do something more sophisticated, it would pass that check, in which case it wouldn't be dug. But this is -- these are pre-determined criteria for establishing when you need to repair something and when you don't and they're based on regulations and codes and sometimes our internal criteria piled on top of that.

Q. So this dig really -- once your group makes that decision, does it go back to integrity management group for their input procedure-wise or not?

A. No. I mean, who's the integrity management group? They're --

Q. From what I understand, and correct me if I'm wrong here, that integrity management is separate group. Your group was a separate group, and the --

MR. JOHNSON: Well, that --

MR. ZIMMERMAN: Well --

MR. JOHNSON: They are the integrity management group.

BY MR. CHHATRE:

Q. No, integrity and I thought risk management was together before Enbridge -- I mean before the incident. But materials group was separate.

A. Pipeline integrity contained -- it was a little bit easier -- it was a little more straightforward just before I got there, actually, because we had a single manager of pipeline integrity -- we had a director of system integrity, and then we had two managers:  pipeline integrity and facilities integrity. Under pipeline integrity, there was a corrosion supervisor, looked after the corrosion ILI and that kind of thing.  There was a materials supervisor who looked after the cracking issues.  What else did we have?  We had a program manager who looked after getting the digs done, and whatnot.

Q.   Right.

A.   I forget if we had another one or not, but -- so that's how it broke down.

Q.   So the two groups that I see are an ILI group -- integrity management group and a materials group.  They may be under the same director, but they are two separate --

A.   Well, no, there was no integrity management group.  That is the integrity management group.  The integrity management is undertaken by pipeline integrity.

Now, the structure is a little bit bigger now, right? And there are different branches to it, and I'm not the best guy to ask about that because I'm not in that group.

Q.   Now, if the ILI -- when ILI is done and there are some immediate alarm -- I guess I'm using this term loosely -- information, do you guys start work on it right away as to whether the dig is needed or you still have to wait for -- because earlier you said, you know, you wait --

A. No.
Q. -- until the whole data is kind of massaged and --
A. Nope.
Q. -- then you decide to dig?
A. In fact, our ILI vendors are instructed to phone us if they find anything alarming. And they do that sometimes. They'll phone up and say we found something that looks like it's off the charts for depth and you might want to get somebody out there right away to look at it. So we typically gather people together right away. We typically put a pressure restriction on the line at that point. We'd ask for more information from the vendor as quickly as we could get it. And we might make a decision to send people out and actually dig that location. And that would be all before we got any detailed reports back from the ILI vendors.
So that happens from time to time. It's not frequent, but it can happen. But the more usual thing is to get the report and analyze the information once the report is in, because then it's gone through all its QA, and whatnot. But anything that looks really bad, we would take action with right away.
Q. So your dig would really involve when some kind of a resolution was needed, either repair, replacement, sleeve, whatever? Did you do any verification digs? If the tool's showing me something and I want to check and see if --
A. Sure.
Q. And that's your group or a different group?

A. No. The materials group that I was the supervisor of, who were the people who were in charge of analyzing the cracking data, for instance, if -- in going through the list, they would be identifying what they thought needed to be repaired based on the criteria they had. They also might find some features that the ILI vendor, you know, thought looked odd or they were a little inconclusive about what kind of feature it was or -- you know, some are cut and dry and some aren't, right? So we -- the materials group would sometimes look at some of those features and say, look, we should actually go dig a couple of these just to see what they are because the ILI call seems a little bit different than all the rest of these things and we don't really know what they're getting at. So those would be put into the verification dig sometimes.

Some lines where there wasn't -- where there -- newer lines where there wouldn't be a lot of features, you'd go and do some digs anyway. I'm thinking of when we ran an ILI tool on Line 19, which is only 10 years old, and it came back pretty clean. There wasn't much to dig. But you always want to go out and do some digs just to verify the accuracy of your tool, right? So then we do verification digs. If there are a lot of digs we have to do anyway, there'd be no reason to do verification digs because you're getting verification in the ditch on the repairs you're doing as well.

Q. Did I understand you correctly that corrosion group is

different than the -- your --
A. The materials group?
Q. -- materials group?
A. Yeah. They're two separate groups that are under the same --
Q. Right.
A. -- management.
Q. So who will do the digs for them, dig packages or digs --
A. Yeah.
Q. -- who will do that for them?
A. Same guys. Those are different groups in terms of analyzing the data because you build up some expertise on corrosion and the models that are associated with that, and you dig up another -- you build up another set of expertise under the cracking problems -- people go back and forth sometimes, and people have knowledge of, you know, cross-technology knowledge, right? They're not isolated.
Q. I guess I just wanted --
A. But the digs themselves, once you decide to do a dig, then it goes to the programs group, and the programs group would coordinate actually doing the digs. And the programs group doesn't care if it's a crack dig or a corrosion dig. You know, they're just organizing digging the pipe up and doing some field assessment and getting the sleeves on.

Q. So programs group actually does the digging, right?

A. Well, they -- no, they don't physically go up there and do it with a shovel, but they're the ones who coordinate that with the operations people in the field --

Q. Right.

A. -- who hire contractors to come in and --

Q. Right. They are the ones who are responsible to make sure the dig is done at the location that is being recommended?

A. Correct.

Q. My question is, like, you prepare the dig package, if you would, for crack. Who does that for the corrosion group? When they see a lot of corrosion, there may not be a crack, but who -- but they would --

A. The same guys. I mean, understanding a dig package is really about telling you which joint to dig up and tell you what you're looking for. And in a dig package, there'll be information on -- you might be going after a corrosion feature because it's the corrosion feature that flunked whatever criteria it had. So the corrosion group has said go and dig at this spot because from what we can see in the ILI data, there could be a bad feature there that needs to be repaired. When you put the package together, of course, you'd identify that feature. You'd also identify whatever other features were on the line. And there could be other crack -- there could be some crack features on the line. They'd be crack features that haven't flunked a criteria for digging because otherwise they would have, you know --

Q. So you --

A. Typically -- but you'll know what's on the line. The dig package will say here's the joint you're uncovering, here's what we saw in 2004 at that point, here's what we saw in 2005 at that point for corrosion, here's what we saw from the cracking, so that the guys who are out in the ditch know what might be there when they start looking.

Q. So your group would do the corrosion package also for the dig?

A. Yes, because there's really no difference between the corrosion dig package and the crack dig package. They look the same.

Q. So how would the corrosion group contact you to prepare a dig package? What is the procedure for that?

A. The corrosion group would send me a list of features, a list of joints, that needed to be repaired.

Q. Okay.

A. And the cracking -- or the materials group would --

Q. So when --

A. -- do the same thing for cracking. And ultimately, when they've identified the joint that needs to be repaired and the feature that's causing that, then the programs group, who's in charge of looking out -- preparing the dig packages and doing the -- getting the digs organized, would go in and look at all of the

data that's there so they can provide all that on the dig package.
Q. You said program group was under your supervision?
A. It was from June of 2000- -- no. It was from -- programs group -- August '09 till June '10, till June 2010.
Q. Okay.
A. Just about a year.
Q. Now, once you prepared a dig package, did you ever know what the correlation was -- your group would know by procedure that somebody has to respond back to you saying this was a match, there was no match, or there is -- once you prepare dig package, are you divorced from the process?
A. If you're in the programs group, once the dig information comes in, the actual data that they found in the field also comes back, and that needs to be documented and recorded, which the programs group would do. And then they would pass that information back to either the corrosion group or the materials group so that they can look at a comparison of what was predicted to be there and what was actually there.
Q. So that'll come back to your group also, and somebody in your group then will disseminate that information to --
A. I'm not sure which of my groups you're talking about now, Ravi. If --
Q. No, I'm talking about --
A. Am I in my programs group chair?
Q. Yes. I mean, you're the one who's preparing the dig

package, right? I mean --
A. Yeah.
Q. -- your group is preparing the dig package?
A. Yeah. So we'd also --
Q. And that was --
A. -- look after -- that group would also look after the -- documenting the actuals and then passing that information back to the analysts in the other groups.
Q. To the requesting group?
A. Yup.
Q. Okay. Now, did the rupture location, do you recall if the calculations were made for that --
A. Go ahead. I'm just getting a glass of water.
Q. No, that's okay.
A. Sorry. Go ahead.
Q. Do you recall the rupture location calculations were made for the particular flaw that caused the rupture?
A. Well, I recall it now.
Q. You recall it now. Prior to the rupture --
A. I mean, you know, we spent a lot of time, of course, as soon as the rupture happened, the first thing you do is you dig into it.
Q. Right. Right. No, I'm talking prior --
A. What did we see there before?
Q. Right.

A. What did we calculate? So it's hard to -- it's almost impossible, like, for me to go back and say what do I remember about that location prior to the rupture? Probably nothing. I probably wouldn't remember anything about it, right?

Q. But would somebody have -- might have looked at a joint before to could make the calculations and --

A. Oh, for sure. I mean, we had -- as you know, we had identified corrosion and cracking features on that joint, and those would have been analyzed and those were analyzed, right, along with lots of others, right?

Q. And to your recollection, was that joint ever mentioned for anything to look at?

A. If my recollection is correct, and again, my recollection comes from having looked at this after the fact, right, I recall that that location had been -- we'd decided that we didn't require a dig at that location at that point in time. It didn't flunk any of our --

Q. Still be some kind of --

A. -- criteria, right? The corrosion depths were not -- there wasn't deep corrosion there. There was some cracking there, but the deeper cracks were short and the longer cracks were shallow, based on the information we had.

Q. But that records should be there someplace? I mean, even --

A. Oh, it is for sure, and you've got it.

Q. We have that?

A. Yeah.

MR. NICHOLSON: Um-hum.

MR. CHHATRE: Okay. All right.

MR. ZIMMERMAN: Yeah.

MR. CHHATRE: That's all for me. Thanks.

MR. JOHNSON: Before we go to Brian, just two things, Ravi. The NTSB was involved with the investigation on a Line 3 failure at Cohasset.

MR. CHHATRE: Whatever -- I was there, but I don't remember the line number. That was my --

MR. JOHNSON: Okay. That was Line 3.

MR. CHHATRE: Yeah. Cohasset, I remember because I was there.

MR. JOHNSON: Right. I do remember you there.

MR. CHHATRE: I was the one who got the pipe out.

MR. JOHNSON: We were trying to hide the pipe from you, but -- and then in 1997, we did replace 11 miles of Line 3 in North Dakota.

MR. CHHATRE: Replace, okay.

MR. JOHNSON: So those are -- those seem to be questions that -- that's before Tom's time. I thought I would fill that in.

MR. CHHATRE: I mean, if you had said Cohasset, it would have come back to me.

MR. JOHNSON: Okay.

MR. CHHATRE: After so many years, you know, I don't remember which line was Cohasset.

MR. JOHNSON: All right.

MR. CHHATRE: Yeah. I was there in Cohasset.

MR. NICHOLSON: Brian?

BY MR. PIERZINA:

Q. All right. So kind of, Tom, just following up on Ravi's recent questions, you -- so since that, have you been involved in the failure analysis of the defect?

A. I was involved -- well, from the day after it happened, I ended up out in the field, and I was involved in the analysis and the investigation from that point in time until close to the end, I guess, of 2010. And then once I transitioned to my new job as director of operation services, I pretty much got out of, then, doing much of that. I carried on with a few things just for continuity, but it was pretty much passing responsibilities to other people. But I was heavily involved from the time of the release until, you know, the end of the year.

Q. Okay. So -- and based on your involvement and observations, can you kind of characterize what your thoughts are on tool accuracy versus the defect as it may have existed in 2005 and/or the growth rate of the defect to the time of the (indiscernible)?

A. Yup. My recollection is that it's difficult for us to establish how accurate the tool was based on that defect because we don't really know how big it was when the tool went past it in 2005.

Q. Sure.

A. We know how big it was when we found it when it ruptured, but we don't know how big it was really in 2005. So it makes it difficult to decide if -- you know, we think one of two things probably happened: Either it grew at a very fast rate from what we saw in 2005, or it was actually much deeper in 2005 when the tool reported, or it was a combination of those two. And we weren't able to establish any means of determining which one of those was the more likely.

Even after looking at the feature in the metallurgical analysis, it wasn't possible to calculate an absolute crack growth rate. If we could have, you could then back it up to decide how big it was back in 2005. But that became difficult to do, so we really couldn't establish based on that feature how accurate the tool was in 2005.

We did have other -- I mean, looking at the other data from digs on that line, you know, that's typically how you get a better idea of what your tool actually is because there's always some scatter. Again, my recollection is that it wasn't bad for that line; it was sort of normal and reasonable scatter around a, you know, a central point, some a little oversized, some a little undersized, but -- and I don't remember the statistics. I'm sure we calculated them. And they've probably been updated since then because we've done a whole lot more digs since then.

Q. Sure.

A. But I haven't seen that data.

Q. The features on that joint that did not fail, how did they compare to the ILI calls?

A. You know what, Brian, I don't remember. We did look at the rest of the features on that joint because, actually, the deepest feature on the failure joint was upstream of where the rupture actually took place. And we found that feature and we split it open. I think we're probably in the same boat in trying to decide whether -- you know, how deep was it in 2005. We still don't really know that. We know how deep it was when we split it open. And I actually can't remember how deep it was compared to what the call was. I think the call was 25 to 40 at that upstream location.

MR. FOX: I've got that data.

MR. ZIMMERMAN: Yeah. I've seen it. I just don't remember.

MR. FOX: Yeah. I wrote it down just -- you had profiled it and got 29 percent --

MR. ZIMMERMAN: Yeah.

MR. FOX: -- off the profile. And, you know, when we broke it open in the lab, we got a depth of about 72 percent.

MR. ZIMMERMAN: Okay, so same thing, either it was -- either the ILI data grossly undersized it or it grew quickly or some combination thereof.

BY MR. PIERZINA:

Q. Okay. On the ILI results -- I'll call it the pipeline listing, what -- you know, it gives a girth weld number and all that stuff.

A. Um-hum.

Q. The report lists a wall thickness of .285 for that joint and many others.

A. Yeah.

Q. And the wall thickness was actually a .250 wall, correct?

A. The nominal wall thickness was .250.

Q. Okay. Do you know where the .285 comes from?

A. I believe it came from an ultrasonic corrosion run, and I'm not sure which one. But we have in the past used the -- what we consider the actual pipe wall thickness, whether it's a little bit bigger or a little bit lower than the nominal wall thickness because we're getting a reading right from the tool on what that wall thickness is. I think that's where the .285 came from. Now, I also think they may have changed their procedures to use nominal wall thickness instead. But when you're running a tool and getting actual measurements at every point along your line, it seems reasonable to use what you think is an actual wall thickness.

Q. So you believe it came from an ultrasonic wall thickness measurement tool run?

A. I think so.

Q. So I'm just trying to understand how that would play out. So you got -- because you have a pipe joint, and you may have thousands of actual wall thickness measurements on that joint. So you think for each feature listing it would -- some process would input an actual wall thickness measurement from a previous --

A. I actually think the ILI vendor gives us a wall thickness measurement for a joint. And does it vary along the joint? I can't remember. But for a given joint of pipe, the ILI vendor does give us a wall thickness measurement. And that would be in the pipe listing.

Q. Is it --

A. That's where the .285 would have come from, in that pipe listing.

Q. It would have come from where?

A. It would have come from the vendor taking an ultrasonic measurement.

Q. Okay, because -- well, no, so the --

A. I mean, they should -- they would know what the nominal was, and the nominal -- I mean, it can change along your line, but I think they used --

Q. Well, I guess that's why I'm curious of whether or not that might have been some type of administrative error, you know?

Could it be a, you know, a data entry error or --

A. My recollection it is not, but I could be wrong on that. I don't think that's the case. I think that .285 came from a wall thickness measurement from the vendor, but that's something that's obviously pretty easy to check.

Q. Okay. So -- and let's -- so the USCD tool has, you know, X number of angled ultrasonic sensors plus some straight beam, which would give you -- you know, for measuring wall thickness. So would --

A. And maybe that's what they used. I'm not sure.

Q. So in any case, that's not a value that comes from Enbridge, to your knowledge?

A. I don't think so. I mean, I think we tell them. I mean, what do we tell them about our line? We give them diameter. Do we give them a listing with wall thickness on it? I'm not sure if we tell them first or if they tell us first, to tell you the truth, understanding by the time -- for Line 3 and Line 6B, we've run lots of tools. So this information exists there someplace, right, and they usually start with some prior information about what's along the line in terms of diameter, wall thickness and that kind of thing.

Q. I think it's --

MR. JOHNSON: Yeah, Ryan will be up next, and he's probably better suited to address that.

MR. ZIMMERMAN: This is easy to figure out if you go back and look because, well, first of all, those guys can tell you whether or not they give them the nominal wall thicknesses or not. Again, my memory is that we -- that that value came from a measurement by the ILI vendor.

MR. PIERZINA: And I don't know how you even write this down as a IR, Jay, but I think it's really important as part of this investigation to understand the source of that.

MR. ZIMMERMAN: Of the .285 --

MR. PIERZINA: Right.

MR. ZIMMERMAN: Yup.

MR. NICHOLSON: And what was used in the subsequent analysis, if it was the .285 or --

MR. PIERZINA: Which -- and that's the next question.

MR. NICHOLSON: The depth of feature --

BY MR. PIERZINA:

Q. So what impact does that .285 have on the fitness-for-purpose calculations --

A. Yup.

Q. -- and fatigue growth, and that type of thing?

A. Yeah. And again, my recollection is on the analysis we would have done after the fact. You know, when we looked at that .285 and when we looked at the pipe that came out of the ditch and realized there was a disconnect there, we did go back and look at what the effect of that was. Again, my recollection is that wouldn't have triggered a dig, so it wouldn't have solved the problem. What would have triggered the dig is recognizing it was a stress corrosion crack, which would have kicked in other criteria in. But based on the fact that we hadn't -- it wasn't classified as an SCC, both the corrosion and the crack analysis would have given you a lower value for your RPR, but it would still have passed the check that it wouldn't have needed to be dug. That's my recollection.

Q. Right, especially in 2005. But if you got 20 percent less wall to deal with, then maybe your fatigue, you know, fatigue growth is much greater?

A. Yup. And I don't -- like I say, my recollection, Brian, from going through that analysis, I do recall wondering how big an effect that would have had. And my recollection was that it, you know, it's something we obviously need to deal with. We've got to be using the right wall thickness. But in this case, it wouldn't have made a difference -- not no difference. It would have changed your numbers, but it wouldn't have made a decision difference in terms of repairing that joint or not.

Q. Okay.

A. And again, that's something that's pretty straightforward to show the actual calculations of it.

Q. Okay. As far as the growth mechanism of the defect, is there -- from your observations, could you tell, you know, is this fatigue growth or SCC growth or corrosion fatigue or --

A. Well, it didn't look like typical fatigue crack growth that I've seen, not that I've seen lots of it, but the investigations I was involved in that were crack -- fatigue crack growth related and those that I'd looked at prior to my coming here just from looking at our -- at failure investigation reports, tended to be a single plane or defect that was over this -- not over the whole length of your rupture, but over the initiation site you might have 3 or 4 or 5 inches where the defect grew, and it would invariably be nearly a single plane. So this didn't look like that because there were many parallel planes that joined up when this thing failed. So from that point of view, it looked quite different to me than a regular fatigue growth.

So based on that, I assumed that this is an SCC mechanism, and, I mean, SCC is driven to some extent by cyclic fatigue, if you like, but it's a bit of a thing on its own in terms of what the -- of how it grows. Typically, people look at SCC as having some kind of linear growth rate even though they understand that's not quite true all the time. We'd also grow features -- any crack feature, we would grow by fatigue mechanisms because we know that can happen even if it starts out as an SCC feature, it can grow with a simple fatigue mechanism taking over.

How much of this was related to cycling and how much was not, I don't know, except that I do know that the cycling wasn't very heavy at that location. Downstream of pump station, so it's got higher pressures which, you know, if you've got cycling, things tend to be worse downstream of pump stations. But I think the cyclic -- the number of cycles and the magnitude of those amplitudes are worse elsewhere on that line than they are at Marshall.

Q. With fatigue and, you know, the Paris -- you know, Enbridge uses the Paris law --

A. Yep.

Q. -- you know, to grow out defects for fatigue, have you looked at the end of defects life to see whether or not that is a viable option for calculating fatigue life?

A. Well, I think the literature would tell you that as a fatigue crack grows, if you calculate crack depth versus the growth rate, that in its very early life it can be quite a flat curve. The center section is quite linear, indicating that the growth rate is constant in terms of the Paris constants that are in that law would not change over time until right near the end of the crack growth when they would take off again. But in conventional fatigue analysis you ignore the very end and the very start and you use that -- those constant properties for fatigue crack growth that are in that middle section. Now, that doesn't mean that fatigue crack growth is constant. It means the Paris laws are constant, that because you've got an exponent in there, the crack does grow more rapidly at the end of its life, even assuming constant Paris -- even assuming that the Paris constants don't change, you still predict faster growth at the end of a crack's life than you do at the beginning.

Q. Are there other alternatives to looking at crack growth rate on, you know, long -- you know, towards the end of the life of the defect?

A. No, there are more sophisticated things you can do, I guess, but that is reasonably sophisticated and fairly standard. And normally the faster crack growth rate that occurs at the end is occurring fast enough that you don't -- you're predicting your fatigue life and even though it's growing fairly fast right near the end, you're taking that into account still just based on the fact you're looking at how long this life could be. If it says 10 years, it might only -- it might take 9 years to grow, you know, two-thirds of that distance and grow very fast for the last third, but you're still putting a safety margin on that fatigue life when you'd expect not to have that close or that very, very rapid crack growth in the last little bit.

Q. Okay.

MR. PIERZINA: I'll pass it on to Matt, then -- have some questions.

MR. NICHOLSON: Matt Fox?

BY MR. FOX:

Q. It kind of sounds like there's -- the materials group and the corrosion group that are, you know, analyzing the results from the various tools that come back.

A. Yeah.

Q. Can you talk about interactions that occur between those groups in comparing data and is there any, you know, I guess, cross-transfer of data that occurs when determining, you know, what sites to dig? You've described the -- you know, once the dig package is generated you get the data from both, but is there any kind of, you know, pulling both -- all the data sets just to determine the severity and what -- where you want to do the dig and is there a value in doing that?

A. There is a value in doing that and we did some of that in the past. I can't tell you exactly how much of that we did, but typically the decisions were made reasonably independently because one check kind of -- the two checks didn't really affect each other. In terms of identifying SCC there are some -- you'd want to know if there is corrosion in the region, for instance, right?

Q. Um-hum.

A. So that kind of information is available. And we did do -- we have done some comparisons over time. I mean, before Marshall occurred, those groups would put their information together and try and decide what this meant. I can't tell you off the top of my head what the rigor around that was. I know that's certainly being looked at even more so now in terms of do we need to do something different when you see these things being coincident.

Q. So the first --

A. We didn't have a different model, right, that -- the crack model grew the crack and -- or evaluated the crack at its full depth.

Q. Right.

A. If there was some corrosion overlaying that, our understanding was that the tool vendor was giving us the actual remaining ligament so that it didn't really matter if there was a bit of corrosion there or not, you have the same crack depth to deal with. So that calculation should give you the right answer.

Q. Okay. I guess the one -- at least a benefit I could see would be, you know, in validating the information that the vendor's giving you or maybe going back per another iteration, you know, in a situation like at Marshall where you've got an identification as a crack, but then you see, well, we have corrosion there, does that -- you know, would that be something that might be a flag that would say let's go back to the vendor and check this data another round?

A. Maybe, and I'm not sure what advances they made in the last year in terms of pushing that forward, but, I mean, the tape-coat lines, you know, Line 3, Line 6A, Line 6B, typically have corrosion and crack. You don't have -- you usually don't have one without -- so they can co-exist. But, again, our experience was that you evaluate the corrosion based on the corrosion models and the crack based on the crack models and that gives you what you need, right; it gave us correct answers. And, you know, there would be certain things that would trigger the vendor to try and call something a stress corrosion crack and if it wasn't called out as a stress corrosion crack, I'm not sure if we'd gone back and put those two things together and made our own determinations in that regard or not. As I said, I'd have to look back at what our criteria was back then.

Q. You know, looking at stress corrosion cracks, I guess do you look at a crack growth rate when trying to, you know, determine an inspection interval or survivability until next inspection?

A. Yeah. If we think there's stress corrosion cracking there, there is a growth rate they put in, a linear growth rate for stress corrosion cracking to try and establish when that might be an issue in terms of when we should regard it. You know, to be honest, SCC wasn't high on my radar, I guess, then because we enjoy -- we had seen very little of it. It had -- I shouldn't say we had seen -- it had caused very few problems on our system. We had some environmental-assisted cracking in terms of speeding up the fatigue crack growth rates, but really hadn't seen much in the way of SCC in terms of failure (indiscernible).

Q. Okay. And then, you know, as far as determining that predicted growth rate, what sort of factors do you apply there? Is it variable or is it a fixed rate for a given system?

A. No, it's -- I guess it's variable and over time I'm not -- I do recall doing these calculations on Line 3, in fact, at another location where we were looking at fitness for service going forward, and we actually -- I think we backed out a potential crack growth rate, linear crack growth rate from SCC by looking at when these features popped up and speculating the time as to when they would have started and how deep they got to where they were and just projecting linear crack growth rate on that basis.

The SCC crack growth rates are more difficult to establish though and there's much less in the literature, you know, except for some round numbers that are thrown out there. So, it is something that will probably change, and I'm sure that we're still changing it.

Q. As far as, I guess, the factors that might go into that, is it -- would you consider maybe the depth and size of the feature or are there other factors, like --

A. In terms of --

Q. -- soil or, you know, the topography or any of those factors that go into determining what linear rate you're going to apply to an SCC feature?

A. I don't know that we've used soil models to try and predict -- or to try and influence what growth rate there might be. I know there's -- I know people have made livings on trying to have a little cook book that says I can look at your temperatures and your soil conditions and your this and that and tell you where to go dig for SCC.

Q. Right.

A. So, a bit of black magic, but I mean people have done that. TransCanada did a lot of that at one point in time because they had more of an issue with stress corrosion cracking. I don't think we've used that kind of input to help us with crack growth rate.

Q. Okay.

A. I think we've relied on some stuff that's in literature and some advice of consultants who work in that area.

Q. Okay. And then during the investigation we had talked about doing a groundwater study, you know, looking at water table levels and seeing if we could do some sort of correlation between that. And I was wondering what the results of that groundwater study were or if that was completed or --

A. Oh, again, I guess I'd have to go look in detail. My recollection is we didn't really have information at the site for groundwater levels, but we had groundwater fluctuations from some areas that were not all that far away --

Q. Okay.

A. -- but which told you what you might expect, that the water table fluctuates over some years. And we thought, well, okay, if it fluctuated there it probably fluctuated at the site. It was a site that was a transition between wet and dry and that could have been a cause for the growth rings we saw, but we weren't able to go back and say, no, there were 10 dry cycles and there's 10 rings and that matches up. We just weren't able to do that.

Q. Okay.

A. We also looked at the pressure data, by the way, and tried to find the same kind of patterns, right?

Q. Sure.

A. And, again, weren't successful.

Q. Yeah. I wonder if that groundwater study -- or if you have that available or is that something that can be provided?

A. Oh, write that down, I guess. Write down --

MR. NICHOLSON: What is it? You asked for the groundwater study --

MR. ZIMMERMAN: We did do some -- we did check into --

MR. NICHOLSON: At Marshall?

MR. ZIMMERMAN: Yeah.

MR. FOX: Yeah, in the area of Marshall looking at ground -- history of, you know, variation of groundwater levels.

MR. ZIMMERMAN: It might -- Matt, it might have got to the point where we had a shiny report from a consultant saying here's your groundwater study. It might have been somebody looking into what data there might be available and finding some for, you know, some wells or something or some river flow things that were close by and saying that doesn't really help us; we're not getting anywhere with this, so --

MR. NICHOLSON: Okay.

MR. ZIMMERMAN: But Jay can find out exactly what the story is.

MR. NICHOLSON: Okay.

MR. FOX: That's pretty much all I had.

MR. NICHOLSON: Jay?

BY MR. JOHNSON:

Q. I'm curious because, you know, I did not read the materials report. Have we determined a cause of the release?

A. Well, I mean, we've -- I mean, that's -- the final determination is yet to be, you know, but we have in the metallurgical report, in the draft report we have identified the features that we see there consistent with stress corrosion cracking, near neutral pH stress corrosion cracking.

Q. So it doesn't say it is, but it says that's what it looks like, right, more or less?

A. Yeah. At this point, yeah.

Q. Yeah. Okay. That was all I had. Thanks.

MR. NICHOLSON: Ravi?

BY MR. CHHATRE:

Q. I got a couple of questions. What is the probability of detection and identification of that particular line?

A. I'm sorry, what are what?

Q. What is the probability of detection and identification for that particular line that (indiscernible) crack? You know, no vendor gives 100 percent, so I'm thinking it's probably 80 or 90 percent. Is that reasonable or it's probably even lower than that, do you think?

A. I think the ILI vendors talk about probability of detection of 90 or 95 percent. It's hard to check because you don't know what you're going to find. I mean, your -- you find certain things and if you find some other things in the field that the tool didn't see, which happens, right, that gives you some indication of what the probability of detection is, but it's not all that conclusive, and it is hard to determine what the probability of detection is.

Q. And my next question then is, because it is not 100 percent, and I do not know any vendors, really, who gives you that, so still the possibility is that a tool can miss it --

A. Yeah.

Q. -- a tool can miscalculate it.

A. Yep.

Q. If there is a real basis for immediate repair, replacement, either, has Enbridge done anything to show that -- I mean, we don't need 10 percent of the cracks to miss, you only need one that can cause the rupture.

A. Yeah.

Q. And my question is, there are so many tools in your bag that was described earlier, was hydro ever considered as in between or the tool to check the current condition?

A. Hydro testing? Nope. We never consider hydro testing.

Q. And the reason given as to why it was discarded?

A. Because our experience is that even though we know the tools aren't perfect, they do miss some things, our experience was that if we run those tools frequently enough and analyze the data carefully and go and dig what we find, that that gives us adequate performance. And so, why -- you know, where is our safety margin coming from? Some of it's coming from the fact that you're digging everything that's below hydro, when in fact the operating pressures are below that, so that gives you some margin. The likelihood of missing a feature -- the combined likelihood of missing a feature, having it in a spot where the fluctuating stresses are high or where the environment is poor, you need a bunch of things piling up on top of each other to result in a failure. And our experience has been that if we run the tools frequently enough and do the digs, that keeps us on top of things. It doesn't provide you an absolute guarantee, but it's very difficult to have that -- you can't get that guarantee either. There's always a possibility of missing something.

And, of course, once you have a failure you wonder if you got that right in terms of how frequently you run the tools and what kind of error margin you put on them and that kind of thing. So that's something you need to think about as lines are getting older. But our experience has been that you can dig and you can find enough things and dig enough things and repair enough things that your failure frequency is low.

Q. I'm not going to get argumentative, but you said three ifs in ILI, that if the run is right, if you analyze the data right, if you do all these things right, it's going to give you a good result.

A. Yeah.

Q. So, there are three ifs, all things to go right to be confident. Now, my question is, since Marshall, will hydro be considered again as a tool to be considered, not let alone to be used?

A. Oh, I know we're talking -- you know, we don't discard hydro out of hand. We know it's a tool in our bag. And I think if you look at past literature that we've produced in reports and whatnot, we talk about hydro as being one of the things that is considered. But our experience was that -- and hydro's not fool-proof either. You can -- you know, there are instances and history of people hydroing a line and getting a failure 8 months later. So, it's not fool-proof either. And our -- again, our experience is that the ILI tools are -- that's the best technology to use and that's the best way to try and find defects and repair them before they fail. So, it doesn't mean we can't get into a situation where we think that hydro is necessary, but our judgment over the years has been that we run lots of ILI tools and that's the best way to try and find stuff.

Q. Okay. Thanks.

MR. NICHOLSON: Brian?

BY MR. PIERZINA:

Q. Yeah. Again, just to kind of follow up on that. So, it's a tool in the bag. I'm just wondering what would get Enbridge to decide that a hydro test was an appropriate assessment, then? You know, is it X number of failures? Is it, you know -- I'm just -- I'm curious what it would take.

A. I think if you lose some faith in your ability to run tools and find defects and keep your failure frequency low, then you'd consider hydro testing. Understanding that when you do hydro test it's not going to eliminate your failures necessarily. There's always a statistical probability that you can get a failure. But I don't say that -- I'm not trying to tell you that hydro testing is not something that should ever be done. I don't believe that. There is a place for it. Our tendency has been not to do that because we've felt these other tools are better and that that's where the real good technology is. That doesn't mean it shouldn't be considered and it shouldn't be done in some locations. And your criteria for when you might consider that can change over time as well based on your confidence in the way your program's been working.

We're probably not alone in industry in saying that hydro tests are not the best way to do things. I think there's lots of documents written by reputable consultants, C-FER being one of them, the guys from CC Technology as being -- or DNV being another, who would make those same statements. But they always qualify the statements, right, but other people have said that.

And, in fact, there are lots of people right now advocating not doing a hydro test on a brand new line because if you do your quality assurance, if you have a high quality assurance program and if you're running tools during the life of the line and maybe even right after it's installed, that you don't need to do hydro test. I'm not going to get into that debate either because that's a hot debate for lots of people to have and, you know, I'm not sure where I'd be on that side of the debate.

I think you're probably never going to get away from initial hydro test, but, you know, what role should hydro testing play in the pipelines across North America? Should we be changing -- you know, because of these recent failures, should we be doing lots more hydro tests than we did? Maybe. But it's not going to completely solve the problem, right? And as the tools get better, you make a better argument for not doing the hydro test, but I acknowledge it is an argument you can have for sure.

MR. JOHNSON: Is the industry doing it? I mean, you asked the question. Ravi asked the question.

MR. CHHATRE: No, my question was basically I haven't seen any documentation so far -- that's not saying it doesn't exist -- that hydro was considered by Enbridge and then decided not to do it. I see documentation that ILI was considered, different ILI techniques were considered.

MR. ZIMMERMAN: Yeah.

BY MR. CHHATRE:

Q. I have not seen so far any documentation that says hydro was considered and for these reasons that was not --

A. The reasons would all be the same, right, that we think the ILI tools were better.

Q. Again, I haven't seen any documentation is what I'm saying. I'm not saying there are no reasons.

A. Yeah.

Q. I'm just saying I haven't seen any thought process that went into making that decision. That's all I'm saying.

A. It probably didn't get written down. I mean, I think every time we run a tool and decided to make repairs, we probably don't have a form that says did you think about hydro test, right? I mean, people know it's a tool and we talk about it being a tool, but it is quite obvious that Enbridge's bias has been to consider that not the best tool and to consider the ILI the best tool. So that's where we lean, for sure, for right or wrong. You know, you can argue that we should have been thinking about hydro test more often and doing them more often. You can take that approach, but that -- our position was that ILI tool is the best technology, so that's what we always gravitated towards.

Q. I'm not even arguing that. I guess my -- the only point I was trying to make is I haven't seen documentation that says you guys did consider it and then went to the bias of ILI. I'm not even questioning -- I haven't seen anything that says hydro was considered.

A. On Line 6B for that set of tool runs, there probably -- that documentation probably doesn't exist because we probably didn't think about it particularly for that. But you can go back into Enbridge documents that talk about our ILI management and say that hydro testing is one of the tools in the box. So we know it's there. People do understand that's a possibility, but almost our default is to say, no, the ILI tools are better. How many times do you need to think about that before you -- you know, before that's just the track you take? Should that change? Maybe, right? Like I said, that's a -- once you have a bad failure, you start to question, gee, are we thinking about this the right way or not, right? So, but I have to admit that hydro testing wasn't one of the things that was high on our list because we thought these other things were better.

MR. NICHOLSON: I got a few.

BY MR. NICHOLSON:

Q. So let's just continue that thread. You're saying the ILI tools were your tool of choice for cracks. How many different ILI tools were being run for cracks knowing it's got some potential to mischaracterize or even miss defects? You must run different types of technology, right, just to overlap?

A. I think our -- I think the USCD tool is our primary crack tool. You run it -- I mean, we ran it in 2005 and again in 2007, I think, and again in 2010. So, I mean, we do, do multiple runs. There are some other vendors with crack tools, but when you build up a history with one type of tool you supposedly know more about it and have more confidence in it. I'd have to look and see what else we ran and that. I mean, we've run other people's crack tools, for sure, but we don't run multiple crack tools in the same line one right after the other. Maybe we will be, but, you know, we weren't at that time because we thought USCD was the best crack tool and we had the most experience with it and we didn't just run it once every 10 years, we ran it -- on some lines we did, but on that line we ran it --

Q. 2007, was that the USCD tool?

MR. PIERZINA: No.

MR. NICHOLSON: No.

MR. ZIMMERMAN: Oh, I could be wrong. Was that WM in 2007?

BY MR. NICHOLSON:

Q. That was MFL.

A. Okay. So we ran it 2005 and again 2010. So that's our -- that's a 5-year interval, which -- again, going back in history, would be fairly short, right? I think we typically were thinking of 10 years between crack runs and we've shortened it up on Line 6B, and on 3 as well, we run crack tools more frequently and had even before the failure.

Q. Why was that?

A. Just because, again, the tape-coated lines that tend to have cracking problems, we don't wait 10 years; we run them more frequently.

Q. Okay. So you did say -- I heard you say that, going back to SCC, you said there's never been a failure on a line caused by SCC as far as we know.

A. I also said that there actually -- I mean, if you open up the National Energy Board document on SCC, which you're familiar with, and look at their list in the back, I think there is one Enbridge failure that's listed an SCC failure. But if you go back and look at the investigation reports, they don't actually mention it as being an SCC report. So there's some --

Q. Right.

A. -- there was some difference of opinion on what that was. And it did look -- when you look at the details of it, it did look -- didn't look exactly like this. It was deeper corrosion and some cracking. So, to me, there was some debate is that an SCC? Well, maybe it is. I won't dispute that. Somebody will (indiscernible) --

Q. But SCC is prevalent on your lines. You've seen it, right? When you say crack field --

A. There is -- there are crack fields that we find on the line.

Q. And you confirm it with digs?

A. But they tend not to be -- they had tended not to be deep or severe, and I hadn't seen a failure as a result of SCC.

Q. So you just buff them out and move on?

A. If they're really shallow you do, or you can sleeve.

Q. Okay.

A. If it's too extensive to buff out or if there's some deep ones, you can also sleeve.

Q. Okay. So you're not immune to SCC; it does exist?

A. No. Oh, yeah, it exists for sure. We're not immune to it. It just hadn't been one of the things that had caused failures on our system.

Q. And because of that, it almost sounds when I hear you talk like it's almost written off or it's considered maybe a lower risk than some of your other fatigue type cracks or corrosion.

A. If you mean by writing it off that we didn't watch for it, that's not true; we did watch for it. If somebody asked me prior to Marshall if I thought SCC was a risk on our line, I'd say no, we've got SCC but we haven't had failures. The big risk is -- again, looking at our statistics, we've had -- most of our ruptures would probably be caused by fatigue cracks at long seams. And that's -- I'm going to guess that's probably 75 or 80 percent of the failures we've had. So, to me, that was the higher risk.

I'd have said SCC was a low risk because I just hadn't seen it resulting in failures. I know it exists and our guys had programs for looking for it and you realize it's going to get worse over time, so people would watch for it and we'd always -- even going into a corrosion dig, you always had people watching for SCC and reporting it and whatnot. So, it's not that we ignored it, but did we think it was a lower risk? Sure we thought it was a lower risk because we hadn't had failures.

Q. You mentioned that there were some reports out there where people had talked about -- talking about, I think it's susceptibility and, you know, temperature, other contributing factors that could give you SCC. Those reports, to me, look pretty good. CFA's (ph.) got one, I think, and as you mentioned there was --

A. National Energy Board.

Q. -- National Energy Board.

A. Yep.

Q. They look pretty good, I thought.

A. They are pretty good.

Q. And when I read through, at least the CFA report, I thought I saw a lot of the indicators that we saw at Marshall. Your seam was at 3:00, 1969 vintage pipe, DSAW, wrinkled tape coating, three-quarters of a mile downstream from a pump station, marshy environment. When you put those kind of indicators together with -- you know, when I look at the ILI data, it's striking. There's a lot of general corrosion right there on that segment.

A. Yeah.

Q. And very long crack indications. I know some of this is hindsight. Can't you just -- can't you put those known factors that contribute to SCC side by side with this MFL and crack tool runs, say, hey, maybe there's something here we need to be looking at that's other than a fatigue crack?

A. Yeah. In hindsight you can do that. The question is should we have known at the time that that was the case? I mean, I think we've certainly got lots of places on Line 3 and 6B and 6A where we're downstream of pump stations, where we've got some corrosion, where we've got wrinkled tape, and we don't have any SCC. And you even know from Matt -- Matt Fox can tell you from looking at the joints that we pulled out at the failure site, you go across the girth weld with exactly the same conditions on the downstream joint of pipe as were on the upstream joint of pipe in terms of the wrinkled coating and the corrosion along the weld seam and the location of the -- I don't remember where the long seam was on that one, but -- and there was no SCC whatsoever. So --

MR. JOHNSON: It's 5:00.

UNIDENTIFIED SPEAKER: Oh, 5:00 --

MR. ZIMMERMAN: Yeah. So, you know, we've -- all those same triggers are there in lots of places where we don't see SCC. You know, should we be -- should our criteria change now? Well, maybe they should, right, when -- like I said, when you have a failure like this, you start looking at all of your criteria, decide if you need to make changes. But we also have to be careful of looking what happened here and saying, well, can't you just take all the things that were common here and apply them elsewhere and go and dig those areas? Well, that's a good thing to do if it comes up with a manageable number to dig, but if it produces all kinds of stuff, then you have to wonder -- and if you don't find the SCC in those places typically, you have to wonder if that's the right way to do it.

BY MR. NICHOLSON:

Q. Just a couple more. How you analyze SCC, is that done -- what program are you using? Is that fitness for service? Is that the same as fatigue?

A. I think -- yeah, I think a crack is a crack is a crack, right? So, it's got a depth and it's got a length and it's got a failure pressure, and it doesn't much matter if it's SCC or if it's fatigue. The growth mechanisms are different, so we grow those cracks differently. For SCC it's linear growth rate and for fatigue it's an increasing growth rate based on the Paris model. But in terms of determining a failure pressure, the model is the same.

Q. Okay. So, you don't try and monitor SCC through its stages, stage 1, stage -- I mean, it sounds like you almost treat it as a stage 2?

A. Correct.

Q. Okay.

A. Yeah. And I think that's pretty common.

Q. Okay. Regardless of depth of feature, it doesn't change from that?

A. Well, by the time it's deep enough to worry about, you're probably going to dig it up anyway.

Q. And just to confirm then that your fitness for service is your CorLAS model?

A. CorLAS is the model that's frequently used, yes. We've used -- we have used different models and multiple models. I think before CorLAS was around we used Kiefner's -- whatever he calls his model that was commonly used in industry, and then CorLAS came out with theirs and there are others around too, and we've dabbled with a bunch of them, but CorLAS is the thing we've used as our workhorse over the last years. It has been identified as one of the more accurate models.

Q. And that's based on API 579; is that right?

A. No, actually, they've sort of got their -- I mean, it's the same basic metallurgical understanding, but they've got their own little twist on the way they do things.

Q. Okay.

A. They use some kind of J integral thing that it's hard to sort out from looking at their actual papers.

MR. NICHOLSON: Someone's going to go through that, right? We get to see that model this week, Jay, right?

MR. JOHNSON: Yes.

MR. NICHOLSON: Who's doing that? Ryan?

MR. JOHNSON: It might be. He's up next, but we got to turn Tom loose here, so --

MR. NICHOLSON: Yeah. Okay, I'm finished. Jay, anything?

MR. JOHNSON: No. No, that's it.

MR. NICHOLSON: Matt Fox? Okay.

MR. PIERZINA: Okay. Thanks, Tom.

MR. NICHOLSON: We'll conclude this interview. Off the record.

(Whereupon, the interview was concluded.)

CERTIFICATE

This is to certify that the attached proceeding before the

NATIONAL TRANSPORTATION SAFETY BOARD

| | |
|---|---|
| IN THE MATTER OF: | ENBRIDGE - LINE 6B RUPTURE IN MARSHALL, MICHIGAN<br>Interview of Tom Zimmerman |
| DOCKET NUMBER: | DCA-10-MP-007 |
| PLACE: | Edmonton, Alberta, Canada |
| DATE: | December 5, 2011 |

was held according to the record, and that this is the original, complete, true and accurate transcript which has been compared to the recording.

__________________________
Danielle VanRiper
Transcriber